Disclaimer

This Report, including the data and information contained in this Report, is provided to you on an "as is" and "as available" basis at the sole discretion of the Government of Alberta and subject to the terms and conditions of use below (the "Terms and Conditions"). The Government of Alberta has not verified this Report for accuracy and does not warrant the accuracy of, or make any other warranties or representations regarding, this Report. Furthermore, updates to this Report may not be made available. Your use of any of this Report is at your sole and absolute risk.

This Report is provided to the Government of Alberta, and the Government of Alberta has obtained a license or other authorization for use of the Reports, from:

Canadian Natural Upgrading Limited, Chevron Canada Oil Sands Partnership and 1745844 Alberta Ltd., as owners, and Shell Canada Energy as operator, for the Quest Project (collectively the "Project").

Each member of the Project expressly disclaims any representation or warranty, express or implied, as to the accuracy or completeness of the material and information contained herein, and none of them shall have any liability, regardless of any negligence or fault, for any statements contained in, or for any omissions from, this Report. Under no circumstances shall the Government of Alberta or the Project be liable for any damages, claims, causes of action, losses, legal fees or expenses, or any other cost whatsoever arising out of the use of this Report or any part thereof or the use of any other data or information on this website.

Terms and Conditions of Use

Except as indicated in these Terms and Conditions, this Report and any part thereof shall not be copied, reproduced, distributed, republished, downloaded, displayed, posted or transmitted in any form or by any means, without the prior written consent of the Government of Alberta and the Project.

The Government of Alberta's intent in posting this Report is to make them available to the public for personal and non-commercial (educational) use. You may not use this Report for any other purpose. You may reproduce data and information in this Report subject to the following conditions:

- any disclaimers that appear in this Report shall be retained in their original form and applied to the data and information reproduced from this Report
- the data and information shall not be modified from its original form
- the Project shall be identified as the original source of the data and information, while this website shall be identified as the reference source, and
- the reproduction shall not be represented as an official version of the materials reproduced, nor as having been made in affiliation with or with the endorsement of the Government of Alberta or the Project

By accessing and using this Report, you agree to indemnify and hold the Government of Alberta and the Project, and their respective employees and agents, harmless from and against any and all claims, demands, actions and costs (including legal costs on a solicitor-client basis) arising out of any breach by you of these Terms and Conditions or otherwise arising out of your use or reproduction of the data and information in this Report.

Your access to and use of this Report is subject exclusively to these Terms and Conditions and any terms and conditions contained within the Report itself, all of which you shall comply with. You will not use this Report for any purpose that is unlawful or prohibited by these Terms and Conditions. You agree that any other use of this Report means you agree to be bound by these Terms and Conditions. These Terms and Conditions are subject to modification, and you agree to review them periodically for changes. If you do not accept these Terms and Conditions you agree to immediately stop accessing this Report and destroy all copies in your possession or control.

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

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

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

Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT -

ALBERTA DEPARTMENT OF ENERGY: 2021

March 2022 (revised July 2022)

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 2021, Quest surpassed 6.8 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.

With the ongoing events of the global pandemic in 2021, all engagements occurred virtually. Knowledge sharing from Shell's experience with Quest was shared with numerous industry, business, academic and non-government associations in 2021.

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

- Sustained, safe, and reliable operations, including a Goal Zero turnaround in the Quest unit.
- 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.
- 2021 turnaround of the Quest unit was successful, on time, and on budget. Overall findings were minimal for a facility entering its seventh year of operations.
- Strong integrated project reliability performance with operational availability at 97.8% since start-up.
- Two successful halite remediations at IW 7-11 and IW 8-19.
- Operating costs continue to be stable.
- Sharing of best practices by networking with other operating facilities continues to help improve maintenance practices and procedures.
- Maintaining local support through the extensive stakeholder engagement activities.
- Continued participation of the Community Advisory Panel (CAP).
- International engagements with the IEAGHG and SPE to support public engagement, global knowledge sharing activities and virtual participation in a number of conferences.
- Serialization in 2021 of 1,394,144 credits from 2020.

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

- Evolvement of safe work practices due to COVID-19.
- Reduced CO2 availability resulted net reduction of capture.
- Quest unit turnaround discovered issues with regenerator inlet vein distributor and replaced in kind during the event.

Quest has seen strong reliability performance through the reporting period to safely inject over 1.055 Mt of CO_2 in 2021. Overall project injection surpassed 6.8 Mt of CO_2 through December 31, 2021.

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) $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 the 2021 compliance year, the value of the TIER fund credit is $40/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 2021 in staffing, Measurement, Monitoring and Verification (MMV), maintenance, and other costs that benefit the local economy.

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

Table of Contents

List of Figures

List of Tables

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 operations phase at Quest started in September 2015. Quest has successfully captured and injected over 6.8 Mt of CO_2 in three injection wells (8-19, 7-11 and 5-35) to the end of 2021.

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

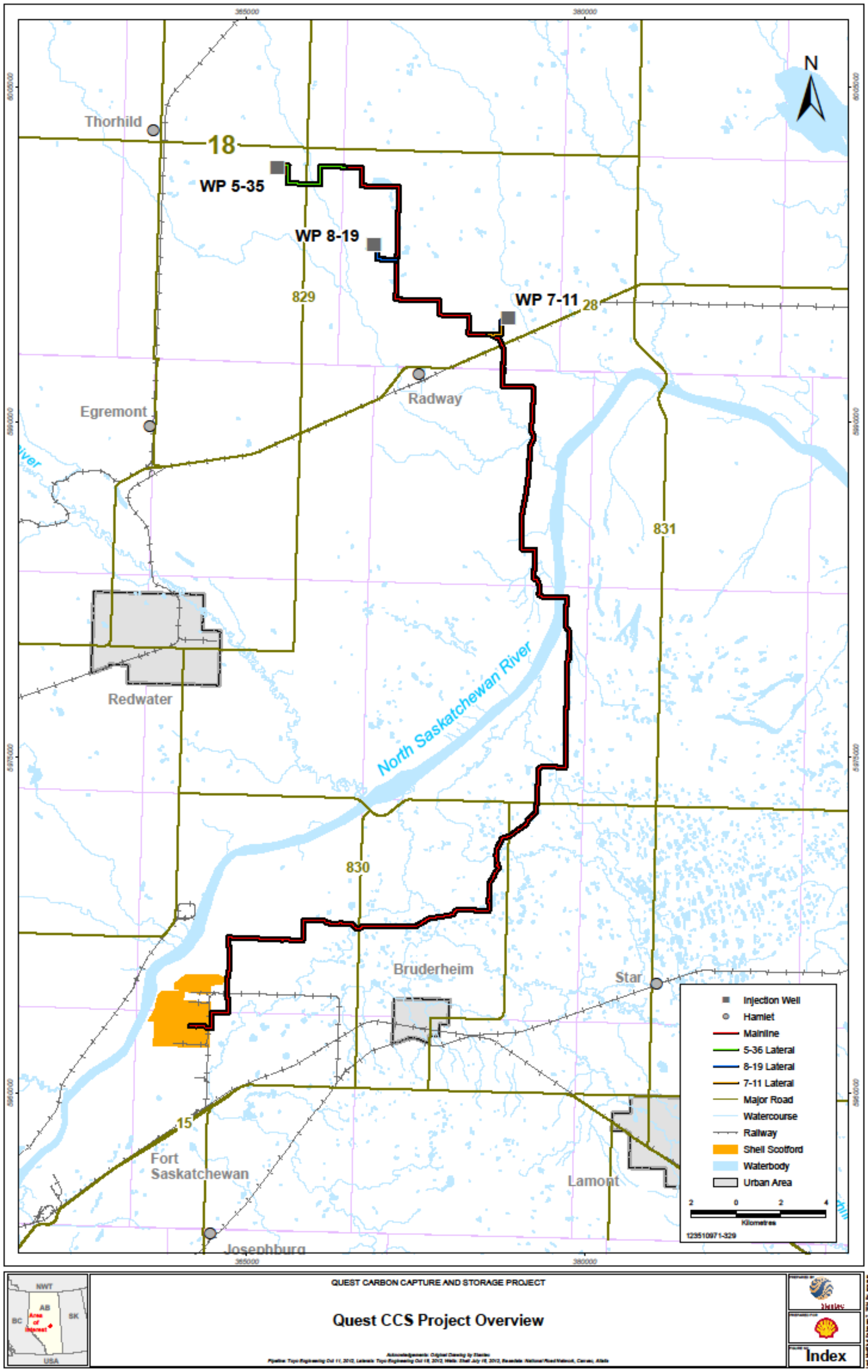

Figure 1-1: Project Facility Locations.

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 2021 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 2021

Quest Operating Summary	2015 Summary	2016 Summary	2017 Summary	2018 Summary	2019 Summary	2020 Summary	2021 Summary	Units
Total CO_2 Injected	0.371	1.11	1.138	1.066	1.128	0.941	1.055	Mt CO_2
CO_2 Capture Ratio[4]	77.4	83.0	82.6	79.1	78.8	76.8	78.2	%
CO_2 Emissions from Capture, Transport and Storage	0.080	0.238	0.241	0.241[5]	0.236[3,5]	0.205[5]	0.232[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]	0.823[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]	0.043[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.

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 2021 was 0.57 tCO_2/MWh (Carbon Offset Emission Factors Handbook). Shell reapplied for this deviation for the 2021 compliance year and was granted this deviation from AEP on February 2, 2022.

As of end 2021, Quest has injected over 6.8 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 2021:

- Injection: Shell and an independent 3rd party verifier conducted the Year 6 Injection certification audit that reviewed injection and mass balance data from October 1, 2020, to September 30, 2021. The audit was closed October 2021 confirming the injected CO_2 volume of 1,051,233 tonnes as reported to Alberta Energy.
- Emissions: Shell and an independent 3rd party verifier conducted 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 is submitted to the Alberta Offset Registry by May 1, 2022.

The Quest CCS project serialized a total of 1,394,144 credits on the Alberta Emission Offset Registry in April/May 2021:

Reporting Period		Base/Additional	Date Serialized	Serialized Emission Offsets
10th (2020)	Jan 1 2020 to Dec 31, 2020	Base	28-Apr-2021	697,072
		Additional	13-May-2021	697,072

4.2 Capture (Absorbers and Regeneration)

CO_2 removal ratio performance of the capture unit was as expected in 2021, with an annual CO_2 capture ratio of 78.2%. 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 2021 were the planned inspection and maintenance downtime of the Quest unit. Other reductions were a result of unplanned unit trips, reduced available volume for capture from upstream units, planned slowdowns, and trips in process units outside of Quest. These periods are summarized below:

- March 23, 2021: HMU3 reduces capture from 80% to 78% for reformer management.
- April 15, 2021: Quest unit is taken offline for turnaround inspection and maintenance window. The carbon capture unit resumed operation May 15, 2021.
- June 11, 2021: HMU3 reduces capture from 78% to 74%. HMU3 operated in this reduced capture mode for the remainder of the year.
- August 30, 2021: HMU1 and HMU2 reduce production and capture due to hydrogen demand. Normal production from HMU1 and HMU2 resumed to normal October 24, 2021.
- September 29, 2021: Pipeline trip stopping injection for 1 day.
- October 30, 2021: Pipeline trip stopping injection for 1 day.
- November 25, 2021: HMU2 carbon capture from 82% to 65% over the course of three weeks for reformer management. Capture remained at 65% for the remainder of the year.

- December 9: HMU2 operations result in reduced available CO_2 for capture.
- December 16, 2021: Pipeline trip stopping injection for 1 day.
- December 27, 2021: HMUs reduced production and resulted in less available CO_2 for capture.

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	Units
Electricity (Capture/Dehydration)	12300	32800	32600	32200	32700	27700	31500	MWh_e[1]
Low Pressure Steam	410	1263	1297	1204	1217	1050	1191	kT
Low Temperature High Pressure Steam	1.96	5.52	5.23	5.01	5.12	6.21	5.01	kT
Nitrogen	178	230	237	258	256	230	171	Ksm^3
Wastewater	24900	80900	61900	57800	60700	50200	54281	m^3
Energy/Heat Recovered	33600	96260	98554	95060	93955	78490	87585	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]	Mt CO_2

[1] The e subscript denotes electrical energy.
[2] The th subscript denotes thermal energy.
[3] 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 is set to 0% under CCIR.
[4] CO_2 emissions have been updated to reflect the 3rd party verified numbers

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 2021, 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 2021, 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 9°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 accelerant content has not affected capture performance at this time.

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 2021, 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 (~84% of total capture emissions), and from electricity for equipment in the capture system (~4% of capture emissions).

4.3 Compression

In 2021, the compressor continued to operate at lower discharge pressures than previous years. 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	Units
Suction Pressure	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	MPag
Motor Electricity Demand	13.3	13.8	14.2	14.0	14.2	13.7	13.6	MW_e

4.4 Dehydration

The dehydration unit performance continued to operate reliably in 2021. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv. Actual water content for 2021 was on average 48 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 2021 being 10ppmw of the total CO_2 injection stream, compared to the 27 ppmw expected in design. The total annual TEG loss was 10,772 kg in 2021, 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 2021 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 2021, the averaged NOx emissions with Quest operational and the FGR online are included below:

- HMU1: 33.14 kg/h, limit 76.5 kg/h
- HMU2: 31.80 kg/h, limit 76.5 kg/h
- HMU3: 56.61 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 2021.

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

Characteristic	Specification	Units	Average Operating Data / Actual Limitations							Original Design
			2015	2016	2017	2018	2019	2020	2021	
General										
Pipeline Inlet Pressure	Normal	MPag	9.4	9.8	9.9	10.3	9.6	9.7	9.5	10
	Maximum Operating	MPag	12	12	13.58	13.58	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	8.8	8.6	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	0.4 (for 3 well scenario)
Temperature	Compressor Discharge	°C	130	130	128	131	131	126	124	130
	Pipeline Inlet after cooler	°C	43	43	41	41	41	42	42	43
	Upset Condition at Inlet	°C	-	-	-	-	-	-	-	60
	Injection Well 7-11 Inlet Temperature	°C	15	16	14	13	15	13	16	-
	Injection Well 8-19 Inlet Temperature	°C	12	12	11	9	12	10	12	-
	Injection Well 5-35 Inlet Temperature (as of Oct 19, 2018)	°C	-	-	-	6	7	6	10	-
Flow rates	Normal Transport Rate	Mt/a	1.04	1.11	1.14	1.06	1.14	0.94	1.06	1.2
	Design minimum	Mt/a	-	-	-	-	-	-		0.36
	Total Transported	Mt	0.371	1.11	1.14	1.06	1.14	0.94	1.06	-
Energy and Emissions	Total Electricity for Transport (compression)	MWh_e	41,527	119,426	121,593	119,396	143,453	124,199	110,619	-

	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]	-

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 (9.9 MPag, 41°C) and with CO_2 leaving the main pipeline to the well sites 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 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%)**	**Design Normal Composition**	**Design Upset Composition**
CO_2	99.45	99.38	99.46	99.44	99.44	99.37	99.40	99.23	95.00
H_2	0.48	0.51	0.47	0.46	0.48	0.48	0.47	0.65	4.27
CH_4	0.06	0.06	0.06	0.06	0.05	0.05	0.06	0.09	0.57
CO	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.02	0.15
N_2	0	0	0	0	0	0	0	0	0.01
Total	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 2021 was 48 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 completed quarterly in 2021.

6 Facility Operations - Storage and Monitoring

This section provides an overview of the wells and MMV activities for the operational year 2021.

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, 2021, about 6.8 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 5-2 and is shown in Figure 6-2.

By the end of December 2021, about 2.88 Mt of $C0_2$ had been injected into the 7-11 well, 2.80 Mt of $C0_2$ into the 8-19 well, and 1.13 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.

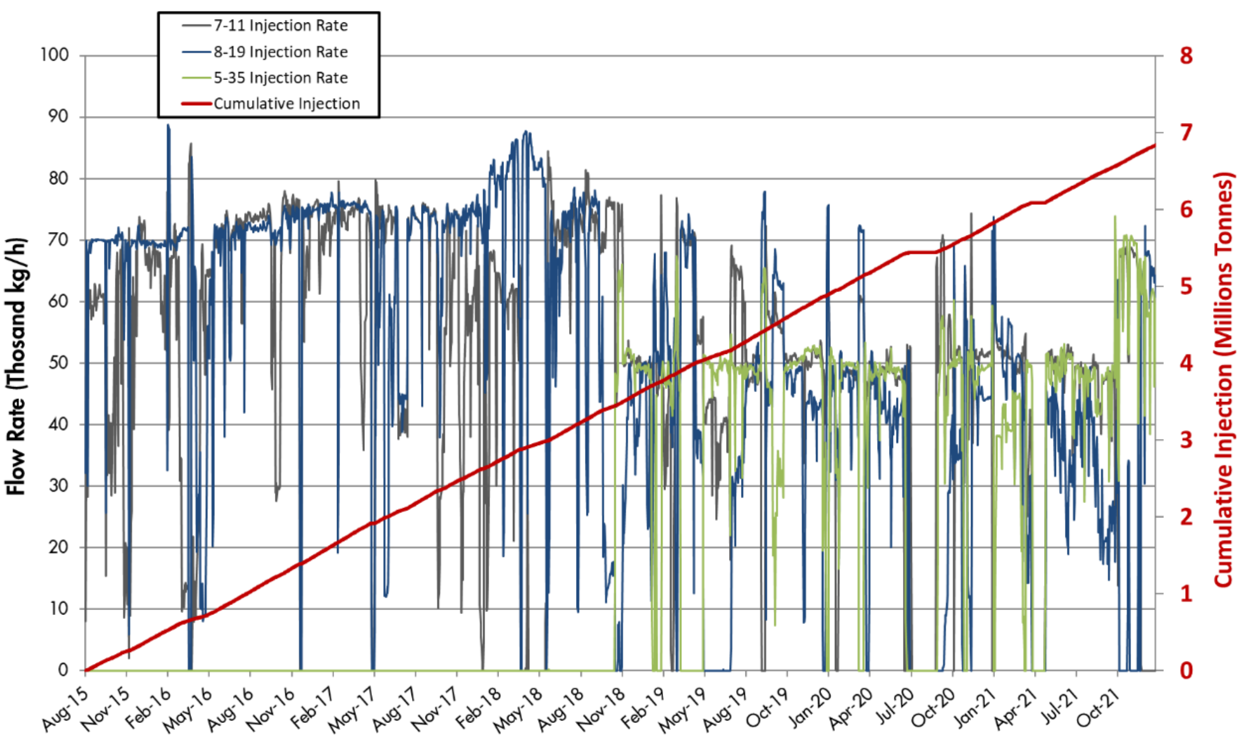

Figure 6-1: Quest Injection Totals: Cumulative CO_2 injected into the wells from start-up through to the end of 2021 (red). The blue, grey and green lines show the average hourly flow rates into each of the injection wells.

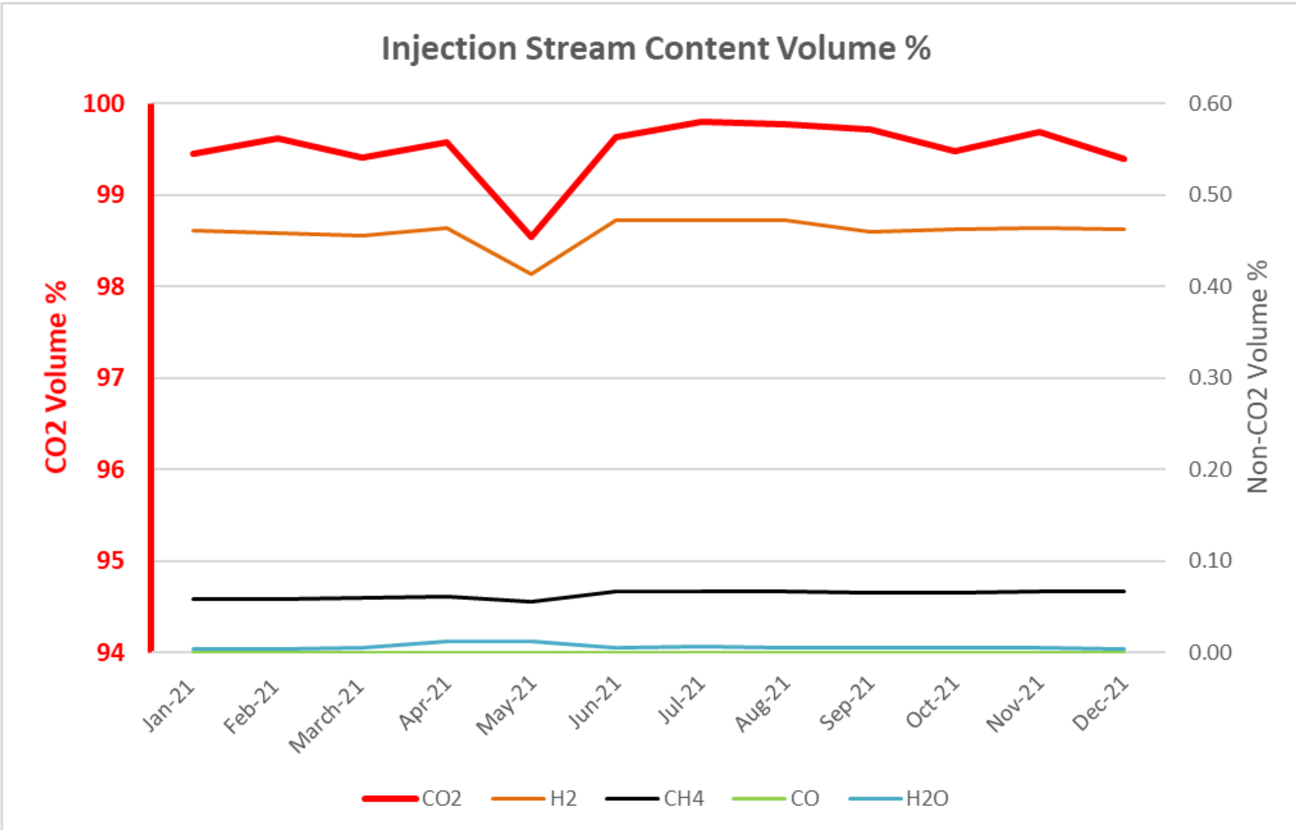

Figure 6-2: Quest Injection Stream Content: Average injection composition for 2021. There was no capture from April 16th to May 14th, 2021.

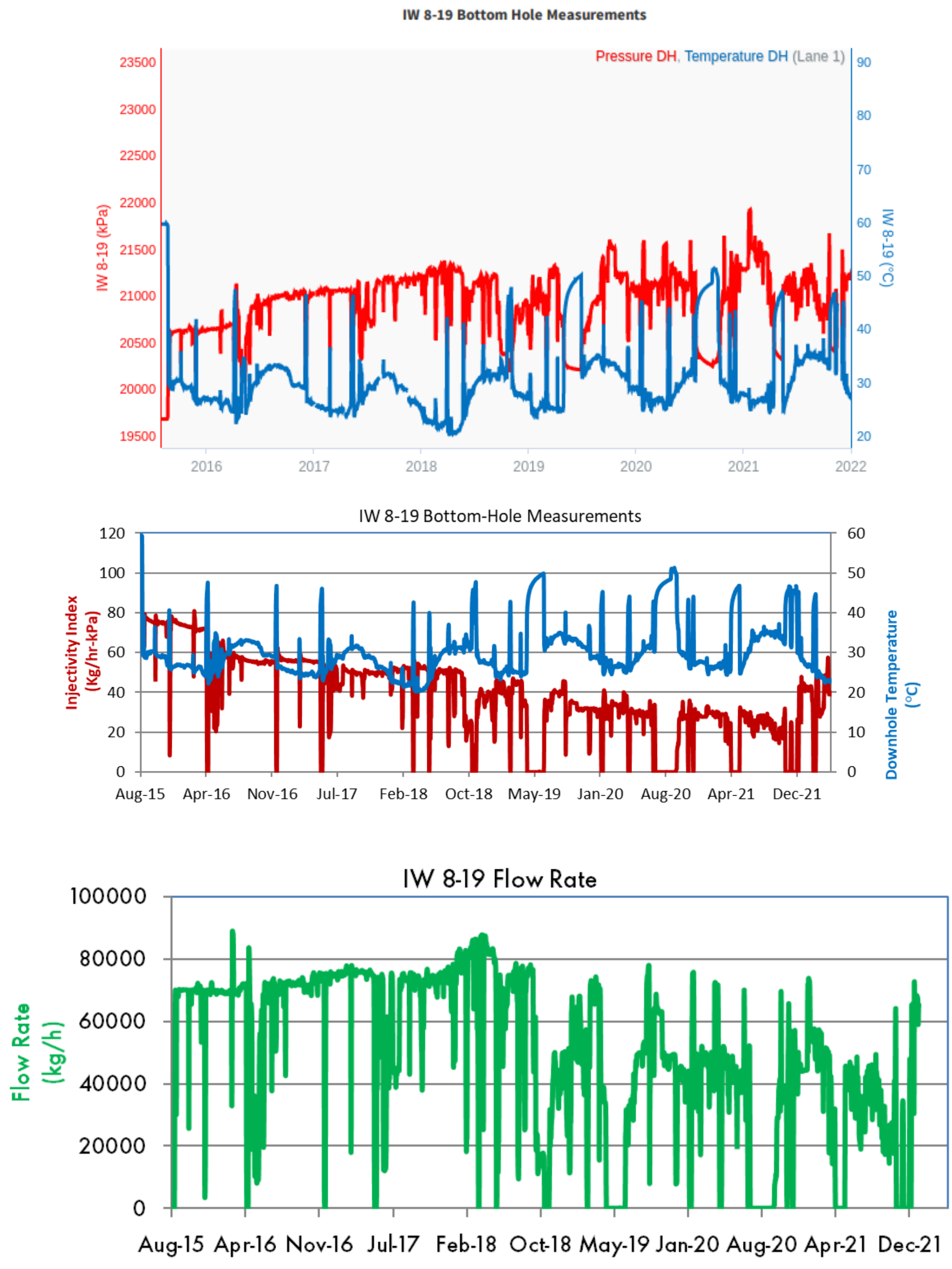

Figure 6-3: The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection to the end of 2021. (Note: Data has been removed during the well workover/inspection from November 15 to December 1, 2021.)

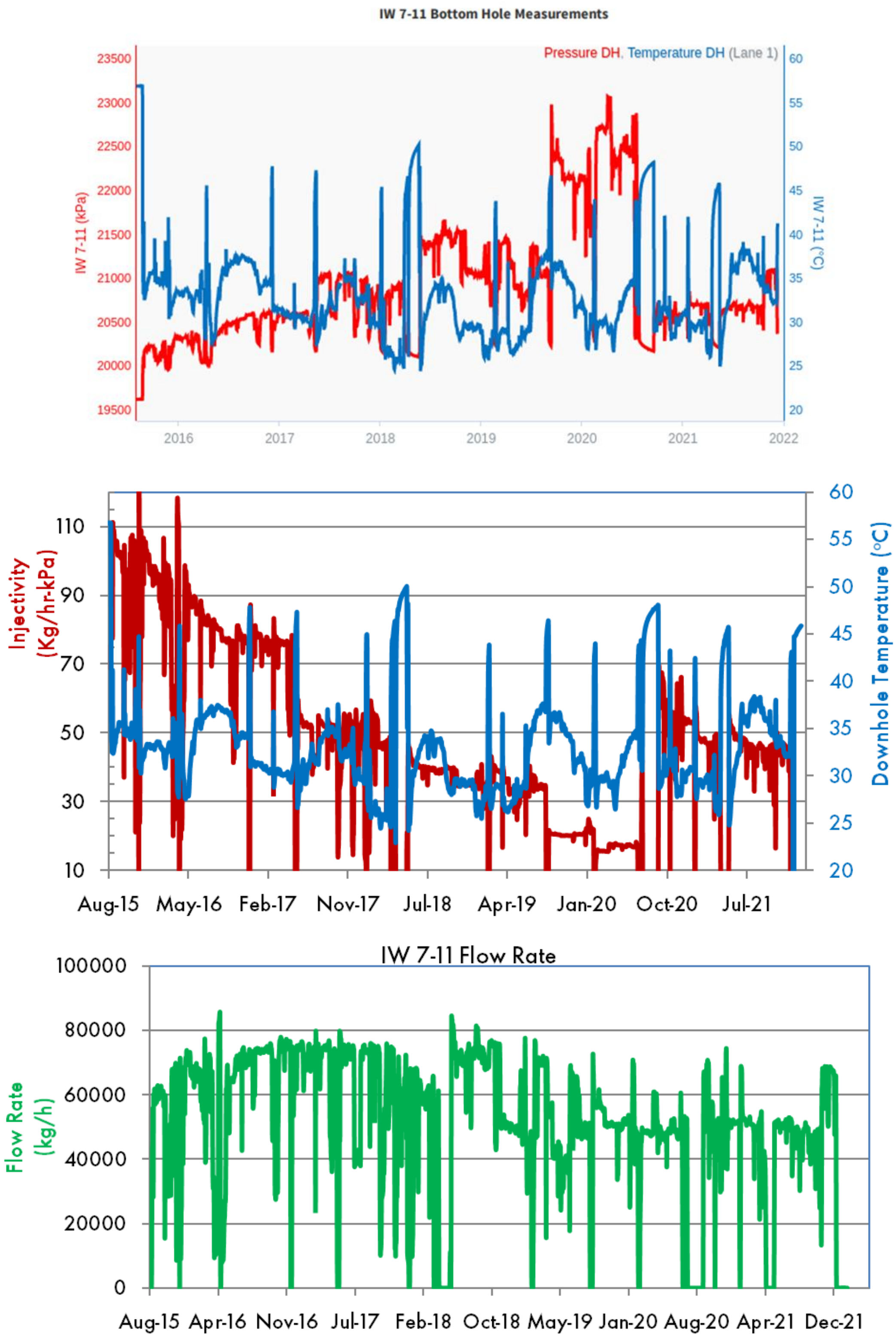

Figure 6-4: The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2021.

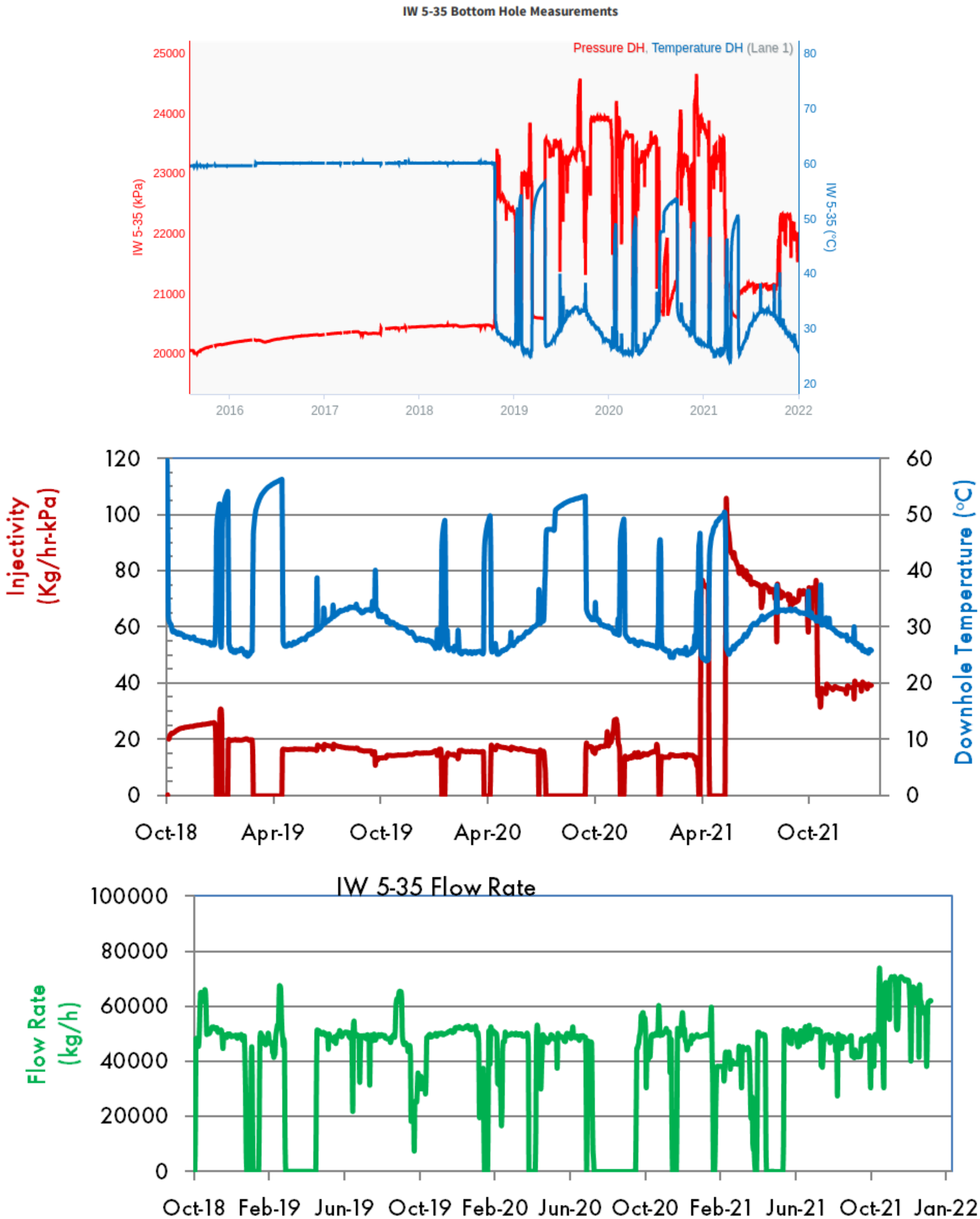

Figure 6-5: The 5-35 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2021.

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 2021 AER Annual Report, Section 3.5: Reservoir Capacity 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 2021.

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
2020	0.941 Mt	21.248 Mt CO_2
2021	1.055Mt	20.193 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.

Following the success of IW 7-11 halite remediation treatment in July 2020, a new treatment was conducted on IW 5-35 at the end of March 2021 with the objective of improving injectivity. The treatment resulted in an injectivity improvement even greater than the first halite remediation treatment conducted on IW 7-11. The enhanced injectivity of IW5-35 right after the treatment was over 5 times of the well's initial injectivity during the first year of operation. A second halite remediation treatment in 2021 was conducted on IW 8-19 in early December 2021 with moderate improvements observed.

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 2021 MMV activities included: atmosphere, hydrosphere, geosphere, and well-based monitoring. The following is a summary of these activities:

Atmosphere domain: Line of sight CO_2 gas detectors and weather stations were replaced at the three Quest well pads. Operator rounds were completed daily at the injection well sites.

Hydrosphere domain: In addition to continuous monitoring of the Quest groundwater wells, discrete sampling at wells was done from Q1 to Q4 2021.

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

Geosphere domain: Monthly satellite image collection for InSAR continued. Since September 2017, a single frame centered over the 3 injection well pads has been used for image collection. In 2021, 3DSEIS and 2DSEIS were acquired at IW5-35 and IW8-19. A 2DVSP was acquired at IW5-35.

Well-based monitoring: ongoing data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes. Routine well maintenance and integrity activities.

The 2020 MMV plan was approved November 25, 2020 and was in use throughout 2021.

No trigger events were identified during 2021 that would indicate a loss of containment per the 2020 MMV plan definition of containment monitoring. Tier 1 technologies are reported in Table 6-2 (2020 MMV Plan).

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

1. The 2019 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 the reservoir is behaving better than expected, and the displacement of brine by the CO_2 may be more effective than the initial pre-injection modelling predicted.
2. Assessment of the pressure data indicates the reservoir has more than enough capacity for the life of this project.
3. In 2021, a few time-significant pressure fall-offs were recorded that 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 2020 model for pressure prediction forecasting for injection rates similar to those observed through 2021.

Further details of the MMV activities undertaken and observations made during 2021 can be found in the 2021 AER Annual Status Report [1].

Table 6-2: Overall assessment of trigger events used to assess loss of containment in 2021 using the 2020 MMV Plan.

Tier	Technology ^	Trigger	2021
Tier 1	IW DHP	Measuring greater than 26 Mpa or less than 20Mpa	
	IW Tubing/Casing Annular Pressure	Anomalous pressue response	
	DMW DHP	Anomalous pressure increase above background levels	

^ based on Table 4-3 of the 2020 MMV Plan

Legend	
	no trigger event
	trigger event
	not evaluated

6.3 Wells Activities

6.3.1 Injection Wells

In 2021, the injection wells underwent routine work including wellhead integrity testing (wellhead maintenance and pressure testing) and packer isolation tests. Hydraulic isolation logging (PNx) was undertaken at IW 5-35, and casing and cement bond logging executed at IW 8-19 and IW 7-11.

Following the success of IW 7-11 halite remediation treatment in July 2020, two halite remediation treatments were executed in 2021. The success of the halite remediation treatments conducted in 2020 and 2021 have demonstrated the effectiveness of the treatment in maintaining injectivity in the Quest CCS saline aquifer wells.

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 have been collected since Q3, 2015, as illustrated in Figure 6-6 and Figure 6-7. Thus far, the Cooking Lake pressure data has not given any behavior to warrant further investigation.

Maintenance at DMW 5-35 and DMW 7-11 occurred in 2021 and included a replacement and re-calibration of the bottom hole pressure gauges.

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 2021.

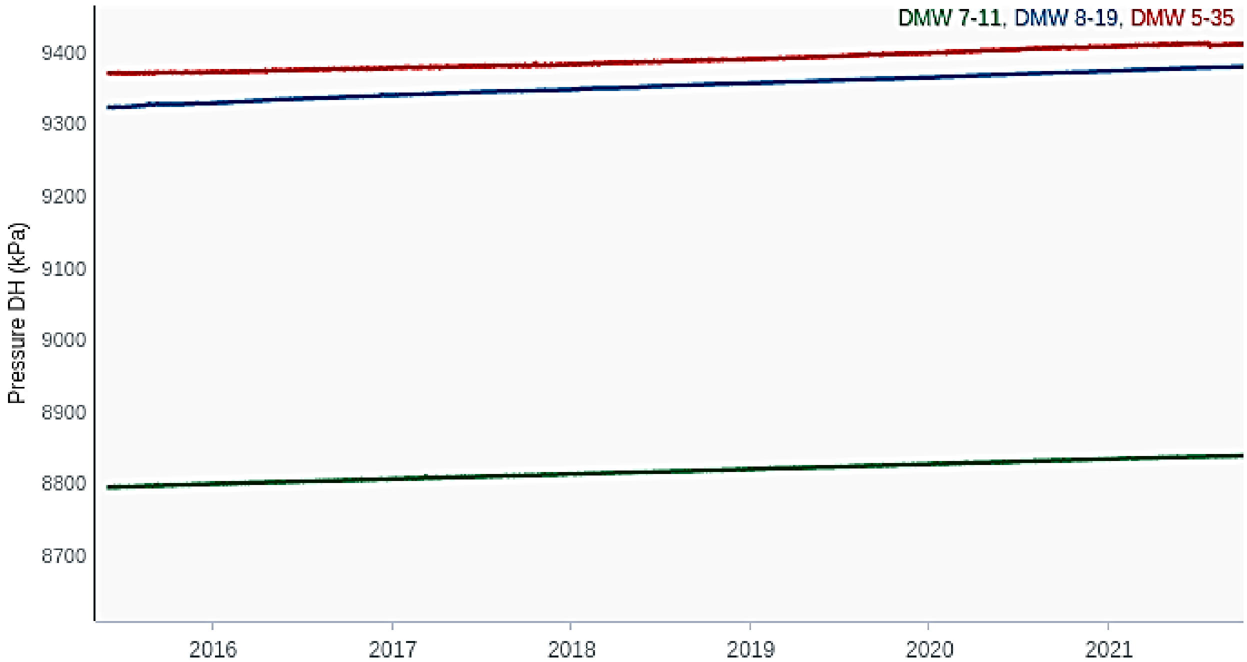

Figure 6-6: Quest DMW pressure history before and during injection.

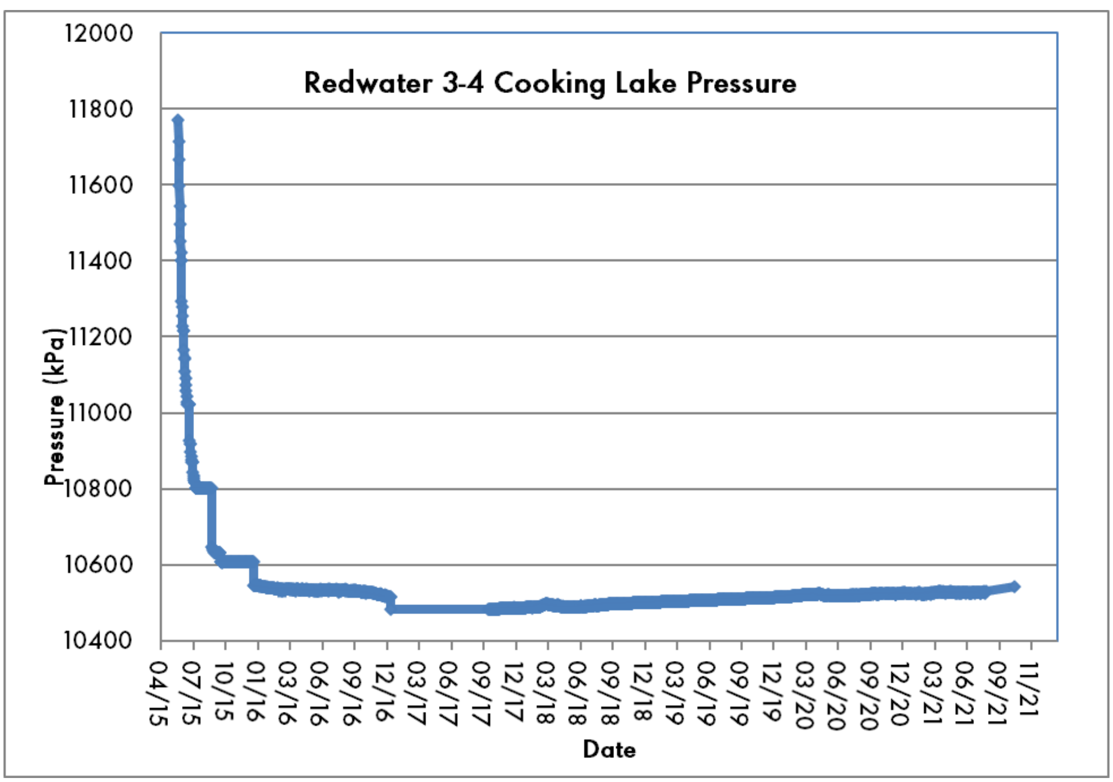

Figure 6-7: Quest 3-4 DMW pressure history.

6.3.3 Surface Casing Vent Flow and Gas Migration Monitoring

Following the 2012-2013 drilling campaign, gas migrations (GM) were observed at IW 5-35 and IW 7-11 in February and March 2013 respectively. Surface Casing Vent Flows (SCVF) were also observed on these two wells and reported as non-serious as per Interim Directive 2003-01. However, since these two wells had a SCVF and a GM, they were automatically classified as serious, as per Bulletin 2009-07.

As part of the approved 2020 MMV Plan and with AER approval, SCVF and in-soil gas migration testing was performed in 2021 and planned for 2024.

SCVFs remain at low levels comparable to previous test results (Figure 6-8) and remain below measurable values at IW 08-19, DMW 07-11 and DMW 8-19. The IW 7-11 GM has also declined to zero. The IW 5-35 GM gas concentrations in the well cellar have decreased; although it is noted that some ambient air contamination did occur in the GM gas samples from the well cellar in 2021. Collectively the data demonstrate that there is no CO_2 flux detected in shallow groundwater wells, injection well SCVFs, deep monitoring well SCVFs or in gas migration measured at surface. In addition, compositional and isotopic data suggests sources of SCVF and GM remain consistent with previous years and continue to decline.

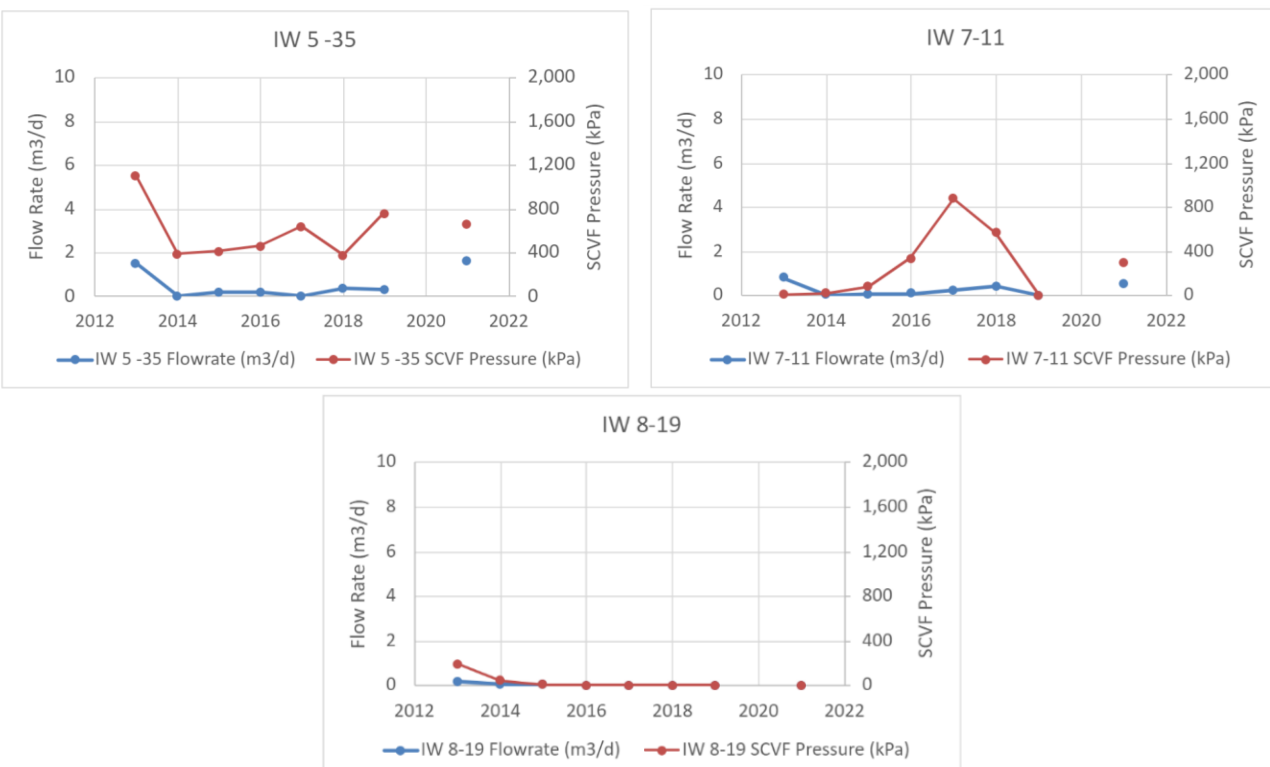

Figure 6-8: SCVF Pressure and Flow rate summary graphs for IW 5-35, IW 7-11 and IW 8-19.

7 Facility Operations - Maintenance and Repairs

In 2021, the Quest facility was taken down for the first major turnaround since start up. Overall, the turnaround was successful being completed on time and budget with only a few findings involving critical equipment in the process. V-24601 (Schopentoeter distribution header damaged), E-24602A/B (lean/rich exchanger fouling) and CM-24701 ($C0_2$ compressor motor winding damage). Most of the equipment opened during turnaround required process engineering inspection and cleaning while the facility was down. Minimal additional scope was added to the turnaround based on findings from inspection and engineering.

Quest simulator training was carried out to increase competency and awareness for operations prior to the Quest turnaround to ensure a safe and timely shutdown/start-up.

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.

<u>Maintenance and repairs during 2021 are as follows:</u>

- 2021 Quest turnaround opened all facility equipment for cleaning, inspection and repair if required.
- V-24601 Schoepentoeter distribution header replaced
- V-24601 tray 20 replaced due to damage
- CM-24701 winding repair phase swap
- P-24607 bearing replaced along with motor
- P-24612 bearing and motor replacement
- UV-247003 deviation trip reprogrammed due to spurious valve openings causing unit upsets
- UV-247003 positioner replaced (pipeline trip)
- E-24605A/B sent offsite for cleaning
- E-24607A/B condensate cooler sent for cleaning
- E-24604A/B lean amine coolers cleaned
- E-24601A sent offsite for bundle pull and shell replacement
- V-24607 LP cond inlet nozzle overlay repair
- V-24602 reflux drum demister replacement
- P-24611A/B inspection and overhaul cooling water pumps
- Replaced Quest absorber C02 FT-24x074
- TEG 3304 valve additions to comply with safe work practice
- C-24701 suction strainers stage 2-7 replaced (start-up strainers still in)
- FV-702204 positioner replacement and UV-702206 packing leak and repair
- Caustic facility HVAC repairs/upgrades to heating capacity
- Amine purchase to increase efficiency of process and reduction of LP steam

- FC-246005 positioner fail and changeout on reboiler x 3
- E-24706/07 fin fan blows to maintain summer rates
- Ventis inspection pipeline
- Replaced insulation soft covers with hard insulation in certain areas due to freezing of instruments.
- HVAC repairs due to inadequate heating and cooling in Quest O/I and substations.
- Wellsite WIT/SIT and isolation logs 7-11/8-19/5-35
- Wellsite 7-11, 8-19, 5-35 halite remediation
- Pigging of full Quest pipeline
- Inlet nozzle repairs E-24701/02/03/04/05 (predetermined, construction issue from manufacturer)
- E-24701/02/03/04/05 cooling water bundles pulled and cleaned
- C-24701 $C0_2$ compressor motor windings repaired until new motor arrives in 2022

<u>2021 Maintenance</u>

- Caustic pump P-24613 replaced
- FT-24x074 MOC 28128
- P-24607 pump replacement and d/s check valve
- E-24605A/B cleaning
- E-24604A/B cleaning
- E-24607A/B cleaning
- E-24601A new shell
- V-24607 inlet nozzle repair
- V-24601 internal repair (20th tray)
- V-24602 demister replacement
- P-24611A/B overhaul
- Reboilers and C-24701 4th stage suction and discharge thermowells replaced
- C-24701 compressor building main HVAC sensor replacement
- CM-24701 motor winding repair
- E-24706/07 cleaning
- E-24701/02/03/04/05 intercooler nozzles inspected and repaired/replaced in 2021 TA
- E-24701/02/03/04/05 bundles cleaned
- UV-247003 positioner
- P-24612 pump replaced
- UV-247003 feedback positioner replaced (C-24701 trip)
- C-24701 permanent suction strainers 2-7 replaced
- 248 TEG isolation valves added to filter skid

2021 Pipeline Maintenance

Trucks

- Jan - IVMS installed
- Unit #2025 new tires
- Unit #351 new tires

Pipeline

- Purchase new generator
- Gage and smart pig run on pipeline

LBV 1

- Relocate Quest LBV solar charger into EFOY cabinet
- Security camera removed for repair

LBV 2

- EFOY replaced
- Change out EFOY batteries and relocated the solar charger to the EFOY cabinet
- Drain tube heat trace modification complete. Firmware update complete
- Security camera replaced

LBV 3

- Relocate Quest LBV solar charger into EFOY cabinet
- Repaired EFOY installed

LBV 4

- Relocate Quest LBV solar charger into EFOY cabinet
- Change out EFOY batteries and relocated solar charger to the EFOY cabinet
- New upgraded EFOY unit installed and tested. Drain tube heat trace modification complete

LBV 5

- Relocate Quest LBV solar charger into EFOY cabinet
- New upgraded EFOY unit installed and tested. Drain tube heat trace modification complete
- Actuator quick exhaust valve replaced - Still losing pressure in cold weather

LBV 6

- Relocate Quest LBV solar charger into EFOY cabinet
- Actuator quick exhaust valve replaced
- Security camera replaced

2021 Wellsite Maintenance

Well Site 1

- $C0_2$ new line of site installed at all well sites
- Injection well flow cross replaced due to leaky joint, WIT Test and BHCV test complete
- UPS System failure and card replacement (pipeline trip occurred)
- New MMV server (Mini Desktop)
- HVAC condenser replaced
- WIT/SIT
- Injection well work over (new down hole gauge and replaced tubing in kind)

Well Site 2

- FV-702204 positioner replaced
- New MMV server (Mini Desktop)
- HVAC condenser fan motor replaced
- HVAC overloads changed out
- Injection well annulus top up
- MMV server upgrade for monitoring well
- Injection well halite remediation
- Injection well annulus N_2 top up/WIT/SIT
- $C0_2$ new line of site installed at all well sites
- UV packing leak - added packing plastic
- Injection well workover (new DHG and replaced tubing in kind)
- Halite remediation
- DAS trial installation

Well Site 3

- Hydraulic isolation logging
- Grease 1st 6" riser valve
- Halite remediation
- New MMV server (Mini Desktop)
- SCVF and GM testing
- $C0_2$ new line of site installed at all well sites
- Injection well fluid shots

Well Site 03-04

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

The Quest 2021 turnaround presented the opportunity to shutdown the entire unit to clean, inspect and repair any damaged equipment. In addition to the items listed above, control valves and safety-relief valves were inspected, repaired or recertified during the turnaround window. The overall turnaround was very successful. Within the scope of work, the V-24601 distribution header, E-24602A/B lean/rich exchanger and the C-24701 C02 compressor were all deemed to require replacement or repair based on design and operating parameters of the Quest unit.

The findings were minimal for a facility entering its seventh 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 by networking with other operating facilities continues to help improve maintenance practices and procedures.

8 Regulatory Approvals

8.1 Regulatory Overview

Regulatory submissions in 2021 followed the schedule set forth by the approval. Regulatory approvals in 2021 addressed the ongoing operations and optimization of safe operations.

8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2021.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to Quest for the 2021 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 6	AE	Submitted November 8, 2021	Submission in accordance with the CCS Funding Agreement
2020 Statement of Project Costs and Revenues	AEP	Submitted February 8, 2021.	Submission in accordance with Additional Credits Agreement
Quest Carbon Capture and Storage Project 2020 Annual Status Report	AER	Submitted March 31, 2021	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 2022 include:

- 2021 Annual status report to AER
- 2021 SCVF/GM submissions

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

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 2021:

- March 9, 2021 – Strathcona County

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 2021, Shell recorded one concern related to Quest operations:

- Concern related to maintenance at one of the Quest wells. The neighbor was provided with the correct information and a one-to-one call was held to help answer questions.

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 2021, the CAP met on June 8 in a virtual format, providing the latest MMV and community information.

Emergency Response

Groundtruthing – where public information packages on hazards and emergency response measures are shared with residents and contact information is verified – was conducted in 2021. A virtual well site emergency response drill occurred on August 12, 2021.

9.3 CCS Knowledge Sharing

Despite the events of the COVID-19 pandemic, which significantly impacted travel, global interest into our experience with the Quest facility continued in 2021.

As such, members of the Quest team attended or hosted numerous conferences, workshops and tours. Table 9-1 below gives an overview of the 2021 activities. All applicable restrictions associated with the COVID pandemic were followed for all of these engagements.

Table 9-1: 2021 Knowledge Sharing

2021 Conferences/Workshops/Tour	Date	Location
SEG Carbon Solutions Taskforce	2 March	Virtual
GHGT-15	16-17 March	Virtual
AAPG CCUS Workshop	24 March	Virtual
APEGA Webinar	25 March	Virtual
EAGE CCS Workshop	11 May	Virtual
SPE CCS Workshop	12 May	Virtual
Queens University MERL Presentation	27 May	Virtual
AER and GOA Presentation	14 June	Virtual
University of Calgary REDevelop Conference	10 May	Virtual
CWLS Presentation	23 June	Virtual
IEAGHG CCUS Summer School	12 July	Virtual
GeoConvention	13-17 September	Virtual
CO2 GeoNet Webinar	21 September	Virtual
SPE CCUS Workshop	22 September	Virtual
SEG - AAPG Panel on the Business of Geophysics in the Changing Energy Marketplace	28 September	Virtual
SEG CCUS Workshop	30 September	Virtual
SEG - AAPG Postconvention Workshop on CCUS	1 October	Virtual
Solid Carbon Workshop	17 November	Virtual

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 2021:

Harvey, S., Hopkins, J., Keuhl, H., O'Brien, S., & Mateeva, A. (2021). Quest CCS Facility: Time-Lapse Seismic Campaigns. Proceedings of the 15th Greenhouse Gas Control Technologies Conference. doi:10.2139/ssrn.3817070

Harvey, S., O'Brien, S., Minisini, S., Oates, S., & Braim, M. (2021). Quest CCS Facility: Microseismic System Monitoring and Observations. Proceedings of the 15th Greenhouse Gas Control Technologies Conference.

Tawiah, P., Wang, H., Bryant, S., Dong, M., Larter, S., & Duer, J. (2021). Effects of temperature and CO_2/Brine cycles on CO_2 drainage endpoint phase mobility – implications for CO_2 injectivity in deep saline aquifers. International Journal of Greenhouse Gas Control. doi:10.1016/j.ijggc.2021.103491

9.4 Quest Advocacy

Quest advocacy activities in 2021 were largely a continuation of previous years general advocacy through knowledge sharing and community engagements. Among the key messages continuing to be shared:

1. Quest proves that CCS works well
2. Costs of CCS are lower than expected
3. CCS is a key technology that can help decarbonize some of the most difficult emissions from Canada’s energy system

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
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]
Power	3,717.70	4,513.96	7,562.80	9,056.83	6,985.35	13,969.08
Steam	8,414.46	8,834.50	5,464.59	6,284.98	7,355.33	12,524.48
Compressed Air	67.67	62.59	50.19	54.05	66.04	78.38
Cooling Water	427.95	389.81	379.14	446.29	474.71	536.04
Direct Labor and Personnel Costs	7,829.42	5,787.86	7,383.90	7,129.00	8,355.62	16,750.14
Maintenance Materials and Technical Services	969.42	942.63	1,435.98	1,286.74	2,252.79	5,380.83
Property Tax	2,003.72	2,000.28	1,842.73	1,916.60	1,959.60	2,036.23
Sequestration Opex[3]	7,052.85	6,797.59	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
Post Closure Stewardship Fund	272.07	264.28	243.33	250.48	225.34	241.78
Other Well Costs	431.49	442.12	102.74	214.11	1,104.13	518.02
Subsurface Tenure Costs	362.50	420.00	400.10	454.20	410.20	435.30
Pipeline - Inspection and Pigging	145.78	340.49	175.36	139.47	259.69	397.16
Amine[4]	340.67	0.00	0.00	0.00	0.00	218.23
Chemicals	20.35	97.92	150.69	157.71	134.41	79.48
Vendor rebates	-122.32	-100.36	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
Sustaining Capital[6]	0.00	54.89	0.00	432.41	63.30	0.00
Total	**33,743.37**	**32,710.26**	**26,280.86**	**28,812.00**	**31,794.12**	**56,596.02**

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 20m^3 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 ($)**
Operating Cost Per Tonne Captured[1]	N/A[3]	27.25	28.73	24.65	25.54	33.80	53.65
Operating Cost per Tonne Avoided[1]	N/A[3]	34.70	36.47	31.82	32.30	43.20	68.77
Total Cost per Tonne Capture d[1, 2]	N/A[3]	84.12	84.08	83.74	81.40	100.79	113.38
Total Cost per Tonne Avoided[1, 2]	N/A[3]	107.12	106.71	108.09	102.93	128.82	145.32

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, 2021. 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 2021 relate to 1,394,144 base and additional credits serialized during the year.

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

Revenue Stream	2009 – 2015	2016	2017	2018	2019	2020	2021	Aggregate Forecast[2] (2022 – 2025)
	Construction	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	40,000
CO_2 emission offset credits[1]		3,226	32,287	68,884	61,682	73,905	55,766	229,099
Total Revenues	**573,345**	**32,677**	**62,387**	**99,680**	**91,732**	**100,938**	**84,772**	**269,099**

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 $40/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 4.0MT CO_2 avoided over the next 4 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 does have 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 six 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**	**Forecast Operating[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, 2020 - 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	40,000
Total Funding	**1,303**	**238,000**	**115,000**	**53,000**	**161,000**	**29,452**	**30,100**	**30,796**	**30,050**	**27,033**	**29,006**	**40,000**
Cu. Gov't Funding % of Total Project Spend	0.5%	18.8%	27.6%	31.7%	44.1%	46.3%	48.7%	51.0%	53.3%	55.4%	57.6%	60.7%

Notes: 1. Modelling suggests that Quest will attain NRP position before 2025, resulting in only partial funding. This modelling does have 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 2021 is shown in Table 11-1.

Table 11-1: Operating Timeline

Operations Timeline	2015	2016	2017	2018	2019	2020	2021
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 Tubing Inspection							Q4

12 General Project Assessment

Project Successes in 2021:

Operational MMV Data Acquisition

- In 2021 monitoring continued including four discrete sampling events at the project groundwater wells. Routine logging and well integrity testing were completed on the IWs.
- SCVF and GM testing at the injection and monitoring wells.
- A seismic acquisition campaign was executed in Q4 2021, including a limited 3D seismic program, two 2D seismic lines and one VSP.

Networking within Industry

- Networking with other industrial operating facilities continued to help better identify maintenance practices and procedures. Despite the challenges of 2021 amid the global pandemic. technical knowledge sharing continued through numerous technical conference presentations, workshop attendance, and knowledge sharing meetings.

Stakeholder Engagement

- Stakeholder management continues to be a priority for Quest. In 2021, 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, primarily virtually.

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

- 6 million tonnes of CO_2 were successfully stored in March of 2021.
- No leaks or spills in 2021.
- Two successful halite remediations at IW 5-35 and IW 8-19.
- Compressor continued to operate at an average discharge pressure of 9.7MPag.
- Strong integrated project reliability performance with overall operational availability at 97.8% from start-up through 2021.
- Compressor availability was 100% in 2021.
- All three HMUs met their NOx level commitments without contravention in 2021 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 1,394,144 credits in 2021, registered on the Alberta Emission Offset Registry.
- Successful completion of the first Quest Unit Turnaround

Project Challenges in 2021:

There have been minor operational challenges to Quest, but none that have been insurmountable to date. The ongoing COVID-19 response actions resulted in adaptations to the way we conducted operational and maintenance activities.

A description of these challenges and activities undertaken to address them is listed below.

Technical Challenges

- Adapting to scheduling and execution of activities amongst COVID-19 restrictions.
- Additional maintenance work identified during the Quest Unit turnaround was executed within the scope of the event.

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 2021, 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:

- Planned major maintenance and inspection turnaround event on the Quest unit.
- Field work done to monitor the hydrosphere properties of the storage area surface and groundwater regions.
- Routine well maintenance and logging.
- 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 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, 2021, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, 2021 ANNUAL STATUS REPORT, will be available at: https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program&tags=Quest+Carbon+Capture+and+Storage+project