# Quest Carbon Capture and Storage Project

# ANNUAL SUMMARY REPORT - ALBERTA DEPARTMENT OF ENERGY: 2017

March 2018

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# Executive Summary

This Summary Report is being submitted in accordance with the terms of the Carbon Capture and Storage (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 Quest CCS facility (Quest) and as agent for and on behalf of the AOSP Joint Venture and its participants, comprising Shell Canada Energy (60%), Chevron Canada Limited (20%) and 1745844 Alberta Limited (20%), as amended. Note that, although Shell Canada Energy has divested its 60% interest in the AOSP Joint Venture to Canadian Natural Upgrading Limited, effective May 31, 2017, Shell Canada Energy continues to hold the rights and obligations under the Carbon Capture and Storage (CCS) Funding Agreement at the date hereof.

The purpose of Quest is to deploy technology to capture $CO_2$ produced at the Scotford Upgrader and to compress, transport, and inject the $CO_2$ for permanent storage in a saline formation near Thorhild, Alberta. Approximately 1.2 Mt/a of $CO_2$ will be captured, representing greater than 35% of the $CO_2$ produced from the Scotford upgrader.

First injection of $CO_2$ into injection wells 7-11 and 8-19 occurred on August 23, 2015 and commercial operation was achieved on September 28, 2015 after the successful completion of the three performance tests outlined in Schedule F of the CCS Funding Agreement. In 2017, Quest surpassed 2 Million tonnes of injected $CO_2$ and was recognized by the Global Carbon Capture and Storage Institute (GCCSI) as setting a new record for the most $CO_2$ sequestered in a calendar year.

Reservoir performance and injectivity assessments thus far indicate that the project will be capable of sustaining adequate injectivity for the duration of the project life; therefore, no further well development should be required. MMV activities are focused on operational monitoring and optimization.

There were no recordable spills/releases to air, soil or water within the Quest capture unit during the 2017 operating period. MMV data indicates that no $CO_2$ has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir to date.

Shell conducted another open house for the local community. Engagement with local governments continued in 2017 to update officials on operations. Engagement with numerous industry and non-government associations for knowledge sharing also continued in 2017.

Quest has experienced a number of successes in this reporting period, including:

- Sustained, safe, and reliable operations
- Low levels of chemical loss from the ADIP-x process
- Significantly lower carryover of triethylene glycol (TEG) into $CO_2$ vs. design with estimated losses on track to be roughly 5,800 kg in 2017 vs. the design makeup rate of 46,000 kg annually
- Injection into the 5-35 well continues to not to be necessary due to strong injectivity performance, which results in significant MMV cost savings
- Strong evidence that Quest will sustain adequate injectivity for the duration of the project life
- Overall maintenance issues have been minimal

- Sharing of best practices by networking with other operating facilities continues to help improve maintenance practices and procedures
- Strong integrated project reliability performance with operational availability at 98.3%
- Maintaining local support through the extensive stakeholder engagement activities
- Continued participation of the Community Advisory Panel (CAP)
- International engagements with the Global CCS Institute to support public engagement, global knowledge sharing activities and numerous tours to the Scotford facility
- Continued work with a United States Department of Energy-funded entity to develop and deploy MMV technologies for use on Quest
- Milestone of 2 million tonnes of $CO_2$ injected was reached in June 2017.
- Operating costs continue to be lower than forecasted.
- Serialization of 1,212,182 credits in 2017 (from 2015 and 2016 operating years)

Challenges for this reporting period were minor operational issues, including:

- Loss of amine circulation due to lean amine charge pump trips on low suction pressures.
- High moisture pipeline trip while placing the TEG carbon filter system in service after carbon filter replacement.

Quest has seen strong reliability performance through the reporting period to safely inject 1.14 Mt of $CO_2$ in 2017. Overall project injection has surpassed 2.6 Mt of $CO_2$ to date.

Revenue streams generated by Quest will remain twofold: (i) the generation of offset credits for the net $CO_2$ sequestered and an additional offset credit generated for the $CO_2$ captured, both under the *Specified Gas Emitters Regulation*; and (ii) $298 million in aggregate funding from the Government of Alberta during the first 10 years of Operation for capturing up to 10.8 million tonnes. In 2017, the value of the offset credit was $30/tonne.

Quest continues to see operating efficiencies with the compressor given the more favourable subsurface pore space. The compressor continues to operate utilizing 13-15 MW versus 18 MW as full design.

Quest provides employment for 14 permanent full time equivalent positions (FTEs) and an additional approximately 10 FTE allocated into existing positions. Quest generated expenditures of ~$32 million in 2017 in staffing, MMV, maintenance, and variable costs to the economy.

Quest continues to receive significant international interest from projects in Norway, delegations from Mexico and the GCCSi, various technical organizations, and presented at COP23 in Bonn, Germany.

# Table of Contents

## List of Tables



## List of Figures

# Abbreviations

| | |
|---|---|
| 2D | 2-Dimensional |
| 3D | 3-Dimensional |
| 4D | 4-Dimensional |
| ACCO | Alberta Climate Change Office |
| 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* |
| 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 |
| FGR | Flue Gas Recirculation |
| FID | Final Investment Decision |
| GHG | greenhouse gases |
| HBMP | Hydrosphere & Biosphere Monitoring Plan |
| HMUs | hydrogen manufacturing units |
| HPLT | High Pressure Low Temperature |
| 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 |
| MSM | Microseismic Monitoring Array |
| ORM | Opportunity Realization Manual |
| *OSCA* | *Oil Sands Conservation Act* |
| PSA | pressure swing adsorber |
| RCM | Reliability Centered Maintenance |
| RFA | Regulatory Framework Assessment |
| ROW | right-of way |

SAP ............................ Systems, Applications, Processes (Equipment Database Software)
SLCN ............................ Saddle Lake Cree Nation
STCC............................ Shell Technology Centre Calgary
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 Scotford Upgrader, operated by Shell Canada Energy, as agent for and on behalf of the Athabasca Oil Sands Project (AOSP) Joint Venture and its participants, comprising Canadian Natural Upgrading Limited (60%), Chevron Canada Limited (20%) and 1745844 Alberta Limited (20%), is part of Shell's Scotford facility located northeast of Edmonton. Note that although Canadian Natural Upgrading Limited is a 60% owner of the Scotford Upgrader, Shell Canada Energy continues to hold the rights and obligations under the Carbon Capture and Storage (CCS) Funding Agreement – Quest Project, dated June 24, 2011, which are associated with that 60% interest. The design concept for Quest is to remove $CO_2$ from the process gas streams of the three hydrogen-manufacturing units (HMUs), within the Scotford upgrader facility. This is done by using amine technology, dehydrating and compressing the captured $CO_2$ to a dense-phase state for efficient pipeline transportation to the subsurface storage area.

The three HMUs 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 included:

- 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 Quest 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.**

Quest technical project activities in the Define phase in 2011 included the engineering work required to deliver key project documents of this phase, including the Basic Design Engineering Package (BDEP), the Project Execution Plan (PEP) and the Storage Development Plan (SDP).

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

Under normal circumstances, the Final Investment Decision (FID) follows the successful conclusion of the Define phase prior to moving to the next phase. However, Quest at that point did not have the required project provincial and federal regulatory approvals that the Shell Executive Committee (EC) set as a condition for approving FID. Energy Resources Conservation Board (ERCB) regulatory hearing dates expected in November in 2011 were scheduled for March 2012 delaying the possible approval date. 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. After receipt of the ERCB Decision Report, the Shell Executive Committee, followed by the AOSP Joint Venture partners, approved the FID of the Project in the summer of 2012. After formal receipt of the various regulatory approvals, the formal announcement of FID was made in early September.

In June of 2012, Shell conducted the first Project Execution Review (PER) as required of the project at that time. A second PER was completed in June 2013 and a third was conducted in June 2014. PER1 examined the status of the project, including the Execute phase deliverables completed at that time as well as reviewing the output of the early works construction readiness review and concluded that the project was proceeding according to plan and ready to start early works construction upon execution of the contracts and receipt of the regulatory approvals. PER2 examined the status of the project including the Execute phase deliverables and provided recommendations to Quest for continued success; the project team completed all recommendations. PER3 was conducted in 2014 and focused on the status of the project as it proceeded towards the commissioning and startup phase; again, recommendations were made and the project team completed all recommendations.

The project technical activities in 2012 correspond with the Execute phase. This included the detailed engineering work required to deliver the approved-for-construction drawings, technical specification for the procurement of all equipment and materials and the management of any changes to the Define phase deliverables.

The project technical activities in 2013 also correspond with the Execute phase. This included completing the detailed engineering work required to deliver the approved-for-construction drawings, delivering the approved for construction drawings, technical specification for the procurement of all equipment and materials and the management of any changes to the Define Phase deliverables.

The Project technical activities in 2014 also 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.

The Execute phase concluded in 2015 after the mechanical completion of the facilities in February of 2015, followed by a successful commissioning and startup, completion of the commercial sustainable operating tests, and subsequently handed over to Shell for operations on October 1, 2015.

The Operate phase of the project officially commenced in Q3 of 2015. Quest Operations successfully captured and injected 2.62 Mt of $CO_2$ in the 7-11 and 8-19 injection wells to the end of 2017.

## 1.4 Facility Locations and Plot Plans

Quest 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 HMUs. See Figure 1-3: Capture Unit Location Schematic for a schematic view of the capture unit location.

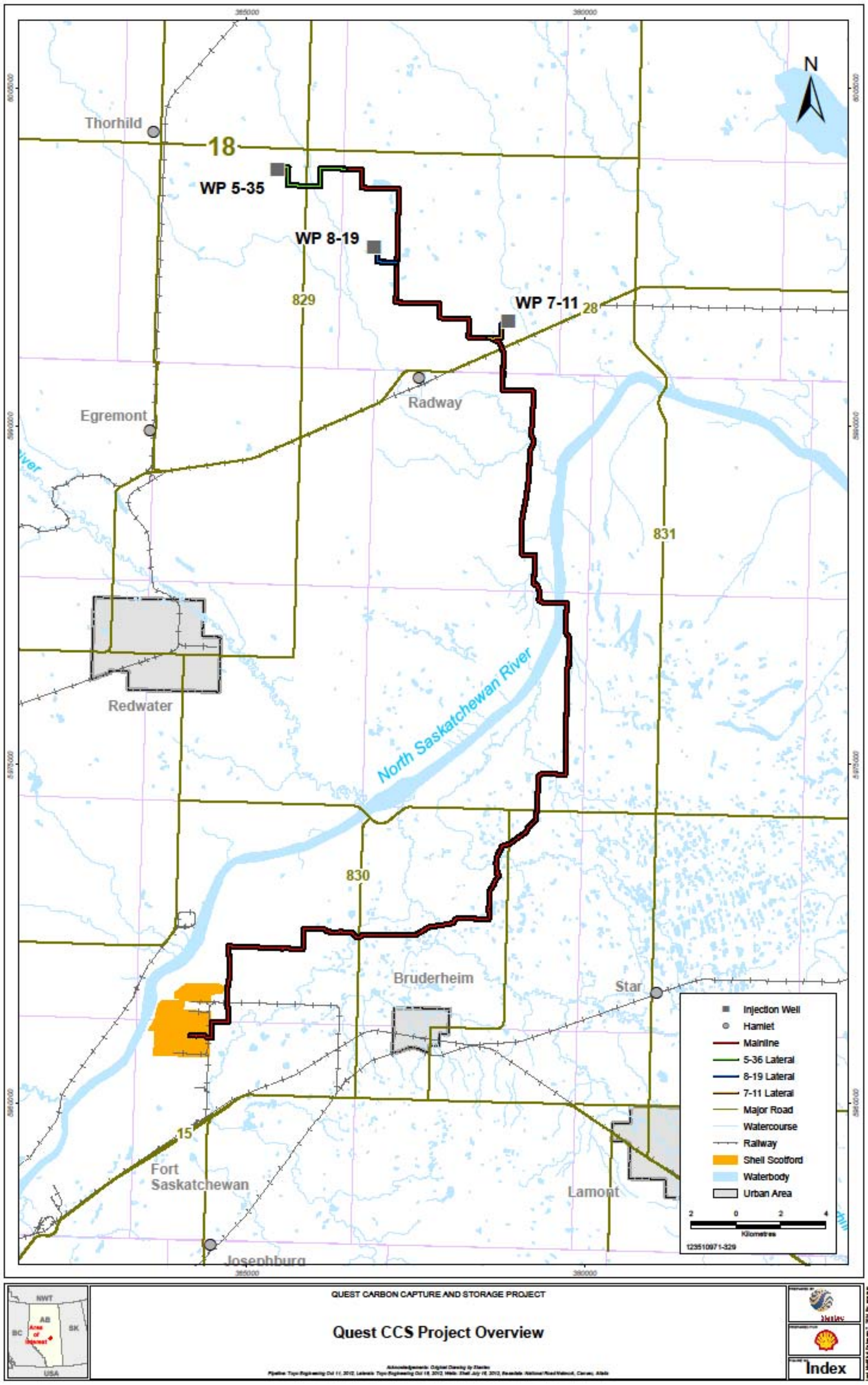



**Figure 1-2: Project Facility Locations.**

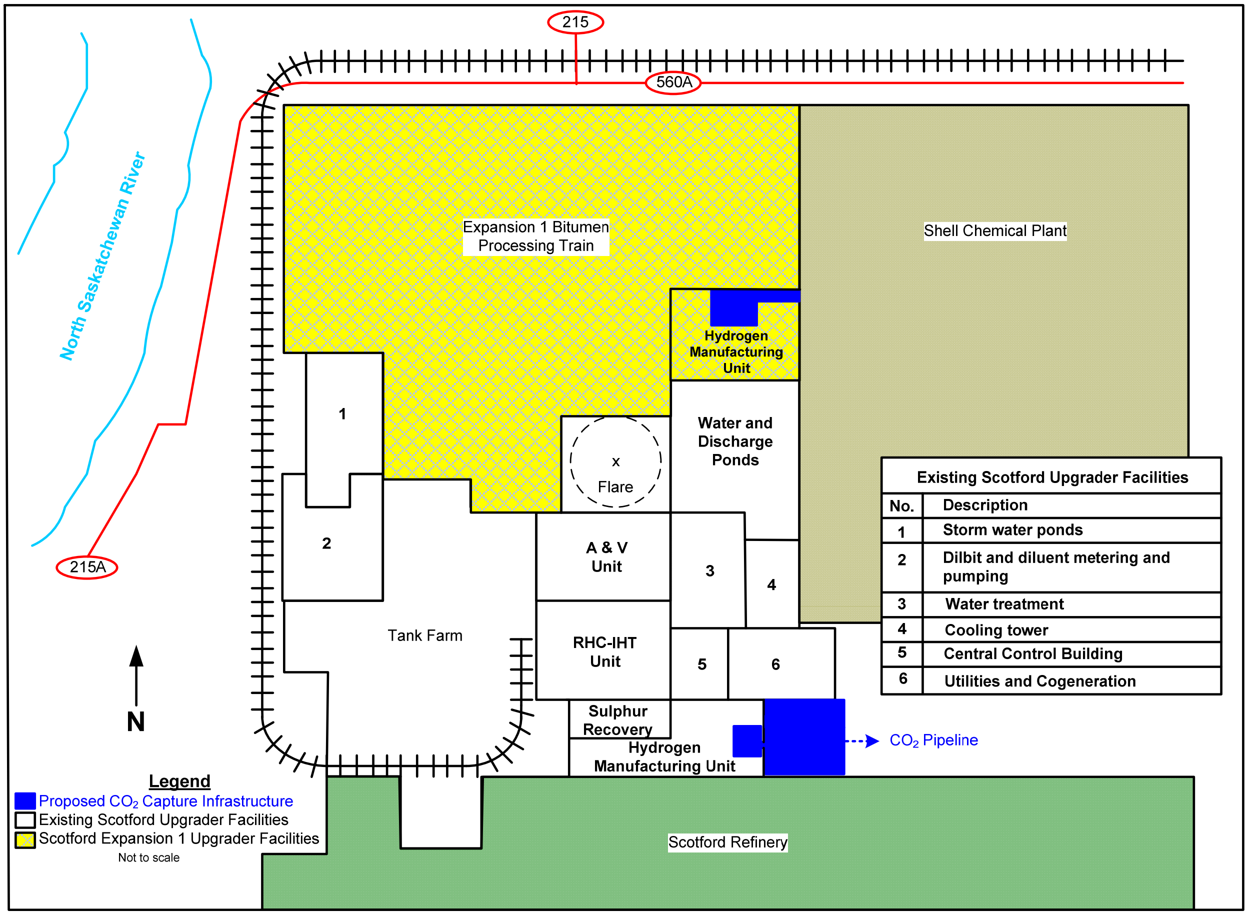



**Figure 1-3: Capture Unit Location Schematic.**

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.

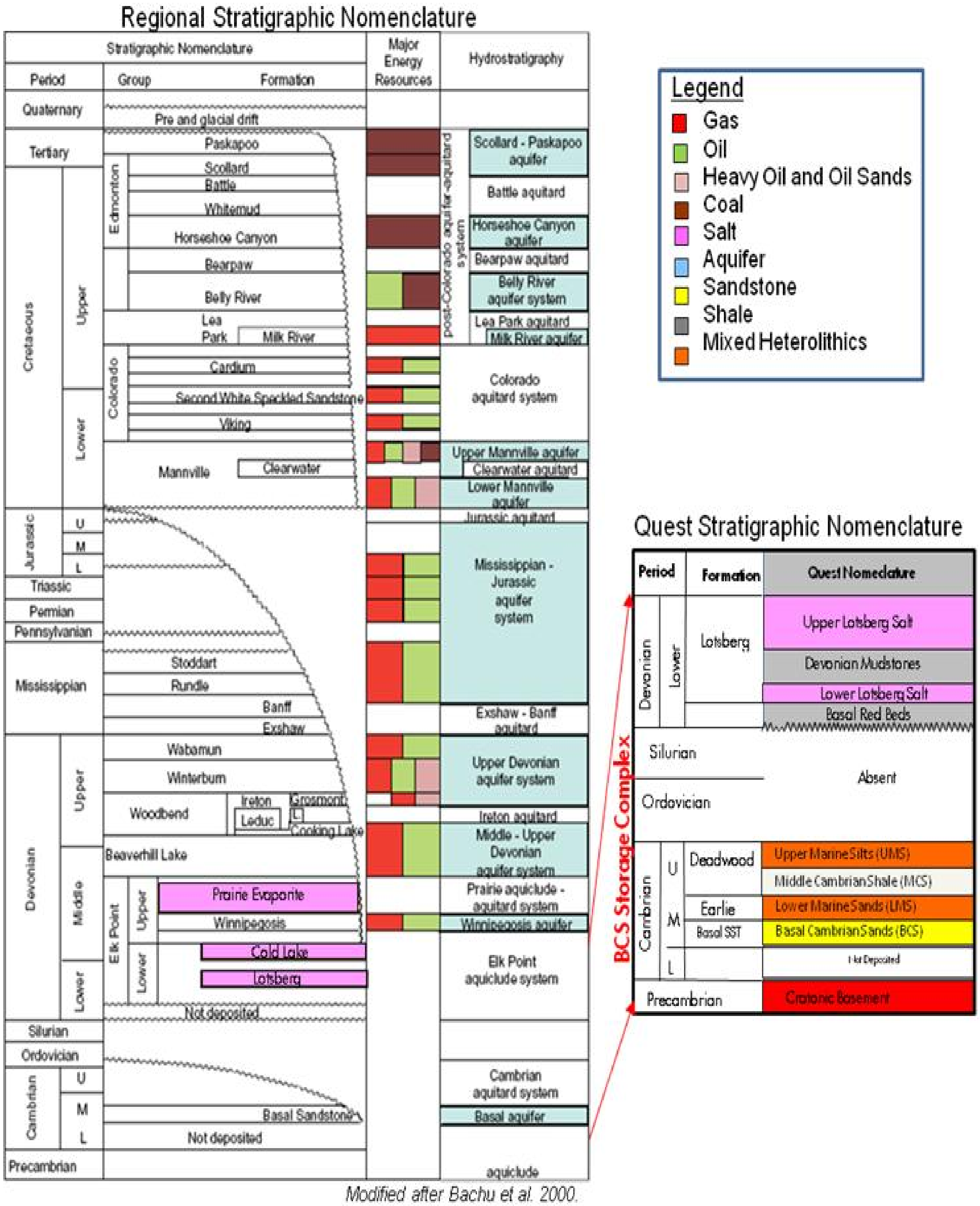



**Figure 1-4: BCS Storage Complex within the Regional Stratigraphy.**

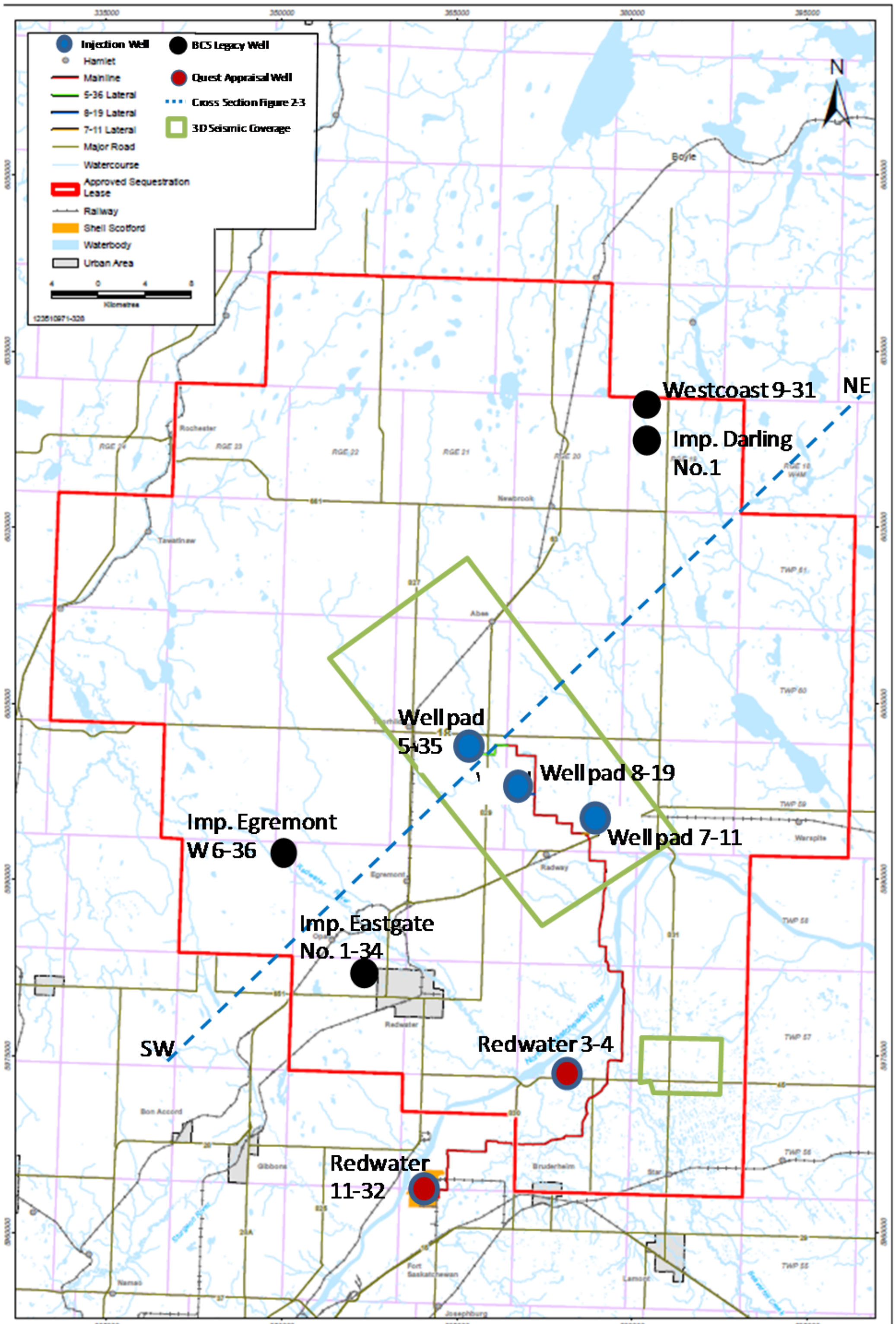



**Figure 1-5: Project Components and Sequestration Lease Area.**

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 the Quest operator of the BCS formation for the project within the SLA is depicted in Figure 1-5. This exclusive use allows the Quest operator 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.

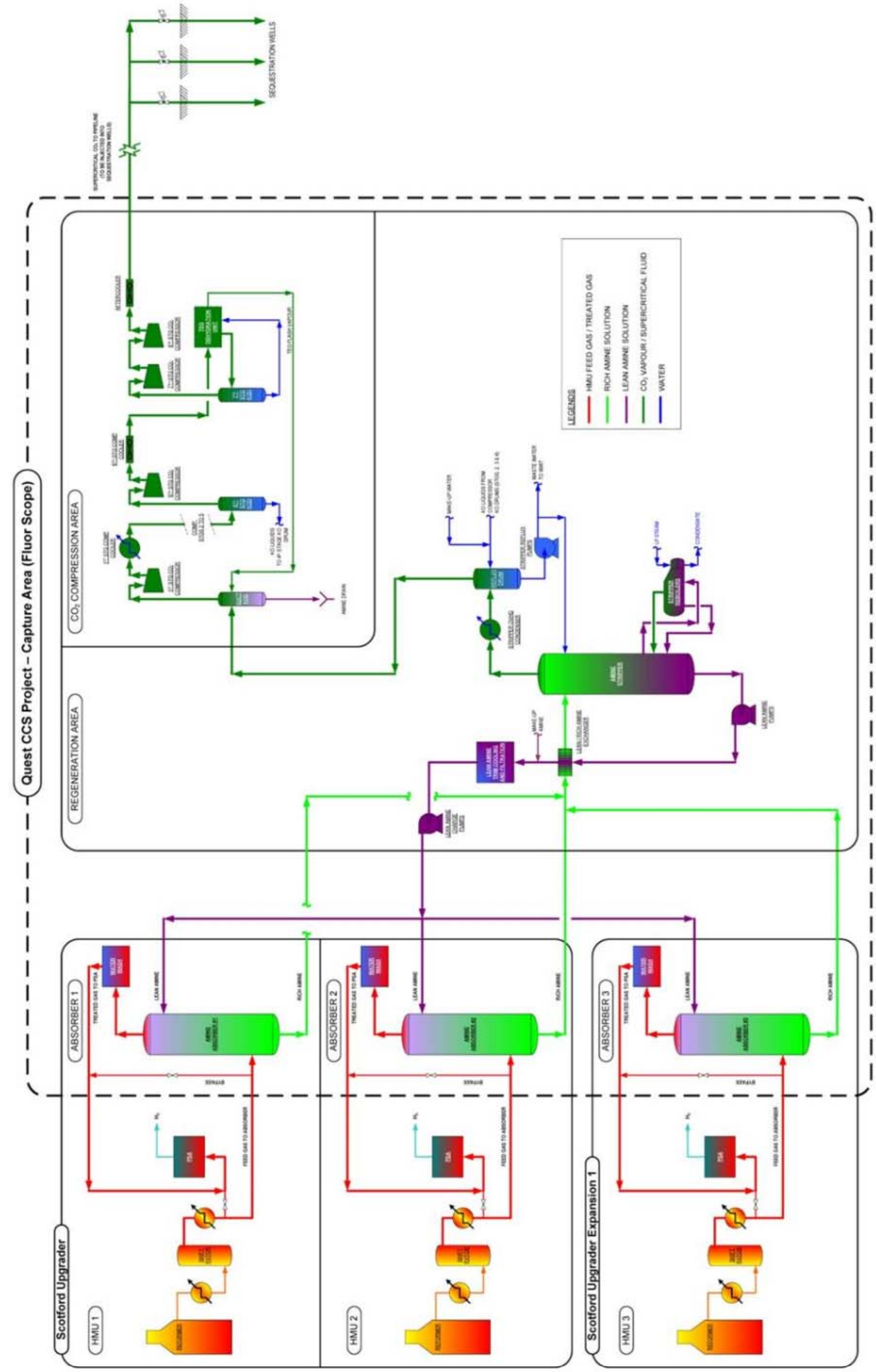



**Figure 1-6: Capture and Compression Process Design.**

### 1.5.1 Process Description

*$CO_2$ Absorption Section*

Quest captures carbon dioxide from the hydrogen-manufacturing units (HMU). In the HMUs, light gas (e.g. natural gas) and steam are reacted in a steam methane reformer (SMR) to form pure hydrogen and carbon dioxide. The impurities are removed in pressure swing adsorbers (PSA) and the pure hydrogen is sent on to the residue hydro conversion unit. The capture process removes the carbon dioxide between the SMR and the PSA.

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 absorber 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, with the bulk of the heat generated within the absorber 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. Warm water is pumped from the bottom of the vessel and cooled 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 protecting the downstream PSA unit adsorbent 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 feed-forward flow from the rich amine stream entering the stripper and is trim-controlled by a temperature signal from the overhead vapour temperature 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 flow is varied to control the level in the reflux drum, and the purge of excess water to wastewater treatment is managed via flow control.

$CO_2$ 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 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 in shell and tube lean amine 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 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 a polyglycol-based anti-foam to the amine absorbers and amine stripper. 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.

*Amine Storage*

The total circulating volume of amine is 315 $m^3$. 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 is blended off-site and provided by an amine supplier. The amine storage tanks are also 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 total amine inventory. 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 is 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 are vented to the atmosphere.

*Compression*

The $CO_2$ from amine regeneration is routed to the compressor suction by way of the compressor suction knock out (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(gauge).

Cooling and separation facilities are provided on the discharge of the first six 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 9,000 kPa(g) to 11,000 kPa(g), resulting in a dense-phase fluid. During commissioning in 2015 the compressor discharge pressure was initially reduced from 14 MPa to 11.5 MPa due to issues with reverse rotation on shutdown. Testing during the 2017 turnaround confirmed that it is currently able to provide a discharge pressure as high as 13.58 MPa. The dense-phase $CO_2$ is cooled in the compressor discharge cooler to roughly 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, 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 was estimated that 27 ppmw of TEG will escape with $CO_2$. Operation to date indicates that the number is actually < 5 ppmw. The dehydrated $CO_2$ is analyzed for moisture and composition at the outlet of the TEG unit.

*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.

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

*$CO_2$ 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 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$^{SM}$ design practices. The project is designed with a maximum module size of 7.3 m (wide) x 7.6 m (high) x 36 m (long) modules that are assembled in the Alberta area and transported by road to the Shell Scotford site by the Alberta Heavy Haul corridor.

Third Generation Modular$^{SM}$ execution is a modular design and construction execution method that is different from the traditional truckable modular construction execution methods 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

Construction reached mechanical completion on February 10, 2015 with all A and B deficiencies completed that were required for commissioning and startup. On February 20, all of the C deficiencies, which were required after startup, were completed. Fluor, the EPC contractor, demobilized by the end of February. In mid-April, the project, Commissioning and Start Up (CSU) team and Upgrader management signed off on the first phase of Project to Asset handover, which signaled the new facilities were ready for startup. The 2015 Upgrader turnaround started in April, which facilitated completion of the Quest scope by mid-May. Scope items included the HMU 1 and common process ties, HMU 1 burner change out and FGR tie-ins, and HMU 1 PSA catalyst change out. Upon completion of the turnaround, the CSU team began executing their start-up plan. The construction engineering team continued to support the CSU team throughout the startup and commercial operations tests. See Figure 2-1 for the actual construction schedule. Handover to Scotford Operations completed the project construction phase.

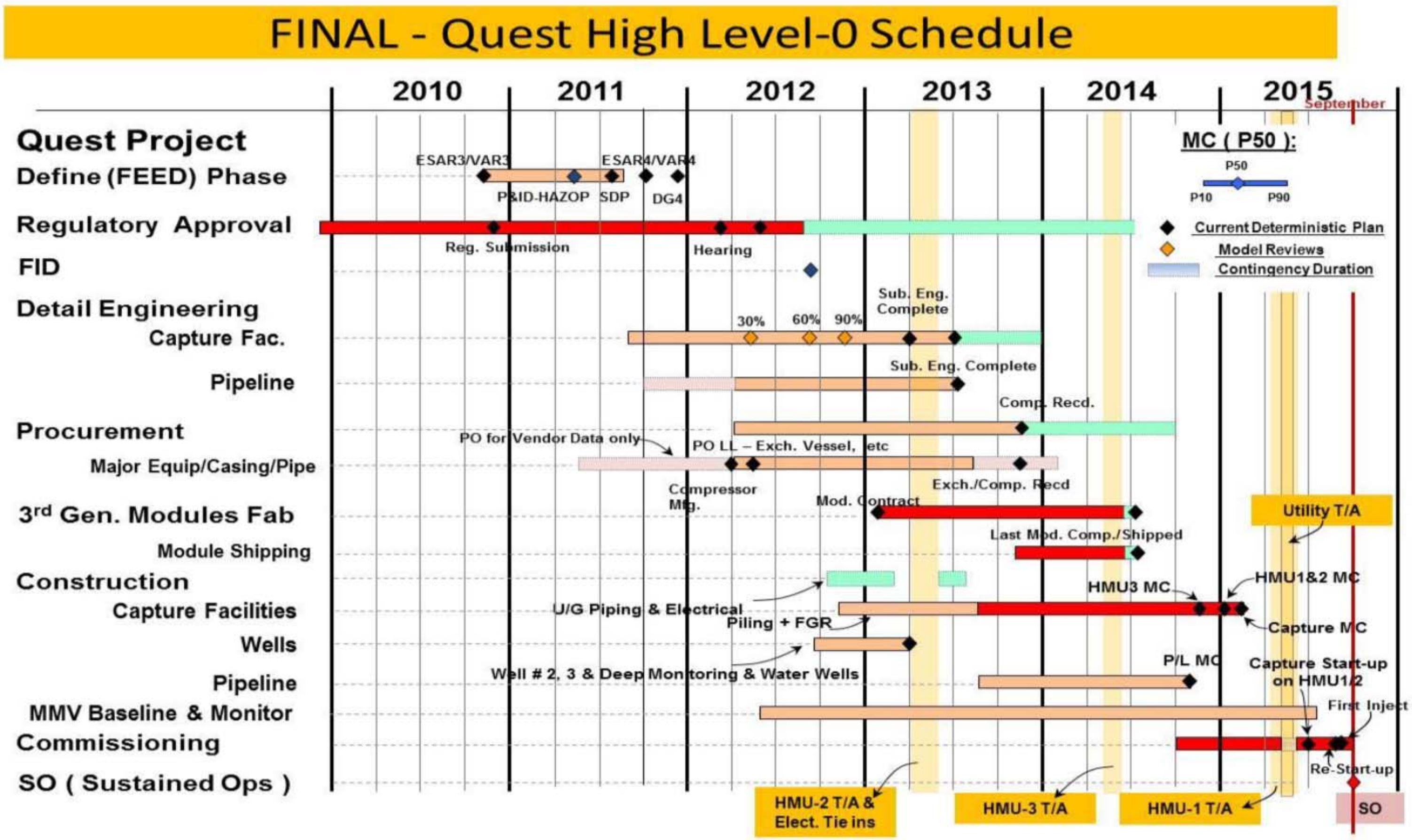



**Figure 2-1: Project Construction Schedule.**

# 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. One set of and those criteria in Table 3-1 shows the properties of the Basal Cambrian Sands (BCS) are compared with storage area selection criteria for CCS projects was developed by the Alberta Research Council (ARC).

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, in May 2011, 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 $CO_2$ Storage**

| Criterion Level | No | Criterion | Unfavourable | Preferred or Favourable | BCS Storage Complex |
|---|---|---|---|---|---|
| Critical | 1 | Reservoir-seal pairs; extensive and competent barrier to vertical flow | Poor, discontinuous, faulted and/or breached | Intermediate and excellent; many pairs (multi-layered system) | Three major seals (Middle Cambrian Shale [MCS], Lower Lotsberg and Upper Lotsberg Salts) continuous over 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 |
| | 15 | Porosity | <10% | ≥10% | 16% |

| Criterion Level | No | Criterion | Unfavourable | Preferred or Favourable | BCS Storage Complex |
|---|---|---|---|---|---|
| Desirable (cont'd) | 16 | Permeability | <20 mD | ≥20 mD | Average over the SLA 20-1000 mD |
| | 17 | Cap rock thickness | <10 m | ≥10 m | Three cap rocks:<br>MCS 21 m to 75 m<br>L. Lotsberg Salt 9 m to 41 m<br>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 (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 comprising 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.

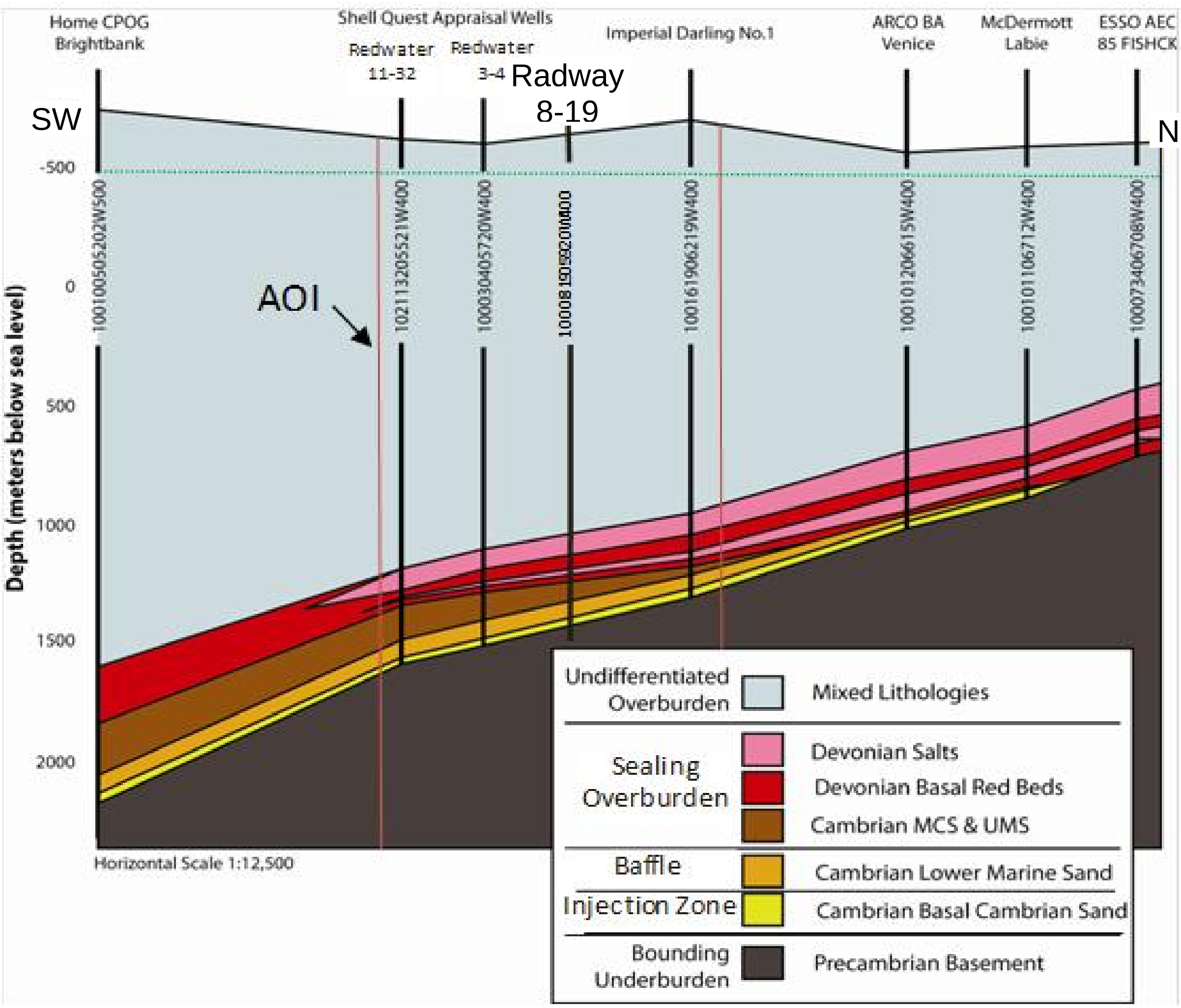



**Figure 3-1: Cross-Section of the WCSB Showing the BCS Storage Complex.**

## 3.3 BCS Reservoir Properties

No new injection wells were drilled in this reporting period. 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.

| | | | Interval Thickness (m) | | |
| --- | --- | --- | --- | --- | --- |
| | | **Geological Zone** | **IW 7-11** | **IW 8-19** | **IW 5-35** |
| | **SEAL** | Prairie Evaporites/ Lower Prairie Evaporites | 126 | 122 | 127 |
| | | Winnipegosis/ Contact Rapids | 75 | 72 | 70 |
| | | | | | |
| **BCS Storage Complex** | **SEAL** | Upper Lotsberg | 84 | 83 | 89 |
| | | | | | |
| | **SEAL** | Lower Lotsberg | 35 | 36 | 36 |
| | | | | | |
| | **SEAL** | MCS | 52 | 51 | 50 |
| | | LMS | | | |
| | **Injection Target** | BCS | 47 | 43 | 42 |
| | | PreCambrian | | | |

**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 of BCS reservoir properties as seen in Figure 3-3.

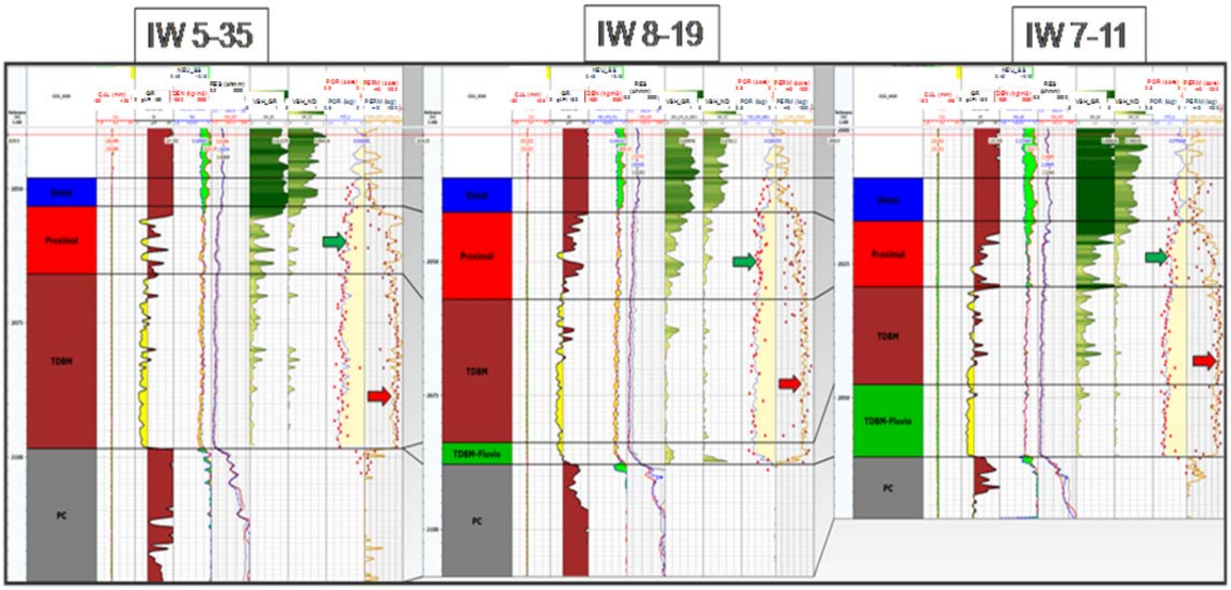



**Figure 3-3: BCS Reservoir Properties. Comparison of log response over the BCS formation and the corresponding core analysis results in all three injection wells.** The Porosity track (green arrows) shows very good correspondence between the core porosity and log porosity. The permeability track (red arrows) show a good agreement between the log and core permeability in IW 5-35, and agreement 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 also observed in 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.

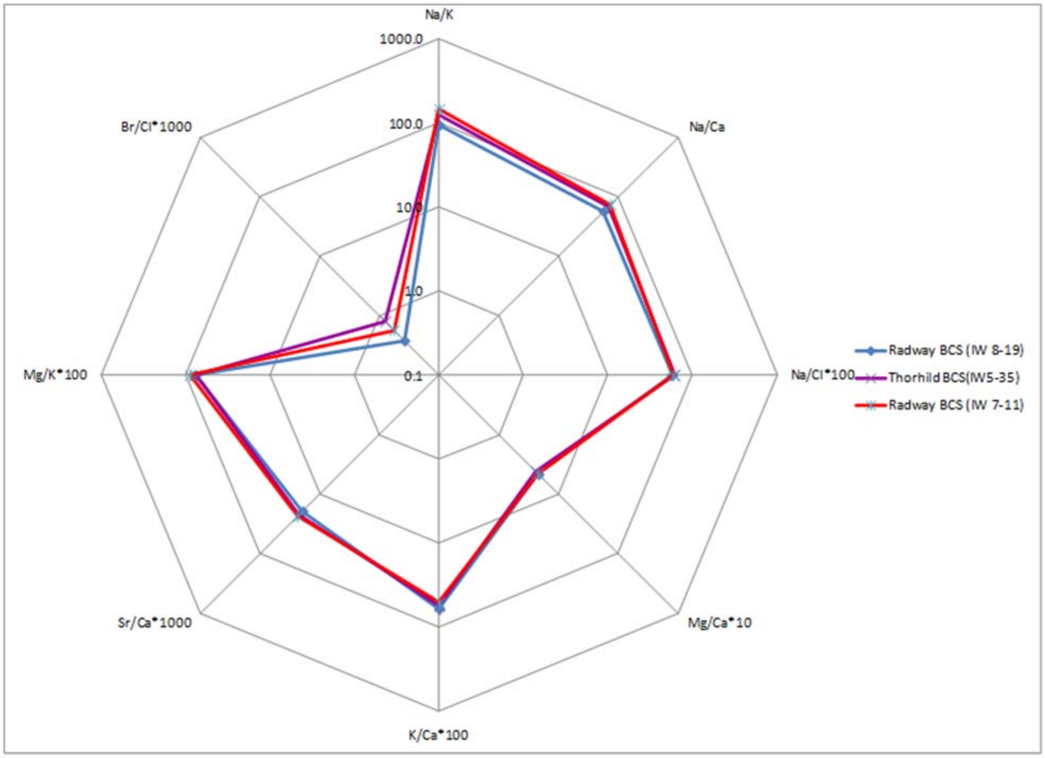



**Figure 3-4: Ion Ration plot of BCS Formation brine waters from IW 8-19 (sampled in 2010), IW 5-35 (sampled in 2012) and IW 7-11 (sampled in 2013).**

## 3.4 Estimate of Storage Potential

There is currently no perceived risk that the current project will not meets the injection targets, as it believed there is sufficient storage capacity for the full project volume of 27 Mt of $CO_2$. Refer to the AER Annual Report (2017) Section 3.5: Reservoir Capacity for discussion. The residual uncertainty in pore volume is unlikely to decrease much further until several years of injection performance data is attained, which may then be used to calibrate the existing reservoir models.

**Table 3-3: Remaining capacity in the Sequestration Lease Area as of end 2017**

| Year | Yearly Injection Total | Remaining Capacity |
|---|---|---|
| Pre-injection | - | 27 Mt $CO_2$ |
| 2015 | 0.371Mt | 26.629 Mt $CO_2$ |
| 2016 | 1.108 Mt | 25.521 Mt $CO_2$ |
| 2017 | 1.138 Mt | 24.383 Mt $CO_2$ |

## 3.5 Injectivity Assessment

The project was designed for a maximum injection rate of about 145 t/hr into three wells. Since start-up in 2015, injection rates have been up to 155 t/hr into two injection wells (the 8-19 and 7-11 wells). The 8-19 well has been injecting consistently at about 70 t/hr when possible with very little pressure build up. It is unlikely that the third well, 5-35, will be needed to meet injectivity requirements.

As well, injection stream compositions and variations (Table 5-3) are within design scope and have not impacted capture or storage operations.

There are no concerns on reactivity of the impurities or impact on the phase behavior.

It is therefore expected that the project will be capable of sustaining adequate injectivity for the duration of the project life; therefore, no further well development is currently necessary to maintain injectivity requirements.

## 3.6 Risk to Containment in a Geological Formation

Prior to commercial operation, nine potential threats to containment were identified:

1) Migration along a legacy well, 2) Migration along an injection well, 3) Migration along a deep monitoring well, 4) Migration along a rock matrix pathway, 5) Migration along a fault, 6) Induced stress re-activates a fault, 7) Induced stress opens fractures, 8) Acidic fluids erode geological seals, and 9) third Party activities.

Each was considered highly unlikely; but any of them are, in principle, capable of allowing $CO_2$ to migrate upwards out of the BCS storage complex.

Evaluation and integration of all available data-to-date (e.g. 2012-2013 drilling campaign, pre-injection phase monitoring, injection phase monitoring, 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 base of the groundwater protection (BGWP) zone even at the injection wells. Therefore, there is no risk of brine leakage impacting groundwater unless there is a severe loss of conformance. BCS pressure monitoring will be used to ascertain if there is a loss of conformance that could 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. In addition, considering the site characteristics of the storage complex capped by the Upper and Lower Lotsberg Salts Formations, wells that do not penetrate the storage complex pose very little to no risk to containment.

Hence, of all potential threats investigated, the key threat to containment at the Quest site is “Migration along an injection well”, as three such wells penetrate the storage complex. The risk of leakage, however, from the storage complex along a leakage pathway in the injection wells is considered very low.

For further details on risk to containment, please refer to Section 3.1.3 of the 2017 MMV plan [3].

# 4 Facility Operations – Capture Facilities

## 4.1 Operating Summary

The Quest CCS project focus for 2017 was to continue reliable and efficient capture and storage of $CO_2$ from operations. Table 4-1 outlines the performance summary of the capture unit in 2015, 2016 and 2017. A discussion of the summary results can be found in the subsequent unit discussions.

**Table 4-1: Quest Operating Summary 2017**

| Quest Operating Summary | 2015 Summary | 2016 Summary | 2017 Summary | Units |
|---|---|---|---|---|
| Total $CO_2$ Injected | 0.371 | 1.11 | 1.138 | Mt $CO_2$ |
| $CO_2$ Capture Ratio | 77.4 | 83.0 | 82.6 | % |
| $CO_2$ Emissions from Capture, Transport and Storage | 0.057 | 0.161 | 0.174 | Mt $CO_2$ |
| Net Amount ($CO_2$ Avoided) | 0.314 | 0.947 | 0.964 | Mt $CO_2$ |

The following is a timeline of significant operational milestones for the 2017 calendar year:

- May 16, 2017: Successful completion of first Quest turnaround.
- June 11, 2017: Reached milestone of 2 million tonnes injected since project start up.
- November 14, 2017: Reached milestone of 1 million tonnes injected in 2017.

### 4.1.1 Quest Audits and Credit Serialization

The Quest project underwent various Audit and Offset verifications in 2017, including the Alberta Energy Injection Certification audit, Alberta Climate Change Office (ACCO) Offset Audit and ACCO Offset Verifications in 2017.

For 2017, the Quest Carbon Capture and Storage Project (Quest) serialized a total of 1,212,182 credits – 415,578 from 2015 and 796,604 from 2016 on the Alberta Emission Offset Registry:

| | |
|---|---|
| Quest Credits from 1st Crediting Period (2015) (August 2, 105 to October 31, 2015) | 166,450 |
| Quest Credits from 2nd Crediting Period (2015/2016) (Nov 1, 2015 to Mar 31, 2016) | 649,836 |
| Quest Credits from 3rd Crediting Period (2016) (Apr 1, 2016 to Sept 30, 2016) | 395,896 |

Subsequent to the completion of the verification of the 1st crediting period, Alberta Climate Change Office (ACCO) assigned a third party auditor which resulted in two material audit findings regarding Quest injection gas online analyzer and the waste heat methodology. The resolution of the online $CO_2$ analyzer has been resolved while the waste heat methodology is still in progress.

Going forward, Shell will be working with ACCO on the transition from the *Specified Emitters Gas Regulation* to the new *Carbon Competitiveness Incentive Regulation*.

## 4.2 Capture (Absorbers and Regeneration)

Solvent composition was on target for 2017 operation vs. the specified formulation for ADIP-X from the design phase, and $CO_2$ removal ratio performance has been as predicted. The annual $CO_2$ capture ratio was 77.4% for 2015, 83.0% for 2016 and 82.6% in 2017.

The main contributors to periods of reduced $CO_2$ capture in 2017 were as follows:

- Periods of lowered hydrogen production demand and trips in process units outside of Quest.
- Planned maintenance activities or trips in the Quest capture unit also contributed to periods of reduced capture. These periods are listed below:
    - May 7-14: Quest spring turnaround to complete a compressor inspection and exchanger cleaning. The capture unit was shut down during this period.
    - May 16: Quest compressor trip testing after implementing MOC to re-rate the C-24701 compressor from 12MPa to 13.58MPa.
    - August 25: Follow up Quest C-24701 compressor pinion inspection and lube oil nozzle replacement.
    - Nov 13-14: Quest high moisture pipeline trip while placing the TEG carbon filter system in service after carbon filter replacement.

- November 13: Loss of amine circulation due to lean Amine charge pump trip on low suction pressure.
- December 9: Loss of amine circulation due to lean Amine charge pump trip on low suction pressure.

The $CO_2$ stripper operation has been stable, and the $CO_2$ product sent to the compression unit has been on target for purity. There are no concerns on reactivity of the impurities or impact on the phase behavior. Performance has been as expected in terms of solvent regeneration. Table 5-3 in the transport section contains the average $CO_2$ product composition from the capture and dehydration units. Table 4-2 provides a summary of the utility and energy sources consumed during the injecting period since start up, for the 0.371, 1.11, and 1.14 Mt $CO_2$ captured and injected in 2015, 2016 and 2017.

**Table 4-2: Energy and Utilities Consumption (Capture, Dehydration)**

| Energy and Utilities | 2015 Usage | 2016 Usage | 2017 Usage | Units |
|---|---|---|---|---|
| Electricity (Capture/Dehydration) | 12300 | 32800 | 32600 | $MWh_e$ |
| Low Pressure Steam | 410 | 1263 | 1297 | kT |
| Low Temperature High Pressure Steam | 1.96 | 5.52 | 5.23 | kT |
| Nitrogen | 178 | 230 | 237 | $ksm^3$ |
| Wastewater | 24900 | 80900 | 61900 | $m^3$ |
| Energy/Heat Recovered | 33600 | 96260 | 98554 | $MWh_{th}$[1] |
| $CO_2$ Emissions for the Capture Process | 0.030 | 0.083 | 0.095 | Mt $CO_2$ |

Electricity, and steam use are approximately on target with design specifications when pro-rated for actual $CO_2$ throughput. Waste water was reduced in 2017 to further mitigate impacts on the downstream carbon steel piping and the waste water treatment system. Nitrogen use is significantly lower than expected due to optimizations made in the dehydration unit. Nitrogen stripping gas flow to the TEG stripper was reduced to avoid over-processing the TEG. In 2017 the operations team targeted approximately 50 ppmv water content to the pipeline, staying within the 84 ppmv spec. Heat recovery in the demin water heaters (cooling the $CO_2$ stripper reboiler steam condensate) is also approximately on target from design.

During the later part of 2016, it was observed that fouling of the lean/rich exchangers was impacting the rich amine inlet temperature to the stripper. A temperature drop of about 2°C was observed over the course of the year. As a result, reboiler duty increased. Cleaning of this exchanger was completed in the 2017 spring turnaround. The exchanger was back flushed by a 3rd party vendor in an attempt to remove any foulant, carbon or other debris. The exchanger cleaning has resulted in a minor duty improvement and stabilization of the fouling trend resulting in the column inlet temperature being maintained through 2017.

[1] e subscript denotes electrical energy, th subscript denotes thermal energy

A success story for the Quest unit operation to-date continues to be the low levels of chemical loss from the ADIP-x process. Amine losses from the capture unit reduced to negligible after the initial commissioning/inventory and startup phases. In 2017 the average amine losses were less than 1 tonne/ month with total amine consumption of 8.2 tonnes.

$CO_2$ emissions for the capture process are primarily those linked to low pressure steam use in the $CO_2$ stripper reboilers (~67% of total capture emissions), and from electricity for equipment in the capture system (~24% of capture emissions).

The most significant operational issue observed since start up has been foaming of the ADIP-X solution in the HMU absorbers, leading to tray flooding and short duration reduction in $CO_2$ capture from the HMUs, with a small impact to stability in the hydrogen plants themselves. The cause has been attributed to several initiating factors: rapid changes in gas flows to the absorbers, carbon fines entrainment in the system, high gas rates to the absorbers and general system impurities. DCS control schemes implemented in 2015 have been successful in mitigating some of these causes. However, the frequency of filter change-outs in the lean amine circuit due to carryover of carbon fines from the carbon filter into the lean amine circuit continued in the first half of 2016.

In June of 2016, the lean amine carbon filter was taken offline as a test run to observe the impact on absorber foaming and mechanical filter change outs. As a mitigation, use of the anti-foam was suspended, and amine quality was monitored. When the filter was taken offline, there were no foaming events, and the frequency of filter changes was reduced.

The carbon filter remained offline until November 2017 when it was taken out of service to complete an inspection of the vessel internals, reload the filter with fresh carbon and then place the filter back in service. The inspection of the carbon filter internals was completed without any damage being discovered. The filter was reloaded with new carbon and a 3rd party contractor was hired to complete a demineralized water back flush to remove carbon fines from the system. The carbon filter was back flushed for approximately 7 days until the amount of carbon fines being removed by the vendor's equipment was negligible. The carbon filter was placed into service mid-November with the new carbon load.

Pre-filter change out lengths have not increased from the standard change out frequency prior to the reload however some minor foaming events have been noticed. Foaming is typical post carbon reload in the other amine units on the Scotford site and this will be monitored to determine if additional investigation is required. Another operational issue noticed after placing the filter back in service is that there is a potential for vapour/Nitrogen used to displace the amine from the pre/ post filters during a filter change to be directed into the process. This has caused the P-24602 amine charge pumps to trip on low suction pressure. Procedural changes have been made to mitigate this issue until permanent vents, drains and DCS control changes can be implemented.

## 4.3 Compression

The compressor operated at low discharge pressures during most of 2017, as the operating strategy was to minimize pipeline pressure within system constraints to reduce compression electricity demand. Table 4-3 below outlines the average operating conditions for the reporting period.

**Table 4-3: Typical Compressor Operating Data**

| Compressor Characteristic | Average 2015 Operation | Average 2016 Operation | Average 2017 Operation | Units |
|---|---|---|---|---|
| Suction Pressure | 0.03 | 0.03 | 0.03 | MPag |
| Discharge Pressure | 9.6 | 10.0 | 10.1 | MPag |
| Motor Electricity Demand | 13.3 | 13.8 | 14.2 | $MW_e$ |

In an on-going attempt to ensure the highest accuracy possible from the $CO_2$ analyzer, AT-24702, barometric pressure compensation of the analyzer measurement was completed in February 2017 using a pressure transmitter in the Cogeneration unit. The change was recommended by the analyzer vendor and was successful in ensuring analyzer accuracy. A dedicated barometric pressure transmitter was installed in the Quest analyzer building in April 2017. Data substitution due to analyzer inaccuracy was suspended as of February 3rd, 2017 with only raw data measured by the analyzer being submitted.

A significant amount of work was completed on the C-24701 Quest $CO_2$ compressor during the spring turnaround. Orifice plates in the compressor blow off lines were removed allowing for additional gas to escape at a faster speed. The orifice plate removal allowed for the Quest compressor to be re-rated back to 13.58MPa, increasing operational flexibility by allowing higher discharge pressures. The bull gear and pinions were also inspected in the May outage. All were in excellent condition besides pinion #2 which showed slight signs of wear on the non-loaded side of the teeth. A subsequent inspection completed on August 25th found that a single lube oil nozzle was not functioning properly. The lube oil nozzle was spraying an oil stream instead of a mist leading to the pinion damage. The nozzle was replaced during the August inspection which has alleviated this damage mechanism. The inlet guide vane and first stage impeller were also inspected and did not show any signs of erosion which was a concern because of the large amount of liquids present in the compressor knockout drums. The only major finding from the inspection was that the temporary start up screen in the first stage of the compressor had failed and required removal. Startup screens remain in the other seven stages of the compressor and are planned for removal at the first possible opportunity.

## 4.4 Dehydration

The dehydration unit performance continued to exceed expectations in 2017. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv. Actual water content for 2017 was on average 46 ppmv, and this was achieved at a lower TEG purity than design (99.6% vs. 99.7%) while maintaining the optimized Nitrgen flow rates described in section 4.2.

Carryover of TEG into the $CO_2$ stream also appears to be significantly less than design, with the estimated losses in 2017 being <6ppmw of the total $CO_2$ injection stream, compared to the 27 ppmw expected in design. Dehydration unit losses of TEG were roughly 5,800 kg annually for 2017 vs. the design makeup rate of 46,000 kg annually.

The TEG pre-filter, carbon filter and post filters were replaced in conjunction with the amine carbon filter in November 2017. The vessel was taken offline, unloaded, inspected, reloaded and then placed back in service after a demineralized water back flush to ensure the removal of carbon fines from the system. Placing the filter section online caused a high moisture trip of the system. This trip is discussed in the "Quest $CO_2$ Dehydration Performance" document.

## 4.5 Upgrader Hydrogen Manufacturing Units

The implementation of FGR (flue gas recirculation) technology, in combination with the installation of low-NOx burners has allowed all three HMUs to meet their NOx level commitments without contravention in 2017 while operating with Quest online. Operation of the FGR has been by direct flow control to achieve the desired NOx level. Installed capacity of the FGR allows operation within a wide range of NOx generation levels, so the system has been operated to maximize furnace efficiency (low FGR flow), while ensuring that enough FGR flow is routed to the burners to maintain NOx levels close to baseline pre-Quest. For 2017, normal NOx emissions with Quest operational and FGR online have been in the range of:

HMU1: 7 - 50 kg/h, limit 76.5 kg/h

HMU2: 7 - 40 kg/h, limit 76.5 kg/h

HMU3: 20 - 110 kg/h, limit 130 kg/h

When the FGR fan trips, NOx levels are below the new limits listed above, but exceed the old limits, pre-Quest, if the $CO_2$ capture ratio is not reduced.

One of the most significant differences in operation of the HMUs after $CO_2$ capture is a reduction in reformer fuel gas pressure. Fuel gas pressure reduces as increasing amounts of $CO_2$ are removed from the raw hydrogen stream, in turn reducing the volume of tail gas generated in the PSA for use as reformer fuel. Low fuel gas pressure was a limiting factor for increased $CO_2$ capture ratio when the HMUs went into production turndown because of reductions in hydrogen demand at the Upgrader.

The flame stability inside the reforming furnace appeared to be influenced by increased $CO_2$ capture rates (i.e. a change in fuel gas composition), resulting in a looser flame pattern when compared to non-Quest operation in early 2015. As capture ratios are increased, the impact to flame stability increases.

Since commissioning in 2015, hydrogen production losses due to hydrogen entrainment in the amine absorbers have been low, at roughly 0.1% loss of total hydrogen production. This is indicated by the roughly 0.5 vol% hydrogen content in the $CO_2$ stream sent to the pipeline.

The Upgrader HMUs have been relatively unaffected from a reliability perspective with the addition of $CO_2$ capture facilities. From an efficiency perspective, the hydrogen production capability of the units remains largely unchanged in 2017 with Quest operating. The loss of hydrogen via entrainment in the $CO_2$ absorbers and into the Quest pipeline meets design expectations and there is a negligible drop in overall hydrogen production capacities. Flue gas recirculation addition to the reformer combustion air stream is running below design expectations. While the addition of the flue gas recirculation results in fuel efficiency improvements in the reformer, NOx emissions are slightly elevated from baseline.

## 4.6 Non-$CO_2$ Emissions to Air, Soil or Water

In accordance with Shell's internal guidelines, all spills – regardless of size – are recorded for tracking purposes. Quest did not experience any leaks in 2017 with the three trips associated to Quest resulting in only $CO_2$ emissions.

In August 2016, a leak was identified in a section of wastewater piping going from the Quest plot to the Scotford Upgrader Wastewater Treatment Plant. Leak location was in the Upgrader Cogeneration Unit, outside the Quest plot. When investigated, the leak was found to be due to high corrosion rates caused by the low pH of Quest stripper reflux water. Piping has since been upgraded to 304 stainless steel. In 2017 to further mitigate impacts on the downstream carbon steel piping and the waste water treatment system a temporary caustic injection skid was installed in Quest to increase the PH of the Quest stripper reflux water. A project is progressing which will evaluate all possible alternatives and determine the best solution to permanently mitigate the low PH water leaving the unit.

## 4.7 Operations Manpower

The Quest CCS facilities are currently operated 24 hours a day, 7 days a week by the Scotford Upgrader operations team. The dayshift includes a control room operator, field operator for the Quest plot (capture, compression, dehydration), and a pipeline and wells operator. In mid-2016, major start-up and commissioning issues had been resolved or mitigated (e.g. absorber foaming, compressor reverse rotation), and unit reliability was consistent. At this point, the decision was made to merge the Quest control room operator position with the existing operator position for the Scotford Upgrader Hydrogen Manufacturing Units. Nightshift coverage is provided by a control room operator and a field operator, with a pipeline and wells operator on-call for emergencies. Maintenance support has been integrated into existing Scotford Upgrader maintenance department resources, and staff support (engineering, specialists, administration, and management) has been rolled into the existing team supporting the hydrogen manufacturing units.

# 5 Facility Operations – Transportation

## 5.1 Pipeline Design and Operating Conditions

Pipeline operation was stable during the reporting period. Table 5-1 below compares operating conditions to design values from the engineering phases of the project.

**Table 5-1: Pipeline Design and Operating Conditions**

| Characteristic | Specification | Units | Average Operating Data / Actual Limitations | | | Original Design |
|---|---|---|---|---|---|---|
| | | | 2015 | 2016 | 2017 | |
| **General** | | | | | | |
| Pipeline Inlet Pressure | Normal | MPag | 9.4 | 9.8 | 9.9 | 10 |
| | Maximum Operating | MPag | 12 | 12 | 13.58 | 14 |
| | Minimum Operating (based on $CO_2$ critical pressure 7.38 MPa) | MPag | 8.5 | 8.8 | 8.7 | 8 |
| | Design maximum | MPag | - | - | - | 14.8 (at 60°C) |
| Pressure Loss from Inlet to Wellsite | Normal | MPa | 0.6 | 0.6 | 0.6 | 0.4 (for 3 well scenario) |
| Temperature | Compressor Discharge | °C | 130 | 130 | 128 | 130 |
| | Pipeline Inlet after cooler | °C | 43 | 43 | 41 | 43 |
| | Upset Condition at Inlet | °C | - | - | - | 60 |
| | Injection Well 7-11 Inlet Temperature | °C | 15 | 16 | 14 | |
| | Injection Well 8-19 Inlet Temperature | °C | 12 | 12 | 11 | |
| Flow rates | Normal Transport Rate | Mt/a | 1.04 | 1.11 | 1.14 | 1.2 |
| | Design minimum | Mt/a | - | - | - | 0.36 |
| | Total Transported | Mt | 0.371 | 1.11 | 1.14 | - |
| Energy and Emissions | Total Electricity for Transport (compression) | $MWh_e$ | 41,527 | 119,426 | 121,593 | - |
| | Total Transport Emissions (includes compression) | Mt $CO_2$eq | 0.027 | 0.077 | .078 | - |

The pipeline has been operated with $CO_2$ in the supercritical phase at the pipeline inlet (9.7 MPag, 43°C) and with $CO_2$ leaving the main pipeline to the wellsites in the liquid phase (9.1 MPag, 15°C). . These two phases are commonly lumped together as "dense phase" in industry. The phase transition from supercritical phase to liquid occurs roughly in the 15-30 km region down the line, based on a field temperature survey in 2015. Heat transfer with the soil, as was expected in the design phase, has caused the majority of the temperature reduction in the pipeline.

$CO_2$ emissions from the transport component of the operation were primarily from the electricity used to power the compressor (99% of total transport emissions).

In 2016, methanol fuel cells were installed at each line break valve (LBV). These fuel cells provide supplemental charge to the LBV battery bank so that there is sufficient power during nighttime and overcast conditions. Since installation of these fuel cells, field charging of the LBV batteries are no longer needed and there were no near miss or actual loss-of-power trips on the $CO_2$ pipeline in 2017. In 2017, the fuel cell methanol consumption was optimized, using performance data collected from winter months, by modifying fuel cell switch-on voltage, absorption time, and maximum charge time. Solar charging during daytime hours was also optimized by connecting the solar charge sense lines to the batteries and compensating for the voltage drop losses. Four out of six methanol fuel cell units experienced issues in the internal reservoir due to an unknown manufacturing defect. The vendor has replaced four of the fuel cell units under warranty and no further issues have been experienced.

Pipeline and laterals/well dimensions as-installed can be found in Table 5-2.

**Table 5-2: Pipeline Dimensional Data**

| Main Flow Line Data | | | | |
|---|---|---|---|---|
| **Characteristic** | **Specification** | **Units** | **2015-2016 Data** | **Value from Design Phase or As-installed** |
| Dimensions | Length | km | - | ~64 |
| | Size | inches, NPS | - | 12 |
| | Wall thickness | mm | - | 12.7 (11.4 +1.3 corrosion allowance) |
| **Laterals Data** | | | | |
| Dimensions | 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 | | MPag | Refer to section 6 | 22 – 33.3 |
| Reservoir temperature | | °C | Refer to section 6 | 63 |
| Well bore tubing diameter | | inches, NPS | - | 3.5 |
| Well depth | | m | - | 2,070 |

Fluid composition in the pipeline was very close to the design normal operating condition for the majority of the operating period. On average, entrained components such as $H_2$ and $CH_4$ are lower than design. The average operating conditions to design values are available in Table 5-3.

**Table 5-3: Pipeline Fluid Composition**

| Component | Actual Operating 2015 (vol%) | Actual Operating 2016 (vol%) | Actual Operating 2017 (vol%) | Design Normal Composition | Design Upset Composition |
|---|---|---|---|---|---|
| $CO_2$ | 99.45 | 99.38 | 99.46 | 99.23 | 95.00 |
| $H_2$ | 0.48 | 0.51 | 0.47 | 0.65 | 4.27 |
| $CH_4$ | 0.06 | 0.06 | 0.06 | 0.09 | 0.57 |
| CO | 0.02 | 0.02 | 0.01 | 0.02 | 0.15 |
| $N_2$ | 0 | 0 | 0 | 0 | 0.01 |
| **Total** | **100** | **100** | **100** | **100** | **100** |

*Capacity for the Future*

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 $CO_2$ volumes.

*Water Content and $CO_2$ Phase Change Management*

Pipeline operation since startup was below the winter water specification of 4 lb / MMscf (84 ppmv). The average for 2017 was 46 ppmv. At this level, hydrate formation is not a concern during normal operation, and zero corrosion is expected. Flow to the pipeline is stopped automatically when the water content reaches 8 lb / MMscf (168 ppmv).

The pipeline system is currently protected from excessive vapour generation, and rapid temperature reduction, when coming out of dense/liquid phase during operation by a low pressure shutdown, currently set to 7 MPag.

*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, operating in Shell Technology Centre Calgary (STCC), 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 pipeline 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) are spaced at no greater than 15 km intervals. There are six LBVs 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. As the LBVs are located in populated areas, they are fenced for security. The fencing is standard 8-foot chain link with three strands of barbed wire on top.

In the event of a single LBV closure, the LBV computer will send a signal to all LBVs to close, thus minimizing loss of containment. Closure of an LBV is expected to take 30 seconds from the open position to the fully closed position, thus minimizing the pressure surge (caused by the kinetic energy of the fluid) at an LBV.

After emergency shutdown due to a pipeline leak or rupture and following repairs of the line, 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.

*Pipeline Leak Detection*

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 Coriolis-type mass flow meters at the Scotford boundary limit and at the wellhead are of custody transfer accuracy.

Automated and manual emergency shutdown systems were installed on the pipeline. An automated shutdown initiates when pressure transmitters on the line indicate a low pressure situation, or a high rate of change in pipeline pressure. Both pressure transmitters at one or more LBV stations must indicate a pressure below the trip point to initiate an automated pipeline shutdown.

Emergency shutdowns can be initiated manually from each of the well sites or from the Scotford control room when pressure, temperature, and flow transmitters indicate upset conditions. The pipeline utilizes the ATMOS leak detection system that senses flow, temperature, and pressure fluctuations to determine whether there is a potential for a leak. Audible and visual alarms are generated at the Scotford Upgrader control room in response to a potential leak. Emergency operating procedures are in place to respond to these alarms.

*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*

In December of 2016, the $CO_2$ pipeline was inspected using an in-line inspection tool (smart pig). The inspection was required as per commitments to Alberta Energy Regulator (AER) and was conducted by a third party vendor. In Line Inspection (ILI) was done on 100% of the first half (34 km) of pipeline from the launcher at the Quest surface facilities at Scotford to the receiver at LBV 3. The ILI was not conducted through the second leg of the pipeline since there is currently no flow to well site 5-35 and pig receiver at LBV-6.

Upon the first launch of the inspection tool, the smart pig was not able to progress past the isolation Orbit valve in the pipeline. This was due to a short drive-cup section and required a Quest unit shutdown and de-pressuring of the first 15 km of pipeline to LBV1 for safe retrieval. The Quest unit outage was ~4.1 days (Dec 2 – 6). Roughly 600 tonnes of $CO_2$ was vented from the pipeline, and the lost $CO_2$ capture opportunity due to taking the outage was roughly 15,000 tonnes. A second run was successfully completed after inspection tool drive-end modifications were made.

As per the results of the inspection, it has been concluded that there is no active internal $CO_2$ corrosion in the pipeline. Five external wall loss anomalies related to piping fabrication were found. However, all five anomalies had wall thickness beyond the 1.3 mm corrosion allowance of pipeline design and the minimum fracture toughness limits per the SGS report GS.10.52923. Using this information and Shells PIMS (pipeline integrity Management System), the next inspection using a smart pig will be in 2021. Dependent upon these results there is potential to complete integrity digs to confirm the findings and assess whether or not repairs are required.

The following inspection and monitoring activities have also been conducted to ensure pipeline integrity:

- Operator rounds of the pipeline and well sites with appropriate frequency
- 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 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 provides an overview of the wells and MMV activities for the operational year 2017.

## 6.1 Storage Performance

Injection of $CO_2$ into the 8-19 and 7-11 wells began on Aug 23, 2015, and as of Dec 31, 2017, about 2.6 Mt $CO_2$ have been injected into the two wells as illustrated in Figure 6-1. The injection stream composition is described in detail in Table 5.3, and is shown in Figure 6-2.

Injection into the 5-35 well has not yet been required for the following reasons:

1) The 7-11 and 8-19 wells have adequate injection capacity between them for all available $CO_2$.
2) The downhole pressure gauge at the 5-35 well provides useful information for the BCS as a deep monitor well. This will help calibrate the reservoir model for the far field response of the injection at the other two wells.
3) The lack of injection reduces some of the MMV requirements at the 5-35 well site, which in turn reduces MMV costs. For example: there was no need to record a monitor VSP survey in 2016 or 2017, since without injection, there is no change in reservoir $CO_2$ saturations at that location.

To simplify the expected pressure response at the 5-35 well, the injection at the 8-19 well was held as constant as possible at roughly 70 tonnes/hour, while the 7-11 well rates varied to accommodate the remaining $CO_2$.

As a result, by the end of December 2017, about 1.25 Mt of $C0_2$ had been injected into the 7-11 well and 1.37 Mt of $C0_2$ had been injected into the 8-19 well. Figures 6-3 and 6-4 show the daily average flow rates and P/T conditions at 7-11 and 8-19 during the injection period.

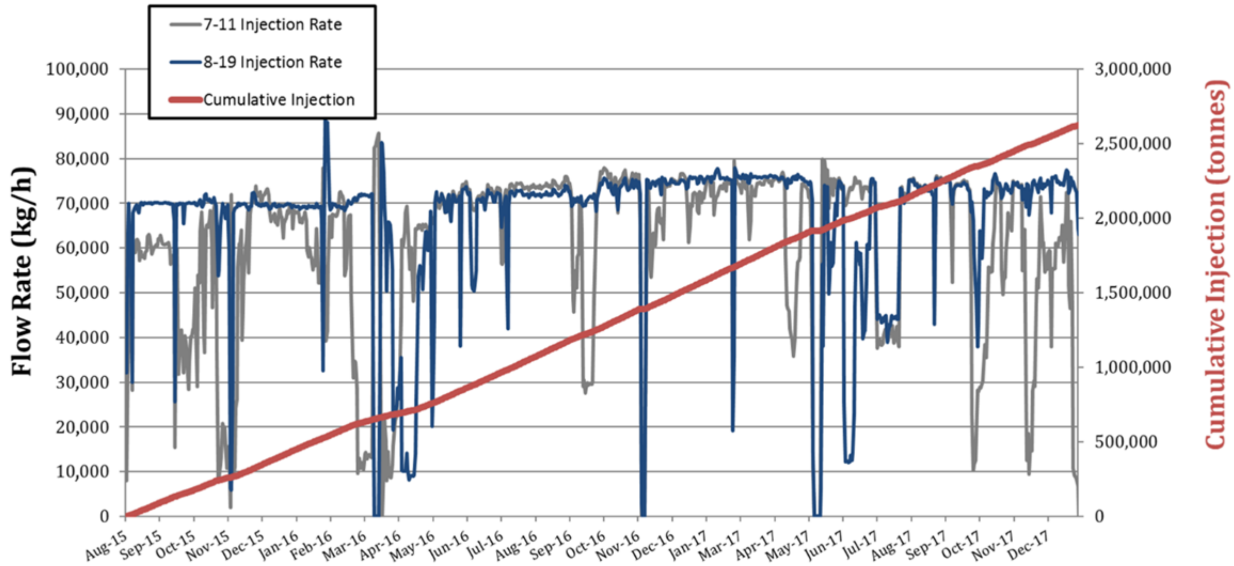



**Figure 6-1: Quest Injection Totals:** Cumulative $CO_2$ injected into the wells from start-up through to the end of 2017 (red). The blue and grey lines show the average hourly flow rates into the two individual injection wells.

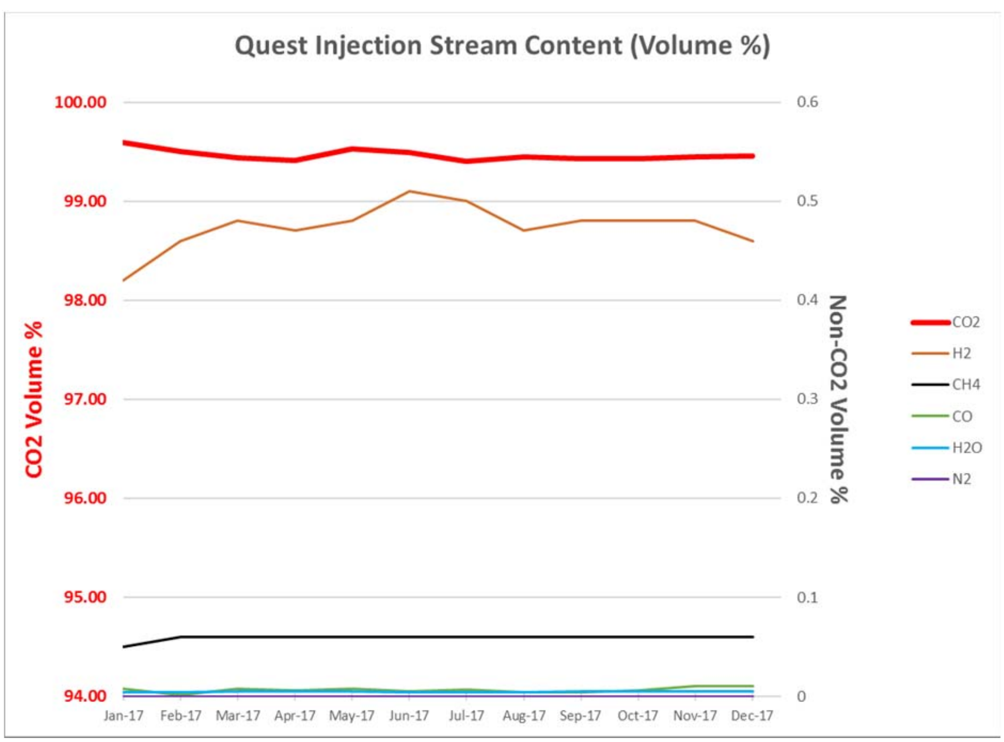



**Figure 6-2: Quest Injection Stream Content: Average injection composition for 2017.**

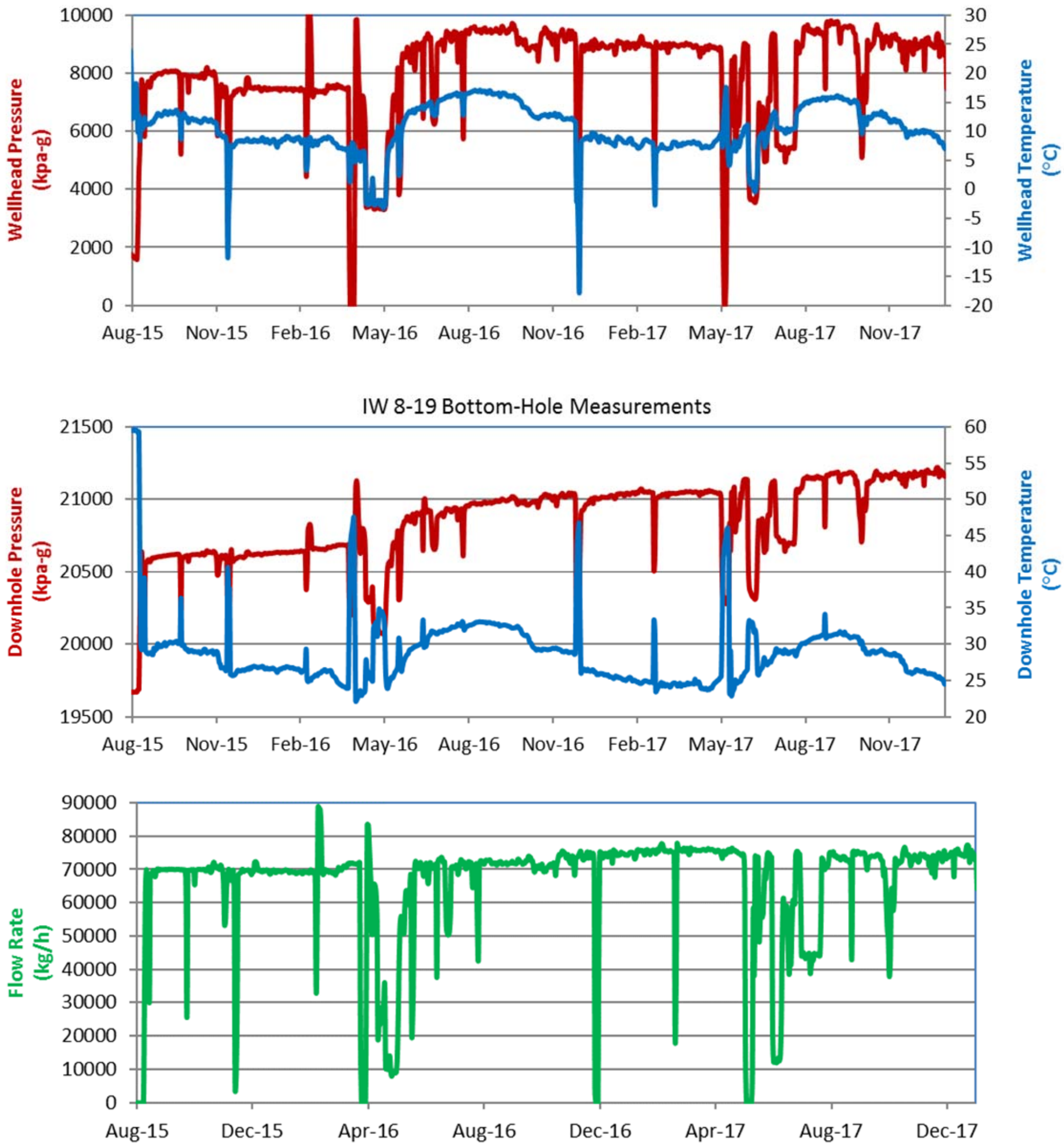



**Figure 6-3: The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection to the end of 2017.**

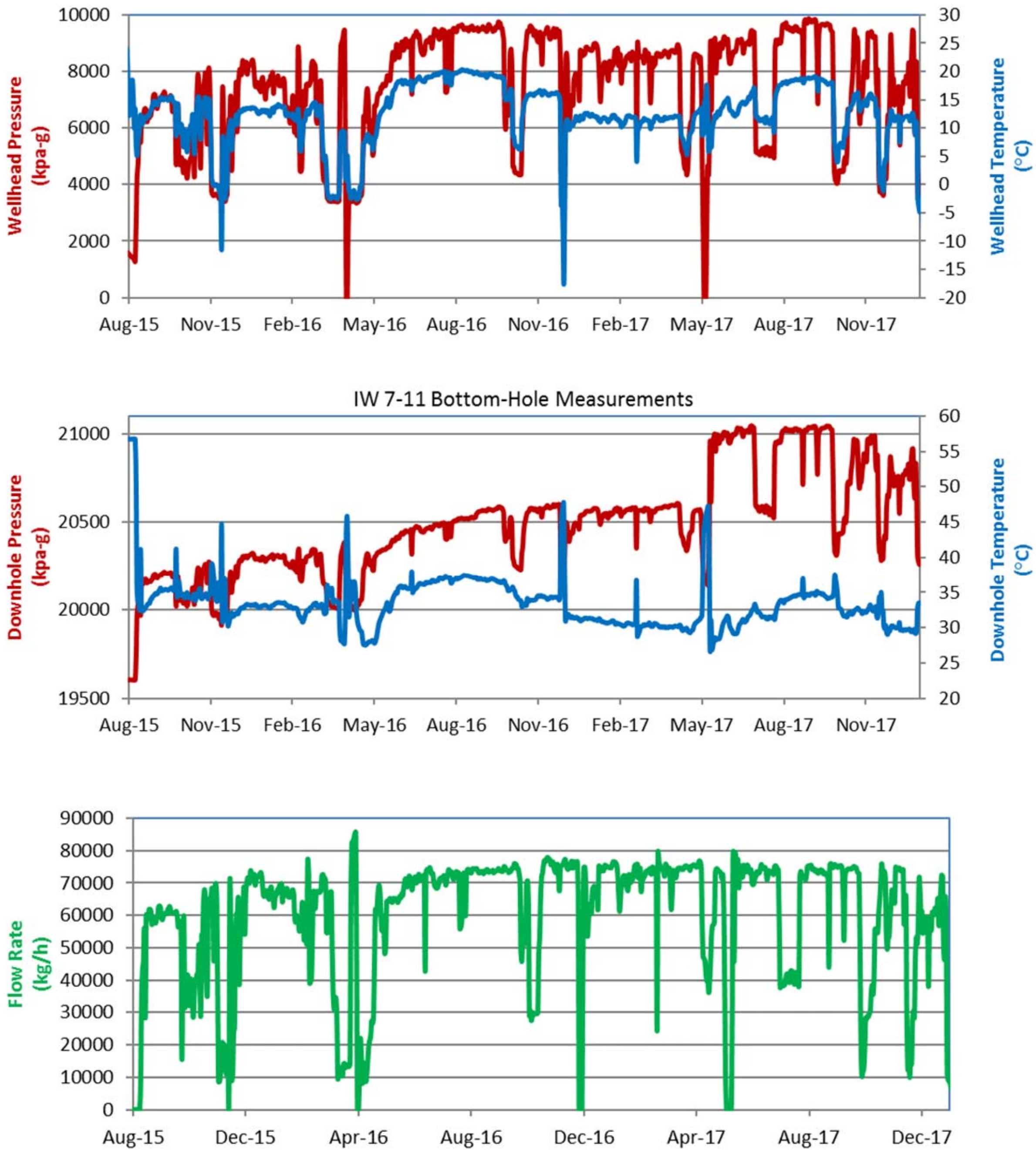



**Figure 6-4: The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2017.**

## 6.2 MMV Activities - Operational Monitoring

During 2017, the following MMV activities were executed:

- **Atmosphere Domain**: Monitoring of $CO_2$ levels within the atmosphere continued using the LightSource technology.
- **Hydrosphere Domain**: Four discrete sampling events (Q1, Q2, Q3, Q4) were executed. Project groundwater wells located on the 3 injection well pads were sampled on a quarterly basis. Landowner groundwater wells within 1 km of the injection well pads were sampled on a quarterly or biannual basis dependent upon well location. Note that additional groundwater well testing/sampling was undertaken in conjunction with the Q1 2nd monitor VSP campaign. Further details on the hydrosphere monitoring activities can be found in Appendix A in [2].
- **Biosphere Domain**: No activities took place regarding soil gas and soil surface $CO_2$ flux measurements.
- **Geosphere Domain**: The second monitor VSP campaign was executed in Q1 around well pads 7-11 and 8-19. Monthly satellite image collection for InSAR continued. Between January and August 2017, images were collected using two satellite frames. Since September 2017, a single frame centered over the 3 injection well pads is used for image collection. A baseline 2D surface seismic survey was also acquired alongside the VSP campaign in Q1 (2DSEIS).
- **Well based Monitoring**: ongoing data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes.

A new MMV plan was submitted and approved in 2017. The 2017 MMV plan includes a tiered system to review and assess the MMV data. The focus in this report will be on Tier 1 technologies. The latter form the basis for assessing whether there is an indication of loss of containment. Depending on the outcome of that assessment, further analysis or investigation of the Tier 2 technologies will be undertaken, and then if needed Tier 3 technologies will be assessed.

No trigger events were identified during 2017 that would indicate a loss of containment (Table 6-1). In other words, data to-date indicate that no $CO_2$ has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir during 2017.

Data to-date also indicate that $CO_2$ injection within the BCS is conforming to model predictions, based on:

- The time-lapse seismic monitoring results indicate that the size of the $CO_2$ plumes, as measured by the 2016 monitor 1 VSP and 2017 monitor 2 VSP, is much smaller than the maximum plume lengths predicted from the Gen 4 model and it is closer to the theoretical minimum. This is another indication that the reservoir is behaving better than expected, and that the displacement of brine by the $CO_2$ may be more effective than the initial modelling predicted.
- Assessment of the pressure data indicates that the reservoir has more than enough capacity for the full life of this project.

Further details of the MMV activities undertaken and observations made during 2017, can be found in the 6$^{th}$ AER Annual Status Report [2].

**Table 6-1: Overall assessment of trigger events used to assess loss of containment in 2017**

| Tier | Technology ^ | Trigger | 2017 |
|---|---|---|---|
| Tier 1 | IW DHP | Measuring greater than 26 Mpa | |
| | DMW DHP | Anomalous pressure increase above background levels | |
| | MSM | Sustained clustering of events with a spatial pattern indicative of fracturing upwards | |
| | DTS | Sustained temperature anomaly outside casing | |
| Tier 1 - when available | Pulsed Neutron log | Indication of $CO_2$ out of zone | |
| | SCVF | Change in geochemical composition indicating presence of project $CO_2$ | |
| | VSP2D | Identification of a coherent and continuous amplitude anomaly above the storage complex | |
| | SEIS3D | Identification of a coherent and continuous amplitude anomaly above the storage complex | not applicable yet |
| | SEIS2D | Identification of a coherent and continuous amplitude anomaly above the storage complex | baseline survey executed in Q1 |

^ based on Table 4-3 of the 2017 MMV Plan

| Legend | |
|---|---|
| | no trigger event |
| | trigger event |
| | not evaluated |

## 6.3 Wells Activities

### 6.3.1 Injection Wells

In 2017, the two wells on injection (8-19 and 7-11) underwent routine work including a WIT (wellhead integrity testing - wellhead maintenance and pressure testing), SIT (packer isolation test) and logging operations consisting of a tubing caliper log and hydraulic isolation log (PNX). The tubing caliper logs displayed negligible tubing corrosion. The hydraulic isolation logs exhibited good hydraulic isolation.

The 5-35 well which has not been on injection to date underwent routine work including a WIT and SIT.

In February 2017, a request was made for a non-routine suspension approval for the IW 5-35 as per AER Directive 013: Suspension Requirements for Wells. In March 2017, temporary approval was obtained to suspend the well in the current configuration, conditional to the well not being used for $CO_2$ injection.

Figures 6-3 and 6-4 show the daily average flow rates and P/T conditions at 7-11 and 8-19 during the injection period.

### 6.3.2 Monitor wells

Discrete pressure measurements were acquired in the Cooking Lake in DMW 7-11, DMW 8-19 and DMW 5-35 through MDT/XPT sampling during the 2012/2013 drilling campaign. Continuous pressure data in the Cooking Lake Formation via four monitoring wells, DMW 7-11, DMW 8-19, and DMW 5-35 and the farther field DMW 3-4 has been ongoing since Q3, 2015, as illustrated in Figures 6-5, 6-6.

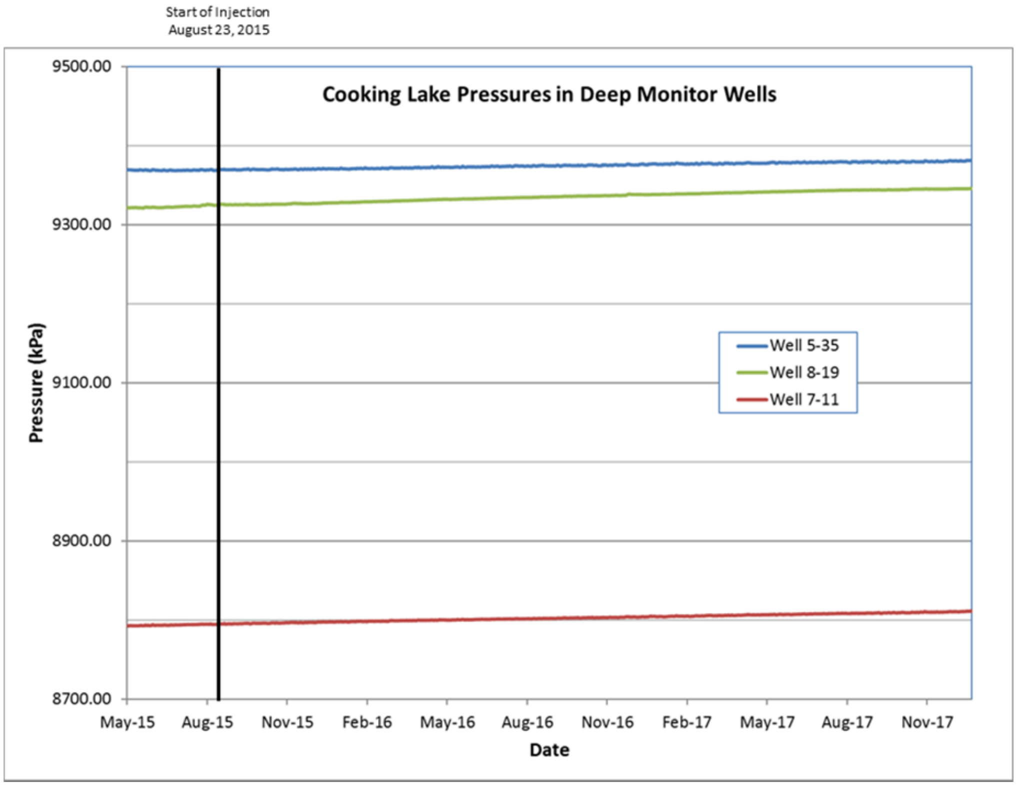



**Figure 6-5. Quest DMW pressure history before and during injection.**

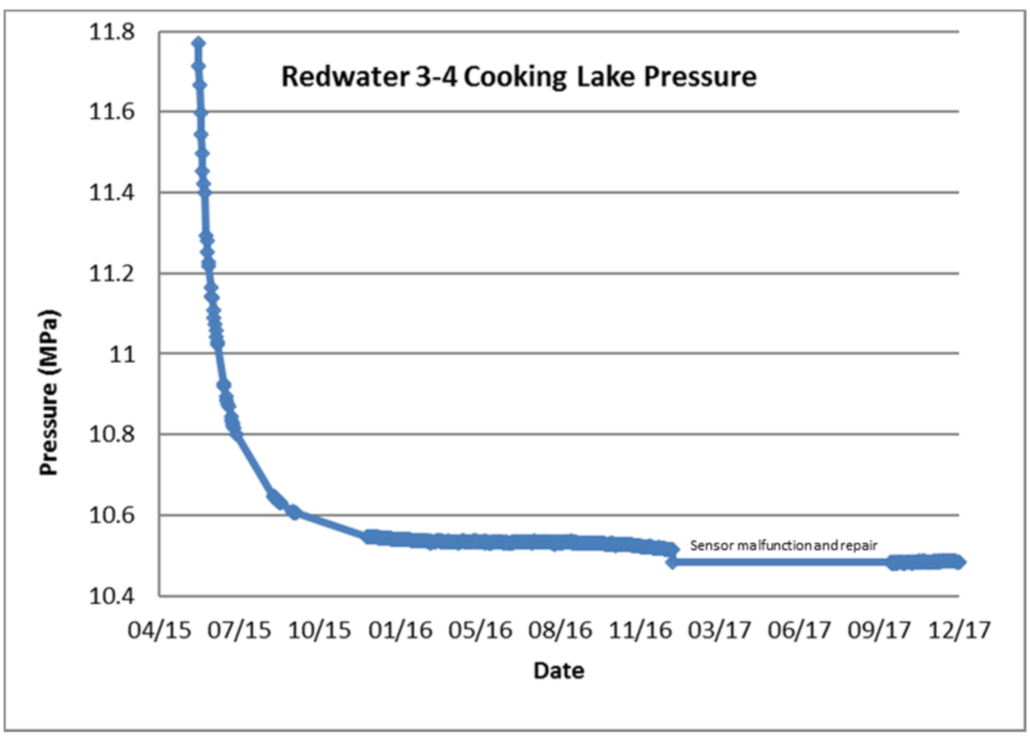



**Figure 6-6: Quest 3-4 DMW pressure history .**

### 6.3.3 Surface Casing Vent Flow and Gas Migration Monitoring

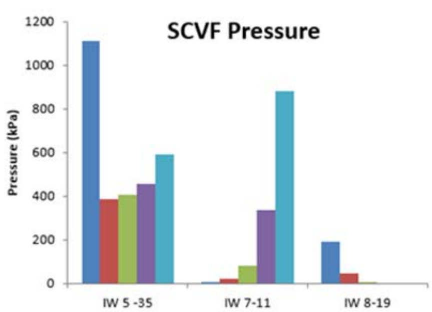
As required, annual testing was completed in 2016 for Surface Casing Vent Flow (SCVF) and Gas Migration (GM) at the injection pads. Reports were sent to AER in June 2017.

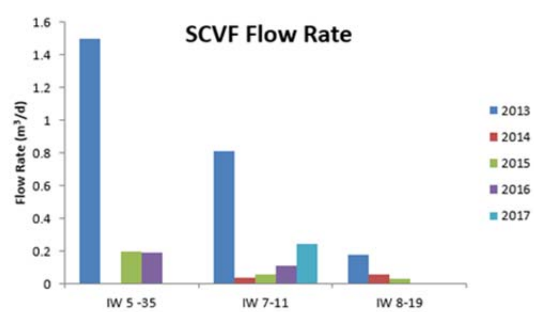
The SCVF flow test results for both IW 5-35 and IW 7-11 are summarized in Figure 6-7. Measurements at the IW 5-35 well are at similar levels to those observed in June 2016. The measured SCVF flowrate reading for IW 5-35 in June 2017 was TSTM (too small to measure). Although there is an increase at IW 7-11 SCVF buildup pressure, the overall level is still low. No gas was detected on the SCVF measurements on IW 8-19 for a second consecutive year, indicating that the surface casing vent flow on this well has declined to zero. The compositional results indicate that the SCVF and GM gas at the IW wells is predominately methane

Gas migration testing as per the suggested method in AER Directive 20, Appendix 2 was performed on both wells. Previously the gas migrations observed on IW 5-35 and IW 7-11 occurred as bubbles in the well cellars. In June 2016, no gas bubbles were observed in the IW 7-11 cellar; however, in June 2017 the gas bubbles had reappeared. The IW 7-11 gas migration is now intermittent. Gas bubbles were observed in the IW 5-35 cellar in both 2016 and 2017.

In 2017, the gas concentration measurements at 30 cm were taken using an inverted funnel and hose for the first time. As such the results obtained are not directly comparable to historical measurements of whole air collected via methane meter suspended over cellar. 2017 method preferentially samples for lighter gases and resulted in LEL measurements in the 96-98% LEL range where 2016 and earlier where whole air measurements were taken resulted in the 4.6-31% LEL range. The gas migration measurements further away from the well are generally very low with a couple relatively higher measurements that are still below the measured values at the cellar. The Gas Migrations still have very limited impact and no potential for concern beyond the lease.

**Figure 6-7: SCVF Pressure and Flow rate summary graphs for IW 5-35, IW 7-11 and IW 8-19.**



# 7 Facility Operations - Maintenance and Repairs

Review and approvals of maintenance plans - including identification of key maintenance activities, were completed in early 2017. Training plans and maintenance procedures for the maintenance personnel are complete and have included vendor training for key components (analysers, compressor). Wherever possible, Shell has leveraged existing processes, systems and procedures to facilitate a smooth transition of the Quest project into Scotford routine maintenance and operations.

Spare parts requirements based on vendor-supplied information have been purchased, with successful delivery. Completion of outstanding reliability centered maintenance (RCM) studies has facilitated creation and population of SAP (equipment database system).

All essential maintenance processes were in place prior to start up and received the appropriate internal approvals to allow the team to advance to the start up phase.

Post startup, in August, regular maintenance plans implemented through SAP based on RCM reports for the capture facility, pipeline and wells have provided a steady and reliable operation.

Maintenance and repairs during 2017 are as follows:

- Amine carbon filter changed out and replaced with fresh carbon. Inspection of vessel complete and no additional repairs required.
- Teg carbon filter changed out and replaced with fresh carbon. Inspection of vessel complete and no additional repairs required.
- Temporary caustic skid in place and operational to maintain proper downstream PH of condensate going to waste water carbon steel piping.
- Replaced insulation soft covers with hard insulation in certain areas due to freezing of instruments.
- Lean/rich amine exchanger back flushed to improve heat transfer. Removed and repaired 2” vapor line on “A” exchanger that had a pinhole leak.
- Repaired seal flush nipple on high pressure amine charge pump.
- Removed and replaced 70 bull plugs/gaskets on E-24707 head due to leaks
- Installed suction screens on P-24611 cooling water pumps
- Replaced lube oil nozzles on 2$^{nd}$ pinion in $CO_2$ compressor gear box
- Replaced 1$^{st}$ stage startup suction screen with post startup suction screen on $CO_2$ compressor. Inspection complete to IGV (inlet guide vane) and first stage impeller.
- Logic changes on DCS surrounding amine filter swings and amine auto pump starts to avoid nuisance trips.

2017 Maintenance

- E-24602A Leak box removed and new piping installed
- Temporary caustic skid added to increase PH on condensate going to wastewater from Quest reflux drum.
- AI-247002 $CO_2$ analyzer accuracy lines up with gas bomb analysis since new barometric compensation added
- LT-246011 guided wave electronics replaced
- Pipeline smart pig sent down the line for inspection and no defects found
- FT-247004 electronics replacement ($CO_2$ flow to pipeline)
- Inspection of piping throughout Quest using UT for corrosion information/tracking

2017 Pipeline Maintenance

- Wellsite flow controller's positioner's replacement
- Maintenance to improve fuel cell reliability and power fluctuations
- Replacement of solar controllers to reduce communication alarms
- Pigging/line inspection
- Boreal Laser repairs and maintenance as required
- Quest truck replacement and maintenance as required
- Road and site ground maintenance as required
- Full ROW inspection, ground repair and vegetation control
- Fuel cell replacement under warranty at LBV's
- MMV building HVAC repairs
- Identification of wellsite #3 drainage issues and future repair plan
-

Overall maintenance issues have been minimal for a new construction startup. Sharing of best practices by networking with other operating facilities continues to help improve maintenance practices and procedures.

# 8 Regulatory Approvals

## 8.1 Regulatory Overview

Regulatory submissions in 2017 followed the schedule set forth by the Approval. Regulatory approvals in 2017 addressed the ongoing operations and optimization of safe operations.

## 8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2017. In 2017, new MMV and Closure plans were submitted and approved, along with the Special Report on InSAR Efficacy.

## 8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to the Project for the 2017 reporting period.

**Table 8-1: Regulatory Approval Status**

| Approval or Permit | Regulator | Status and Timing of Approval/Permit | Comments |
|---|---|---|---|
| **$CO_2$ Injection and Storage** | | | |
| AER Approval No.11837C<br>Directive 13 | AER | Submitted Feb 24, 2017 | Request for non-routine suspension for SCL THORH 5-35-59-21 |
| Shell Quest AER Approval No.11837C<br>MMV Plan Update | AER and GOA | Submitted February 23, 2017<br>Approved May 11, 2017 | Requirement to submit updated MMV Plan every three years as required by the Sequestration Lease Approval from Alberta Energy. |
| Shell Quest AER Approval No.11837C<br>Closure Plan Update | AER and GOA | Submitted February 27, 2017<br>Approved May 10, 2017 | Requirement to submit updated Closure Plan every three years as required by the Sequestration Lease Approval from Alberta Energy. |
| Quest Carbon Capture and Storage Project<br>Fifth ANNUAL STATUS REPORT | AER | Submitted March 30, 2017<br>Received March30, 2017 | Annual Report |
| Shell Quest AER Approval No. 11837C<br>InSAR Efficacy Report | AER | Submitted March 31st, 2017 | Requirement to submit a Special Report on the efficacy or InSAR as per Condition 16 of Approval 11837C. |
| Shell Canada limited Oil Sands Processing plant (Bitumen Upgrader) Environmental Protection and Enhancement A Approval no. 49587-01-00, as amended | AER | Submitted renewal approval application on October 5, 2016 | Expiry date of EPEA Approval 49587-01-07 has been extended (2nd extension) to Oct 31, 2018 |

## 8.4 Next Regulatory Steps

The regulatory requirements will be focused on demonstrating compliance with existing agreements. With ongoing operations, minor changes may be required to improve operational efficiency while ensuring safe performance.

Expected submissions for 2018 include:

- The Sixth Annual Status Report to AER

# 9 Public Engagement

## 9.1 Background on Project and Construction Consultation and Engagement

Shell conducted a thorough public engagement and consultation program beginning in 2008 in support of the Quest CCS project. Stakeholder engagement began with meetings with regulatory agencies and local authorities before the formal commencement of the public consultation process for Quest. Regulatory agencies and local authorities provided input on the planned participant involvement program. Quest was publicly disclosed in October 2008 via an information booklet and news release, followed by a publicly advertised open house in Fort Saskatchewan on October 16, 2008.

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 response to landowner feedback, efforts were made to accommodate stakeholder concerns. Several re-routes of the pipeline were undertaken to avoid the Bruderheim Natural Area and re-route through the North Saskatchewan River in response to landowner feedback. Overall, more than 30 pipeline re-routes were made due to stakeholder 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.

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. Provincial regulators advised that aboriginal consultation was not required for the project. Shell advised provincial and federal regulators that it would continue to provide project information to interested aboriginal stakeholders and consult with parties upon request.

## 9.2 Stakeholder engagement for the Quest CCS Facility

Upon start-up of the Quest CCS facility, stakeholder engagement focused on two streams: community relations and CCS knowledge sharing/public awareness.

### 9.2.1 Community Relations

Community stakeholder engagement activities for Quest in 2016 fell into the following categories:

1) Updates to municipal governments
2) Working to resolve public concerns
3) Participation in the Community Advisory Panel (CAP)
4) Community events/Public information sessions

### Municipal Government Updates

Annual updates were given to town and county authorities at their council sessions to provide the most recent project progress information. Specifically, updates were provided to the following municipalities:

- January 24, 2017 – Strathcona County
- February 28, 2017 – Fort Saskatchewan

Shell's updates to the above councils were well received. No major issues were raised specific to the Quest facility and questions were answered immediately at the council sessions.

### Public Concerns

Shell has a comprehensive public concerns process that is designed to encourage community feedback. It does not take a formal complaint for a concern to be entered into the process. A concern or query from an informal conversation would still be captured to help Shell understand the pulse of the concerns from the community. These concerns can range from impact from our operations – both real and perceived – all the way to inquiries that are not attributable to Shell. In 2017, Shell recorded 26 concerns related to the Quest facility. This represents the total number of queries/complaints – not the number of individuals.

Most of the concerns from 2017 were related to soil quality due to pipeline construction and water runoff from the 5-35 well pad.

Shell responded to all of the individuals who raised concerns and put in action plans to address any issues that were identified.

### Participation on Community Advisory Panel (CAP)

To involve the public in the development of the MMV plan, a Community Advisory Panel (CAP) was formed in 2012. The CAP comprises local community members including educators, business owners, emergency responders, and medical professionals as well as academics and AER representation. The mandate of the panel is to provide input to the Quest Project on the design and implementation of the MMV Plan on behalf of the broader community and to help ensure that results from the program are communicated in a clear and transparent manner. In 2017, the CAP met on May 11 to review the latest MMV data.

### Public Information Session

An open house was held in Thorhild County on February 27, 2017 to give community members the opportunity to meet with Shell, learn more about the project, and ask questions about Quest. The open house was held at Thorhild Central School with it open to students from 1-2:30 p.m. and open to the community from 4-8 p.m.

## 9.3 CCS Knowledge Sharing

Global interest into our experience with the Quest facility continued to be high in 2017. As such, members of the Quest team attended or hosted numerous conferences, workshops and tours. The table below gives an overview of the 2017 activities:

**Table 9-1: 2017 Knowledge Sharing**

| 2017 Conferences/Workshops/Tours | Date | Location |
|---|---|---|
| RITE CCS Technical Workshop | Jan-18 | Tokyo, Japan |
| RCSP Review | Jan 23-27 | Pittsburgh |
| DC Forum | Feb 7-8 | Washington, DC |
| MMV Plan Update | Feb 23-27 | Calgary |
| Quest Open House | Feb-27 | Thorhild |
| Thorhild Council Meeting | Feb-28 | Thorhild |
| ASES 2017 | Mar-05 | Calgary |
| U of C, GLGY 581 | Mar-9,13 | Calgary |
| Gener8 Conference - Inside Education | Mar-10 | Kananaskis |
| GeoConvention | May-11,16 | Calgary |
| US-Can-Mex Trilateral | Mar 28-30 | Pittsburgh |
| Chevron Gorgon knowledge sharing | Apr-03 | Virtual |
| CCUS Conference | April 10-12 | Chicago |
| Acquistore Knowledge Share | Apr-19 | Calgary |
| APEGA Summit Awards | Apr-27 | Calgary |
| AER Review - MMV and Closure Plans | Apr-28 | Calgary |
| CSLF Mid-Year Meeting | May 1-3 | Abu Dhabi |
| ARB CCS Program Review | May-08 | Virtual |
| IEAGHG ExCo | May-11 | Edmonton |
| CAP Meeting | May-11 | Thorhild |
| Clean Energy Ministerial | June 6-8 | Beijing |
| Gordon Research Conference | Jun 12-15 | Connecticut |

| | | |
|---|---|---|
| IEAGHG Monitoring Network | Jun 13-15 | Traverse City |
| IEAGHG Summer School | July 16-22 | Regina |
| U of C CFREF Team Visit | Aug-02 | Calgary |
| EAGE/SEG CCS Research Workshop | Aug 28-31 | Trondheim, Norway |
| EAGE Environmental Workshop | Sep 4-7 | Malmo Sweden |
| MGSC Microseismic Review | Sep 19-21 | Champaign, Illinois |
| Mission Innovation | Sep 26-29 | Houston, Texas |
| NDRC/ERI Mission to Alberta | Sep-26 | Scotford |
| Global CCS Institute Study Tour | Sep 27-28 | Scotford |
| CCS Institute Symposium | Oct 3-5 | Regina |
| Asian Development Bank | Oct-06 | Scotford |
| SPE Annual Technical Conference | Oct 9-11 | San Antonio, TX |
| PCOR Meeting | Oct-24 | Plano, TX |
| Shell Integrated Development Conference | Nov 15 | Houston, TX |
| American Geophysical Union | Dec 11-13 | New Orleans |

# 10 Costs and Revenues

The majority of Quest spend is Canadian content; less than 5% of total spend is foreign currency (USD and Euros). Foreign exchange rate is managed through treasury at a daily spot rate.

## 10.1 Capex Costs

Quest reached commercial operation in Q4 2015 and while the asset switched to operation, some remaining closeout capital transactions continued to flow through. Table 10-1 reflects the project's incurred costs to the end of 2017. The categories follow those used by Shell over the life of the project to track project costs. Total capital costs comprise $790 million versus the original $874 million to reach commercial operation on October 1, 2015. *Sustaining capital required to operate the venture in fiscal 2017 has been shown in a separate column.

**Table 10-1: Project Incurred Capital Costs (,000)**

| | 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 2015/16 April 1 , 2015 - March 31, 2017 | Total Capex to reach Commercial Operation | FISCAL 2017 April 1, 2017 - December 31, 2017 Sustaining Capital |
|---|---|---|---|---|---|---|---|---|
| **Overall Venture Costs** | 19,470 | | | | | | | |
| **Shell Labour, & Commissioning** | 19,470 | 5,414 | 32,638 | 23,466 | 57,311 | 29,057 | 147,886 | |
| **Tie-in Work /Brownfield Work** | | | | | | | | |
| Tie-In/Turnaround Work Capture | 0 | 0 | 7,331 | 10,234 | 10,430 | 7,938 | 35,934 | |
| Tie-In Work Pipeline | | 0 | 196 | 518 | 334 | 161 | 1,209 | |
| **Sub Total** | 0 | 0 | 7,527 | 10,753 | 10,764 | 8,099 | 37,143 | |
| **Capture Facility*** | 52,671 | | | | | | | |
| Engineering | | 6,662 | 40,889 | 32,799 | 5,180 | 1,378 | 86,907 | |
| Construction Management | | 0 | 218 | 16,967 | 21,338 | 31 | 38,554 | |
| Material | | 6,092 | 42,315 | 56,502 | 7,466 | -5,080 | 107,295 | |
| Site Labor | | 0 | 0 | 9,456 | 36,038 | 0 | 45,494 | 152 |
| Subcontracts | | 0 | 0 | 1,380 | 7,799 | -37 | 9,143 | |
| Mod Yard Labor Including Pipe Fab | | 0 | 14,250 | 60,697 | 29,832 | 0 | 104,780 | |
| Indirects / Freight | | 0 | 15 | 32,339 | 12,987 | -28 | 45,314 | |
| FGR Mods/HMU Revamps | | 0 | 0 | 0 | 0 | 0 | 0 | |
| **Sub Total** | 52,671 | 12,753 | 97,688 | 210,141 | 120,640 | -3,736 | 437,486 | 152 |
| **SUBSURFACE - Wells*** | 63,175 | | | | | | | |
| Injection Wells | | 1,090 | 17,970 | 3,641 | 167 | 1,833 | 24,700 | |
| Monitor Wells | | 0 | 1,311 | 54 | -20 | 571 | 1,916 | |
| Water Wells | | 0 | 1,620 | -53 | 1 | 0 | 1,569 | |
| Other MMV | | 0 | 1,657 | 3,309 | 5,295 | 1,925 | 12,186 | |
| **Sub Total** | 63,175 | 1,090 | 22,558 | 6,951 | 5,443 | 4,329 | 40,370 | |
| **PIPELINES - TOE*** | 4,035 | | | | | | | |
| Engineering | | 576 | 4,272 | 2,782 | 1,085 | 51 | 8,766 | |
| Materials and Equipment | | 0 | 1,878 | 24,823 | 4,485 | 12 | 31,199 | 55 |
| Services | | 0 | 0 | 60,101 | 27,366 | 11 | 87,477 | |
| **Sub Total** | 4,035 | 576 | 6,150 | 87,706 | 32,936 | 74 | 127,441 | 55 |
| **Total Contingency, Inflation & Mrkt Escalation** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| **Sub Total** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| **Grand Total** | 139,351 | 19,832 | 166,561 | 339,016 | 227,094 | 37,823 | 790,326 | 207 |

* Shell labour costs during FEED are booked here.

*Sustaining capital in 2017 consists of equipment purchase for pipeline reliability monitoring and site labor costs associated with capture facilities operations simulator capital investment in 2017.

## 10.2 Opex Costs

Operating costs associated with the venture for the first two years of commercial operations are shown in the table below. The overall forecast for Opex in 2018 ranges from $29 to $34 Million.

**Table 10-2: Project Operating Costs (,000)**

| Cost Category | Oct 1, 2015 – Dec 31, 2016 | 2017 Jan 1 – Dec 31 |
|---|---|---|
| Power | 3,717.70 | 4,513.96 |
| Steam | 8,414.46 | 8,834.50 |
| Compressed Air | 67.67 | 62.59 |
| Cooling Water | 427.95 | 389.81 |
| Direct Labour and Personnel Costs | 7,829.42 | 5,635.83 |
| Maintenance Materials and Technical Services | 969.42 | 942.63 |
| Property Tax | 2,003.72 | 2,000.28 |
| Sequestration Opex | 7,052.85 | 6,797.59 |
| MMV after Operations | 1,690.41 | 1,655.74 |
| Post Closure Stewardship Fund | 272.07 | 264.28 |
| Other Well Costs | 431.49 | 442.12 |
| Subsurface Tenure Costs | 362.50 | 420.00 |
| Pipeline - Inspection and Pigging | 145.78 | 340.49 |
| Amine | 340.67 | 0.00 |
| Chemicals | 20.35 | 97.92 |
| Vendor rebates | -122.32 | -100.36 |
| Corporate and Other Costs | 119.24 | 205.95 |
| **Total** | **33,743.37** | **32,503.34** |

Notes:

1. Minimal loss of amine was observed in 2017, hence no additional expenditure was required.
2. In 2017, $100,000 CAD in vendor rebates were received for project insurance premium refunds.
3. Review of allocations to Quest will occur in 2018, with potential resulting updates to past operating years.

## 10.3 Revenues

Revenues reflect funding as well as $CO_2$ reduction Credits received up to December 31, 2017.

The $CO_2$ reduction credits received during 2017 consist of 1,212,182 t $CO_2$ e Serialized Verified Emission Reductions for the period August 23, 2015 – September 30, 2016. Single and additional credits, valued at $30/tonne, have been issued and are included in the table below. As per the multi-credit agreement signed with the Province of Alberta, additional credits are expected one year after base credits are issued and reported in the period in which they are received. Pending third party verification, credits for emissions reductions after October 1, 2016 will be serialized and reported in 2018.

**Table 10-3: Project Revenues**

| | **2009 – 2015** Construction | **2016** Operation | **2017** Operation | Aggregate Revenues Forecast |
|---|---|---|---|---|
| | Jan 1, 2009 – Dec 31, 2015 | Jan 1, 2016 – Dec 31, 2016 | Jan 1, 2017 – Dec 31, 2017 | Jan 1, 2018 – Dec 31, 2025 |
| 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 | $573,345,454.60 | $29,451,643.52 | $30,100,000.00 | $238,448,356.48 |
| $CO_2$ reduction credits | | $3,330,800.00 | $36,365,460.00 | $465,600,000.00 |
| | $573,345,454.60 | $32,782,443.52 | $66,465,460.00 | $704,048,356.48 |

Forecast Assumptions:

- Quest Project does not enter a Net Revenue Position before September 31, 2025
- Estimate 7.8MT $CO_2$ avoided over next 8 years
- Double credits received; each $CO_2$ reduction credit valued at $30

.

## 10.4 Funding Status

To date, the Project has received a total of $6.3 million from the Alberta Innovates program, which has concluded. Quest 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 remaining 10% holdback received after commercial operation. 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, $38 million in October 2014, $15 million in March 2015 and a further $149 million at Commercial operation in October 2015. Quest has now been in the operating funding phase for two years.

Funding during operations is determined by the net tonnes of carbon dioxide sequestered in each year Pursuant to section 4.2 of the Funding Agreement.

**Table 10-4: Government Funding Granted and anticipated**

Government funding granted through construction of the Quest project.

| Government Funding | 2009<br>January 1, 2009 - March 31, 2010 | 2010<br>April 1, 2010 - March 31, 2011 | 2011<br>April 1, 2011 - March 31, 2012 | 2012<br>April 1, 2012 - March 31, 2013 | 2013<br>April 1, 2013 - March 31, 2014 | 2014<br>April 1, 2014 - March 31, 2015 | 2015<br>April 1, 2015 - September 30, 2015 | Operating 2016<br>October 1, 2015 - September 30, 2016 | Operating 2017<br>October 1, 2016 - September 30, 2017 | Operating<br>October 1, 2017 - March 31, 2026 |
|---|---|---|---|---|---|---|---|---|---|---|
| Alberta Innovates Grant | $ 3,225,847 | $ 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 | $ 29,451,644 | $ 30,100,000 | $ 238,448,356 |
| | | | | | | | | | | |
| Total Funding | $ 3,225,847 | $ 1,817,101 | $ 1,302,507 | $ 238,000,000 | $ 115,000,000 | $ 53,000,000 | $ 161,000,000 | $ 29,451,644 | $ 30,100,000 | $ 238,448,356 |
| | | | | | | | | | | |
| Cummulative Gov't Funding as Percentage of Total Project Spend | 0.2% | 0.4% | 0.5% | 17.5% | 25.8% | 29.6% | 41.1% | 43.2% | 45.4% | 62.5% |

# 11 Project Timeline

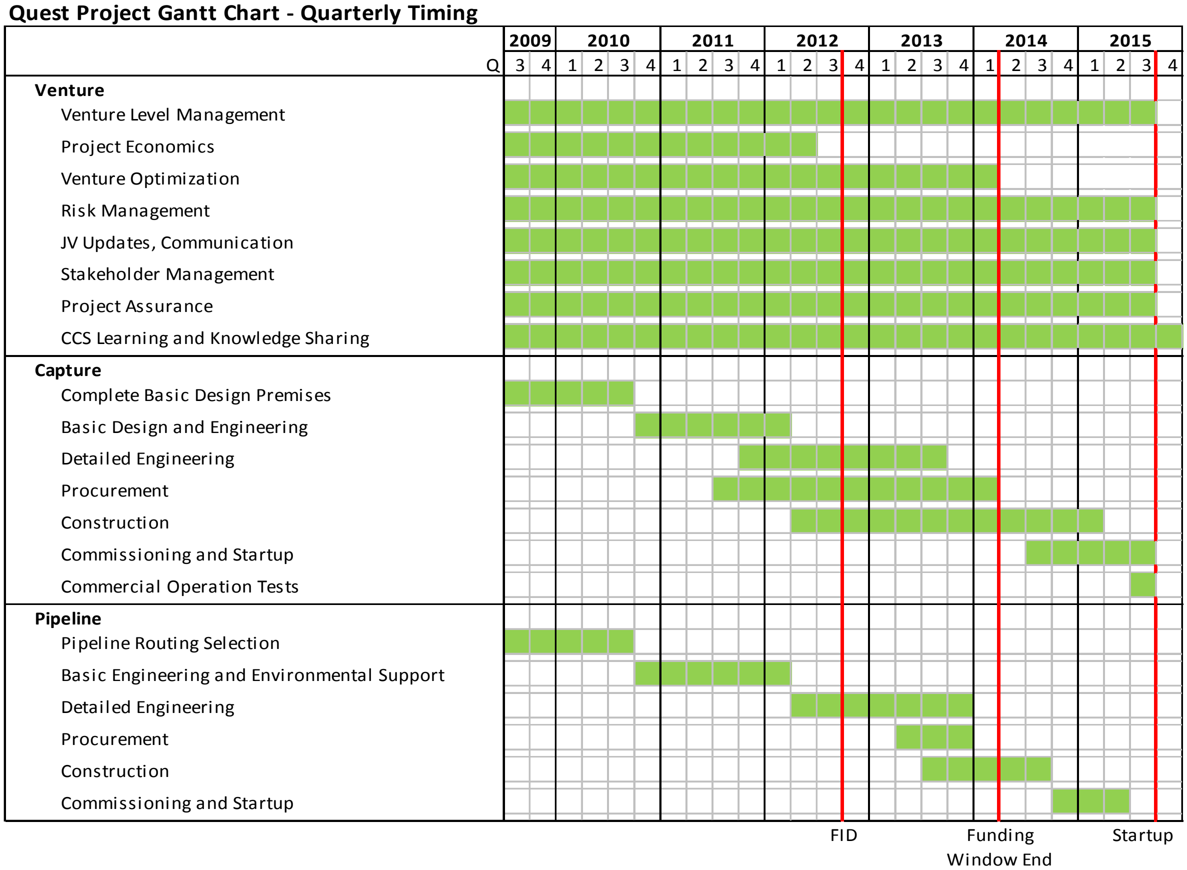
The timeline for Quest is shown in Table 11-1. The only departure from the project timeline is the advancement of the completion of the capture commercial operation tests. The tests were originally scheduled to run into Q4 2015, but all tests were completed by the end of Q3 2015.

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

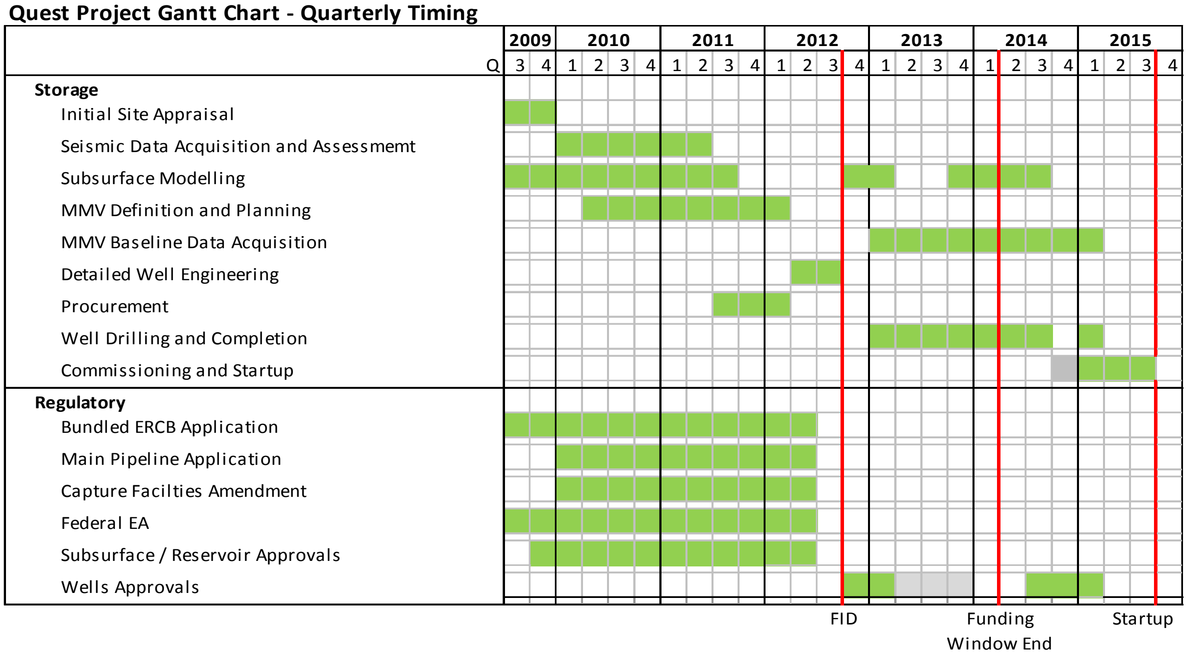
The projected forecast for $CO_2$ injected is as submitted in Schedule "C" Projected Payment Schedule after the achievement of commercial operations.

## Table 11-1: Project Timeline

**Quest Project Gantt Chart - Quarterly Timing**




**Quest Project Gantt Chart - Quarterly Timing**



# 12 General Project Assessment

The project schedule, as noted in Section 11, was largely maintained with the actual achievement of commercial operation on September 28, 2015. Project development costs were on budget; the final capital costs were under budget. Operating costs for 2017 were under budget as well based on lower power costs and operational efficiencies.

**Project Successes in 2017:**

*Operational MMV Data Acquisition*

In 2017 continued monitoring occurred including the acquisition and interpretation of the second monitor VSP. Routine logging and well integrity testing was also completed on the IWs.

In June 2017, Quest reached the milestone of 2 million tonnes of $CO_2$ injected.

*Networking within Industry*

Networking with external, operating facilities continued to help better identify maintenance practices and procedures. Technical knowledge was also shared and gained through numerous technical conference presentations and workshop attendance.

*Stakeholder Engagement*

Stakeholder management continues to be a priority for Quest. In 2017, Shell continued the use of open houses/coffee sessions for community engagement. The community advisory panel continues to be a valuable tool to share information and collect feedback from the community and key stakeholders. Although we have built on the strength years of community engagement, we realize that we must continue this dialogue.

Quest continues to attract interest from various industries, government and non-government organizations. Shell attended and provided information to a large number of organizations at conferences and meetings over the course of the year.

*Provincial Government Milestones*

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

Continued funding of the project occurs by annual funding installment payments (for up to 10 years) and through credits.

*Environmental Stewardship*

*Technical Successes*

In 2017, the low levels of chemical loss from the ADIP-x process continued, with significantly lower carryover of TEG into $CO_2$ vs. design with estimated losses on track to be roughly 5,800 kg annually vs. the design makeup rate of 46,000 kg annually.

Furthermore, implementation of FGR (flue gas recirculation) technology, in combination with the installation of low-NOx burners has allowed all three HMUs to meet their NOx level commitments without contravention in 2017 with the capability to maintain NOx levels slightly elevated from pre-Quest baseline.

Successful compressor inspection, trip testing and re-rating of the C-24701 compressor from 12Mpa to 13.58Mpa for increased operational flexibility.

Cleaning of the lean/rich exchangers during the 2017 spring turnaround resulted in stabilization of the fouling trend and impacted rich amine inlet temperature to the stripper observed in 2016. This cleaning of the exchanger resulted in minor duty improvement and temperature maintenance in the column inlet in 2017.

The Lean Amine carbon filter was placed back in service in November 2017 after inspection and reloading with only minor foaming events observed.

On the subsurface side, injection into the 5-35 well continues not to be necessary to meet injectivity requirements, resulting in a significant savings in MMV costs. In addition, the uncertainty in the capacity of the BCS storage complex has been further reduced post-injection. There is strong evidence to support the assessment of BCS having more than sufficient capacity to store the required volume for up to 27 MT of $CO_2$ over the life of this project with negligible likelihood of fracturing, fault reactivation, or $CO_2$ leakage.

The second monitor VSP was completed in Q1 2017 as well as groundwater data sampling in all quarters.

Strong integrated project reliability performance with operational availability at 98.3%.

Annual $CO_2$ capture ratio was maintained in Quests 2$^{nd}$ full year of operations at 82.6%.

Injection certification, audits, offset verifications completed, with serialization of 2015 and 2016 credits, registered on the Alberta Emission Offset Registry.

## Challenges in 2017:

There have been minor operational challenges to Quest, but none that have been insurmountable to date. A description of these challenges and activities undertaken to address them follows.

*Technical Challenges*

High corrosion rates caused by the low pH of Quest stripper reflux water remain a concern to the Scotford Upgrader Wastewater Treatment Plant. Sections of piping have been upgraded to 304 stainless steel (2016) with further mitigation enacted in 2017 by the installation of a temporary caustic injection skid at Quest to increase the pH of the Quest water.

Loss of Amine circulation due to lean Amine charge pump trips on low suction pressure. Temporary procedural changes are in place to address this issue until a permanent solution is implemented.

## 12.1 Indirect Albertan and Canadian Economic Benefits

Quest is an in integrated operation that spans upstream through to downstream processes. In the development and construction of Quest, the project had over 2000 people contribute to its success. These skilled contributors included: Trades workers, Engineers, Geologists, Geophysicists, Technicians, Environmental professionals, Land SMEs, Administrative professionals, and Management. At peak construction, the project had over 800 workers spanning a period of over 2 years.

The primary benefits in this reporting period has been additional business generated with Canadian and Albertan third-party contractors for the following activities:

- Field work done to monitor the hydrosphere properties of the storage area surface and groundwater regions
- Routine well maintenance, logging and SCVF testing

Ongoing benefits during operations for the local communities, Alberta, and Canada include:

- Employment for ~25 FTE people.
- Tax additions to the local governments of Strathcona County, Thorhild, Lamont, Sturgeon County Alberta, and Canada.
- At a municipal level, Strathcona County (and even broader, Alberta's Industrial Heartland) derives benefit from the international attention that Quest generates.
- Recognition by the international community of Canada and Alberta as leaders in CCS deployment through policy, regulation, and funding.
- Maintenance and repair contracts around $2-4 million per year.

In addition to the above, 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. During 2017, work was completed to update and finalize a demonstration agreement with a technology provider. Partnerships such as this with the US DOE will assist in raising the profile of Quest and emphasize the Leadership demonstrated by Alberta and Canada in support of sustainable development of resources through innovation.

# 13 Next Steps

The ongoing focus for Quest, into its third year of operations, is to maintain reliable and efficient operations. Sustainable operations are not only critical in order to continue to meet the requirements of the funding agreement with the Government of Alberta, but also to affirm the position of Quest as an innovative and achievable technology on the global stage.

Quest will continue with the following activities to enable this:

- Capture of operational issues and lessons learned in order to retain institutional memory and facilitate improvements in processes and procedures.
- Evaluating possible alternatives to determine the best solution to permanently mitigate the low PH water leaving the Quest.
- Ongoing MMV activities will be consistent with the approved 2017 MMV Plan update.
- Reservoir model will be updated using available operational data as required.
- Regulatory activities will focus on demonstrating compliance with existing agreements and work will begin to facilitate obtaining the reclamation certification for the Quest pipeline in early 2018.
- Public engagement activities will continue to ensure continued public knowledge and acceptance of Quest operations. The Community Advisory Panel will continue in 2018 to update the group on Quest activities with focus on sustaining reliable operations. Ongoing reporting will continue to the Province of Alberta in accordance with the respective funding agreements.
- Active knowledge sharing through publications and participation in conferences, workshops, and tours into 2018.
- Working with ACCO on the transition from the *Specified Emitters Gas Regulation* to the new *Carbon Competitiveness Incentive Regulation*.
- With the improved operating performance and economic performance versus design, understand the revenue and cost forecast better to determine impacts to the Net Revenue statement.
- Evaluate opportunities to integrate renewable power with Quest.

# 14 References

[1] AER, 2016, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, Fifth ANNUAL STATUS REPORT, available at:
http://www.energy.alberta.ca/CCS/3848.asp

[2] AER, 2017, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, Sixth ANNUAL STATUS REPORT, will be available at:
http://www.energy.alberta.ca/CCS/3848.asp

[3] GOA, 2017, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, 2017 MMV Plan, will be available at:
http://www.energy.alberta.ca/CCS/3848.asp