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Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT -

ALBERTA DEPARTMENT OF ENERGY: 2019

March 2020

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 2019, Quest surpassed 4 million tonnes of injected CO_2. It achieved the record of having stored underground the most CO_2 of any onshore CCS facility in the world with dedicated geological storage.

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.

A single leak from surface equipment was experienced in 2019 due to a seal flush tubing failure on the Quest Lean Amine pump (P-24602B). MMV data indicates that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir to date.

In 2019 Shell conducted another open house for the local community and held an engagement with local government officials to provide updates on operations. Knowledge from Shell's experience with Quest was shared with numerous industry, business, academic and non-government associations in 2019.

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

- Sustained, safe, and reliable operations
- Low levels of chemical loss from the ADIP-X process
- Dehydration unit performance continued to exceed expectations, with lower than expected water content, TEG carryover and unit losses of TEG
- Acquisition of the first monitor 2D VSP and 2D surface seismic at the 5-35 injection well
- Continued 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 99.6%
- 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
- Completion of a United States Department of Energy-funded demonstration project for fibre based CO_2 sensor technology
- Operating costs continue to be lower than forecasted
- Serialization of 1,787,416 credits in 2019 (including re-verification of previous periods)

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

- Reformer burner degradation continued in the HMU's as a result of flame instability at higher CO_2 capture rates, resulting in capture rate restrictions
- Seal flush tubing leak on Lean Amine charge pump P-24602B

Quest has seen strong reliability performance through the reporting period to safely inject over 1.12 Mt of CO_2 in 2019. Overall project injection has surpassed 4.8 Mt of CO_2 to December 31, 2019.

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 ~$25 million in 2019 in staffing, MMV, maintenance, and variable costs to the economy.

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

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Abbreviations

AEP	Alberta Environment and Parks
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

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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 to capture CO_2 then compressing and dehydrating the captured CO_2 to a dense-phase state for efficient pipeline transportation to the subsurface storage area. Design, construction and start-up of the Quest project occurred from 2009 to 2015. Further details on these phases can be found in previous annual reporting submissions on Alberta's Open Government Resources website.

The operations phase at Quest started in September 2015. Quest has successfully captured and injected over 4.8 Mt of CO_2 in three injection wells (8-19, 7-11 and 5-35) to the end of 2019.

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

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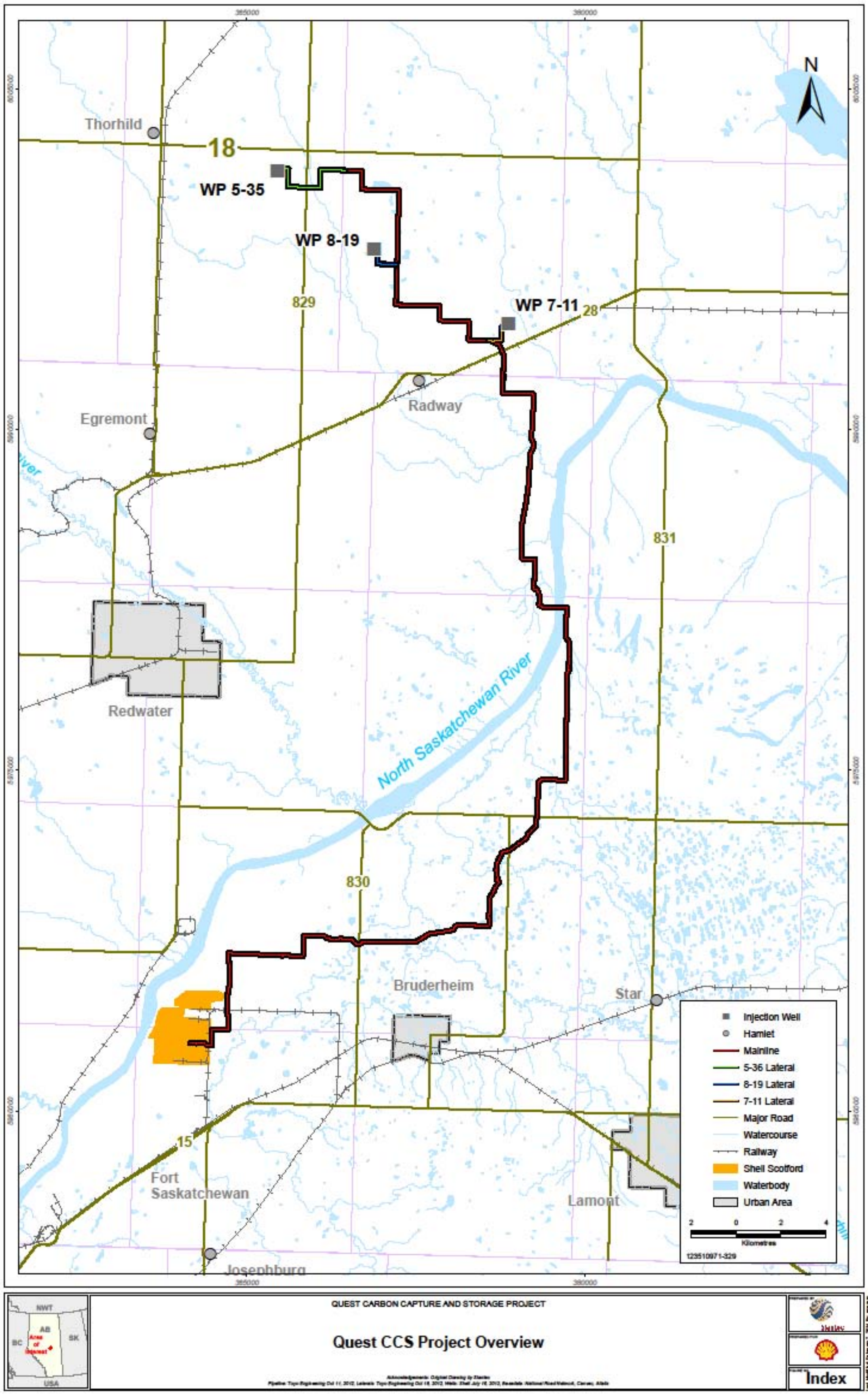

Figure 1-1: Project Facility Locations.

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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.

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4 Facility Operations – Capture Facilities

4.1 Operating Summary

The Quest CCS project focus for 2019 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 reporting period, Alberta Environment and Parks (AEP) assigned a third-party auditor which resulted in two material audit findings regarding Quest injection gas online analyzer and the waste heat methodology. The audit findings for the online CO_2 analyzer and the waste heat methodology have been resolved as of Dec 31, 2019 and are reported below.

Going forward, Shell will continue to work with AEP and Alberta Energy (CCS Unit) on implications of the new Technology Innovation and Emissions Reduction (TIER) Regulation that replaced the Carbon Competitiveness Incentive Regulation (CCIR) on January 1, 2020.

Table 4-1:Quest Operating Summary 2019

Quest Operating Summary	2015 Summary	2016 Summary	2017 Summary	2018 Summary	2019 Summary	Units
Total CO_2 Injected	0.371	1.11	1.138	1.066	1.128	Mt CO_2
CO_2 Capture Ratio[4]	77.4	83.0	82.6	79.1	78.8	%
CO_2 Emissions from Capture, Transport and Storage	0.080[3]	0.238[3]	0.241[3]	0.241[5]	0.237[5]	Mt CO_2
Net Amount (CO_2 Avoided)	0.291[3]	0.870[3]	0.897[3]	0.826[1,2,3]	0.891[1,2]	Mt CO_2
Waste Heat Credits	0.022[1]	0.062[1]	0.051[1]	0.044[1]	0.044[1]	Mt CO_2

1. Under SGER, waste heat credits were claimed from 2015-2017. As of Jan 1, 2018, under CCIR, waste heat was claimed under the Scotford Upgrader. Quest is an integrated operation within the Scotford Upgrader Complex, therefore, in 2018 and 2019 the Net CO_2 Avoided includes 0.044 Mt CO_2.
2. 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 set to 0% under CCIR.
3. 2015-2018 CO_2 emissions have been updated based on AEP's audit close out on waste heat methodology. The revised emissions now include the addition of 3rd party verified waste heat claims.
4. The CO_2 capture ratio refers to the percentage of CO_2 captured from the syngas (raw hydrogen) feed stream to the absorbers.
5. Indirect GHG emission from imported electricity now capturing electricity usage from both the Upgrader Cogen (0.37 tCO_2/MWh) and the grid (0.64 tCO_2/MWh).

The reported CO_2 emissions for 2015 to 2018 have been revised as a result of AEP's closeout of audit findings on allocation of integrated waste heat usage. Additional to this, calculation of CO_2 emissions for 2018 are also impacted by the CCIR, which became effective January 1st, 2018.

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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 was set to 0% under CCIR.

In the Quest Offset Project Plan (OPP) the electricity generation for Quest was anticipated to be grid electricity. In recent years, there has been an increase in electricity from the gas turbine in the Scotford Upgrader Cogeneration Plant (Upgrader cogen) to Quest. On June 19, 2019, AEP provided approval for a deviation request to use the CCIR electricity benchmark of 0.37 tCO_2/MWh for Quest electricity directly connected to the Upgrader cogen, while the grid factor for 2019 was 0.64 tCO_2/MWh. For the 2018 and 2019 numbers in Table 4-1, Quest is capturing imported electricity from both the Upgrader cogen and the grid.

The following is a timeline of significant operational milestones for the 2019 calendar year:

- April 12, 2019: Reached milestone of 4 million tonnes injected since project start up
- November 22, 2019: Reached milestone of 1 million tonnes injected in 2019

4.1.1 Quest Audits and Credit Serialization

The Quest CCS Offset project underwent various audits and verifications in 2019:

- Alberta Energy conducted the Year 4 Injection certification audit in September and October 2019 to confirm the injected CO_2 volume of 1,089,058 tonnes.
- Alberta Environment and Parks (AEP) issued letter on May 9, 2019 stating the completion of the re-verification for the 1st Reporting Period (August 23, 2015 to October 31, 2015).
- Shell hired a third-party verifier to verify:
  - 3rd, 4th and 5th Reporting Periods with a claim for waste heat
  - 6th, 7th and 8th Reporting Periods

For 2019, the Quest CCS project serialized a total of 1,787,416 credits on the Alberta Emission Offset Registry:

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Reporting Period		Base/Additional	Date Serialized	Serialized Emission Offsets
2nd (2015)	Nov 1 to Dec 31, 2015	Base (waste heat only)	25-Mar-2019	4,473
		Additional (waste heat only)	25-Mar-2019	4,473
2nd (2016)	Jan 1 to March 31, 2016	Base (waste heat only)	25-Mar-2019	8,830
		Additional (waste heat only)	25-Mar-2019	8,830
3rd (2016)	Apr 1 to Sept 30, 2016	Base (waste heat only)	7-Oct-2019	41,646
		Additional (waste heat only)	31-Oct-2019	41,646
4th (2016)	Oct 1, 2016 - Dec 31, 2016	Base (waste heat only)	13-Dec-2019	11,356
		Additional (waste heat only)	13-Dec-2019	11,356
4th (2017)	Jan 1 - Mar 31, 2017	Base (waste heat only)	13-Dec-2019	9,303
		Additional (waste heat only)	13-Dec-2019	9,303
5th (2017)	Apr 1 to Sept 30, 2017	Base (waste heat only)	24-Dec-2019	36,638
		Additional (waste heat only)	24-Dec-2019	36,638
7th (2018)	Jan 1, 2018 to June 30, 2018	Base	29-Oct-2019	351,496
		Additional	5-Nov-2019	351,496
8th (2018)	July 1, 2018 to Dec 31, 2018	Base	6-Nov-2019	429,966
		Additional	12-Nov-2019	429,966

4.2 Capture (Absorbers and Regeneration)

Solvent composition was mainly on target for 2019 operation vs. the specified formulation for ADIP-X from the design phase. 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, 79.1% in 2018, and 78.8% in 2019.

The main contributors to periods of reduced CO_2 capture in 2019 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:
    - February 11, 2019: Reduced capture due to HMU1 amine absorber level SIS transmitter (LT-241154) dropped out, resulting in the closure of XV-241020.
    - March 1, 2019: HMU2 LT-242155B was frozen and caused HMU2 absorber to trip. ESD for 8-19 was initiated to control the valve position due to a deficiency with the input value and actual valve position.
    - April 9, 2019: Reduced capture rate due to Quest compressor trip as a result of a failed analog card.
    - May 19, 2019: Reduced capture rates due to LP steam inlet valve (FV-246006) positioner failed. This caused the valve to close and loss of steam on E-24603B.
    - July 8-9, 2019: Quest compressor (C-24701) tripped due to 138kV transmission line trip.

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- July 24, 2019: The lean amine charge pump, P-24602B was shut down due to seal flush tubing leak while P-24602A was isolated for motor bearing repair.
- September 12-13, 2019: Reduced capture due to IW 8-19 shut-in for well integrity test. High pipeline and TEG pressure was observed during this period, capture reduced on HMU1&2.
- October 3, 2019: Reduced capture rate due to IW 5-35 shut-in on lower master valve inspection with ice ball observed on the lower master valve.

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: Energy and Utilities Consumption (Capture, Dehydration)

Energy and Utilities	2015 Usage	2016 Usage	2017 Usage	2018 Usage	2019 Usage	Units
Electricity (Capture/Dehydration)	12300	32800	32600	32200	32700	MWh_e[2]
Low Pressure Steam	410	1263	1297	1204	1217	kT
Low Temperature High Pressure Steam	1.96	5.52	5.23	5.01	5.12	kT
Nitrogen	178	230	237	258	256	ksm[3]
Wastewater	24900	80900	61900	57800	60700	m^3
Energy/Heat Recovered	33600	96260	98554	95060	93955	MWh_{th}[3]
CO_2 Emissions for the Capture Process	0.030[1]	0.083[1]	0.095[1]	0.195[4]	0.183[4]	Mt CO_2

1. 2015-2018 CO_2 emissions have been updated based on AEP's audit close out on waste heat methodology. The revised emissions now include the addition of 3rd party verified waste heat claims.
2. The e subscript denotes electrical energy.
3. The th subscript denotes thermal energy.
4. 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 set to 0% under CCIR.

Electricity, and steam use are 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. In 2019, 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.

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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 third-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 3°C for a total of 5°C since start-up. These heat exchangers are planned to be cleaned during the next turnaround.

Low levels of chemical loss from the ADIP-X process is a continued success for the Quest capture operations. Amine losses from the capture unit have been minimal since the initial commissioning/inventory and start-up phases. Certain amine contents started to drop below the designed composition at the end of 2017 and continued into 2019. Amine was introduced from the amine storage tank to the amine stripper in November 2019 to increase the amine contents.

In 2019, a management of change process was initiated to increase the name plate capacity of Quest from 3564tpd to 3836tpd. This was achieved by increasing the amine flow rates on HMU1&2 absorbers. Based on the test run results, the unit was re-rated to 3750 tpd, limited by the thermal well vibration constraint on the reboiler and the flame impingement issue on the reformer tubes.

CO_2 emissions for the capture process are primarily those linked to low-pressure steam use in the CO_2 stripper reboilers (~84% of total capture emissions), and from electricity for equipment in the capture system (~5% of capture emissions).

The most significant operational issue observed since start up has been foaming of the ADIP-X solution in the HMU absorbers. This leads 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. The carbon filter was placed into service mid-November 2017 with the new carbon load. Another operational issue, noticed after placing the carbon 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

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caused the P-24602 amine charge pumps to trip on low suction pressure. The carbon bed was taken offline again in February 2018 after the foaming incident on HMU3. The carbon filter remained offline in 2019. Since the carbon bed has been offline, steady operation has been observed in the absorbers, and no foaming events have occurred.

In March 2018, low pH carbonic acid water was observed leaking 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. Work was completed to plug the reinforcing pad which required Quest to shut down in order to isolate the exchanger for repair. Based on these findings, the same failure is expected in E-24601B. A new shell was ordered and is in the schedule to be installed.

In June 2019, housing retrofit was done on the pre-filters to solve the repetitive gulling issue during filter installation and filter elements manufacture was changed due to lead-time issues. 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.

4.3 Compression

In 2019, the compressor operated at lower discharge pressures than previous years. This is due less rate testing on 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	Average 2019 Operation	Units
Suction Pressure	0.03	0.03	0.03	0.03	0.03	MPag
Discharge Pressure	9.6	10.0	10.1	10.5	9.8	MPag
Motor Electricity Demand	13.3	13.8	14.2	14.0	14.2	MW_e

4.4 Dehydration

The dehydration unit performance continued to exceed expectations in 2019. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv.

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Actual water content for 2019 was on average 42 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 2019 being <10ppmw of the total CO_2 injection stream, compared to the 27 ppmw expected in design. Dehydration unit losses of TEG were roughly 11,100kg annually for 2019 vs. the design makeup rate of 46,000 kg annually.

4.5 Upgrader Hydrogen Manufacturing Units

The implementation of flue gas recirculation (FGR) technology, in combination with the installation of low-NOx burners, has allowed all three HMUs to meet their NOx level commitments without contravention in 2019 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 2019, the averaged NOx emissions with Quest operational and the FGR online are included below:

- HMU1: 37.7 kg/h, limit 76.5 kg/h
- HMU2: 30.7 kg/h, limit 76.5 kg/h
- HMU3: 60.6 kg/h, limit 130 kg/h

When the FGR fan trips, NOx levels are below the new limits listed above; however, they 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. The burners were replaced in 2019 Spring turnaround on HMU3; however, the burners were replaced in kind. The flame instability issue will remain until a new type of burner is installed.

Since commissioning in 2015, hydrogen production losses due to hydrogen entrainment in the amine absorbers has 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 2019 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 one leak in 2019.

In July 2019, the seal flush tubing on Quest lean amine pump (P-24602B) failed resulting in a leak of lean amine. The ½ inch compression fitting/piping failed at the fitting connection on the tubing. A thicker tubing was replaced on P-24602A/B/C as the same failure is expected on all three pumps. The leak was mostly contained in the berm.

4.7 Operations Workforce

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

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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. Staff support (engineering, specialists, administration, and management) has been rolled into the existing team supporting the hydrogen manufacturing units.

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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	2019	
General								
Pipeline Inlet Pressure	Normal	MPag	9.4	9.8	9.9	10.3	9.6	10
	Maximum Operating	MPag	12	12	13.58	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	8.8	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	0.6	0.4 (for 3 well scenario)
Temperature	Compressor Discharge	°C	130	130	128	131	131	130
	Pipeline Inlet after cooler	°C	43	43	41	41	41	43
	Upset Condition at Inlet	°C	-	-	-	-	-	60
	Injection Well 7-11 Inlet Temperature	°C	15	16	14	13	15	
	Injection Well 8-19 Inlet Temperature	°C	12	12	11	9	12	
	Injection Well 5-35 Inlet Temperature (as of Oct 19, 2018)	°C	-	-	-	6	7	
Flow rates	Normal Transport Rate	Mt/a	1.04	1.11	1.14	1.06	1.14	1.2
	Design minimum	Mt/a	-	-	-	-	-	0.36
	Total Transported	Mt	0.371	1.11	1.14	1.06	1.14	-
Energy and Emissions	Total Electricity for Transport (compression)	MWh_e	41,527	119,426	121,593	119,396	143,453	-
	Total Transport Emissions (includes compression)	Mt CO_2eq	0.027	0.077	0.078	0.045[1]	0.054[1]	-

1. Indirect GHG emission from imported electricity now capturing electricity usage from both the Upgrader Cogen (0.37 tCO_2/MWh) and the grid (0.64 tCO_2/MWh).

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The pipeline operates with CO_2 in supercritical phase at the pipeline inlet (9.9 MPag, 41°C) and with CO_2 leaving the main pipeline to the wellsites in liquid phase (9.3 MPag, 14°C). These two phases are commonly lumped together as “dense phase” in industry. The phase transition from supercritical to liquid occurs roughly 15-30 km downstream from the pipeline inlet, based on a field temperature survey completed in 2015. Heat transfer with the soil, as was expected in the design phase, causes the majority of the temperature reduction in the pipeline.

CO_2 emissions from the transport component of the operation are 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 most of the operating period. On average, entrained components such as H_2 and CH_4 are lower than design. The average operating conditions to design values are available in Table 5-2.

Table 5-2: Pipeline Fluid Composition

Component	Actual Operating 2015 (vol%)	Actual Operating 2016 (vol%)	Actual Operating 2017 (vol%)	Actual Operating 2018 (vol%)	Actual Operating 2019 (vol%)	Design Normal Composition	Design Upset Composition
CO_2	99.45	99.38	99.46	99.44	99.44	99.23	95.00
H_2	0.48	0.51	0.47	0.46	0.48	0.65	4.27
CH_4	0.06	0.06	0.06	0.06	0.05	0.09	0.57
CO	0.02	0.02	0.01	0.01	0.01	0.02	0.15
N_2	0	0	0	0	0	0	0.01
Total	**100**	**100**	**100**	**100**	**100**	**100**	**100**

Water Content and CO_2 Phase Change Management

Pipeline operation since start-up was below the winter water specification of 4 lb / MMscf (84 ppmv). The average for 2019 was 42 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.

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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 line break valves (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 are done quarterly as per an agreement with the AER. In August 2018, the frequency of flyover inspections was reduced from bi-weekly to quarterly. This was done to reduce the safety exposure during the aerial flights as well as program cost as previous flights had not yielded any significant findings. The Q3 2019 aerial inspection was missed due to a vendor timing and contracts and procurement conflict. The Q4 2019 flyover was completed by Canadian Helicopters Limited with no noteworthy findings. Moving forward, Shell has contracts in place with Ventus Geospatial Canada to utilize an unmanned aerial vehicle (UAV) for inspections. This will allow for inspections to be completed with less health and safety risks to personnel (no pilot required) and overall cost reduction.

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6 Facility Operations - Storage and Monitoring

This section provides an overview of the wells and MMV activities for the operational year 2019.

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, 2019, about 4.8 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.

By the end of December 2019, about 2.15 Mt of C02 had been injected into the 7-11 well, 2.23 Mt of $C0_2$ into the 8-19 well, and 0.43 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.

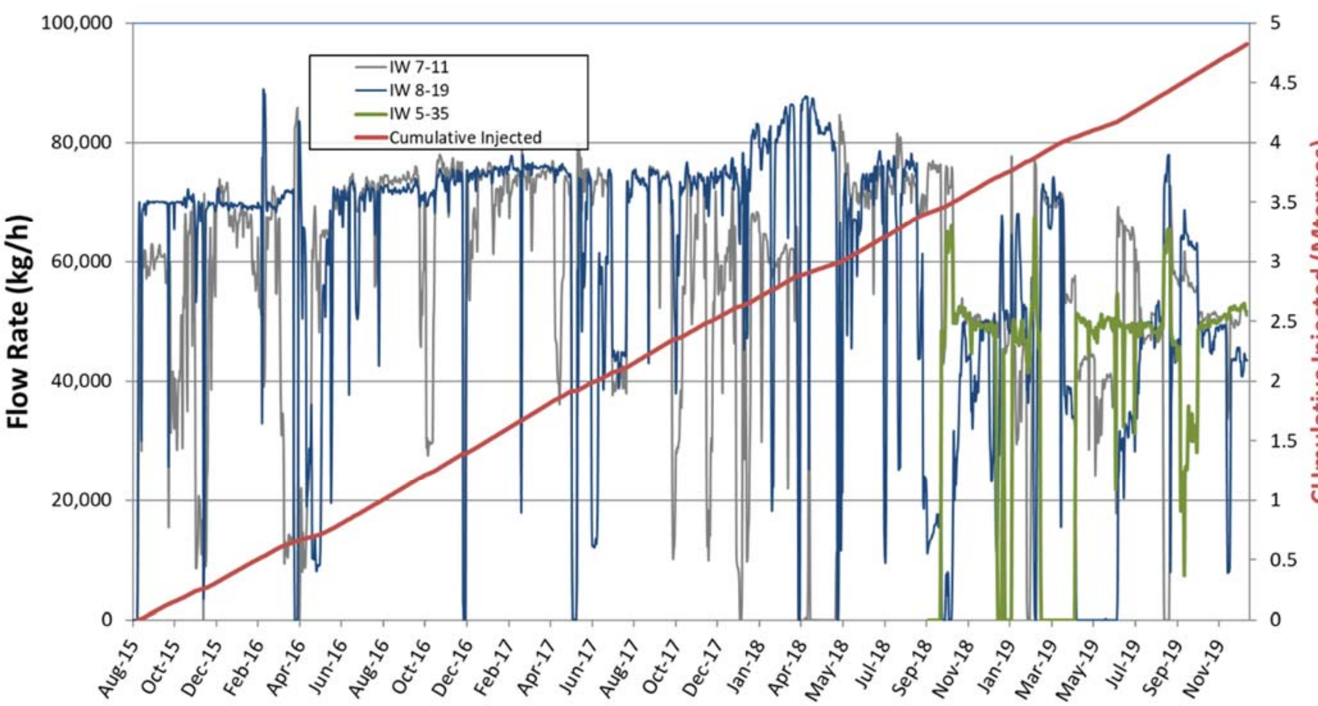

Figure 6-1: Quest Injection Totals: Cumulative CO_2 injected into the wells from start-up through to the end of 2019 (red). The blue, grey and green lines show the average hourly flow rates into each of the injection wells.

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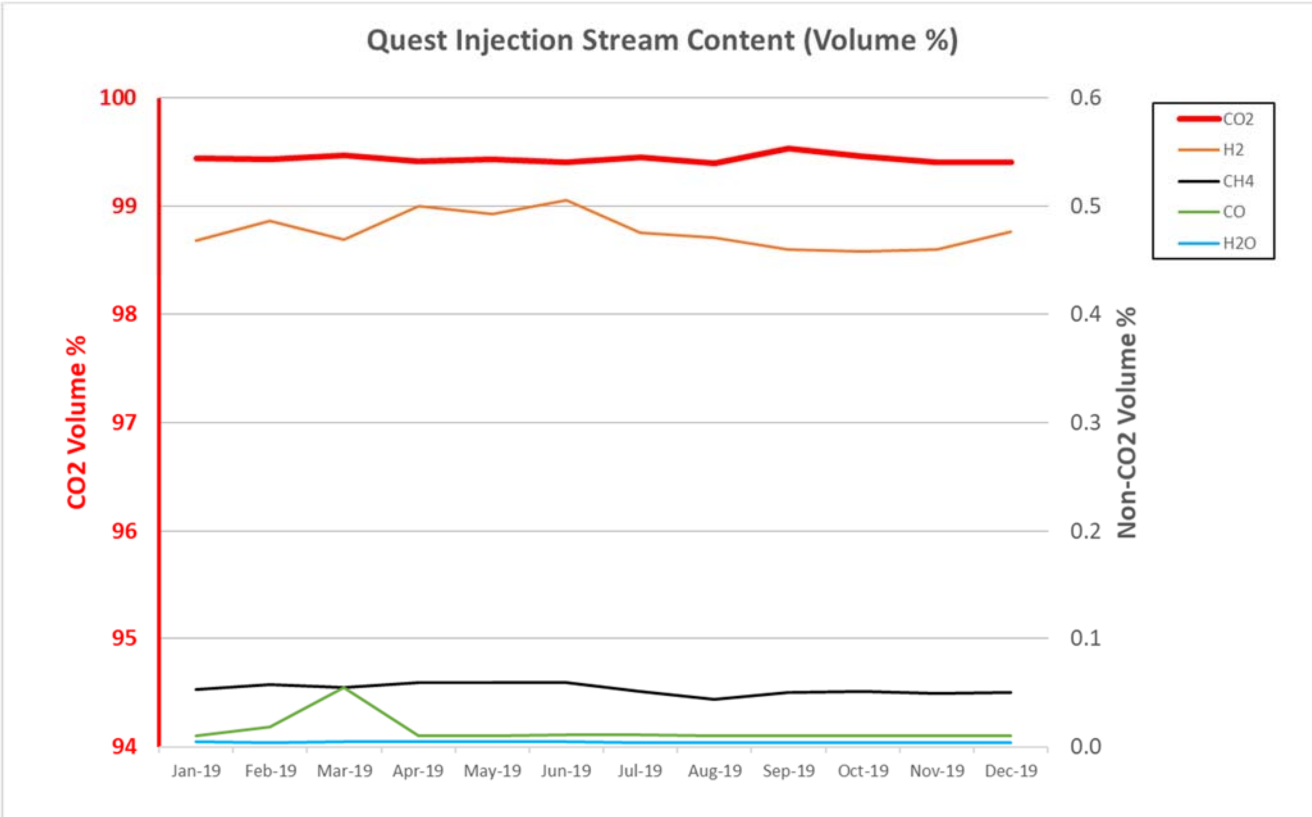

Figure 6-2: Quest Injection Stream Content: Average injection composition for 2019.

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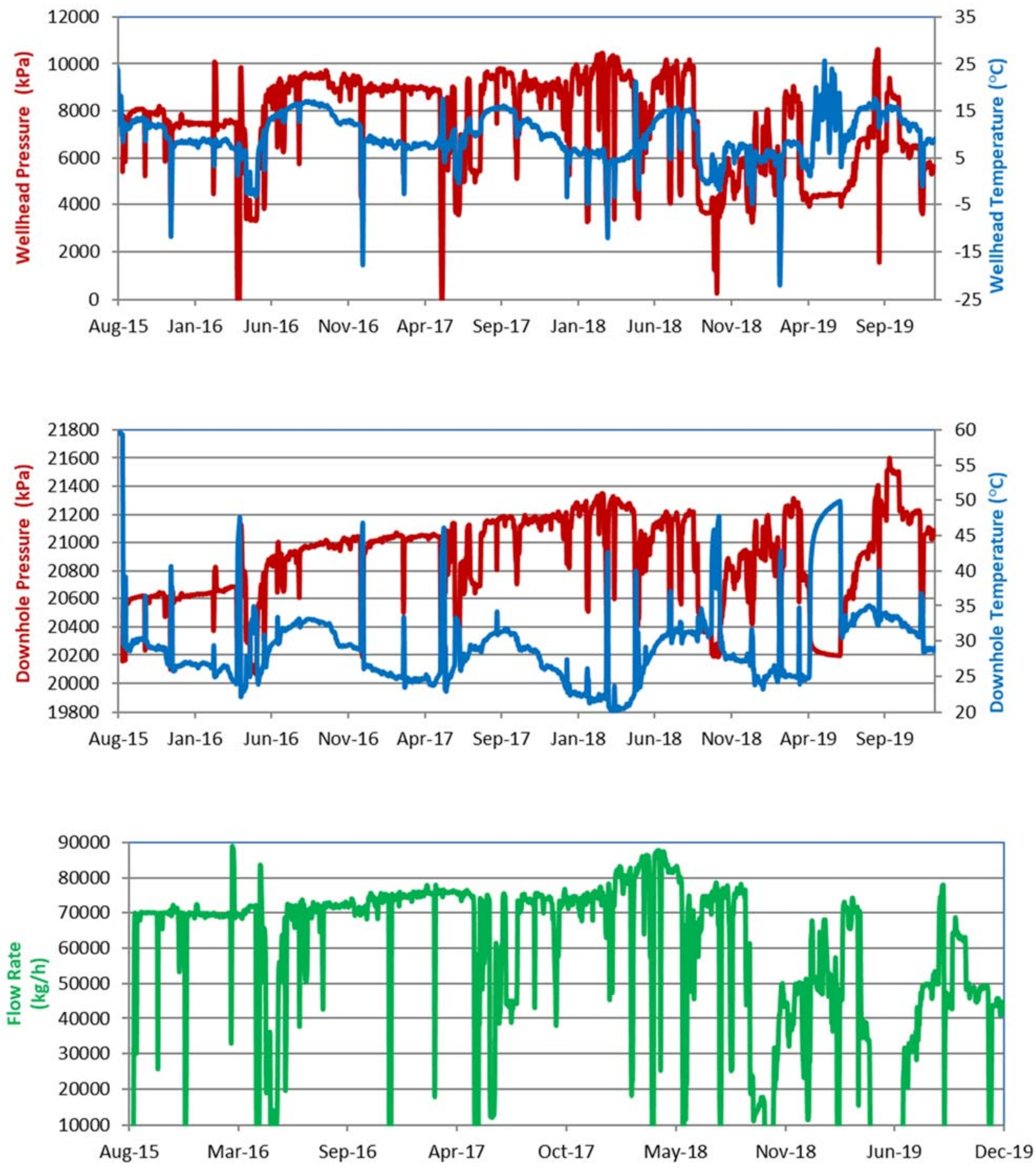

Figure 6-3: The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection to the end of 2019.

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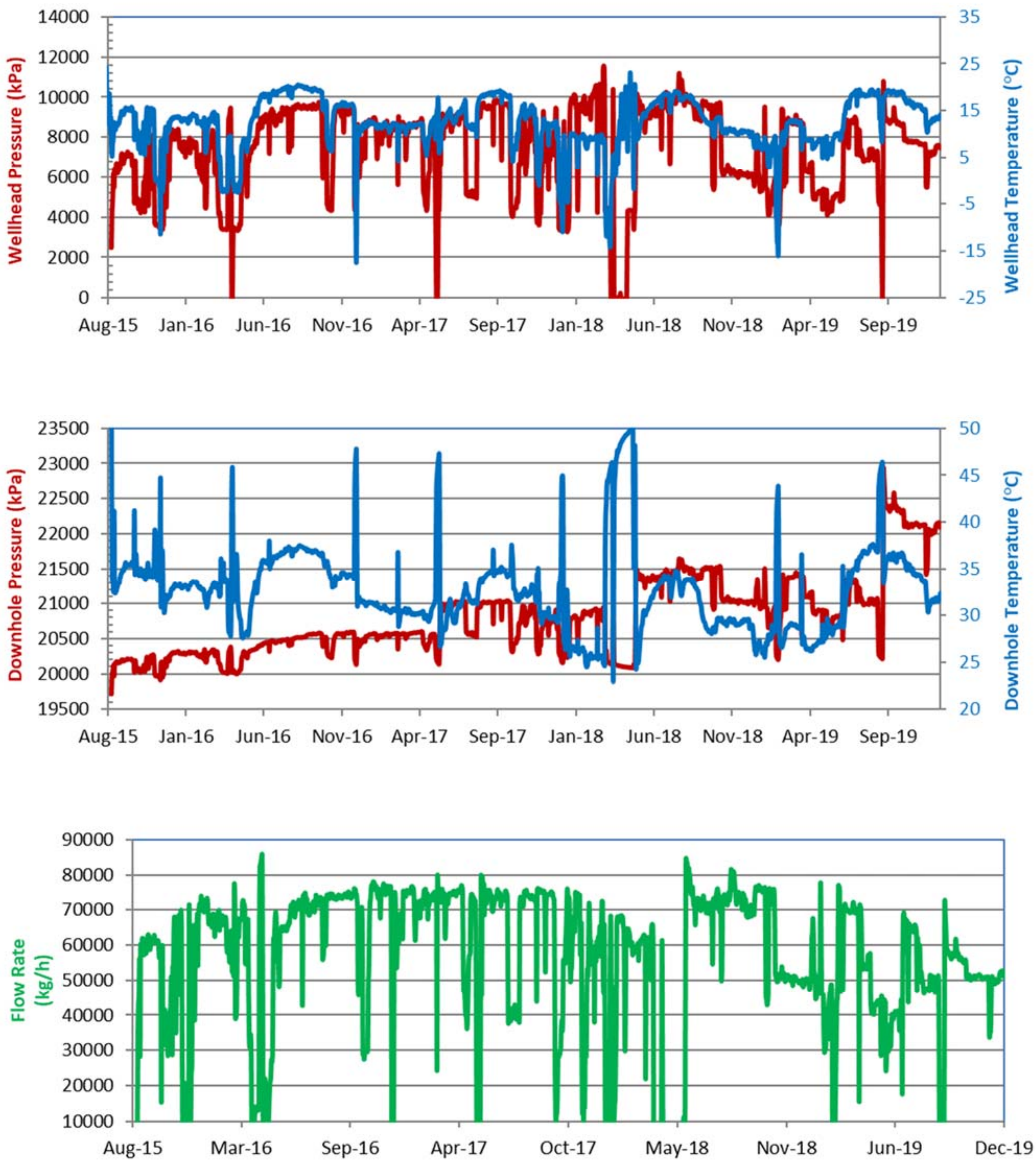

Figure 6-4: The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2019.

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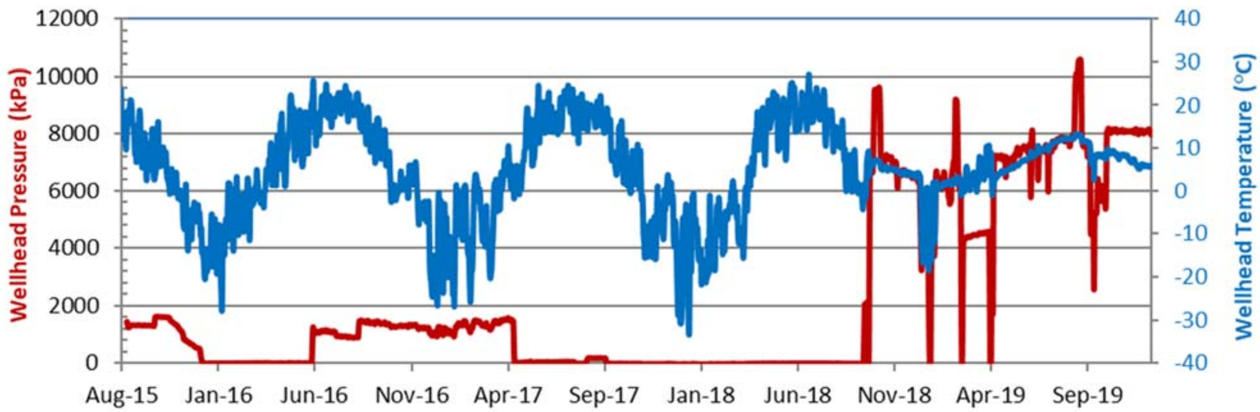

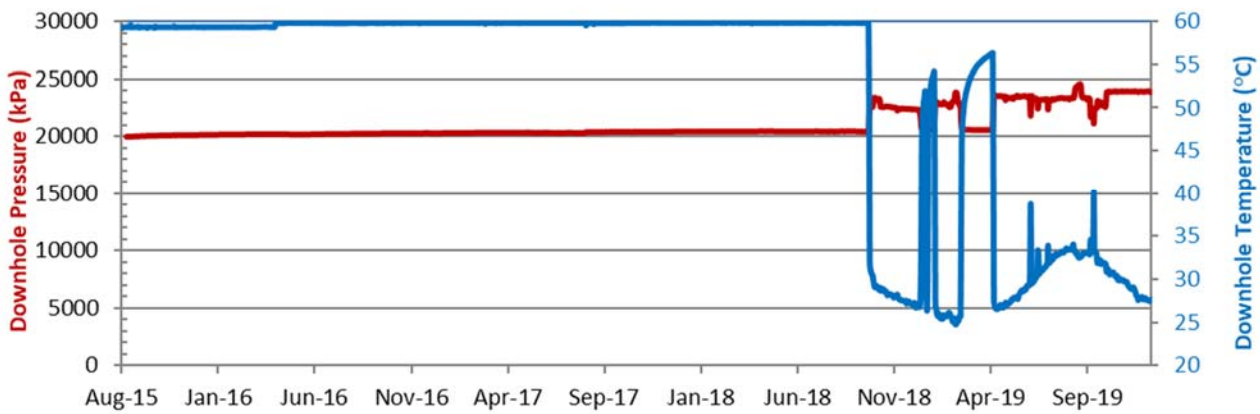

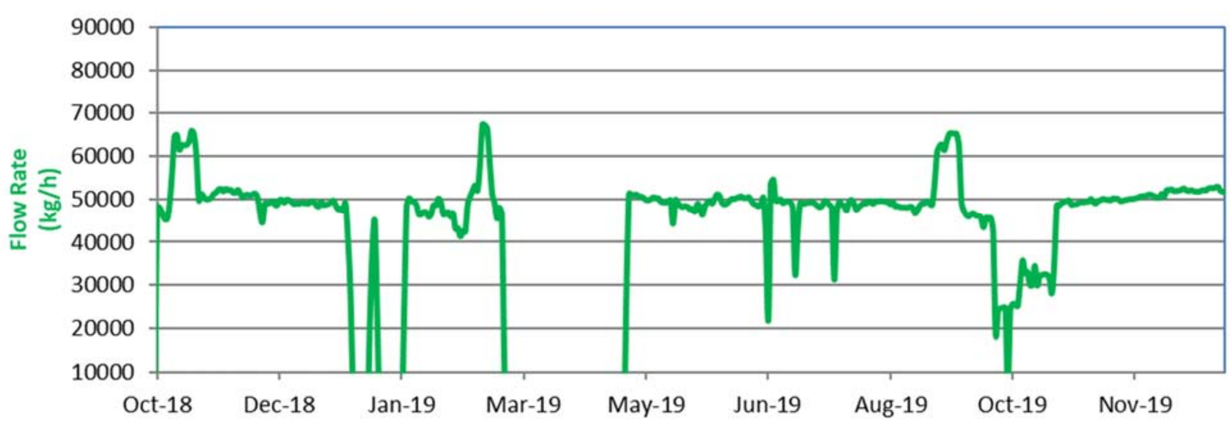

Figure 6-5: The 5-35 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2019.

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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 (2019) Section 3.5: Reservoir Capacity for discussion. The residual uncertainty in pore volume is unlikely to decrease much further since several years of performance data has now been collected and used to calibrate the reservoir model.

Table 6-1: Remaining capacity in the Sequestration Lease Area as of end 2019

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
2019	1.128 Mt	22.189 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. The 5-35 injection well was brought on in October 2018 for reasons of operational optionality.

Injection stream compositions and variations (Table 5-2) 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.

Injectivity reductions have been observed following short well shut in periods; however, as the initial injectivity was very high, these injectivity reductions currently do not form an operational constraint. At this time, the cause of the injectivity reductions is unknown and understanding how to reduce or even reverse these injectivity reductions may be important for maintaining reliable CO_2 injection at Quest and other CCS wells.

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 2019 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. Operator rounds daily at the injection well sites.

Hydrosphere Domain: Discrete sampling at select Landowner water wells before and after the 2019 VSP program in the vicinity of the 05-35 and 08-19 well sites.

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

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Geosphere Domain: Monthly satellite image collection for InSAR continued. Since September 2017, a single frame centered over the 3 injection well pads was used for image collection. 2D VSP and 2D SEIS data were acquired at IW5-25 and IW8-19 well in Q1 2019.

Well based Monitoring: ongoing data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes. Routine well maintenance and integrity activities (Section 2.4).

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 2019 that would indicate a loss of containment (Table 6-2). As a result, the focus of this report is on Tier 1 technologies.

With the data collected so far, 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 monitor VSPs is much smaller than the maximum plume lengths predicted from the Gen 4 model. 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 pre-injection modelling predicted.
- Assessment of the pressure data indicates that the reservoir has more than enough capacity for the full life of this project.
- In 2018 and 2019 a few time-significant pressure fall-offs were recorded and this enabled a calibration of conformance to shut-in stabilized pressures. The modelled borehole pressures show that the reservoir model pressure fall-off response is similar to those observed in the longer more stabilized pressure fall-offs. With this additional calibration it is reasonable to use the model for pressure prediction forecasting for injection rates similar to those observed to date.

Further details of the MMV activities undertaken and observations made during 2019 can be found in the 2019 AER Annual Status Report [1].

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Table 6-2: Overall assessment of trigger events used to assess loss of containment in 2019

Tier	Technology ^	Trigger	2019
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	Monitor survey executed in Q1/2019

^ 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 2019 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. Tubing integrity logging (caliper) and hydraulic isolation logging (PNx) was undertaken at 5-35.

Figure 6-3, Figure 6-4, and Figure 6-5 show the daily average flow rates and P/T conditions at the three injection wells 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 Figure 6-6 and Figure 6-7.

Project groundwater monitoring wells had maintenance checks performed on the downhole gauges and downloading pressure and basic water quality data. As per the MMV Tiering system, no discrete groundwater and gas sampling is planned to occur on the Project groundwater wells unless there is evidence of potential loss of CO_2 containment or as requested.

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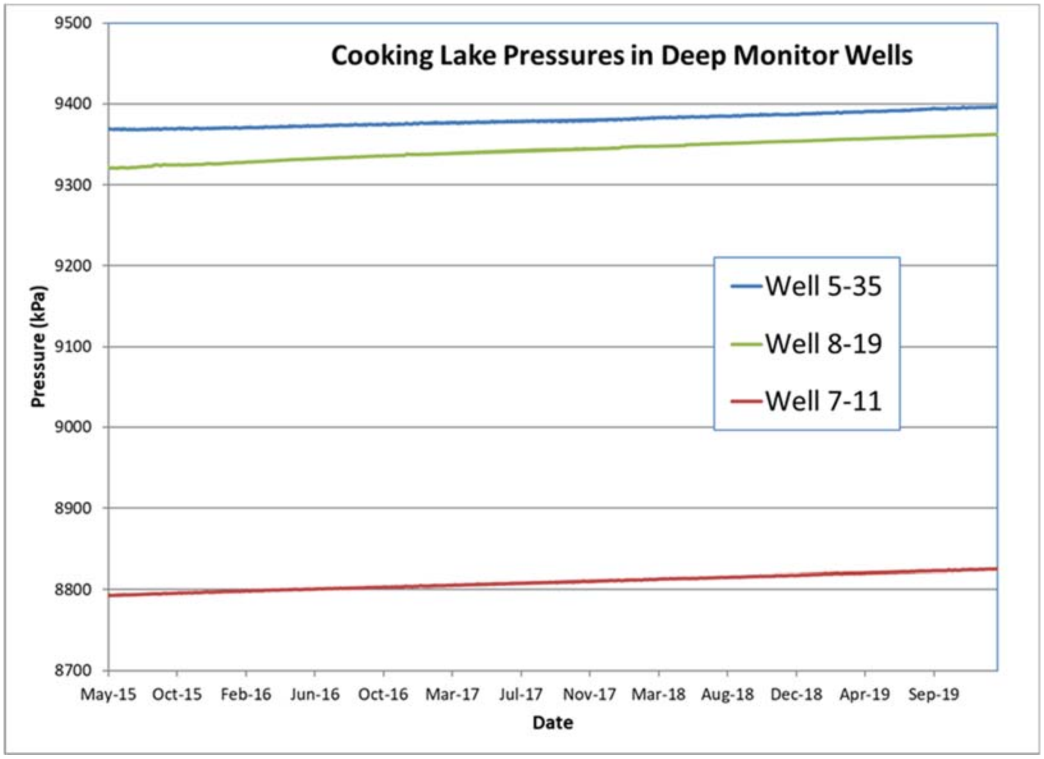

Figure 6-6: Quest DMW pressure history before and during injection.

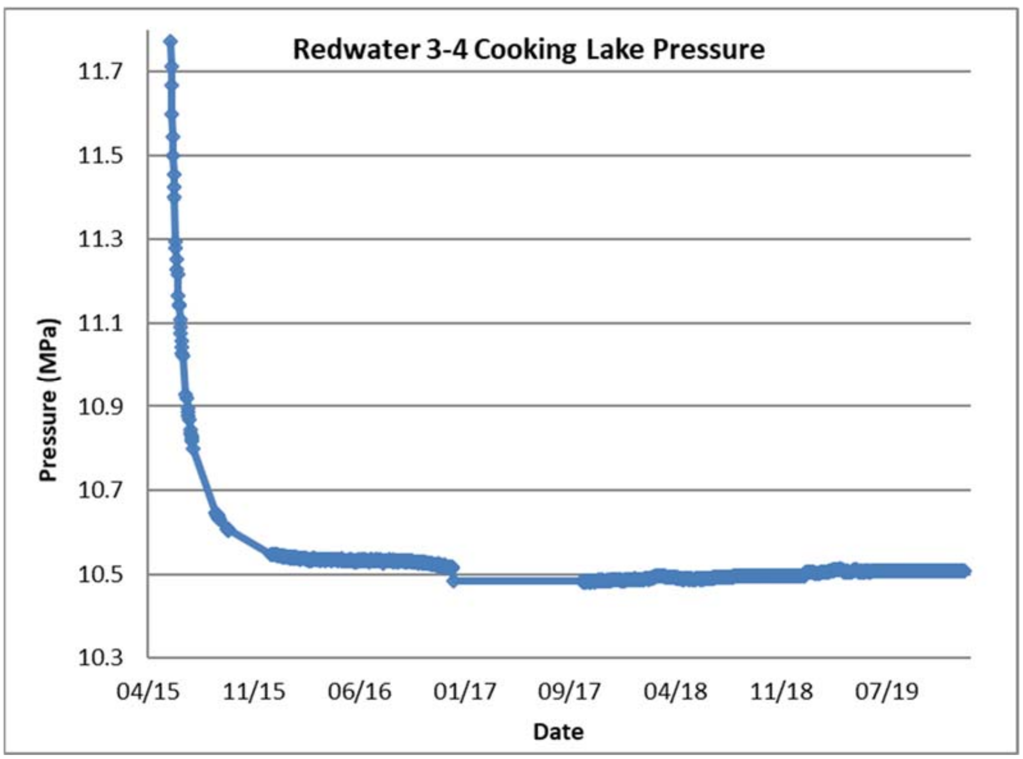

Figure 6-7: Quest 3-4 DMW pressure history.

6.3.3 Surface Casing Vent Flow and Gas Migration Monitoring

As required, annual testing was completed in 2019 for surface casing vent flow (SCVF) and gas migration (GM) at the injection pads. Reports were sent to the AER in July 2019.

The SCVF flow test results for IW 5-35 and IW 7-11 are summarized in Figure 6 8. Measurements at the IW 5-35 well are at similar levels to those observed historically. The IW 7-11 SCVF declined to zero in 2019. The IW 8-19 SCVF tested at zero for a fourth consecutive year.

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. The gas migration measurements at 30 cm from the wellhead are inside the well cellar which is typically water filled. In 2019 and 2018 the gas concentration measurements at 30 cm were whole air measurements collected via methane meter suspended over the well cellar. Consistent with 2018 results, the 2019 gas migration detections were limited to the well cellar. Measurements taken from soil gas sampling core holes did not detect any hydrocarbon lower explosive limits (LELs).

In April 2019 the IW 5-35 wellsite was flooded with freshwater (meltwater and rainwater) and bubbles were observed in two locations near the wellhead but outside the standard gas migration testing area. The locations were marked and in June 2019, gas migration testing was also performed on these two marked locations as a precaution. Each of the soil gas testing core holes were tested for LELs and CO_2. No LELs were detected at either of the test location core holes. A soil gas sample was acquired at both locations and submitted for analysis despite field observations. The gas isotopic analysis results indicate that the CO_2 present in the sample is atmospheric. No methane or other hydrocarbons were identified in the samples. Therefore, the observed bubbles at IW 5-35 are unlikely indicative of additional or further migrated gas.

Overall, while gas migration remains at IW 5-35 and IW 7-11; it remains consistent in composition and isotopic signature and has very limited impact and no potential for concern beyond the lease.

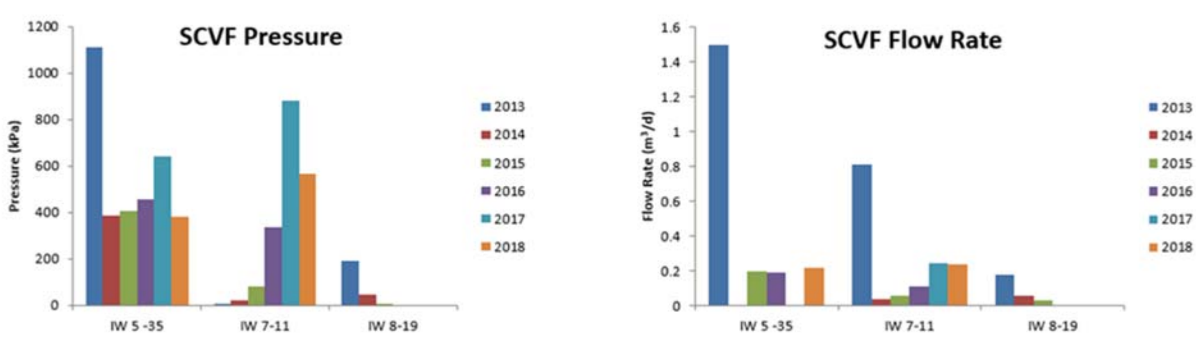

Figure 6-8: SCVF Pressure and Flow rate summary graphs for IW 5-35, IW 7-11 and IW 8-19.

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7 Facility Operations - Maintenance and Repairs

–A simulator for HMU/Quest is currently used and maintained to increase operator competency in the Quest unit. This should result in longer run time and reliability. Training plans and maintenance procedures for the maintenance personnel were completed and included vendor training for key components (analysers, compressor). Wherever possible, Shell has leveraged existing processes, systems and procedures to facilitate a smooth transition of Quest into Scotford routine maintenance and operations.

Spare part requirements based on reliability centred maintenance were purchased and delivered. The amine filter supplier was changed due to availability and cost.

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

Maintenance and repairs during 2019:

- Well site FV-702104/204 (limited rates Mar 4)/304 sticking in cold weather, positioner replacement.
- Amine charge pump logic MOC completed to make axial vibration trip 2 out of 2 to increase reliability.
- Amine charge pump P-24602A axial probe replacement. False indication which caused Quest trip and unplanned down time of Quest.
- P-24602A/B/C seal flush line replacement due to B failure (July 24/2020).
- V-24604/09 filter retrofit complete (New internal filter rod design to reduce maintenance and filter costs).
- C-24701 tripped as a result of exciter panel analog card failure; card was replaced and compressor restarted.
- Quest creep study and testing completed to safely increase CO_2 rates from 3550 tpd to 3750 tpd.
- The new Boreal line of site detection in C-24701 building, E-24706/07 and Quest well sites required servicing and calibration along with training for on site Shell instruments technicians.
- Started civil work for new permanent caustic facility in Quest, all concrete work completed (completion of piping and caustic building second quarter 2020).
- Loss of communication MOC completed to provide time delay for DCS alarms (cooling tower plume interfere with SCADA communication system).
- Replaced insulation soft covers with hard insulation in certain areas due to freezing of instruments.
- Valve bonnet failure requiring installation of quill and injection on V-24607 LP condensate valve
- HP condensate sample point tee pinhole leak downstream LV-248003 cut out and repaired.

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- Logic changes on DCS surrounding amine filter swings and amine auto pump starts to avoid nuisance trips.
- C-24701 trip due to factory voltage drop logic, MOC created to change to Shell settings and avoid power bump trips.
- C-24701 HVAC repairs due to in adequate heating in compressor building.

2019 Maintenance

- Permanent caustic skid civil work started 4th quarter 2019
- V-24607 LP condensate bonnet failure
- LV-248003 HP condensate sample tee replacement
- E-24601B new shell ordered and delivered
- P-24607 pump replacement and d/s check valve
- C-24701 analog card in exciter PLC failed
- C-24701 compressor building main HVAC sensor replacement
- P-24601B outboard bearing pump seal leak repaired
- V-24604/09 filter retrofit complete
- E-24707C fan replacement
- P-24602B seal flush line replacement (Tubing failed)
- P-24602B motor replacement
- P-24602A outboard motor seal replaced

2019 Pipeline Maintenance

- Wellsite flow controller positioner's replacement due to high nitrogen usage at well site FV's
- Changed out LBV1 EFOY unit in March/2019
- 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 (Hydraulic logging Jan 29/19)
- 5-35 lower master packing leak repaired
- Quest truck replacement and maintenance as required (Purchased Dec 2019)
- Quest well site office trailer purchase
- Road and site ground maintenance as required
- Full ROW inspection, ground repair and vegetation control
- MMV building HVAC repairs

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- Identification of wellsite #3 drainage issues and future repair plan (execution spring 2019)
- Security cameras set up at all LBV's and well sites
- Fluid Shots (CWI) at well site 7-11/8-19/5-35
- SCVF and Gas Migration testing complete at 7-11/8-19/5-35
- 5-35 wing valve leak repaired
- 5-35 flow cross top ring gasket replacement
- WIT Complete at 7-11/8-19/5-35 (Well integrity testing)

2019 Wellsite and MMV Maintenance

- Injection well fluid shots and top up of N_2 in the annulus at all 3 injection wells.
- Replaced the wellhead flow cross, top, and corresponding ring gaskets at IW 5-35
- Greasing and injection of stem packing into valve stems Lower Master Valve, Upper Master Valve and Flow Wing Valve on the IW 5-35 wellhead
- Replacement of one Paladin A/D converter at the DMW 8-19 junction box.
- Replacement of battery at DMW 3-4.
- Maintenance of groundwater well Troll gauges included in the installation of new sensors in the gauges for pH, ORP, EC and temperature.
- Well site IT servers were remediated.

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

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8 Regulatory Approvals

8.1 Regulatory Overview

Regulatory submissions in 2019 followed the schedule set forth by the approval. Regulatory approvals in 2019 addressed the ongoing operations and optimization of safe operations.

8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2019.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to Quest for the 2019 reporting period.

Table 8-1:Regulatory Approval Status

Approval or Permit	Regulator	Status and Timing of Approval/Permit	Comments
CO_2 Injection and Storage			
Quest Carbon Capture and Storage Project 2018 Annual Status Report	AER	Submitted March 31, 2019	Annual Report
Annual Submission for SCVF and GM testing.	AER	Submitted July 29th, 2019	Submission in accordance with conditional approval of September 4, 2013 regarding Shell's request to defer repair of SCVF and GM for IW 5-35 and IW 7-11.
Scotford Upgrader Raw Water License to Divert (Shell Canada Limited)	AER	Received approval renewal on February 7, 2019	Water Act Approval No. 70013-02-00

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 2020 include:

- 2020 MMV plan submission
- 2020 Closure plan submission
- 2019 Annual status report to AER
- 2019 Net revenue position of statement of project costs and projects revenues (as per additional credits agreement)

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9 Public Engagement

9.1 Stakeholder engagement for the Quest CCS Facility

Upon start-up of the Quest CCS facility, stakeholder engagement focused on multiple streams: community relations, sharing of CCS knowledge and CCS advocacy.

9.2 Community Relations

The following community stakeholder engagement activities tok place for Quest in:

1) Updates to municipal governments

2) Working to resolve public concerns

3) Participation in the Community Advisory Panel (CAP)

4) Emergency Response

Municipal Government Updates

Annual updates were offered to municipal governments at their council sessions to provide updates on Quest operations. Updates were provided to the following municipalities in 2019:

- February 12, 2019 – Thorhild County
- March 12, 2019 – Strathcona County

No major issues were raised specific to the Quest facility and questions were answered immediately at the council sessions.

Public Concerns

Shell has a comprehensive public concerns process that is designed to encourage community feedback. In 2019, Shell recorded eight concerns related to Quest operations. Three concerns were related to crop loss. These concerns were associated with the weed management program and ongoing recovery of the soil following pipeline construction. Engagement with landowners continues as Shell works with impacted stakeholders to find the most appropriate actions to address these impacts. Three concerns were related to the quarterly testing of water wells. These concerns were related to water well maintenance rather than the testing of the wells themselves (not related to Shell's activity). One concern was related to the potential for a landowner's water well to be impacted by Shell MMV activities. One concern was related to water pooling on the 5-35 well pad. While a project to deal with the water pooling issue was completed in the summer of 2019, heavy rainfall through the spring and summer made it was necessary to haul water off-site.

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, academics, emergency responders, the AER and public health professionals. 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 2019, the Quest CAP met on June 12 to review the latest MMV data. New

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representatives were in attendance from Thorhild County and the Alberta Energy Regulator (AER). The terms of reference was updated to reflect the current state now that Quest has been operational for a few years.

Emergency Response

Groundtruthing – an activity to update contact information and to communicate information about the project for residents within the emergency response zone – was conducted in 2019 for the bi-annual update of the emergency response plan. Stakeholders were invited to meet with Shell during the groundtruthing process.

9.3 CCS Knowledge Sharing

Global interest into our experience with the Quest facility continued in 2019.

As such, members of the Quest team attended or hosted numerous conferences, workshops and tours. Table 9-1 below gives an overview of the 2019 activities.

The following are a list of Quest CCS publications by Shell in 2019:

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Table 9-1: 2019 Knowledge Sharing

2019 Conferences/Workshops/Tours	Date	Location
Carbon Capture Coalition Workshop	January 22	Houston, TX
CSA Standard Working Group	February 6	Online
API CCS Working Group	February 11	USA
NAIT Carbon Productivity Workshop	February 24	Edmonton, AB
Int. CCS Knowledge Centre	March 6	Regina, SK
SINOPEC	March 7	Fort Saskatchewan, AB
API CCS Working Group	March 12	USA
U of A Economics and Environment class tour	March 22	Fort Saskatchewan, AB
API CCS Working Group	April 11	USA
NRCAN (Minister Sohi) Tour	April 24	Fort Saskatchewan, AB
GeoConvention	May 13-15	Calgary, AB
GRC 2019 - Carbon Capture, Utilization and Storage	May 5-10	Geneva, Switzerland
API CCS Working Group	May 23	USA
GoA Annual Report presentation	May 29	Edmonton, AB
CAP Meeting	June 12	Thorhild, AB
Equnior - Northern Lights CCS Workshop	June 17	Online
GOA Review - MMV and Closure Plans	June 18	Edmonton, AB
AIHA Tour (Conservative MPs)	July 19	Fort Saskatchewan, AB
IEAGHG Summer School	July 8	Regina, SK
Kuwait KOC/KNPC Tour	September 24	Fort Saskatchewan, AB
45Q and IRS meeting	September 25	Washington, DC
EU SECURe Delegation Tour	September 27	Fort Saskatchewan, AB
API CCS Working Group	December 13	USA

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The Quest team also publishes work to share findings and lessons learned from experience in operating the facility. The following are a list of Quest CCS publications by Shell in 2019:

- Duong, C., Bower, C., Hume, K., Rock, L., & Tessarolo, S. (2019). Quest carbon capture and storage offset project: Findings and learnings from 1st reporting period. International Journal of Greenhouse Gas Control, 89, 65-75. https://doi.org/10.1016/j.ijggc.2019.06.001.
- Tawiah, P. et al. (2019) 'CO_2 injectivity behaviour under non-isothermal conditions – Field observations and assessments from the Quest CCS operation', International Journal of Greenhouse Gas Control. https://doi.org/10.1016/j.ijggc.2019.102843.

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9.4 Quest Advocacy

Quest advocacy activities in 2019 were largely related to the milestone of capturing 4 million tonnes of CO_2. Among the key messages shared:

- Quest is exceeding expectations.
  - In less than four years, the Quest carbon capture and storage (CCS) facility has captured and safely stored four million tonnes of CO_2, ahead of schedule and at a lower cost than anticipated. Four million tonnes of CO_2 is equal to the annual emissions from about one million cars.
  - Quest is breaking records. Quest has now stored underground the most CO_2 of any onshore CCS facility in the world with dedicated geological storage.
- Costs of CCS are coming down
  - If Quest were to be built again today, it would cost 20-30% less to build and operate, thanks to a variety of factors including replication, capital efficiency improvements and a lower cost environment.
  - Shell is sharing knowledge and lessons learned about Quest, together with our government and joint venture partners, to help bring down future costs that will help CCS scale up globally.
  - Quest was made possible through funding for CCS from the governments of Alberta and Canada (C$745 million and C$120 million). It's through these funding arrangements that we are publicly sharing Quest's designs and lessons learned.
- Canada can be a leader in CCS and clean tech
- CCS is viable in the energy transition

A news release was distributed on May 23, with most coverage occurring that day. The communications campaign around the 4 million tonne milestone was successful in generating earned media coverage in key markets across Canada. A paid social media campaign followed the announcement. Overall, social media reaction to the coverage and paid campaign was net positive in nature.

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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

Table 10-1 reflects the project's incurred capital phase costs. The categories follow those used by Shell over the life of the project to track project costs. Total capital costs required to reach commercial operation on October 1, 2015 were approximately $790 million, versus the original estimate of $874 million.

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

-	FEED	CAPITAL / CONSTRUCTION					
-	2009 - 2011	FISCAL 2011	FISCAL 2012	FISCAL 2013	FISCAL 2014	FISCAL 2015/16	**Total Capex to reach Commercial Operation**
	Jan 1, 2009 - Dec 31, 2011	Jan 1, 2012 - Mar 31, 2012	Apr 1, 2012 - Mar 31, 2013	Apr 1, 2013 - Mar 31, 2014	Apr 1, 2014 - Mar 31, 2015	Apr 1, 2015 - Mar 31, 2017	
Overall Venture Costs							
Shell Labor, & Commissioning	19,470	5,414	32,638	23,466	57,311	28,753	147,582
Sub Total	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	35,919
Tie-In Work Pipeline		0	196	518	334	150	1,199
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	38,562
Material		6,092	42,315	56,502	7,466	-5,155	107,220
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	24,643
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	12,123
Sub Total	63,175	1,090	22,558	6,951	5,443	4,209	40,251

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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	87,496
Sub Total	4,035	576	6,150	87,706	32,936	93	127,460
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**	**37,326**	**789,830**

Notes:

1. Although Quest began its operating phase in Q4 2015, some remaining capital costs continued to flow through beyond the Quest reached commercial
2. Shell Labour costs during FEED phase are shown as aggregates against categories notated with an Asterisk (*)
3. Capital costs in Fiscal 2015/16 column have been restated to correctly reflect final actual costs.

10.2 Opex Costs

Operating costs associated with the venture for the first four years of commercial operations are shown in the table below. The total forecast for operating costs in 2020 is approximately $31 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	2019 Jan 1 – Dec 31
Power	3,717.70	4,513.96	7,562.80	9,056.83
Steam	8,414.46	8,834.50	5,464.59	6,284.98
Compressed Air	67.67	62.59	50.19	54.05
Cooling Water	427.95	389.81	379.14	446.29
Direct Labour and Personnel Costs	7,829.42	5,787.86	7,383.90	7,129.00
Maintenance Materials and Technical Services	969.42	942.63	1,435.98	1,286.74
Property Tax	2,003.72	2,000.28	1,842.73	1,916.60
Sequestration Opex[1]	7,052.85	6,797.59	0.00	0.00
MMV after Operations	1,690.41	1,655.74	625.64	381.34
Post Closure Stewardship Fund	272.07	264.28	243.33	250.48
Other Well Costs	431.49	442.12	102.74	214.11
Subsurface Tenure Costs	362.50	420.00	400.10	454.20
Pipeline - Inspection and Pigging	145.78	340.49	175.36	139.47
Amine[2]	340.67	0.00	0.00	0.00
Chemicals	20.35	97.92	150.69	157.71
Vendor rebates	-122.32	-100.36	0.00	0.00
Corporate and Other Costs	119.24	205.95	133.08	302.39
Sustaining Capital[3]	0.00	54.89	0.00	432.41
Total	**33,743.37**	**32,710.26**	**25,950.27**	**28,506.61**

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Notes:

1. Methodology for fixed overhead allocations captured under Sequestration Opex was reviewed in 2017. It is now distributed to the appropriate categories prospectively (from 2018).
2. Some amine loss was observed in 2019. A total of 20m^3 of amine was added to the amine stripper from the amine reservoir tank, however no new amine has been procured.
3. Sustaining Capital has been captured as an operating cost as per the Funding Agreement guidance.

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10.3 Revenues

Revenues reflect both capital and operational funding, as well as CO_2 reduction credits received up to December 31, 2019.

The value of CO_2 emission offset credits reported in a given year do not reflect the CO_2 volumes injected in that year due to the time taken to verify injection volumes and issue credits. The value of CO_2 emission offset credits in 2019 relate to 1,787,416 base and additional credits serialized during the year (valued at $30/tonne). 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	**2016**	**2017**	**2018**	**2019**	Aggregate Revenues Forecast ($)
	Construction ($)	Operation ($)	Operation ($)	Operation ($)	Operation ($)	
Revenue Stream	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, 2019	Jan 1, 2020 – 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	573,345,455	29,451,644	30,100,000	30,796,466	30,049,934	177,601,957
CO_2 emission offset credits		3,330,800	34,702,760	63,146,160	53,622,480	349,200,000
Total Revenues	**573,345,455**	**32,782,444**	**64,802,760**	**93,942,626**	**83,672,414**	**526,801,957**

Forecast Assumptions:

- Quest does not enter a Net Revenue position before September 31, 2025
- Estimate 6.1MT CO_2 avoided over next 6 years
- Double credits received; each CO_2 reduction credit valued at $30

10.4 Funding Status

Quest received a total of $6.3 million from the Alberta Innovates program. Quest met the criteria of allowable expenses for the $120 million National Resources of Canada. 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

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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 four 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 ($'000)

Government funding granted through construction of the Quest project.

	2009	2010	2011	2012	2013	2014	2015	Operating 2016	Operating 2017	Operating 2018	Operating 2019	Operating
Government Funding	Jan 1, 2009 - Mar 31, 2010	Apr 1, 2010 - Mar 31, 2011	Apr 1, 2011 - Mar 31, 2012	Apr 1, 2012 - Mar 31, 2013	Apr 1, 2013 - Mar 31, 2014	Apr 1, 2014 - Mar 31, 2015	Apr 1, 2015 - Sep 30, 2015	Oct 1, 2015 - Sep 30, 2016	Oct 1, 2016 - Sep 30, 2017	Oct 1, 2017 - Sep 30, 2018	Oct 1, 2018 - Sep 30, 2019	Oct 1, 2019 - Mar 31, 2026
Alberta Innovates Grant	3,226	1,817	1,303									
NRCan Funding				108,000			12,000					
GoA Funding				130,000	115,000	53,000	149,000	29,452	30,100	30,796	30,050	177,602
Total Funding	**3,226**	**1,817**	**1,303**	**238,000**	**115,000**	**53,000**	**161,000**	**29,452**	**30,100**	**30,796**	**30,050**	**177,602**
Cu. Gov't Funding as Percentage of Total Project Spend	0.3%	0.4%	0.5%	19.8%	29.2%	33.5%	46.6%	48.9%	51.4%	53.9%	56.3%	70.8%

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, 2019	2015		2016				2017				2018				2019				2020			
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Capture Facility																						
Compressor Inspection																						
E-24601 Repair																						
Quest Creep Test Run																						
Pipeline and Wells Surface Facility																						
Pipeline Inspection																						
Storage and Subsurface																						
5-35 Commissioning																						

12 General Project Assessment

Project Successes in 2019:

Operational MMV Data Acquisition

- In 2019 continued monitoring occurred including discrete groundwater well sampling related to the VSP and ongoing well-based monitoring. Routine logging and well integrity testing were also completed on the IWs.
- In May 2019, Quest reached the milestone of 4 million tonnes of CO_2 injected. It achieved the record of having stored underground the most CO_2 of any onshore CCS facility in the world with dedicated geological storage.

Networking within Industry

- Networking with other industrial 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 2019, Shell continued engagement sessions within the community and responded to stakeholder concerns. Although Shell has built on years of successful community engagement, we realize we must continue this dialogue.
- Quest continues to attract interest from various industries, government and non-government organizations. Shell attended and provided information to many organizations/stakeholders at conferences and meetings over the course of the year.

Provincial Government Milestones

- The funding provided by the Government of Alberta for Quest is contingent on a series of milestones that were agreed upon in the agreement. Funding payments are based on successful completion of these. 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

- 4 Million tonnes of CO_2 was successfully stored in April of 2019.
- In 2019, the low levels of chemical loss from the ADIP-x process continued, with amine introduced from the storage tanks to the stripper to increase certain amine constituents.
- All three HMUs met their NOx level commitments without contravention in 2019 with continued capability to maintain NOx levels slightly elevated from pre-Quest baseline.
- Name plate capacity increased from 3564 tpd to 3750 tpd.
- Strong integrated project reliability performance with operational availability at 99.6%.
- Annual CO2 capture ratio was maintained at 78.8% in the fourth full year of operations.

- Injection certification, audits, offset verifications and updates to waste heat claims were completed, with serialization of 1,787,416 credits, registered on the Alberta Emission Offset Registry.
- Approvals granted for Quest to utilize the CCIR electricity benchmark for electricity utilized directly from on-site co-generation unit.

Challenges in 2019:

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 is listed below.

Regulatory Changes and Credit Serialization

- Further clarification of the CCIR introduced in 2018, as well as audit findings and approvals of waste heat methodology and calculations have impacted the net CO_2 numbers for Quest.

Technical Challenges

- Reformer burners are in poor condition due to change in burner fuel composition with CO_2 capture, this is observed in all HMU's. In 2019, HMU3 capture rate was limited due to the flame instability and temperature controllability. These issues will continue until a new type of burner is utilized (replacement in 2019 on HMU3 was in-kind).
- Frozen level transmitter in HMU2 LT-242155B resulted in an absorber trip.
- Failure of seal flush tubing on the Quest Lean Amine pump (P-24602B) occurred - resulting in a leak of lean amine.
- Well injectivity reductions after short shut-ins are being investigated and potential options considered.

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. The workforce included: trades workers, engineers, geologists, geophysicists, technicians, environmental professionals, land professionals, administrative professionals, and management. At peak construction, the project had over 800 workers spanning a period of over 2 years.

In 2019, the main beneficiaries of Quest operations were third-party contractors. These contractors were responsible 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
- Maintenance and repair contracts around $2-4 million per year.

Ongoing benefits during operations include:

- Employment for ~25 full-time equivalent people.
- Property tax sent to the municipal governments of Strathcona County, Thorhild County, Lamont County, and Sturgeon County.
- Recognition from the international community of Canada and Alberta as leaders in CCS deployment through policy, regulation, and funding.

In addition to the above, discussions began in 2014 with the US Department of Energy 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 sensors were deployed in 8 of 9 of the Quest groundwater wells as a CO_2 sensor demonstration project. The technology trial was deemed successful, and the instrumentation was demobilized in mid-2019.

Partnerships such as this assist in raising the profile of both Quest operations and the leadership of the Alberta and Canadian governments in supporting sustainable resource development through innovation and government-industrial collaboration.

13 Next Steps

The focus for Quest 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 CCS as a necessary technology required to help meet climate targets.

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 facility.
- New MMV and closure plans to be submitted in 2020.
- Regulatory activities will focus on demonstrating compliance with existing agreements.
- Public engagement activities and advocacy will continue to ensure public knowledge and acceptance of Quest operations. Ongoing reporting will continue to the Province of Alberta in accordance with the respective funding agreements.
- Active sharing of CCS knowledge through publications and participation in conferences, workshops, and tours into 2020.
- Continue working with AEP and Alberta Energy (CCS Unit) on evolving regulations (i.e. TIER) and the 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, 2019, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, 2019 ANNUAL STATUS REPORT, will be available at: https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program&tags=Quest+Carbon+Capture+and+Storage+project