Terms and Conditions you agree to immediately stop accessing this Report and destroy all copies in your possession or control.

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

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

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

Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT -

ALBERTA DEPARTMENT OF ENERGY: 2018

March 2019

Executive Summary

This Summary Report is being submitted in accordance with the terms of the Carbon Capture and Storage (CCS) Funding Agreement – Quest Project, dated June 24, 2011 between Her Majesty the Queen in Right of Alberta and Shell Canada Energy, as operator of the Quest CCS facility (Quest) and as agent for and on behalf of the AOSP Joint Venture and its participants, comprising Canadian Natural Upgrading Limited (60%), Chevron Canada Limited (20%) and 1745844 Alberta Limited (20%), as amended.

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

In 2018, Quest surpassed 3 Million tonnes of injected CO_2.

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

There were no recordable spills/releases to air, soil or water within the Quest capture unit during the 2018 operating period, and MMV data indicates that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir to date.

In 2018, Shell conducted another open house for the local community and held an engagement with local government officials to provide updates on operations. Knowledge Sharing with numerous industry and non-government associations also continued in 2018.

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

- Sustained, safe, and reliable operations
- Low levels of chemical loss from the ADIP-X process
- Significantly lower carryover of triethylene glycol (TEG) into CO_2 vs. design with estimated losses on track to be roughly 8,700 kg in 2018 vs. the design makeup rate of 46,000 kg annually
- Injection into the 5-35 well began in October 2018 to enable operational flexibility in scheduling well workovers and interventions.
- Strong evidence that Quest will sustain adequate injectivity using the three wells for the duration of the project life.
- Overall maintenance issues have been minimal
- Sharing of best practices by networking with other operating facilities continues to help improve maintenance practices and procedures
- Strong integrated project reliability performance with operational availability at 99. 2%
- Maintaining local support through the extensive stakeholder engagement activities
- Continued participation of the Community Advisory Panel (CAP)
- International engagements with the Global CCS Institute to support public engagement, global knowledge sharing activities and numerous tours to the Scotford facility

- Continued work with a United States Department of Energy-funded entity to develop and deploy MMV technologies for use on Quest
- Operating costs continue to be lower than forecasted
- Serialization of 2,104,872 credits in 2018 (from 2016 and 2017 operating years)

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

- Reformer burner degradation in the HMU's as a result of flame instability at higher CO_2 capture rates was observed
- Foaming event observed in HMU3 and carbon filter taken offline
- Design flaw in weld resulted in a shell outlet nozzle leak in overhead condenser E-24601A

Quest has seen strong reliability performance through the reporting period to safely inject 1.07 Mt of CO_2 in 2018. Overall project injection has surpassed 3.6 Mt of CO_2 to December 31, 2018.

Revenue streams generated by Quest are twofold: (i) the generation of offset credits for the net CO_2 sequestered and additional offset credit generated for the CO_2 captured, both under the Carbon Competitiveness Incentive Regulation (CCIR) which replaced the Specified Gas Emitters Regulation (SGER) on Jan 1, 2018.; 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 2018, the value of the offset credit was $30/tonne.

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

Quest provides employment for 15 permanent full time equivalent positions (FTEs) and an additional approximately 10 FTE allocated into existing positions. Quest generated expenditures of ~$26 million in 2018 in staffing, MMV, maintenance, and variable costs to the economy.

Quest continues to receive significant international interest from various technical organizations.

Table of Contents

List of Figures

List of Tables

Abbreviations

ACCO	Alberta Climate Change Office
AER	Alberta Energy Regulator
AOSP	Athabasca Oil Sands Project
ARC	Alberta Research Council
BCS	Basal Cambrian Sands
CCS	carbon capture and storage
CO_2	carbon dioxide
FEED	Front End Engineering and Design
FGR	Flue Gas Recirculation
GHG	greenhouse gases
HMUs	hydrogen manufacturing units
InSAR	Interferometric synthetic aperture radar
LBV	line break valve
MMV	measurement, monitoring and verification
ORM	Opportunity Realization Manual
PSA	pressure swing adsorber
RCM	Reliability Centered Maintenance
RFA	Regulatory Framework Assessment
ROW	right-of way
SAP	Systems, Applications, Processes (Equipment Database Software)
TEG	triethylene glycol
VSP	vertical seismic profile

1 Overall Quest Design

The Scotford Upgrader, operated by Shell Canada Energy, as agent for and on behalf of the Athabasca Oil Sands Project (AOSP) Joint Venture and its participants, comprising Canadian Natural Upgrading Limited (60%), Chevron Canada Limited (20%) and 1745844 Alberta Limited (20%), is part of Shell's Scotford facility located northeast of Edmonton. The design concept for Quest is to remove CO_2 from the process gas streams of the three hydrogen-manufacturing units (HMUs), within the Scotford upgrader facility. This is done by using amine technology, dehydrating and compressing the captured CO_2 to a dense-phase state for efficient pipeline transportation to the subsurface storage area.

Design, Construction and Startup of the Quest project occurred from 2009 to 2015. Further details on these phases can be found in previous annual reporting submissions on the Alberta Government CCS Knowledge Sharing Website.

The Operations phase at Quest commenced in September 2015. Quest operations have successfully captured and injected over 3.6 Mt of CO_2 in three injection wells (8-19, 7-11 and 5-35) to the end of 2018.

Quest facility locations are shown in Figure 1 1: Project Facility Locations.

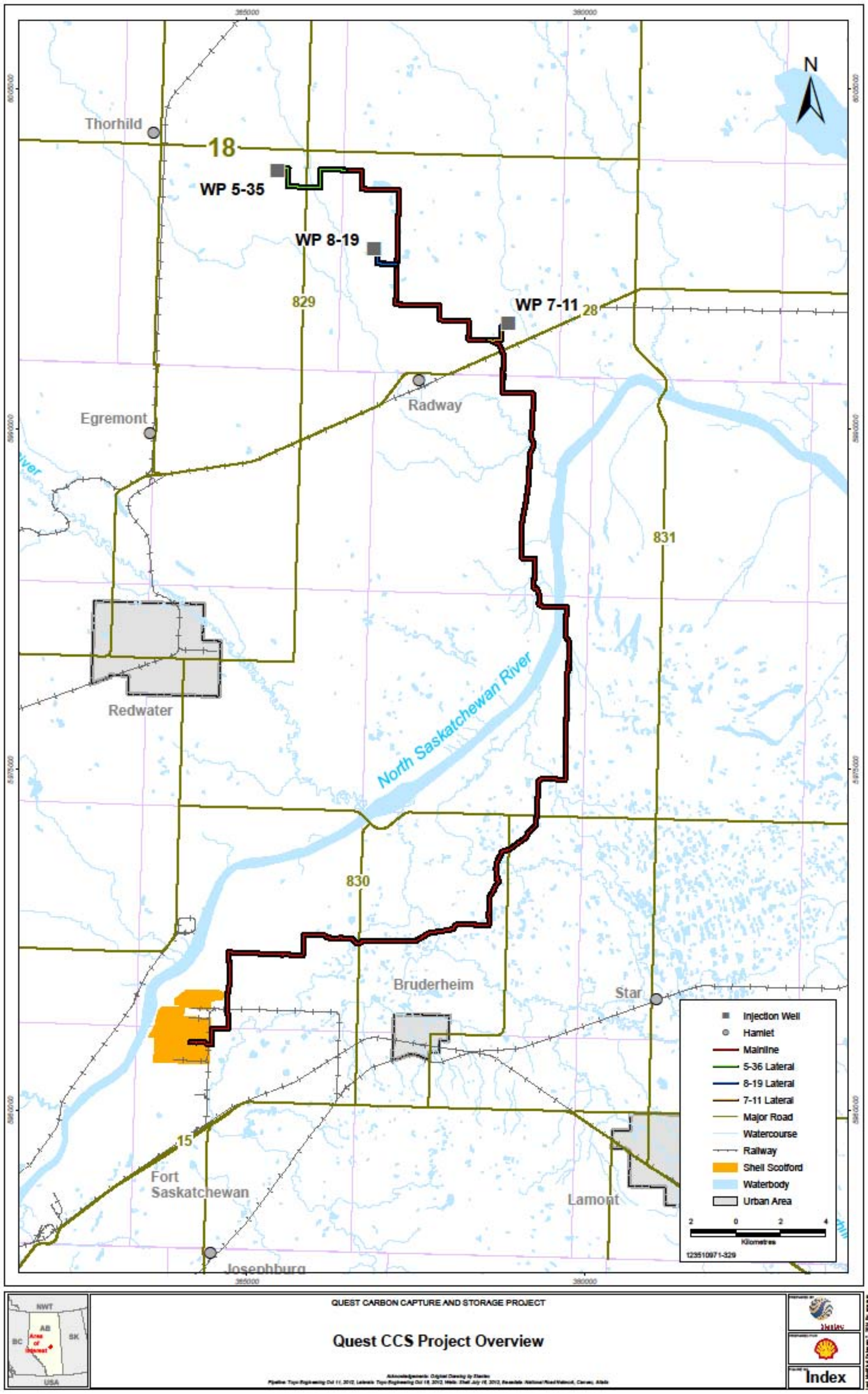


Figure 1-1: Project Facility Locations.

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 start-up. For further details, please refer to past submissions.

3 Geological Formation Selection

Storage Area selection and assessment occurred between 2008 and 2013. No new activities related to this have occurred within the reporting period. For further details, please refer to past submissions.

Updates for the reporting period as to the Estimate of Storage Potential and Injectivity Assessment previously included in this section are now found in Sections 6.1.1 and 6.1.2.

4 Facility Operations – Capture Facilities

4.1 Operating Summary

The Quest CCS project focus for 2018 was to continue reliable and efficient capture and storage of CO_2 from operations. Table 4-1 outlines the performance summary of the capture unit. A discussion of the summary results can be found in the subsequent unit discussions.

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

Going forward, Shell will continue to work with ACCO and Alberta Energy (CCS Unit) on implications of the new Carbon Competitiveness Incentive Regulation.

Table 4-1:Quest Operating Summary 2018

Quest Operating Summary	2015 Summary	2016 Summary	2017 Summary	2018 Summary	Units
Total CO_2 Injected	0.371	1.11	1.138	1.066	Mt CO_2
CO_2 Capture Ratio[4]	77.4	83.0	82.6	79.1	%
CO_2 Emissions from Capture, Transport and Storage	0.082[3]	0.239[3]	0.234[3]	0.217	Mt CO_2
Net Amount (CO_2 Avoided)	0.289[3]	0.871[3]	0.904[3]	0.849[1,2]	Mt CO_2

1. Quest is an integrated operation within the Scotford Upgrader Complex, Net CO_2 Avoided, includes 0.059 Mtonnes CO_2 that will be claimed under the Scotford Upgrader Offset Project as per the new 2018 Carbon Competitiveness Incentive Regulation.
2. Includes 0.039 Mtonnes CO_2 of large final emitter target reduction. Under SGER, the reported indirect GHG emissions from imported steam for Quest was reduced by the Target (e.g. 20%), which is the required reduction in GHG intensity for large final emitters such as the Upgrader. Under CCIR, there is no target specified. As a result, the Target is retained from SGER, pending further clarification with ACCO.
3. Historical CO2 emission have been updated based on the audit ruling on waste heat methodology. Numbers will be finalized based on certification audits when these occur.
4. The CO_2 capture ratio refers to the percentage of CO_2 captured from the syngas (raw hydrogen) feed stream to the absorbers.

The reported CO_2 emissions for 2015 to 2018 have increased as a result of the audit findings on allocation of integrated waste heat usage. Additional to this, calculation of CO2 emissions for 2018 are also impacted by the new Carbon Competitiveness Incentive Regulation (CCIR), which became effective January 1st, 2018.

Due to the expiry of the Specified Gas Emitters Regulation (SGER) at the end of 2017, it is not clear whether there will continue to be a rebate on the indirect GHG emissions from imported steam for Quest. Under SGER, the reported indirect GHG emissions from imported steam for Quest was reduced by the Target (e.g. 20%), which is the required reduction in GHG intensity for large final emitters such as the Upgrader. Under CCIR, there is no target specified. As a result, the Target is retained from SGER, pending further clarification with ACCO.

The following is a timeline of significant operational milestones for the 2018 calendar year:

- May 30, 2018: Reached milestone of 3 million tonnes injected since project start up
- December 12, 2018: Reached milestone of 1 million tonnes injected in 2018

4.1.1 Quest Audits and Credit Serialization

The Quest project underwent various audits in 2018:

- Alberta Energy conducted an Injection Certification Audit in September/October 2018 to confirm the injected CO_2 volumes.
- The Alberta Climate Change Office (ACCO) conducted a re-verification audit of the 2nd Reporting Period (November 1, 2015 to March 31, 2016) starting in December 2018
- Shell hired a third party verifier to audit:

- 4th and 5th Reporting Periods (October 1, 2016 to September 30, 2017) for Quest without a claim for waste heat.
- 2nd Reporting Period with a claim for waste heat.

For 2018, the Quest Carbon Capture and Storage Project (Quest) serialized a total of 2,104,872 credits – 819,490 from 2016 and 1,285,382 from 2017 on the Alberta Emission Offset Registry:

Quest Credits from 1st Crediting Period (2015) (August 2, 105 to October 31, 2015)	166,540 (Base) 166,540 (Additional)
Quest Credits from 2nd Crediting Period (2015/2016) (Nov 1, 2015 to Mar 31, 2016)	324,918 (Base) 324,918 (Additional)
Quest Credits from 3rd Crediting Period (2016) (Apr 1, 2016 to Sept 30, 2016)	395,896 (Base) 395,896 (Additional)
Quest Credits from 4th Crediting Period (2016/2017) (Apr 1, 2016 to March 31, 2017)	448,158 (Base) 448,158 (Additional)
Quest Credits from 5th Crediting Period (2017) (Apr 1, 2017 to Sept 30, 2017)	406,330 (Base) 406,330 (Additional)

4.2 Capture (Absorbers and Regeneration)

Solvent composition was on target for 2018 operation vs. the specified formulation for ADIP-X from the design phase, and CO_2 removal ratio performance has been as predicted. The annual CO_2 capture ratio was 77.4% for 2015, 83.0% for 2016, 82.6% in 2017, and 79.1% in 2018.

The main contributors to periods of reduced CO_2 capture in 2018 were as follows:

- Periods of lowered hydrogen production demand, planned slowdowns and trips in process units outside of Quest.
- Planned maintenance activities or trips in the Quest capture unit also contributed to periods of reduced capture. These periods are listed below:
  - January 9: Quest compressor and pipeline trip due to loss of power associated with electrical lighting panel work. This resulted in 1273 tonnes of CO_2 vented.
  - February 17-21: On February 17th, there were indications of foaming in the stripper and in the HMU3 absorber, which resulted in the HMU3 absorber tripping.
  - March 27-May 25: During this time period Quest was shutdown to isolate exchanger, E-24601A. After the isolation was complete, there was significant rate reduction due to the exchanger being offline for repair of the process leak. This is because the overhead condensers, E-24601A/B were designed to be 2x50%. Once

the repairs were complete, Quest needed to be shut down in order to deblind the isolated condenser, E-24601A.

- June 12-13: The lean amine charge pump, P-24602C tripped due to an axial vibration probe. At the time of the trip, the 3rd standby pump, P-24602A was isolated for a pin hole leak repair.
- July 30-31: Rate reduction due to loss of amine flow to HMU3 absorber due to faulty flow control valve, FV-441075.

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.

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

Energy and Utilities	2015 Usage	2016 Usage	2017 Usage	2018 Usage	Units
Electricity (Capture/Dehydration)	12300	32800	32600	32200	MWh_e[2]
Low Pressure Steam	410	1263	1297	1204	kT
Low Temperature High Pressure Steam	1.96	5.52	5.23	5.01	kT
Nitrogen	178	230	237	258	ksm^3
Wastewater	24900	80900	61900	57800	m^3
Energy/Heat Recovered	33600	96260	98554	95060	MWh_{th}[3]
CO_2 Emissions for the Capture Process	0.030[1]	0.083[1]	.095[1]	0.140	Mt CO_2

1. Subject to change based on audit ruling on waste heat methodology. Final numbers will be updated based on certification audits.
2. The e subscript denotes electrical energy
3. The th subscript denotes thermal energy

Electricity, and steam use are approximately on target with design specifications when pro-rated for actual CO_2 throughput. Waste water was reduced in 2018 to further mitigate impacts on the downstream carbon steel piping and the waste water treatment system. Nitrogen use is significantly lower than expected due to optimizations made in the dehydration unit. Nitrogen stripping gas flow to the TEG stripper was reduced to avoid over-processing the TEG. In 2018 the operations team targeted approximately 50 ppmv water content to the pipeline, staying within the 84 ppmv spec. Heat recovery in the demin water heaters (cooling the CO_2 stripper reboiler steam condensate) is also approximately on target from design.

During the later part of 2016, it was observed that fouling of the lean/rich exchangers was impacting the rich amine inlet temperature to the stripper. A temperature drop of about 2°C was observed over the course of the year. As a result, reboiler duty increased. Cleaning of this exchanger was completed in the 2017 spring turnaround. The exchanger was back flushed by a 3rd party vendor in an attempt to remove any foulant, carbon or other debris. Since the exchanger cleaning, the stripper inlet temperature has continued to drop about 2°C for a total of 4°C since start-up. These heat exchangers are planned to be cleaned during the next turnaround.

A success story for the Quest unit operation to-date continues to be the low levels of chemical loss from the ADIP-X process. Amine losses from the capture unit reduced to negligible after the initial commissioning/inventory and startup phases.

CO_2 emissions for the capture process are primarily those linked to low pressure steam use in the CO_2 stripper reboilers (~69% of total capture emissions), and from electricity for equipment in the capture system (~16% of capture emissions).

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

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

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

Pre-filter change out lengths have not increased from the standard change out frequency prior to the reload however some minor foaming events have been noticed. Foaming is typical post carbon reload in the other amine units on the Scotford site and this will be monitored to determine if additional investigation is required. Another operational issue, noticed after placing the filter back in service, is that there is a potential for vapour/Nitrogen used to displace the amine from the pre/post filters during a filter change to be directed into the process. This has caused the P-24602 amine charge pumps to trip on low suction pressure. Procedural changes have been made to mitigate this issue until permanent vents, drains and DCS control changes can be implemented. In February of 2018, there was a foaming event that took place in the HMU3 absorber. At the time, the HMU1/2 absorbers operated normally, with no increase in differential pressure. As a result, the carbon bed was taken offline and is still offline currently. The cause has not been determined, however it may be attributed to hydrocarbon carryover in the HMU3 absorber. Since the carbon bed has been offline, steady operation has been observed in the absorbers, and no foaming events have occurred since. The pre-filter change-out lengths have remained the same; however there were periods throughout the year when the time required between change-outs increased.

On March 11th, 2018, low pH carbonic acid water was observed to be leaking through the ¼" NPT weep hole of the reinforcing pad on the 30" shell outlet nozzle S3. The leak was believed to be from a pre-existing defect in the weld overlay of the nozzle which allowed the corrosive low pH water to corrode the shell through a pinhole. An MOC was completed to plug the reinforcing pad which required Quest to shut down in order to isolate the exchanger for repair. Throughout the repair, Quest was at reduced capacity because the exchanger arrangement was designed to be 2 x 50%. Based on these findings, the same failure is expected in E-24601B, and a new shell has been ordered.

During the 2018 upgrader spring turnaround, the HMU2 absorber was opened and inspected, and the vessel was good condition. All hardware was in place, except 7 missing valve caps that were replaced prior to closing.

4.3 Compression

In 2018, the compressor operated at higher discharge pressures than previous years. This is due to rate testing the wells. The objective was to collect pressure drop data in the lateral lines and well tubing by operating the wells at maximum rates. Table 4-3 below outlines the average operating conditions for the reporting period.

Table 4-3:Typical Compressor Operating Data

Compressor Characteristic	Average 2015 Operation	Average 2016 Operation	Average 2017 Operation	Average 2018 Operation	Units
Suction Pressure	0.03	0.03	0.03	0.03	MPag
Discharge Pressure	9.6	10.0	10.1	10.5	MPag
Motor Electricity Demand	13.3	13.8	14.2	14.0	MW_e

4.4 Dehydration

The dehydration unit performance continued to exceed expectations in 2018. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv. Actual water content for 2018 was on average 44 ppmv, and this was achieved at a lower TEG purity than design (99.6% vs. 99.7%) while maintaining the optimized Nitrogen flow rates described in section 4.2.

Carryover of TEG into the CO_2 stream also appears to be significantly less than design, with the estimated losses in 2018 being <9ppmw of the total CO_2 injection stream, compared to the 27 ppmw expected in design. Dehydration unit losses of TEG were roughly 8,700kg annually for 2018 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 2018 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 2018, the averaged NOx emissions with Quest operational and the FGR online are included below:

HMU1: 39.0 kg/h, limit 76.5 kg/h

HMU2: 28.2 kg/h, limit 76.5 kg/h

HMU3: 63.5 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. The spring 2018 turnaround revealed poor burner condition in the HMU2 reformer. With Quest online, the burners are physically cracking, coking, and breaking due to changes in burner fuel composition and flow. Burner degradation has the potential to add to the already observed poor flame patterns and hot spots within the reformer. The above is also true for the HMU1 and HMU3 burners.

In November of 2018, HMU3 started to restrict the capture ratio to 78%. This was due to a temperature cycling phenomenon in row E of the reformer, which stems from the burners. Since the burners are in poor condition, this leads to poor air to fuel mixing. This reduction is expected to last until a burner change is performed.

Since commissioning in 2015, hydrogen production losses due to hydrogen entrainment in the amine absorbers have remained 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.

From an efficiency perspective, the hydrogen production capability of the units remains largely unchanged in 2018 with Quest operating. The loss of hydrogen via entrainment in the CO_2 absorbers and into the Quest pipeline meets design expectations and there is a negligible drop in overall hydrogen production capacities. Flue gas recirculation addition to the reformer combustion air stream is running below design expectations. While the addition of the flue gas recirculation results in fuel efficiency improvements in the reformer, NOx emissions are slightly elevated from baseline.

4.6 Non-CO_2 Emissions to Air, Soil or Water

In accordance with Shell's internal guidelines, all spills – regardless of size – are recorded for tracking purposes. Quest experienced two leaks in 2018.

In March of 2018, low pH carbonic acid water was leaking from the ¼" NPT weep hole of the reinforcing pad on the 30" shell outlet nozzle of the overhead condenser, E-24601A. The leak was believed to be from a pre-existing defect in the weld overlay of the nozzle which allowed the corrosive low pH water to corrode the shell through a pinhole. The leak was collected in the potentially oil water system and diluted with recovered clean condensate to increase the pH to prevent corrosion concerns. Based on these findings, the same failure is expected in E-24601B, and a new shell has been ordered.

In August 2016, a leak was identified in a section of wastewater piping going from the Quest plot to the Scotford Upgrader Wastewater Treatment Plant. Leak location was in the Upgrader Cogeneration Unit, outside the Quest plot. When investigated, the leak was found to be due to high corrosion rates caused by the low pH of Quest stripper reflux water. Piping has since been upgraded to 304 stainless steel. In 2017 and 2018, to further mitigate impacts on the downstream carbon steel piping and the waste water treatment system, a temporary caustic injection skid was installed in Quest to increase the PH of the Quest stripper reflux water. A project to permanently mitigate the low PH water leaving the unit is currently underway.

4.7 Operations Manpower

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

5 Facility Operations – Transportation

5.1 Pipeline Design and Operating Conditions

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

Table 5-1:Pipeline Design and Operating Conditions

Characteristic	Specification	Units	Average Operating Data / Actual Limitations				Original Design
			2015	2016	2017	2018	
	General						
Pipeline Inlet Pressure	Normal	MPag	9.4	9.8	9.9	10.3	10
	Maximum Operating	MPag	12	12	13.58	13.58	14
	Minimum Operating (based on CO_2 critical pressure 7.38 MPa)	MPag	8.5	8.8	8.7	8.8	8
	Design maximum	MPag	-	-	-		14.8 (at 60°C)
Pressure Loss from Inlet to Wellsite	Normal	MPa	0.6	0.6	0.6	0.9	0.4 (for 3 well scenario)
Temperature	Compressor Discharge	°C	130	130	128	131	130
	Pipeline Inlet after cooler	°C	43	43	41	41	43
	Upset Condition at Inlet	°C	-	-	-	-	60
	Injection Well 7-11 Inlet Temperature	°C	15	16	14	13	
	Injection Well 8-19 Inlet Temperature	°C	12	12	11	9	
	Injection Well 5-35 Inlet Temperature (as of Oct 19, 2018)	°C	-	-	-	6	
Flow rates	Normal Transport Rate	Mt/a	1.04	1.11	1.14	1.06	1.2
	Design minimum	Mt/a	-	-	-	-	0.36
	Total Transported	Mt	0.371	1.11	1.14	1.06	-
Energy and Emissions	Total Electricity for Transport (compression)	MWh e	41,527	119,426	121,593	119,482	-
	Total Transport Emissions (includes compression)	Mt CO_2e q	0.027	0.077	0.078	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).

Fluid Composition

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 5-2:Pipeline Fluid Composition

Component	Actual Operating 2015 (vol%)	Actual Operating 2016 (vol%)	Actual Operating 2017 (vol%)	Actual Operating 2018 (vol%)	Design Normal Composition	Design Upset Composition
CO_2	99.45	99.38	99.46	99.44	99.23	95.00
H_2	0.48	0.51	0.47	0.46	0.65	4.27
CH_4	0.06	0.06	0.06	0.06	0.09	0.57
CO	0.02	0.02	0.01	0.01	0.02	0.15
N_2	0	0	0	0	0	0.01
Total	**100**	**100**	**100**	**100**	**100**	**100**

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 2018 was 44 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.

5.2 Pipeline Inspections

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

- Daily operator rounds of the pipeline, well sites, and LBVs.
- Non-destructive examination (ultrasonic thickness test) on above ground piping to identify possible corrosion of the pipeline based on Shell's Risk Based Inspection calculations. These intervals are subject to change depending on corrosion loop monitoring data tracked through Shell's Integrity Management System (IMS)
- 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. The required AER in line inspection (ILI) interval is currently every 5 years. The next ILI inspection is scheduled for 2021.
- 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. This is done quarterly as per an agreement with the AER. In August 2018, the frequency of flyover inspections reduced from bi-weekly to quarterly. This was done as a cost savings initiative and to reduce the safety exposure during the aerial flights, as previous flights had not yielded any significant findings.

6 Facility Operations - Storage and Monitoring

This section provides an overview of the wells and MMV activities for the operational year 2018.

6.1 Storage Performance

Injection of CO_2 into the 8-19 and 7-11 wells began on Aug 23, 2015, and 5-35 commenced injection October 19, 2018. As of Dec 31, 2018, about 3.7 Mt CO_2 have been injected into the three wells as illustrated in Figure 6-1. The injection stream composition is described in detail in Table 5-3 and is shown in Figure 6-2.

Injection into the 5-35 well commenced to improve operational flexibility, primarily for when scheduling well intervention activities.

By the end of December 2018, about 1.76 Mt of C02 had been injected into the 7-11 well, 1.83 Mt of $C0_2$ into the 8-19 well, and 0.09 Mt of $C0_2$ into the 5-35 well Figure 6-3, Figure 6-4 and Figure 6-5 show the daily average flow rates and P/T conditions at the wells during the injection period.

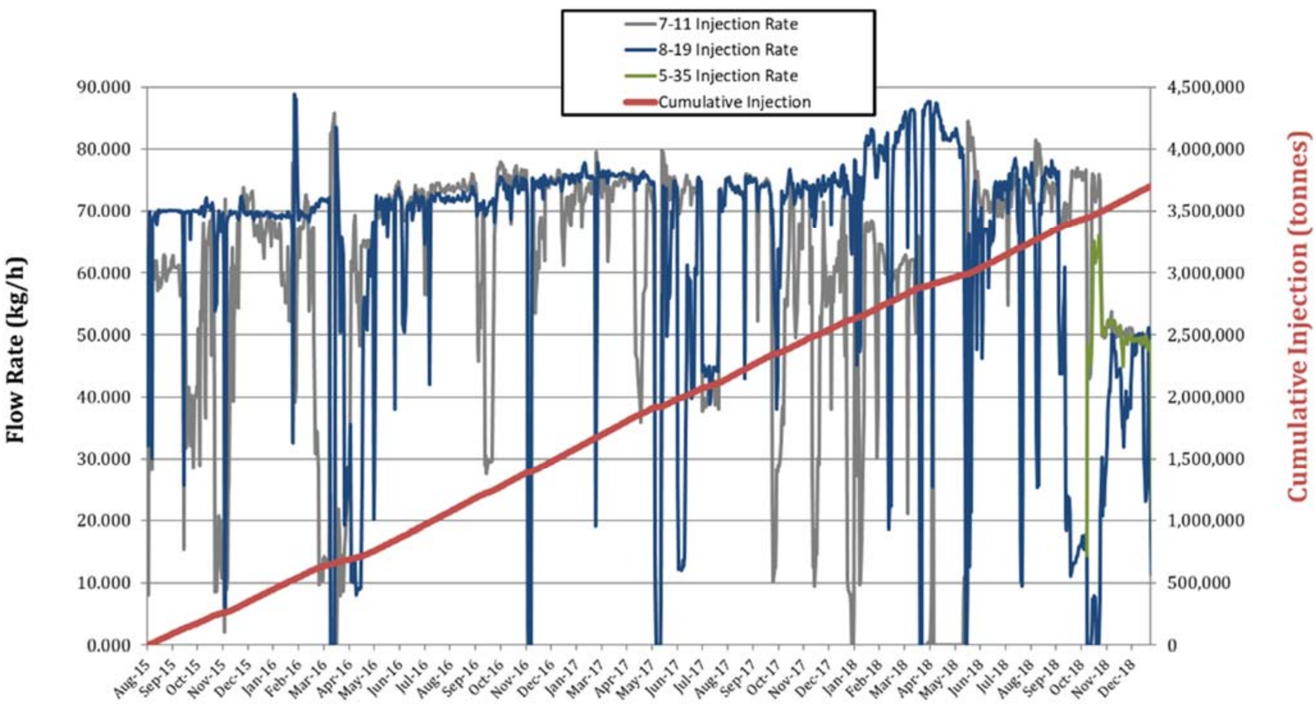


Figure 6-1: Quest Injection Totals: Cumulative CO_2 injected into the wells from start-up through to the end of 2018 (red). The blue, grey and green lines show the average hourly flow rates into each of the injection wells.

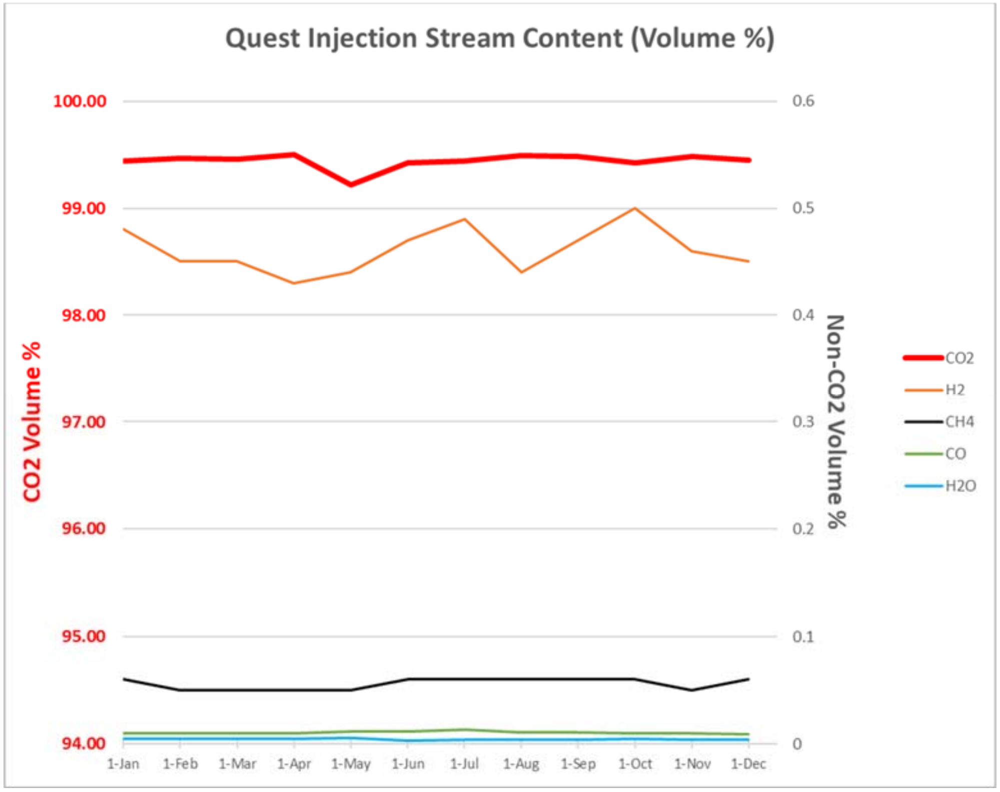


Figure 6-2: Quest Injection Stream Content: Average injection composition for 2018.

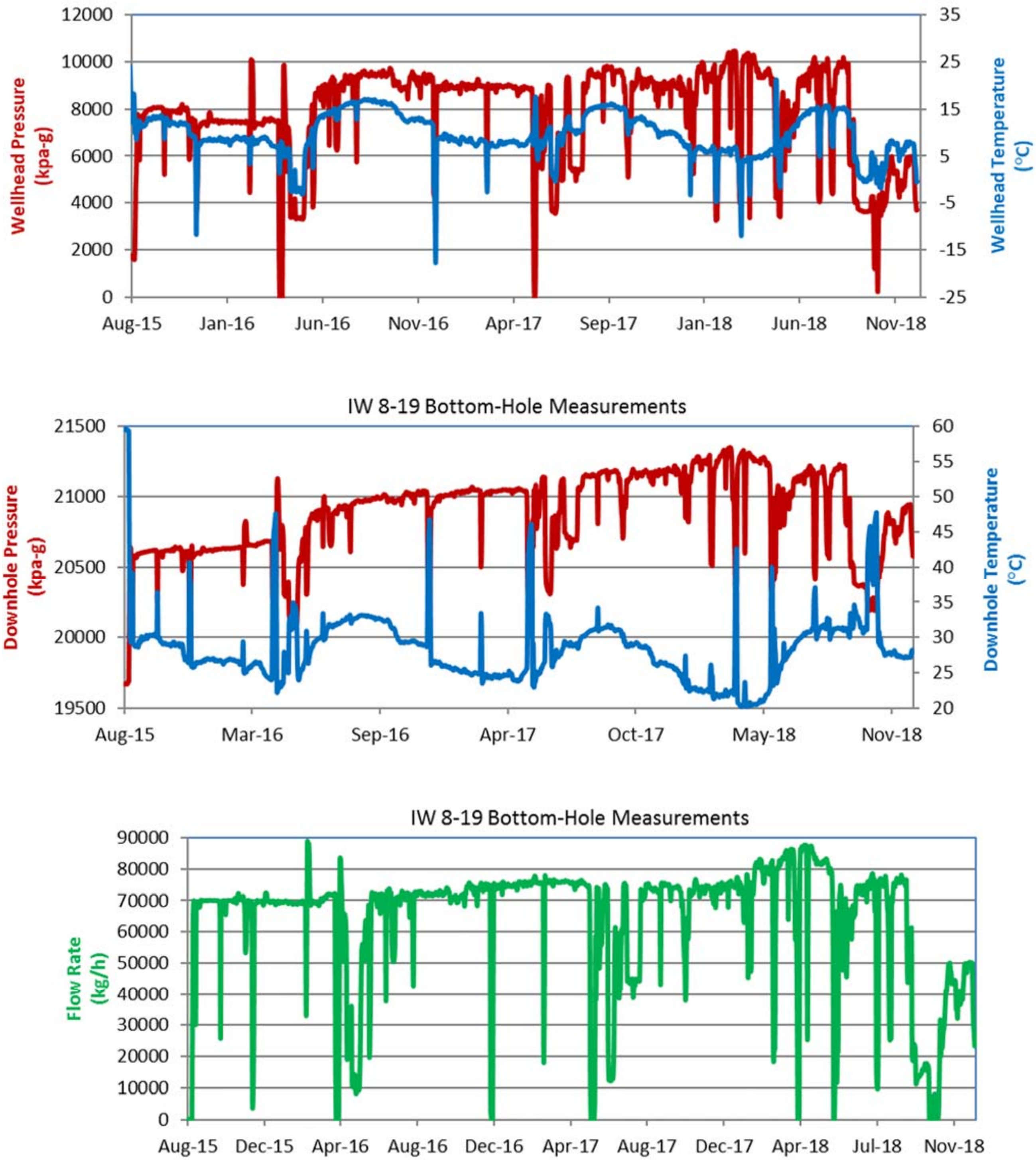
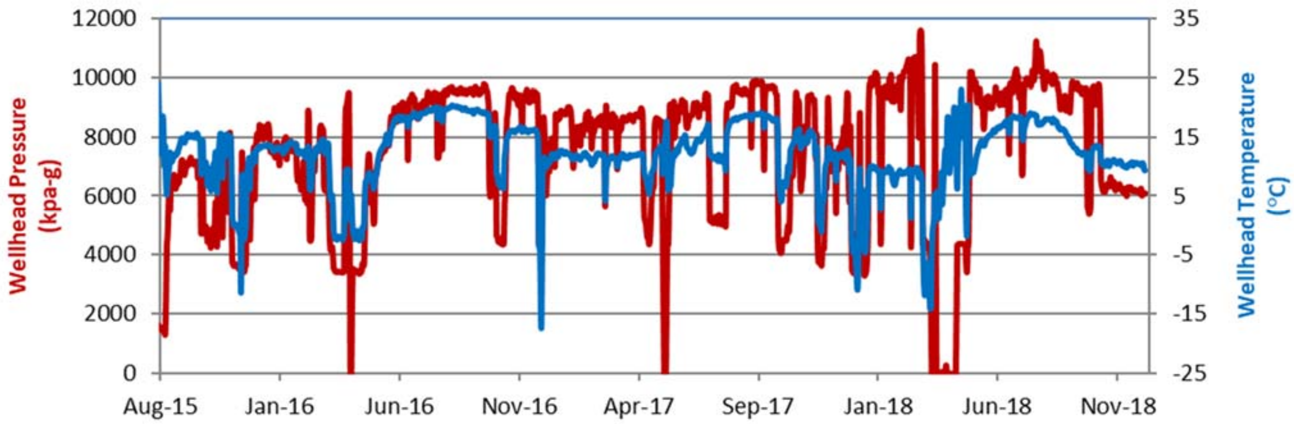
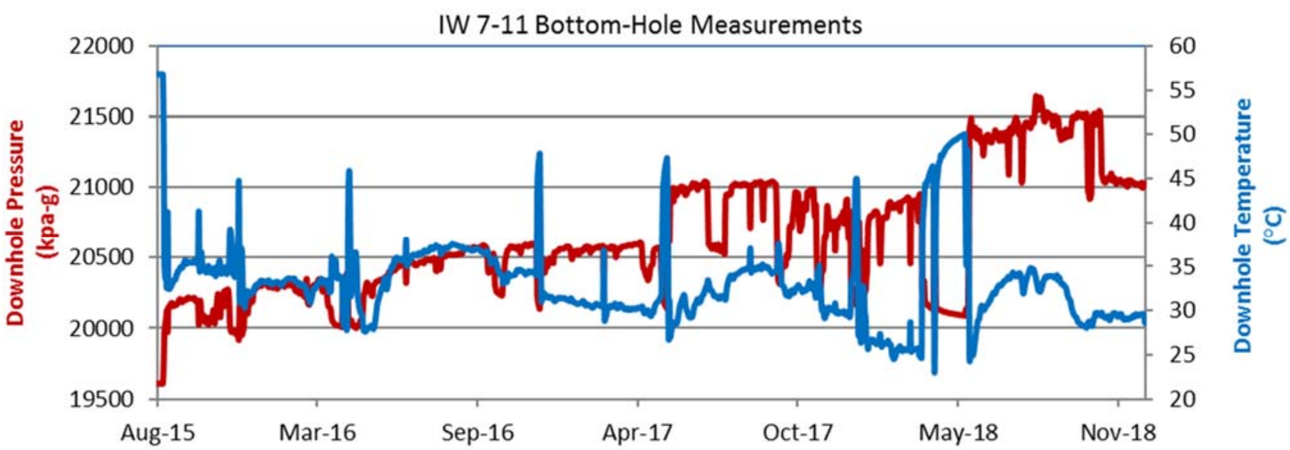


Figure 6-3: The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection to the end of 2018.





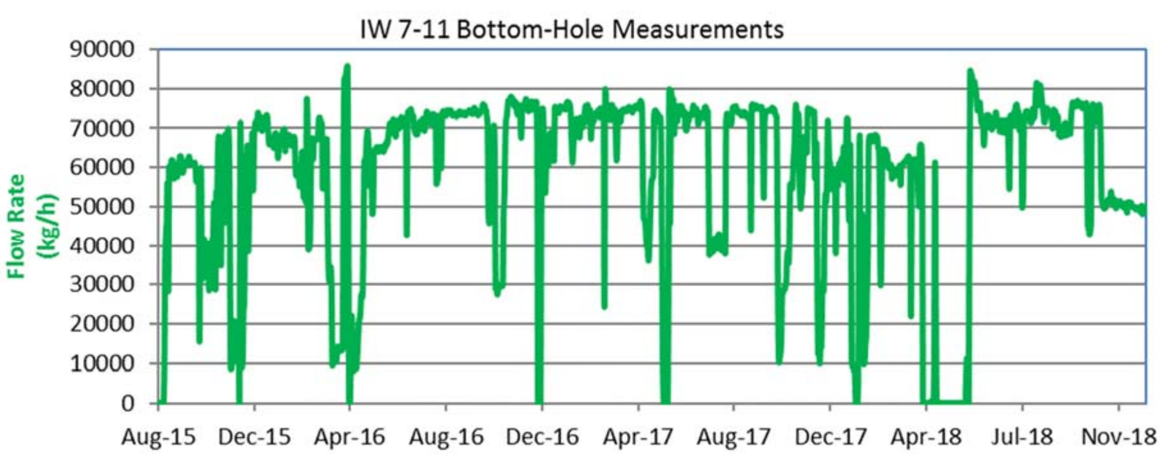


Figure 6-4: The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2018.

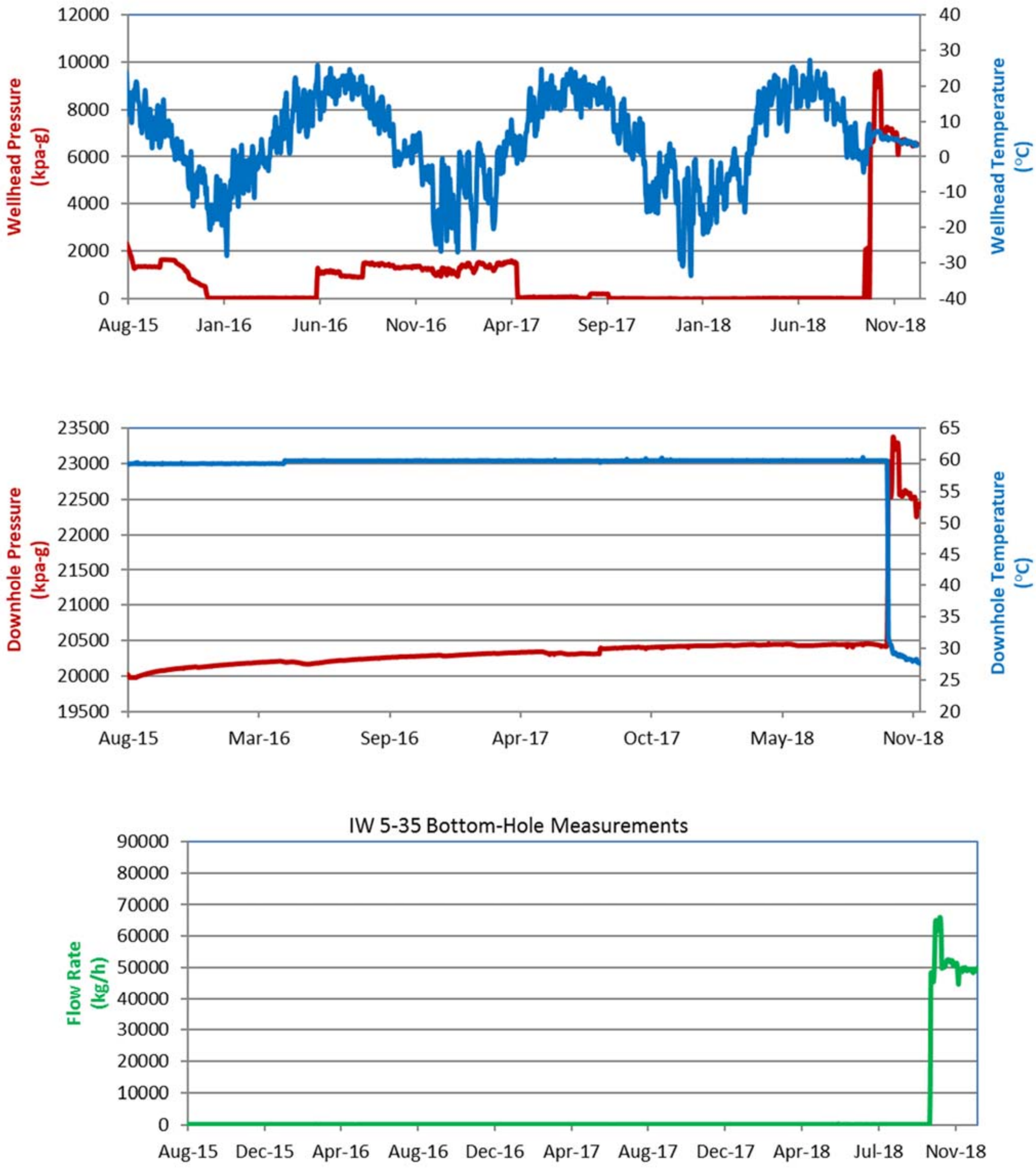


Figure 6-5: The 5-35 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2018.

6.1.1 Estimate of Storage Potential

Reservoir modelling continues to indicate that there is more than sufficient storage capacity for the full project volume of 27 Mt of CO_2. Refer to the AER Annual Report (2018) Section 3.5: Reservoir Capacity for discussion. Since several years of performance data have now been collected and used to calibrate the reservoir model, the residual uncertainty in pore volume is unlikely to decrease much further

Table 6-1: Remaining capacity in the Sequestration Lease Area as of end 2018

Year	Yearly Injection Total	Remaining Capacity
Pre-injection	-	27 Mt CO_2
2015	0.371Mt	26.629 Mt CO_2
2016	1.108 Mt	25.521 Mt CO_2
2017	1.138 Mt	24.383 Mt CO_2
2018	1.066 Mt	23.317 Mt CO_2

6.1.2 Injectivity Assessment

The project was designed for a maximum injection rate of about 145 t/hr into three wells. Since start-up in 2015, injection rates have been up to 155 t/hr into two injection wells (the 8-19 and 7-11 wells). The 8-19 well has been injecting consistently at about 70 t/hr when possible with very little pressure build up. The 5-35 injection well was brought on in October 2018 for reasons of operational optionality.

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 expected that the project will be capable of sustaining adequate injectivity for the duration of the project life.

6.2 MMV Activities - Operational Monitoring

In 2018, MMV activities included: atmosphere, hydrosphere, geosphere, and well-based monitoring. The following is a summary of these activities:

Atmosphere Domain: Monitoring of CO_2 levels in the atmosphere at the injection well sites continued using the Light Source technology.

Hydrosphere Domain: Four discrete sampling events (Q1, Q2, Q3, Q4) were executed. Project groundwater wells located on the 3 injection well pads were sampled on a quarterly basis. Landowner groundwater wells within 1 km of the injection well pads were sampled on a quarterly basis. Further details on the hydrosphere monitoring activities can be found in Appendix A.

Biosphere Domain: No activities took place regarding soil gas and soil surface CO_2 flux measurements.

Geosphere Domain: Monthly satellite image collection for InSAR continued. Since September 2017, a single frame centered over the 3 injection well pads has been used for image collection.

Well based Monitoring: ongoing data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes.

The 2017 MMV plan includes a tiered system to review and assess the MMV data. Tier 1 technologies form the basis for assessing whether or not there is an indication of loss of containment. Depending on the outcome of that assessment, further analysis or investigation of the Tier 2 technologies will be undertaken and then, if needed, Tier 3 technologies will be assessed.

No trigger events were identified during 2018 that would indicate a loss of containment (Table 6-2). As a result, the focus of this report is on Tier 1 technologies.

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

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

Further details of the MMV activities undertaken and observations made during 2018, can be found in the 2018 AER Annual Status Report [1].

Table 6-2: Overall assessment of trigger events used to assess loss of containment in 2018

Tier	Technology ^	Trigger	2018
Tier 1	IW DHP	Measuring greater than 26 Mpa	
	DMW DHP	Anomalous pressure increase above background levels	
	MSM	Sustained clustering of events with a spatial pattern indicative of fracturing upwards	
	DTS	Sustained temperature anomaly outside casing	
Tier 1 - when available	Pulsed Neutron log	Indication of CO_2 out of zone	
	SCVF	Change in geochemical composition indicating presence of project CO_2	
	VSP2D	Identification of a coherent and continuous amplitude anomaly above the storage complex	
	SEIS3D	Identification of a coherent and continuous amplitude anomaly above the storage complex	not applicable yet
	SEIS2D	Identification of a coherent and continuous amplitude anomaly above the storage complex	baseline survey executed in Q1/2017

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

Legend	
	no trigger event
	trigger event
	not evaluated

6.3 Wells Activities

6.3.1 Injection Wells

In 2018 the injection wells (8-19, 7-11 and 5-35) underwent routine work including a WIT (wellhead integrity testing - wellhead maintenance and pressure testing) and a packer isolation test. A downhole video log was performed in April 2018 on 7-11 to observe the status of the perforations. Some partial plugging was observed and the well continues to display good injection performance.

In February 2017, a request was made for a non-routine suspension approval for the IW 5-35 as per AER Directive 013: Suspension Requirements for Wells. In March 2017, temporary approval was obtained to suspend the well in the current configuration, conditional to the well not being used for CO_2 injection. In October 2018, CO_2 injection was initiated on the IW 5-35 well. Therefore, the nonroutine suspension approval for the IW 5-35 well is no longer in effect.

Figure 6-3, Figure 6-4 and Figure 6-5 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.

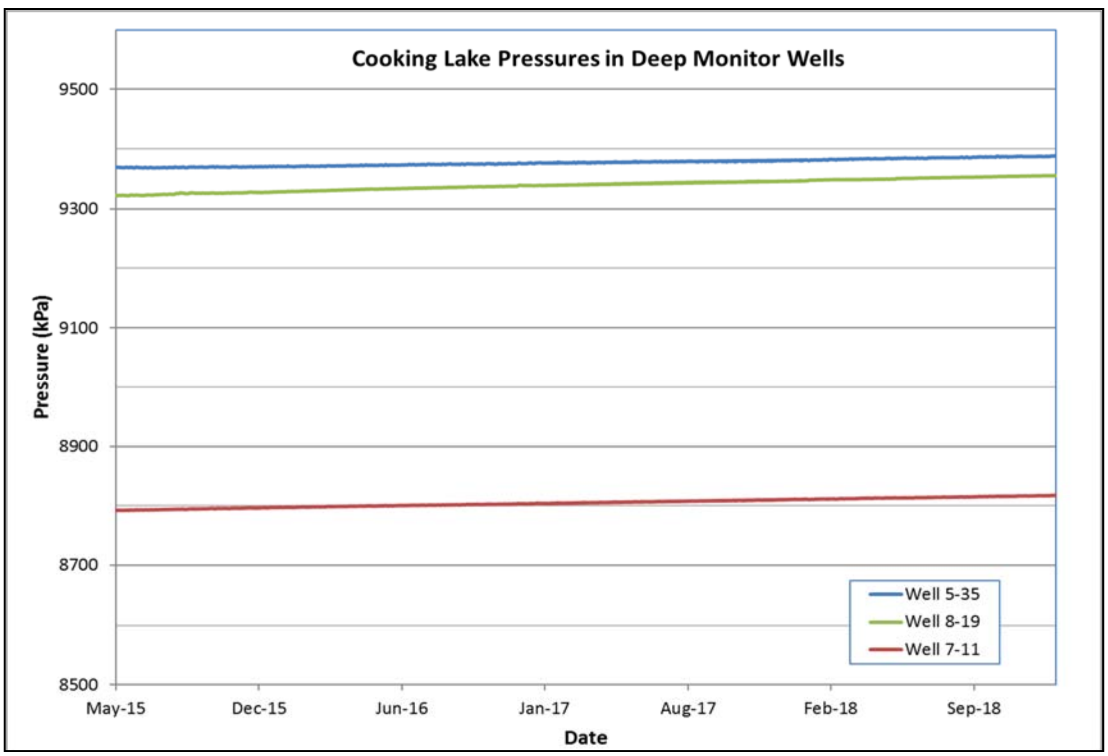


Figure 6-6: Quest DMW pressure history before and during injection.

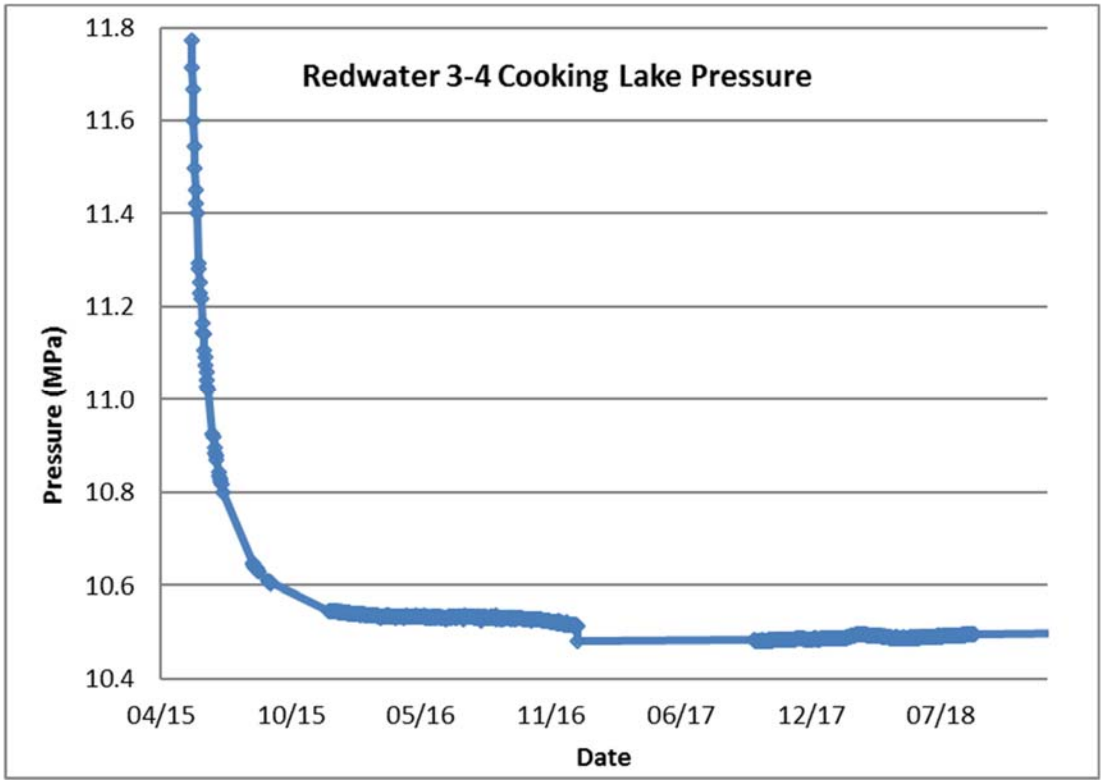


Figure 6-7: Quest 3-4 DMW pressure history.

6.3.3 Surface Casing Vent Flow and Gas Migration Monitoring

As required, annual testing was completed in 2018 for surface casing vent flow (SCVF) and gas migration (GM) at the injection pads. Reports were sent to the AER in July 2018.

The SCVF flow test results for both IW 5-35 and IW 7-11 are summarized in Figure 2 1. Measurements at the IW 5-35 well are at similar levels to those observed historically. The IW 7-11 SCVF buildup pressure decreased from 2017 levels and the overall level remains low. The SCVF measurements on IW 8-19 were at very low levels for a third consecutive year, indicating that the surface casing vent flow on this well has almost completely ceased.

Gas Migration testing, as per the suggested method in AER Directive 20, Appendix 2, was performed on both wells. Previously, the gas migrations observed on IW 5-35 and IW 7-11 occurred as bubbles in the well cellars.

Note that the gas migration measurements at 30 cm from the wellhead are inside the well cellar which is typically water filled. In 2018, the gas concentration measurements at 30 cm were whole air measurements collected via a methane meter suspended over the cellar. In 2017 the room gas concentration measurements at 30 cm were taken using an inverted funnel and hose for the first time. As such, the results obtained are not directly comparable to the historical measurements of whole air collected via methane meter suspended over cellar.

The 2017 method preferentially sampled lighter gases and resulted in LEL measurements in the 96-98% LEL range whereas sampling in 2018, 2016 and earlier, where whole air measurements were taken, resulted in measurements in the 4.6-65% LEL range.

The 2018 gas migration measurements taken from soil gas sampling holes did not detect any hydrocarbon LEL's. The gas migrations still have very limited impact and no potential for concern beyond the lease.

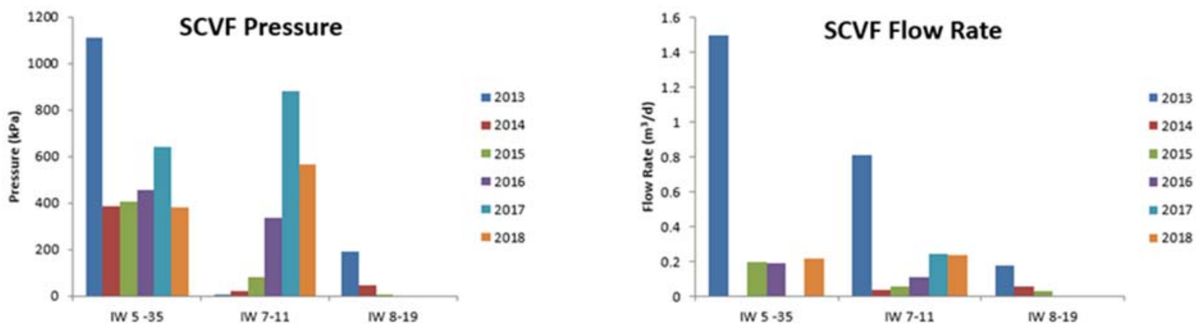


Figure 6-8: SCVF Pressure and Flow rate summary graphs for IW 5-35, IW 7-11 and IW 8-19.

7 Facility Operations - Maintenance and Repairs

Review and approvals of maintenance plans - including identification of key maintenance activities, were completed in early 2018. A simulator for HMU/Quest was implemented and is currently being used to increase operator competency in the unit to result in longer run time and reliability. Training plans and maintenance procedures for the maintenance personnel are complete and have included vendor training for key components (analysers, compressor). Wherever possible, Shell has leveraged existing processes, systems and procedures to facilitate a smooth transition of the Quest project into Scotford routine maintenance and operations.

Spare part requirements based on vendor-supplied information have been purchased, with successful delivery. Amine filter supplier changed due to availability and cost.

All essential maintenance processes are in place and received the appropriate internal approvals.

In April/May 2018, shut down/inspection and maintenance took place on Quest absorber and associated equipment, which was the first major inspection done since start up with no major findings. Regular maintenance plans implemented through SAP, based on RCM reports for the capture facility, pipeline and wells, have provided a steady and reliable operation.

Maintenance and repairs during 2018 are as follows:

- Amine absorber inspection and replacement of bottom raschig rings. Inspection of vessel complete and no additional repairs required.
- Overhead condenser shell leak (E-24601A) resulted in Quest shutdown to repair. (ordered new shell for E-24601B as inspection showed corrosion on the outlet nozzles)
- Amine charge pump logic MOC completed to increase reliability
- Amine charge pump P-24602A axial probe replacement. False indication which caused Quest trip
- Loose power supple feeding SIS lighting panel lead to C-24701 trip
- Replaced LBV6 hydraulic skid (stop pressure swings that lead to valve trips)
- Replaced all CO_2 line of site detectors with new Boreal line of site in C-24701 building and at E-24706/07 (service and reliability issues with old style)
- Temporary caustic skid pump and hording tarps replaced
- Replaced insulation soft covers with hard insulation in certain areas due to freezing of instrument.
- Logic changes on DCS surrounding amine filter swings and amine auto pump starts to avoid nuisance trips.
- Plan in place for MH-24602 leak repair
- TEG pumps required rebuilds after finding burnt oil in gearbox

2018 Maintenance

- Temporary caustic skid pump replacement (increase's PH on condensate going to wastewater from Quest reflux drum)
- P-24801A/B rebuilds
- E-24601A shell leak repaired
- V-24218 bottom packing rings replaced after vessel inspection
- FT-247004 MOC in place to limit amount of CO_2 captured to design limits
- C-24701 compressor building main HVAC sensor replacement (tripping unit)
- C-24701 natural gas unit heater fan blade and shroud replacement
- V-24604 amine internal filter rod replacement
- E-24707D fan replacement
- P-24602A pinhole weld repair on bypass
- R-24602 building HVAC motor replacement

2018 Pipeline Maintenance

- Wellsite flow controller's positioner's replacement due to high nitrogen usage at well site FV's
- Fuel cell replacement at LBV 3,4,5 ,6
- SCADA MOC to increase timer for "loss of communication alarms to DCS" (caused by chemicals cooling tower plume with line of sight to well site1)
- 5-35 well site put in service Oct 19
- LBV 6 hydraulic skid replacement
- Quest truck replacement and maintenance as required (not completed in 2018)
- Road and site ground maintenance as required
- Full ROW inspection, ground repair and vegetation control
- MMV building HVAC repairs
- Identification of wellsite #3 drainage issues and future repair plan (execution spring 2019)
- Camera set up at LBV1 for security surveillance
- High press Trip MOC complete (MOC 16460) on all 3 well sites
- Fluid Shots (CWI) at well site 7-11/8-19
- Filter Change at 7-11/8-19
- FV702104 removed for inspection, Clean

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

8 Regulatory Approvals

8.1 Regulatory Overview

Regulatory submissions in 2018 followed the schedule set forth by the Approval. Regulatory approvals in 2018 addressed the ongoing operations and optimization of safe operations.

8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2018.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to the Project for the 2018 reporting period.

Table 8-1:Regulatory Approval Status

Approval or Permit	Regulator	Status and Timing of Approval/Permit	Comments
CO_2 Injection and Storage			
AER Approval No.11837C:	AER	Submitted December 14th, 2017 Approved January 24, 2018	Request for extension, Logging Condition C.
AER Approval No.11837C:	AER	Submitted Janauary 15, 2018 Approved July 24, 2018 (with conditions)	Groundwater Sampling Plan for 2018 & 19 Update to 2017 MMV Plan
Quest Carbon Capture and Storage Project Sixth Annual Status Report	AER	Submitted March 31, 2018	Annual Report
Annual Submission for SCVF and GM testing.	AER	Submitted July 26, 2018	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.
Shell Canada limited Oil Sands Processing plant (Bitumen Upgrader) Environmental Protection and Enhancement Act Approval no. 49587-02-00, as amended	AER	Received a renewal approval application on October 30, 2018.	EPEA Approval 49587-02-00 renewed to Oct 31, 2028 Amendment to EPEA Approval 49587-02-01 issued Nov 5th, 2018.

8.4 Next Regulatory Steps

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

Expected submissions for 2019 include:

- The 2019 Annual Status Report to AER

9 Public Engagement

9.1 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 Community Relations

Community stakeholder engagement activities for Quest in 2018 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 offered to city and county authorities at their council sessions to provide the most recent project progress information. Specifically, updates were provided to the following municipalities who accepted our offer:

- March 13, 2018 – Strathcona County

Shell's updates to the above council was well received. No major issues were raised specific to the Quest facility and questions were answered immediately at the council sessions. We are scheduled to provide an update to the Thorhild County Council in early 2019.

Public Concerns

Shell has a comprehensive public concerns process that is designed to encourage community feedback. In 2018, Shell recorded eight concerns related to Quest operations. There were three concerns related to crop loss associated with the weed management program and ongoing recovery of the soil following pipeline construction. Three concerns arose during the quarterly water well tests, which were related to water well maintenance, not Shell's activity, and one was concerned about the potential for their water well to be impacted. A call was received about a site alarm which the operator had responded to resolve a minor maintenance job. A plan is in place to address water pooling on the 5-35 well pad, but construction won't start until spring of 2019. Hauling water off-site may still be needed in the spring if flooding in the region is significant again. Shell responded to the individuals who raised concerns and put in action plans to address them for the future.

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 of local community members including educators, business owners, emergency responders, and medical professionals as well as academics, Thorhild County and AER representation. The mandate of the panel is to provide input to the Quest Project on the design and implementation of the MMV Plan on behalf of the broader community and to help ensure that results from the program are communicated in a clear and transparent manner. In 2018, the Quest MMV CAP met on June 7 to review the latest MMV data.

Shell also provided a tour of the 8-19 well site for the members of the CAP to get a first-hand view of operations and the MMV systems in place.

Public Information Session

An Open House in the format of a 'Coffee on Shell', was held in Thorhild County at the Radway Public Library on October 3, 2018 from 9-11 am. As Quest has been operating for over 3 years, this event was an opportunity for community members to connect with Shell, meet the new Community Liaison representative, learn more about how Quest operations were going, and ask questions. The event was advertised in the local paper and invitations were sent to landowners along the pipeline right of way and well sites. Two members of the community and a local reporter attended and asked questions. On October 9, the local newspaper ran a front-page news story providing the update on Shell Quest operations to anyone who reads the Redwater Review in print or online.

9.3 9.3 CCS Knowledge Sharing

Global interest into our experience with the Quest facility continued in 2018.

As such, members of the Quest team attended or hosted numerous conferences, workshops and tours. The table below gives an overview of the 2018 activities:

Table 9-1: 2018 Knowledge Sharing

2018 Conferences/Workshops/Tours	Date	Location
GLOBE Forum	March 14-16	Vancouver
Government of Alberta Annual Report Presentation	March 23	Edmonton
AER Review – MMV and Closure Plans	May 1	Calgary
Geo Convention	May 7-11	Calgary
Norway Delegation Quest Tour	April 11	Scotford
CSLF Mid-Year Meeting	April 22-23	Grand Forks
CO_2 Geonet	April 24-26	Italy
CAP Meeting	June 7	Thorhild
CAP Wellsite Tour	June 7	8-19 well site
IEAGHG Monitoring Network	June 18-22	Grand Forks
US CCS Regulatory Framework	August 9-10	Houston/Dallas
US CCS Regulatory Framework	September 4-6	Washington, DC
China Delegation Quest Tour, with Alberta Government and Energy Company representatives	September 12	Scotford
Industry Tour (Wolf Midstream & Enhance Energy)	September 19	Scotford
US-Can-Mex Trilateral	September 20-21	Mexico
Norsk Industry Conference	September 24-28	Bodo, Norway
Quest Open House / Coffee on Shell	Oct 3	Radway
SEG Conference	October 15-17	San Francisco
GHGT Conference	October 21-26	Melbourne, Australia
CO_2 Storage Workshop	November 21-23	Virtual
SPE CCUS Forum	November 26-29	San Antonio
California CCS	December 4-5	San Francisco
MMV in Saline Aquifers (Wolf Midstream)	December 14	Calgary

10 Costs and Revenues

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

10.1 Capex Costs

Quest reached commercial operation in Q4 2015 and, while the asset switched to operation, some remaining closeout capital transactions continued to flow through. Table 10-1 reflects the project's incurred costs to the end of 2018. The categories follow those used by Shell over the life of the project to track project costs. Total capital costs comprise $790 million versus the original $874 million to reach commercial operation on October 1, 2015. *Sustaining capital required to operate the venture in fiscal 2017 has been shown in a separate column. No sustaining capital costs were incurred in 2018.

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

	FEED 2009 - 2011 Jan 1 , 2009 - Dec 31, 2011	FISCAL 2011 Jan 1 , 2012 - March 31, 2012	FISCAL 2012 April 1 , 2012 - March 31, 2013	FISCAL 2013 April 1 , 2013 - March 31, 2014	FISCAL 2014 April 1 , 2014 - March 31, 2015	FISCAL 2015/16 April 1 , 2015 - March 31, 2017	Total Capex to reach Commercial Operation	FISCAL 2017 April 1, 2017 - December 31, 2017 Sustaining Capital
Overall Venture Costs	19,470							
Shell Labour, & Commissioning	19,470	5,414	32,638	23,466	57,311	29,057	147,886	
Tie-in Work /Brownfield Work								
Tie-In/Turnaround Work Capture	0	0	7,331	10,234	10,430	7,938	35,934	
Tie-In Work Pipeline		0	196	518	334	161	1,209	
Sub Total	0	0	7,527	10,753	10,764	8,099	37,143	
Capture Facility*	52,671							
Engineering		6,662	40,889	32,799	5,180	1,378	86,907	
Construction Management		0	218	16,967	21,338	31	38,554	
Material		6,092	42,315	56,502	7,466	-5,080	107,295	
Site Labor		0	0	9,456	36,038	0	45,494	152
Subcontracts		0	0	1,380	7,799	-37	9,143	
Mod Yard Labor Including Pipe Fab		0	14,250	60,697	29,832	0	104,780	
Indirects / Freight		0	15	32,339	12,987	-28	45,314	
FGR Mods/HMU Revamps		0	0	0	0	0	0	
Sub Total	52,671	12,753	97,688	210,141	120,640	-3,736	437,486	152
SUBSURFACE - Wells*	63,175							
Injection Wells		1,090	17,970	3,641	167	1,833	24,700	
Monitor Wells		0	1,311	54	-20	571	1,916	
Water Wells		0	1,620	-53	1	0	1,569	
Other MMV		0	1,657	3,309	5,295	1,925	12,186	
Sub Total	63,175	1,090	22,558	6,951	5,443	4,329	40,370	
PIPELINES - TOE*	4,035							
Engineering		576	4,272	2,782	1,085	51	8,766	
Materials and Equipment		0	1,878	24,823	4,485	12	31,199	55
Services		0	0	60,101	27,366	11	87,477	
Sub Total	4,035	576	6,150	87,706	32,936	74	127,441	55
Total Contingency, Inflation & Mrkt Escalation	0	0	0	0	0	0	0	
Sub Total	0	0	0	0	0	0	0	
Grand Total	139,351	19,832	166,561	339,016	227,094	37,823	790,326	207

* Shell labour costs during FEED are booked here.

*Sustaining Capital in 2017 consists of equipment purchase for pipeline reliability monitoring. In 2017, site labor costs associated with capture facilities operations simulator capital investment was included in Sustaining Capital. In 2018, this has been reallocated to Direct Labour as part of operating costs to better support the interpretation of Sustaining Capital.

10.2 Opex Costs

Operating costs associated with the venture for the first three years of commercial operations are shown in the table below. The overall forecast for Opex in 2019 is $29 Million.

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

Cost Category	Oct 1, 2015 – Dec 31, 2016	2017 Jan 1 – Dec 31	2018 Jan 1 – Dec 31
Power	3,717.70	4,513.96	7,562.80
Steam	8,414.46	8,834.50	5,464.59
Compressed Air	67.67	62.59	50.19
Cooling Water	427.95	389.81	379.14
Direct Labour and Personnel Costs	7,829.42	5,787.86	7,383.90
Maintenance Materials and Technical Services	969.42	942.63	1,435.98
Property Tax	2,003.72	2,000.28	1,842.73
Sequestration Opex	7,052.85	6,797.59	0.00
MMV after Operations	1,690.41	1,655.74	625.64
Post Closure Stewardship Fund	272.07	264.28	243.33
Other Well Costs	431.49	442.12	102.74
Subsurface Tenure Costs	362.50	420.00	400.10
Pipeline - Inspection and Pigging	145.78	340.49	175.36
Amine	340.67	0.00	0.00
Chemicals	20.35	97.92	150.69
Vendor rebates	-122.32	-100.36	0.00
Corporate and Other Costs	119.24	205.95	133.08
Sustaining Capital	0.00	54.89	0.00
Total	**33,743.37**	**32,710.26**	**25,950.27**

Notes:

1. Sustaining Capital has been captured under Opex as per the Funding Agreement guidance. The adjustment to Sustaining Capital of $152,032 in this reporting period has been reclassed to Direct Labour as mentioned in the Capex section, resulting in an adjusted 2017 operating cost total.

2. Methodology for automatic fixed overhead unit allocations captured under Sequestration Opex has been reviewed in 2017. It is now distributed amongst other categories prospectively and will be the methodology followed going forward.
3. Minimal loss of amine was observed in 2018, hence no additional expenditure was required.

10.3 Revenues

Revenues reflect funding as well as CO_2 reduction Credits received up to December 31, 2018.

The CO_2 reduction Credits received during 2018 consist of 2,104,872 t CO_2 e Serialized Verified Emission Reductions for the period September 30, 2016 – September 30, 2017. Single and additional credits, valued at $30/tonne, have been issued and are included in the table below. As per the multi-credit agreement signed with the Province of Alberta, additional credits are expected one year after base credits are issued and reported in the period in which they are received.

Table 10-3:Project Revenues

	2009 – 2015 Construction	2016 Operation	2017 Operation	2018 Operation	Aggregate Revenues Forecast
	Jan 1, 2009 – Dec 31, 2015	Jan 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017	Jan 1, 2018 - Dec 31, 2018	Jan 1, 2019 – Dec 31, 2025
Revenues from CO2 Sold	$ -	$ -	$ -	$ -	
Transport Tariff	$ -	$ -	$ -	$ -	
Pipeline Tolls	$ -	$ -	$ -	$ -	
Revenues from incremental oil production due to CO2 injection	$ -	$ -	$ -	$ -	
Revenue for providing storage services	$ -	$ -	$ -	$ -	
Other incomes – Alberta innovates Grant, NRCan Funding & GoA Funding	$573,345,454.60	$29,451,643.52	$30,100,000.00	$30,796,465.56	$207,651,890.92
CO2 emission offset credits		$3,330,800.00	$36,368,160.00	$63,146,160.00	$465,600,000.00
	$573,345,454.60	$32,782,443.52	$66,468,160.00	$93,942,625.56	$673,251,890.92

Forecast Assumptions:

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

10.4 Funding Status

To date, the Project has received a total of $6.3 million from the Alberta Innovates program, which has concluded. Quest has met the criteria of allowable expenses for the $120 million NRCan funding from the Government of Canada, and 90% of the funding was paid in August 2012, with the remaining 10% holdback received after commercial operation. Funding from the Government of Alberta CCS Funding Agreement of $15 million was received in May 2012, $40 million in October 2012, $75 million in April 2013, $100 million in October 2013, $15 million in April 2014, $38 million in October 2014, $15 million in March 2015 and a further $149 million at Commercial operation in October 2015. Quest has now been in the operating funding phase for three years.

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

Table 10-4:Government Funding Granted and anticipated

Government funding granted through construction of the Quest project.

	2009	2010	2011	2012	2013	2014	2015	Operating 2016	Operating 2017	Operating 2018	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 - September 30, 2016	October 1, 2016 - September 30, 2017	October 1, 2017 - September 30, 2018	October 1, 2018 - March 31, 2026
Alberta Innovates Grant	$ 3,225,847	$ 1,817,101	$ 1,302,507								
NRCan Funding				$ 108,000,000			$ 12,000,000				
GoA Funding				$ 130,000,000	$ 115,000,000	$ 53,000,000	$ 149,000,000	$ 29,451,644	$ 30,100,000	$ 30,796,466	$ 207,651,891
Total Funding	$ 3,225,847	$ 1,817,101	$ 1,302,507	$ 238,000,000	$ 115,000,000	$ 53,000,000	$ 161,000,000	$ 29,451,644	$ 30,100,000	$ 30,796,466	$ 207,651,891
Cummulative Gov't Funding as Percentage of Total Project Spend	0.2%	0.4%	0.5%	17.8%	26.2%	30.1%	41.9%	44.0%	46.2%	48.5%	63.6%

11 Project Timeline

The timeline for major maintenance activities in the Quest operating period is shown in Table 11-1.

Table 11-1:Operating Timeline

Operation Timeline - December 31, 2018	2015		2016				2017				2018				2019			
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Capture Facitity																		
Compressor Inspection																		
E-24601 Repair																		
Pipeline and Wells Surface Facility																		
Pipeline Inspection																		
Storage and Subsurface																		
5-35 Commissioning																		

12 General Project Assessment

To date, the Quest project has demonstrated successful operations as an integrated CCS facility.

Project Successes in 2018:

Operational MMV Data Acquisition

In 2018 continued monitoring occurred including discrete groundwater well sampling and ongoing well-based monitoring. Routine logging and well integrity testing was also completed on the IWs.

In May 2018, Quest reached the milestone of 3 million tonnes of CO_2 injected.

Networking within Industry

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

Stakeholder Engagement

Stakeholder management continues to be a priority for Quest. In 2018, Shell continued the use of open houses/coffee sessions for community engagement. The community advisory panel continues to be a valuable tool to share information and collect feedback from the community and key stakeholders. Although we have built on the strength years of community engagement, we realize that we must continue this dialogue.

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

Provincial Government Milestones

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

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

Technical Successes

In 2018, 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 8,700 kg annually vs. the design makeup rate of 46,000 kg annually.

All three HMUs met their NOx level commitments without contravention in 2018 with continued capability to maintain NOx levels slightly elevated from pre-Quest baseline.

Injection into the 5-35 commenced in October 2018 to allow for operational flexibility when scheduling well workovers and interventions. Although a third well was not required to meet injectivity requirements, having 5-35 available as an observation well benefited reservoir understanding in the early injection years. It also resulted in significant savings in MMV costs over the first three years of the project.

Strong integrated project reliability performance with operational availability at 99.2%.

Annual CO_2 capture ratio was maintained in Quests 3rd full year of operations at 79.1%.

Injection certification, audits, offset verifications completed, with serialization of 2016 and 2017 credits, registered on the Alberta Emission Offset Registry.

Challenges in 2018:

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.

Regulatory Changes and Credit Serialization

With moving from the Specified Gas Emitters Regulation (SGER) to the Carbon Competitiveness Incentive Regulation (CCIR) introduced in 2018, as well as audit findings and approvals of waste heat methodology and calculations, the net CO2 for Quest has been impacted. Engagement with ACCO and AE CCS Unit is expected in 2019 for clarification on application of CCIR.

Technical Challenges

High corrosion rates caused by the low pH of Quest stripper reflux water remain a concern to the Scotford Upgrader Wastewater Treatment Plant. Sections of piping have been upgraded to 304 stainless steel (2016) with further mitigation enacted in 2017 by the installation of a temporary caustic injection skid at Quest to increase the pH of the Quest water. Replacement of the temporary caustic injection skid pump occurred in 2018 and projects progressed to permanently mitigate the low pH water.

Flame instability in the reforming furnace due to increased capture ratios, resulted in poor burner conditions in all the HMU's. Resulting temperature cycling phenomenon and restricted capture ratios occurred in HMU3 that are anticipated to continue until a burner change is performed in 2019.

Continued temperature drop in the rich amine inlet to the stripper.

12.1 Indirect Albertan and Canadian Economic Benefits

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

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

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

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

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

In addition to the above, discussions began in 2014 with the US DOE to utilize Quest as a project to develop and deploy additional MMV technologies to support either reduced technology cost or improved monitoring for containment security. During 2018 fibre-based CO_2 sensors were deployed in 8 of 9 of the Quest Groundwater wells, actively recording data. Partnerships such as this with the US DOE will assist in raising the profile of Quest and emphasize the Leadership demonstrated by Alberta and Canada in support of sustainable development of resources through innovation.

13 Next Steps

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

Quest will continue with the following activities to enable this:

- Capture of operational issues and lessons learned in order to retain institutional memory and facilitate improvements in processes and procedures.
- Enact permanent solution to mitigate the low PH water leaving the Quest.
- Ongoing MMV activities will be consistent with the approved 2017 MMV Plan update.
- Decision was made to acquire time-lapse seismic data in Q1/2019.
- Regulatory activities will focus on demonstrating compliance with existing agreements
- Public engagement activities will continue to ensure continued public knowledge and acceptance of Quest operations. The Community Advisory Panel will continue in 2019 to update the group on Quest activities with focus on sustaining reliable operations. Ongoing reporting will continue to the Province of Alberta in accordance with the respective funding agreements.
- Active knowledge sharing through publications and participation in conferences, workshops, and tours into 2019.
- Continue working with ACCO and Alberta Energy as to the interpretation and implications of the Carbon Competitiveness Incentive Regulation and long term viability of CCS within Alberta.
- With the improved operating performance and economic performance versus design, understand the revenue and cost forecast better to determine impacts to the Net Revenue statement.
- Working on energy saving opportunities, to reduce variable cost pressures of steam and electricity on Quest.

14 References

[1] AER, 2018, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, Seventh ANNUAL STATUS REPORT, will be available at: https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program&tags=Quest+Carbon+Capture+and+Storage+project