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: 2014

March 2015

Executive Summary

This Summary Report is being submitted in accordance with the terms of the CCS Funding Agreement – Quest Project dated June 24, 2011 between Her Majesty the Queen in Right of Alberta and Shell Canada Energy, as operator of the Project and as agent for and on behalf of the AOSP Joint Venture and its participants, comprised of Shell Canada Energy, Chevron Canada Limited, and Marathon Oil Canada Corporation, as amended.

The purpose of the 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. Up to 1.2 Mt/a of CO_2 will be captured, representing greater than 35% capture of the CO_2 produced from the Scotford Upgrader. The Project 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 Project has completed the Define phase whereby the Project scope is finalized and the Front End Engineering and Design (FEED) is completed. The project is now in the Execute Phase and will be until early 2015.

In 2014, all 3 Wells were ready for Operation although permitting activities remained. The D51 and D65 amendment for the Wells 5-35 and 7-11 were submitted and are awaiting AER approval. Storage properties of the BCS complex have been validated through analysis of the data obtained from drilling five wells into the BCS formation (two appraisal and three injection wells). Risks of CO_2 containment loss are comprehensively detailed along with mitigation activities in the Measurement Monitoring and Verification (MMV) plan.

A detailed MMV plan has been developed and adapted. All pre-injection activities have not been initiated with the last activity being the Microseismic monitoring. In the future, the MMV Plan will be integrated with the GHG reporting system in place at the Scotford Upgrader.

The last module was received in August 2014 for the Capture Facility at Scotford. The pipeline construction was finalized with remaining groundwork after the winter remaining to clean-up the right of way in line with regulatory and stakeholder expectations.

The Operations Readiness activities continue with preparation of both Operations and Maintenance procedures and ramping up the hiring and onboarding of new staff and contractors. All procedures were completed in 2014, pre-start up reviews were conducted, training of Operations and Maintenance staff were significantly progressed, and Ready For Start Up deliverables were well underway.

Shell continues to conduct open houses for the local communities including two in the last part of October at Thorhild and Radway. We continued to engage with local governments updating them on our progress. We continued to engage with numerous industry and non government associations for sharing our knowledge.

The current estimate of capital costs is about $811 million, which is a reduction from our original AFE. The current estimate of operating costs is about $41 million per year. Project revenues will be zero during construction and will be $27 million per year during

operations from the sale of carbon credits at 2014 carbon prices plus those from the ADOE Funding Agreement.

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

- Holding schedule in line with Final Investment Decision.
- All pre-injection MMV activities completed.
- Near 100% complete on construction activities for the Capture facility including successful attainment of the first and last module milestones.
- 100% Mechanical completion of the pipeline.
- 100% completion of the Operating Procedures.
- Near 100% completion on the major engineering work
- Continued execution of the MMV HBMP activities.
- Maintaining local support through the extensive stakeholder engagement activities
- Continued engagement of the Community Advisory Panel for the Thorhild County Stakeholders.
- International engagements with the Global CCS Institute to support Public Engagement, knowledge sharing activities at the CCUS in Pittsburgh, MIT in Boston, and numerous tours to the Scotford facility.
- Initiated discussions with the US DOE to develop and deploy MMV technologies for use on Quest.

Project challenges included:

- Maintaining good stakeholder relationships with the neighbours, with the significant construction in the area posed by Shell and other Operating companies for their pipeline construction. This includes closing out any related right of way clean up issues and ground water monitoring issues.
- Containing cost pressures from Pipeline construction.
- Integration into Scotford in a progressively challenging economic environment due to the decreasing oil price.

These challenges have been managed successfully with the result that the Quest team remains on track for a 2015 startup.

Within the next reporting period we are expecting to have completed Commercial Operations tests successfully and moved fully into the Operate phase of the project. Stakeholder engagement activities will continue to enable local residents to maintain their awareness of Project progress and our activities to safeguard them.

Table of Contents

List of Tables

List of Figures

Abbreviations

2D	2-Dimensional
3D	3-Dimensional
4D	4-Dimensional
AER	Alberta Energy Regulator
AEW	Alberta Environment and Water
AFN	Alexander First Nation
AGS	Alberta Geological Survey
AOI	Area of Interest
AOSP	Athabasca Oil Sands Project
ARC	Alberta Research Council
ASLB	approved sequestration lease boundary
ASRD	Alberta Sustainable Resources Development
BCS	Basal Cambrian Sands
BHP	bottom-hole pressure
BLCN	Beaver Lake Cree Nation
CCS	carbon capture and storage
CEAA	*Canadian Environmental Assessment Act*
CRC	Calgary Research Center
CSU	Commissioning & Start Up
D51	Directive 51 application
D56	Directive 56 application
D65	Directive 65 application
ERCB	Energy Resources Conservation Board
FEED	Front End Engineering and Design
FEP	fracture extension pressure
FID	Final Investment Decision
GHG	greenhouse gases
HBMP	Hydrosphere & Biosphere Monitoring Plan
HMUs	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 Assessment
ROW	right-of way
SLCN	Saddle Lake Cree Nation
TEG	triethylene glycol
UMS	Upper Marine Siltstone
VSP	vertical seismic profile
WCSB	Western Canada Sedimentary Basin

WIIP.................... water initially in place

1 Overall Facility Design

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 for the Project is to remove CO_2 from the process gas streams of the three hydrogen-manufacturing units (HMUs), which are a part of the Scotford Upgrader infrastructure, by using amine technology, and to dehydrate and compress the captured CO_2 to a dense-phase state for efficient pipeline transportation to the subsurface storage area.

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

1.2 Design Scope

The design scope for the facilities includes:

- 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
- Three injection wells

1.3 ORM Design Framework and Project Maturity

The design framework followed by the 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. Deliverables for each phase are reviewed to ensure proper quality before proceeding to the next phase.

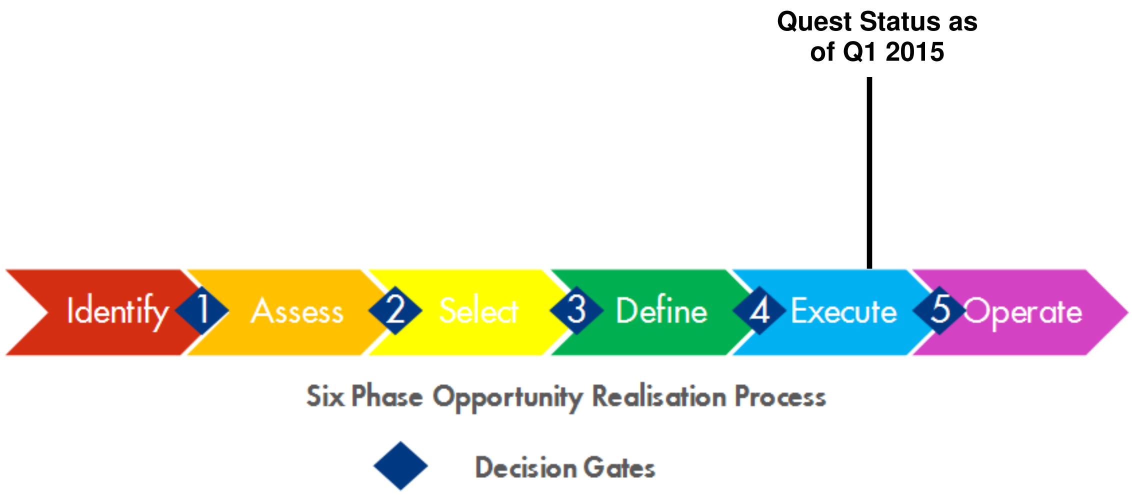


Figure 1-1: ORM Phases with current Project Maturity

The Project technical activities in the past year correspond with the Execute Phase, specifically the construction of the pipeline and wellsites, the fabrication of modules, the installation of modules at Scotford, and stick-built construction at Scotford.

In December 2011, Shell made a risk-based decision to proceed into the Execute Phase before final regulatory approval in order to hold to the Project schedule. The Shell Executive Committee, followed by the Joint Venture partners, approved the FID of the Project in the summer of 2012 after the ERCB Decision Report on the hearing was received. This approval was announced in early September after formal receipt of the various regulatory approvals.

The Execute Phase will conclude after the facility has been successfully commissioned and started up, and subsequently handed over to Shell Scotford for sustained operations. This is planned to occur in the latter half of 2015.

1.4 Facility Locations and Plot Plans

The Project facility locations are shown in *Figure 1-2: Project Facility Locations*.

The capture facility is situated within the Scotford Upgrader. The pipeline routing is shown as the dotted line in *Figure 1-2* and the final well count and locations are labeled appropriately.

The capture unit is located adjacent to two of the Scotford Upgrader HMU's. See *Figure 1-3: Capture Unit Location Schematic* for a schematic view of the capture unit location.

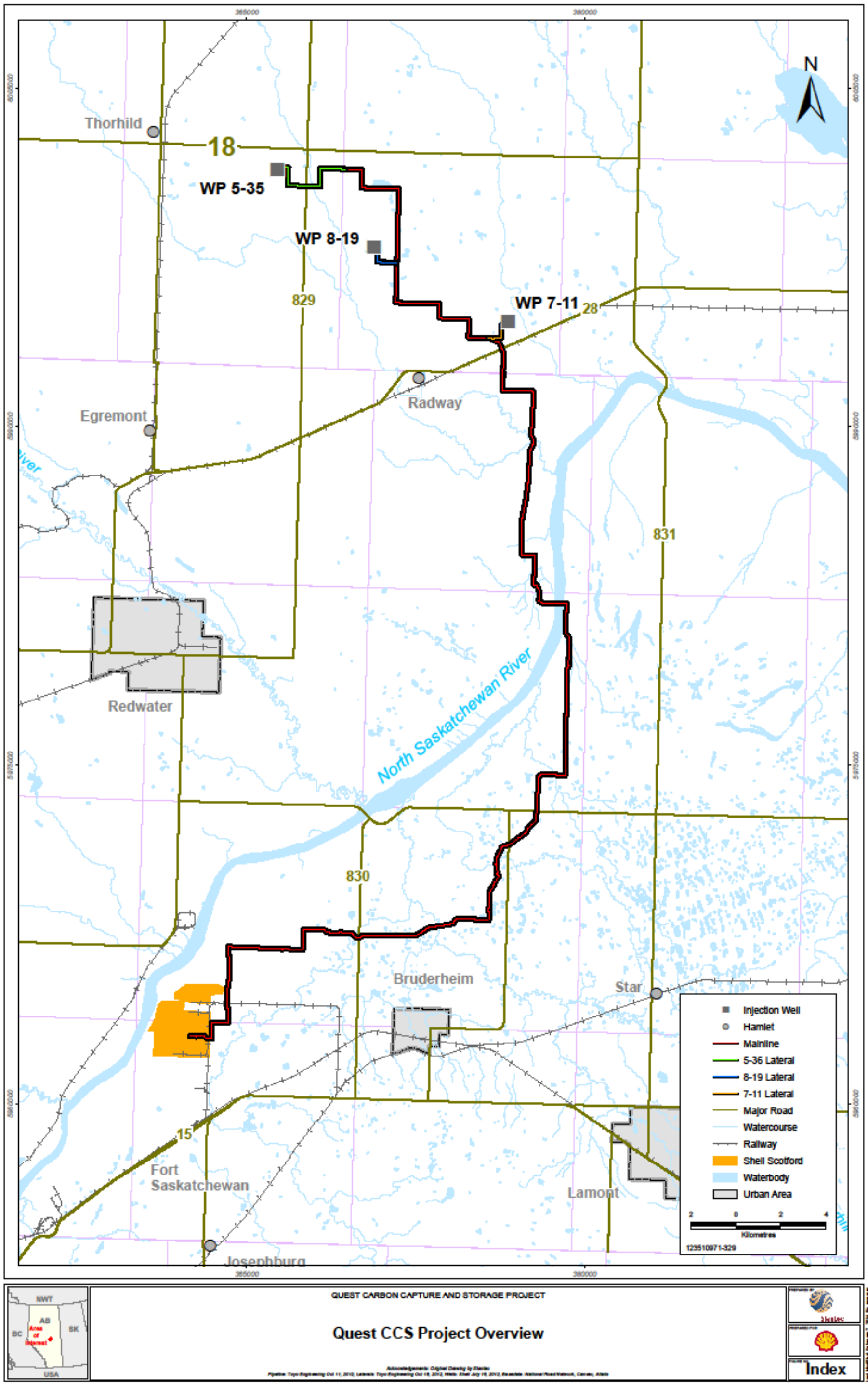


Figure 1-2: Project Facility Locations

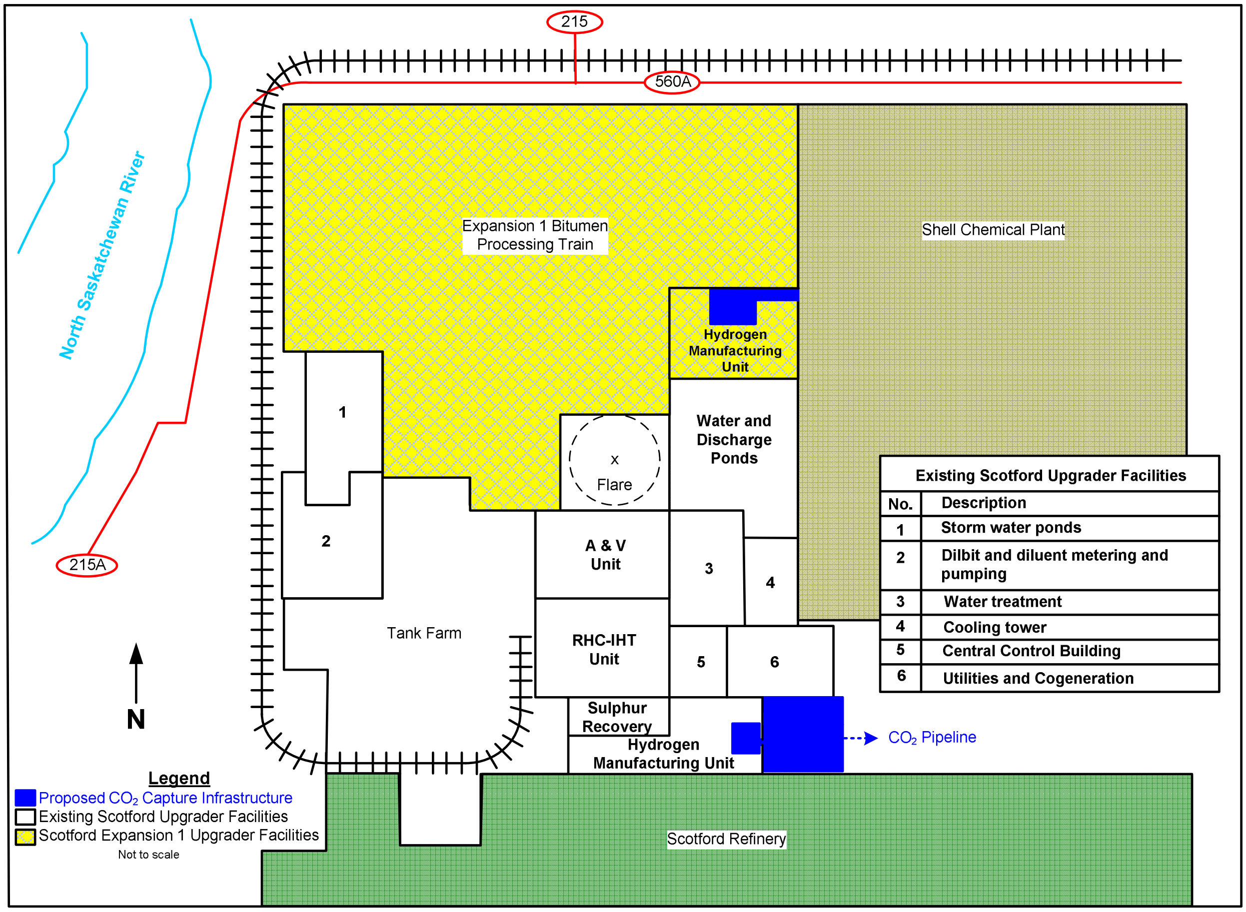


Figure 1-3: Capture Unit Location Schematic

Extensive work was done during the Define Phase to validate the BCS formation CO_2 storage properties and to establish the optimum storage location. *Figure 1-4* shows the BCS storage complex.

The figure shows the approved Sequestration Lease Area (SLA), formerly called the area of interest [AOI], which had a different boundary) for the storage area. Criteria for this selection included the BCS rock properties within the location, minimizing the number of legacy wells into the BCS storage complex (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). Section 3 contains additional details on the selection and properties of the BCS formation.

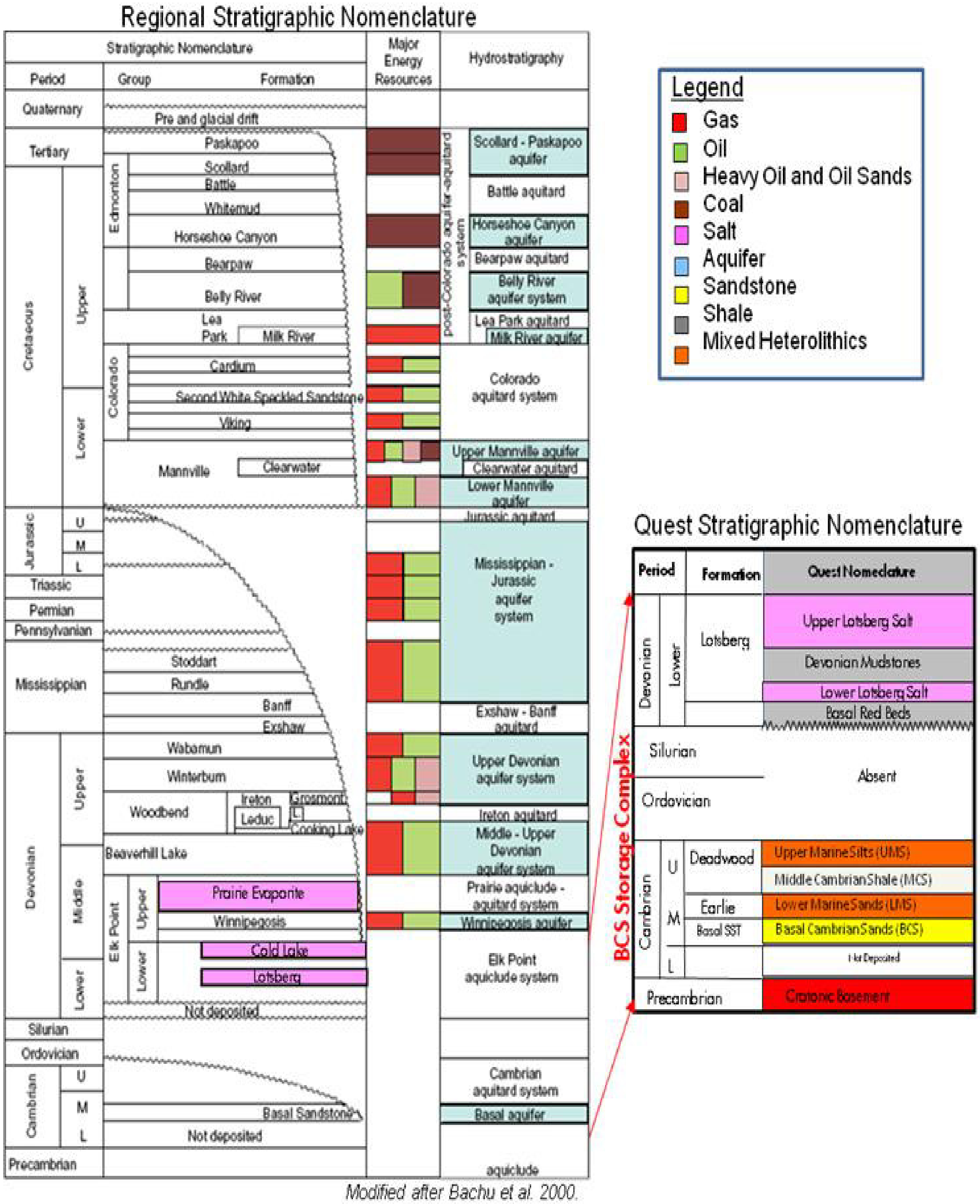


Figure 1-4: BCS Storage Complex within the Regional Stratigraph

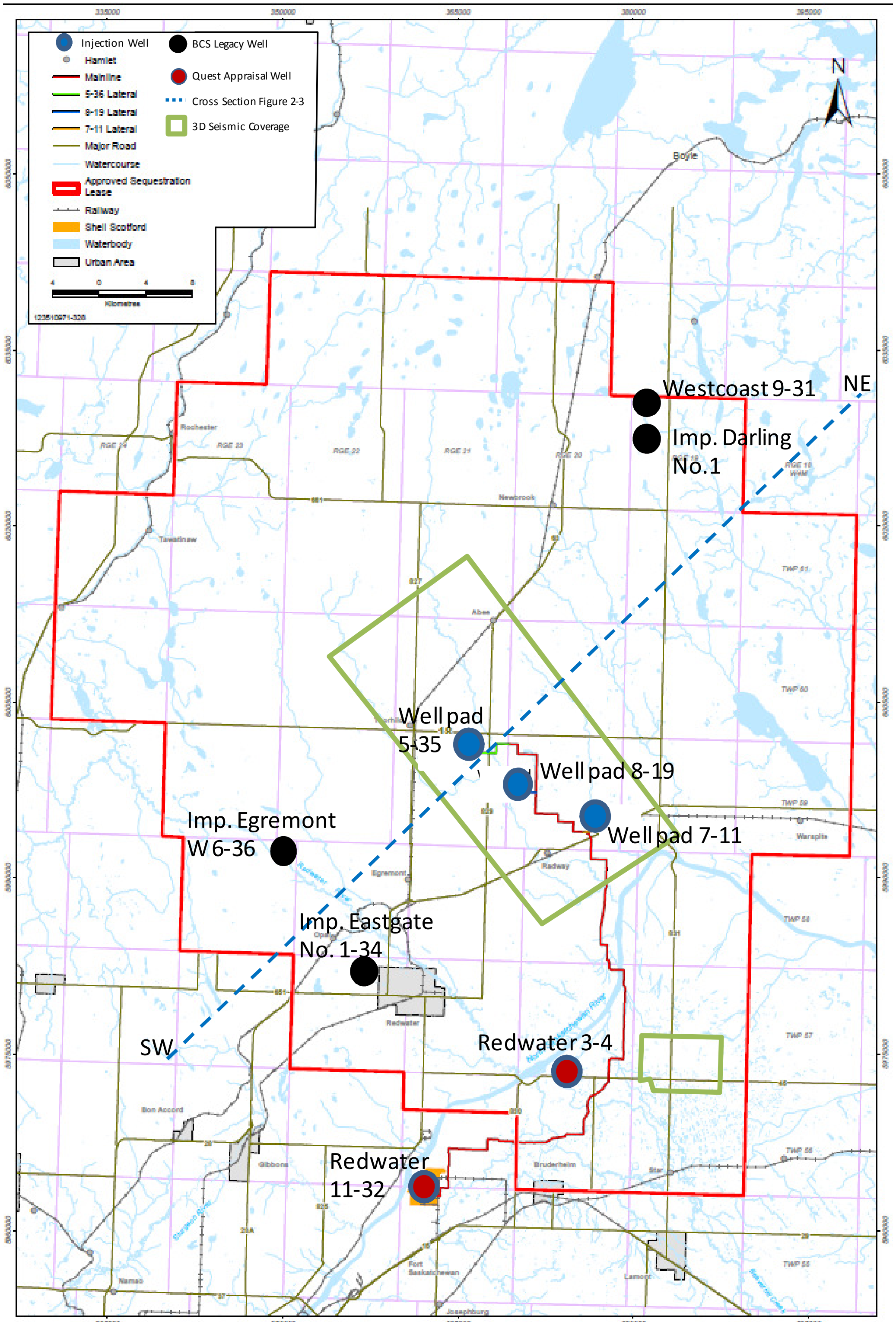


Figure 1-5: Project Components and Sequestration Lease Area

A critical requirement of the Project was that the storage area 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 in May 2011 for the exclusive use by Shell of the BCS formation for the Project within the SLA is 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 Project, which would raise the required injection pressures and threaten the Project objectives.

1.5 Process Design

The process flow scheme for the Project is shown in *Figure 1-6.*

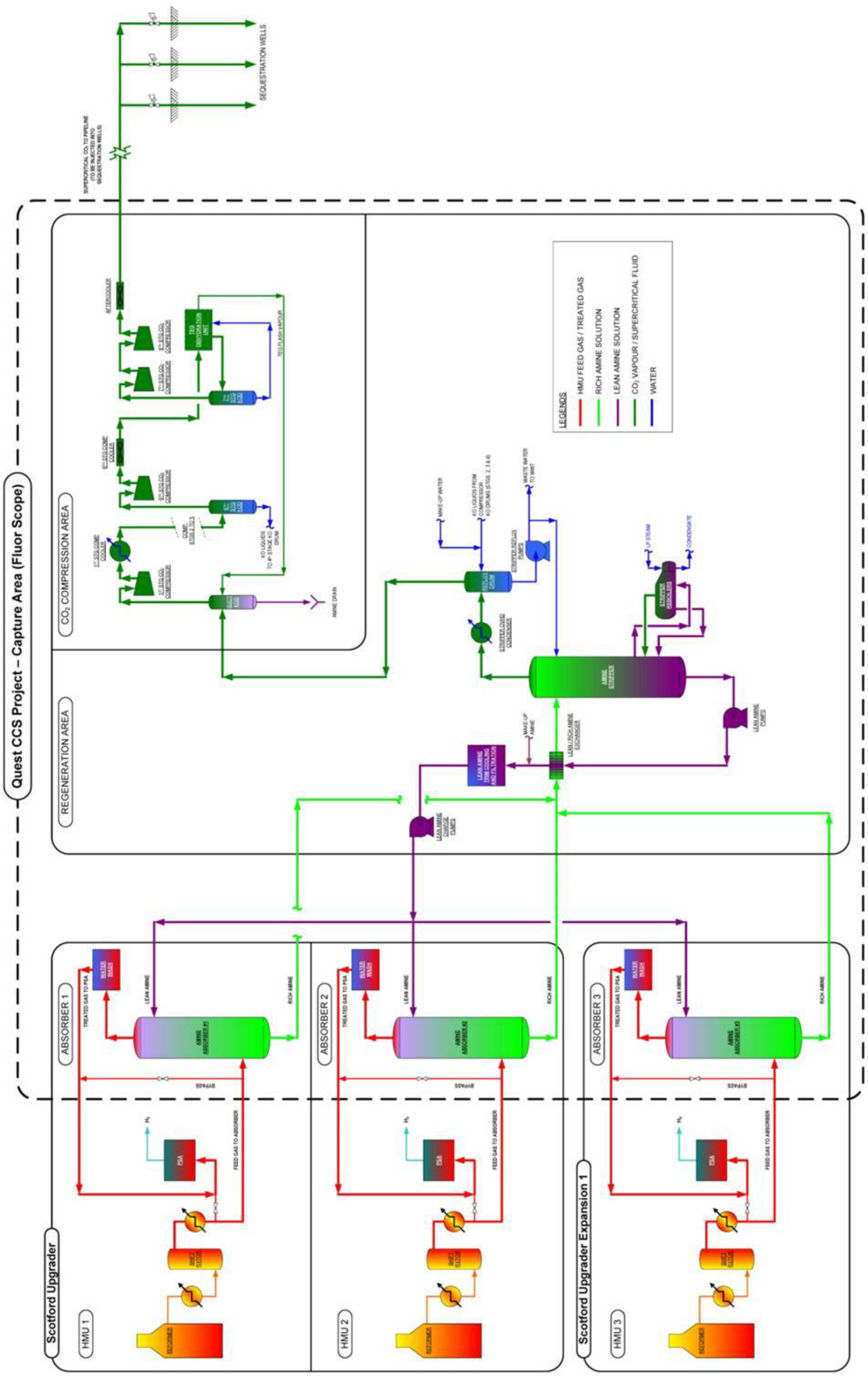


Figure 1-6: Capture and Compression Process Design

Process Description

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 kPa(g). 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 1ppmw; 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 backpressure controller, which reduces two-phase flow in the line. The pressure is let down across the 2 x 50% backpressure 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 kPa(g). 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. The 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 further cooled by the lean amine coolers, which are shell and tube exchangers. The lean amine is cooled to its 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 minimal 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. During major turnarounds, when the entire system needs to be de-inventoried, a temporary tank will be required for the duration of the turnaround. 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 temperature in the tank. A nitrogen blanketing system maintains an inert atmosphere in the tank, which prevents degradation of the amine. The storage tanks will have ventilation to the 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. 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 kPa(g).). Since H_2 impurity greater than 5% may lead to potential surge situations in the compressor the compressor can be put into 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 fifth and sixth stage KO drums and the TEG inlet scrubber are routed to the compressor fourth 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 seventh 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 kPa(a). Consequently, an interstage pressure in the 5,000 kPa(a) range is specified for the compressor. This pressure is expected to be obtained at the compressor sixth 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 kPa(g) to 11,000 kPa(g), 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 the 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 wells.

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 kPa(g). 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 CO_2 pipeline as per CSA Z662 transporting the dehydrated, compressed, and dense-phase CO_2 from the capture facility to the injection wells. 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, with small changes in the Execute 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 CO_2 storage 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 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 crosses the North Saskatchewan River and continues north along an existing pipeline corridor for approximately 10 km, where the route angles to the northwest to the endpoint well, approximately 8 km north of the County of Thorhild, Alberta. The total pipeline length is 64 km.

This pipeline crosses the Counties of Strathcona, Sturgeon, Lamont and Thorhild.

There are 336 crossings by the pipeline:

- 55 road crossings
- 4 railroad crossings
- 19 watercourse crossings
- 194 pipeline crossings
- 32 cable crossings
- 32 overhead crossing

CO2 Storage

The storage facilities design and construction activities consist of:

- The drilling and completion of three 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 three deep observation wells
- The conversion of Redwater Well 3-4 to a deep BCS / Cooking Lake pressure monitoring well
- The drilling of nine groundwater wells.

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 for the benefit to scheduling and cost.

The modularization approach for the Project is to use Fluor Third Generation Modular℠ 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℠ execution is a modular design and construction execution method that is different from the traditional truckable modular construction execution methods because 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.

The module's boundaries were reflected in the three-dimensional model and matured through 30%, 60% and 90% model reviews of multi-disciplinary teams as well as safety, operability and maintainability reviews. The weight and dimensions of each model were accurately tracked through the process to ensure compliance with the maximum weight and size restrictions for the heavy load corridor. The structural steel manufacturing and fabrication for the modules was bid, awarded and manufacture of the steel commenced in 2012. In August of 2012, a request for proposal went out to five pre-qualified module yard contractors on the heavy load corridor. Proposals were received in October and evaluated thereafter. Award recommendations were made to Shell's contract board in mid-January 2013 followed by approval by the Joint Venture Executive Committee late in January 2013. The contract was signed in February. Fabrications of the structural steel for the modules started in early February and in mid-February, kick off meetings were held in the module yard to start the preparation work to start module pipe fabrication and module construction. The module assembly was completed and all modules were transported to site by mid July 2014.

2 Facility Construction Schedule

At the end of 2014, construction was 98% complete. The 2014 pitstop on HMU #3 allowed for process tie-ins, installation of the Flue Gas Recycle and changing out of the burners in the steam methane reformer. The 2015 plant turnaround is scheduled for Q2, which will enable similar work to be done on HMU #1. See *Figure 2-1* for the overall construction schedule.

At the Capture site, the main stripper tower dressing was complete in early March 2014 followed by lifting it onto its foundation in mid-March. Absorber towers #1 and #2 dressing was complete by the third week in March and set on their foundations the last week of March. The compressor and motor were placed in the compressor building in May and June respectively. Pipe fabrication was completed in July as well as the module assembly. The last module arrived at the Scotford site in mid-July and all modules were set in place by mid-August. Interconnecting piping commenced as soon as modules or equipment were set and completed in mid- December. The main electrical substation for the compressor was one of the modules set in second quarter; it was connected and energized in November. The compressor motor was bumped for the first time in December, though a full run-in was not completed by end-2014.

Pipeline main line welding was complete by the end of March 2014 with all tie-ins and backfilling complete at the end of April. Hydrotesting of the pipeline was completed in July followed by cleaning and drying of the line in August. The Line Break valves were installed after completion of the cleaning of the line. Wellsite skids fabrication was completed in August and final installation in September. All the electrical and instrumentation work was completed and site turned over to operations in October. The pipeline was preserved with nitrogen in early October.

Turnover of systems started in July 2014 and by end-December 75 of 134 were turned over to operations. The remaining systems are to be turned over by February 2015. Commissioning started in October 2014 when there were sufficient systems handed over to sustain a commissioning workforce. Commissioning will be ongoing throughout Q1 2015, and will not be complete until after the final tie-ins to HMU #1 are implemented during the Q2 2015 turnaround.

Construction activities have been completed to support the deterministic start up dates. All construction activities have been phased to meet the planned startup in Q3 2015.

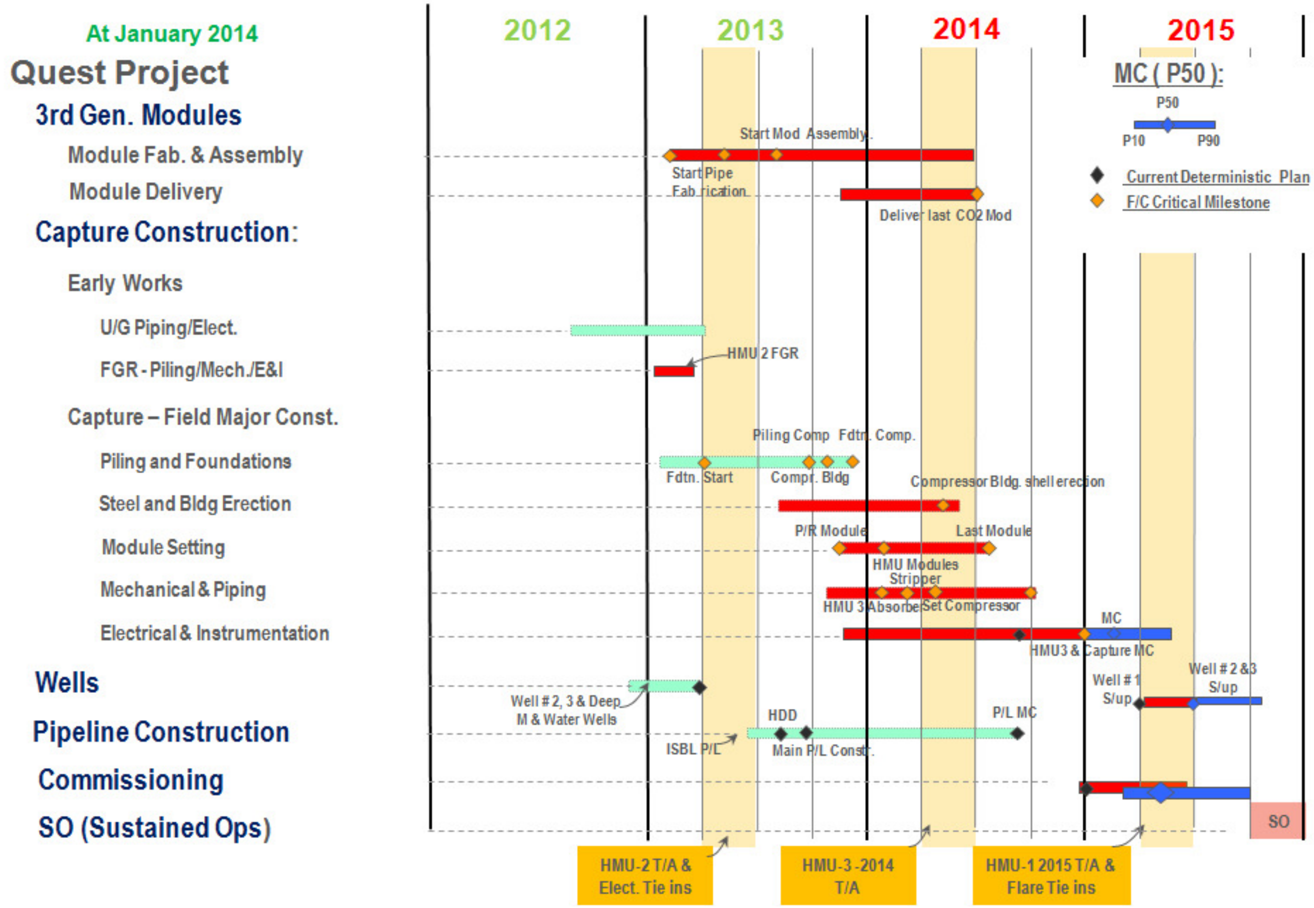


Figure 2-1: Project Construction Schedule

3 Geological Formation Selection

3.1 Storage Area Selection

A screening process resulted in a preferred storage area 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 storage area characterization comprised a period of intensive data acquisition, resulting in storage area endorsement prior to submitting the regulatory applications on November 30, 2010 and culminating in the award of a Carbon Sequestration Leases by Alberta Energy on May 27, 2011.

Storage area selection was mainly based on data, analyses and modeling of the two CO_2 appraisal wells with supplemental data from legacy wells, seismic and study reports. Storage area 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.

The approved sequestration lease area (SLA), as defined by the approved Carbon Sequestration Leases and pursuant to Section 116 of the Mines and Minerals Act, was granted to Shell, on behalf of the ASOP Joint Venture, by the Alberta Department of Energy.

Table 3-1: Assessment of the BCS for Safety and Security of CO2 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 the entire SLA. Salt aquicludes thicken up dip to the northeast.
	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
	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

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
	15	Porosity	<10%	≥10%	16%
Desirable (cont'd)	16	Permeability	<20 mD	≥20 mD	Average over the SLA 20-500 mD
	17	Cap rock thickness	<10 m	≥10 m	Three cap rocks MCS 21 m to 75 m L. Lotsberg Salt 9 m to 41 m U. Lotsberg Salt 53 m to 94 m
SOURCE: CCS Site Selection and Characterization Criteria – Review and Synthesis: Alberta Research Council, Draft submission to IEA GHG R&D Program June 2009: http://sacccs.org.za/wp-content/uploads/2010/11/2009-10.pdf					

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 1-4*).

The BCS storage complex includes, in ascending stratigraphic order:

- Precambrian granite basement unconformable underlying the Basal Cambrian Sands
- Basal Cambrian Sands (BCS) of the Basal Sandstone Formation – the CO_2 injection storage area
- 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.

The rocks that comprise the BCS storage complex 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 SLA, 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 3-1* (the AOI is the former name for the SLA). The SLA is within a tectonically quiet area; no faults crosscutting the regional seals were identified in 2D or 3D seismic data.

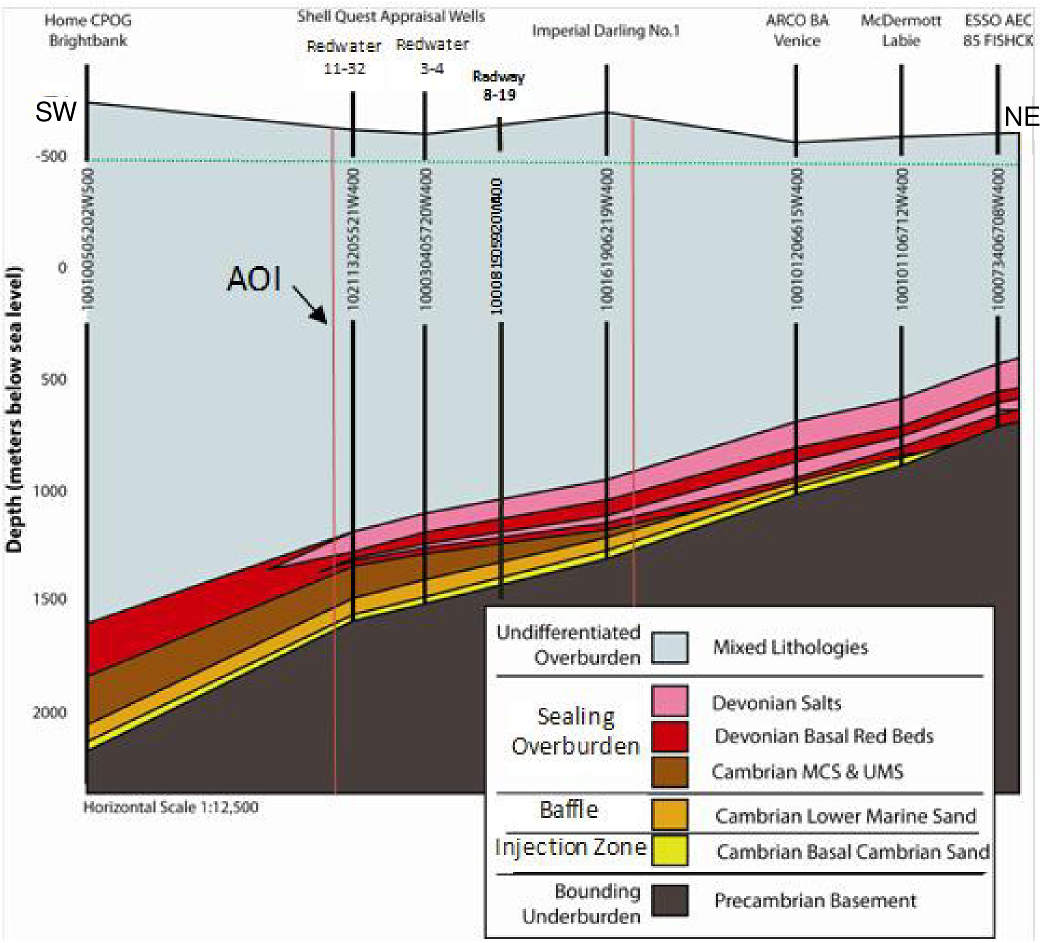


Figure 3-1: Cross-Section of the WCSB Showing the BCS Storage Complex

3.3 BCS Reservoir Properties

No new injection wells were drilled in this reporting period. However, it is confirmed based on 2012 drilling that the stratigraphic framework within the QUEST project area is as expected. *Figure 3-2* provides a summary of the formation thicknesses within the BCS storage complex and selected overlying formations up to the top of the Quest Sequestration Lease rights for IW 8-19, IW 5-35 and IW 7-11. The formation thicknesses observed within the 'new' injection wells IW 5-35 and IW 7-11 are very similar (almost identical) to those that were observed in IW 8-19. For instance, the BCS has a thickness of 47m in IW 8-19 versus 43 m in IW 5-35, and the MCS has a thickness of 52 m in IW 8-19 versus 51 m in IW 5-35. The differences between actual depth and prognosed (prog) formation thickness are also shown for the new IW 5-35 and 7-11 and are as expected.

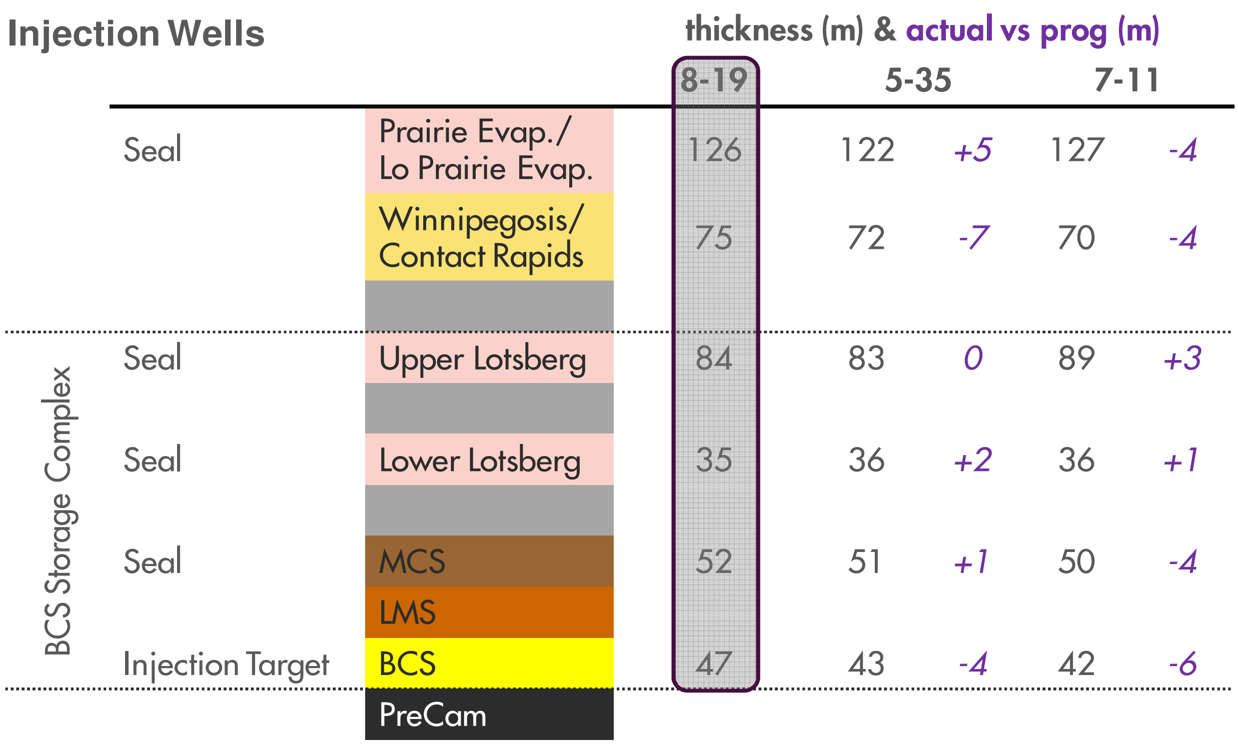


Figure 3-2: Summary of zone thicknesses for Quest Sequestration rights interval

With regards to the BCS reservoir properties, good agreement was observed between core analyses and log data (*Figure 3-3*).

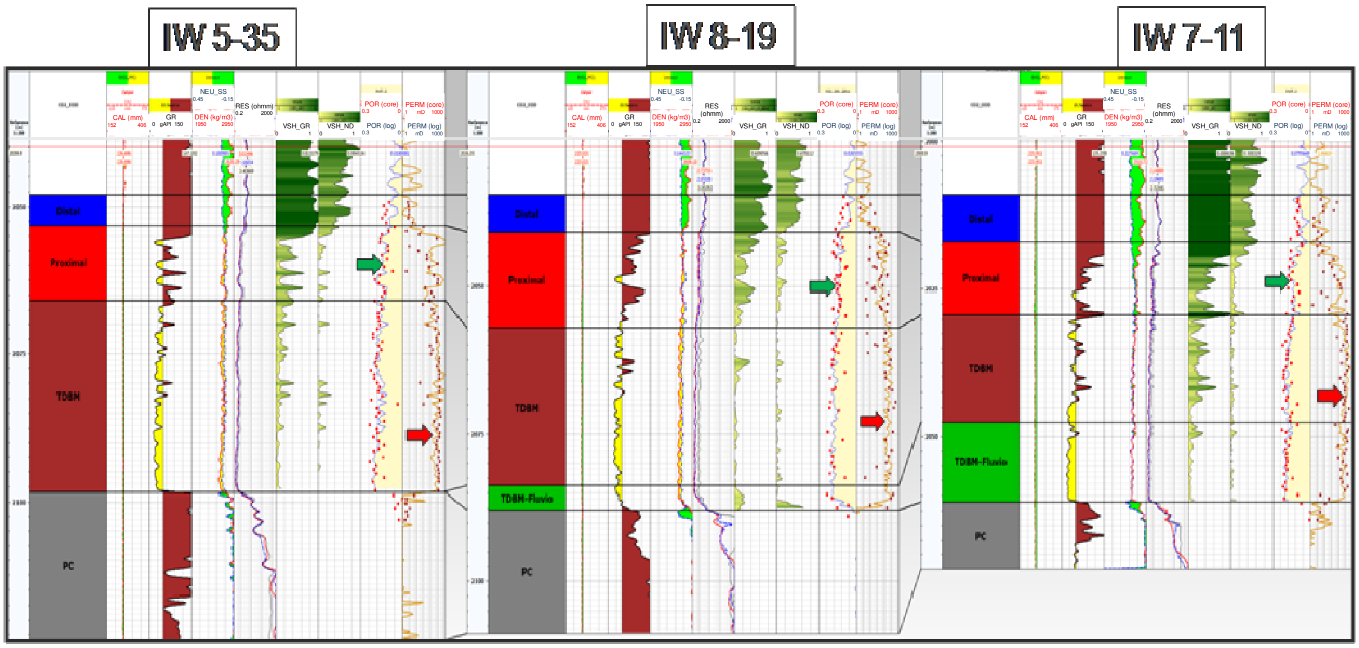


Figure 3-3: BCS Reservoir Properties Comparison of log response over the BCS formation and the corresponding core analysis results in all three injection wells. The green arrows are pointing to the porosity track, very good correspondence between the core porosity and log porosity. The red arrows are pointing at the permeability track, a good agreement between the log and core permeability in IW 5-35, whereas the correspondence is better in IW 7-11.

Based on the IW 5-35 and IW 7-11 BCS cores, the depositional environment was interpreted to be consistent with IW 8-19, as illustrated in *Table 3-2*

Table 3-2: Depositional Environment in LMS-BCS for the injection wells from the core data.

Depositional Paleo-Environment	IW 8-19, thickness (m)	IW 5-35, thickness (m)	IW 7-11, thickness (m)
Distal Bay	11*	5*	8*
Proximal Bay	10	12	11
Tide Dominated Bay Margin (TDBM)	25	30	17
TDBM (Fluvial Influenced)	4.5	2.4	13
* Based on core data only – log data indicates that that Distal Bay is significantly thicker.			

Consistency was observed with regards to the geochemical composition of the BCS Formation brine from IW 5-35 and IW 7-11 compared to IW 8-19, as illustrated in *Figure 3-4.*

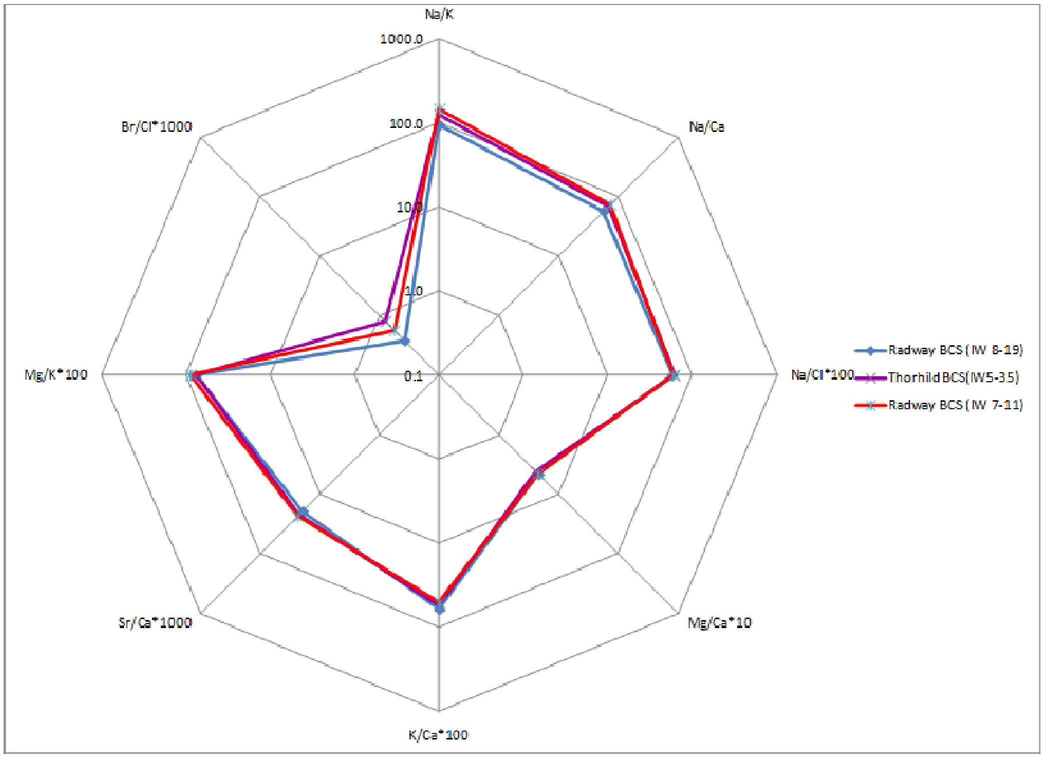


Figure 3-4: Ion Ration plot of BCS Formation brine waters from IW 8-19 (sampled in 2010), IW 5-35 (sampled in 2012) and IW 7-11 (sampled in 2013).

3.4 Estimate of Storage Potential

The uncertainty in the capacity of the storage area, the BCS storage complex, has reduced considerably over time due to appraisal data gathering two appraisal wells, three injection wells, 2D seismic, 3D seismic and the ongoing reservoir modeling 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 Gen-4 dynamic model results, as presented in the 2013 status report to the AER, indicate that the pressure build up in the BCS is expected to be less than 2 MPa of DeltaP at the perforations of the injection wells while flowing at the end of the project life. Recent well results from IW 5-35 and IW 7-11 support this forecast and indicate an even lower DeltaP may occur. This pressure increase of 2 Mpa is less than 12% of the Delta Pressure required to exceed the BCS fracture extension pressure and less than 20% of the pressure required to exceed the AER operating constraint on bottom hole pressure (D65 approval condition).

Gen-5 static and dynamic reservoir models were presented in the third annual status report to the AER (submitted January 31, 2015). The current (Gen-5) dynamic model results indicate that the pressure build-up in the BCS is expected to be less even than 2 MPa of differential pressure (DeltaP) at the injection wells by the end of the project life. This pressure build-up is illustrated in *Figure 3-5* on a well by well basis. It is also illustrated in *Figure 3-6* with an aerial cross-section of pressure in 2040.

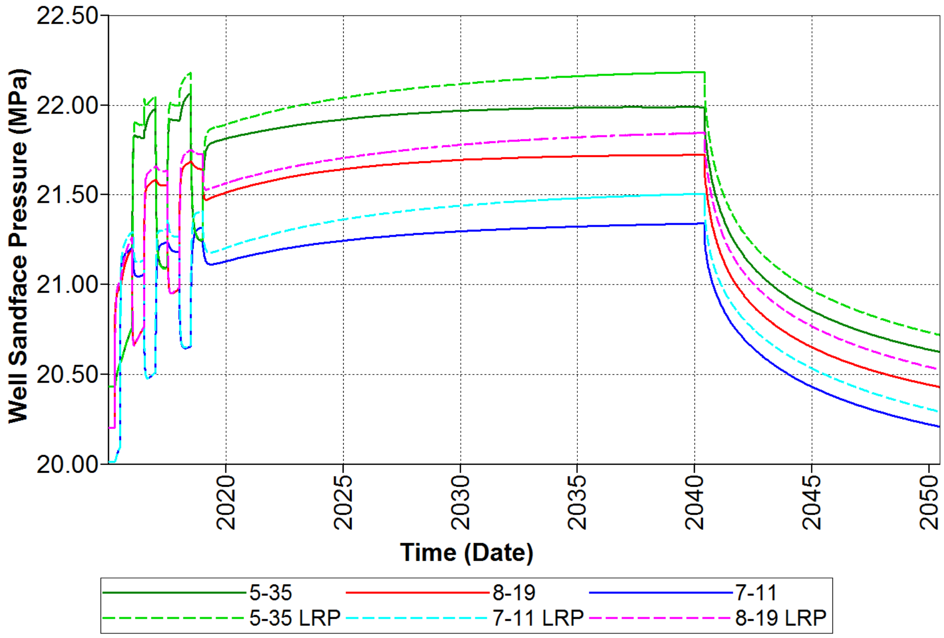


Figure 3-5: Well by well expected pressure build forecast for base and low relative permeability scenarios.

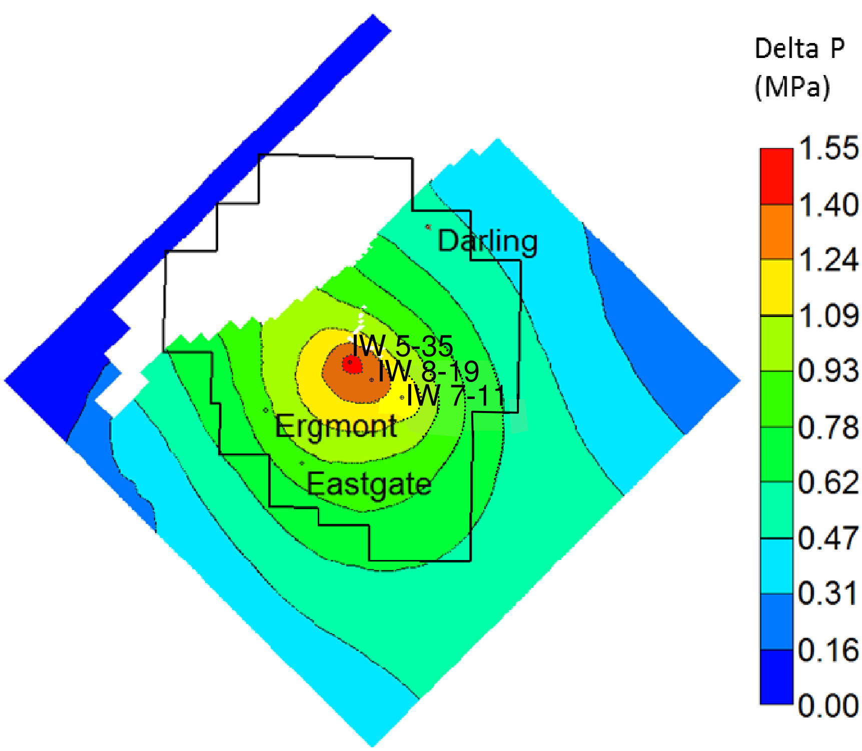


Figure 3-6: Aerial cross-section of pressure in 2040.

3.5 Initial Injectivity Assessment

The project requires an initial water injectivity greater than 380 m3/d/MPa to confidently inject 1.08Mt/a of CO_2 to meet project objectives. *Table 3-3* summaries the project wells names and associated UWI's. Two prior appraisal wells were drilled in 2008 and 2009 and have been evaluated (respectively Red 11-32 and Red 03-04). IW 8-19, the first injection well, was drilled end 2010 and tested through January 2011. The regulatory approval for the acid gas disposal scheme (D65) was obtained in summer 2012, which enabled the execution of the drilling the rest of the Injection Wells and deep monitoring wells (IW and DMW respectively).

Table 3-3: Summary of Project Well Names

Well Name	UWI
Red 11-32	1AA/11-32-055-21W4/00
Red 3-4	100/03-04-057-20W4/00
IW 8-19	100/08-19-059-20W400
DMW 8-19	102/08-19-059-20W400
IW 5-35	102/05-35-059-21W400
DMW 5-35	100/05-35-059-21W400
IW 7-11	103/07-11-059-20W400
DMW 7-11	102/07-11-059-20W400

The results of the well test support initial injectivity of each individual injection well (IW 7-11, IW 5-35, IW 8-19) greater than the full project requirement. *Table 3-4* summarizes the injectivity assessments for all of the wells tested in the BCS.

Table 3-4: Summary of Injectivity Estimates for the BCS Formation

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

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

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

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

3.6 Risk to Containment in a Geological Formation

There are nine potential threats to containment identified and explained in detail in Section 4.3.3 of the MMV Plan. The latest risk assessment summary is included in the MMV plan update supplied to Alberta Energy on 31st January 2015. Each are considered unlikely but are, in principle, capable of allowing CO_2 or BCS brine to migrate upwards out of the BCS storage complex.

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

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

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

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

Risk Assessment:

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

- In the Quest SLA, there are four legacy wells that penetrate through all seals in the BCS storage complex with the closest one to an existing injection well located 18 km away. This is more than three times the distance the CO_2 plume is expected to extend. Taking into account the main uncertainty of relativity permeability this still more than twice the distance the plume could extend with the high relative permeability case (Figure 2-3). Therefore, there is no risk of CO_2 leakage at these wells unless there is a severe loss of conformance.

- The status and condition of existing wells penetrating the BCS has been reviewed from multiple data sources. There are no known issues with legacy well integrity other than the uncertainty that arises from the age of the cement plugs and the inability to pressure test old cement plugs. The following barriers are in place in the BCS legacy wells:
  - Multiple cement plugs of significant length at various intervals
  - Open hole abandonment across the salt allows for the opportunity for hole closure by salt creep
  - Impermeable plugs may have formed through settlement of solids out of drilling mud in the well bore
- BCS plume monitoring will be used to ascertain if there is a loss of conformance which would give rise to a potential threat to containment associated legacy wells far in advance of any impact above the storage complex. At that time, MMV plans would be updated appropriately.
- Use of the BCS injection wells as monitoring wells for the project life to monitor pressure build-up and interference will ensure reservoir pressure are not high enough to raise brine to the base of groundwater protection long before a potential problem arises.

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

Explanation:

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

- **Compromised cement:** Initial cement bond, or deterioration of the cement bond through time due to stress cycling, or chemical alteration may allow upward fluid migration outside the casing.
- **Compromised casing:** Casing corrosion through time due to oxygen ingress, or contact with saline or acidic fluids may allow upward fluid migration inside or outside the casing.
- **Compromised completion or wellhead:** Loss of integrity of the completion or wellhead due to undetected flaws in the initial design or execution or subsequent degradation due to corrosion, or deterioration of seals in the presence of CO_2 may allow fluids to escape through the wellbore.
- **Well interventions:** During the course of normal operations, routine well interventions may result in loss of well control.

- **Compromised abandonment:** Injection and observation wells will be properly abandoned prior to site-closure. Undetected flaws in the design or execution of well abandonment or subsequent degradation of materials may allow upwards migration of fluids.

Risk Assessment:

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

- The evaluation of the cement bond in all injection wells both behind the intermediate casing and the main casing shows isolation of the BCS storage complex with a good bond across all three seals (MCS and the Lower and Upper Lotsberg Salts) with the exception of IW 5-35. At IW 5-35, a poor bond has been interpreted across the MCS which could extend into the LMS baffle below. The poor bond is interpreted from 1891 m MD (below the lower Lotsberg Salt) down to a depth of 1967 m MD which was the total depth to which the log was acquired. The casing shoe is set at 2004 m MD and the top of the LMS is at 1988 m MD. There is 50 m of good cement from the top of the BCS to the intermediate casing shoe which provides an effective isolation of the BCS. Regardless, the good cement across the Lotsberg Salts provides isolation of the BCS storage complex.
- The excellent cement bond over the all three seals in IW 8-19 and 7-11 is supported by the conclusion of the Independent Review. Quoted from the Independent Review Report:

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

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

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

- In the Quest Project, Surface Casing Vent Flows (SCVFs) and Gas Migrations (GMs) were detected and reported to AER in IW 5-35 and IW 7-11. Upon further review, IW 8-19 was also determined to have a SCVF. Analytical results from data acquired in both Q2 2013 and 2014 show that the SCVFs and GMs are independent of each other and that the GMs originate from the ground water zone while the SCVFs originate just below the surface casing (shallow source < 200 m depth). Due the shallow depth of the source of the SCVFs and GMs, these minor leaks to surface are not considered a threat to containment and isolation of the BCS storage complex.
- The independent review confirms the interpretation of the isotope data and the sources of the SCVFs and GMs. Quoted from the report:
- *"Carbon isotope and hydrocarbon concentration data were collected during drilling and collected from the wells with GMs and SCVFs. These data were used to help establish the source zones for the gas samples collected since completion. The results of data comparisons of the GM and SCVF data to data collected during drilling imply that the GM gas sources in both wells are behind the surface casing and the SCVF sources are not far below the bottom of the surface casing"*

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

Risk Assessment:

This is risk is currently considered very low because:

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

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

Risk Assessment:

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

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

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

Risk Assessment:

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

- Faults exist as discontinuities over a range of length-scales in many rock formations. However, large faults that transect regional scale geological seals within the Quest SLA of the Alberta Basin are rare (more than 100 km separates the Snowbird Tectonic Zone from the Hay River Shear Zone to the north).
- There is no evidence of faults with throws greater than 15 m crossing the seal complex from 2D and 3D seismic data covering the full SLA. The 2D seismic data spans the entire SLA with an approximate 3 km spacing and 435 km^2 of 3D seismic data is available over the central portion of the SLA (Figure 1-1).
- There is a period of approximately 1.5 billion years between the granite and the deposition of the BCS. Therefore, it is unlikely that any Precambrian faults were active in the BCS time of deposition.
- Even when present, many faults are sealing and retain fluids under pressure over geological time-scales.
- Mechanisms associated with fault slip, such as clay smear and cataclysis, reduce permeability within the fault zone. Other mechanisms, such as dilation and fracturing may enhance fault permeability.

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

Explanation:

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

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

Risk Assessment:

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

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

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

Explanation:

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

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

Risk Assessment:

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

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

Explanation:

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

Risk Assessment:

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

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

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

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

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

Explanation:

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

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

Risk Assessment:

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

- According to the Sequestration Lease Rights Shell has the exclusive right to drill through and store within the Zone of Interest (below the Elk Point Group). However, there are P&NG rights held by third-parties within the SLA that extend to the basement including Shell's ZOI. As a result, the ADOE has flagged the Quest Project in their system and will not be giving out new P&NG rights within the ZOI within the SLA. In addition, Shell would be notified of any third party attempting to drill into the ZOI so risk could be assessed on an individual basis. As per the AER Decision report [3] number [180] the panel concluded that this is extremely unlikely to happen taking into account the current state of knowledge and the fact that there are no hydrocarbons below the Elk Point Group in the SLA.
- There are no other third party CCS projects proposed in the vicinity of the Quest Project. Any new CCS project would be accessed on the impact created by the overall pressure increase in the BCS.
- A conceptual site model (CSM) of the Quest Project SLA does not foresee a pathway connecting the source to any receptor (Figure 3-8). Hence, no pathway has been identified through which saline brine from the injection interval may reach aquifers above the base of the groundwater protection zone. Furthermore, pressures are too low for BCS brine to be lifted to above the BGWP zone.

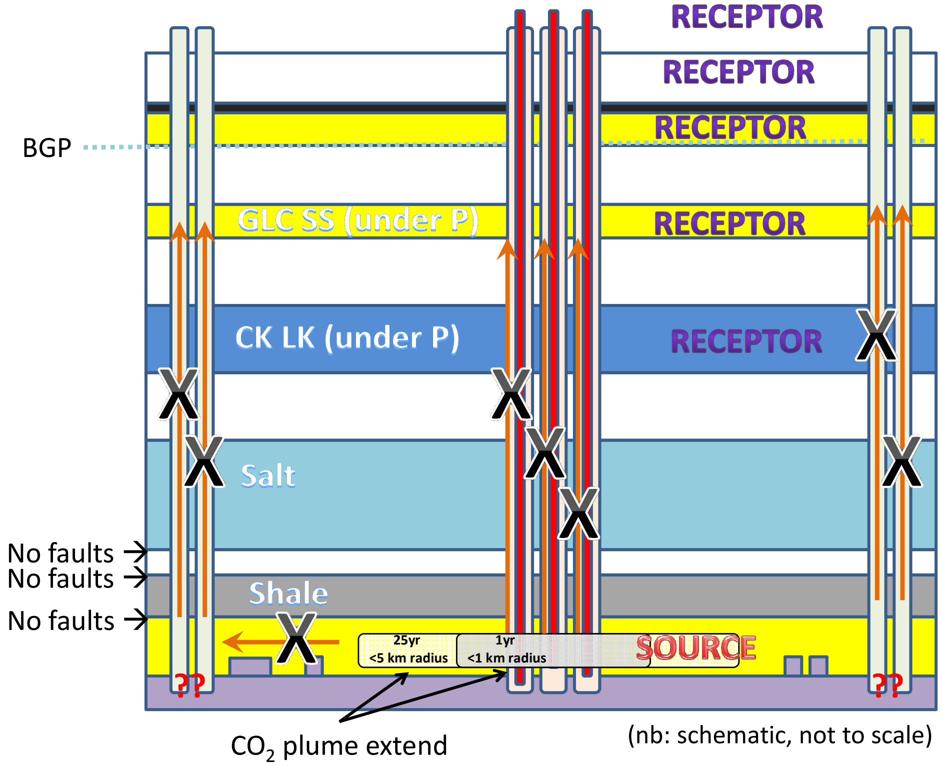


Figure 3-7: CSM for the Quest Project SLA.

Note: BGWP refers to base groundwater protection; under P refers to under-pressured formation.

4 Facility Operations – Capture Facilities

4.1 Operations Activities

The facility did not operate in 2014. From the design basis, expected performance is as follows:

- Anticipated Energy demand - Steam ~103.7 MWh, Electricity ~ 65.9 GWh,
- Anticipated Heat or energy recovered - 13 MWh due to heat integration
- Anticipated CO_2 capture ratio - 80%
- Anticipated Total CO_2 captured - 1.08 million tonnes per year (T/a)
- Anticipated CO_2 emissions to atmosphere - 139,000 T/a
- Other emission to air, soil or water - No reportable incidences in 2014

Operations activities for the past reporting period focused on the following activities:

Flawless project delivery monitoring and inspection of module construction with an emphasis on making sure systems are clean, operable, and maintainable. Flawless project delivery is Operations driver to a smooth commissioning and start-up of the Project. From the identified lessons learned from other Shell projects, and generally accepted good trade practices, two major "flawless" activities chosen were cleanliness, & tightness of the piping and equipment sub components. These two flaws contribute the most to start-up issues, and hence commissioning and start-up costs and production delays.

The pipeline and well pads were turned over to Operations for care, custody and control by the Commissioning and Start-Up (CSU) Operations organization. The wells (7-11, 5-35 and 8-19) were completed & turned over to Operations in 2013.

By December 31, 2014, 75 of 135 construction systems had reached Initial Completion Notice (ICN) meaning all deficiencies that would prevent start-up have been addressed and the CSU team can begin cleaning & commissioning activities while Construction completes the remaining deficiencies (eg insulation). Of the 75 systems handed over, 50 had reached Final Completion Notice (FCN) meaning all construction deficiencies have been addressed & the system has been handed over to CSU Operations care, custody, and control.

"Systems" cleaning has begun, focusing on utilities and the amine process. Commissioning has been completed on the following systems and they were put on line by year end:

HMU 3 Instrument air header

HMU 3 Utility air header

HMU 3 N_2 Header

All procedures required for cleaning, commissioning, and operating the facility were completed in 2014:

51 procedures were generated for system cleaning, and 17 for system commissioning were completed by October.

107 normal operating procedures, and 30 emergency operating procedures were completed by the end of December.

The Operations staff is nearing completion of training in anticipation of start-up, and training of Operators in Production Units 1, 2, and 3 have already begun, utilizing the respective Trainers in those areas, in conjunction with the training material generated by the CSU team.

Interface management between Shell Scotford Operations organization and the Construction team will end by Q3, 2015. This included activities to provide clarity on responsibilities around HSE interface, site access, permitting, and execution of tie-ins. An important element is the Project to Asset handover document. Formal agreement on who, what, where, when, and why of handover to Scotford base Operations has already begun.

Operations led activities for the implementation of the Maintenance planning and execution activity preparation continues, and meets the facilities needs through the commissioning and start-up phases. A key activity that was completed is the identification of the preventative maintenance activities required for the capture facility.

The CSU Operations team was staffed with 12 permanent Operators, up to 9 contract operators (for cleaning, commissioning, and start-Up) and 3 temporary staff. The Maintenance organization of CSU was constant through 2014, and up to 56 contract trades people have been brought in to support CSU. By steady state operation, we are anticipating only two additional permanent maintenance positions.

4.2 Next Steps

Key Operations activities for 2015 include the following:

- Project acceptance – The remaining 60 systems will be turned over to CSU for preparation for start-up, and the Constructors will depart.
- The Activity Based CSU plan is developed and will be implemented as systems are handed over from Construction.
- Turnaround Scope - Execution of the turnaround work required for Hydrogen Manufacturing Units one and two (HMU1, HMU2) that includes tie-ins to Flare and utilities systems.
- Hiring and Onboarding - Hiring of contract Maintenance personnel to support system cleaning, commissioning, and start-up (CSU).
- The Project to Asset Transition Plan has been initiated. Items for handover have been agreed upon with Site and close out of items has begun. We expect that all items will be addressed by Q4 2015. This includes un-used commissioning materials, engineering and operations documents (procedures), drawings and assurance documentation.
- Shell Pre-Start-up Audit to assure we are prepared for start-up.

- Shell Pre-Start-Up Safety Reviews on the installed facility.
- Completion of start-up of all systems, including well sites, with system performance equal to or better than required to meet the 3 test criteria, namely
    - 24 consecutive hours at 2960 T/d or greater of CO_2 captured
    - 20 consecutive days processing a minimum of 75% of the total CO_2 produced from HMU's 1, 2, and 3.
    - 30 consecutive days of operation at a minimum of 30% of 2960 T/d
- Utilize external networks to strengthen skills and competencies with pipeline, subsurface, CO_2 operations, and maintenance.

5 Facility Operations – Transportation

5.1 Pipeline Design

Some minor changes to the pipeline general design conditions as outlined in Table 5-1 have occurred over the development of this project. The current design specifications are as below, changes highlighted in bold text.

Table 5-1: Pipeline Design and Operating Conditions

Characteristic	Specification	Units	Value
General			
Pressure	Normal	MPa	**10**
At inlet	Design minimum	MPa	8
	Design maximum	MPa	14.8
Estimated Delta P to Well Site			0.4 (for three-well scenario)
Temperature	(@ Comp Discharge)		
	Normal (Winter)		43°C
	Normal (Summer)		43°C
	Upset condition		60 °C (max – summer, cooling unit down)
Flow rates	Normal	Mt/a	1.2
	Design minimum	Mt/a	0.36
Main Flow Line Data			
	Length	Km	~**64**
	Size	Inches, NPS	12
	Wall thickness	Mm	12.7 (11.4 +1.3 corrosion allowance)

Laterals Data			
	Length	Km	**3 laterals:~1, 1.6 and 3.8**
	Size	Inches, NPS	6
	Wall thickness	Mm	7.9 (6.6+1.3 corrosion allowance)
Reservoir pressure		MPa	22 – 33.3
Reservoir temperature			63°C
Well bore tubing diameters		NPS/ID mm	4.5/99.06
Well depth		M	2,070

Pipeline Fluid Composition

The composition is described in Table 5-2.

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 1.2 Mt/a. The CO_2 pipeline is designed to receive and transport up to an additional 2.2 Mt/a of CO_2, should there be a commercial option to receive CO_2 from a third party or additional Shell volumes.

Water Content and CO2 Phase Change Management

Operating experience around the world with dense phase CO_2 in carbon steel pipelines, is that corrosion is not an issue for high purity CO_2 with low water content (below 100 ppmw). Under these conditions, zero corrosion rates have been observed. Quest exceeds these conditions: the >99% purity CO_2 will be dehydrated to a water content of 96 kg/MSm^3 (52 ppmw) during summer and 64 kg/MSm^3 (35 ppmw) during winter, within the capture facilities.

A moisture analyzer will be installed between the sixth and seventh stages of the compressor, with a system trip at 68 ppmw. There will be a sampling procedure to confirm the moisture analyzer measurement.

The system will normally be kept in the dense phase by operating at ~10 MPa. The system will trip at pressures below 8MPa. (The critical point pressure to maintain CO_2 in the dense phase is approximately 7.4 MPa).

When the pipeline is depressured for whatever reason, it will be brought back up to a pressure greater than 8MPa with dry nitrogen.

Design Life

Design life for the pipeline and associated surface facilities is for the remaining life of the Scotford 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 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. There are six LBV's in this system.

The line break valves have been 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. The fencing is standard 8-foot chain link with three strands of barbed wire on top.

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, after repairs, the depressurized section will be brought up to temperature and pressurized again, slowly, by the line break bypass valves, which also serve as temperature-controlled vents in the case of emergency.

Flow Meters

Leak detection is based upon the principles laid out in CSA Z662 Annex E as pertaining to HVP lines. Leak detection is based on material balance. The mass flow meter at the Shell Scotford boundary limit and at the wellhead will be of custody transfer accuracy, 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 Pressure Indicating Transmitter) 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.

The pipeline will utilize the ATMOS leak detection system that senses flow, temperature, and pressure fluctuations to determine whether there is a potential for a leak. The response to alarms triggered by ATMOS will be immediately investigated.

Corrosion Protection

Following regulatory requirements and the Pipeline Integrity Management Plan, cathodic protection has been installed for the pipeline, including the laterals. Installation includes the following:

- Impressed current anodes and anode leads
- Impressed current rectifiers
- Calcined petroleum coke breeze and bentonite chips
- Vent pipes and anode junction boxes

- Monitoring test stations
- Thermite welds for pipe connections and coating repair at those locations
- Temporary magnesium anodes at designated test stations

Inspection

An in-line inspection tool (smart pig) run of the 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:

- Routine (daily) operator tours of the pipeline facilities above ground will commence during the CSU phase of project.
- 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 when pipeline is down for maintenance. 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

This section describes the type, frequency and coverage of monitoring activities included in the monitoring plan for the four domains, namely the Atmosphere, Biosphere, Hydrosphere, and Geosphere. As of December 31, 2014, no storage volumes have been injected. Data collection for the purposes of gaining baseline information and related studies has been ongoing.

The Third Annual Status Report and the updated MMV Plan were submitted to AER in January 2015.

6.1 Summary of MMV Operations and Maintenance Activities

In 2014, activity associated with the MMV Plan has included: atmospheric, biosphere, hydrosphere, geosphere, and well-based monitoring. Specific activities related to each of these monitoring zones can be seen in Table 6-1 and have been summarized in the following sections. These have also been detailed in the updated MMV Plan (Third Annual Status Report: Appendix A).

In addition to baseline data acquisition, Shell has developed a private, secure network which will transmit all data types between well sites, the Scotford Upgrader, the Calgary office, and relevant external parties. This will be fully operational in Q1 2015 and ahead of anticipated first injection.

Shell also completed, and submitted to the AER, feasibility studies on the use of both artificial and natural tracers for CO_2 [SPECIAL REPORT #3 - Tracer Feasibility Report submitted to the AER on 16th June 2014].

Table 6-1: Summary of specific MMV activities in 2014

Monitoring Zone	Activity	Data Acquired	Analysis & Reports
Atmospheric	LightSource system installed at 8-19	LightSource winter CO_2 background data	LightSource detection limits – Report (Third Annual Status Report: Appendix B)
	Eddy covariance (EC) equipment relocated at 8-19 well pad	CO_2 flux measurements	EC measurements and analysis- Report [Black, T.A. et al., 2014. Eddy-Covariance Measurements of Carbon, Water and Energy Fluxes at the Shell Quest Site (Pad 08-19), June 1-Ocober 31, 2014. Biometeorology and Soil Physics Group, University of British Columbia, Shell Internal Report.]
Biosphere	Continued HBMP baseline sampling	As per the HBMP	Golder HBMP Annual Summary - Report (Third Annual Status Report: Appendix C)
	Measurements on the wellpads with field	Soil gas, soil surface	Biogenic Flux of CO_2 – Report (Third Annual

	deployable state of the art laser analyzer equipment	flux, $\delta^{13}C$ (CO_2 and CH_4) at the wellpads	Status Report :Appendix D) SAR Feasibility Update-Report (Third Annual Status Report: Appendix E) Analysis on the wellpad surveys (ongoing)
Monitoring Zone	**Activity**	**Data Acquired**	**Analysis & Reports**
Hydrosphere	Groundwater well sampling as per HBMP	As per HBMP plan	Golder Annual Summary - Report [Golder, 2015. 2014 HBMP Summary Report: Shell Quest CCS Hydrosphere Biosphere Monitoring Program, Golder Associates Ltd.] AITF Ground Water study report – final report (in Draft) [Brydie, J., Jones, D., Perkins, E., Jones J-P, and Taylor, E., 2014. Draft Final Report: Groundwater Study for the Quest Carbon Capture and Storage (CCS) Project, Confidential Client Report to Shell Canada Energy, Alberta Innovates – Technology Futures]
SCVF and GMs	Completed SCVF/GM measurements and sampling	Pressures, Flow rates and Isotopic fingerprinting data	Reports submitted to the AER [Response on SCVFs in relation to Alberta Energy Regulator (AER) conditional approval of September 4, 2013 regarding Shell's request to defer repair of surface casing vent flow (SCVF) and gas migration (GM) submitted on 31st March 2014]
Geosphere	Initiated DTS study		
	Completed in well Fiber Optic retesting		
	Continued INSAR image acquisition	8 INSAR images	INSAR data analysis and detection limts –Report (Third Annual Status Report: Appendix F) INSAR Feasibility – Report [Alfaro, M.C., Bourne, S and Dean, M., 2015. Technical Feasibility of InSAR for CO2 Storage Monitoring and Leak Detection – 2015 Update (Draft). Shell Canada, Heavy Oil Controlled Document, Quest CCS Project]

	Installed microseismic monitoring in DMW 8-19	Seismic activity data recorded since November 6, 2014	
	Baseline walkaway VSP Surveys- Planning & Permitting		
	Power connected to Cooking Lake Formation pressure monitoring gauges in DMW 5-35 and 7-11	Cooking Lake Formation Pressure data in IW 5-35 and 7-11	Application to AE to monitor Cooking Lake Formation in Redwater 3-4

6.1.1 Atmospheric Monitoring – Light Source

A LightSource field trial was successfully completed between September 8 and 13, 2013. Due to higher than originally anticipated background variability of atmospheric CO_2 concentrations, detectability sensitivity for CO_2 emission mapping has decreased (Third Annual Status Report: Appendix B).

Boreal Laser delivered a new enhanced performance single line-of-sight CO_2 sensor which was successfully tested in this field trial, refined, and subsequently installed at the 8-19 pad site in December 2014 in the three beam final design configuration. This system is now operational and collecting additional background data during the winter months. Installation at the other two injector sites is planned for later in 2015.

The information from the field trial has been used as input to calibrate the monitoring system and to help set revised detection thresholds that will be used for LightSource atmospheric CO_2 monitoring. The new detection limits based on the 2013 controlled release test are:

- CO_2 source detection at a range of 100 m (the beam area or full pad) would require a release rate of ~45 kg/hr
- CO_2 source detection at a range of 1 km would require a release rate ~800 kg/hr

A second LightSource controlled gas release test has been planned for May 2015 to further refine the detectability capability of the system.

In addition to LightSource, EC data has been collected at the 8-19 well site. These atmospheric CO_2 flux measurements, which demonstrate similar fluxes to the soil gas measurement, provide calibration for LightSource and will continue to be recorded until June 2015.

6.1.2 Hydrosphere Biosphere Monitoring Activities

6.1.2.1 Summary

A summary overview of Hydrosphere Biosphere Monitoring Plan (HBMP) activities can be seen in Table 6-2. The planned baseline HBMP sampling campaigns have now been completed (Third Annual Status Report: Appendix C). Extensive datasets with regards to the hydrosphere and biosphere have been gathered during 2012, 2013, and 2014 across the Area of Review (AOR).

Table 6-2: Summary overview of HBMP activities completed to-date.

During 2014, tracer feasibility studies were completed for both artificial and natural tracers. The resulting report entitled "Special Report #3: Tracer Feasibility Report" was submitted to AER in June 2014 [SPECIAL REPORT #3 – Tracer Feasibility Report submitted to the AER on 16th June, 2014]. The proposed action plan outlined in that Report stated the following:

- Artificial tracer injection will not be used on a regularly scheduled basis when injection commences for the Quest Project.
- Instead, an alternative technique will be used which makes use of the inherent stable carbon isotopic composition of CO_2 ($\delta^{13}C$), a suitable and valuable tracer for tracking the movement and fate of the injected CO_2.
- In the unlikely event of an unresolved leakage claim, artificial tracers can be injected and other alternatives can also be implemented. Note that an injection port for the artificial tracer is part of the facility design, and is available in the event that there is a requirement to use artificial tracer (PFC) injection. There are small risks associated with every technique.

- Further sample collection and analysis from the Scotford Upgrader is already planned for 2014 and 2015. Background source sampling is currently on-going as part of HBMP sampling program. Hence, systematic sampling of injection CO_2 source and background CO_2 sources is on-going and will be adapted as needed.

Note that two manuscripts have been submitted to the peer-reviewed journal *International Journal of Greenhouse Gas Control* in 2014 related to work completed by Shell in conjunction with the University of Calgary in relation to the isotopic composition of CO_2. The University of Calgary was the lead author on the manuscripts entitled:

- "Assessing the Usefulness of the Isotopic Composition of CO_2 for Leakage Monitoring at CO_2 Storage Sites: A Review"
- "Stable carbon and oxygen equilibrium isotope fractionation of supercritical and subcritical CO_2 with DIC and H_2O in saline reservoir fluids".

6.1.2.2 Biosphere Monitoring Activities

Soil and Vegetation Sampling and Remote Sensing Calibration

Fifteen soil and vegetation plots were sampled over three different field events in the spring, summer, and fall of 2014. A summary of the campaign completed to date is provided in the Third Annual Status Report: Appendix C [reference number].

The feasibility of using remote sensing, both radar image analysis (RIA) and multispectral satellite imagery (MIA) methods, for brine leak and CO_2 release detection respectively, was investigated through the baseline period and results and recommendations were made in 2014.

The RIA for brine leak detection (SAR) technical feasibility study was completed in Q4 2014 (Third Annual Status Report: Appendix E). Relatively poor correlation coefficients were achieved from season to season as well as for individual plots with presence of elevated salinity or water saturations as would be expected in the case of a brine leak. With limitations on these parameters, correlation coefficients were still less than 0.5 thus demonstrating the limitation of this technology for use in the Quest Project.

MIA using RapidEye was collected from 2012 – 2014. It has been deemed as insufficient for direct, real-time monitoring and detection of CO_2 releases in the atmosphere due to the spectral and spatial resolution of the available sensors. Multiple parameters would influence the spectral response of the vegetation, and the magnitude of the lag time between exposure and measurable changes in the spectral response is anticipated to be too large to provide useful leak detection.

Soil Gas and Soil Surface CO_2 Flux Sampling

A significant soil gas and soil surface CO_2 flux sampling program has been carried out between 2012 and 2014 in order to support the planned HBMP baseline monitoring program (Third Annual Status Report: Appendix C). The first soil gas and soil surface CO_2 flux sampling campaign took place in Q3 2012, which was followed by four sampling campaigns each in 2013 and 2014. The sampling campaigns were distributed throughout the year to capture expected seasonal changes. Measurements included CO_2 flux, CO_2 concentration, and isotopic composition of CO_2 ($\delta^{13}C$). A summary of the soil gas and soil surface CO_2 flux sampling campaign completed as part of the HBMP during 2014 is provided in the Third Annual Status Report: Appendix C.

Besides the soil gas and soil surface CO_2 flux measurements related to the HBMP baseline sampling campaign, an additional sampling campaign took place in July 2014 using state-of-the-art field deployable instrumentation. The in-situ field measurements included soil gas probes, CO_2 flux chambers, and walk-over surveys close to the injection wells. The state-of-the-art field deployable instrumentation enabled collection of in-situ field measurements of CO_2 flux, CO_2 concentration, and isotopic composition of CO_2 ($\delta^{13}C$).

The Third Annual Status Report: Appendix D contains a detailed report on all baseline soil gas and soil surface CO_2 flux data from the HBMP as well as the additional July 2014 field campaign and analysis of surface CO_2 flux and soil gas data collected for different soil types throughout the Quest Project Area of Review (AOR) from 2012 – 2014. Hence, a very comprehensive dataset has been collected on not only CO_2 flux and CO_2 concentration, but also the isotopic composition of CO_2 ($\delta^{13}C$) across the Quest AOR.

6.1.2.3 Hydrosphere Monitoring Activities

A significant groundwater sampling program has been carried out between 2012 and 2014 in order to support the baseline monitoring program. The first groundwater sampling campaign took place in Q4 2012, which was followed by four sampling campaigns each in 2013 and 2014. The sampling campaigns were evenly distributed throughout a year to capture seasonal variability.

A summary of the 2014 HBMP water well sampling campaign is provided in the Third Annual Status Report: Appendix C.

The data collected as part of the HBMP groundwater sampling campaign were used in a study entitled "GROUND WATER STUDY FOR QUEST CCS PROJECT" that Alberta Innovates – Technology Futures (AITF) was contracted to complete. This study commenced in April 2013 to support the HBMP and has been completed. The aim of the study was to assess the characteristics of potable groundwater aquifers across the Quest AOR and to evaluate potential physical and chemical trigger conditions which may suggest a deviation of key potable groundwater aquifers from the established groundwater monitoring baseline. As part of this work, the conceptual geological model from surface to the Lea Park Formation within the Quest Project AOR was revised and updated as needed. The conceptual geological model for the Quest Project AOR is shown in Figure 6-1.

Key findings drawn directly from AITF's study are summarized below:

- "*Based upon previous potable water aquifer classifications across the Quest Study Area, four distinct aquifers were defined which included, from structurally and stratigraphically lowest to highest to lowest, the Basal Belly River Sandstone (BBRS), Foremost, Oldman, and Surficial. The BBRS is formally considered to be a component of the Foremost aquifer, but for the purposes of this study, it is treated as a separate aquifer. Except for the BBRS aquifer, all other overlying aquifers are considered to be in hydraulic communication, as indicated by their respective hydraulic head distributions and water chemistry*."
- *"Hydrogeological characteristics of each aquifer within the Quest Study Area have been assessed in order to provide information related to aquifer-specific hydraulic head distribution, inferred groundwater flow direction(s) and calculated groundwater flow magnitudes within the target aquifers."*
- *"Identified water types vary across the Quest Study Area from Ca-Mg-HCO3 to NaCl and Na-SO4 with a range of Total Dissolved Solid (TDS) of 58 to 18,300 mg/L, which includes all target aquifers." (Figure 6-2)*
- *"Based upon all available information, including Alberta Groundwater Information Centre (GIC), Quest seismic data" (refers to data collected as part of 2010-2011 seismic acquisition campaign) and HBMP data ", descriptive statistical analysis were carried out on these data to establish the minimum, mean, and maximum parameter values and analyte concentrations. These calculated values provided end member limits with which to construct a list of monitoring trigger values. When the trigger values are exceeded, the trigger locations are displayed on the various aquifer base aquifer maps using symbology proportional to the magnitude of the trigger event."*

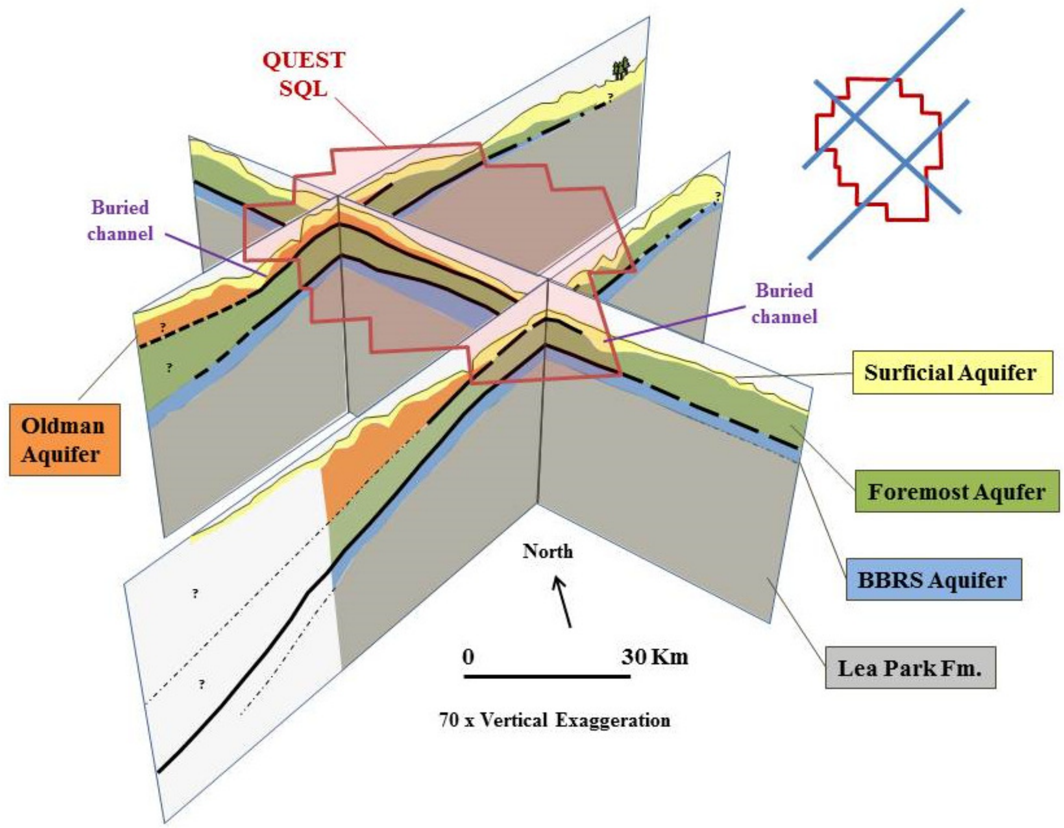


Figure 6-1: Conceptual geological model for the Quest Project AOR.

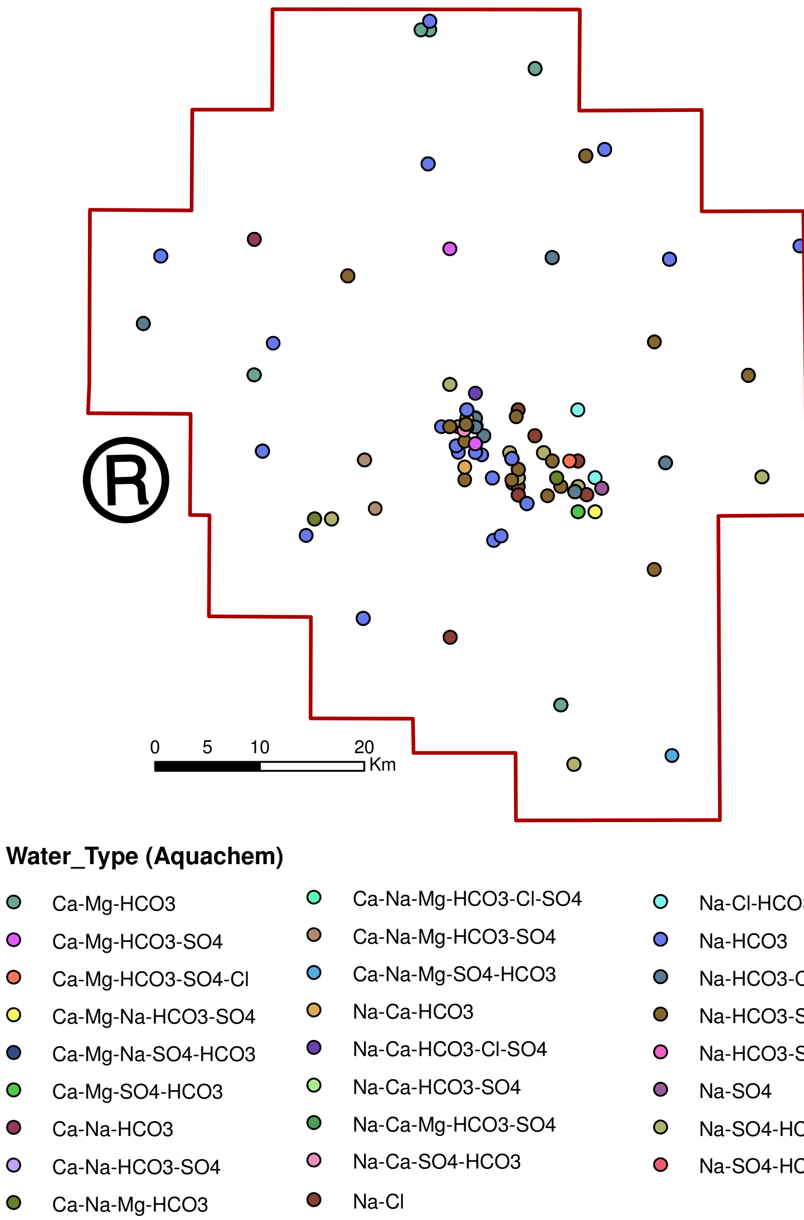


Figure 6-2: Summary of defined water types across the Quest Study Area within all aquifers. Data were taken from the HBMP dataset (Q4 2012 – Q2 2014).

A shortlist of parameters specifically related to CCS leak detection assessment was identified. This shortlist forms the core recommended list of parameters and analytes which should be included in ongoing monitoring for containment assessment and assurance monitoring purposes. The short list and rationale are summarized in Table 6-3. Please refer to the MMV Plan for further details on the trigger values (Third Annual Status Report: Appendix A).

Table 6-3: Summary of short-list parameters considered to be important in the context of the Quest Project.

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

6.1.3 SCVF and Gas Migration Monitoring

As required, annual testing was completed in 2014 for SCVF and GM at the injection pads. Reports were sent to AER in March 2014 with regards to the SCVF testing and in June 2014 with regards to the gas migration (GM) testing [reference numbers]. Please note that during July 2014, state-of-the-art field deployable equipment was used to gather additional CH_4 data (flux, concentration, and isotopic) at and near the injection well pads. Analysis of these data is on-going.

The SCVF testing measurement indicate that a significant decrease in flow rates at IW 5-35 with a designation of Too Small To be Measured (TSTM). There was also a significant drop in pressure at the IW 5-35 well and a slight increase at IW 7-11. Note that the pressure at IW 7-11 is still very low. The result from the SCVF measurements on IW 8-19 shows that both pressure and flow rates have decreased since the last measurement in June 2013.

The GM testing at the IW 5-35 and 7-11 injection wells show that the highest recorded gas content value is at or below 41% of the Lower Explosion Level (LEL) 30 cm away from the IW 5-35 wellhead; this occurred when the wind was constantly changing direction and swirling. The gas content values fell below 1% LEL in both wells 2 m away from the wellheads. Values reached 0% LEL 3 m from each wellhead in all directions. The gas migrations still have very limited impact and no potential for concern beyond the wellpad.

6.1.4 Geosphere Monitoring Activities

6.1.4.1 Distributed Acoustic Sensor/ Distributed Temperature Sensor

The optical fibers that were previously cemented within the injection wells on each well pad will be used for temperature and acoustic measurements distributed along the wellbore. These fibers were successfully deployed, and initial testing showed that they were functional. Subsequent testing in 2014 demonstrated that a single mode fiber in the IW 7-11 was not functional. Repair of this fiber will be attempted prior to injection start-up if it does not bring risk to the other hardware in the well. Note that the damaged fiber in this well is a redundant fiber and that additional fibers within the well currently exist that can be used to acquire the required data. Hardware associated with Distributed Acoustic Sensor (DAS) and Distributed Temperature Sensor (DTS) data collection will be installed at the 8-19 well site prior to injection start-up and at subsequent injection sites later in 2015. Studies completed to date support DAS/DTS for use in the following:

- DTS as a temperature log that can be used to for hydraulic isolation testing across the BCS storage complex when the well has been shut-in for a short period of time
- The DAS system has been demonstrated to be of similar quality to a conventional vertical seismic profile (VSP) survey, and Shell plans to use DAS for the baseline walkaway VSP surveys that will be acquired in Q1 2015

Remaining technical work will focus on the ability to use DTS/DAS to detect potential leaks real-time while injection is occurring. The work will be undertaken in 2015 to determine the feasibility of this application with continuous data acquisition planned for a period spanning pre-injection into the injection phase. SageRider and Lawrence Berkley National Laboratories (LBNL) were contracted to assess the detectability limits and feasibility of using DTS for real-time leak detection. This work is ongoing, and a report and recommendations are expected in Q1 2015. Shell is also in discussion with LBNL on a research project to determine if the DAS string can also be used for real-time well integrity analysis and /or real-time leak detection.

6.1.4.2 Microseismic Monitoring

A microseismic array was installed in DMW 8-19 and began recording background microseismicity on November 6, 2014 as per the MMV Plan (Third Annual Status Report: Appendix A). Trigger files are created when a specified threshold criteria is met on multiple geophones. These files are sent for trigger categorization and processing. Currently, Shell receives a daily report with the date, number of triggers, and breakdown of trigger type (Table 6-4). There have been no locatable or single phase events recorded since recording commenced.

Table 6-4: Trigger classifications used for the Quest Project and trigger totals as of January 14, 2015

Trigger Type	Description	Total
Automatic	Hourly triggering intended to ensure health of the system	1640
High Frequency Noise	Caused by elevated, high frequency background noise	4124
Acoustic	Caused by energy travelling up and down the wellbore	381
Hammer Tap Test	Tap test on the wellhead to test geophone functionality	6
Locatable Events	Events with clear P- and S-wave arrivals exhibiting waveform characteristics typical of microseismic events	0
Single-Phase Events	Seismic signals that lack significant P- and S-wave arrivals and can not be located	0
Surface	Events that originate at the surface	6
Electrical	Caused by electrical interference	0
Orientation Shots	Induced events such as surface-based seismic sources that are used to orient the geophones	0
Potential Regional Events	Far offset earthquake events that occur beyond the AOR	25
Total		**6138**

As of January 14, 2015, a total of 25 regional earthquake events have been recorded beyond the Quest Project AOR. One example of a regional event was recorded on December 10, 2014 at 13:34:18 Mountain Standard Time (MST) (Figure 6-3). This regional earthquake event corresponds to an earthquake with a magnitude of 3.0 located approximately 88 km west of Rocky Mountain House, Alberta that was identfied by the Natural Resources Canada (NRCan) regional monitoring network. While the primary purpose of the microseismic array is not to detect and locate regional earthquakes, detection of these events indicates that the array is in good working order. These far offset events may also be used to assist in orienting the geophones in the array in conjunction with the orientation shots prior to CO_2 injection. However, the on-site orientation shots should be the primary source of data used for the geophone orientation.

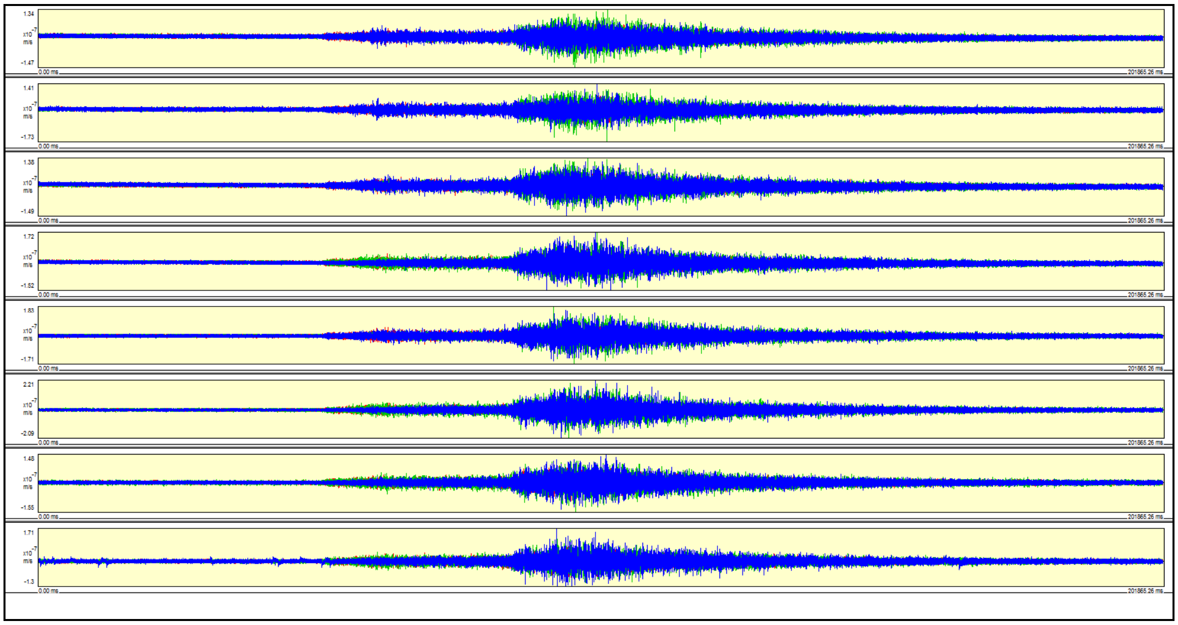


Figure 6-3: Regional earthquake located near Rocky Mountain House, AB

Note: recorded by the DMW 8-19 microseismic monitoring array December 10, 2014 at 13:34:18 MST.

6.1.4.3 Baseline Walkaway VSP Surveys

The baseline VSP design was developed through an integrated effort between the acquisition team, processing team, and the Quest Project. The intent is to design and acquire a baseline survey that will have highly repeatable shot point locations, monitor the CO_2 plume extent over time, and be cost effective.

Shell conducted internal modeling to determine optimal shot location, shot spacing, vibrator truck sweep length, and sweep frequency range. Final forward modeling concluded that:

- Horizontal resolution is dominated by receiver spacing rather than shot spacing
- Vertical resolution is controlled by frequency

The current design includes eight walkaway VSP lines that have maximum offsets of 2400 m from the well. From an acquisition standpoint, the walkaway lines are orientated along paths that are easily accessible, minimize permit issues and disruptions to local landowners, and should increase the percent of repeatable shots obtained during monitor surveys.

The baseline walkaway surveys will be acquired in Q1 2015 when the ground is frozen and prior to first CO_2 injection at the sites. The survey will use the DAS fibers in each well to record the data. The light box which records the seismic data will be connected near the well head to decrease the total length of live fiber during recording thus enabling higher sensitivity.

6.1.4.4 InSAR

Two sets of 45 RadarSat2 satellite imagery were collected for the InSAR baseline period from 2012 to 2014. The full set of images acquired up to Q3 2014 have been re-processed using a similar processing flow as was used in 2012 (TRE's proprietary SqueeSAR algorithm) in order to complete the baseline phase prior to injection (Third Annual Status Report: Appendix F).

The baseline dataset indicates minimal ground movement has occurred with deformation trends that are consistent with the initial baseline analysis from 2012 (Figure 6-4). Measurement point density has also increased to 14.47 points/km2 with average displacement rate detection sensitivity of 0.87 mm/year.

The surface deformation modelling was also updated based on the remodelled BCS pressure predictions from the GEN-5 modelling. The expected maximum surface heave over is shown in Figure 6-5 over the project life along with a map of the deformation expected after the first year of injection. These updated results indicate in the best case (high case geomechanical properties) InSAR can detect surface deformation within the first year of injection. However, as this modelling represents the maximum displacements based on geomechanical properties with an uncertainty of one order of magnitude, deformation may be too small to be captured within the first number of years of injection.

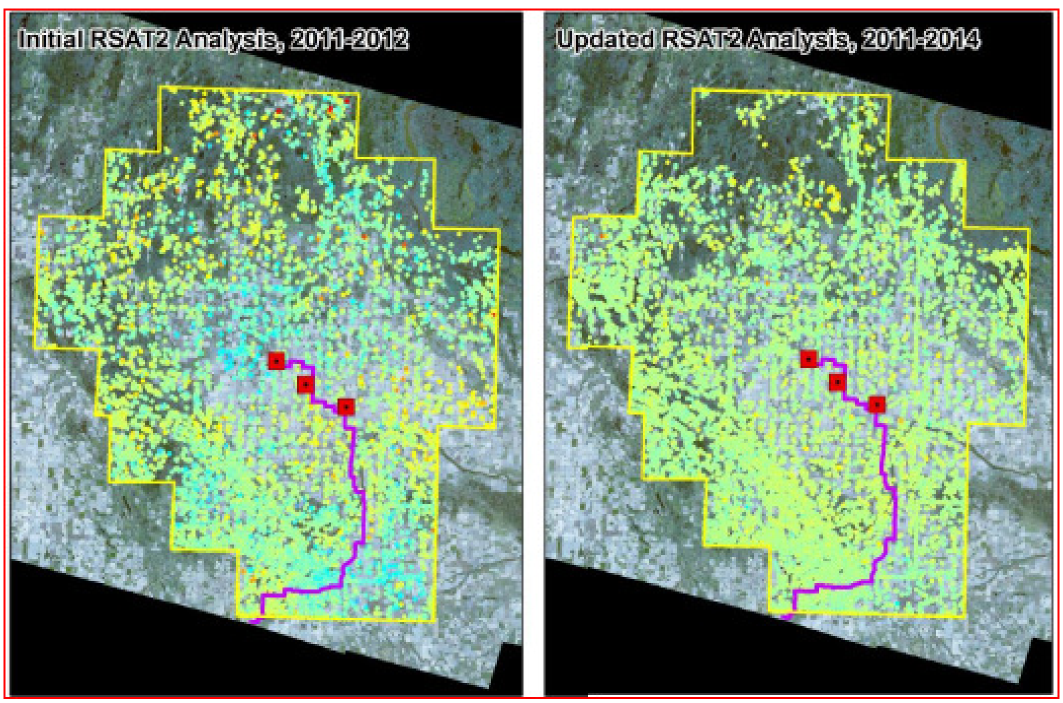


Figure 6-4: InSAR analysis of baseline period data collection from 2012 – 2014

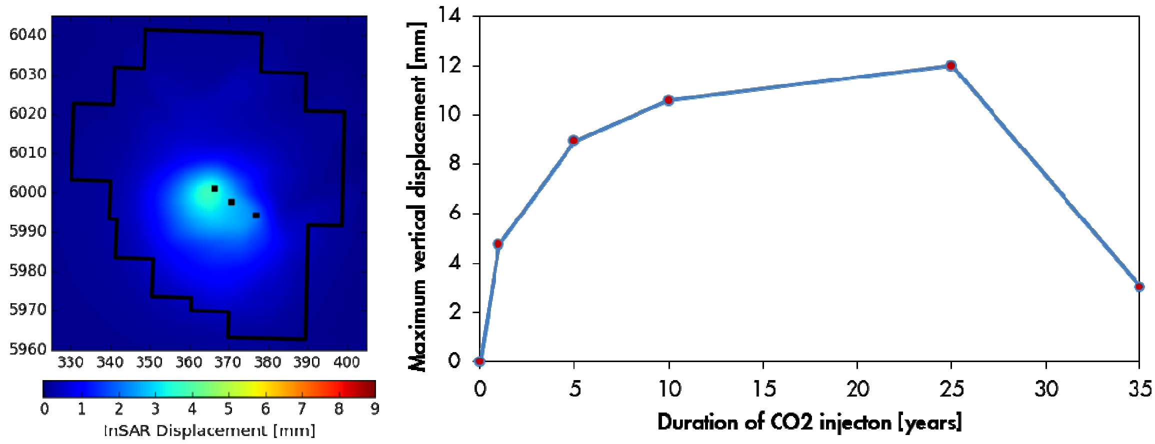


Figure 6-5: Surface heave after one year of injection (left) and maximum surface heave over the life of the project (right)

6.1.5 In-Well Monitoring Activities

6.1.5.1 DMW Pressure Monitoring

Continuous baseline pressure data acquisition in the Cooking Lake Formation via DMW 7-11 and DMW 5-35 commenced in January 2014, and the data are plotted in Figures 6-6 and 6-7. Completion of DMW 8-19 in the Cooking Lake Formation has been delayed until Q1 2015. At this time, the microseismic monitoring array will be retrieved and reinstalled with a pressure sensor after the well has been perforated.

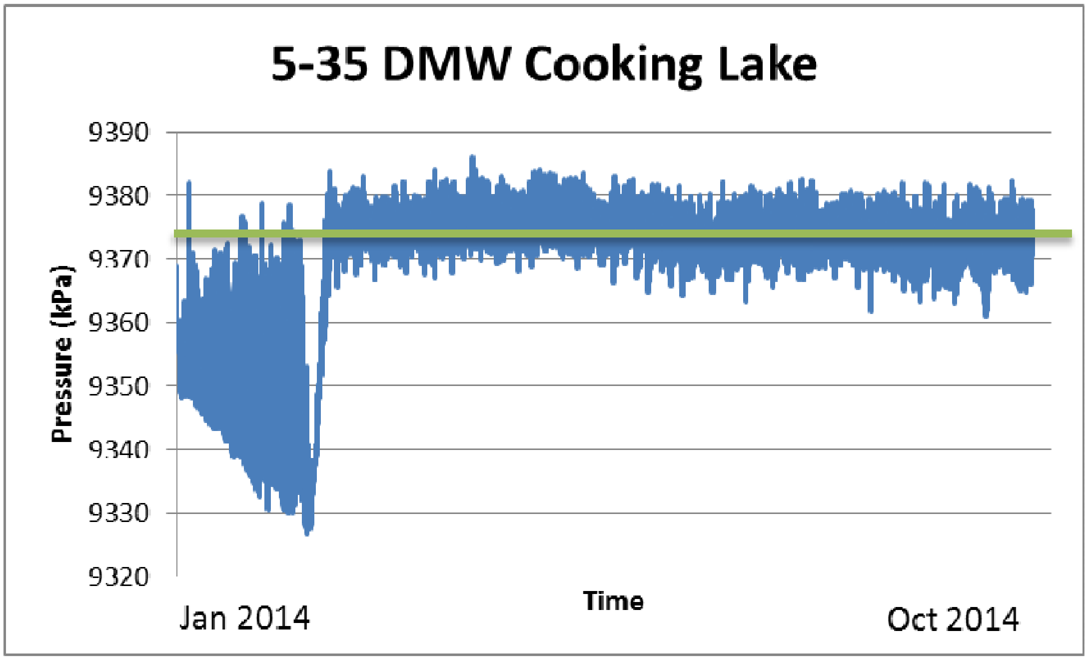


Figure 6-6: Pressure in the Cooking Lake Formation at the DMW 5-35

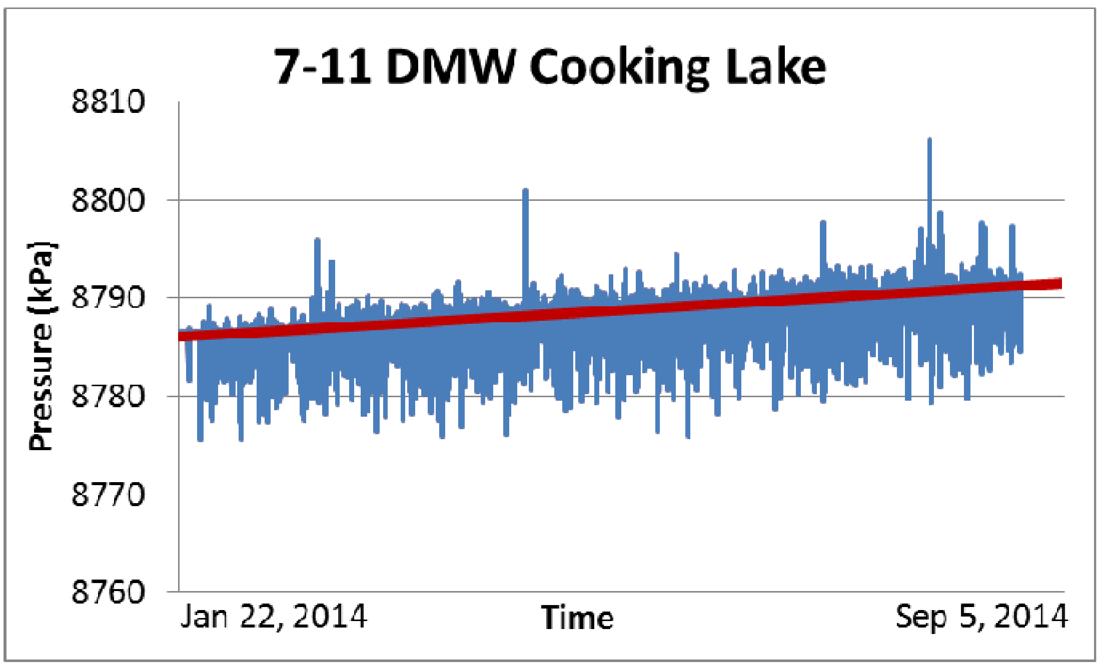


Figure 6-7: Pressure in the Cooking Lake Formation at the DMW 7-11

Thus far, the baseline dataset illustrates that fluctuations of up to 100 kPa may be expected. Furthermore, the DMW 7-11 pressure appears to be drifting upwards; it is unclear at this time if this is related to gauge drift or a real reflection of the reservoir pressure moving towards hydrostatic equilibrium. The pressure in the Cooking Lake

Formation is not at equilibrium due to offset production from the Leduc Reef, which is connected to the Cooking Lake Formation as illustrated in Figure 6-8. These pressure transients in the Cooking Lake Formation could lead to misinterpretation of the data observed by the Quest Project. As the Redwater 3-4 well is located considerably closer to the Leduc Reef, any pressure data collected there could be used as a proxy for the Leduc Reef pressure response; this could greatly increase the project's ability to interpret what is actually happening within the Cooking Lake Formation. Therefore, Shell has requested Alberta Energy to include Redwater 3-4 into the scope of the previous consent to monitor pressures in the Cooking Lake Formation. This request is currently being reviewed .

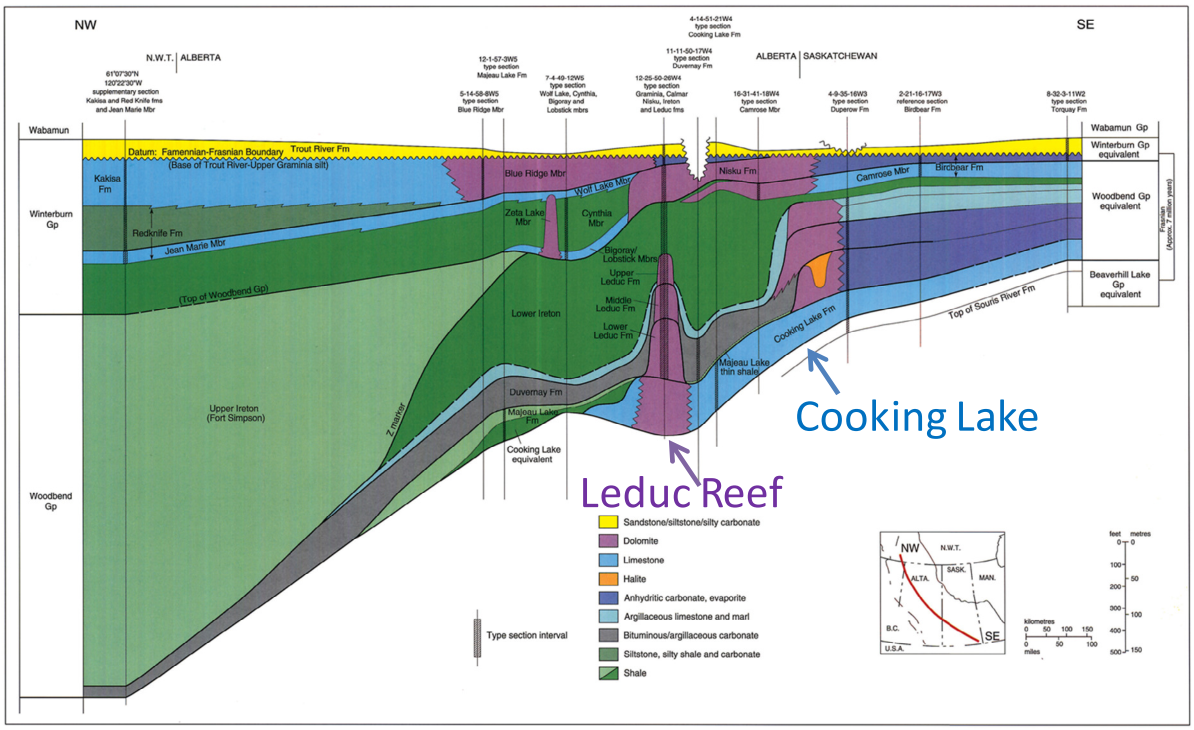


Figure 6-8: Schematic cross section illustrating Cooking Lake Formation connection to the Leduc Reef connection

Reference http://www.ags.gov.ab.ca/graphics/atlas/fg12_07.jpg

6.1.6 MMV Infrastructure

In 2014, all of the downhole pressure and temperature (DHPT) gauges in the injection and deep monitoring wells and the TROLL gauges in the groundwater wells were connected to an on-site building which was designed to accommodate the electronic interface , recording, and transmission equipment in the MMV building (Figure 6-9). The data from these sensors has been interfaced into the SCADA system that links directly to the Production Information (PI) database at Scotford. Safety critical signals such as the injection wells injection pressure will also be displayed via this system in the Scotford control room.

Figure 6-9: MMV infrastructure – Groundwater well surface interface equipment (left) and MMV building (right)

In addition, Shell has developed a web-based toolkit that interfaces directly with the PI database and displays these data online in real-time at any Shell location. The system will be fully operational in Q1 2015 when the final connection is completed between the SCADA system and the PI database.

Finally, Shell has developed and installed a dedicated private radio link to transmit other MMV data, such as LightSource, DAS/DTS, and microseismic data, to Scotford and onto a Shell server where it can be accessed by third party service providers. This system is expected to be operational in Q1 2015 when the radio equipment is installed on the tower at the 8-19 well site. The well site sensor hook-up and data transmission approach is illustrated in Figure 6-10.

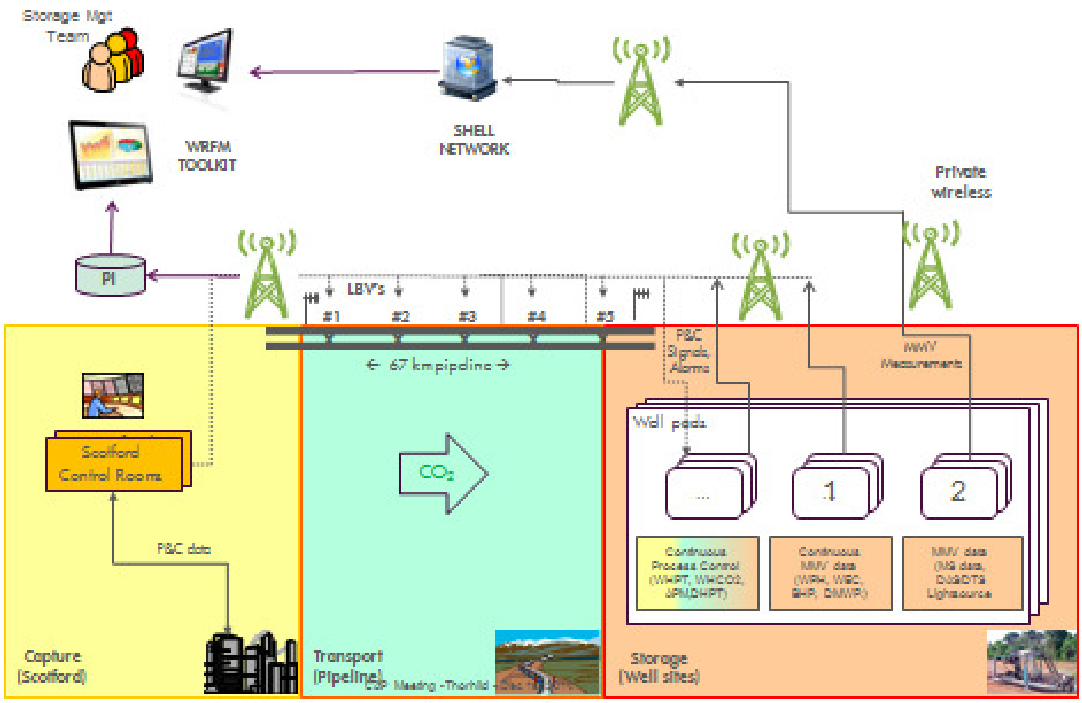


Figure 6-10: MMV infrastructure – well site sensor hook-up and data transmission

7 Facility Operations - Maintenance and Repairs

With approximately 4 months remaining before start-up, work developing the maintenance plans for the capture facility, pipeline, and wells is complete. Identifying the key preventative maintenance activities and final reviews and approvals is approximately 75% complete, with no key activities required for commissioning and start-up outstanding. Training plans and the maintenance procedures for the maintenance personnel is well under way, and has included vendor training for key components (analysers, compressor).

Wherever possible, we are leveraging existing processes, systems and procedures to facilitate a smooth transition of the Quest project into Site routine maintenance and operations.

Spare parts requirements based on vendor supplied information have been purchased, with delivery of all kit expected by the end of February 2015. As well, we have completed the last of our RCM studies. SAP (electronic equipment database) structure has been created and populated with all required information.

Networking with external, operating facilities continues to help better identify maintenance practices and procedures.

8 Regulatory Approvals

8.1 Regulatory Overview

As stated in the previous annual report, a public hearing was conducted March 5 to 9, 2012, by the ERCB (now AER) to assess the applications that had been submitted for the Project. These applications included an amendment to the existing Scotford Upgrader license 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 8-19 injection well. These were submitted in November 2010 along with a harmonized federal/provincial Environmental Assessment.

The Decision Report outlining the ERCB response to the hearing and applications was released on July 10, 2012. This report provided approval of the Project subject to 23 conditions relating to various aspects of the Project that are required to be carried out. Shell subsequently accepted these conditions and Minister's approval of the application was granted on August 18, 2012.

Ongoing regulatory work, in this reporting period, included involvement in the Regulatory Framework Assessment (RFA) which was completed in November 2012, and involvement in the GHG quantification protocol development and application for lateral and monitoring well approvals. In the RFA process, Shell participated in the technical subcommittees and the steering committee to develop a framework of regulations required for the ongoing CCS projects. This developmental work concluded in December 2012. The GHG quantification process followed a similar path of Shell participation in the discussions and development of the draft protocols for GHG quantification.

In 2014 applications submitted to the AER included a Directive 56 amendment application (D56) for the main pipeline, a Directive 65 application (D65) for the storage scheme along with a Directive 51 application (D51) for the 05-35 and 07-11 injection well. A Directive 56 well amendment application (D56) will also be submitted in Q1 of 2015 for the 08-19 well.

8.2 Regulatory Hurdles

The Quest project experienced 3 hurdles during this reporting period. In the 2014 MMV Plan Update, the Quest project indicated that it intended to acquire 6 months of baseline data in the pre-injection phase. Due to unforeseen complexities in the well-head design the baseline monitoring period would have to be reduced from 6 to 2 months. The Alberta Geological Survey (AGS) has stated that industry perception has changed due to increased seismic activity identified in other areas of North America, which makes the collection of baseline data more of a priority. The Quest project met with the AER to discuss this change from the MMV plan on August 30, 2014.

The Quest project was able to make the well-head design work and started to collect data on November 15, 2014. On January 21, 2015 the Quest project met with AER again to discuss the results acquired from 2.5 months of micro-seismic data collection. AER was asked if 4.5 months of micro-seismic data collection, showing no micro-seismic activity, would be acceptable; if so, this would enable Quest to start-up in April 2015. AER responded and agreed that 4.5 months of baseline micro-seismic data is sufficient. However, if injection starts later than planned, Quest will continue with baseline data collection until injection starts or until 6 months of data is collected, whichever comes first.

Second, two injection wells require D51 Approval prior to commencement of injection. Hydraulic isolation test/log is a D51 requirement but it requires injection, usually water, to perform it. Our experience with the IW 08-19 well test has been that water injection has a high risk of causing formation damage in the BCS. The Quest project has therefore evaluated the options for hydraulic isolation testing to meet the D51 requirements and a proposal has been included with the D51 applications in Oct 2014.

Furthermore, post drilling, the Quest project identified surface casing vent flows in all deep monitoring and injection wells as well as gas migrations in injection wells IW 07-11 and IW 05-35. Detailed discussions have been held with AER concerning this issue and approval was granted to defer any repair until well abandonment with a number of monitoring commitments (see the MMV plan). The Quest project has concluded that this issue does not impact the hydraulic isolation and containment risk of the BCS. This has been confirmed by an independent external study on injection well integrity.

Finally, MMV Plan approval is required before injection can begin. AER has been informed that the projected injection date is April 4, 2015, and is doing everything possible to ensure approval is secured in time to support this date.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to the Project for the reporting period of March 2014 to March 2015.

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	Received on June 20, 2012	
CO_2 Capture Infrastructure			
Decision regarding Application No. 013-49587 pursuant to Division 2, Part 2 of *EPEA*	AEW	Received on August 3, 2012	
Decision regarding Application No. 1671615 pursuant to Section 13 of the *Oil Sands Conservation Act,* and to amend Approval No. 8255	ERCB	ERCB Decision Report received on July 10, 2012 Ministerial Order Approval received on August 18, 2012	ERCB Public hearing held March 5 – 9, 2012
CO_2 Pipeline			
Decision regarding Application No. 011-284507 pursuant to *EPEA*	AEW	Decision received on February 15, 2013	
Decision regarding Application No. 1689376 pursuant to Part 4 of the *Pipeline Act*	ERCB	ERCB Decision Report received on July 10, 2012 Ministerial Order Approval received on August 18, 2012 AER (formerly ERCB) Main Pipeline Approval received August 24, 2012. Amendments to Main Pipeline approval to be done in Q1 2014.	ERCB Public hearing held March 5 – 9, 2012
Pipeline lateral line approvals	AER (formerly ERCB)	Received April 22, 2013, August 22, 2013 and September 17, 2013	
Pipeline main line MOP decrease amendment	AER	Received July 8, 2014	
CO_2 Injection and Storage			
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	AER	ERCB Decision Report received on July 10, 2012 Ministerial Order Approval received on August 18, 2012	ERCB Public hearing held March 5 – 9, 2012
CO_2 Disposal Class II Scheme Approval No. 11837, Application No. 1670112	AER	Received on August 24, 2012	
Well License approvals to drill injection, deep monitoring and groundwater monitoring wells, Application No. 1739197, 1739195, 1739220, 1739215, 1739194, 1739201, 1739198	AER	Received on June 16, 2012, November 16, 2010, September 17 and 19, 2012	
Directive 065/051 applications for 5-35 and 7-11 injection wells	AER	Submitted Q4 2014	Required for wells 7-11 and 5-35
Directive 56 amendment application 8-19 injection	AER	Planned submission Q1 2015	Change well type from test to injection

8.4 Next Regulatory Steps

In the upcoming period, the Project regulatory activity will focus on obtaining the remaining permits required for the Project.

During construction of the main pipeline, re-routes were found to be needed at five locations to address environmental and safety risks. Although minor in nature, three of these re-routes will require amendments to the current pipeline license to ensure accurate mapping records with the AER. These amendments will also change the pipeline length to that which is now contemplated. These amendments were completed in Q1 2014.

A minor amendment is needed to the well license for the 8-19 injection well to change the well type from “test hole” to “injection”. This amendment will be done prior to injection. Applications under D51 for injection in the 7-11 and 5-35 wells were submitted to AER in Q4 2014. The associated amendment to the D65 scheme approval for sequestration will also be submitted to AER.

Ongoing support work is expected throughout 2014 and 2015 for the continued work on the RFA process and the GHG quantification protocols being developed by Alberta.

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 its 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 2010. The consultation program included stakeholders such as:

- Directly affected landowners and occupants along the pipeline route and within 450m 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 representatives

- Provincial and federal regulators
- Aboriginal communities

Face-to-face consultation with landowners and occupants along the 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

In the reporting period of 2014, the following specific stakeholder engagement events occurred:

- Shell conducted two Quest Open Houses in the communities of Thorhild and Radway in October 2014 to update the local stakeholders on the pipeline construction and progress to date on the capture plant and local drilling activities.
- Shell – as a part of its regulatory license renewal process at Scotford – also held open houses in the communities of Bruderheim, Josephburg and Fort Saskatchewan in October and November 2014 where Quest representatives were on hand to share information on the project and progress to date.
- Shell held three “coffee” chats where an advertisement was placed in the local newspaper asking residents to join Shell for free coffee and have a conversation about Quest. The events were well attended and were an opportunity for face-to-face dialogue with residents in a local establishment in their community.
- Shell attended a series of local community events in the summer of 2014 to provide more of a community presence and information about the Project, which allowed for a broader reach of community members. (Events included the Fort Sask Trade

Show; Community Appreciation Day; Canada Day Festivities and Parade in Fort Saskatchewan; Bruderheim Ag Days; and various Days of Caring activities.)

- County/Town Council specific Project updates were given to councils in Thorhild, County,the City of Fort Saskatchewan, the Town of Bruderheim and Strathcona County. The meetings were held in the spring and summer of 2014.
- In 2014, Shell issued two community newsletters to stakeholders in the Quest communities providing an update on the Quest project.

- In order to provide more stakeholder involvement in the storage area-monitoring program, a Community Advisory Panel (CAP) has been convened with participation from local citizens. The Panel will provide input into the development of the monitoring program and review the results of work. The CAP was initiated in November 2012 and had two meetings in 2014.

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 used by Shell over the life of the Project to track project costs.

The cost estimate is $812 million versus the original $874 million and premised on a Base Case of three injection wells and a reduced pipeline length. Other changes include updated phasing based on actual project costs and incorporating changes due to construction delays. Actual spending and forecasting is on an incurred basis.

Development costs for the Project for the FEED stage (January 1, 2009 to December 31, 2011) are included in the table below and reflect costs associated with front end engineering for the capture and pipeline units as well as sub-surface modeling and early drilling. Capitalization of the project began January 1, 2012 as per Shell Canada Limited capitalization policy.

Table 10-1 Anticipated Project Capital Costs (February 2015 Estimate)

	FEED 2009 - 2011 Jan 1 , 2009 - Dec 31, 2011	FISCAL 2011 Jan 1 , 2012 - March 31, 2012	FISCAL 2012 April 1 , 2012 - March 31, 2013	FISCAL 2013 April 1 , 2013 - March 31, 2014	FISCAL 2014 April 1 , 2014 - March 31, 2015	FISCAL 2015 April 1 , 2015 - March 31, 2016	Total
Overall Venture Costs	19,470						
Shell Labour, & Commissioning	19,470	5,414	32,639	23,466	48,078	27,745	137,342
Tie-in Work /Brownfield Work							
Tie-In/Turnaround Work Capture	0	0	7,331	10,234	9,607	9,808	36,980
Tie-In Work Pipeline		0	196	518	287	0	1,002
Sub Total	0	0	7,527	10,753	9,894	9,808	37,982
Capture Facility*	52,671						
Engineering		6,662	40,889	32,799	5,426	0	85,775
Construction Management		0	218	16,967	21,859	0	39,044
Material		6,092	42,315	56,502	11,309	0	116,218
Site Labor		0	0	9,456	36,816	0	46,271
Subcontracts		0	0	1,380	7,431	0	8,811
Mod Yard Labor Including Pipe Fab		0	14,250	60,697	29,832	0	104,780
Indirects / Freight		0	15	32,339	12,531	0	44,885
FGR Mods/HMU Revamps		0	0	0	0	0	0
Sub Total	52,671	12,753	97,688	210,141	125,203	0	445,785
SUBSURFACE - Wells*	63,175						
Injection Wells		1,090	17,970	3,641	276	671	23,648
Monitor Wells		0	1,311	54	-20	0	1,345
Water Wells		0	1,620	-53	1	0	1,569
Other MMV		0	1,657	3,309	5,774	3,094	13,833
Sub Total	63,175	1,090	22,558	6,951	6,032	3,765	40,395
PIPELINES - TOE*	4,035						
Engineering		576	4,272	2,782	1,172	0	8,802
Materials		0	1,878	24,823	4,736	0	31,437
Services		0	0	60,101	26,984	375	87,460
Sub Total	4,035	576	6,150	87,706	32,892	375	127,698
Total Contingency, Inflation & Mrkt Escalation	0	0	0	0	1,926	20,562	22,488
Sub Total	0	0	0	0	1,926	20,562	22,488
Grand Total	139,351	19,832	166,563	339,016	224,024	62,255	811,690

* Shell labour costs during FEED are booked here.

10.2 Opex Costs

Opex reflects an average year spend. All years are anticipated to be similar, based on the injection profile of up to 1.2 Mt/a of CO_2 injected.

Estimates previously provided were from the original assessment. No design changes have been implemented, but the operating costs has been updated with 2015 premise pricing. The premise natural gas price is $3.54/GJ and $111.00/MWhr for electricity.

Table 10-2 Anticipated Project Operating Costs (2015 Estimate)

Item	Average Costs per Year (,000)
Steam and Electricity	25,801
Chemicals	275
Labour & Maintenance	5,945
Insurance	178
Property Tax	4,286
Directs vs. indirect costs	183
MMV Costs	3,776
Tariffs	0
Sustaining Capital	1,359
Turnarounds	2,099
Total	**43,901**

10.3 Revenues

Revenues reflect funding received and to be received (Table 10-3) until commercial operation. Ongoing revenues during operations will be estimated on the basis of credits received for the CO_2 volumes stored, along with the additional credits received as per the multi-credit agreement signed with the Province of Alberta. Using 2013 Alberta carbon prices of $15 per tonne, and on the basis of the draft *Quantification Protocol for the Capture of* CO_2 *from Steam Methane Reforming and Permanent Storage In Saline Geological Formations* (to be finalized in 2015), the approximate revenue is expected to be approximately $30 million per year.

Table 10-3: Anticipated Project Revenue 2009 – 2015

	2009	2010	2011	2012	2013	2014	2015
	Apr 1, 2009 – Mar 31, 2010	Apr 1, 2010 – Mar 31, 2011	Apr 1, 2011 – Mar 31, 2012	Apr 1, 2012 – Mar 31, 2013	Apr 1, 2013 – Mar 31, 2014	Apr 1, 2014 – Mar 31, 2015	Apr 1, 2015 – Mar 31, 2016
Revenues from CO_2 Sold							
Transport Tariff	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pipeline Tolls	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenues from incremental oil production due to CO_2 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	$161,000,000
	$3,547,059	$1,817,101	$1,302,507	$238,000,000	$115,000,000	$53,000,000	$161,000,000

Table 10-4: Government Funding Granted 2009 – 2015

Government funding granted or pending through construction of Quest project.

	2009	2010	2011	2012	2013	2014	2015	
Government Funding	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	April 1 , 2016 - March 31, 2026
Alberta Innovates Grant	$ 3,547,059	$ 1,817,101	$ 1,302,507					
NRCan Funding				$ 108,000,000			$ 12,000,000	
GoA Funding				$ 130,000,000	$ 115,000,000	$ 53,000,000	$ 149,000,000	$ 298,000,000
	$ 3,547,059	$ 1,817,101	$ 1,302,507	$ 238,000,000	$ 115,000,000	$ 53,000,000	$ 161,000,000	$ 298,000,000
Gov't Funding as Percentage of Total Project Spend	0.3%	0.4%	0.5%	17.5%	25.7%	29.5%	40.9%	62.2%

10.4 Funding Status

To date, the Project has received a total of $6.6 million from the Alberta Innovates program, which is concluded. The Project has met the criteria of allowable expenses for the $120 million NRCan funding from the Government of Canada, and 90% of the funding was paid in August 2012 with the Project having met the CEAA compliance. Within the terms of the NRCan agreement, 10% of the $120 million will be held back pending full completion of the Project work and successful Commercial Operations to the end of the NRCan program. Funding from the Government of Alberta CCS Funding Agreement of $15 million was received in May 2012, $40 million in October 2012, $75 million in April 2013, $100 Million in October 2013, $15 million in April 2014 and a further $38 million in October 2014.

Funding levels expected in the next reporting period will be $15 million from the Province of Alberta associated with the CCS Funding Agreement Milestone #7 (invoice March 2015) and $149 million at Commercial operation to be invoiced in October 2015. Additionally, once we have completed the Commercial Test runs, we are expected to receive the remaining holdback from NRCAN of $12 million less expenses.

11 Project Timeline

The timeline for the Project is shown in Table 11-1. There were no significant changes in schedule in this reporting period.

Minor changes in schedule, since last reporting period, are reflected in the following activities:

- Main venture activities are extended into 2015 to reflect commercial operations to Q4 2015
- Commissioning and start up for the pipeline continues into 2015
- Commission and start up of the wells are in 2015 to follow the start up of HMU3
- Regulatory activities extend into 2014 to include the D51 injection well application, amendments to the main line D56 approval and the amendment required for the D65 storage approval.

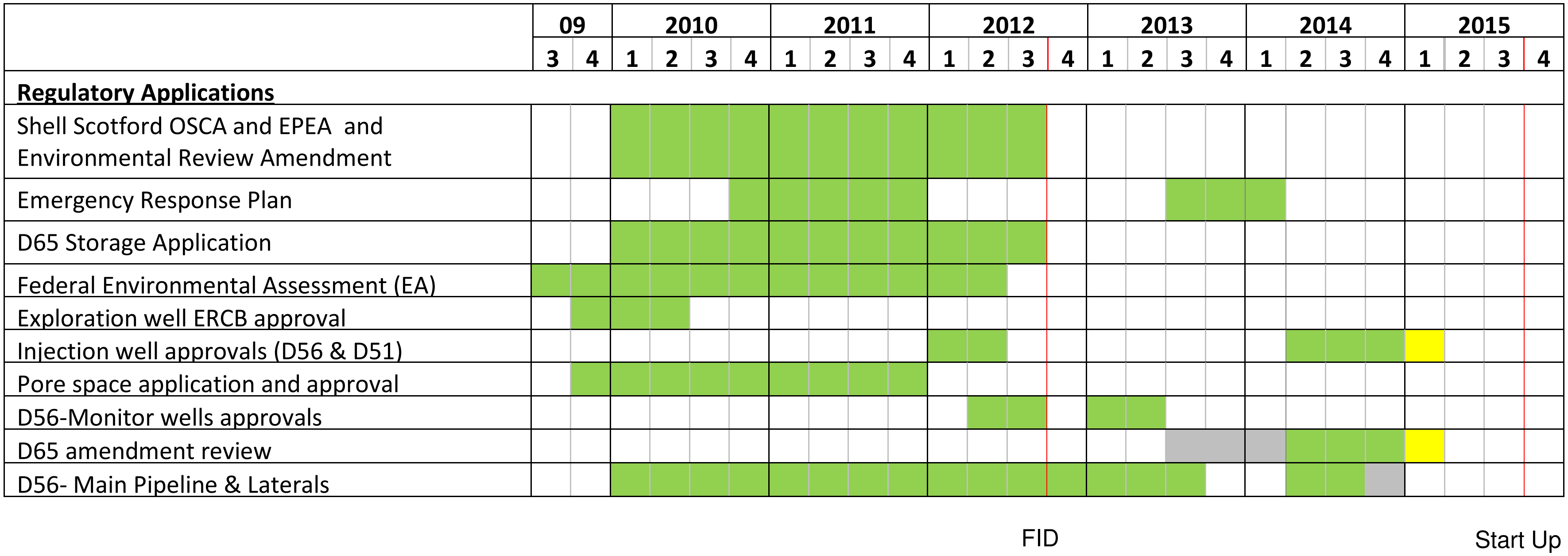
For further details on the construction activities, see Section 2, *Figure 2-1*.

Table 11-1: 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: 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																										
CO2 injection test Radway Well 8-19																										
Storage Performance Assessment																										
Produce 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 injection wells/monitoring wells																										
Injection wells drilled/completed																										
Monitor wells drilled/completed																										
Commissioning and start-up																										


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
Shell Scotford OSCA and EPEA and Environmental Review Amendment
Emergency Response Plan
D65 Storage Application
Federal Environmental Assessment (EA)
Exploration well ERCB approval
Injection well approvals (D56 & D51)
Pore space application and approval
D56-Monitor wells approvals
D65 amendment review
D56- Main Pipeline & Laterals
FID
Start Up

12 General Project Assessment

The Project schedule, as noted in Section 11, is largely maintained with the plan of achieving commercial operation by end of 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 – 2014

Capital Cost Management

As a greenhouse gas reduction project, the Project does not carry the revenue streams that traditional projects do and is economically challenged. Additionally, government funding for the Project is on a fixed basis and any cost overruns will be borne strictly by Shell and the joint venture owners. These concepts result in the capital management being a major focal point for the Project. The Project was able, through examination of the subsurface data, to lower the Base Case number of wells required for injection from five injection wells to three injection wells. Although the pipeline portion of the project saw higher costs than originally anticipated due to number and depth of crossing, and weldability of the line pipe, offsets were found in other areas resulting in an overall reduction in the expected final cost as shown in Section 10. This resulted in a reduction of capital required and the current capital forecast is reduced as shown in Section 10. As of this date, the updated capital costs forecast are being maintained at the expected level with no indications of an overrun. Although there are cost and schedule pressures, the team has been able to successfully mitigate and manage these risks. The focus on cost will remain during the commissioning and start up of the facilities in 2015.

Detailed Engineering

Detailed engineering is complete. A small team remains in Q1 2015 to complete as-built drawings and support the closeout of purchase orders.

Module Work

All modules were completed in July of 2014 and successful set in place by mid August.

Construction Work

Construction is complete (final tie-ins excepted) and all systems have been handed over to the Commissioning & Startup team.

Deep Injection and Monitoring Well Drilling Campaign

The Base Case for Project's subsurface program is a three-injection well concept with each one also having a deep monitoring well located next to it. In total, these six wells are the scope of the deep drilling for the Project. One of the wells was completed earlier when it was drilled as the final test well and the resulting favourable analysis of the storage area resulted in it being re-designated as an injection well. Over the period of end 2012 to early 2013, Shell drilled the five remaining wells at the predetermined sites. Drilling activities during the campaign were carried out and the initial studies of the local storage areas are positive. The second and third injection wells were flow tested with better than expected results, thereby confirming that the three injection wells complete the required deep drilling program for the Project.

Baseline MMV Data Acquisition

A key criteria of the monitoring, measurement and verification program is the establishment of baseline data prior to operations. In the spring of 2012, this program commenced with field data gathering of soil, air, groundwater and other tests. This program was completed at the end of 2014 fulfilling a commitment to acquire this baseline data for a 2 year period. Two of the deep monitoring wells were completed in the Cooking Lake formation in September 2013; the down-hole gauges have been recording pressure data since January of 2014. The third deep monitoring well was completed in November 2014 with a temporary installation of a micro-seismic array and has been recording data since mid-November 2014. A field system for measuring the C13 isotope of CO2 was successfully tested and baseline data acquired at the wellpads in July 2014 and this approach has since been added to the monitoring program. A baseline walkaway VSP was completed in February 2015 at all 3 injection wells.

MMV Infrastructure

All the onsite cable connections, interfaces and the SCADA equipment has been installed and all the downhole pressure and temperature data in the deep wells and the data from the probes in the shallow ground water wells is now relayed real time to the Storage Management Team in Calgary. A private radio system has also been installed and is being used to transmit the micro seismic data real time. The final configuration of the laser Lightsource system has been installed at the 8-19 well pad in preparation for injection at this well in April 2015.

Stakeholder Engagement

Stakeholder management continues to be a priority for Shell. The high level of stakeholder involvement continued in 2014 with three open houses located near the Project's activities. Bi-annual engagements with the municipal and county councils in the areas also received positive feedback. Shell maintained a visible local presence by attending a number of community events in the region over the summer of 2013.

Quest continues to attract wide media coverage and interest from various industry organizations. Shell attended and provided Project information and updates to a large number of these organizations at conferences and meetings over the course of the year in addition to media interviews. Such events included Quest being presented at the EU hearings in Brussels in June 2013, involvement in the CSLF (Carbon Sequestration Leadership Forum) Technical and Ministerial events, and presentation to the Energy Ministry in Norway.

Provincial Government Milestones

Critical to the Project funding for the Government of Alberta is a series of milestones that have been agreed to within the funding agreement that measures the progress of the Project. Funding payments are based on the Project completing these milestones as they come up. All milestones to this point have been passed as scheduled.

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.

Land Acquisition

Acquisition of Amendments to right-of-way and temporary workspace agreements for the pipeline and riser sites is a key Project activity to ensure that construction can safely complete the project and adhere to all environmental and regulatory requirements. Since the initial acquisition of the pipeline right-of-way, area land values have increased by six thousand dollars per acre in the Heartland Industrial district, which has increased costs for revisions and has created an issue for some area stakeholders who have been requesting top-up compensation to address the change in area rates. Negotiation with landowners and legal representatives has taken place to alleviate landowner concerns and all agreement revisions and additional area acquisitions had been acquired with strict time sensitivity to meet construction needs. Since initial acquisition there have been parcels of land that have changed ownership which has created new landowner concerns and demands for compensation. Another challenge has been construction of the pipeline right-of-way paralleling several other area operator projects that are currently under construction, thus limiting the area the Shell Quest team has for construction as landowners had since sold the areas for the Quest temporary workspace to other companies for right-of-way.

Capture Site Construction

The Project experienced delays in the delivery of valves and some electrical and instrumentation bulk items that affected the timely fabrication of pipe spools for the modules and site construction as well as assembly of the modules. Efforts were made to expedite this material as well as source from other vendors to maintain the project schedule. Where we could not advance delivery to match the required ship-to-site dates for the modules, work-arounds were engineered to allow those components to be installed at site. The construction schedule was adjusted to slow down the ramp up of the workforce to match when work was available. A nightshift was put in place in the latter half of July through to the end of November to enable a higher peak manpower with limited working space. Construction also worked with the CSU team to ensure priority systems were delivered as soon as possible to enable commissioning to start.

Landowners

Several landowners were not satisfied with the level of clean up on their sections of right of way and have requested additional work be done. We are visiting each of the landowners individually to document additional work required and have started some work while the ground is frozen but remaining will need to wait until after spring break up. County of Thorhild is also concerned about drainage in one area due to previous years flooding. Working with landowner and county to determine what else is required.

Regulatory

Two injection wells require D51 Approval prior to commencement of injection. Hydraulic isolation test /log is a D51 requirement but it requires injection, usually water, to perform it. Our experience with the IW 8-19 well test has been that water injection has a high risk of causing formation damage in the BCS. We have therefore evaluated the options for hydraulic isolation testing to meet the D51 requirements and a proposal has been included with the D51 applications in Oct 2014.

Furthermore, post drilling, Shell identified surface casing vent flows in all deep monitoring and injection wells as well as gas migrations in injection wells IW 7-11 and IW 5-35. Detailed discussions have been held with the AER concerning this issue and approval was granted to defer any repair until well abandonment with a number of monitoring commitments (see the MMV plan). Shell has concluded that this issue does not impact the hydraulic isolation and containment risk of the BCS. This has been confirmed by an independent external study on injection well integrity

Stakeholder Engagement

Shell has developed and initiated an extensive stakeholder management plan to proactively engage the communities that we will be working in. With this, we have however observed some increased landowner concerns associated with the increased activity in the region. This activity has included the initiation of the groundwater-sampling program, vegetation analysis program, construction activities for our pipeline, and construction activities for two additional pipelines in the region not associated with Quest. As such, we are evaluating additional opportunities to improve our relationships including good neighbor deeds such as clearing driveways of snow, brochure handouts associated with the groundwater-sampling program to better explain the program, increasing Shell employee presence in the field, and providing Quest Coffee talks with the residences. We are also evaluating changes to our Open House content to better manage the real-time issues.

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 the following activities:

- Engineering design in the Calgary offices
- Construction work at the Scotford Upgrader site
- Well drilling in the storage area
- Field work done to benchmark the hydrosphere and biosphere properties of the storage area surface and groundwater regions

Well drilling activities and engineering design were completed in 2013. The construction work and benchmarking activities will continue throughout 2014.

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.

There are additional benefits in the Edmonton area as the module yard that is constructing the modules for the capture facility will be in full production in Sherwood Park. Pipeline construction is using local labour and was complete in Q3 2014.

Discussions began in 2014 with the US DOE to utilize Quest as a project to develop and deploy additional MMV technologies to support either reduced technology cost or improved monitoring for containment security. It is expected that work continues in

2015 towards deploying some of these technologies. This will help raise the profile of the CCS leadership that Alberta and Canada are demonstrating.

13 Next Steps

The Project is now in the Execute Phase through to the end of 2015 and the focus in the upcoming reporting period will be to complete commissioning and startup activities, and ultimately to handover the new facility to Shell Scotford for sustained operations.

The priority for the CSU team is to complete the cleaning of HMU #3 and main Capture plot systems. Following successful completion of a pre-start up audit and signoff of all Statement of Fitness documents, the CSU team will start up the amine system in HMU #3 and the regeneration system in the main capture plot. Once that operation stabilizes the compressor and dehydration system will start up. The opening of the discharge valve will follow this to allow CO2 to push the nitrogen from the pipeline preparing for first injection.

In April/May, the 2015 turnaround will complete the final process and utility ties in for HMU #1 and common facilities as well as the change of catalyst in the Pressure Swing Absorbers and burner change out in the steam methane reformer. The Quest facilities will be down during the common utility outage and then restart on HMU #3 when the utilities are back on stream. HMU #2 systems will come on stream as the plant comes back up after the turnaround. The CSU team will complete the final commissioning activities on HMU#1 after the turnaround and then that system will be started up. Data collection for the three government tests will begin as soon as the system is stable.

Microseismic data will continue to be collected as committed in the MMV plan. The final completion work on the three injection wells and installation of final microseismic array and pressure monitoring in the 8-19 deep monitoring well along with the DTS recording equipment will be carried out in the first quarter of the year to match the projected startup. The monitoring phase of the hydrosphere and biosphere will begin on start of injection.

Regulatory activities will focus on receiving the D 51 approvals to convert our wells to injection wells as well as submitting and gaining approval of the updated MMV plan submitted on 31st Jan 2015 to convert our wells to injection wells. Work will continue as needed on providing assistance to the provincial regulators on the Regulatory Framework Assessment and GHG offset quantification protocols currently in progress.

Stakeholder engagement activities will continue to ensure continued public knowledge of the Project's progress. The Community Advisory Panel will continue in 2015 and continue to update the group on Quest activities as our focus moves from construction to commissioning and start up. Similarly, ongoing reporting will continue to both the Governments of Canada and the Province of Alberta in accordance with the respective funding agreements to keep these bodies apprised of Project activities. On a milestone basis, *Figure 13-1* lists the major activities occurring during the next reporting year.

Figure 13-1 Project Milestones

Key Milestone (Bold indicates GoA milestone)	Original Target	Actual/ Forecast	Status	Status Comment
HMU 1 &2 Amine Absorber tower – Set/Install	Mar 31, 2014	Mar 21, 2014		Completed
GOA milestone 5 – Set 3rd Gen Module	Mar 31, 2014	Mar 31, 2014		Module in place.
Last Module Set/Install	June 30, 2014	Aug 13, 2014		Last module received July 18th. Last module set Aug 13th.
Compressor final alignment	Aug 30, 2014	Feb 5, 2015		Removed from critical path by doing pipe strains in advance and lube oil flush
GOA milestone 6 – Set all 3rd Gen Modules	Sep 30, 2014	Aug 30, 2014		Certificate received.
Pipeline Mechanical Completion	Oct 31, 2014	Oct 28, 2014		Completed
GOA Milestone 7 Quest "Substantial Completion"	Mar 31, 2015	Mar 31, 2015		On track
First Injection	June 30, 2015	Mar 31, 2015		On track
Full Capacity	Sept 30, 2015	July 31, 2015		On track
GoA Milestone – Sustained Commercial Operations	Dec 31, 2015	Oct31, 2015		On track