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Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT - ALBERTA DEPARTMENT OF ENERGY: 2016

March 2017

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 Project and as agent for and on behalf of the AOSP Joint Venture and its participants, comprising of Shell Canada Energy (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%), as amended.

The purpose of the Project 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. Up to 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.

Reservoir performance to date along with initial injectivity assessments indicate the project will be capable of sustaining adequate injectivity for the duration of the project life; therefore, no further well development should be required. Post injection startup, MMV activities have shifted to operational monitoring.

There were no recordable spills/releases to air, soil or water within the Quest capture unit during the 2016 operating period. MMV data indicates that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir to date.

Shell continued to conduct open houses for the local communities. Engagement with local governments continued in 2016 in order to update officials on operations. Engagement with numerous industry and non-government associations for knowledge sharing also continued in 2016.

The Project 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 6,900 kg in 2016 vs. the design makeup rate of 46,000 kg annually
- Injection into the 5-35 well continues to not to be necessary in 2016 due to strong injectivity performance, which results in significant MMV cost savings
- Strong evidence that the project will be capable of sustaining adequate injectivity for the duration of the project life
- Overall maintenance issues have been minimal
- Sharing of best practices by networking with external operating facilities continues to help improve maintenance practices and procedures
- Strong integrated project reliability performance with operational availability at 98.8%
- Maintaining local support through the extensive stakeholder engagement activities

- Continued engagement 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 the Department of Energy-funded entity to develop and deploy MMV technologies for use on Quest
- Milestone of 1 million tonnes of CO_2 injected was reached on August 8, 2016. Operating costs are also lower than forecasted.
- The Capture unit reached its nameplate rate of 1.2 Mt/a and the first CO_2 pipeline in-line inspection was completed

Project challenges for this reporting period were minor operational issues, including:

- A leak identified in the wastewater piping going from Quest to the Scotford Upgrader Wastewater Treatment Plant. Piping was upgraded to 304 stainless steel to deal with high corrosion rates of the Quest low pH water. Additionally, 3 leaks to secondary containment occurred within the Quest capture unit in 2016.
- CO_2 injection was suspended in early December 2016 for retrieval of an inline inspection tool.
- Drifting of the CO2 online analyzer, for which mitigation measures were put into place in order to improve measurement.

Quest has seen strong reliability performance through the reporting period to safely inject 1.11 Mt of CO_2 in 2016. Overall project injection has surpassed 1.5 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 2016, the value of the offset credit was $20/tonne and in 2017 the value will increase to $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 will provide employment for six permanent full time equivalent positions (FTEs) and an additional approximately 13 FTE incorporated into existing positions. Quest is expected to generate expenditures of up to $44 million per year in staffing, MMV, maintenance, and variable costs to the economy.

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Abbreviations

2D	2-Dimensional
3D	3-Dimensional
4D	4-Dimensional
AER	Alberta Energy Regulator
AEW	Alberta Environment and Water
AFN	Alexander First Nation
AGS	Alberta Geological Survey
AOI	Area of Interest
AOSP	Athabasca Oil Sands Project
ARC	Alberta Research Council
ASLB	approved sequestration lease boundary
ASRD	Alberta Sustainable Resources Development
BCS	Basal Cambrian Sands
BHP	bottom-hole pressure
BLCN	Beaver Lake Cree Nation
CCS	carbon capture and storage
CEAA	*Canadian Environmental Assessment Act*
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 Athabasca Oil Sands Project (AOSP) is a joint venture operated by Shell and owned by Shell (60%), Chevron Canada Corporation (20%) and Marathon Oil Sands LP (20%). The AOSP owns the Scotford Upgrader, which is part of Shell's Scotford facility located northeast of Edmonton. The design concept for the Project is to remove CO_2 from the process gas streams of the three hydrogen-manufacturing units (HMUs), which are a part of the Scotford Upgrader infrastructure, by using amine technology, and to dehydrate and compress the captured CO_2 to a dense-phase state for efficient pipeline transportation to the subsurface storage area.

The three 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 the Project is the standard Shell approach in project design, called the Opportunity Realization Manual (ORM). The ORM process manages a project as it matures through its lifecycle from initial concept to remediation following closure. ORM divides this lifecycle into stages as shown in Figure 1-1. Deliverables for each phase are reviewed to ensure proper quality before proceeding to the next phase.

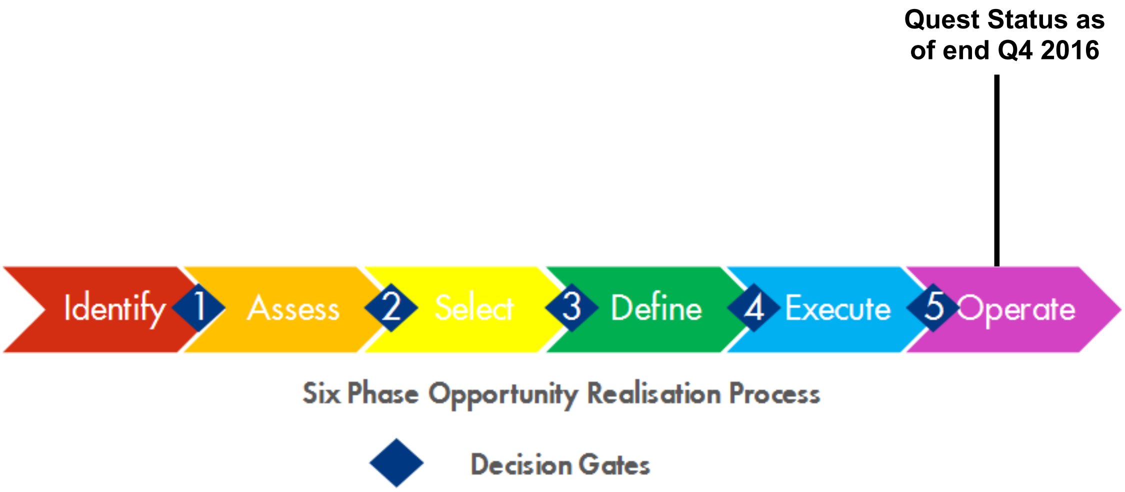


Figure 1-1: ORM Phases with current Project Maturity

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 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 Scotford for sustained operations on October 1, 2015.

The Operate Phase of the project officially commenced in Q3 of 2015 and continued in 2016. The Quest Scotford Operations successfully captured and injected 1.48 Mt of CO_2 in the 7-11 and 8-19 injection wells to the end of 2016.

1.4 Facility Locations and Plot Plans

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

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

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

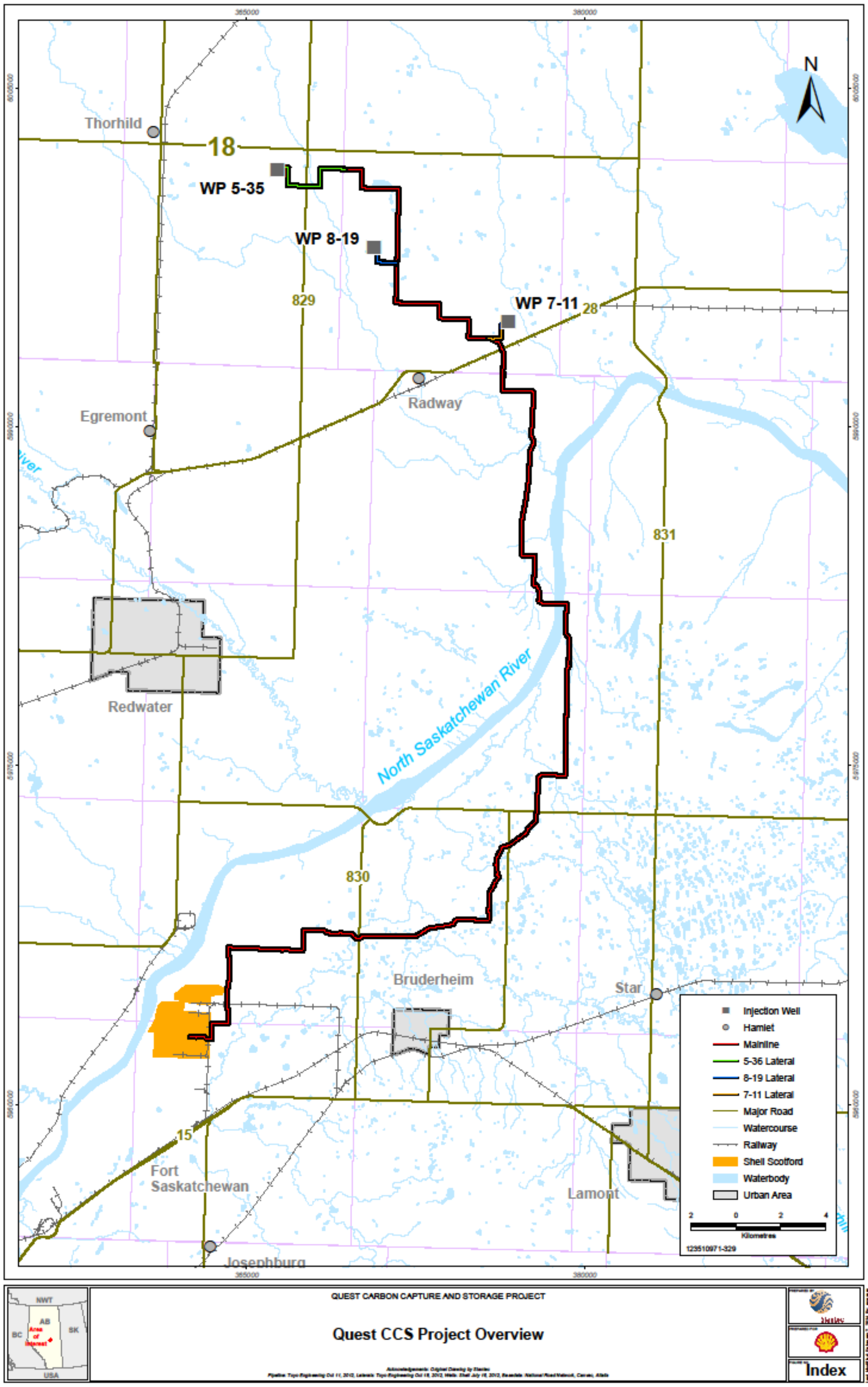


Figure 1-2: Project Facility Locations

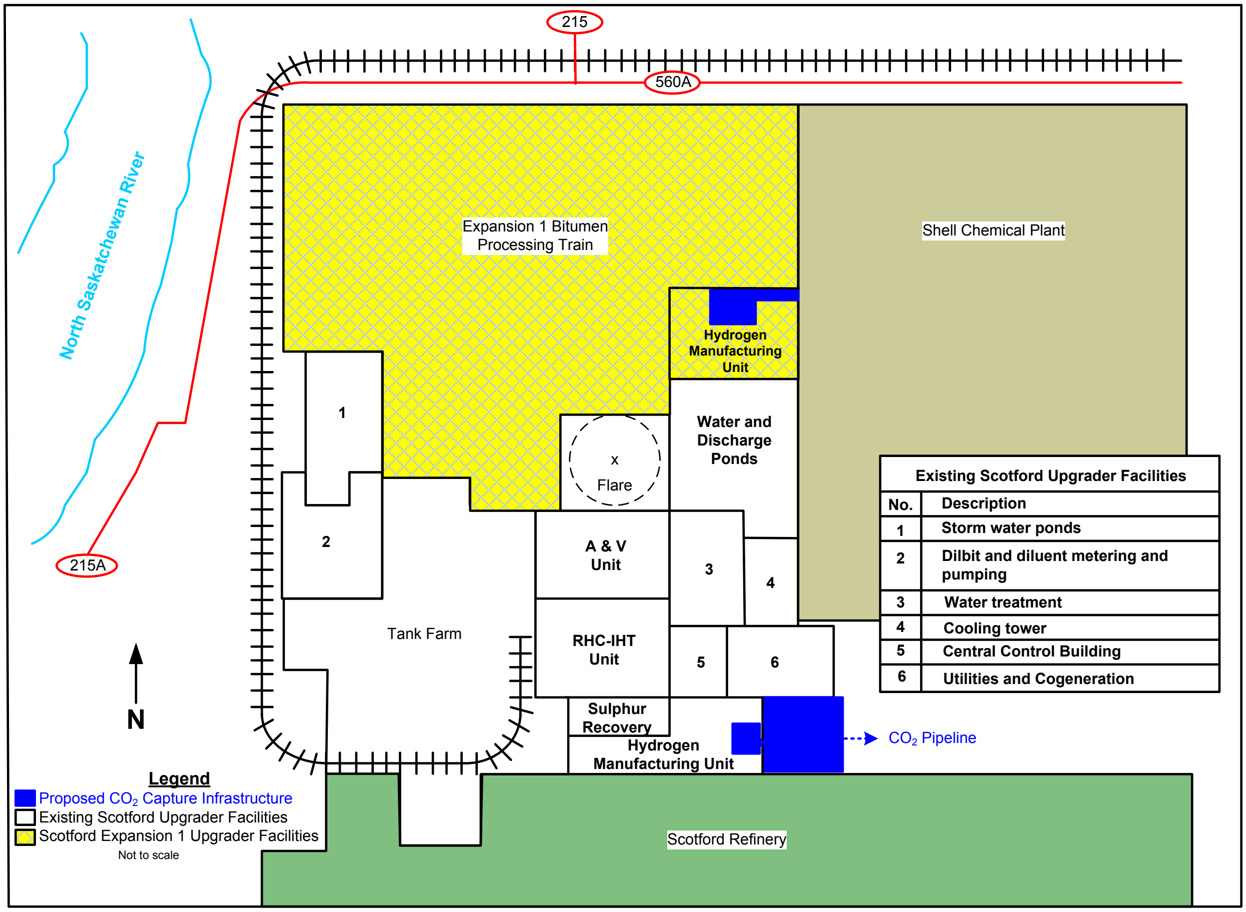


Figure 1-3: Capture Unit Location Schematic

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.

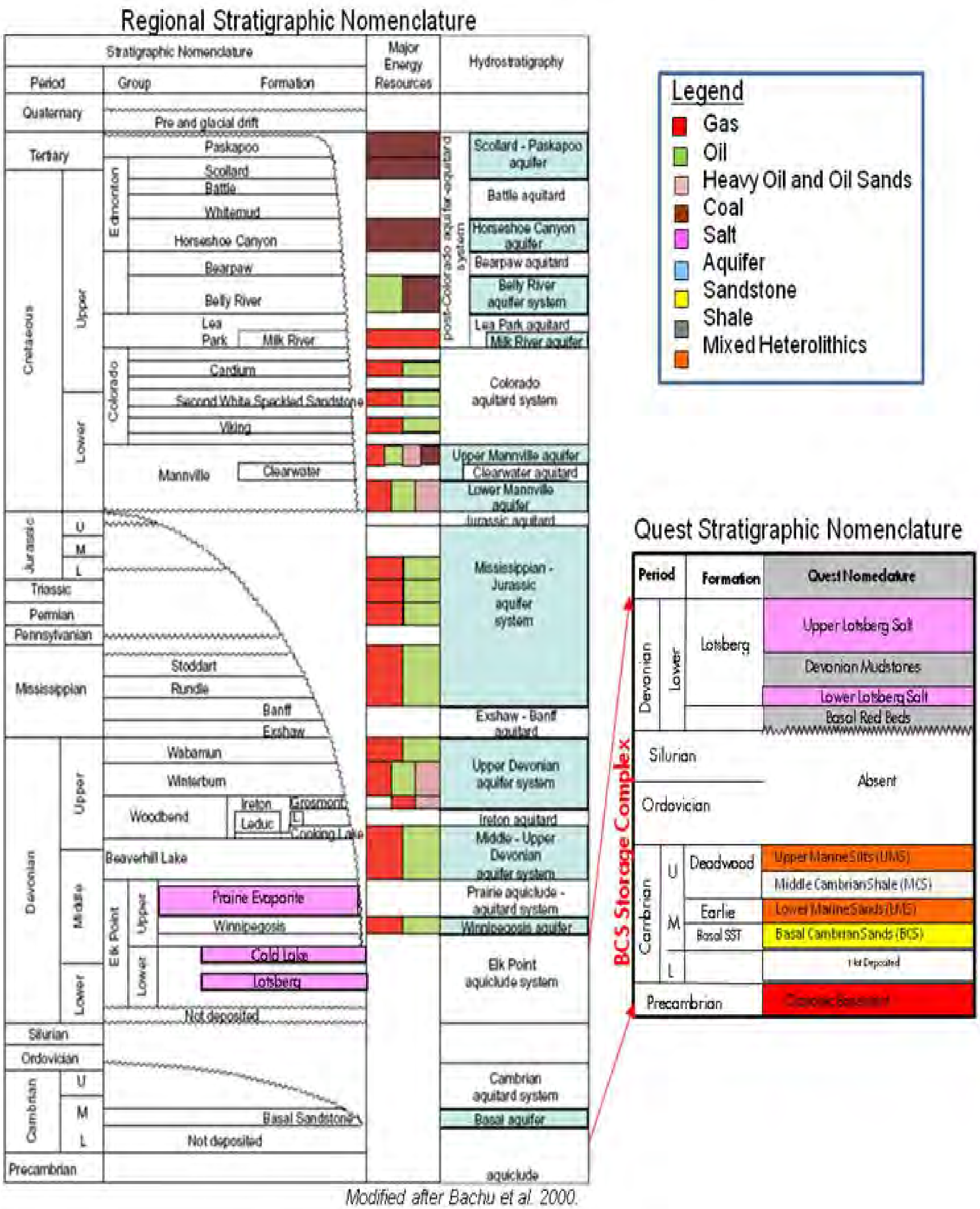


Figure 1-4: BCS Storage Complex within the Regional Stratigraphy

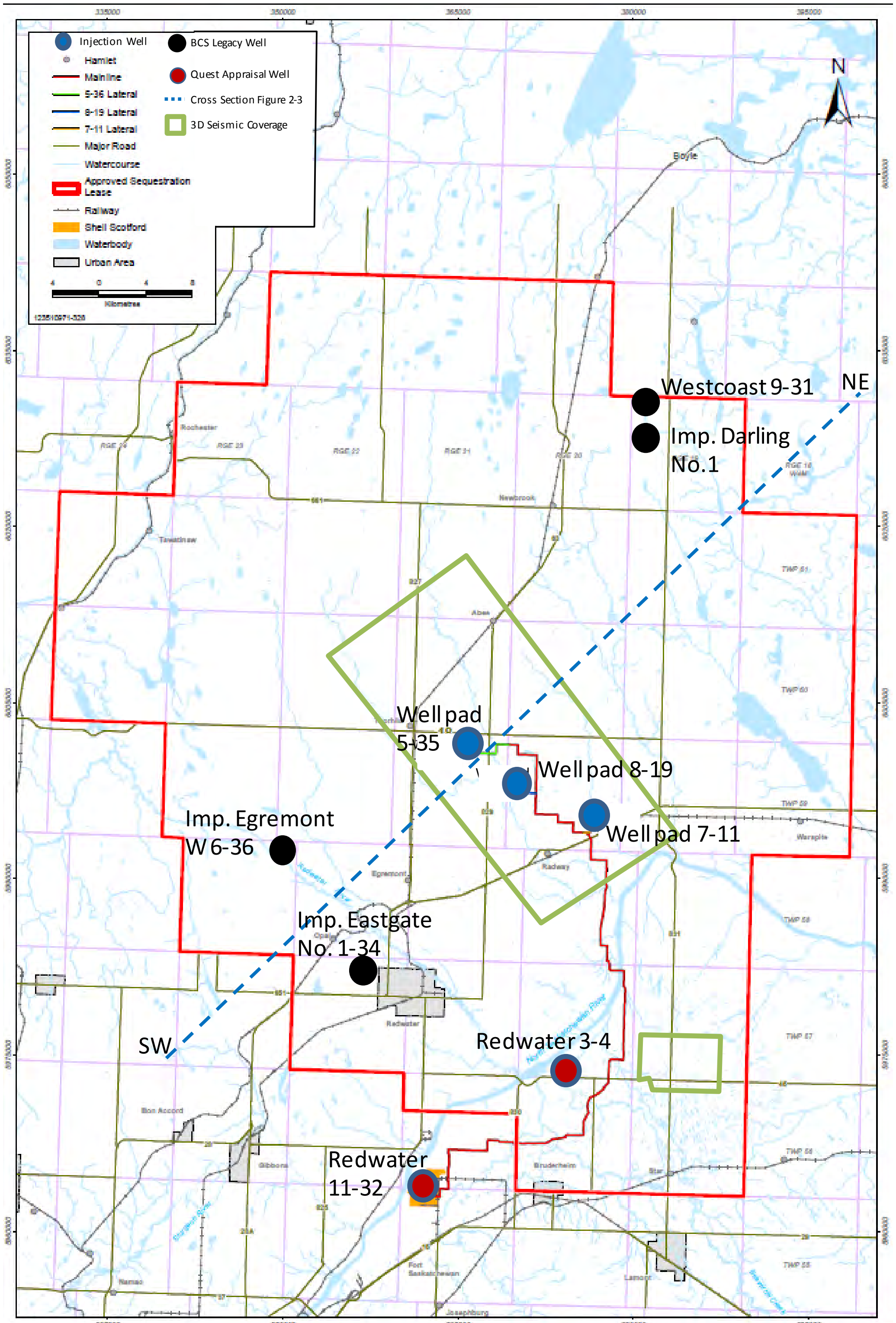


Figure 1-5: Project Components and Sequestration Lease Area

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 Shell of the BCS formation for the Project within the SLA is depicted in *Figure 1-5*. This exclusive use allows Shell to store the design volumes of CO_2 into the formation without the risk of another CCS operator storing CO_2 in proximity to the Project, which would raise the required injection pressures and threaten the Project objectives.

1.5 Process Design

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

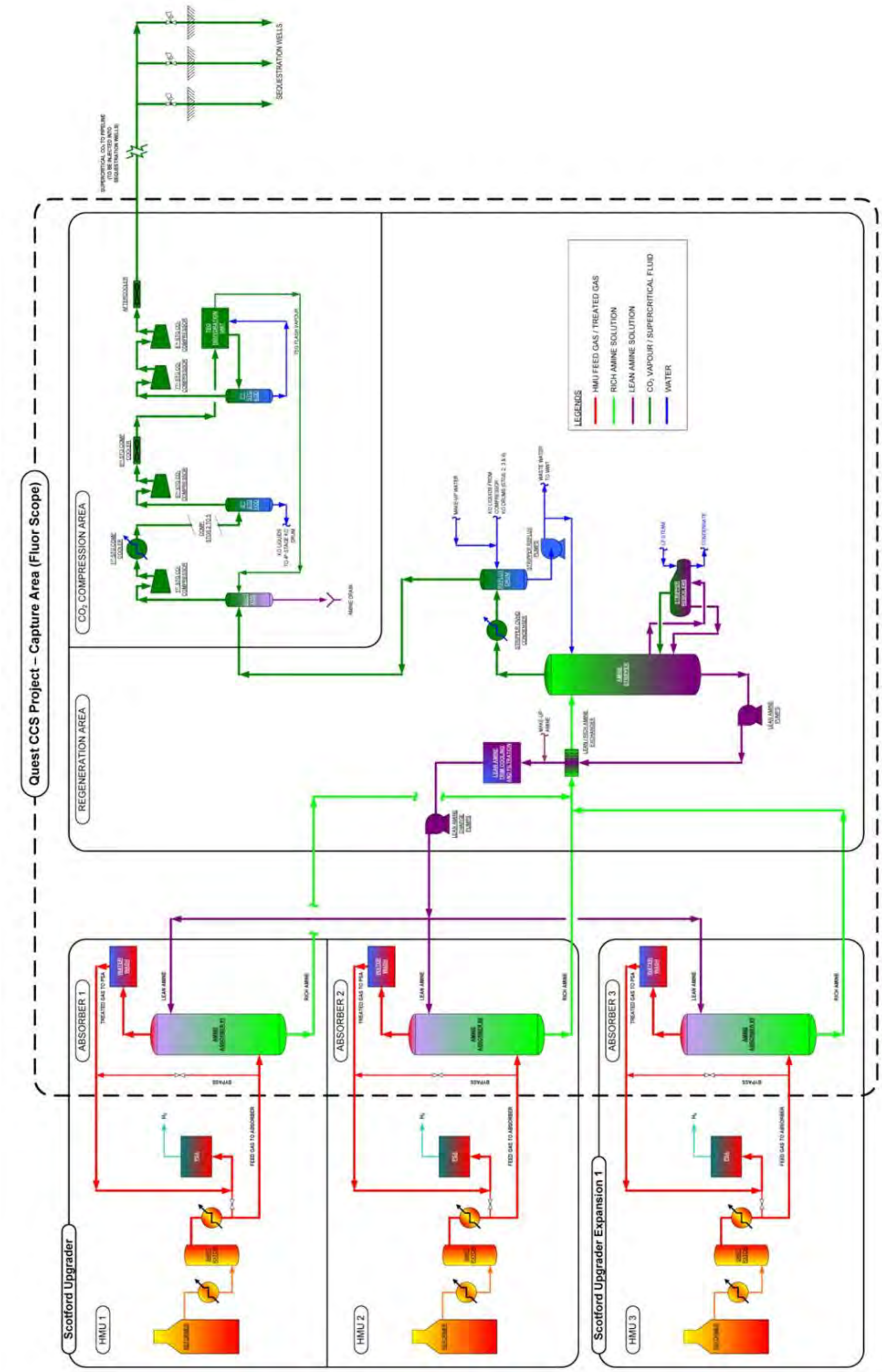


Figure 1-6: Capture and Compression Process Design

Process Description

CO_2 Absorption Section

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 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 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. The CO_2 compressor is currently able to provide a discharge pressure as high as 11,500 kPag, reduced from 14,000 kPag initially due to issues identified during commissioning and startup with reverse rotation of the compressor on shutdown. 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 deep BCS / Cooking Lake pressure monitoring well
- The drilling of nine groundwater wells.

1.6 Modularization Approach

A key feature of the FEED work for the Project was the decision to use a modularization approach for the CO_2 capture infrastructure for the benefit to scheduling and cost.

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

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

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

2 Facility Construction Schedule

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.

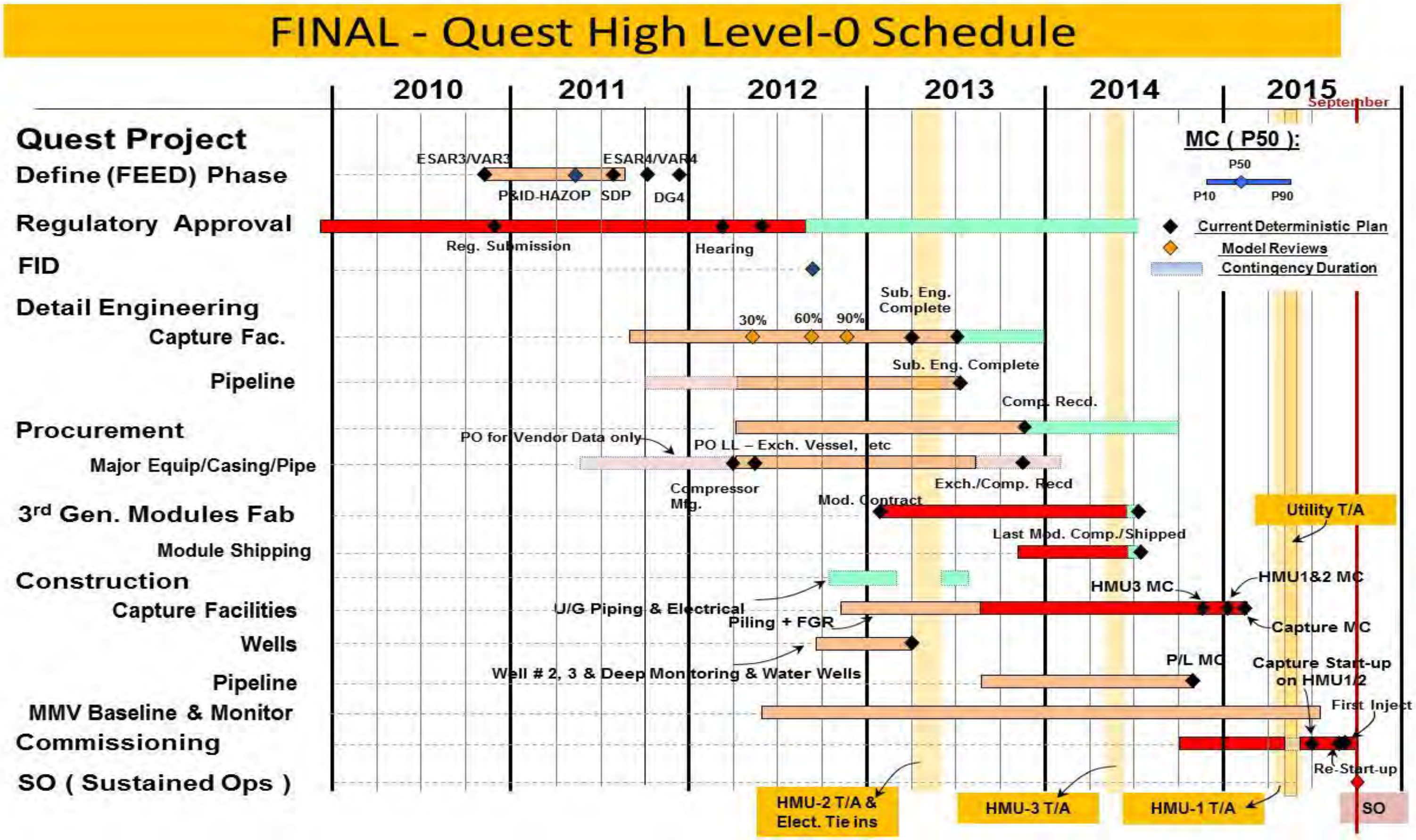


Figure 2-1: Project Construction Schedule

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

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
	13	Pressure	<7.5 MPa	≥7.5 MPa	20.45 MPa
	14	Thickness	<20 m	≥20 m	>35 m
	15	Porosity	<10%	≥10%	16%
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: MCS 21 m to 75 m L. Lotsberg Salt 9 m to 41 m U. Lotsberg Salt 53 m to 94 m
SOURCE: CCS Site Selection and Characterization Criteria – Review and Synthesis: Alberta Research Council, Draft submission to IEA GHG R&D Program June 2009: http://sacccs.org.za/wp-content/uploads/2010/11/2009-10.pdf					

3.2 Geological Framework

The BCS is at the base of the central portion of the Western Canada Sedimentary Basin (WCSB), directly on top of the Precambrian basement. The BCS storage complex is defined herein as the series of intervals and associated formations from the top of the Precambrian basement to the top of the Upper Lotsberg Salt (see *Figure 1-4*).

The BCS storage complex includes, in ascending stratigraphic order:

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

The rocks 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.

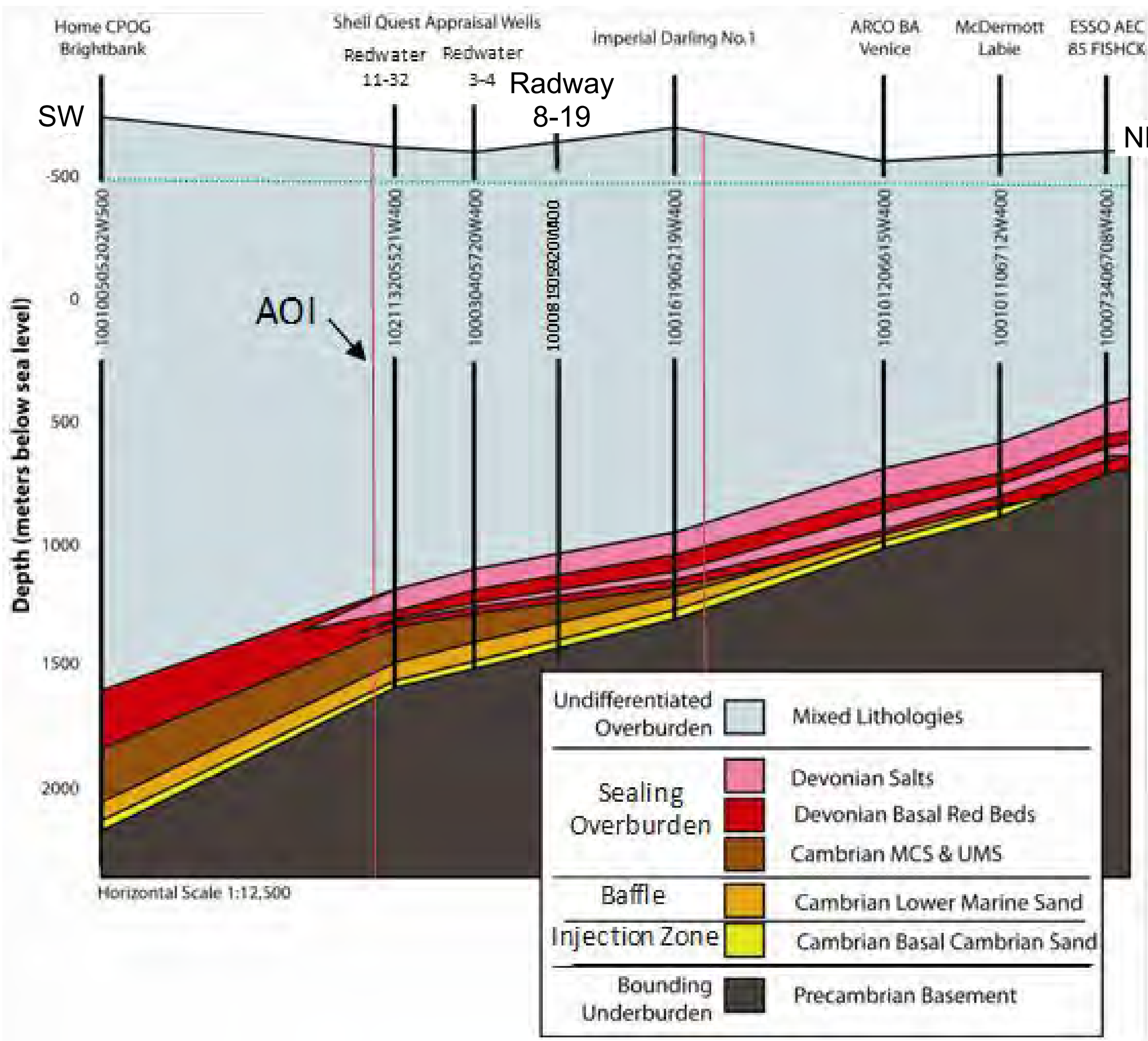


Figure 3-1: Cross-Section of the WCSB Showing the BCS Storage Complex

3.3 BCS Reservoir Properties

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

Injection Wells — thickness (m) & actual vs prog (m)

			8-19	5-35	actual vs prog	7-11	actual vs prog
	Seal	Prairie Evap./ Lo Prairie Evap.	126	122	+5	127	-4
		Winnipegosis/ Contact Rapids	75	72	-7	70	-4
BCS Storage Complex	Seal	Upper Lotsberg	84	83	0	89	+3
BCS Storage Complex							
BCS Storage Complex	Seal	Lower Lotsberg	35	36	+2	36	+1
BCS Storage Complex							
BCS Storage Complex	Seal	MCS	52	51	+1	50	-4
BCS Storage Complex		LMS					
BCS Storage Complex	Injection Target	BCS	47	43	-4	42	-6
		PreCam					

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*.

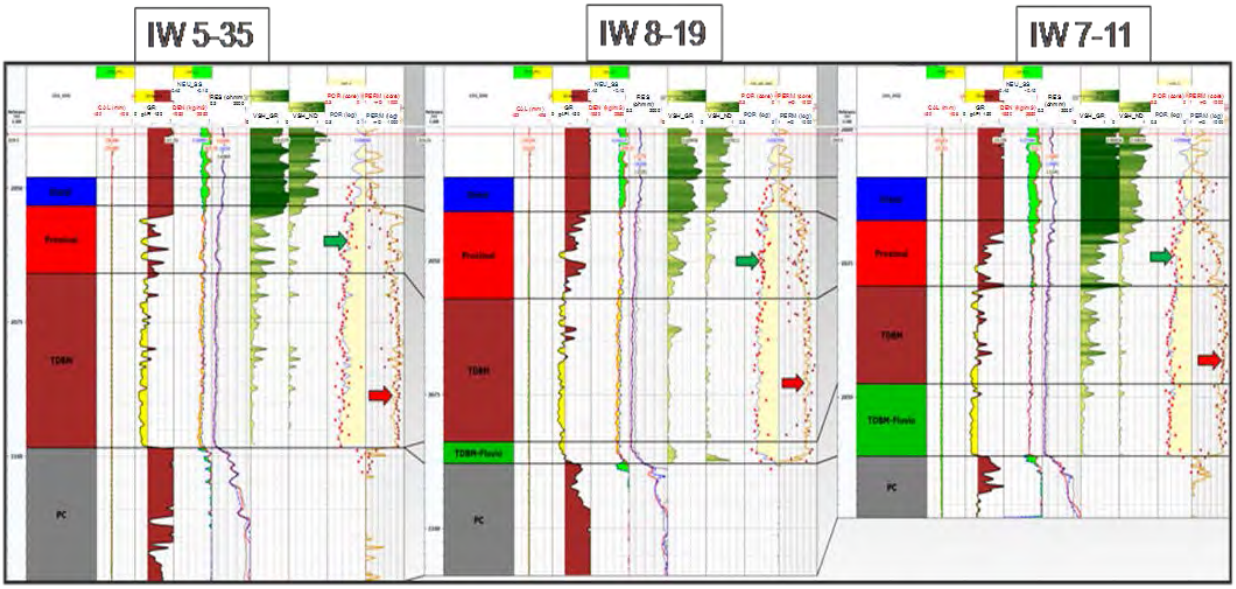


Figure 3-3: BCS Reservoir Properties Comparison of log response over the BCS formation and the corresponding core analysis results in all three injection wells. The green arrows are pointing to the porosity track, very good correspondence between the core porosity and log porosity. The red arrows are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

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

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

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

Consistency was 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.*

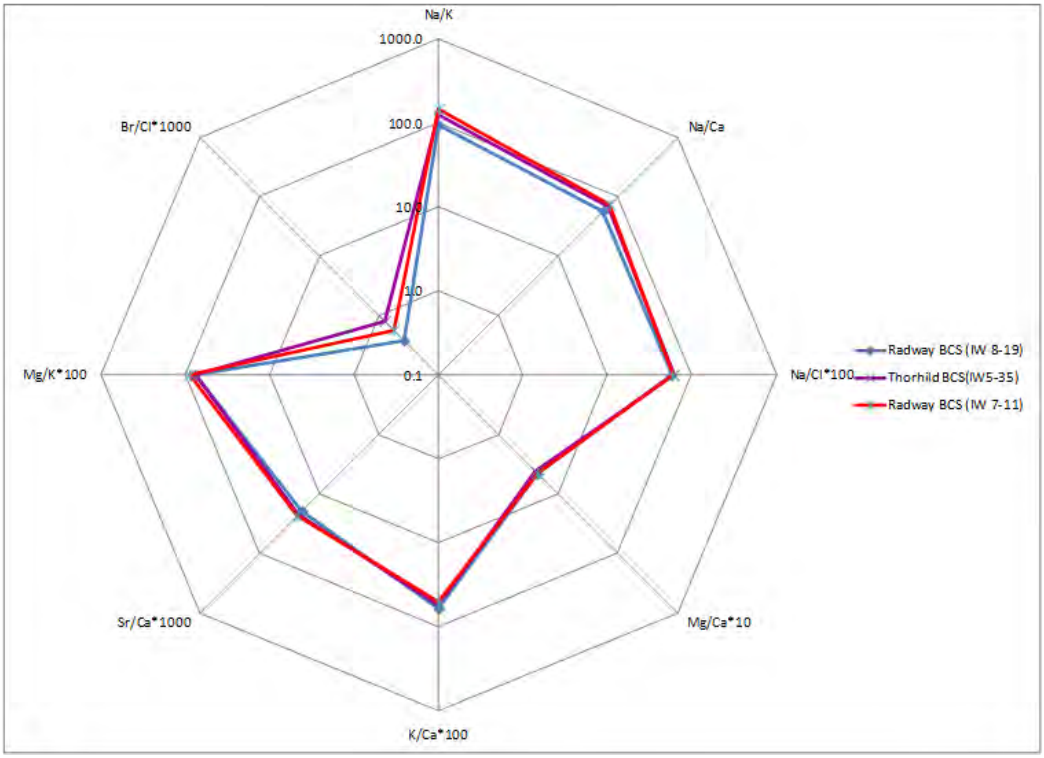


Figure 3-4: Ion Ration plot of BCS Formation brine waters from IW 8-19 (sampled in 2010), IW 5-35 (sampled in 2012) and IW 7-11 (sampled in 2013).

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 (2016) Section 3.4: 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 that maybe used to calibrate the existing reservoir models.

Table 3-3: Remaining capacity in the Sequestration Lease Area as of end 2016

Estimated total capacity	Year	Yearly Injection total	Remaining Capacity
27Mt	2015	0.371Mt	26.629 Mt CO_2
27Mt	2016	1.108 Mt	25.521 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 over this time period with very little pressure build up. It is quite 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 should be required for injectivity requirements.

3.6 Risk to Containment in a Geological Formation

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

Evaluation of data from the 2012 – 2013 drilling campaign and the most recent GEN-5 modeling of the BCS has confirmed that the pressure increase in the BCS will not reach a level sufficient to lift BCS brine to the BGWP (Base Groundwater Protection) zone even at the injection wells (AER, 2015, Section 5.3.1). Therefore, there is no perceived risk of brine leakage impacting groundwater. BCS pressure monitoring will be utilized to ascertain if there is a loss of containment that would give rise to a potential threat related to brine leakage far in advance of any impact above the storage complex. At that time, MMV plans would be updated appropriately.

Even if there was sufficient pressure, dynamic leak path modeling 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.

4 Facility Operations – Capture Facilities

4.1 Operating Summary

The Quest CCS project focus for 2016 was to reliably and efficiently operate the Quest capture, pipeline and wells systems, post achievement of commercial operations. Table 4-1 outlines the performance summary of the capture unit in 2015 and 2016. A discussion of the summary results can be found in the subsequent unit discussions.

Table 4-1: Quest Operating Summary 2015

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

The following is a timeline of significant operational milestones for the 2016 calendar year:

- August 8, 2016: Reached milestone of 1 million tonnes injected.
- September 24, 2016: Capture unit first reached nameplate rate of 1.2 Mt/a.
- December 13, 2016: CO_2 pipeline in-line inspection completed.

The Quest project also underwent two audits in 2016 – Alberta Energy Injection Certification and Alberta Climate Change Office under the Specified Gas Emitters Regulation Offset Program. These will complete in 2017.

4.2 Capture (Absorbers and Regeneration)

Solvent composition was on target for the majority of 2016 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 and 83.0% for 2016. Amine circulation rates were higher than unit benchmark during 2016, leading to the higher capture ratio observed.

The main contributors to periods of reduced CO_2 capture in 2016 were as follows:

- Reduced CO_2 capture ratio during a period of low hydrogen demand at the Upgrader/Refinery in April-May 2016 and October 2016. Lean amine trim cooler (E-24605B) plate pack re-assembly and cleaning also completed on October 9-19, 2016 as opportunity work.

- Loss of amine circulation due to amine charge pump trip on low suction pressure on June 21, 2016. Capture suspended for approximately 9 hours. CO_2 compressor also shutdown from no CO_2 feed.

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 and 1.11Mt CO_2 captured and injected in 2015 and 2016.

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

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

Electricity, steam, and water use are all approximately on target with design specifications when pro-rated for actual CO_2 throughput. 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. The operations team targeted approximately 60 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 in the lean/rich exchangers was impacting rich amine 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 for this exchanger is planned for 2017.

A success story for the Quest unit operation to-date has been 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. Since commissioning, the average amine loss is 5 tonnes/month, compared to the 10 tonnes/month expected. In 2016, total amine consumption was 38 tonnes.

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

CO_2 emissions for the capture process are primarily those linked to low pressure steam use in the CO_2 stripper reboilers (65% of total capture emissions), and from electricity for equipment in the capture system (~26% 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 has been suspended, and amine quality is being monitored. Since the filter was taken offline, there have been no foaming events, and the frequency of filter changes has been reduced. An inspection and carbon bed replacement is planned for 2017. The inspection is expected to determine the cause of the carry-over of carbon fines. As a learning for future change-outs of the carbon filter media, a back-flushing procedure to prepare the carbon filter for service will be employed to ensure that it is left with minimal amounts of carbon fines present.

4.3 Compression

The compressor operated at low discharge pressures during most of 2016, 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	Units
Suction Pressure	0.03	0.03	MPag
Discharge Pressure	9.6	10.0	MPag
Motor Electricity Demand	13.3	13.8	MW_e

Please see Appendix A for a detailed account of the work done to ensure accuracy of the CO_2 online analyzer for pipeline CO_2.

From Dec 1-6, 2016, CO_2 injection was suspended for retrieval of an in-line-inspection tool. Refer to Section 5: Facility Operations – Transport for more details regarding the in-line inspection of the CO_2 pipeline.

4.4 Dehydration

The dehydration unit performance continued to exceed expectations in 2016. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv. Actual water content for 2016 was on average 55 ppmv, and this was achieved at a lower TEG purity than design (99.5% vs. 99.7%). Meeting the specification at a lower purity resulted in the nitrogen stripping gas optimization opportunity 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 being <7ppmw of the total CO_2 injection stream, compared to the 27 ppmw expected in design for 2016. Dehydration unit losses of TEG are roughly 6,900 kg annually for 2016 vs. the design makeup rate of 46,000 kg annually.

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 2016 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 2016, normal NOx emissions with Quest operational and FGR online has been in the range of:

HMU1: 17 - 41 kg/h, limit 76.5 kg/h
HMU2: 12 - 34 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 2016 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

There were no significant reportable spills or releases due to Quest capture operations in 2016. However, in accordance with Shell's internal guidelines, all spills – regardless of size – are recorded for tracking purposes. Quest experienced a small number of leaks in the capture unit, each of which were successfully contained and corrective actions or mitigation plans put into place. The following is a list of the noted spills/releases to air, soil or water within the Quest capture unit during the 2016 calendar year.

- March 2016: Pinhole leak on lean-rich exchanger (E-24602A) vent line (~0.5L amine to secondary containment). Leak box constructed and leak controlled.
- March 2016: Water leak from demin water heater plate pack (E-24606B). Leak assessed and entered as 2017 maintenance scope for pack replacement.
- June 30, 2016: Plate pack leak on (E-24605B) lean amine trim cooler (30L amine to secondary containment). Leak mitigated when identified. Plate pack re-assembled in October 2016.

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.

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. In December 2016, an in-line inspection tool was used to inspect a section of the pipeline. The results from this inspection are discussed later in this section.

Table 5-1: Pipeline Design and Operating Conditions

Characteristic	Specification	Units	Average Operating Data / Actual Limitations		Original Design
			2015	2016	
General					
Pipeline Inlet Pressure	Normal	MPag	9.4	9.8	10
	Maximum Operating	MPag	12	12	14
	Minimum Operating (based on CO_2 critical pressure 7.38 MPa)	MPag	8.5	8.8	8
	Design maximum	MPag	-	-	14.8 (at 60°C)
Pressure Loss from Inlet to Wellsite	Normal	MPa	0.6	0.6	0.4 (for 3 well scenario)
Temperature	Compressor Discharge	°C	130	130	130
	Pipeline Inlet after cooler	°C	43	43	43
	Upset Condition at Inlet	°C	-	-	60
	Injection Well 7-11 Inlet Temperature	°C	15	16	
	Injection Well 8-19 Inlet Temperature	°C	12	12	
Flow rates	Normal Transport Rate	Mt/a	1.04	1.11	1.2
	Design minimum	Mt/a	-	-	0.36
	Total Transported	Mt	0.371	1.11	-
Energy and Emissions	Total Electricity for Transport (compression)	MWh_e	41,527	119,426	-
	Total Transport Emissions (includes compression)	Mt CO_2eq	0.027	0.077	

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 2016. Performance is continuing to be monitored.

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 H2 and CH4 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%)**	**Design Normal Composition**	**Design Upset Composition**
CO_2	99.45	99.38	99.23	95.00
H_2	0.48	0.51	0.65	4.27
CH_4	0.06	0.06	0.09	0.57
CO	0.02	0.02	0.02	0.15
N_2	0	0	0.00	0.01
Total	**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 from a third party or additional Shell 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 2016 was 55 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 Shell 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 Shell 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 Shell 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. Appendix B describes the chronology of inspection activities and also includes the final inspection report.

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 were beyond the 1.3 mm corrosion allowance of pipeline design and the minimum fracture toughness limits per the SGS report GS.10.52923. The Scotford Static Engineering group is continuing to evaluate results to determine if any action is 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 baseline information gathering pre-injection and for the initial monitoring post-injection. Data collection for the purposes of gaining baseline information and related studies has been ongoing. For more detailed information, refer to the Fifth Annual Status Report to the AER.

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 2016, about 1.5 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.

Injection into the 5-35 well was not required at this time 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 saturations.

In order to simplify the expected 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 was allowed to vary to accommodate the remaining CO_2.

As a result, by the end of December, 2016, 0. 701 Mt of $C0_2$ had been injected into the 7-11 well and 0.778 Mt of $C0_2$ had been injected into the 8-19 well. Figures 6-2 and 6-3 show the daily average flow rates and P/T conditions at 7-11 and 8-19 during the injection period.

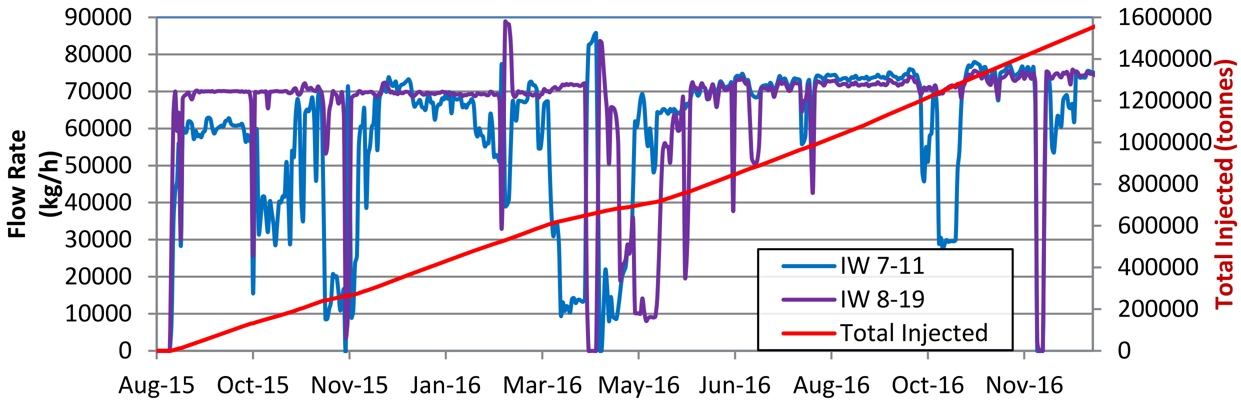


Figure 6-1: Quest Injection Totals: The red line shows the cumulative CO_2 injected into the wells from start-up through to the end of 2015. The blue and purple lines show the average hourly flow rates into the wells and the pipeline. Note that the pipeline fill began a week before the wells were started.

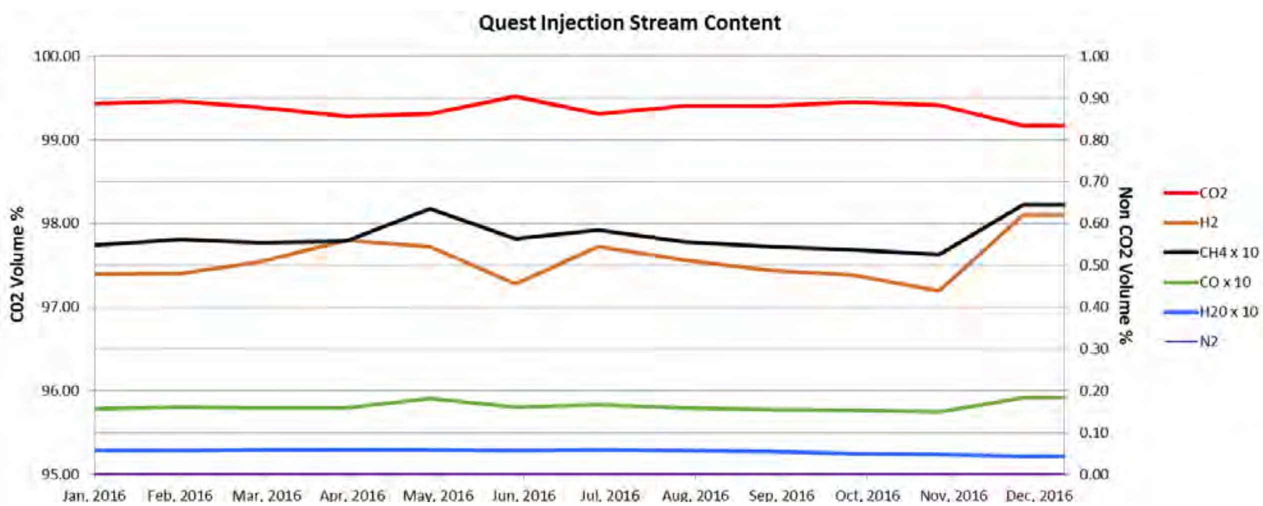


Figure 6-2: Quest Injection Stream Content: Average injection composition for 2016.

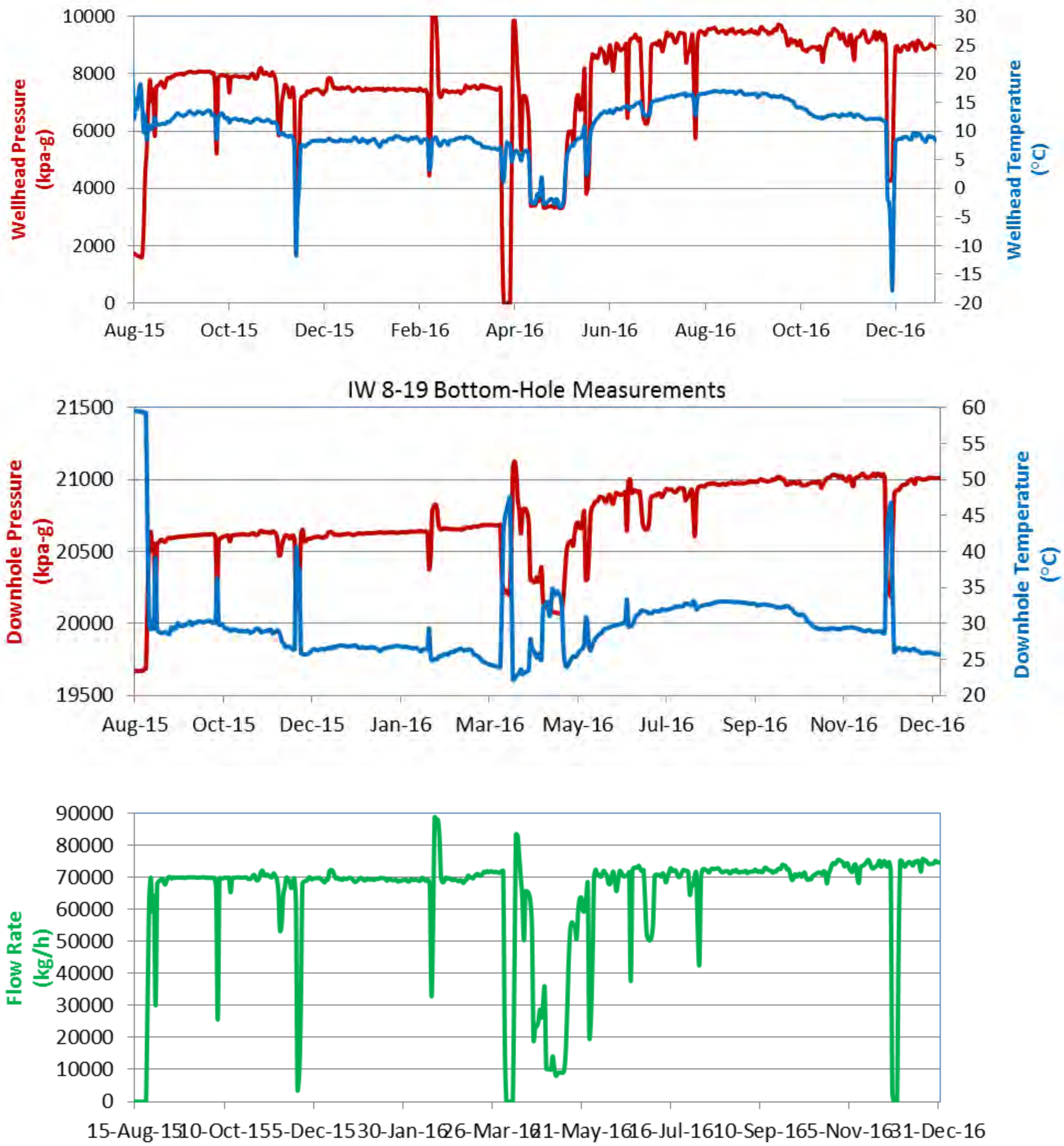


Figure 6-3: The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection to the end of 2016.

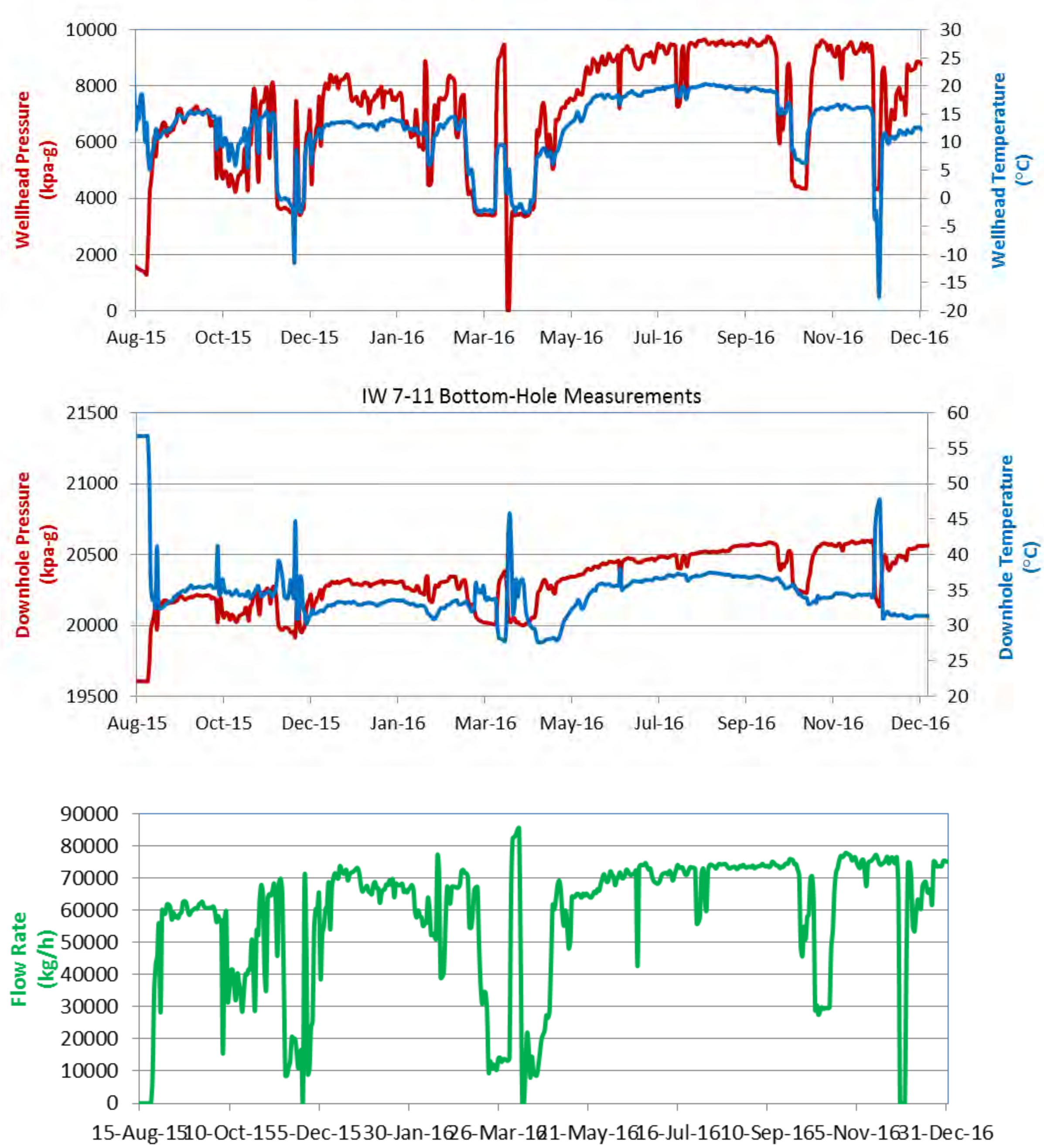


Figure 6-4: The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2016.

6.2 MMV Activities - Operational Monitoring

During 2016, the following MMV activities were executed:

- **Atmosphere Domain**: Monitoring of CO_2 levels within the atmosphere continued using the LightSource and EC systems.
- **Hydrosphere Domain**: Four discrete sampling events (Q1, Q2, Q3, Q4) were executed at all the project groundwater wells located on the 3 injection well pads, and the landowner groundwater wells within 1 km of the well pads 7-11 and 8-19. Three distinct sampling events (Q1, Q3, Q4) were executed at the landowner wells within 1 km of well pad 5-35. Note that additional groundwater well testing/sampling was undertaken in conjunction with the Q1 1st monitor VSP campaign.
- **Biosphere Domain**: Two sampling events (June, October) of soil gas and soil surface CO_2 flux measurements were undertaken on each injection pad.
- **Geosphere Domain**: The first monitor VSP campaign was executed in Q1 around well pads 7-11 and 8-19. In addition, monthly satellite image collection for assessing InSAR continued.
- **Well based Monitoring**: ongoing data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes.

No trigger events were identified that indicate a loss of containment (Table 6-4), indicating that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir during this reporting period. Note that the analysis of a pulsed neutron logging run post-start of injection data indicates that CO_2 is contained within the perforated interval of BCS reservoir.

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

- Results from the 2016 monitor DAS VSP show that the measured time-lapse response is smaller for wells 7-11 and 8-19 than the forecasted CO_2 plume from the reservoir model, but larger than the theoretical minimum plume size. This theoretical minimum assumes that the CO_2 expands cylindrically away from the well, displacing all the water in the pore space and therefore preserving 100% concentration. Therefore, the VSP time-lapse measurement indicates that the CO_2 is filling the pore space in the reservoir more effectively than predicted. This result, together with other geophysical data, will be used to calibrate plume movement in the modelling and to determine the timing and necessity of the subsequent surveys.
- 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 2016, can be found in the 5th AER Annual Status Report available at the Quest knowledge sharing website [http://www.energy.alberta.ca/CCS/3845.asp].

Table 6-1: Overall assessment of trigger events used to assess loss of containment during 2016

Domain		Technology ^	Trigger Event indicating loss of containment	2016
Atmosphere		LightSource	Sustained locatable anomaly above background levels	
Biosphere		Soil Gas	Outside established baseline range	
Biosphere		Surface CO2 Flux	Outside established baseline range	
	Hydrosphere	Tracer	Outside established baseline range	
	Hydrosphere	WPH	Sustained decrease in baseline pH values	
	Hydrosphere	WEC	Sustained increase in baseline WEC values	
	Hydrosphere	Geochemical Analyses	Outside established baseline range	
Geopshere		DHPT CKLK	Pressure increase 200 Kpa above background levels	
Geopshere		DHMS	Sustained clustering of events with a spatial pattern indicative of fracturing upwards	
Geopshere		DTS	Sustained temperature anomaly outside casing	
Geopshere		VSP2D	Identification of a coherent and continuous amplitude anomaly above the storage complex	
Geopshere		SEIS3D	Identification of a coherent and continuous amplitude anomaly above the storage complex	not applicable yet
Geopshere		InSAR	Unexpected localized surface heave	monthly data collection; completing feasibility study as per condition 16 of Approval 11837C

^ based on Table 7-4 from the MMV plan dated January 31st, 2015

Legend	
	no trigger event
	trigger event
	not evaluated

6.3 Wells Activities

6.3.1 Injection Wells

In 2016, 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, SIT and logging operations consisting of a pressure and temperature gradient log.

During the logging operations the downhole safety devices (check valves) were pulled and reinstalled in all three injection wells. The anchoring component of the downhole safety device was changed from a G-Packoff and slipstop to an Avalon QUP plug.

Figures 6-2 and 6-3 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.

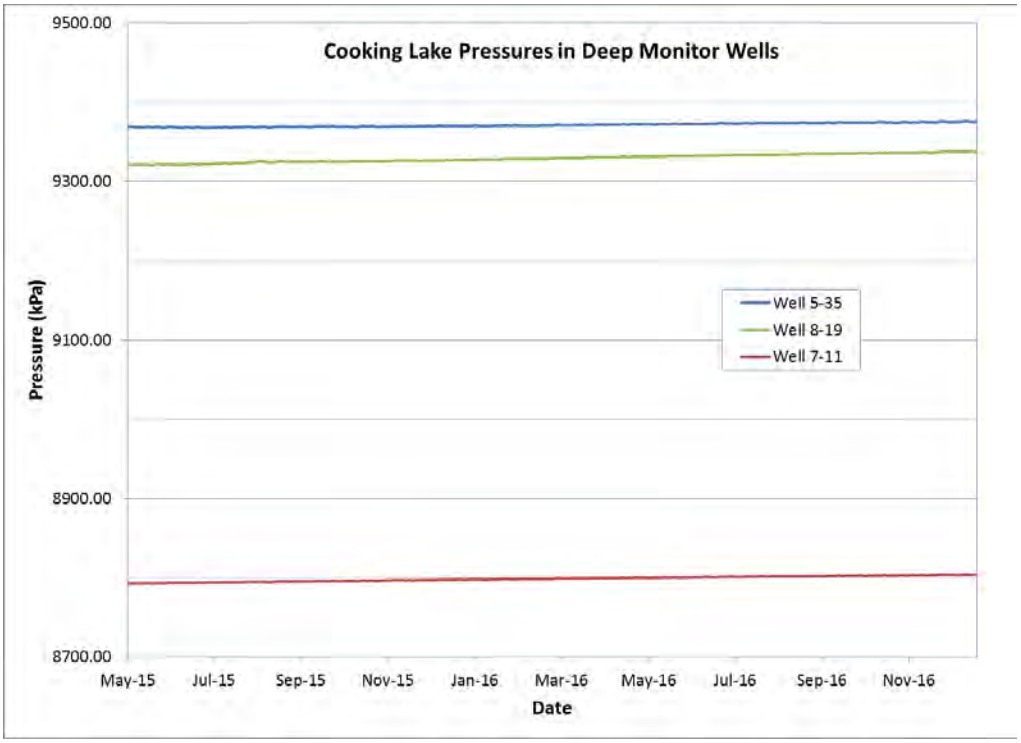


Figure 6-5. Quest DMW pressure history before and after injection

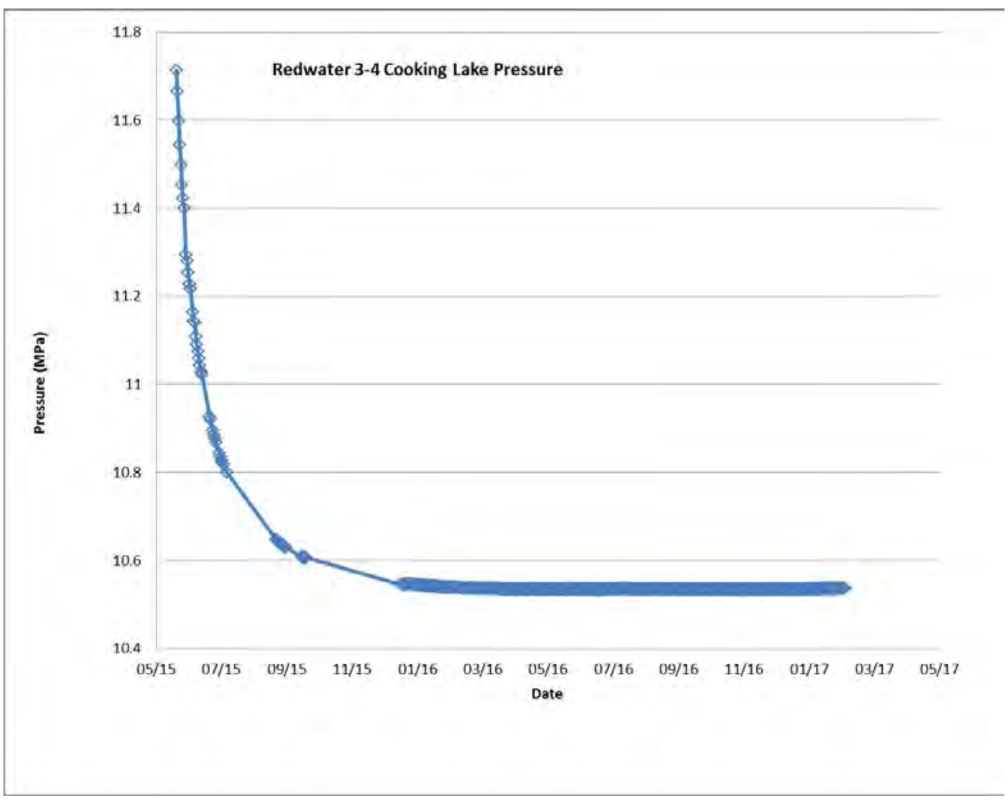


Figure 6-6 Quest 3-4 DMW pressure history before and after injection

6.3.3 Surface Casing Vent Flow and Gas Migration Monitoring

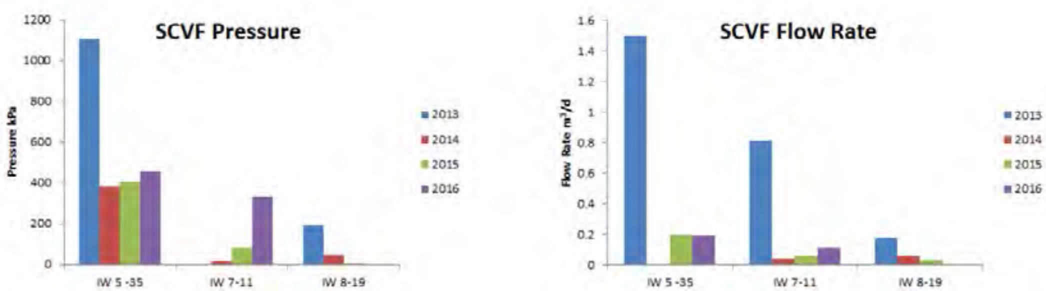
As required, annual testing was completed in 2016 for Surface Casing Vent Flow (SCVF) and Gas Migration (GM) at the injection pads. Reports were sent to AER in June 2016.

The SCVF flow test results for both IW 5-35 and IW 7-11 are summarized in Figure 6-. Measurements at the IW 5-35 well are at similar levels to those observed in June 2015. There is an increase at IW 7-11 though the overall level is still very low. No gas was detected on the SCVF measurements on IW 8-19, indicating that the surface casing vent flow on this well has declined to zero (see Figure 6-). The compositional results indicate that the SCVF gas in the IW wells is predominately methane.

Gas Migration testing (as per the suggested method in AER Directive 20, Appendix 2) was also performed on both wells. Previously the gas migrations observed on IW 5-35 and IW 7-11 occurred as bubbles in the well cellars. The air gas concentration measurements were sampled along the 4 cardinal directions, starting 30cm from each wellhead and then every 1m until 6 points have been acquired in every direction. In June 2016 no gas bubbles were observed in the IW 7-11 cellar. Gas bubbles were observed in the IW 5-35 cellar.

No gas was detected around the IW 7-11 well. The gas migration at this location appears to have declined to zero. For the IW 5-35 well the gas measurements at 30 cm from the wellhead have declined from 57% to 31% relative to 2015. For the IW 5-35 well the gas measurements at 130 cm from the wellhead increased marginally from 4.3% to 4.8% relative to 2015. At 230 cm from the wellhead the measurements decline from 0.86% to 16 ppm. 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 2016. 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.

Regular maintenance plans implemented through SAP based on RCM reports for the capture facility, pipeline and wells continue to provide a steady and reliable operation.

Maintenance and repairs in the capture facility are as follows:

- E-24602A Leak box installed for pinhole weld flaw on 2" elbow
- E-24605B Plate pack leak requiring cleaning reinstall
- Downstream piping upgrade to wastewater due to carbon steel corrosion resulting from low PH condensate from Quest
- AI-247002 CO_2 analyzer accuracy drifting, requires barometric compensation before daily gas sample can be reduced
- LT-248005 K-Tek part replacement
- XV-247001 Hydraulic oil leak repair of actuator
- FT-247004 electronics replacement (CO_2 flow to pipeline)
- MCC roof repairs to stop leaks
- Inspection of piping throughout Quest using UT for corrosion information/tracking
- Amine filter drain pan fabrication for V-24604

Pipeline maintenance and repairs are as follows:

- Wellsite flow controllers positioner upgrade due to sticky valve at prolonged outputs
- Installation of methanol fuel cells at all 6 LBVs (Line block valves) to improve pipeline reliability from trips due to power loss
- Replacement of solar controllers to reduce communication alarms
- Pigging/line inspection
- Cathodic rectifier repair (started in 2016)
- Boreal Laser repairs and Maint as required
- Quest truck repairs and maint as required
- Road and site ground maint as required
- Full ROW inspection, ground repair and vegetation control
- Solar battery replacement (LBV 3)
- MMV Building HVAC Repairs

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

8 Regulatory Approvals

8.1 Regulatory Overview

Regulatory submissions in 2016 followed the schedule set forth by the Approval. Regulatory approvals in 2016 addressed the ongoing operations and optimization of safe operations.

8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2016. In order to account for new information about MMV technologies and alignment of storage operations with Scotford operations and maintenance schedules, there were several waiver requests for changes to the AER Directive 65 Approval No. 11837, Carbon Dioxide Disposal approval. In some instances, the AER asked for additional clarifying information and were satisfied with the responses. In general, these approvals were obtained in a timely manner and no activities were impacted.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to the Project for the 2016 reporting period.

Table 8-1: Regulatory Approval Status

Approval or Permit	Regulator	Status and Timing of Approval/Permit	Comments
CO_2 Injection and Storage			
Shell Quest AER Approval No.11837C Request for extension, InSAR Efficacy Report (Condition 16)	AER	Submitted Jan 7, 2016	Request to extend deadline of condition 16, July 31, 2016 to March 31, 2017
AER Approval No.11837C: Request for extension, Logging Condition C	AER	Submitted Jan. 18, 2016 Approved March 22, 2016	Request for an extension to the submission of the IW hydraulic isolation log to March to May 2016.
Well integrity discussion- AER Approval No. 11837C- Condition 5 c	AER	Submitted Feb 17, 2016	Request for extend submission of hydraulic isolation log for wells 03/07-11-059-20W4/0 and 00/08-19-059-20W4/0
Quest Carbon Capture and Storage Project Fourth ANNUAL STATUS REPORT	AER	Submitted March 30 2016 Received March30, 2016	Annual Report
Shell Quest AER Approval No.11837C: MMV Plan –Section 6.2.3.2 change	AER	Submitted April. 8, 2016 Approved May 13, 2016	Waiver to cancel the Q2-2016 groundwater sampling campaign of landowner wells located within a 1 km radius

			(LIW) of the injection well 5-35-59-21W4.
Annual Submission for SCVF and GM testing.	AER	Submitted June. 23, 2016	Submission in accordance with conditional approval of September 4, 2013 regarding Shell's request to defer repair of surface casing vent flow (SCVF) and gas migration for IW 5-35 and IW 7-11.
Letter-Shell Quest MMV Plan & AER Approval No.11837C Synopsis of updates - changes	DoE, GoA	Submitted Aug. 25, 2016	List of various request/ updates submitted to AER in relation to Quest MMV Plan
First extension of Approval expiry date, Shell Canada limited Oil Sands Processing plant (Bitumen Upgrader) EPEA approval no. 49587-01-00, as amended	AER	Submitted October 5, 2016	Renewal of Environmental Protection and Enhancement Act Approval No. 49587-01-00
Shell Quest AER Approval No.11837C: MMV Plan –Section 6.2.3.2 change request withdrawal letter	AER	Submitted Nov. 24, 2016:	Withdraws request to cancel the Q4-2016 groundwater sampling campaign of landowner wells located within a 1 km radius (LIW) of the injection well 5-35-59-21W4.

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 2017 include:

- The Fifth Annual Status Report to AER
- Suspension of IW 5-35
- Submission of and Updated MMV and Closure Plans
- Submission of Special Report on InSAR efficacy

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 the Project. Regulatory agencies and local authorities provided input on the planned participant involvement program. The Project 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 26, 2016 – Strathcona County
- November 8, 2016 – 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. Council updates will continue throughout 2017.

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 2016, Shell recorded 41 concerns related to the Quest facility. This represents the total number of queries/complaints – not the number of individuals.

Most of the concerns are related to timely payment of compensation from pipeline construction, concerns related to on-going MMV activities, and concerns related to the perceived safety of Quest CO_2 storage.

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.

As Quest was operational for in 2016, the meetings focused on operations updates and a review of the MMV data. The following meetings were held in 2016:

- April 19, 2016
- October 11, 2016

Community Events and Public Information Sessions

Two open houses were held in Thorhild County to give community members the opportunity to meet with Shell and ask questions about the Quest project. The meetings were held on the following dates:

- January 14, 2016
- October 11, 2016

Shell also attended the following community events:

- April 7, 21 & 22 – Green Schools Career Fair (Edmonton Public Schools)
- October 7 – Radway Fishpond Opening (Thorhild County)

9.3 CCS Knowledge Sharing

As Quest moved from the project to operations phase, there was a significant increase in global interest into our experience with the Quest facility. As such, members of the Quest team attended or hosted numerous conferences, workshops and tours in 2016. The table below gives an overview of the 2016 activities:

Table 9-1: 2016 Knowledge Sharing

2016 Conferences/Workshops/Tours				
Event	**Timing**	**Location**	**What**	**Why**
Energy Futures Lab	Jan 25	Scotford	Tour	
DC Forum	Annual, February	Washington, DC	NGO organized event to promote CCS.	Engages with key stakeholders - event is attended by GoA and NRCAN.
MRU Presentation	Feb	Calgary	Presentation	Quest knowledge sharing
Geophysics Workshop: microseismic and inversion	Mar 2-3	Virtual (Calgary/Houston)	working session to develop workflow for interpretation	Explore synergies for using Geophysical technology
U of C Presentation	Mar	Calgary	Presentation	Quest knowledge sharing
SPE Complex Reservoir Fluids Workshop	Mar-13	Malaysia	SPE Conference to share experience dealing with reservoir fluids	Presentation - Shell CCS Experience
European Technology Platform on Zero Emission Fossil Fuel Power Plants	Mar 15	Scotford	Tour	
John Hopkins University	Mar 17	Scotford	Tour	
SPE-EOR Workshop	Mar-21	Oman	SPE Conference for ME EOR opportunities	Executive Panel - Shell Knowledge Sharing (Quest/Peterhead)

IEAGHG CCS cost reduction workshop	Mar-22	Boston	Industry forum on CCS costs	Mitigate global concerns about cost of CCS, Quest messaging
SPE/SEG Induced Seismicity Workshop	Mar 28-30	Fort Worth, TX	Workshop looking at injection induced seismicity	Share Quest knowledge
US/CDN/MEX Trilateral CCUS Meeting	April 12-13	Mexico	Government policy advisory meeting	Supported and requested by NRCAN
Asia-Pacific GCCSI Members meeting	April	Melbourne	Regional meeting with GCCSI	Share Quest messaging
CO_2GeoNet Open Forum	May 9-11	Venice, Italy	Annual technical meeting for CO_2GeoNet	Key event for subsurface technogies related to CO_2 storage
2016 Midwest Carbon Sequestration Science Conference	May 16-17	Champaign, IL	US DOE, Regional partnerships	Experience sharing with Decatur
Global CCS Institute Board	May 18	Scotford	Tour	
Emerald Awards	Jun-08	Calgary	Award Ceremony	Quest nominated for Environmental award
GCCSI Japan CCS Workshop	June 15-16	Tokyo	Presentation/Panel discussion	GCCSI invitation
CCUS Conference	June 14-16	Tysons, VA	presentation, networking	US DOE sponsored, collaboration on MMV
AAPG	June 19-22	Calgary	Industry Geology Conference	
AAPG Field Trip	June	Calgary	Workshop	
CSEG Luncheon Presentation	Jun-20	Calgary	Presentation	Quest messaging - Calgary geoscience community
International Core Conference	June 23-24	Calgary AER	AAPG/Industry	

CSLF Mid-Year Meeting	June 27-30	London	Annual technical meeting for CSLF	Key event for global stakeholders
IEAGHG Monitoring Network	Jul-06	Edinburgh	MMV	Focus on MMV research and experience
Stampede Investment Forum AIH Tour	Jul-11	Scotford	Presented on Quest	
IEAGHG International Summer School	Jul 17-23	Regina	Intro to CCS	Training for future CCS professionals
Aquistore AGM	Aug 16-17	Ottawa	General Meeting	Info share with Boundary Dam team
USDoE NETL Project Review	Aug 16-18	Pittsburgh	US DOE, Regional partnerships	Interaction with USDoE, talk about future collaboration
California Air Resources Board - CCS Technical Series (MMV)	Aug-05	Sacramento	CARB forum	CARB could become an important stakeholder: CCS acceptance within LCFS
PCOR Annual Meeting	Annual, Sept	US locations	US DOE, Regional partnerships	Shell Canada is partnership member
Strathcona County Administration Leadership Team	Sept 14	Scotford	Tour	
ASEC Alberta Students Energy Conference	Sep-16	Alberta	Student Conference	
California Air Resources Board - CCS Technical Series (Site Selection)	Sep-23	Sacramento	CARB forum	CARB could become an important stakeholder: CCS acceptance within LCFS
EU Parliament MPs	Sep 21	Scotford	Tour	

GCCSI Quest Workshop	Sep 21-22	Scotford	Quest Focused Workshop - lessons learned	Knowledge sharing - global outreach
GCCSI EU Members Meeting	Sep-24	Aberdeen	Lead a panel on GCCSi	Collaboration with UK government and supported by NRCAN
ISO/CSA WG6 Standards	Sep 26-30	Toronto	Practical input into a CCS ISO standard	Supported and requested by NRCAN
UBC Engineering	Sep 29	Scotford	Tour	105 students from UBC
CSPG CCS Session	Sep-29	Calgary	Workshop	Quest messaging - Calgary geoscience community
GCCC Annual Meeting	Sep-29	Houston	US DOE, Regional partnerships	GCCC is project attached to Kemper and EOR project
CSLF Annual Mtg	Oct 3-7	Tokyo		US DOE sponsored, collaboration on MMV. 2015 event attended and sponsored by NRCAN, GoA attendance
MRCSP Annual Meeting	Oct	US locations	US DOE, Regional partnerships	
GCCSI CCS FORUM/EMEA Members Meeting	Oct 13-14	Oslo	panel on CCS	Collaboration with European CCS Community
Environment and Sustainable Development of Canada	Oct 17	Scotford	Tour	
ENGO Webinar	Oct-20	Online	Presentation	Engagement with NGO Network
Mexico Delegation at Quest	Oct-24	Scotford	Present Quest Learnings	Supported and requested by NRCAN

US/CDN/MEX Trilateral CCUS Meeting	Oct 25-27	Regina	Government policy advisory meeting	Supported and requested by NRCAN
IEAGHGT-13	Nov 14-18	Lausanne, Switzerland	Networking, presentations	Global reach - primary international CCS conference
GCCSI Webinar	Nov-22	Online	Webinar to present first year results	GCCSI invitation - important global connection
IEA International CCS Regulatory Network	Nov 23-24	Paris, France	Networking	Important international CCS regulatory meeting
Universidad Simon Bolivar	Dec	Caracas, Venezuela	Presentation to Geosciences Dept	

Proactive Media Relations
In 2016, we also achieved the first million tonnes of CO_2 captured milestone. A news release was issued on September 14, 2016 to help create awareness around the milestone and lessons learned from the first year of operations.
http://www.shell.ca/en_ca/media/news-and-media-releases/news-releases-2016/shell_s-quest-carbon-capture-and-storage-project-reaches-signifi.html

On October 9, Shell Canada's Country Chair penned an OpEd in the Globe and Mail on CCS and why it plays an important role in achieving the UN's Intergovernmental Panel on Climate Change believes the world's climate goals.
http://www.theglobeandmail.com/report-on-business/rob-commentary/why-carbon-capture-is-just-as-important-as-renewable-energy/article32311433/

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

The Quest project 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 final incurred costs to the end of 2016. The categories follow those used by Shell over the life of the Project to track project costs. The final cost for the project is $790 million versus the original $874 million. Development costs for the Project for the FEED stage (January 1, 2009 to December 31, 2011) reflect costs associated with front end engineering for the capture and pipeline units as well as sub-surface modeling and early drilling. Capitalization of the project began January 1, 2012 as per Shell Canada Limited capitalization policy.

Table 10-1: 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 April 1 , 2015 - December 31, 2016	Total Capex
Overall Venture Costs	19,470						
Shell Labour, & Commissioning	19,470	5,414	32,638	23,466	57,311	28,753	147,582
Tie-in Work /Brownfield Work							
Tie-In/Turnaround Work Capture	0	0	7,331	10,234	10,430	7,924	35,934
Tie-In Work Pipeline		0	196	518	334	150	1,209
Sub Total	0	0	7,527	10,753	10,764	8,074	37,118
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	39	38,554
Material		6,092	42,315	56,502	7,466	-5,155	107,295
Site Labor		0	0	9,456	36,038	0	45,494
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	-3,803	437,419
SUBSURFACE - Wells*	63,175						
Injection Wells		1,090	17,970	3,641	167	1,776	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	1,862	12,186
Sub Total	63,175	1,090	22,558	6,951	5,443	4,209	40,251
PIPELINES - TOE*	4,035						
Engineering		576	4,272	2,782	1,085	51	8,766
Materials		0	1,878	24,823	4,485	12	31,199
Services		0	0	60,101	27,366	29	87,477
Sub Total	4,035	576	6,150	87,706	32,936	93	127,460
Grand Total	139,351	19,832	166,561	339,016	227,094	37,326	789,830

* Shell labour costs during FEED are booked here.

10.2 Opex Costs

Quest started commercial operations on October 1, 2015 hence the costs indicated under 2015 are only for a 3-month period (October 1 , 2015 - December 31, 2015). It is important to note that these costs are not representative of a typical operations spend as some costs were carried under Capital for consistency throughout the year. Additionally, automatic unit allocations are only adjusted for at the beginning of the year; as a result, $1.1M of 2015 costs are reflected in 2016.

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

Cost Category	2015 Oct 1 - Dec 31	2016 Jan 1 - Dec 31	2017 **estimate**
Power	510.72	3,206.98	3,367
Steam	899.15	7,515.31	7,891
Compressed Air	10.50	57.16	60
Cooling Water	70.53	357.42	375
Direct Labour and Personnel Costs	1,563.83	6,265.60	6,579
Maintenance Materials and Technical Services	63.94	905.48	1,772
Property Tax	392.62	1,611.10	1,976
Sequestration Opex	11.42	7,041.43	7,394
MMV after operations	30.65	1,659.76	2,904
Post Closure Stewardship Fund		272.07	269
Other Well Costs	3.25	428.23	1,470
Subsurface Tenure Costs		362.50	363
Pipeline - Inspection and Pigging		145.78	153
Amine		340.67	358
Chemicals		20.35	21
Vendor rebates from construction		-122.32	-100
Corporate and Other Costs		119.24	125
Total	**3,556.60**	**30,186.77**	**34,977**

Vendor rebates from construction: In 2016, we received $122 thousand in rebates for government deductions on vendor invoicing during the construction (capex) phase. The credit is recognized under Opex as the construction phase has closed. We are also expecting to receive a rebate of $100 thousand related to project insurance premiums.

10.3 Revenues

Revenues reflect funding as well as CO_2 reduction credits received up to December 31, 2016.
The CO_2 reduction credits received during the period consist of 166,540 t CO_2 e Serialized Verified Emission Reductions for the period August 23 - October 31, 2015. Single credits, valued at $20/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 will be reported in the period in which they are received.
Pending third party verification, credits for emissions reductions after October 31, 2015 will be serialized and reported in 2017.

Aggregate Revenues Forecast has been developed assuming that the Quest project does not enter a net revenue position before September 30, 2025, with an estimated 8.1 MT of CO_2 avoided over the next 9 years, and with the receipt of double credits with each CO_2 reduction credit valued at $30.

Table 10-3: Project Revenues

	2009 – 2015 Construction	**2016** Operation	Aggregate Revenues Forecast
	Jan 1, 2009 – Dec 31, 2015		Jan 1, 2017 – 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	$268,548,356.48
CO_2 reduction credits		$ 3,330,800.00	$486,000,000.00
	$573,345,454.60	$ 32,782,443.52	$754,548,356.48

10.4 Funding Status

To date, Quest has received a total of $6.6 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 is now in the operating funding phase of the project.

The remaining 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 Quest project.

	2009	2010	2011	2012	2013	2014	2015	Operating
Government Funding	January 1, 2009 - March 31, 2010	April 1, 2010 - March 31, 2011	April 1, 2011 - March 31, 2012	April 1, 2012 - March 31, 2013	April 1, 2013 - March 31, 2014	April 1, 2014 - March 31, 2015	April 1, 2015 - September 30, 2015	October 1, 2015 - 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	$ 298,000,000
Total Funding	$ 3,225,847	$ 1,817,101	$ 1,302,507	$ 238,000,000	$ 115,000,000	$ 53,000,000	$ 161,000,000	$ 298,000,000
Cummulative Gov't Funding as Percentage of Total Project Spend	0.2%	0.4%	0.5%	17.9%	26.3%	30.2%	42.0%	63.9%

11 Project Timeline

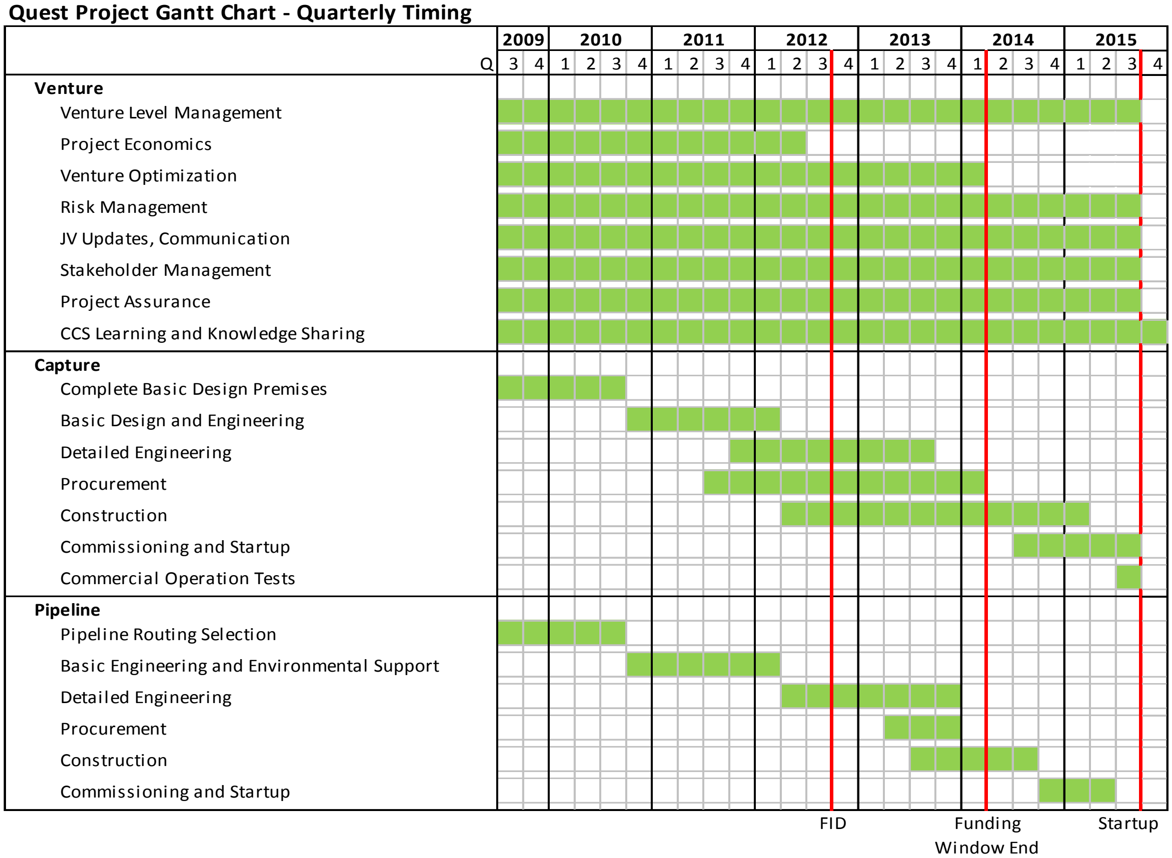
The timeline for Quest is shown in Table 11-1. The only departure from the project timeline is the advancement of the completion of the capture commercial operation tests. The tests were originally scheduled to run into Q4 2015, but all tests were completed by the end of Q3 2015.

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

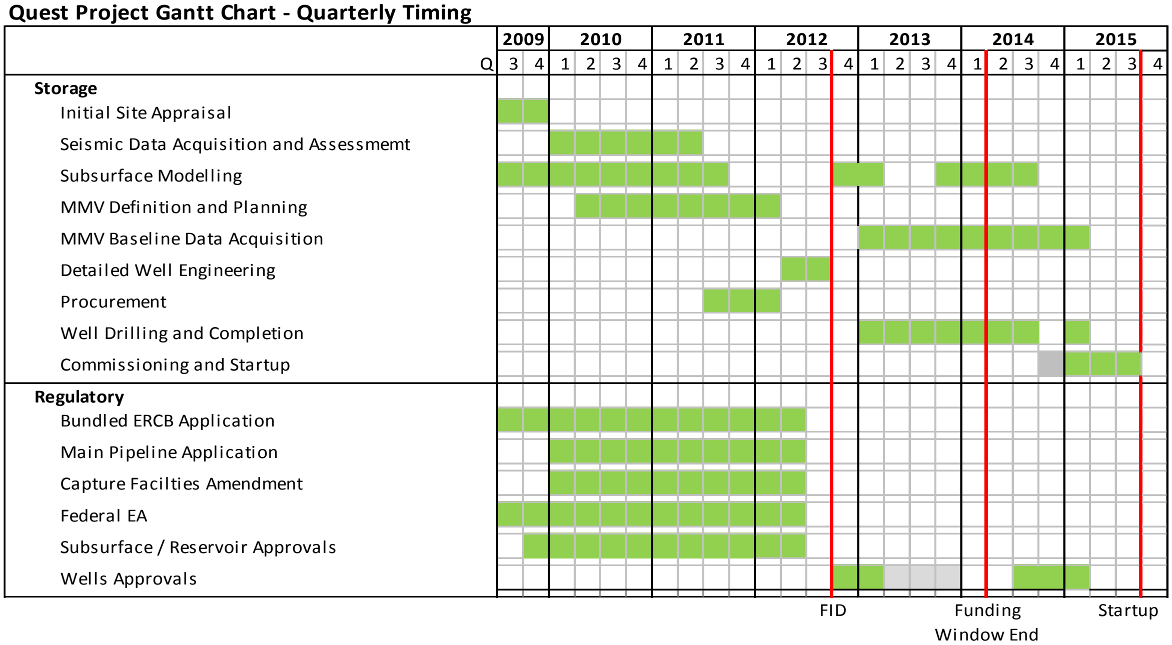
The projected forecast for CO_2 injected is as submitted in Schedule “C” Projected Payment Schedule after the achievement of commercial operations.

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 2016 were under budget as well based on lower power costs and operational efficiencies.

Project Successes –2016

Operational MMV Data Acquisition

In 2016 continued monitoring during the injection phase occurred including the acquisition and interpretation of the first monitor VSP. Routine logging and well integrity testing was also completed on the IWs.

On August 8, 2016 Quest reached the milestone of 1 million tonnes of CO_2 injected.

In 2016, the capture unit also reached its nameplate rate of 1.2 Mt/a and the first CO_2 pipeline in-line inspection was completed.

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 Shell. In 2016, 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 wide media coverage and interest from various industry 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

Over and above regulatory requirements, Shell successfully completed the post-construction reclamation assessment and weed control program of the pipeline ROW in 2016.

Technical Successes

In 2016, 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 6,900 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 2016 with the capability to maintain NOx levels close to baseline values pre-Quest.

Installation of methanol fuel cells at each LBV to provide supplemental charge to the battery bank, thereby increasing reliability of the power supply to the LBV stations on the pipeline route.

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. 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 first monitor VSP was completed in Q1 2016 as well as groundwater data sampling in all quarters.

Strong integrated project reliability performance with operational availability at 98.8%.

Annual CO_2 capture ratio increased to 83%, resulting from amine circulation rates higher than unit benchmark during 2016.

Challenges in 2016

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

A leak was identified in the wastewater piping going from Quest to the Scotford Upgrader Wastewater Treatment Plant. Piping was upgraded to 304 stainless steel to deal with high corrosion rates of the Quest low pH water. Further to this, three secondary containment leaks occurred within the Quest capture unit in 2016. While none of the leaks were significant reportable incidents, they have been recorded as per Shell's internal processes.

As a result of the pipeline inspection in December, the smart pig was not able to progress through the isolation Orbit valve. This required suspension of CO_2 injection and the depressurization of the first 15km of pipeline for retrieval of an inline inspection tool (see Appendix B and Section 5.2).

Also, drifting of the CO2 online analyzer was observed, for which mitigation measures were put into place in order to improve measurement – see Appendix A for further details.

12.1 Indirect Albertan and Canadian Economic Benefits

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

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

Additionally, there are benefits in terms of salaries paid to the Albertan and Canadian employees of Shell Canada who are working on the Quest team and supporting operations of Quest.

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. Work continued in 2015 and 2016 with assessment of technologies. 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.

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

- Full-time employment for an additional 13 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 $4 million per year.

13 Next Steps

With the commencement of commercial operations, Quest is embedded in Shell Scotford operations. Now the focus has shifted to maintaining 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.

Capture of operational issues and lessons learned in order to retain institutional memory and facilitate improvements in processes and procedures.

Cleaning of the lean/rich exchangers is planned for 2017 to address the impact on rich amine temperature to the stripper.

Microseismic data will continue to be collected as committed in the MMV plan along with monitoring of the hydrosphere and biosphere during injection operations. Work continues to move towards a more automated, online data access/retrieval system of DTS data.

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 2017 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.

Quest will continue active knowledge sharing through publications and participation in conferences, workshops, and tours into 2017.

14 References

[1] AER, 2015, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, Fourth ANNUAL STATUS REPORT, will be available at http://www.energy.alberta.ca/CCS/3848.asp

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

Appendix A: Quest Protocol Variance Request

Shell Scotford
P.O. Bag 23
Fort Saskatchewan, Alberta T8L 3T2
Internet www.shell.ca

February 7, 2017

Director of Climate Change Compliance
Alberta Climate Change Office
12th Floor, 10025 - 106 Street
Edmonton, AB T5J 1G4

Dear Sir:

Re: Shell Canada Limited ("Shell") - Quest Carbon Capture and Storage Project (Quest)
Update to Variance Request on Measurement of Injected Gas CO_2 Concentration

The purpose of this letter is to provide an update to Shell's letter dated August 24, 2016 requesting for a variance or deviation from the *Quantification Protocol for CO_2 Capture and Permanent Storage in Deep Saline Aquifers, ("Protocol"),* June 23, 2015 on the requirement to measure injection gas composition at a minimum of daily samples averaged monthly on a volumetric basis (Table 6 in the Protocol). In addition, Shell is requesting a variance for the guidance for continuous measurement frequency (defined as at minimum one measurement every 15 minutes) for the injection gas stream in Table 8 of the Protocol.

The following sections will describe 1) the issues with the online continuous CO_2 analyzer and the improvements that have been made, and 2) how Shell's method to replace incorrect CO_2 online analyzer data with on-site lab's sample data (Lab Data) or data from regression model predictions is accurate, conservative and transparent.

These are all significant lessons for measurement and analysis of a high concentration CO2 stream that will enable future CCS projects globally.

Performance of the online GC analyzer

As per Shell's August 24, 2016 letter, Shell identified that the CO_2 online analyzer started drifting from August 2015. Shell immediately implemented corrective actions to address the analyzer issues (see Appendix A), which included rebuilding the switching valves every month. The failing quality of the Valve Sliders resulted in leakage of sample gas and inaccurate values for CO_2.

After several months of extensive troubleshooting activities regarding the drifting of the CO_2 analyzer, Shell contacted the manufacturer, ABB, and had them come to the Scotford facility to assist in solving the issue. ABB indicated their supplier for the Valve Sliders had moved out of state, and, subsequently, the product quality had dropped significantly. In addition, ABB released a Bulletin BTN/Process Analytics/030-EN on August 3, 2016 indicating the problems with the M2CP Valve Sliders (see Appendix B).

As a result of this finding with the Valve Sliders and other issues identified with the online CO_2 Analyzer, a number of improvements were made to the analyzer as shown in Table 1. In addition, the frequency of calibration was increased from monthly to every two weeks and then to weekly.

Table 1. Quest GC CO_2 Analyzer Maintenance History and Improvements

Issue #	Issues	How does this affect the analyzer?	Solutions
1	Failing quality of manufacturer's switching valve replacement parts resulted in monthly rebuilds.	Wear and tear of switching valves resulted in internal leaks and CO_2 concentration readings variability.	New Valco diaphragm valves (with known higher reliability) installed on Sept. 12, 2016.
2	Initial accuracy from the factory of $\pm$1% resulted in 1% variability over 8 hours.	Accuracy not sufficient for application.	Increased volume of injected gas samples in the injection loop to achieve variability of 0.3% over a 48-hour period (Aug. 30, 2016)
3	Analyzer is sensitive to flow and barometric pressure changes	Injection pressure must be stable.	Installed back pressure regulator on Nov. 3, 2016 to stabilize the injection system to absolute pressure.

Issue #1 and #2, which were causing most of the drifting observed, were successfully corrected when the changes were implemented as described in Table 1. However, it was determined in January 2017 after contacting the manufacturer several times that the Shell installed absolute back pressure regulator was not working as well as anticipated. The fourth time the manufacturer, ABB, was contacted, the manufacturer conceded there was an issue with ABB's internal pressure regulators. As a result, the Shell installed back pressure regulator was not correcting Issue number three and was removed on January 16, 2017.

Shell then proceeded to make the following changes to correct Issue #3. It was determined the sensitivity of the CO2 analyzer to barometric pressure changes could be corrected through ambient pressure compensation in the Digital Control System (DCS). There are several absolute pressure transmitters at Scotford that measure ambient pressure. As a result, on January 16, 2017, modifications were made to the data historian to produce Ambient Pressure Compensated CO_2 concentration data (Appendix C). Modifications were subsequently made to the DCS on February 2, 2017 to set up a tag that provides Ambient Pressure Compensated CO_2, which will be used on a go forward basis. Also, Shell will subsequently install a dedicated absolute pressure transmitter for the ambient pressure compensation discussed above.

The pressure compensation in the DCS will be performed based on the following constant. For each 1 kPA change in ambient pressure, there is a change of 0.43 mole% CO_2 by the CO_2 analyzer. This constant has been determined through several measurements as shown in Appendix C. Finally, in addition to the graph in Appendix C, proof will be provided that the Ambient Pressure Compensation is working through daily tests using Validation Gas, which is pure 100% CO_2. Through these validation tests, Shell will show that the Ambient Pressure Compensated CO_2 mole% is consistently at 100 mole% CO_2 proving that the Ambient Pressure Compensated CO_2 data is accurate and precise and the barometric pressure issue has been addressed. Note that the validation tests will be in addition to the weekly calibration checks, where the calibration gas has a CO_2 mole% very similar to the Injection Gas Stream (e.g. 99.4%).

Data Substitution

In the August 24th letter, Shell requested for data substitution for the First Crediting Period (August 23 to October 31, 2015). As a clarification to this request, Shell is proposing to replace data from the online CO_2 analyzer with the following:

Period	Data Substitution
Aug. 2015	No substitution
Sept. 1, 2015 to Feb. 29, 2016	Daily lab sample data
Mar. 1 to Aug. 10, 2016	Regression Model 1 (see below)
Aug. 10, 2016 to Nov 30, 2016 *Daily samples were collected and analyzed in the lab starting Aug. 10, 2016 **Daily lab sample data will be used until the online CO_2 analyzer issues were fully resolved	Daily lab sample data
Dec. 1, 2016 to Feb 2, 2017	Regression Model 1 (see below)
Feb. 3, 2017 onwards	No substitution (raw data measured by the analyzer and applying a pressure compensation)

Performance of the on-site lab GC analyzer

From December 1, 2016 to February 2, 2017, the on-site lab GC analyzer's total un-normalized mole % of the sampled components dropped to 80%. The drop in mole percent coincides exactly with the date that the lab switched from the "old" GC model to the "new" GC model. The "old" GC was sent out on Dec 1st for repairs due to a leak issue. The detector in each GC responds differently resulting in different total mole % values. The root cause for the total mole% drift is still undetermined and under investigation. A service representative came to site to ensure the GC is back in operation as of January 26, 2017.

Regression Models

Regression Model 1: Shell's August 24, 2016 letter described how Shell wanted to use a regression model (based on the strong correlation between the CH_4 and H_2 concentrations from the online analyzer and the CO_2 concentrations from lab data) to predict CO_2 concentration. This multi-variable regression model (Regression Model 1), which was developed by Shell's contractor, Cap-Op Energy, was thought to be more accurate, transparent, and repeatable than the substitution method. This regression analysis is described in the Quest Project Report for the period from August 23 to October 31, 2015 and was verified by the third party verifier, ICF International.

Regression Model 2: Tetra Tech EBA Inc., a third party auditor hired by the Alberta Climate Change Office (ACCO) and Alberta Energy (AE), raised a number of potential issues with the injection gas composition data including Cap-Op's regression model, lab sample data, and calculations with the composition data such as normalization. In particular, Tetra Tech proposed an alternative single variable regression model, which they indicated was more accurate (Regression Model 2). Tetra Tech submitted a Technical Memo on August 22, 2016 to ACCO, which described these issues (see Appendix D), and Shell provided a response to these specific issues in Appendix E.

Regression Model 3: Shell developed multi-variable regression analysis using October 2016 data only on the basis that most of the issues with the online CO_2 analyzer were fixed by the end of August 2016, including some minor contamination issues with lab data. A comparison of Regression Model 1, 2, and 3 was provided to ACCO on November 24, 2016 and is included in Appendix F.

Shell subsequently determined how each method: lab data substitution and Regression Model 1, 2, and 3 affected the final results for mass of gross CO_2 injected. The results in Table 2 show that all of these methods provided very similar results in terms of mass of gross CO_2 injected. The lab data substitution method used by Shell for November 2015 to February 2016 was very close (e.g. 26 tonnes CO_2) to the most conservative method for this time period, which was Regression Model 3. Also, Regression Model 1, used from March to August 10, 2016, was 2 tonnes CO_2 greater than the most conservative method for this time period, which was Regression Model 2.

Table 2. Comparison of Calculated Mass of Gross CO_2 Injected using Lab Data Substitution and Regression Model 1, 2, and 3 Methods

	Gross Injection Mass						
	Substitution (tonne CO2e)	Regression Model 3 (tonne CO2e)	Difference of Substitution and Model 3 (tonne CO2e)	Regression Model 1, (Cap-Op) (tonne CO2e)	Difference of Substitution and Model 1 (tonne CO2e)	Regression Model 2, (Tetra Tech) (tonne CO2e)	Difference of Substitution and Model 2 (tonne CO2e)
Nov-15	70,869	70,878	- 9	70,887	- 17	70,883	- 14
Dec-15	100,280	100,262	18	100,280	- 0	100,279	0
Jan-16	101,375	101,385	- 10	101,405	- 30	101,404	- 29
Feb-16	89,828	89,801	27	89,816	11	89,814	13
Nov 2015-Feb 2016	362,352	362,326	26	362,387	- 36	362,381	- 29
					Difference of Model 3 and 1 (tonne CO2e)		Difference of Model 3 and 2 (tonne CO2e)
Mar-16		81,710		81,712	- 2	81,707	3
Apr-16		52,126		52,097	29	52,104	22
May-16		75,993		75,996	- 3	75,992	1
Jun-16		101,004		101,051	- 46	101,043	- 39
Jul-16		102,439		102,394	45	102,402	37
Aug-16		106,714		106,708	5	106,710	4
Mar-Aug 2016		519,985		519,959	27	519,957	29
Nov 2015-Aug 2016		882,311		882,346	- 35	882,338	- 27
(green)	lowest value (most conservative)						
(blue)	2nd lowest value						
(yellow)	3rd lowest value						
(orange)	highest value (least conservative)						

Data Accuracy

As discussed above, the requirement in the Protocol is to use daily injection gas composition data and then calculate a monthly average of these samples. Shell's method is more accurate than the minimum requirement in the Protocol, because Shell is using daily injection gas composition data and daily mass injection data to calculate a daily value for mass of gross CO_2 injected. Averaging daily composition data over a month and then calculating the mass of gross CO_2 injected is less accurate due to errors from averaging.

Data Conservativeness

Although the information above indicates that the four methods, Lab Data Substitution and Regression Model 1, 2, and 3 provide very similar results, the methods Shell has used for replacing inaccurate online CO_2 Analyzer data are conservative for the following reasons:

1. Normalization of injection gas composition data resulted in less gross CO_2 injected volumes than if the injection gas composition data was not normalized (Appendix E, Table 2):
    a. 383 tonnes of CO_2 for the 1st Crediting Period, August 23 to October 31, 2015.
    b. 29 tonnes of CO_2 for the 2nd Crediting Period, November 1, 2015 to March 31, 2016.

    Below is the for equation used for normalization, where i is each of the components in the Injection Gas Stream (CO_2, CH_4, H_2O, H_2, and CO).

$$Normalized\%_{Component\ i,day} = \frac{\%_{Component\ i,day}}{\%_{CO2,day} + \%_{CH4,day} + \%_{H2O,day} + \%_{H2,day} + \%_{CO,day}}$$

2. For Regression Model 1, the application of this method is conservative, because the threshold difference for replacing analyzer data with the prediction from the regression model is only 0.1% when the analyzer is higher than the prediction and is 0.3% when the analyzer is lower than the prediction. As a result, this procedure will tend to result in mole % CO_2 values that are lower than actual, which is conservative.

3. For the lab data substitution method that was used from September 1, 2015 to February 29, 2016, the threshold for replacing analyzer data with lab sample data was when the analyzer dropped below 99.0 mole %. An analysis of the composition data from samples collected from October 22, 2015 to September 18, 2016 and analyzed in the lab (Appendix E, Figure 1) shows that the mean is 99.40% and the mean minus two standard deviations is 99.18%. If the distribution is normal, then 95% of the values will be within the mean +/- 2 SD. The distribution is more or less normal with the exception of a few outliers, and 95% of the values are expected to be greater than 99.18%. As a result, when, the analyzer is providing values between 99.0% and 99.18%, these values are likely lower than the actual CO_2 concentration. However, Shell is using any values from the analyzer that are between 99.0% and 99.18%, which is conservative.

4. For August 2015, no substitution was made even though the analyzer drifted down towards the end of the month. As a result, the analyzer data used toward the end of the month is conservatively low.

5. Two lab samples were taken for the month of September 2015: September 2, 2015 (99.83 mole % CO_2) and September 16, 2015 (99.19 mole % CO_2). September 16 lab data was used, because the mole % CO2 was lower and more conservative.

Summary

Based on the above results, Shell is proposing that the original methods 1) lab data substitution for September 1, 2015 to February 29, 2016 and 2) Regression Model 1 for March 1 to August 10, 2016 will be used for the following reasons:

- All four methods yielded very similar results.
- Minimize time and effort required by ACCO, AE, the auditor, and Shell by using data already certified by the government auditor. Tetra Tech has already provided the Certification to AE for this period.

Also, Shell's new verification contractor, GHD Limited, has reviewed this letter and supporting documentation. GHD is part way through the verification for the 2nd Crediting Period and 3rd Crediting Period and has provided a letter based on their assessment of Shell's calculation procedures (Appendix G).

Please do not hesitate to contact Celina Duong at (780) 997-5117 if you require further information.

Yours truly,

Tim Wiwchar
AOSP Portfolio Manager, Shell Canada

Cc: Shan Pletcher, Alberta Climate Change Engineer
Lindsay Mclaren, Policy Advisor
Charles Bower, GHG Reporting Specialist

Appendix B: Pipeline Inspection Report out and Chronology of events

Background

Initial plan to Smart pig the CO_2 pipeline by end of August 2016 was delayed due to resource constraints of ILI tool vendors and technical issues with temperature limitations of the Smart pig. Revisions to depressurization procedures and modifications of smart pig was required. Pig receivers on pipeline were also too short on the receiving end causing interference between smart pig and isolation valves.

A submission was made to AER to extend the initial timeline, an extension until the end of the year was granted.

Internal Inspection

In Line Inspection (ILI) was done on 100% of first half (34 km) of pipeline from the Upgrader launcher to the receiver at BV 3. The Second leg of the pipeline is currently not flowing to well site at LBV-6 and pig receiver. In Line Inspection will be done on second leg once flow to final well site is initiated.

UT inspection was done on above ground piping at all LBV locations to assess for potential corrosion damage. All readings were found at or above nominal thickness with no evidence of corrosion or damage.

Annual CP readings were reviewed and no indication of excess current draw were noted that would indicate coating damage, in addition annual Corrosion probe readings were taken and no indication of corrosion activity was noted.

Eleven (11) Above Ground Marker (AGM) locations were used along the pipeline for verification of pig distance and time confirmation for the ILI tool.

Pigging was carried out between Nov. 28 and Dec. 16, 2016. The initial configuration of pigging tool did not account for spacing of orbit valves (Line Block Valves) and resulted in the pig stalling at the Block Valve at the SP-249001 Launcher. CO_2 Pipeline was taken offline, pigging tool was retrieved, minor repairs and alterations to smart pig setup were made. Final pig run occurred Dec. 13, 2016 and was successful.

Results

Preliminary data showed no considerable defects. Based on the final pigging report five (5) External wall loss anomalies related to piping fabrication were found. 1 anomaly on a Girth Weld (likely grinding), the remainder were mill anomalies on the pipe wall (likely Mill gouges).

As per the results of the ILI it has been concluded that there is no active internal CO_2 corrosion in the pipeline. All five anomalies were beyond the 1.3 mm Corrosion Allowance of pipeline design and the minimum fracture toughness limits per the SGS report GS.10.52923 for the Quest Pipeline, an assessment is underway do determine if any action is required.

Chronology of Events for Smart Pigging of Pipeline.

August 30, 2015 - CO_2 Pipeline commissioning completed and put into continuous service.

November/December 2015 - Initial discussions within Shell Inspection group regarding timelines and consultations with Shell Pipeline Technical Authorities on Best Practices about pigging. Initial estimates indicated that the pigging would start in July 2016 and Final reporting for August 2016

February 2016 - Initial stakeholder meetings and actions identified for pigging project implementation. (Stakeholders: Operations, Contracts & Procurement, Maintenance and Inspections.).

Four vendors were considered; Baker Hughes, General Electric, Onstream (Declined to submit formal bids for pigging due to size of their ILI tools) and TD Williamson, the short list was based on vendor capabilities and experience in pipeline smart pigging. During the initial pigging assessment an issue was identified with the size of pig receivers.

March 2016 -Preventative Maintenance WO 28166169 generated for Mtc Plan #100558883 initiated for Pipeline Internal Inspection (per Inspection Reference Plan submitted for Initial license application and hearing. AER License #54407.) Workorder Time period, scheduled start July 2016 and schedule to finish by Dec 2016.

June 2016 - Formal Request for Quotation issued to vendors (GE and BH).

July 2016 - Vendor field visit invitation scheduled first week of July. BH accepted, GE did not. BH identified that receiver barrels would be too short to receive the smart pig safely for double valve isolation.

GE and BH (initially) both declined to submit a proposal due to resource limitations and concerns for damage to equipment during depressurization. Further negotiation with BH resulted in them tentatively agreeing to do a pig run with certain conditions.

Alteration and field test of depressurization procedure was done to ensure temperature limitations of Pigging equipment could be managed. Heating coils and use of Nitrogen during depressurization were used as part of the revised procedure.

Baker Hughes worked on developing an inspection plan for the pipeline using modified smart pig(as short as possible) and manufacturing an internal sleeve to compensate for short receiver barrel to retrieve the smart pig.

Due to an imminent delay of the pipeline inspection resulting from vendor issues/timeline and pig receiver size, the following pipeline integrity assurance activities were executed:

- Pipeline aerial monitoring reports were reviewed for soil disturbance along pipeline ROW for possible external damage locations.
- External visual inspection and select UT survey was performed on all above ground sections of the pipeline.

Upon execution of the above activities and confirmation that there were no evident issues with the pipeline, AER was engaged to update on status of pipeline and to request and extension of the initial pigging commitment made during the pipeline application.

August 2016 – A presentation was made to AER on August 31, 2016 related to inspection and maintenance activities to date and request to extend inspection timeline to the end of 2016.

An Integrity assessment was completed to assess Internal CO_2 corrosion potential, On-stream monitoring to ensure integrity of pipeline through CO_2 product dryness and CP protection of line. In addition Visual and NDE inspections were conducted to ensure integrity of accessible portions of 12" line pipe and well site laterals.

External visual inspection revealed all above ground stations to be like new condition. No external damage or corrosion was noted. Soil to Air interface at all locations was intact and in good condition, coating on pipeline is all in as-fabricated condition.

All supports and attachment locations are in like-new condition.

UT survey was carried out. Basis was to inspect locations that would be susceptible to CO_2 corrosion damage, this included – Dead legs, Low point elbows, piping and elbows before and after Soil to Air interface, as well as the filters at each well site. All UT readings taken showed that all components were at or above nominal thickness.

Readings were taken on the three pipeline corrosion probes located at each injection skid, these readings compared to those taken one year ago indicated no corrosion rate.

Sept. 2016 - AER submission and approval for extension of pipeline pigging to year end 2016 Approved.

November 2016 - AGM locations identified by operations.

Week of Nov. 16, 2016 Gauge pig was run through line to check for ID size and any possible damage that could affect smart pig, No issues were found.

Pigging attempted week of Nov. 28-29 but resulted in pig getting stuck at first LBV due to insufficient spacing on Pig seal diaphragms. LBVs are ORBIT valves and were identified as such but was not picked up by vendor. Flow will bypass the diaphragm seals if shorter than spacing of orbit gap as happened in this case.

December 2016 -Week of Dec 7th CO_2 pipeline was shutdown and stuck smart pig was retrieved.

Plan with BH to repair and modify smart pig and attempt a second run.

Week of Dec. 12th a second attempt was made and pigging was successful. Approx. 12 hrs time required to run smart pig from Upgrader facility to LBV-3.

Initial report received last week of December. First pass of data from CO_2 line pigging did not detect any gross defects equal or greater than 50% wall loss.

The final detailed report will indicate all anomalies greater than 10% of wall thickness and will require approx. 30 business days to complete. Expecting report by end of January 2017

January 2017 - Final report received and reviewed. Five (5) external manufacture anomalies found. 1 anomaly on a Girth Weld (likely excessive surface grind), the remainder were on the pipe wall (likely mill gouges). All had varying depths, lengths and widths. All five anomaly depths were beyond the 1.3 mm Corrosion Allowance of pipeline design.

All five locations also exceeded the minimum thickness for rupture strength determination made per report GS.10.52923

Review of results is underway by Static Engineering to ensure pressure integrity and minimum rupture strength.

Geometry and Metal Loss Inspection Report prepared for:

Shell Scotford Upgrader

12'' CPIG™ MFL +Caliper Inspection

NPS12 Scotford Upgrader

Quest CO_2 Pipeline

NE 32-55-21-4W4M to 02-35-57-20W4M

CPIG™ Inspection Date: December 13, 2016

Baker Hughes Pipeline Inspection 3905 71 Ave, Leduc, Alberta, Canada, T9E 0R8

Signature Block	Name	Date	Initial
MFL Analysis Supervisor	Katherine Pospisil	Jan 19, 2017	K.M. Pospisil
MFL Analysis Team Lead	Qamar Ahmad	Jan 19, 2017	Q. A.
Caliper Analysis Lead	Yongtao Zhu	Jan 19, 2017	[illegible]
Caliper Analyst	Di Zhou	Jan 19, 2017	周迪
MFL Analyst	Muhammad Sultan	Jan 19, 2017	M. Sultan

Issue Number	Release Date	Issue Date	Description of Changes
631143 Issue A	Jan 20, 2017	Jan 19, 2017	Initial Issue

This report has been specifically prepared for Shell Scotford Upgrader (herein after called 'Shell'). Any use which a third party makes of this report, or any sole reliance on or decisions to be made based on the information contained herein, are the sole responsibility of such third parties. Baker Hughes Pipeline Inspection accepts no responsibility for the damages, if any, suffered by any third party as a result of decisions made or actions based on the information contained in this report.

Information provided herein represents the best efforts of Baker Hughes Pipeline Inspection to evaluate the described lines. Judgements concerning pipe condition are left entirely to Shell. All information herein represents only Baker Hughes Pipeline Inspection's interpretation of the pipeline inspection information and shall not be construed as a warranty or guarantee of the structural condition of the pipeline, its fitness for use, or any other condition.

Executive Summary

Baker Hughes Pipeline Inspection has successfully completed a high resolution CPIG™ inspection of Shell's 32.63 km pipeline NPS12 Scotford Upgrader Quest CO_2 line NE-32-55-21-W4 to 02-35-57-20-W4 on December 13, 2016.

The magnetic metal loss inspection was performed to identify and assess the severity of anomalies contained in this pipeline. A comprehensive analysis of the magnetic flux leakage data collected by the Baker Hughes's CPIG™ tool on this pipeline identified no individual detected magnetic anomalies.

The purpose of the CPIG™ caliper survey inspection was to determine pipeline geometry, which includes curvature, pipe wall shape and deformations. The caliper analysis has identified no anomalies above 2% of the nominal O.D. of the pipeline.

Since IMU was not employed for this survey, there will be no GPS coordinates provided for this line. There were a total of 10 AGM's and 7 Valves used in this survey. 2 AGMs were excluded due to their close proximity to the Valves. All other 8 AGMs and 7 Valves are marked as reference features. All reference features are listed in Appendix 04.

Since IMU was not employed for this survey, gyro data was used for bend detection. The analysis of gyro data has identified 70 bends with an angle larger than 5° and a radius of curvature less than 100D. No bends tighter than 5D were identified in this line. The complete bend listing is included in appendix 14.

We would like to thank Shell for their assistance and cooperation during this inspection and we look forward to working together in the near future.

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Appendices

1.1 Inspection Summary

1.1.1 Operational Details

Baker Hughes Pipeline Inspection has mobilized equipment and a qualified crew to perform in-line inspections of the following system:

BHI Job Number	631143
Pipeline Operator	Shell Scotford Upgrader
Line or Segment Name	NPS12 Quest CO2 Pipeline
Launch Site	NE-32-55-21-W4
Receive Site	02-35-57-20-W4
Section Length	32.63 km
Pipeline Nominal Diameter	12”
Predominant Weld Type	ERW
Pipeline Grade (API)	X52
Product	CO_2
Date of CPIG™ Inspection	December 13, 2016
Duration of CPIG™ Inspection	12 hours and 5 minutes
Field Project Manager	Jerrod Carrobourg

Table 1. Operational Details

After passing all of the pre-run inspection procedures the CPIG™ tool was transported to the site and launched at 10:40 on December 13, 2016. The tool was received at 22:45 the same day.

The CPIG™ tool was received in good condition with minor damage mechanically and electrically. There was a piece of polyurethane missing from the front chain tow link and the sensors were damaged due to the effects of de-pressuring the CO2. After the inspection, the complete data was downloaded on site and later analyzed.

Preliminary field analysis indicated that a complete set of MFL data was collected for the entire run. All other systems including odometers functioned throughout the inspection.

1.1.2 Tool Specifications

Baker Hughes Pipeline Inspection provided a high resolution 12” CPIG™ (MFL + Caliper) tool for this inspection. This tool was specifically tailored at Baker Hughes’ tool assembly shop and the general specifications are detailed as follows:

CPIG™ (MFL)

Tool Diameter	12”
Minimum Bend Radius	1.5D
Sensor Type (MFL)	Hall Effect
Number of Sensors (MFL)	144
Sensor Type (Caliper)	Mechanical Caliper
Number of Sensors Arms (Caliper)	24 (MFL/Cal™ only)
Number of bodies	2
Maximum run Length (time)	>70 hours
Maximum Operating Pressure	1740 psig (120 bar)
Maximum Operating Temperature	140˚ F (60˚ C)
Maximum Optimal Tool Velocity	4 m/s

Table 2. Tool specifications

1.1.3 Data Analysis Parameters

Baker Hughes Pipeline Inspection configured its 12” CPIG™ (MFL) specifically for this run to achieve the following sizing performance specifications.

Corrosion Detection Threshold	10% of wall thickness
Depth Sizing Accuracy	+/- 10% of wall thickness
Length Sizing Accuracy	+/- 0.4” or 10mm
Interaction Criteria	“3t x 3t” (by expansion) CLS A

Table 3. Sizing Specifications. Accuracies are based on general corrosion Anomalies not interacting with girth welds, using a confidence interval of 80%

1.1.4 Reporting threshold

As specified by Shell, 10% threshold for metal loss features was implemented.

For deformations, the reporting criteria is to report deformations which are greater than or equal to 2% of the nominal O.D., and those dents interacting with metal loss

1.2 Metal Loss Summary

1.2.1 Ten most significant metal loss anomalies by mB31.G RPR

Baker Hughes Pipeline Inspection has identified 0 individual detected magnetic anomalies

BHI Identifier	BHI Chainage (m)	Clock Position (hh:mm)	Wall Surface Location	U/S BHI GWD#	Peak Depth (%)	Length (mm)	Width (mm)	RPR (mB31.G) SMYS	MAOP (kpa)

No Individual Magnetic Anomalies were detected

Table 4. Top 10 anomalies by mB31.G RPR (SMYS)

Company Name	Segment	MAOP (kPa)	Pipe Grade API	Product	Date of Run
Shell	NPS12 Scotford Upgrader Quest CO_2 Pipeline	12000	X52	CO_2	December 13, 2016

Table 5. Pipeline Information

1.2.2 Most significant metal loss Anomalies by depth

Baker Hughes Pipeline Inspection has identified 0 individual detected magnetic anomalies.

BHI Identifier	BHI Chainage (m)	Clock Position (hh:mm)	Wall Surface Location	U/S BHI GWD#	Peak Depth (%)	Length (mm)	Width (mm)	RPR (mB31.G) SMYS	MAOP (kpa)

No Individual Magnetic Anomalies were detected

Table 6. Top 10 anomalies by depth

Company Name	Segment	MAOP (kPa)	Pipe Grade API	Product	Date of Run
Shell	NPS12 Scotford Upgrader Quest CO_2 Pipeline	12000	X52	CO_2	December 13, 2016

Table 7. Pipeline Information

1.2.3 Tabulation of Detected Magnetic Anomalies by wall location and depth

The quantity and classification of identified metal loss anomalies are listed below:

Depth	External Anomalies	Internal Anomalies	Total # of Anomalies
>=10% and <20%	0	0	0
>=20% and <30%	0	0	0
>=30% and <40%	0	0	0
>=40% and <50%	0	0	0
>=50% and <60%	0	0	0
>=60% and <70%	0	0	0
>=70% and <80%	0	0	0
>=80%	0	0	0

Table 8. Depth distribution of internal and external anomalies.

1.2.4Detected Magnetic Anomalies Histogram

NO DATA TO REPORT

Figure 1. A three dimensional histogram groups together all of the identified metal loss anomalies into pre-selected chainage ranges. By grouping and plotting peak depth versus chainage, a visual representation of the metal loss anomalies with respect to the entire pipeline is possible. No Histogram was created as a result of 0 anomalies.

1.2.5RPR Severity Graph

NO DATA TO REPORT

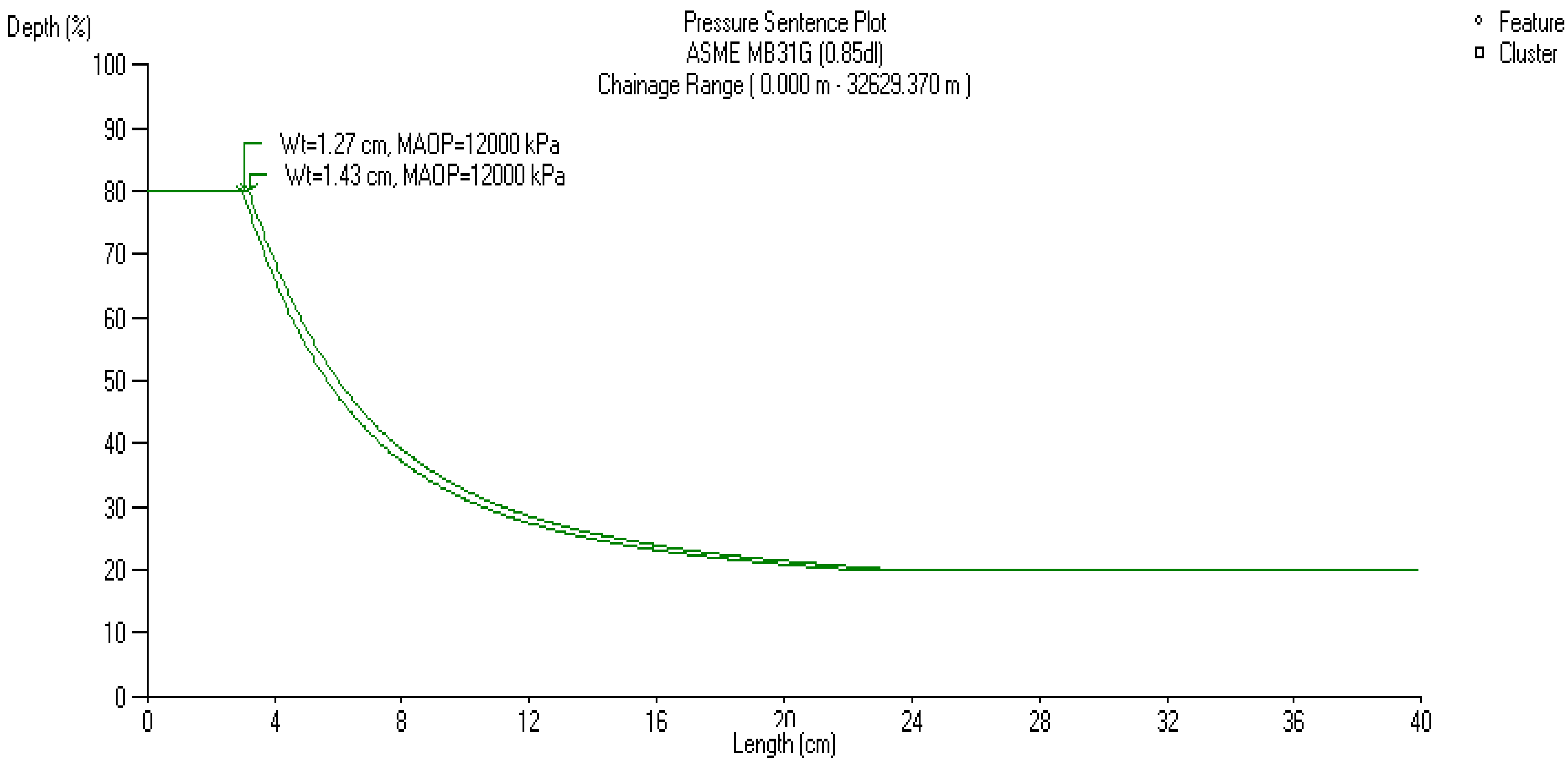

Figure 2. This RPR Severity graph or "pressure sentence plot" displays all of the anomalies identified by the MFL tool. By plotting the peak depth versus the axial length of each feature we can see the relative significance of each detected metal loss feature. The plotted curved lines are based on the ASME mB31G failure pressure calculations. No Graph was created as a result of 0 anomalies.

1.2.6 Metal Loss Feature Orientation Plot

NO DATA TO REPORT

Figure 3. An orientation plot shows all of the metal loss features contained in this pipeline with respect to their detected orientation. No Plot was created as a result of 0 anomalies.

1.3 Other Significant Features

Baker Hughes Pipeline Inspection is capable of finding more than just metal loss anomalies with its CPIG™ tool. The following features have been located and classified:

Feature	Number of Features
Anchor	0
Bend	70
Casing	0
Fitting	0
Flange	8
Sleeve	0
Support	29
Tap / Tee	20
Valve	7
Metal Object	1
Girth Weld	2177

Table 9. List of identified pipeline features

1.3.1 Manufactured / Pipe Mill Anomalies

During the manufacturing process of creating a piece of pipe, numerous material flaws can occur during the fabrication and/or welding of the pipe. These abnormalities can include laminations, inclusions, hard spots, slivers, blisters, laps, weld trim, internal coating imperfections, or other features that have altered the magnetic permeability of the pipe line. If analysis identifies an indication consistent with that of one of these features, it is characterized as a Pipe Mill Anomaly (PMA).

BHI's sizing algorithms are based on the assumption that the flux leakage measured is associated with pure metal loss. As manufacturing anomalies can be the result of other physical properties of the actual depths and dimensions may differ significantly to those estimated during analysis. It is for this reason that the predicted dimensions of a PMA are often provided as a general extent of an anomaly, though location will be precise (Chainage and Clock Position). The depth measurement reported for the PMA is the equivalent metal loss that would be calculated from the flux leakage signal response were it pure metal loss resulting as an example from corrosion. Where a manufacturing anomaly contains multiple signals the dimensions will correspond to the overall extent of the anomaly and the depth measurement to the deepest equivalent metal loss calculated within the PMA.

BHI Pipeline Inspection Services has identified 4 pipe mill features in this pipeline

1.3.2 Weld Anomalies (GWA/SWA)

There are various circumstances that can create an MFL signal on a circumferential/axial weld. If there is metal loss in the vicinity of the weld for example, then conservatively BHI will assume that the signal was due to associated metal loss and characterize it accordingly. Besides metal loss due to corrosion, there could be an isolated flaw caused during the welding process. These flaws are difficult to discern as an air gap in the weld and metal loss due to corrosion have very similar signals. For consistency, BHI employs a defined decision process to characterize such anomalies.

Once an anomaly is identified on a circumferential/axial weld, it is determined if the signals are possible metal loss. After that, it is determined if the signals are restricted to the weld. If the signal is not restricted to the weld, then it is automatically assumed to be metal loss and characterized as a DMA (on GWD/SWD). If the signal is indeed restricted to the weld (i.e. the signal does not extend to either side of the weld), has related metal loss in the vicinity and is greater than 10% of the provided wall thickness, then the anomaly is deemed to be a DMA that is a possible GWA (Girth Weld Anomaly) / SWA (Seam Weld Anomaly). The signal would be characterized as a positive GWA/SWA if it is restricted to the weld, is greater than 10% of the provided wall thickness and is not part of any related metal loss identified in the vicinity. BHI has identified 1 girth weld anomaly and 0 seam weld anomalies in this pipeline.

1.3.3 Unknown

Any anomalies identified that do not have indications consistent with those exhibited in testing and verification by features such as metal loss, dents or other standard pipeline features are classified as ‘Unknown’ features. BHI has classified 0 unknown features in this line.

1.4 Caliper Survey

The CPIG™ caliper survey provides the information on the internal diameter and shape of the pipe, allowing for detection and measurement of pipe wall anomalies (dents, ovalities and wrinkles), wall thickness changes, valves, tees and girth welds. The pipe internal diameter measured by the calipers is used for calculation of pipe wall thickness assuming a constant pipe O.D.

1.4.1 Pipe Wall Deformations

The purpose of the CPIG™ caliper survey inspection was to determine pipeline geometry, which includes curvature, pipe wall shape and deformations. The caliper analysis has identified no pipe wall deformations above 2% of the nominal O.D. of the pipeline.

Summary of Pipewall Deformations

Deformations		Dents				Ovalities	Inward Wrinkles	Outward Wrinkles
		All (≥ 2%)	≥ 6%	Top of Pipe	Near GWD			
Total Number		0	0	0	0	0	0	0
Largest	Size (%OD)							
	BHI Chainage (m)							

1.5 MFL Deformation Analysis

The Baker Hughes CPIG™ high-resolution MFL tool was outfitted with caliper sensors during the survey. MFL tools can detect (based upon both the MFL signal and any sensor lift-off) pipe deformations. Utilizing the caliper sensors the classified deformations can be assigned a percent restriction value relative to the outside diameter of the pipe.

1.5.1 Mechanical Damage Gouges

Gouges are typically characterized by an elongated groove or cavity caused by mechanical removal of metal. By closely examining the MFL signal, as well as accounting for the geographical position and the feature orientation, BHI has found no evidence of any gouges in this line.

1.5.2 Anomaly on Dents

Anomaly on a dent is a relatively easy feature to identify, as long as the hall-effect sensors used to detect the magnetic leakage field remain in close proximity to the deformation surface. BHI Pipeline Inspection has identified none of these features in this line.

1.6 Reference Features and Bends

1.6.1 Reference Features

Since IMU was not employed for this survey, there will be no GPS coordinates provided for this line. There were a total of 10 AGM's and 7 valves in this line. 2 AGM's were excluded due to their close proximity to the Valves. All other 8 AGM's and 7 valves have been included as reference features. All reference features are listed in Appendix 04.

1.6.2 Bends

Since IMU was not employed for this survey, gyro data was used for bend detection. The analysis of the gyro data has identified 70 bends with an angle larger than 5° and a radius of curvature less than 100D. No bends are equal to or tighter than 5D in this line. All the bends are listed in Appendix 14.

1.7.1 CPIG™ Velocity

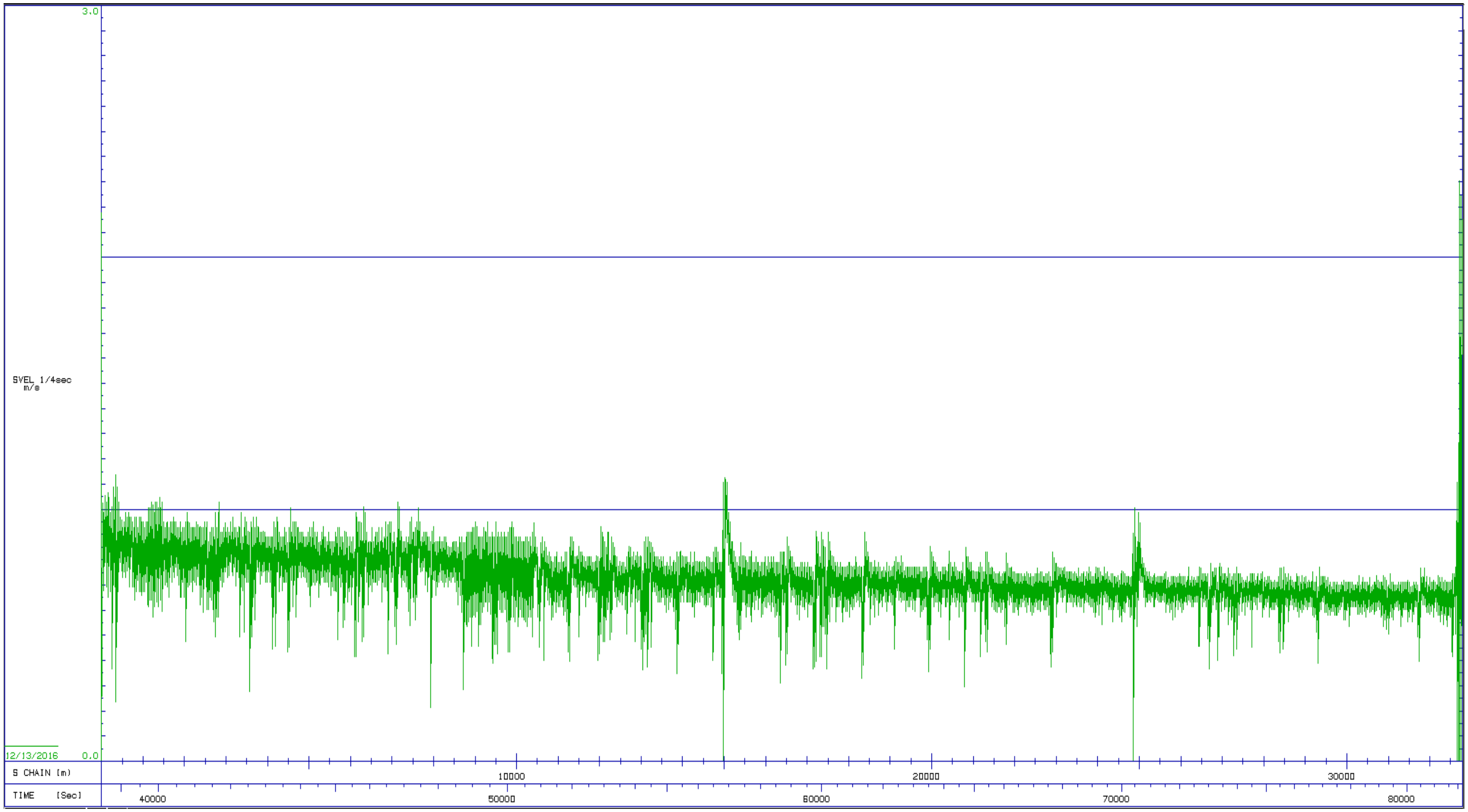

Figure 5. This graph shows the velocity of the tool as it progresses through this particular pipeline segment during the CPIG™ inspection run. This graph is shown in a "chainage mode". The axis on the left indicates velocity in m/s, while the bottom axis has 2 different scales. One scale represents distance, while the other contains time in seconds.