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Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT -

ALBERTA DEPARTMENT OF ENERGY: 2022

March 2023

(Updated Aug 2023)

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 Oil Sands Partnership (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. As of December 2022, Quest surpassed 7.7 million tonnes of injected CO_2 since project start-up.

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 and MMV data indicate that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir to date.

2022 was a transitional year with respect to the global COVID19 pandemic and starting mid-year, many of the Knowledge sharing events transitioned from virtual to in person. Tours of the Quest facility also start back up and were provided to numerous different external parties through the year. Knowledge sharing opportunities for Shell, as operator, to provide learnings from Quest were shared with numerous industry, business, academic and non-government associations in 2022.

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

- Sustained, safe, and reliable operations, and did not have any safety incidents or spills throughout the calendar year.
- Overall maintenance issues have been minimal.
- 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.
- Strong integrated project reliability performance with operational availability at 98% since start-up.
- Transitioning to full-time contractor on pipeline maintenance has reduced the amount of time to complete maintenance activities.
- Successful well workover at the IW 5-35, confirming tubing, casing and cement integrity remain high after 5+ years of operation.
- Successful change out of the DMW8-19 Geophysical Array.
- Sharing of best practices by networking with other operating facilities continues to help improve maintenance practices and procedures.
- Continued participation of the Community Advisory Panel (CAP).

- International engagements with AAPG (American Association of Petroleum Geologists), GHGT (Greenhouse Gas Control Technologies), SPE (Society of Petroleum Engineers), etc. to support public engagement, global knowledge sharing activities and participation both in person and virtually in a number of conferences.
- Serialization in 2022 of 784,241 base offset credits from 2021.
- Approvals in place to proactively change out compressor motor in 2023 to reduce potential future unplanned downtime.

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

- Reduced CO2 availability due to extended Upgrader HMU3 turnaround and other rate reductions in the HMUs that resulted net reduction of capture.
- Newly replaced downhole gauges in IW 7-11 and IW 8-19 reading erroneous data at various times throughout 2022. Troubleshooting was initiated in April 2022 and resolved at the 7-11 location in July, 2022. For 8-19 downhole pressure gauge trouble shooting is still ongoing at year end. Additional details are described in detail in Quest Carbon Capture and Storage Project, 2022 ANNUAL STATUS REPORT [1, section 4.3.1 IW DHP].
- DMW 8-19 Seismic Monitoring Array replacement took longer than expected due to fishing operations. Water pumped into the well during the operation resulted in a temporary increase in pressure inside the wellbore, that then, following the completion of the intervention continues to trend back towards base line pressure. No regional pressure increase in the Cooking Lake was observed confirming the pressure response was a result of the intervention and not a containment risk.
- Operating costs are trending higher with material increases to natural gas/electricity prices

Quest has seen strong reliability performance through the reporting period to safely inject over 0.970 Mt of CO_2 in 2022. Overall project injection surpassed 7.7 Mt of CO_2 through December 31, 2022.

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, under the Technology Innovation and Emissions Reduction Regulation (TIER), which replaced the Carbon Competitiveness Incentive Regulation (CCIR) on Jan 1, 2020; and (ii) and annual Operational Funding from the Government of Alberta during the first 10 years of operation (as long as the project is not Net Revenue Positive). In the 2022, the value of the TIER fund credit is $50/tonne.

Given the favourable characteristics of the reservoir within the subsurface pore space, Quest continues to see operating efficiencies with the compressor. The compressor operated from 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 FTEs allocated into existing positions. Quest generated expenditures of over $50 million in 2022 in staffing, Measurement, Monitoring and Verification (MMV), maintenance, utilities and other costs that benefit the local 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
CAP .... Community Advisory Panel
CCS .... carbon capture and storage
CO_2 .... carbon dioxide
DEDA .... diethyldiamine
FEED .... Front End Engineering and Design
FGR .... Flue Gas Recirculation
GHG .... greenhouse gases
HMUs .... hydrogen manufacturing units
IEAGHG .... International Energy Agency Greenhouse Gas
ILI .... inline inspection
InSAR .... Interferometric synthetic aperture radar
LBV .... line break valve
MMV .... measurement, monitoring and verification
OPP .... Offset Project Plan
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)
SGER .... Specified Gas Emitters Regulation
TEG .... triethylene glycol
TIER .... Technology Innovation and Emissions Reduction Regulation
UAV .... unmanned arial vehicle
VSP .... vertical seismic profile
WIT/SIT .... well integrity test/subsurface integrity test

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 Oil Sands Partnership (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 2013, 2014 and 2015 reports specifically have substantial information regarding operations start up as well as construction completion information.

The operations phase at Quest started in September 2015. Quest has successfully captured and injected over 7.7 Mt of CO_2 in three injection wells (8-19, 7-11 and 5-35) to the end of 2022.

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

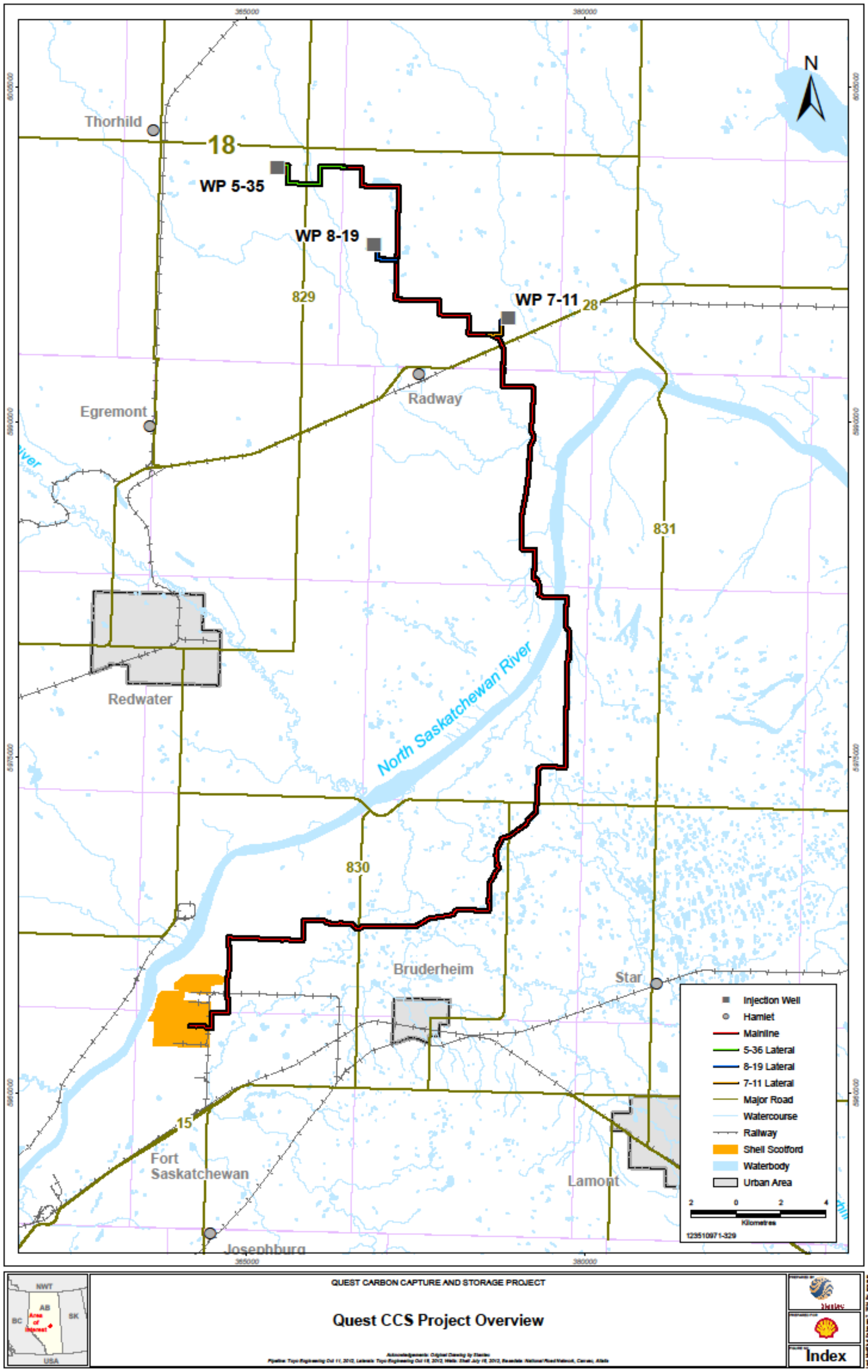


Figure 1-1: Project Facility Locations.

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 2022 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-specific discussions.

Table 4-1: Quest Operating Summary 2022

Quest Operating Summary	2015 Summary	2016 Summary	2017 Summary	2018 Summary	2019 Summary	2020 Summary	2021 Summary	2022 Summary[6]	Units
Total CO_2 Injected	0.371	1.11	1.138	1.066	1.128	0.941	1.055	0.971	Mt CO_2
CO_2 Capture Ratio[4]	77.4	83.0	82.6	79.1	78.8	76.8	78.2	77.3	%
CO_2 Emissions from Capture, Transport and Storage	0.080	0.238	0.241	0.241[5]	0.236[5]	0.205[5]	0.231[3,5]	0.215[5]	Mt CO_2
Net Amount (CO_2 Avoided)	0.291	0.870	0.897	0.826[1,2]	0.892[1,2,3]	0.736[1,2,3]	0.824[1,2,3]	0.755[1,2]	Mt CO_2
Waste Heat Credits	0.022[1]	0.062[1]	0.051[1]	0.044[1]	0.044[1]	0.038[1]	0.044[1]	0.040[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 onwards the Net CO_2 Avoided includes the "Waste Heat Credits".
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. CO_2 emissions have been updated to reflect the 3rd party verified numbers.
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. Starting in 2018, GHG emissions from imported electricity are now capturing electricity usage from both the Upgrader Cogen and the grid.
6. 2022 unverified data – 3rd party verification will be complete by May 1, 2023

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/TIER, there is no target specified. As a result, the target was set to 0% under CCIR/TIER.

In the Quest offset project plan, the electricity generation for the Quest project 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 to Quest. On June 19, 2019, AEP provided approval for a deviation request to use the CCIR/TIER electricity benchmark of 0.37 tCO_2/MWh for Quest electricity directly connected to the Cogen plant while the electricity grid displacement factor with line loss applied for 2022 was 0.57 tCO_2/MWh (Carbon Offset Emission Factors Handbook, Version 2.0). Shell re-applied for this deviation for the 2022 compliance year and was granted this deviation from AEP on February 28, 2023.

As of end 2022, Quest has injected over 7.7 million tonnes since the project started up.

4.1.1 Quest Audits and Credit Serialization

The Quest offset project underwent several audits and verifications in 2022:

- Quest Injection Certification: Alberta Energy's 3rd party verifier (Brightspot Climate) conducted the Year 7 Injection certification audit that reviewed injection and mass balance data from October 1, 2021, to September 30, 2022. The audit was closed November 2022 confirming the Total Mass of CO2 injected of 976,523 tonnes as reported to Alberta Energy.
- Annual Offset Verification: Shell hired an independent 3rd party verifier (Tetratech) to conduct the annual emissions verification to meet the requirements in the *Technology Innovation and Emissions Reduction* (TIER) Regulation as set out by the Government of Alberta. The time period of the analysis was data from January 1, 2021 to December 31, 2021. The final GHG Assertion for the 2021 RP was submitted to the Alberta Offset Registry by May 1, 2022.

The Quest CCS project serialized a total of 1,054,918 tCO2e on the Alberta Emission Offset Registry in May 2022:

11th (2021)	Jan 1 2021 to Dec 31, 2021	Injected CO2		1,054,918
		Base	24-May-2022	784,241
		Additional	27-May-2022	784,241

4.2 Capture (Absorbers and Regeneration)

CO_2 removal ratio performance of the capture unit was as expected in 2022, with an annual CO_2 capture ratio of 77.3%. The solvent composition continues to change as the amine degrades from use. This has not impacted unit performance. The CO_2 produced by the capture unit continues to be on target for purity, with minimal solvent carryover into the gas stream. 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 5-1 in Section 5 contains the average CO_2 product composition from the capture and dehydration units.

The main contributors to periods of reduced CO_2 capture in 2022 were the planned inspection and maintenance downtime upstream of the Quest unit. Other reductions were a result of reduced available CO_2 volume for capture from upstream units and trips in process units outside of Quest. These periods are summarized below:

- Jan 1: Continued reduced capture in HMU3 since March 2021 to manage flame impingement on the reformer tubes
- Jan 23: Lower CO2 availability in HMU1/2 due to upstream upset
- Feb 14: No capture from HMU3 due to HMU3 shutdown. HMU 3 remained offline until May 12 for Turnaround (TA)
- May 12: HMU3 online after TA, bypassing Quest until June 6
- June 17: Capture reduction due to Quest reboiler positioner maintenance
- July 1: HMU 1 trip
- Aug 1: Artificial high capture rate due to a pipeline power failure. Regular injection returned when pipeline came back online
- Sept 13: Pipeline trip stopping injection for 1 day
- Oct 24: Lower CO2 availability due to HMU1/2 rate reduction
- Dec 22: Lower CO2 availability due to HMU1/2 rate reduction

Table 4-2 is a summary of the Energy and Utilities consumption of 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	2020 Usage	2021 Usage	2022 Usage	Units
Electricity (Capture/ Dehydration)	12300	32800	32600	32200	32700	27700	31500	32600	MWh_e[1]
Low Pressure Steam	410	1263	1297	1204	1217	1050	1191	1100	kT
Low Temperature High Pressure Steam	1.96	5.52	5.23	5.01	5.12	6.21	5.01	5.64	kT
Nitrogen	178	230	237	258	256	230	171	279	Ksm^3
Wastewater	24900	80900	61900	57800	60700	50200	54281	60974	m^3
Energy/Heat Recovered	33600	96260	98554	95060	93955	78490	87585	94270	MWh_t[2]
CO_2 Emissions for the Capture Process	0.030	0.083	0.095	0.195[3,4]	0.182[3,4]	0.158[3,4]	0.180[3]	0.167[3]	Mt CO_2

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 2022, the operations team targeted approximately 50 ppmv water content to the pipeline, staying within the 84 ppmv spec. Heat recovery in the demineralized water heaters used to cool the CO_2 stripper reboiler steam condensate is also approximately on target from design.

In 2022, significant fouling of the lean/rich exchangers continued to impact the rich amine inlet temperature to the stripper. Outlet temperatures have continued to decrease at a rate of 1.5°C per annum. As a result, reboiler duty increased. Cleaning of this exchanger was completed in the 2017 turnaround and in the 2021 turnaround. The exchanger was back flushed to remove any foulant, carbon or other debris. Since the exchanger cleaning, there has been no improvement in the performance of this exchanger and the stripper inlet temperature has continued to drop for a total of 10°C since start-up.

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. The diethyldiamine (DEDA) content started to drop below the designed composition at the end of 2017 and continued to degrade into 2021. Fresh amine was introduced to the amine storage tank in November 2021 to increase the DEDA content. The decreased DEDA content has not affected capture performance at this time. It is uncertain at what point the decreased DEDA content will impact absorption at current rates. The decreased DEDA content may hinder attempts to increase the Quest capture rate. At such time, this could be compensated by an increase in solvent circulation rate or by introducing fresh amine into the system. It is currently planned to introduce fresh amine at the end of 2023 to increase the DEDA content.

In 2019, the name plate capacity of Quest was increased from 3564tpd to 3836tpd. This was achieved in a test run 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. In 2022, the new nameplate rates were not achieved in operations due to HMU limitations.

CO_2 emissions for the capture process are primarily those linked to low-pressure steam use in the CO_2 stripper reboilers (~82% of total capture emissions), and from electricity for equipment in the capture system (~7% of capture emissions).

4.3 Compression

In 2022, the compressor continued to operate at expected discharge pressures. Table 4-3 below outlines the average operating conditions for the reporting period.

Table 4-3: Typical Compressor Operating Data – Average Operation

Compressor Characteristic	2015	2016	2017	2018	2019	2020	2021	2022	Units
Suction Pressure	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	MPag
Discharge Pressure	9.6	10.0	10.1	10.5	9.8	9.7	9.7	9.7	MPag

Motor Electricity Demand	13.3	13.8	14.2	14.0	14.2	13.7	13.6	12.8	MW_e

4.4 Dehydration

The dehydration unit performance continued to operate reliably in 2022. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv. Actual water content for 2022 was on average 42 ppmv, while maintaining the optimized nitrogen flow rates described in Section 4.2.

Carryover of the TEG into the CO_2 stream remains low relative to the unit design, with the average losses in 2022 being 11ppmw of the total CO_2 injection stream, compared to the 27 ppmw expected in design. The total annual TEG loss was 10,410 kg in 2022, outperforming 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 2022 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 2022, the averaged NOx emissions with Quest operational and the FGR online are included below:

- HMU1: 28.91 kg/h, limit 76.5 kg/h
- HMU2: 33.22 kg/h, limit 76.5 kg/h
- HMU3: 53.71 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.

All three HMUs manage capture near 80% which minimize the impacts of Quest on HMU reformer management. To date, Quest has not impacted the hydrogen production capability of the HMUs. 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. The addition of the flue gas recirculation results in fuel efficiency improvements in the reformer, however NOx emissions remain slightly elevated in comparison to pre-Quest operation.

4.6 Non-CO_2 Emissions to Air, Soil or Water

In accordance with Shell internal guidelines, all spills – regardless of size – are recorded for tracking purposes. Quest had no leaks or spills in 2022.

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. 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 is from the Scotford Upgrader maintenance department and staff support (engineering, specialists, administration, and management) is from within the greater team that supports the upgrader and 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

Charact-eristic	Specification	Units	Average Operating Data / Actual Limitations								Original Design
			2015	2016	2017	2018	2019	2020	2021	2022	
Pipeline Inlet Pressure	Normal	MPag	9.4	9.8	9.9	10.3	9.6	9.7	9.5	9.54	10
	Maximum Operating	MPag	12	12	13.58	13.58	13.58	13.58	13.58	11	14
	Minimum Operating (based on CO_2 critical pressure 7.38 MPa)	MPag	8.5	8.8	8.7	8.8	8.8	8.8	8.6	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	0.6	0.7	0.6	0.4 (for 3 well scenario)
Temp-erature	Compressor Discharge	°C	130	130	128	131	131	126	124	127	130
	Pipeline Inlet after cooler	°C	43	43	41	41	41	42	42	42	43
	Upset Condition at Inlet	°C	-	-	-	-	-	-	-	-	60
	Injection Well 7-11 Inlet Temperature	°C	15	16	14	13	15	13	16	16	-
	Injection Well 8-19 Inlet Temperature	°C	12	12	11	9	12	10	12	11	-

	Injection Well 5-35 Inlet Temperature (as of Oct 19, 2018)	°C	-	-	-	6	7	6	10	12	-
Flow rates	Normal Transport Rate	Mt/a	1.04	1.11	1.14	1.06	1.14	0.94	1.06	0.97	1.2
	Design minimum	Mt/a	-	-	-	-	-	-	-		0.36
	Total Transported	Mt	0.37 1	1.11	1.14	1.06	1.14	0.94	1.06	0.97	-
Energy and Emissions	Total Electricity for Transport (compression)	MWh_e	41,527	19,426	121,593	119,396	143,453	124,199	110,619	110,695	-
	Total Transport Emissions (includes compression)	Mt CO_2eq	0.027	0.077	0.078	0.045[1]	0.054[1,2]	0.047[1]	0.052[1]	0.08	-
	1. Indirect GHG emission from imported electricity is now capturing electricity usage from both the upgrader cogen (0.37 tCO_2/MWh) and the grid (0.57 tCO_2/MWh) 2. 2019 CO_2 emissions have been updated to reflect the 3rd party verified numbers									

The pipeline operates with CO_2 in supercritical phase at the pipeline inlet (9.74 MPag, 42°C) and with CO_2 leaving the main pipeline to the well sites in liquid phase (9.0 MPag, 10°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 temperature reductions in the pipeline.

CO_2 emissions from the transport component of the operation are primarily from the electricity used to power the compressor.

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%)	Actual Operating 2020 (vol%)	Actual Operating 2021 (vol%)	Actual Operating 2022 (vol%)	Design Normal Composition	Design Upset Composition
CO_2	99.45	99.38	99.46	99.44	99.44	99.37	99.40	99.45	99.23	95.00
H_2	0.48	0.51	0.47	0.46	0.48	0.48	0.47	0.50	0.65	4.27
CH_4	0.06	0.06	0.06	0.06	0.05	0.05	0.06	0.07	0.09	0.57
CO	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.15
N_2	0	0	0	0	0	0	0	0	0	0.01
Total	100	100	100	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 2022 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 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). As of 2020 these inspections occur every 5 years.
- Annual cathodic protection surveys and corrosion probe monitoring is performed.
- 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 most recent ILI inspection occurred in 2021, with no significant findings.
- 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 2021, an unmanned aerial vehicle (UAV) was used for inspections. This allows for inspections to be completed with less health and safety risks to personnel (no pilot required) and overall cost reduction. Aerial ROW surveys were continuing to be completed quarterly in 2022.

6 Facility Operations - Storage and Monitoring

This section provides an overview of the wells and MMV activities for the operational year 2022.

6.1 Storage Performance

Injection of CO_2 into the 8-19 and 7-11 wells began on August 23, 2015, and 5-35 commenced injection October 19, 2018. As of December 31, 2022, about 7.7 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 5-2 and is shown in Figure 6-2.

By the end of December 2022, about 3.18 Mt of $C0_2$ had been injected into the 7-11 well, 3.18 Mt of $C0_2$ into the 8-19 well, and 1.42 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.

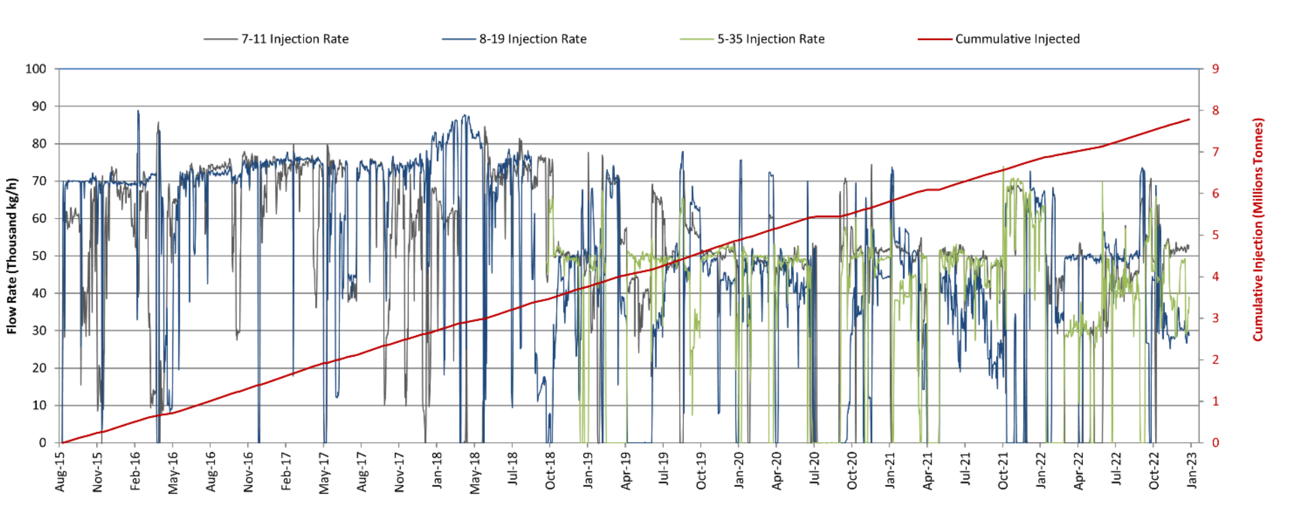


Figure 6-1: Quest Injection Totals: Cumulative CO_2 injected into the wells from start-up through to the end of 2022 (red). The blue, grey and green lines show the average hourly flow rates into each of the injection wells.

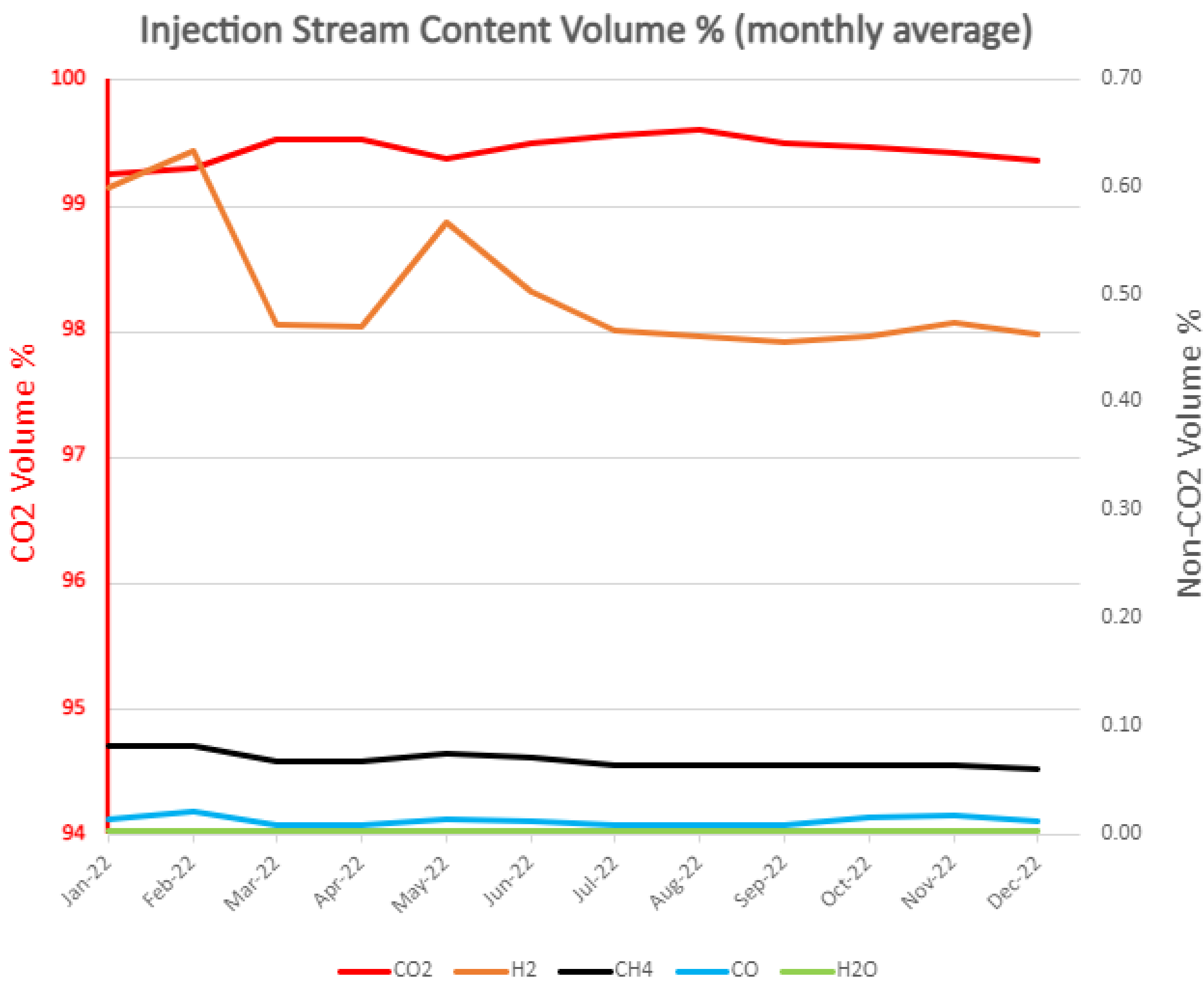


Figure 6-2: Quest Injection Stream Content: Average injection composition for 2022.

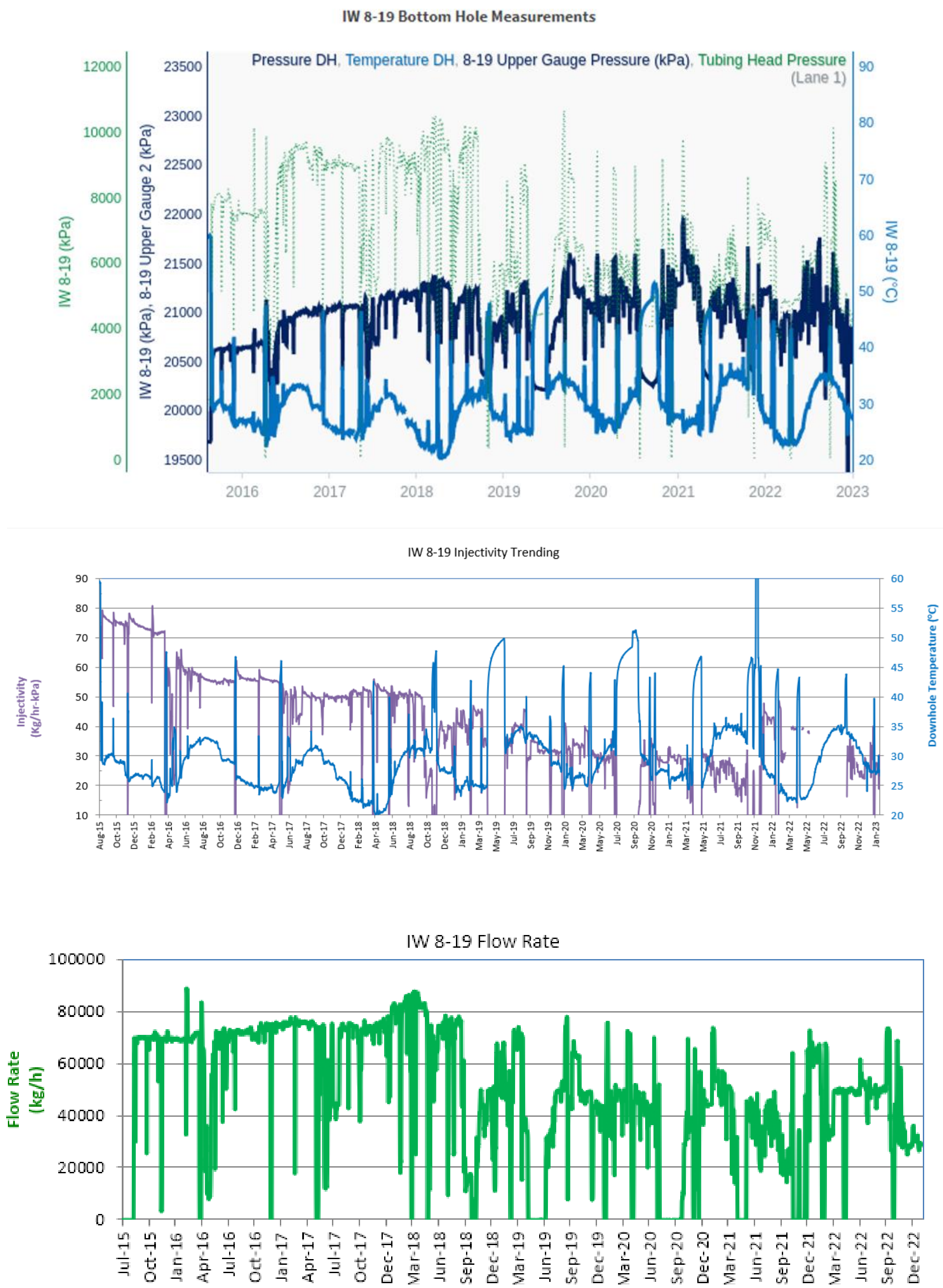


Figure 6-3: The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection to the end of 2022. (Note: Workover/Intervention and erroneous data has been removed)

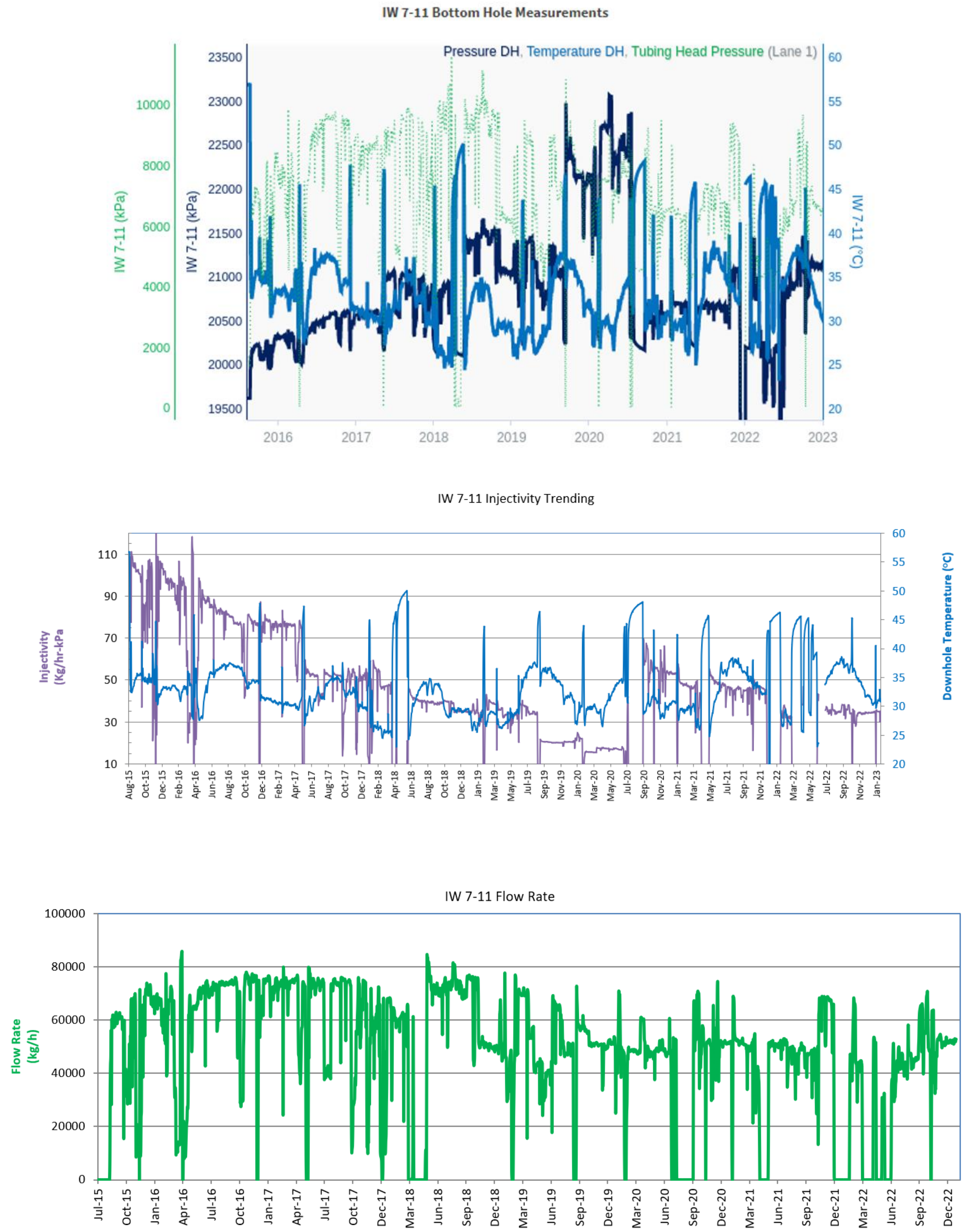
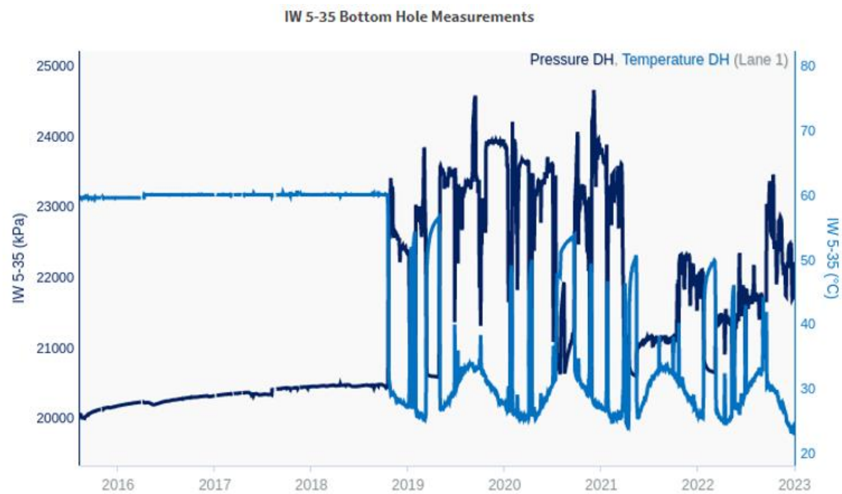
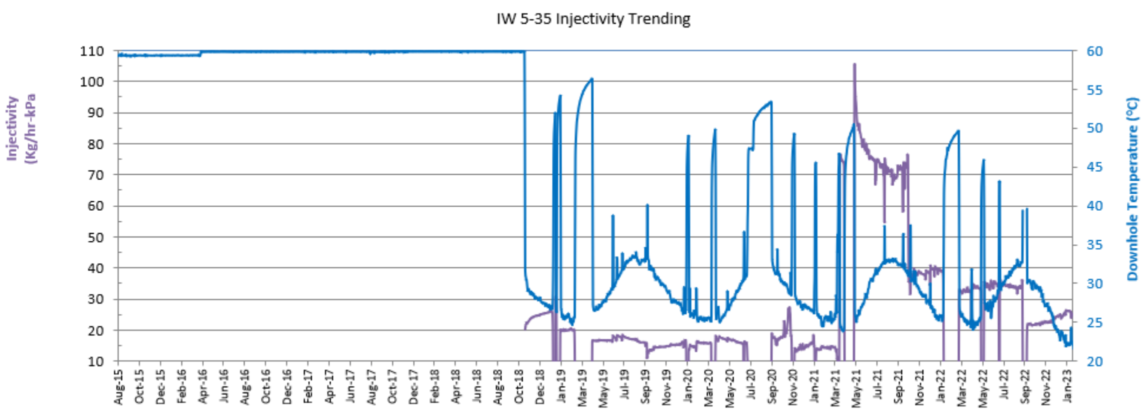


Figure 6-4: The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2022.





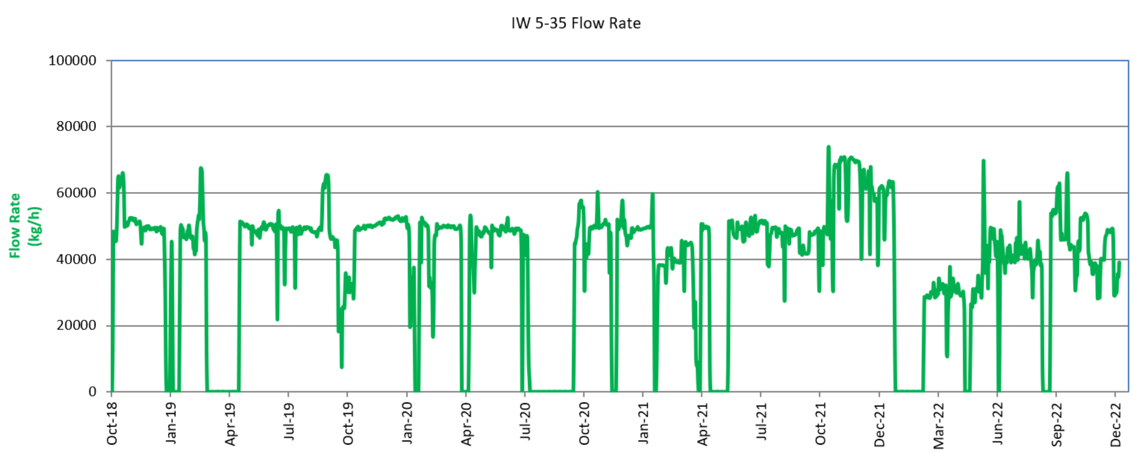


Figure 6-5: The 5-35 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2022.

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 2022 AER Annual Report, Section 3.4: Reservoir Modelling for discussion [1]. 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 licensed injection volume in the Sequestration Lease Area as of end 2022.

Year	Yearly Injection Total	Remaining Licenced Volume
Pre-injection	-	27 MT CO_2
2015	0.371 MT	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
2020	0.941 MT	21.248 MT CO2
2021	1.055 MT	20.193 MT CO_2
2022	0.971 MT	19.222 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 as high as 155 t/hr. The 5-35 injection well was brought on in October 2018.

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.

In 2022, no halite remediation interventions were completed. However, this technique is now considered one of our standard injectivity maintenance activities and will be budgeted and executed on an appropriate cadence going forward.

The injectivity index for all three wells is displayed in Figure 6-3, Figure 6-4 and Figure 6-5.

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 2022, 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 using the Light Source technology. Equipment maintenance was carried out to fix low light signal due to alignment issues and frosting on the OPX heads. After the 2021 infrastructure and IT update, Lightsource data systems are still being optimized and analysis of data system is ongoing. Operator rounds continue to be daily at the injection well sites.

Hydrosphere Domain: In addition to continuous monitoring of the Quest ground water wells, discrete sampling at Project wells was done from Q1 to Q4 2022.

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

Geosphere Domain: Monthly satellite image collection for InSAR. Since September 2017, a single frame centered over the 3 injection well pads has been used for image collection. In 2021, 3DSEIS was acquired over the IW 5-35 and IW 8-19 as well as two 3 component (3c) 2DSEIS lines through the same IWs. A 2DVSP was acquired at IW 5-35 along with its associated 2DSEIS along the 2DVSP acquisition lines. In 2022 the 3DSEIS, 3c 2DSEIS and 2DVSP data were processed for interpretation in 2023.

Well based Monitoring: Ongoing data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes. During 2022 the downhole gauges on IW 7-11 and IW 8-19 showed erroneous data at times during the year. Instrumentation trouble shooting occurred throughout the year in an effort to correct the data and rectify the issue. Well head pressures were continuously monitored against a maximum allowable limit to ensure that Bottom Hole Injection Pressure limits were not exceeded. This strategy was communicated to the AER and is covered in detail in D65 compliance reporting (1).

The 2020 MMV plan was approved November 25, 2020 and was in use throughout 2022.

No trigger events were identified during 2022 that would indicate a loss of containment per the 2020 MMV plan definition of containment monitoring. However, there were two trigger events that did occur, both associated with down hole pressure monitoring data described below. In summary, Tier 1 technologies are reported in Table 6-2 (2020 MMV Plan).

Table 6-2: Overall assessment of trigger events used to assess loss of containment in 2022 using the 2020 MMV Plan. Both instances of erroneous pressure data were investigated and neither situation indicated any risk of loss of containment.

Tier	*Technology*	*Trigger*	*Magnitude of CO_2 Detection Capability*	*2022 Q1*	*2022 Q2*	*2022 Q3*	*2022 Q4*
Tier 1	IW DHP	Measuring greater than 26 Mpa or less than 20 Mpa	N/A				
	IW Tubing / Casing Annular Pressure	Anomalous pressure response	N/A				
	DMW DHP	Anomalous pressure increase above background levels	deca tonne/day				

2022 Q2 – IW 7-11 DH Pressure less than 20 MPa*:* From April 1 to June 30, 2022, there were 3 time periods in which a DH pressure recorded less than 20 MPa. As per the 2020 MMV plan, this is defined as a trigger event, as the pressure was trending towards the previously defined minimum trigger pressure (less than 20 MPa). An assessment of the data over these periods identified that this was erroneous data from the DHP gauge, first identified as an occurrence in the Q1 2022 P20 report. During shut in times, the bottom hole pressure would fluctuate over 24-hour periods. As a result, this drop in DHP is not a “real” or true trigger. When the erroneous readings were identified, Shell put in place a conservative maximum injection surface pressure constraint of 10 MPa on the Tubing Head Pressure. At this surface pressure, modelling the ‘worst case’ conditions (low temperature/low injection rates) results in a maximum bottom hole pressure of less than 28 MPa, which is below the maximum licensed bottom hole injection pressure of 30 MPa. The issue with the DH pressure erroneous readings was resolved for IW 7-11 in July 2022 through maintenance.

Further commentary on this issue is provided in 2022 Annual Status Report [1]. The other Tier 1 Technologies did not detect any trigger events over this period.

Note: As detailed in the 2022 Annual Status Report [1] erroneous down hole pressure was also identified on IW 8-19, however the pressure recorded never exceeded the high or low pressure trigger and was inconsistent, switching from correct data to erroneous throughout the year. A similar surface pressure constraint to IW 7-11 THP was placed on the IW 8-19 THP that would prevent the BHP form being exceeded in real time. On September 7, 2022, Shell met with the AER Resource Recovery Group and AER Well Specialists and provided documentation on the erroneous DH pressure data issue, the surface pressure mitigation, and results of the ongoing troubleshooting. The AER confirmed that operating in this manner was acceptable and was not a non-compliance to the License 11837C or 2020 MMV Plan, nor was it a threat to containment. This communication was then shared by the AER to the GOA.

2022 Q4 – DMW 8-19 DHP Anomalous pressure increase above background levels: The Cooking Lake pressure trend at the DMW 8-19 had an “*anomalous pressure response above background levels*” in October 2022. This pressure increase occurred as an outcome of the 8-19

DMW microseismic monitoring (MSM) array replacement and well bore inspection from September 19 to October 10, 2022. Although classified as trigger event, data indicates that this a well bore condition and not a result of CO_2 migration outside the Storage Complex into the Cooking Lake Formation. Further commentary on this issue is provided in [1, Section 4.3.1 IW DHP]. The other Tier 1 Technologies did not detect any trigger events over this period

With the data collected so far, CO_2 injection within the BCS is conforming to model predictions, based on:

1. In 2022, a significant modeling update was performed that refreshed multiple components of the reservoir model. Based on these updates, the dynamic model was reconstructed and calibrated against the pressure fall-offs through to the end of Q3 2022.
2. Consistent with the previously generated models, the new model representation also predicts that by the end of the project life, the pressure increase in the BCS above initial reservoir pressure is forecasted to be less than 2 MPa. This pressure increase represents less than 12% of the delta pressure required to exceed the BCS fracture extension pressure and less than 25% of the pressure increase required to exceed the AER Approval operating constraint on bottom hole pressure. As previously, this indicates that there is sufficient capacity in the Quest SLA for the entire licensed CO2 volume, as well as potential room for growth for the Quest project.
3. Continued trending of low end-of-life reservoir pressures indicates that it is extremely improbable for CO2 leakage to occur via fracturing or fault reactivation.

Further details of the MMV activities undertaken and observations made during 2022 can be found in the 2022 AER Annual Status Report [1].

6.2.1 Additional MMV Activities

2021 3D/4D Seismic Campaign

In Q3/Q4 2021 five seismic datasets were acquired at Quest over two of the injection wells (Figure 6-6). One 2DVSP (Vertical Seismic Profile) monitor dataset was acquired at IW 5-35 in December 2021. During the 2DVSP, surface geophones were deployed along the 2DVSP acquisition lines. All surface geophones were live during the 2DVSP acquisition, creating a sparse 3D illumination pattern with high density subsurface illumination along the coincident shot and receiver lines. Two long 2DSEIS lines were also acquired with high density shot and receiver points (50m and 25m, respectively). These lines ran East/West through the IW 5-35 and North/South through IW 8-19 with lengths of approximately 11.5km and 9.5km, respectively. These 2D lines are referred to as 'regional' 2DSEIS. Additionally, a subset of the 2010/11 SEIS3D survey was acquired over an area of approximately 200 square kilometers covering IW 5-35 and IW 8-19.

The objective of the 2DVSP survey over IW 5-35 was to acquire a second monitor survey at this injection well which came onstream in late 2018 and was previously surveyed in 2015 and 2019. This provided an excellent data source for measuring time-lapse changes as well as draw correlations between the seismic response measured by 2DVSP and the response measured by the SEIS3D of the same vintage. The purpose of the associated sparse 3DSEIS acquired along the 2DVSP lines was to provide the first sparse 3DSEIS monitor at IW 5-35 after the baseline taken in

2019. It should be noted that, although all receivers were live creating a sparse 3D patch, the key information extracted and utilized was from the coincident shot and receiver lines which produced a 2D profile through the well.

The objective of the 3DSEIS acquired in Q4 2021 was to provide the first repeat survey of the baseline 3DSEIS survey acquired in 2010/11. This survey was acquired with the same survey design as the 2010/11 survey and comparable vibroseis sources.

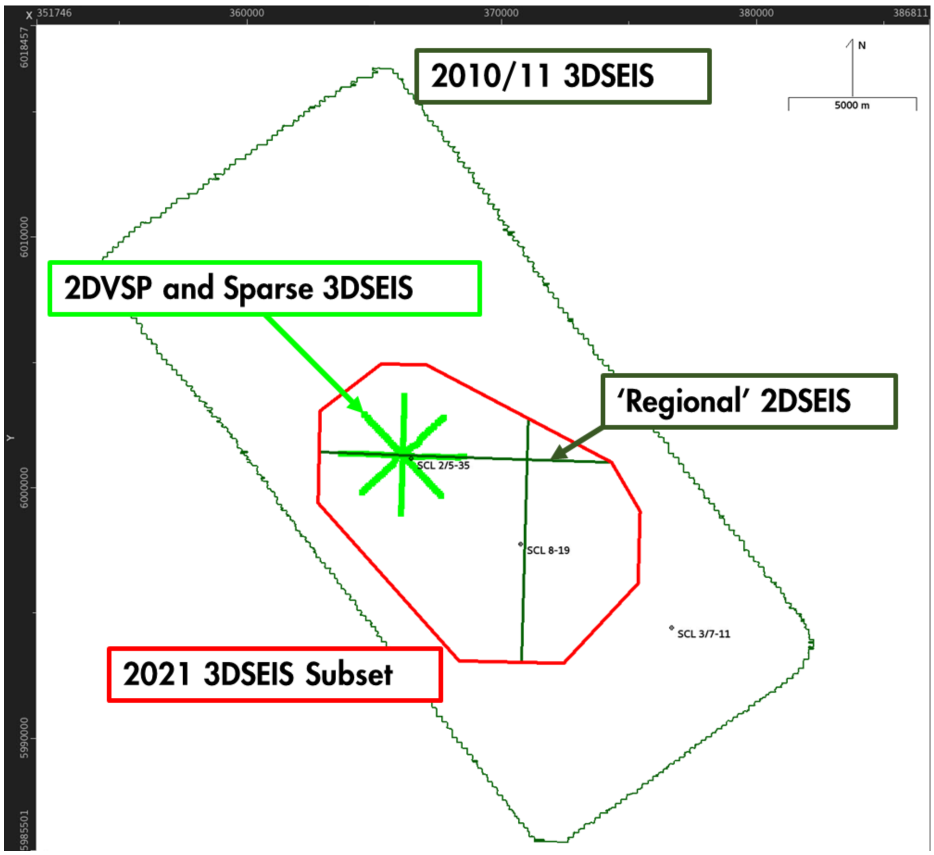


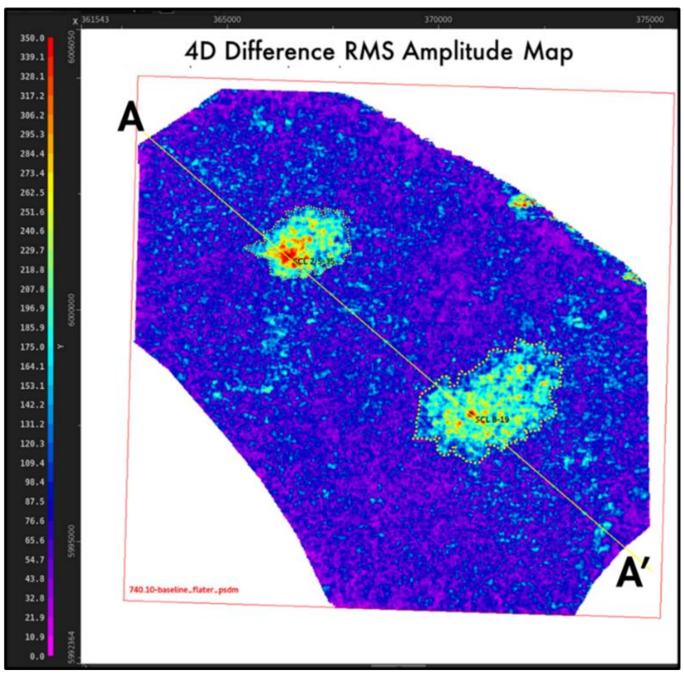
Figure 6-6 2021 Acquisition Data Set Summary

2022 Seismic data processing (SEIS2D, 2DVSP, SEIS3D)

In Q1 of 2022 through to the end of Q4, four of the five datasets were processed including the IW 5-35 2DVSP, the two regional 2DSEIS surveys as well as the 3DSEIS data by Shell's internal onshore seismic processing and time-lapse specialists.

The 3DSEIS acquisition was processed along with the respective subset from the 2010/11 baseline seismic survey in order to produce the first spatially extensive time-lapse 3DSEIS at Quest. This seismic processing workflow utilized standard onshore processing workflows combined with additional time-lapse workflows to match the two datasets and provide an interpretable time-lapse image. RMS repeatability Ratio (RRR) measurements were taken at each stage of the processing flow, monitoring improvements made at each processing step. A final RRR of 0.078 was achieved. A RRR of 0 indicates a perfectly repeatable dataset while 1.41 indicates a perfectly non-repeatable dataset. The seismic anomaly associated with the plume is estimated to be visible at repeatability levels of 0.15 and below indicating the final 3DSEIS results were suitable for time-lapse measurements.

Initial interpretation of the time-lapse image has confirmed a strong visible anomaly associated with the CO_2 plume easily interpretable over the noise floor both when measuring amplitude changes in a windowed RMS difference extraction and reflectivity cross sections through the two wells surveyed (Figure 6-7).



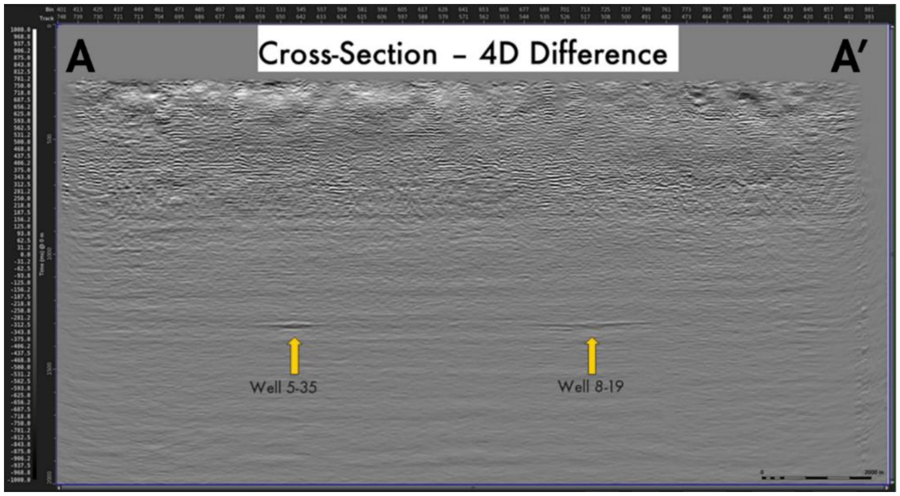


Figure 6-7 Windowed time-lapse RMS difference extraction and cross section view through the time-lapse response

Processing of the regional 2DSEIS was also conducted using a very similar workflow to that of the 3DSEIS however, due to the regional 2DSEIS being the baseline survey, the time-lapse portion of the workflow and repeatability analysis was omitted. In the future the regional 2DSEIS may be used for AVO analysis to determine the feasibility of CO_2 detection in AVO trends across the lines. The 2022 regional 2DSEIS processing produced excellent structural images (Figures 6-8, 6-9).

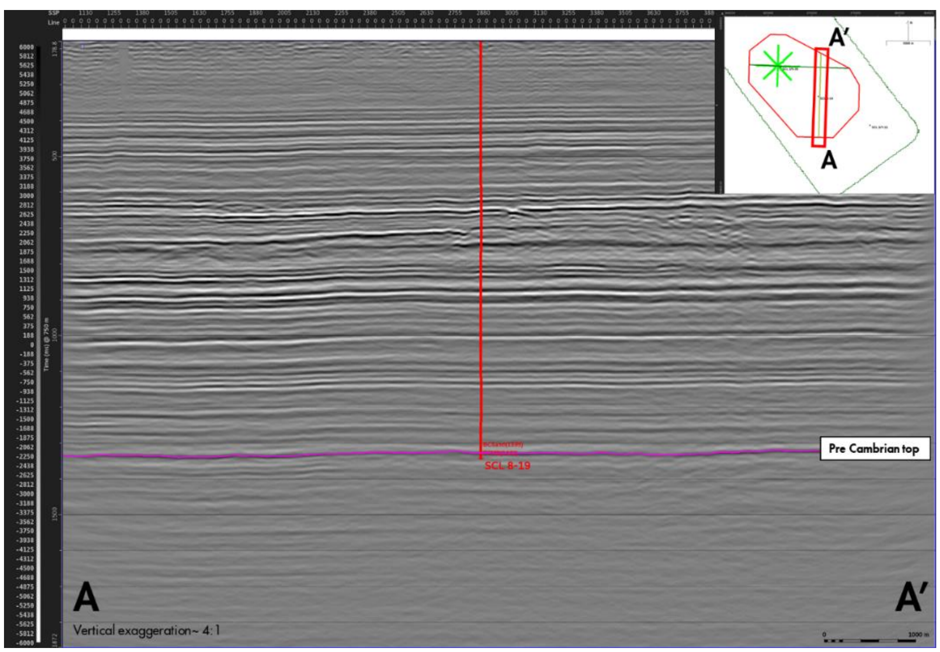


Figure 6-8 Regional 2DSEIS through IW 8-19 migrated image

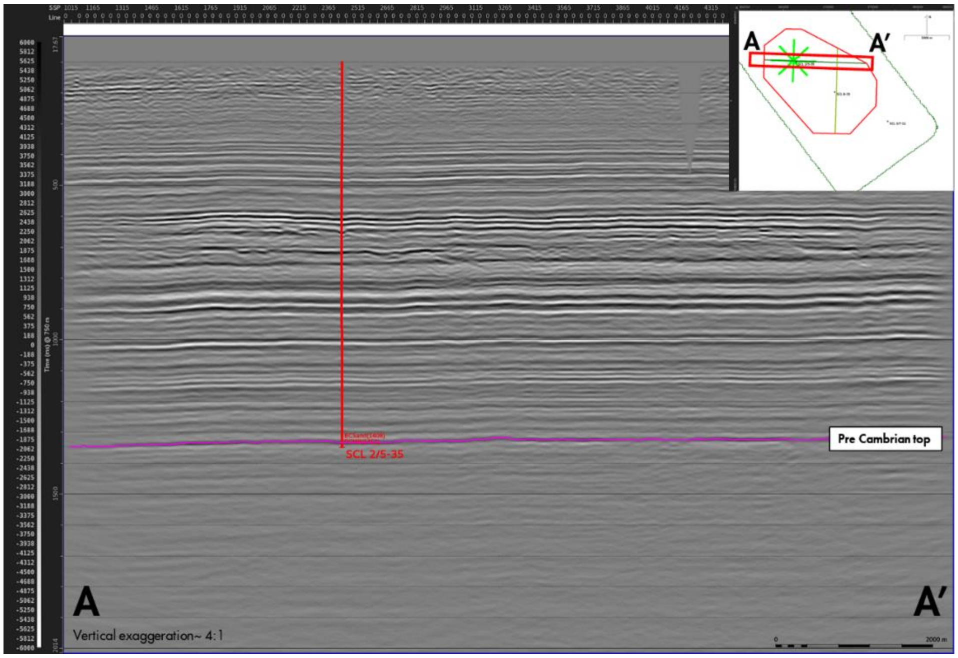


Figure 6-9 - Regional 2DSEIS through IW 5-35 migrated image

In 2022, the 2DVSP acquired in 2021 was processed to provide the second monitor for the IW 5-35 (Figure 6-10) with results provided to the Quest team in Q1 2023. Currently, time-lapse interpretation is underway.

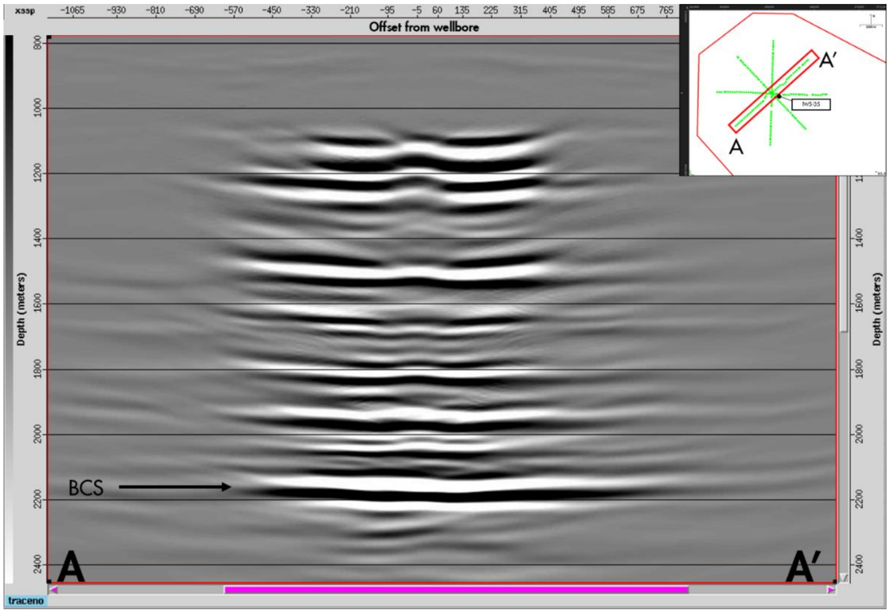


Figure 6-10 2DVSP migrated image through IW 5-35

Future seismic acquisition campaign frequency

As of 2022, the edge of the seismic anomaly associated with the plume has extended beyond the imaging extent of the 2DVSP at each of the injection wells. This is inline with the expectation that the 2DVSP would be an early injection monitoring technology only and not a long term conformance technology. As a result, there are no plans for additional conformance monitoring VSP surveys at the injection wells. Work is underway to assess and define the future acquisition frequency of other currently available surface seismic technologies as well as testing new technology applications on the Quest project.

DAS/Node Trials

Technology field trials were completed in 2022 to assess the feasibility of monitoring seismicity from surface stations and from downhole optical fiber using a DAS lightbox interrogator. From June 2021 to August 2022, surface nodes were deployed over the Quest region. Two DAS (Distributed Acoustic Sensing) systems at were installed at wellsite's 8-19 and 7-11, collecting seismicity data from January 2022 to September 2022. Detailed analysis and comparison of the downhole geophone array, DAS and surface nodes systems is currently being conducted by the ENSURE Partnership.

An initial finding of these technology trials concluded that a combination of the current downhole geophone array located at DMW 8-19 with surface seismic monitoring stations would be an adequate solution to monitor basement seismicity. This hybrid monitoring could be considered as a potential alternative contingency monitoring approach to installing additional future downhole geophone arrays at Quest for the purposes of monitoring basement seismicity.

An initial finding of the trials for DAS technology for monitoring seismicity is that this technology has progressed substantially. DAS technology is capable of detecting seismicity at Quest when triggered by an event detected on the downhole array. There is a lot of promise for this technology to aid in reducing depth uncertainty. Continued DAS technology advancements are expected to provide viable future hybrid monitoring options for Quest. Although not considered commercial for Quest at this time, DAS combined with surface stations is an exciting prospect for monitoring seismicity.

6.3 Wells Activities

6.3.1 Injection Wells

In 2022, the injection wells underwent routine work including wellhead integrity testing (wellhead maintenance and pressure testing), packer isolation tests. All three injection wells also had new APIx ANSI adapters installed between the casing valve and pressure transducer. A service rig workover was completed at the IW 5-35 location to inspect production casing condition and complete a cement bond log. This marks the completion of all the five-year checks on casing/tubing/cement for the injection wells. The results of these workovers confirm that the tubing, casing and cement are in good condition and there is no evidence of corrosion or reduced cement bond log in comparison with original logs.

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 have been collected since Q3, 2015, as illustrated in Figure 6-11 11. The additional far-field monitoring is in the 3-4 Observation well which provides an opportunity to observe any potential pressure changes coming from offsetting activity in the Cooking Lake. Thus far, the Cooking Lake pressure continues to behave as expected, with no further investigation recommended.

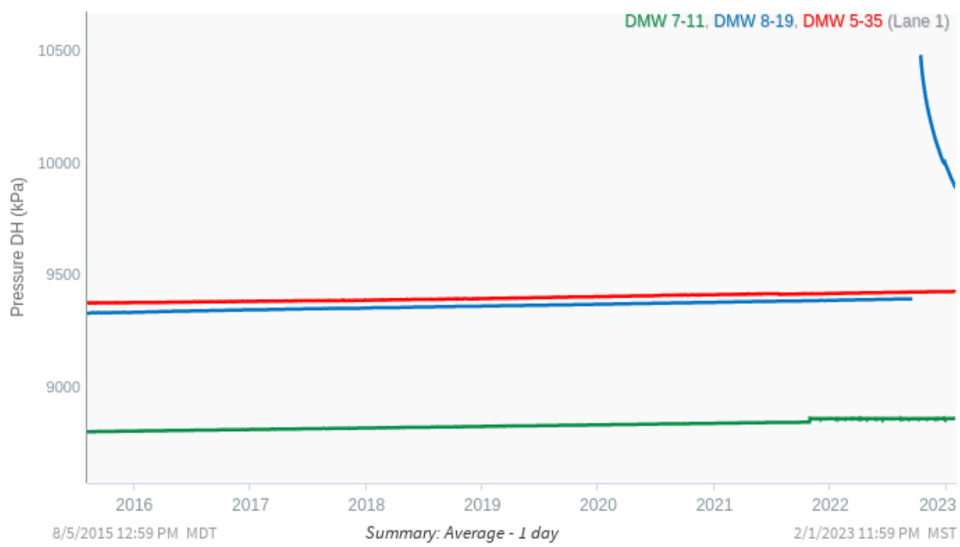


Figure 6-11 11- Quest DMW pressure history before and during injection. Pressure increase in the DMW 8-19 in October of 2022 is a result of a 2-week intervention, where a fishing job was required during the replacement of the geophysical monitoring array. It is anticipated that it may take up to two years for the wellbore to return to the base Cooking Lake pressure.

Project groundwater monitoring wells had quarterly maintenance checks performed on the downhole gauges, including downloading pressure and basic water quality data. Sampling events occurred quarterly throughout 2022.

7 Facility Operations - Maintenance and Repairs

Facility Operations - Maintenance and Repairs

2022 Saw the kickoff of the Quest De-Bottlenecking Project.

C-24701 C02 compressor motor replacement has been in planning throughout 2022. Due to delays on motor delivery, the work is scheduled for September 2023.

Quest simulator training is on-going. This will increase competency and awareness for operations prior to any Quest upsets and to ensure safe and efficient operation of the Unit.

2022 was a busy year on the pipeline. All three wells 7-11, 5-35, 8-19, underwent a complete work over in Sept.-Oct of 2022. Complete overhauls on LBV's 1-6 have also been in planning throughout 2022. This work will be completed coinciding with the C-24701 motor replacement in Sept. 2023.

Training plans and maintenance procedures for the maintenance/operations personnel were reviewed and changed accordingly prior to turnaround to align with current site practices.

Spare part requirements based on reliability centred maintenance have been reviewed based on findings from turnaround.

All essential maintenance processes are in place.

2022 Capture Maintenance and Repairs

- P-24607 bearing replaced along with motor
- P-24612 bearing and motor replacement
- E-24706C Fin Fan Belt replaced
- E-24706/07 fin fan blows to maintain summer rates
- Replaced insulation soft covers with hard insulation in certain areas due to freezing of instruments.
- HVAC repairs due to inadequate heating and cooling in S-24604
- Installed thermometers, installed deck for HVAC access, and repaired exhaust fan on S-24605
- E-24706C Fin Fan Belt change out
- C-24701 Faulty Bearing RTD repaired
- Wellsite 7-11, 8-19, 5-35 Complete work over done
- C-24701 $C0_2$ compressor motor windings repaired until new motor arrives in 2023
- FV-246005 Replace Positioner
- PCV-246045 Replacement

2022 Pipeline Maintenance

Pipeline

Contractors

- Connect Energy Onboarded

Line Break Valves:

LBV 1

- Solenoid Diode and I/O Card Replacement
- Aug Hydraulic Filter Change Out

LBV 2

- Solenoid Diode and I/O Card Replacement
- Aug Hydraulic Filter Change Out

LBV 3

- Solenoid Diode and I/O Card Replacement
- Aug Hydraulic Filter Change Out

LBV 4

- EFOY Unit in for Repair due to Multiple Error Code 73 - Repair included replacing internal Res
- Solenoid Diode and I/O Card Replacement
- Aug Hydraulic Filter Change Out
- May, EFOY Cabinet Thermostat Replaced

LBV 5

- Solenoid Diode and I/O Card Replacement
- Aug Hydraulic Filter Change Out

LBV 6

- Solenoid Diode and I/O Card Replacement
- Aug Hydraulic Filter Change Out

2022 Wellsite Maintenance

Well Site 1, 07-11

- Injection SD Post Workover Jan 1 - Feb 1st
- PT-107 Adapter Flange Installed
- March - Corrosion Probe Readings
- Injection WIT/SIT
- Injection Well BHD ERD Reader Installed to address DHP erroneous readings

Well Site 2, 08-19

- ASN DAS Trial - New Sim Card installed Jan 7th

- Jan 3 - B/C Annulus WIT Complete
- PT-207 Adapter Flange Installed
- GWW (x5) Comm Issues - Notification #17176383
- 08-19 Well Site 2 - UV-702206 Bonnet Leak - Notification #17107692 (Re-Packed on April 13th) Reinstated on April 21st
- DMW Microseismic array replacement
- Inj Well WIT/SIT, Logs Completed
- Injection Well BHD ERD Reader Installed to address DHP erroneous readings

Well Site 3, 05-35

- Silixa Trial- New Sim Card Installed Jan 7th
- PT-307 Adapter Flange Installed
- Jan WIT/SIT Completed
- 05-35 Well Site 3 - UPS common alarm registers locally, but not at DCS panel - Notification #17148640.
- Injection Well Workover New Tubing Installed

Well Site 03-04

-Downhole pressure and temp reading retrieved and recorded
-SCVF and GM testing

The findings were minimal for a facility entering its eighth year of operations. The Quest operations team continues to strive for the highest reliability and are always searching for better designs and technology. As a result, these actions will equate into a longer and more predictable maintenance schedule – thus reducing overall maintenance costs. Sharing of best practices with other operating facilities continues to help improve maintenance practices and procedures. With Quest Debo. Kick off in 2022 and the Polaris carbon capture project also under way in 2022 as well. Sharing and collaborating will be an ongoing endeavor.

8 Regulatory Approvals

8.1 Regulatory Overview

Regulatory submissions in 2022 followed the schedule set forth by the approval. Regulatory approvals in 2022 addressed the ongoing operations and optimization of safe operations.

8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2022.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to Quest for the 2022 reporting period.

Table 8-1: Regulatory Approval Status

Approval or Permit	Regulator	Status and Timing of Approval/Permit	Comments
CO_2 Injection and Storage			
Statement of Project Costs Revenues – Year 7	AE	Submitted November 17, 2022	Submission in accordance with the CCS Funding Agreement
2022 Statement of Project Costs and Revenues	AEP	Submitted February 15, 2023	Submission in accordance with Additional Credits Agreement
Quest Carbon Capture and Storage Project 2022 Annual Status Report	AER	Submitted by March 31, 2023	Annual Report

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 2023 include:

- 2023 Annual status report to AER – by March 31, 2024
- 2023 MMV Plan Update – 3-year cycle
- 2023 Closure Plan Update - 3-year cycle

9 Public Engagement

9.1 Stakeholder engagement for the Quest CCS Facility

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

9.2 Community Relations

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 2022:

- March 8, 2022 – Strathcona County
- March 16, 2022 – Bruderheim
- May 10, 2022 – Fort Saskatchewan

No major issues were raised specific to the Quest facility. Questions from council members were answered immediately at the council sessions.

Public Concerns

Shell has a comprehensive public concerns process that is designed to encourage community feedback.

In 2022, Shell recorded no concerns related to Quest operations.

Participation on Community Advisory Panel (CAP)

To involve the public in the development of the MMV plan, a Community Advisory Panel (CAP) was formed in 2012. The CAP comprises local community members, academics, emergency responders, the AER and public health professionals. The mandate of the panel is to provide input to Quest 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 2022, the CAP met on November 14 in a virtual format, providing the latest MMV and community information.

Emergency Response

Groundtruthing – This is a protocol where public information packages on hazards and emergency response measures are shared with residents and contact information is verified. This Ground truthing was last conducted in 2021 with current information.

9.3 CCS Knowledge Sharing

2022 brought a transition to a new way of working, as the COVID-19 pandemic continues to transition into an endemic phase. This year was a return to many in person events yet retaining the benefit and cost-conscious capability to hold virtual sessions when possible. Global interest into our experience with the Quest facility continued in 2022, and with new carbon capture projects being proposed in Alberta, local interest to learn from this project continues to be high.

As such, members of the Quest team attended or hosted numerous conferences, workshops and tours. Table 9-1 below gives an overview of the 2022 activities.

Table 9-1: 2022 Knowledge Sharing

2022 Conferences/Workshops/Tours	Date	Location
SPWLA Abu Dhabi Chapter Presentation	January 25	Virtual
GOA Presentation	March	Virtual
AAPG Carbon Capture and Storage	March	Houston, TX
ASME Webinar	March 16	Virtual
Shell Geophysics Week – CCS & MMV	May 19	Virtual
Quest Tour: UPV/I VP	June 9	Scotford
ACT Knowledge Sharing Workshop	June 9	Virtual
Quest Tour: Equinox Energy, Wolf and Santos	June 15	Scotford
Quest Tour: Argentinian Delegation	June	Scotford
MMV presentation to Qatar Energies	June 28	Virtual
Delft Summer School	July 7	Delft
2022 PNWER 31st Annual Summit (Quest booth)	July 25	Calgary
Quest Tour: Shell CCUS Global Leaders	August 24	Scotford
DFOS SPE Workshop	August 9-10	San Antonio, TX
IMAGE Conference	September 1	Houston, TX
ACT SHARP Webinar	September 7	Virtual
ACT SHARP Workshop Panel Discussion	September 28	Copenhagen

Carbon Capture Canada Conference	September	Edmonton, AB
MIC and Canada CCUS	September	Calgary
Daya Bay Workshop	October 17	Virtual
Quest Tour: Mitsubishi	October 18	Scotford
SPE Workshop (panelist on Modern MMV)	October 19	Calgary
SMART AUV Workshop	October 19	Oslo
GHGT-16	October	Lyon
Shell CO2 Storage of SS Professionals	7 classes	Virtual
Chevron Presentation	November 8	Virtual
Quest Tour: Chevron Energy Solutions	November 9	Scotford

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 2022:

Brown, C., Lackey, G., Schwartz, B., Dean, M., Dilmore, R., Blanke, H., O'Brien, S., Rowe, C. (2022) Integrating Qualitative and Quantitative Risk Assessment Methods for Carbon Storage: A Case Study for the Quest Carbon Capture and Storage Facility. 16th International Conference on Greenhouse Gas Control Technologies GHGT-16.

Goertz-Allmann, B., Langet, N., Kuhn, D., Bird, A., Oates, S., Rowe C., Harvey, S., Oye, V., Nakstad, H., (2022) Effective microseismic monitoring of the Quest CCS site, Alberta, Canada. 16th International Conference on Greenhouse Gas Control Technologies, GHGT-16

Robinson, N., Kassam, S., Halladay, A., O'Brien S., Liston ,R., Smith, N,. Harvey, S. (2022) The Quest Carbon Capture and Storage Operation - Decarbonizing the Oil Sands. AAPG Carbon Capture and Storage Conference. Houston, TX.

10 Costs and Revenues

The majority of Quest spend is in Canadian dollars. ~5% of total spend is foreign currency (USD and EUR). 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
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 date Quest reached commercial operation.
2. Shell Labour costs during FEED phase are shown as aggregates against categories notated with an asterisk (*)

10.2 Opex Costs

Operating costs associated with the venture from the start of commercial operations are shown in Table 10-2 below.

Table 10-2: Project Operating Costs ($'000)

Cost Category	2015/2016[1]	2017	2018	2019	2020	2021[2]	2022
Power	3,717.70	4,513.96	7,562.80	9,056.83	6,985.35	13,969.08	22,223.37
Steam	8,414.46	8,834.50	5,464.59	6,284.98	7,355.33	12,524.48	16,102.14
Compressed Air	67.67	62.59	50.19	54.05	66.04	78.38	103.43
Cooling Water	427.95	389.81	379.14	446.29	474.71	536.04	713.02
Direct Labor and Personnel Costs	7,829.42	5,787.86	7,383.90	7,129.00	8,355.62	16,750.14	6,387.57
Maintenance Materials and Technical Services	969.42	942.63	1,435.98	1,286.74	2,252.79	5,380.83	1,714.33
Property Tax	2,003.72	2,000.28	1,842.73	1,916.60	1,959.60	2,036.23	2,127.66
Sequestration Opex[3]	7,052.85	6,797.59	0.00	0.00	0.00	0.00	0.00
MMV after Operations	1,690.41	1,655.74	625.64	381.34	1,335.51	1,913.12	4,080.38
Post Closure Stewardship Fund	272.07	264.28	243.33	250.48	225.34	241.78	224.60
Other Well Costs	431.49	442.12	102.74	214.11	1,104.13	518.02	1,846.05
Subsurface Tenure Costs	362.50	420.00	400.10	454.20	410.20	435.30	411.10
Pipeline - Inspection and Pigging	145.78	340.49	175.36	139.47	259.69	397.16	119.10
Amine[4]	340.67	0.00	0.00	0.00	0.00	218.23	0.00
Chemicals	20.35	97.92	150.69	157.71	134.41	79.48	63.84
Vendor rebates	-122.32	-100.36	0.00	0.00	0.00	0.00	0.00
Corporate & Other Costs[5]	119.24	205.95	463.67	607.78	812.09	1,517.76	1,010.20
Sustaining Capital[6]	0.00	54.89	0.00	432.41	63.30	0.00	0.00
Total	**33,743.37**	**32,710.26**	**26,280.86**	**28,812.00**	**31,794.12**	**56,596.02**	**57,126.80**

Notes:

1. Includes Q4 2015 – Quest began commercial operation October 1, 2015.
2. Quest's first turnaround event took place in 2021. This event required the entire operational unit to be taken offline for an extended period to perform required inspections and maintenance. Costs associated with this event are reflected primarily in the Labor and Maintenance costs categories.
3. Methodology for fixed overhead allocations captured under Sequestration Opex was reviewed in 2017. It is now distributed to the appropriate categories prospectively (from 2018) to provide greater transparency.
4. Some amine loss was observed in 2019. A total of 20m³ of amine was added to the amine stripper from the amine reservoir tank. As such, no amine purchase costs were recognised in that year.
5. Due to internal audit findings, prior year costs (2018 onwards) have been restated to include building/infrastructure support costs incorrectly omitted in prior reporting periods.
6. Sustaining Capital has been captured as an operating cost as per the Funding Agreement guidance.

10.3 Cost Per Tonne

Cost per tonne (CPT) in Table 10-3 has been calculated based on the capital and operating costs outlined in Section 10.2 above, and the gross CO_2 captured (injected) and net CO_2 avoided volumes outlined in Section 4.1.

Table 10-3: Cost Per Tonne

Cost per Tonne Summary	2015 ($)	2016 ($)	2017 ($)	2018 ($)	2019 ($)	2020 ($)	2021 ($)	2022 ($)
Operating Cost Per Tonne Captured[1]	N/A[3]	27.25	28.73	24.65	25.54	33.80	53.65	58.83
Operating Cost per Tonne Avoided[1]	N/A[3]	34.70	36.47	31.82	32.30	43.20	68.35	75.66
Total Cost per Tonne Capture d[1, 2]	N/A[3]	90.07	89.88	89.93	87.25	107.80	119.63	130.52
Total Cost per Tonne Avoided[1, 2]	N/A[3]	114.70	114.70	116.09	110.33	137.79	152.42	167.86

Notes:

1. If needed, volumes of CO_2 avoided for previous years have been updated to reflect the 3rd party verified numbers.
2. Total Cost Per Tonne is calculated using an annualized capital cost. This rate is dependent on economic inputs, including inflation and discount rates, which are adjusted each reporting period.
3. CPT has not been calculated for 2015. The project was only capturing CO_2 for 131 days and in commercial operation for 92 days. Due to the transition into commercial operations, extrapolation of costs and volumes would not provide an appropriate cost per tonne metric for the 2015 year.

10.4 Revenues

Revenues reflect both capital and operational funding, as well as CO_2 reduction credits received up to December 31, 2022. The value of CO_2 emission offset credits reported each 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 2022 relate to 1,568,482 base and additional credits serialized during the year.

Table 10-4: Project Revenues ($'000)

Revenue Stream	2009 – 2015	2016	2017	2018	2019	2020	2021	2022	Aggregate Forecast[2] (2023 – 2025)
	Construction	Operation	Operation	Operation	Operation	Operation	Operation	Operation	
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	29,452	30,100	30,796	30,050	27,033	29,006	26,945	*29,000*
CO_2 emission offset credits[1]		3,226	32,287	75,311	69,956	84,462	62,736	78,424	187,650
Total Revenues	**573,345**	**32,677**	**62,387**	**106,107**	**100,006**	**111,496**	**91,743**	**105,369**	**216,650**

Notes:

1. CO_2 emission offset credits have been restated. Serialized credits sold have been restated to reflect the weighted average sale price achieved for each parcel. Serialized credits used for compliance reflect the applicable TIER fund price. All remaining serialized credits still held have been restated to $50/credit to reflect the TIER fund price increase outlined in Ministerial Order 87/2021 [Environment and Parks] Technology Innovation and Emissions Reduction credit amount order.
2. Shell Forecast Assumptions:
   - Estimated 2.6MT CO_2 avoided over the next 3 years.

- Additional credits are received for 2022 (serialized in 2023).
- Modelling suggests that Quest will attain NRP position before 2025, resulting in only partial funding. This modelling has uncertainty due to unexpected reliability events and/or forward-looking carbon pricing that may impact the projection.

10.5 Funding Status

Quest received a total of $6.3 million from the Alberta Innovates program. Quest met the criteria of allowable expenses for $120 million National Resources of Canada funding. 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 achievement of commercial operation in October 2015. Quest has now been in the operating funding phase for seven 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 10-5: Government Funding Granted and anticipated ($'000)

Government funding granted through construction of the Quest project.

	2009 -2011	2012	2013	2014	2015	Operating 2016	Operating 2017	Operating 2018	Operating 2019	Operating 2020	Operating 2021	Operating 2022	Forecast [1]
Government Funding	Jan 1, 2009 - 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 – Sep 30, 2020	Oct 1, 2020 – Sep 30, 2021	Oct 1, 2021 – Sep 30, 2022	Oct 1, 2022 - Mar 31, 2026
Alberta Innovates Grant	6,345												
NRCan Funding		108,000			12,000								
GoA Funding		130,000	115,000	53,000	149,000	29,452	30,100	30,796	30,050	27,033	29,006	26,945	29,000
Total Funding	1,303	238,000	115,000	53,000	161,000	29,452	30,100	30,796	30,050	27,033	29,006	26,945	29,000

Cu. Gov't Funding % of Total Project Spend	1.2%	19.6%	28.8%	33.1%	46.0%	48.4%	50.8%	53.3%	55.7%	57.8%	60.2%	62.3%	64.7%

Notes: 1. Modelling suggests that Quest will attain NRP position before 2025, resulting in only partial funding. This modelling has uncertainty due to unexpected reliability events and/or forward-looking carbon pricing that may impact the projection.

11 Project Timeline

The timeline for major maintenance activities in the Quest operating period through 2022 is shown in Table 11-1.

Table 11-1: Operating Timeline

Operations Timeline		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capture Facility									
Compressor Inspection				Q2					
E-24601 Repair					Q2				
Quest Creep Test Run						Q3			
Quest Unit Turn-Around								Q2	
Pipeline and Wells Surface Facility									
Pipeline Inspection			Q4					Q4	
Storage and Subsurface									
5-35 Commissioning					Q3				
Injection Well Halite Remediation							Q3	Q4	
Injection Well Casing Inspection	Well 7-11							Q4	
	Well 8-19							Q4	
	Well 5-35								Q3
8-19 Microseismic Array Inspection/ Replacement									Q4

12 General Project Assessment

Project Successes in 2022:

Operational MMV Data Acquisition

- In 2022 monitoring continued including four discrete sampling events at the project groundwater wells. Routine logging and well integrity testing were completed on the IWs.
- Processing of the Q4 2021 seismic acquisition program progressed throughout 2022. This new data continues to be analyzed into 2023. Early results are suggesting that this onshore 4D volume is able to image the growing CO2 plume, which unlocks an exciting capability that will continue to underpin conformance modelling throughout the life of the Quest injection phase.

Networking within Industry

- The Quest operations continue into "mid life" of the asset and new learnings continue to come out of this project. The Quest team continues to participate in numerous technical conference presentations, workshop attendance, and knowledge sharing meetings.

Stakeholder Engagement

- Stakeholder management continues to be a priority for Quest. In 2022, Shell continued engagement sessions within the community and responded to stakeholder concerns. Although Shell has built on years of successful community engagement, continued dialogue is important.
- 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.
- Funding of the project will continue to occur by annual funding installment payments until the project is able to demonstrate a positive net revenue position.

Technical Successes

- 7 million tonnes of CO_2 were successfully stored in March of 2022.
- No leaks or spills in 2022.
- Compressor continued to operate at an average discharge pressure of 9.7MPag.
- Strong integrated project reliability performance with overall operational availability at 98% from start-up through 2022.
- Compressor availability was 100% in 2022.
- All three HMUs met their NOx level commitments without contravention in 2022 with continued capability to maintain NOx levels slightly elevated from pre-Quest baseline.
- Injection certification, audits, offset verifications and updates to waste heat claims were completed, with serialization of 784,241 credits in 2022, registered on the Alberta Emission Offset Registry.

Project Challenges in 2022:

There have been minor operational challenges to Quest in 2022. A description of these challenges and activities undertaken to address them is listed below.

Technical Challenges

- Adapting to scheduling and execution of activities amongst changing and reduced COVID-19 restrictions, transitioning to a 'new hybrid way of working' that is anticipated to be the standard going forward.
- After installation of new bottom hole gauges in both IW 7-11 and IW 8-19 in 2021, resolving the resulting erroneous data issues throughout 2022 continues. The forward thinking of the team to have installed double gauges in the 2021 workovers continues to help troubleshoot and improved the understanding of the issue.

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 2022, the main beneficiaries of Quest operations, in addition to the Quest Project owners, were third-party contractors. These contractors were responsible for the following activities:

- Maintenance and inspection on the Quest unit, including planned turnaround activities.
- Field work done to monitor the hydrosphere properties of the storage area surface and groundwater regions.
- Maintenance and repair contracts around $2-4 million in 2022.
- MMV Expenses were $3-4 million in 2022.

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 of Alberta as a leader in CCS deployment through policy, regulation, and funding.

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:

- Use lessons learned to retain institutional memory and facilitate improvements in processes and procedures.
- Regulatory activities to demonstrate compliance with existing agreements.
- Public engagement activities and advocacy to build public knowledge and acceptance of CCS operations.
- Active sharing of CCS knowledge through publications and participation in conferences and workshops.
- Work with AEP and Alberta Energy (CCS Unit) on evolving regulations (i.e. TIER) and the long-term viability of CCS within Alberta.
- Work on energy-saving opportunities to reduce variable cost pressures of steam and electricity on Quest.
- Focus on optimizing operational costs.
- 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.

14 References

[1] AER, 2022, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, 2022 ANNUAL STATUS REPORT, will be available at: https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program&tags=Quest+Carbon+Capture+and+Storage+project