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SHELL CANADA LIMITED

Quest Carbon Capture and Storage Project

Fourth ANNUAL STATUS REPORT

Prepared By:
Shell Canada Limited
Calgary, Alberta

March 31, 2016

The Fourth Annual Status Report addresses the AER application approval referenced in the Carbon Dioxide Disposal Approval No. 11837C the "Approval", issued on May 12th, 2015 to Shell Canada Limited [1]. This report addresses the Conditions 10 and 17 of the Approval, and is required to be submitted by March 31, 2016.

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1. SPECIFIC REQUIREMENTS

The following Table 1-1 lists the requirements for Annual Reporting as listed in the AER QUEST Project Approval No 11837C [1], and the corresponding Section in this report:

Table 1-1: Concordance Table

Requirement as listed in the Alberta Energy Regulator (AER) Quest Project Approval No 11837C	**Section**
10) The Approval Holder must provide annual status reports and presentations. The reports must be aligned with the most current MMV plan and submitted to ResourceCompliance@aer.ca. The report must be in metric units and include:	
a) a summary of scheme operations including, but not limited to,	2
i) any new project wells drilled in the reporting period,	2.2
ii) any workovers/treatments done on the injection and monitoring wells including the reasons for and results of the workovers/treatments,	2.3
iii) changes in injection equipment and operations,	2.3
iv) identification of problems, remedial action taken, and impacts on scheme performance.	6.3
b) complete pressure analysis including but not limited to stabilized shut-in formation pressures and a discussion on how the pressure compares with the formation pressure expected for the cumulative volume of CO_2 injection, along with an updated estimate of what the actual cumulative injection volume will be at the maximum shut-in formation pressure specified in clause 5) a),	3 3.3 3.4 3.5
c) discussion of the overall performance of the scheme, including: how the formation pressure is changing over time; updated geological maps; and updated CO_2 plume extent and pressure distribution models, if needed. The updated models should be based on all new data obtained since the last model run including the cumulative CO_2 injected to the end of the reporting period.	3 3.4
d) a summary of MMV Plan activities, performance and results in the reporting period, including, but not limited to:	4 5
i) a report on any event that exceeded the approved operating requirements or triggered MMV activities,	5.2
ii) comparison of measured performance to predictions,	5.3
iii) summary of operations and maintenance activities conducted,	5.1

Requirement as listed in the AER Quest Project Approval No 11837C	Section
iv) details of any performance or Measurement, Monitoring, and Verification (MMV) Plan issues that require attention,	5.4
v) pressure surveys, corrosion protection, fluid analyses, logs and any other data collected that would help in determining the success of the scheme, and	2.3
vi) discussion of the need for changes to the MMV plan.	6
e) a table for all wells listed in clause 3)(1) a), showing the following injection data for each month of the reporting period:	3.1
i) mole fraction of the CO_2 and impurities in the injection stream,	3.1
ii) volume of the CO_2 injected at standard conditions,	3.1
iii) formation volume factor of the injected CO_2 stream (not applicable since CO_2 is in dense phase),	N/A
iv) cumulative volume of the injected CO_2 at standard conditions following the commencement of the scheme,	3.1
v) volume of the CO_2 injected at reservoir conditions,	3.1
vi) hours on injection,	3.1
vii) maximum daily injection rate at standard conditions,	3.1
viii) average daily injection rate at standard conditions,	3.1
ix) maximum wellhead injection pressure (MWHIP) and corresponding wellhead injection temperature,	3.1
x) average wellhead injection pressure, corresponding average wellhead injection temperature,	3.1
xi) maximum bottom hole injection pressure (MBHIP) at the top of injection interval and the corresponding bottom hole injection temperature, and	3.1
xii) average bottom hole injection pressure at the top of injection interval and the corresponding average bottom hole injection temperature.	3.1
f) a table showing the volumes of injected CO2 on a monthly and cumulative basis,	3.1
g) Hall Plots of constant average reservoir pressure where unexplained anomalous injection rate and pressure data could indicate fracturing.	3.2
h) a plot showing the following daily average data at standard conditions versus time since the commencement of CO_2 injection:	3.1
i) daily CO_2 injection rate,	3.1
ii) wellhead and bottom hole injection pressure, and	3.1

Requirement as listed in the AER Quest Project Approval No 11837C	Section
iii) estimated or measured average reservoir pressure in the Basal Cambrian Sandstone (BCS) formation.	3.1
i) the potential need for installing additional monitoring towards the periphery of the pressure build up area later in the project life,	6.3.1
j) evaluate the need for additional deep monitoring wells adjacent to the four legacy wells in the approval area. Based on the information provided the ERCB may require the Approval Holder to drill one or more such deep monitoring wells, and	6.3.2
k) discussion of stakeholder engagement activities in the reporting period.	7
17) The Approval Holder must provide ongoing annual reports beginning March 31, 2016 through to March 31, 2040. The report must include all the requirements listed in clause 10. The Approval Holder must provide a report and presentation of general performance of prior calendar year, identification of operations problems, and discussion of the need for MMV changes. Include updates, conclusions and review of:	
a) need for additional deep monitoring wells adjacent to the four legacy wells in the approval area,	6.3.2
b) results from well testing including data from annual hydraulic isolation logging,	2.3 6.3.3
c) need for further hydraulic isolation logging beyond the first five years of injection,	2.3
d) projected timing for additional 3D surface seismic surveys,	6.2
e) required frequency of time-lapse seismic surveys,	6.2
f) update of CO_2 plume and pressure front models including the results of the prescribed BCS Formation reservoir pressure fall-off test two years after the start-up of each injection well,	3.4
g) need for ongoing BCS Formation fall-off shut-in reservoir pressure tests in all injection wells,	6.3.3
h) updated geology, and	3.4.1
i) potential need for additional monitoring wells towards the periphery of the pressure build up area.	6.3.1

N/A means that the specific requirement is not applicable at this time.

2. CONSTRUCTION AND SCHEME OPERATIONS UPDATE

2.1. Capture and Pipeline Construction

Overall progress for Capture and Pipeline as of December 31, 2015 includes:

- Mechanical completion of Capture facilities achieved February 10, 2015.
- Completion of Operating Procedures: 100% by December 31, 2015.
- Commissioning and Start-up activities executed through Q3/2015.
- First injection August 23, 2015
- Completion of start-up of all systems, including well sites, with system performance equal to or better than required to meet the 3 test criteria on September 28, 2015, namely,
  - 24 consecutive hours at 2960 T/d or greater of CO_2 captured. COMPLETE.
  - 20 consecutive days processing a minimum of 75% of the total CO_2 produced from HMU's 1, 2, and 3. COMPLETE
  - 30 consecutive days of operation at a minimum of 30% of 2960 T/d. COMPLETE.
- Quest received certification for the commercial operating tests on September 30 completing the construction/start up milestones for the project [2]**Error! Reference source not found.**.

Construction reached mechanical completion on February 10, 2015 with all A (required for commissioning) and B (required for start-up) deficiencies completed on all systems. On February 20th, all the C deficiencies (required after start-up) were completed and Fluor, EPC contractor, demobilized by the end of February. In mid-April, the project, the site Commissioning and Start-Up (CSU) team and the site signed off on the first phase of Project to Asset handover, signaling that the new facilities were ready for start-up.

The 2015 plant turnaround started in April and the remaining Quest scope was completed by mid-May which included the HMU #1 and common process ties, HMU #1 burner change out and FGR tie ins, and HMU #1 PSA catalyst change out. Upon completion of the turnaround, the CSU team began executing their start-up plan. The construction engineering team continued to support the CSU team throughout the start-up and commercial operations tests, which were completed in September 2015.

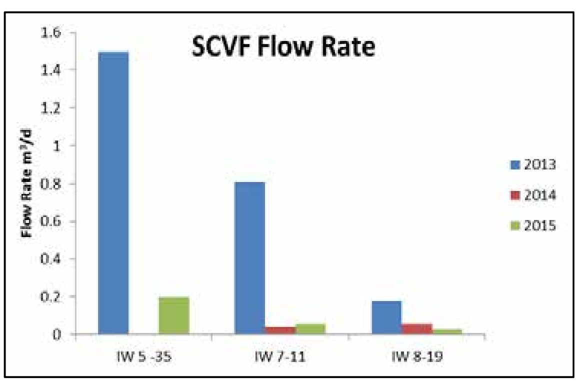
2.2. **Project Wells / SCVF**

Shell completed drilling all the wells currently planned for the operations phase of the Project in 2012 and 2013. Table 2-1 is a synopsis of all the completed drilling activity for the Quest Project. No more wells are expected to be drilled for this project unless required as per the conditions in AER approval 11837C [1].

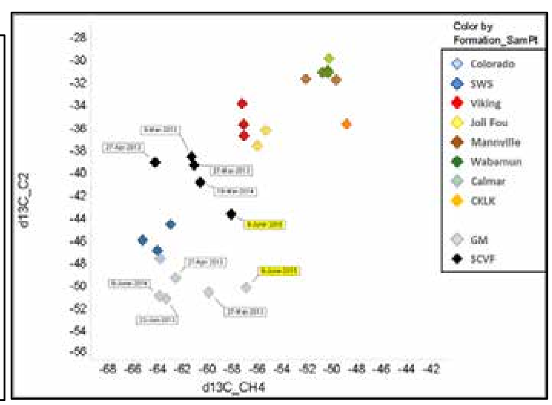
Post drilling, surface casing vent flows (SCVF) were identified in all deep monitoring and injection wells, as well as gas migrations (GM) in Injection Well (IW) 7-11 and IW 5-35 (Figure 2-1). Annual testing was completed in 2015 for SCVF and GM at the injection pads. Reports were sent to AER in June 2015 with regards to the SCVF testing and the GM testing [5].

The measurements indicate that SCVF rates in wells IW 5-35 and IW 7-11 are steady and low. Pressure at IW 5-35 well measures the same as in March 2014 with a slight increase at IW 7-11. Note that the pressure at IW 7-11 is still very low. The result from the SCVF measurements on IW 8-19 shows that both pressure and flow rates have decreased since the last measurement in March 2014.

Gas migrations were observed on IW 5-35 and IW 7-11 as bubbles in the cellar. Results from June 2015 show the highest recorded gas content value is at or below 57% LEL 30cm away from the IW 5-35 wellhead and 80% LEL 30cm away from the IW 7-11 (note that the wind was swirling), falls below 1% LEL in both wells 2 m away from the wellheads, and then reaches 0% LEL beyond 3m from each wellhead in every direction. The gas migrations have very limited impact and no potential for concern beyond the lease.



a)



b)

Figure 2-1: a) SCVF rates at the three injection wells, showing that the rates have decreased significantly over the last two years. b) Isotopic analysis performed at well 5-35, indicating that the gas sources are shallow and similar to previous measurements in 2013 and 2014.

Table 2-1: Quest Well Summary.

UWI	Well type	Well name in this report	Spud date [d/m/y]	Rig release [d/m/y]	Total Depth [m MD]	TD formation
1AA/11-32-055-21W400	Appraisal (Abandoned)	Redwater 11-32	10/11/2008	02/01/2009	2240.6	Precambrian
100/03-04-057-21W400	Observation	Redwater 3-4	23/01/2009	18/03/2009	2190.0	Precambrian
100/081905920W4/00	Injection	IW 8-19	01/08/2010	08/09/2010	2132.0	Precambrian
102/081905920W4/00	Deep Monitoring	DMW 8-19	30/09/2012	15/10/2012	1696.0	Ernestina Lake
102/053505921W4/00	Injection	IW 5-35	21/10/2012	20/11/2012	2143.0	Precambrian
100/053505921W4/00	Deep Monitoring	DMW 5-35	24/11/2012	06/12/2012	1710.0	Ernestina Lake
103/071105920W4/00	Injection	IW 7-11	14/12/2012	20/01/2013	2105.0	Precambrian
102/071105920W4/00	Deep Monitoring	DMW 7-11	23/01/2013	05/02/2013	1664.5	Ernestina Lake
1F1/081905920W4/00	Groundwater	GW 1F1/8-19	08/12/2010	08/01/2011	201	Lea Park
UL1/081905920W4/00*	Groundwater	GW UL1/8-19	14/01/2011	17/01/2011	101.0	Foremost
UL2/081905920W4/00*	Groundwater	GW UL2/8-19	12/01/2011	13/01/2011	62.8	Foremost
UL3/081905920W4/00*	Groundwater	GW UL3/8-19	09/01/2011	10/01/2011	37.5	Foremost
UL4/081905920W4/00*	Groundwater	GW UL4/8-19	11/01/2011	11/01/2011	20.0	Oldman
1F1/053505921W4/00	Groundwater	GW 1F1/5-35	08/02/2013	17/02/2013	200	Lea Park
UL1/053505921W4/00*	Groundwater	GW UL1/5-35	17/02/2013	18/02/2013	23	Foremost
1F1/071105920W4/00	Groundwater	GW 1F1/7-11	19/02/2013	26/02/2013	180	Lea Park
UL1/071105920W4/00*	Groundwater	GW UL1/7-11	26/02/2013	27/02/2013	30.7	Foremost

Legend: *: well name used in Shell but not official UWIs as these wells do not require a well licensed because they are less than 150m depth

2.3. **Well Workovers and Treatments**

2.3.1. Injection Wells

No new wells have been drilled since completion of the 2012-2013 drilling campaign.

During 2015, the following activities were executed in the Injector wells:
IW 8-19:

- Wellhead Integrity Test and packer Test: passed.
- Preparation for Start-up: Pull suspension plug, RST Log, Install flapper valve.
- SCVF and Conductor vent flow test

IW 7-11:

- Wellhead Integrity Test and packer Test: passed.
- Preparation for Start-up: Pull suspension plug, RST Log, Install flapper valve.
- GM testing

IW 5-35:

- Wellhead Integrity Test and packer Test: passed.
- Preparation for Start-up: Pull suspension plug, RST Log, Install flapper valve.
- SCVF and GM test

2.3.2. Deep Monitoring Wells Completions

In April 2015, the microseismic array (installed November 2014) was retrieved from DMW 8-19 so that the well could be perforated at the Cooking Lake Formation (CKLK) and a pressure gauge installed in the well along with the microseismic array. Orientation shots at the surface were then required in order to orient the geophones in the well and to allow the project to accurately locate microseismic events. These were acquired using a vibrator truck source both before the array was retrieved and after it was re-installed.

As with the previous, the current geophone array was designed and manufactured to be a semi-permanent, retrievable array. It has eight magnetically coupled geophones spaced at 57 m intervals between 1250 to 1650 m MD (Figure 2-2). The array was deployed as a super cable configuration which has a secured wireline cable that takes the weight off the geophone array and the sensitive analogue cable.

The analogue cable exits the well head through a pack off and terminates at a junction box near the well head where the signal is converted from analog to digital and time stamped (Figure 2-3). From here the quarter millisecond digitized data travels to the MMV building nearby and is housed on an on-site server (Figure 2-4). The on-site server is monitored remotely via a permanent radio link that replaced the temporary modem on February 24, 2015. When trigger files are created by the system, they are downloaded for processing. The nature of the trigger files is discussed in more detail in Section 4.2.3.3.

The array began recording background microseismicity at the site on November 6, 2014. Data quality and results to date are discussed in Section 4.2.3.3.

A pressure gauge was installed in the Redwater 3-4 well in the Cooking Lake Formation in May 2015.

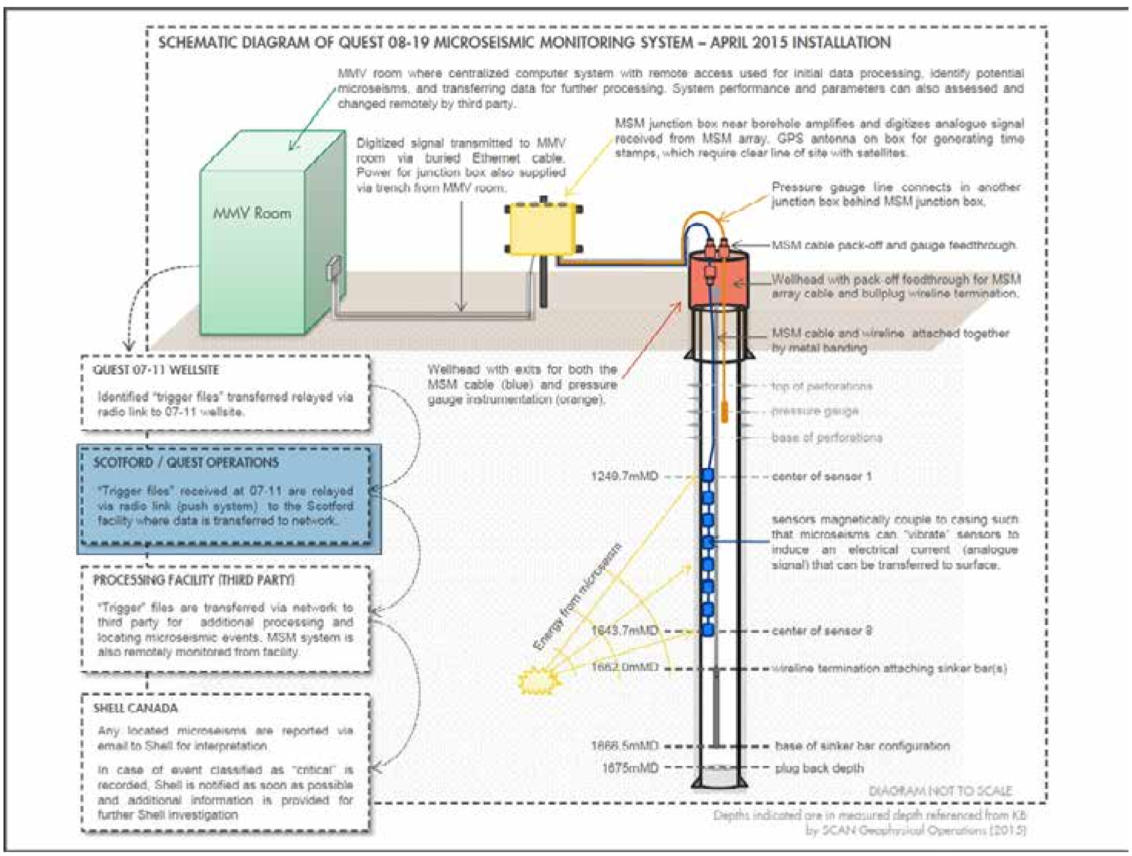


Figure 2-2: Schematic drawing highlighting key features related of the final DMW 8-19 completion focused on the microseismic system.

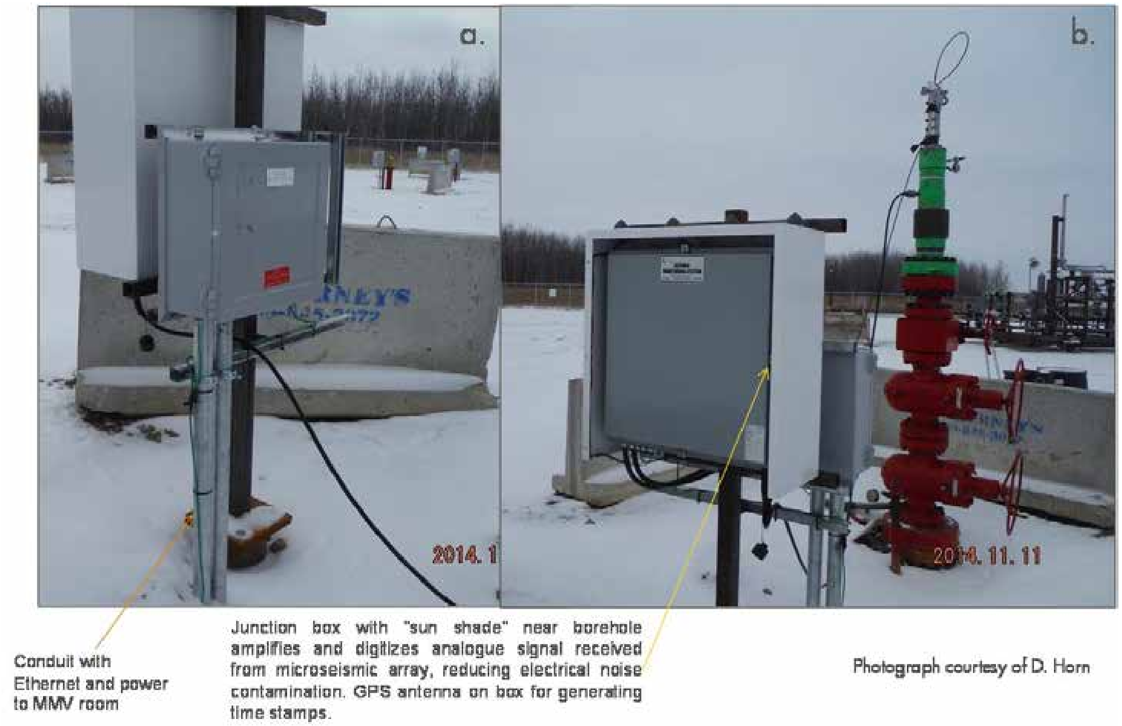


Figure 2-3: a) Ethernet connection to the on-site MMV room. b). Analogue cable exiting the wellhead and the junction box that digitizes the analogue microseismic data.

Figure 2-4: On-site microseismic server in the 8-19 pad MMV room.

2.3.3. Groundwater Wells Completions

The groundwater well drilling and completion campaign was completed in 2013. A full report can be found in the Second Annual Status Report [3].

No new wells have been drilled since the 2012-2013 drilling campaign.

3. INJECTION WELL PERFORMANCE

3.1. Injection Data Reporting

Overall, the project has been running very smoothly. The monthly totals for October and November show that the Quest project experienced rate changes as a consequence of capture facility optimizations, which is well within normal expectations for the first year of operating an asset (Table 3-1).

Table 3-1: 2015 Quest CO_2 Injection Summary

Mass of Injected CO_2 (thousand-tonnes)					
Month	**5-35**	**8-19**	**7-11**	**Total**	**Cum Total**
Aug	-	13	9	22	22
Sep	-	50	44	94	116
Oct	-	51	33	84	200
Nov	-	45	26	71	271
Dec	-	52	48	100	371

3.2. Injectivity

Overall, the Quest project has more than sufficient injectivity, demonstrated by the utilization in 2015 of only two of the three injection wells despite full project rates up to 140t/hr (

Table 3-2, Table 3-3). Therefore, with the inclusion of IW 5-35, we believe the existing wells will be capable of sustaining injectivity greater than the project goal of 140t/hr (1.2Mt/year) for the duration of the project life, and no further infill well development will be required.

IW 8-19 well has been injecting consistently at approximately 70 t/hr over this time period with very little pressure build up (solid blue line in **Error! Reference source not found.**Figure 3-3). IW 7-11 has been receiving the remaining available volumes (solid green line in Figure 3-3). IW 5-35 currently is not under injection. Further investigation of the Injectivity stability is illustrated in the injectivity index plots shown in Figure 3-1 and Figure 3-2. Ignoring the transient affects, the index illustrates that 8-19 and 7-11 have been holding steady at about 70 and 100 kg/h-kPa respectively.

Injectivity Index monitoring was used to report the injection performance for CO_2 injection (vs the Hall Plot method designed for water injection [9]), as shown in Figure 3-1 and Figure 3-2.

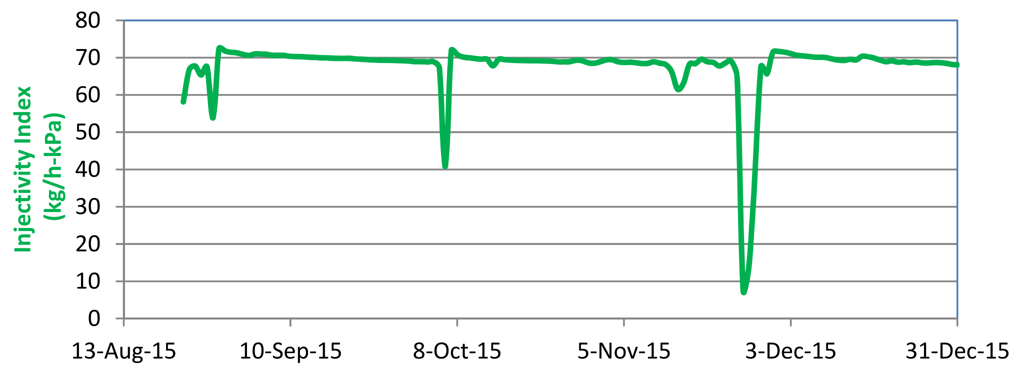


Figure 3-1: Injectivity Index for 8-19 over time

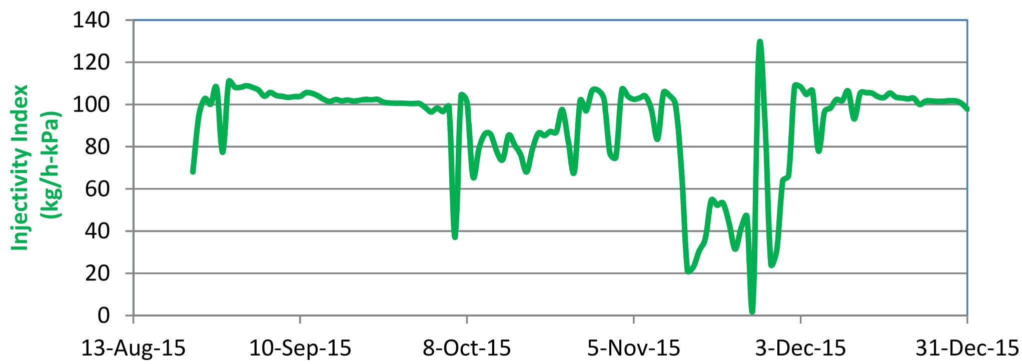


Figure 3-2: Injectivity Index for 7-11 over time

Table 3-2: 2015 Quest CO_2 Injection Summary: Injection data

Monthly Averages	Inject Stream content (Mole Fraction)				
	CO_2	H_2	CH_4	CO	H_20
Aug-15	99.48	0.45	0.05	0.014	0.003
Sep-15	99.47	0.46	0.06	0.016	0.002
Oct-15	99.36	0.57	0.05	0.015	0.005
Nov-15	99.42	0.49	0.06	0.017	0.006
Dec-15	99.44	0.48	0.06	0.016	0.006

Monthly Averages	Injection Wells		
Mass of CO_2 Injected[1] (kt)	**IW 7-11**	**IW 8-19**	**IW 5-35**
Aug-15	9	13	N/A
Sep-15	44	50	N/A
Oct-15	34	51	N/A
Nov-15	26	45	N/A
Dec-15	48	52	N/A
Cumulative Mass of CO_2 Injected [1] (kt)			
Aug-15	9	13	N/A
Sep-15	53	63	N/A
Oct-15	87	114	N/A
Nov-15	113	159	N/A
Dec-15	161	211	N/A
Total Monthly Hours on Injection (hours)			
Aug-15	183	190	N/A
Sep-15	720	720	N/A
Oct-15	730	732	N/A
Nov-15	695	674	N/A
Dec-15	744	744	N/A
Max Daily Inj Rate (t/h)			
Aug-15	60	70	N/A
Sep-15	63	70	N/A
Oct-15	68	71	N/A
Nov-15	70	72	N/A
Dec-15	74	72	N/A
Average Daily Inj Rate (t/h)			
Aug-15	21	28	N/A
Sep-15	61	70	N/A
Oct-15	45	68	N/A
Nov-15	36	62	N/A
Dec-15	65	70	N/A

[1]Volume of CO_2 is reported in standard units for CO_2, i.e. mass.

Table 3-3: 2015 Quest CO_2 Injection Summary: Pressures and Temperatures

Monthly Averages	IW 7-11		IW 8-19		IW 5-35	
Max WHIP and WHIT	**WHIP (kPa-g)**	**WHIT (°C)**	**WHIP (kPa-g)**	**WHIT (°C)**	**WHIP (kPa-g)**	**WHIT (°C)**
Aug-15	6 417	24	7 790	24	N/A	N/A
Sep-15	7 296	16	8 091	14	N/A	N/A
Oct-15	7 923	16	8 077	14	N/A	N/A
Nov-15	8 143	16	8 204	12	N/A	N/A
Dec-15	8 422	14	7 859	9	N/A	N/A
Average WHIP and WHIT	**WHIP (kPa-g)**	**WHIT (°C)**	**WHIP (kPa-g)**	**WHIT (°C)**	**WHIP (kPa-g)**	**WHIT (°C)**
Aug-15	3 275	13	4 413	13	N/A	N/A
Sep-15	6 895	14	7 961	13	N/A	N/A
Oct-15	5 563	11	7 810	12	N/A	N/A
Nov-15	5 261	6	7 187	9	N/A	N/A
Dec-15	7 288	12	7 483	8	N/A	N/A
Max BHIP and BHIT	**BHIP (kPa-g)**	**BHIT (°C)**	**BHIP (kPa-g)**	**BHIT (°C)**	**BHIP (kPa-g)**	**BHIT (°C)**
Aug-15	20 203	57	20 638	60	N/A	N/A
Sep-15	20 218	36	20 619	30	N/A	N/A
Oct-15	20 243	41	20 629	36	N/A	N/A
Nov-15	20 276	45	20 653	40	N/A	N/A
Dec-15	20 325	33	20 637	27	N/A	N/A
Average BHIP and BHIT	**BHIP (kPa-g)**	**BHIT (°C)**	**BHIP (kPa-g)**	**BHIT (°C)**	**BHIP (kPa-g)**	**BHIT (°C)**
Aug-15	19 809	47	20 052	46	N/A	N/A
Sep-15	20 192	35	20 603	30	N/A	N/A
Oct-15	20 115	35	20 599	30	N/A	N/A
Nov-15	20 087	35	20 563	29	N/A	N/A
Dec-15	20 246	32	20 610	27	N/A	N/A

Note: kPa-g refers to gauge pressure.

3.3. **Model to Performance Conformance**

Gen-5 static and dynamic reservoir models were documented in the Third Annual Status Report to the AER (submitted January 31, 2015) [6].

Results thus far indicate a project end-of-life pressure in the BCS of less than 2 MPa of differential pressure (DeltaP) at the injection wells. This pressure increase of less than 2 Mpa is less than 12% of the delta pressure required to exceed the BCS fracture extension pressure and less than 20% of the pressure increase required to exceed the AER operating constraint on bottom hole pressure (D65 approval condition).

Figure 3-3 illustrates that the actual pressure build up in the reservoir to date has been less than the model-predicted expectation case (dashed lines in Figure 3-3). Note that no injection has occurred at IW 5-35, but reservoir pressure is being monitored. This implies that the modelled reservoir properties are likely better than the previous expectation case.

The key implication is that lower injection pressures are required to meet injection/rate targets over the life of the project. More importantly, the lower than predicted end-of-life reservoir pressures significantly increases our confidence that it is inconceivable for CO_2 leakage to occur via fracturing or fault reactivation.

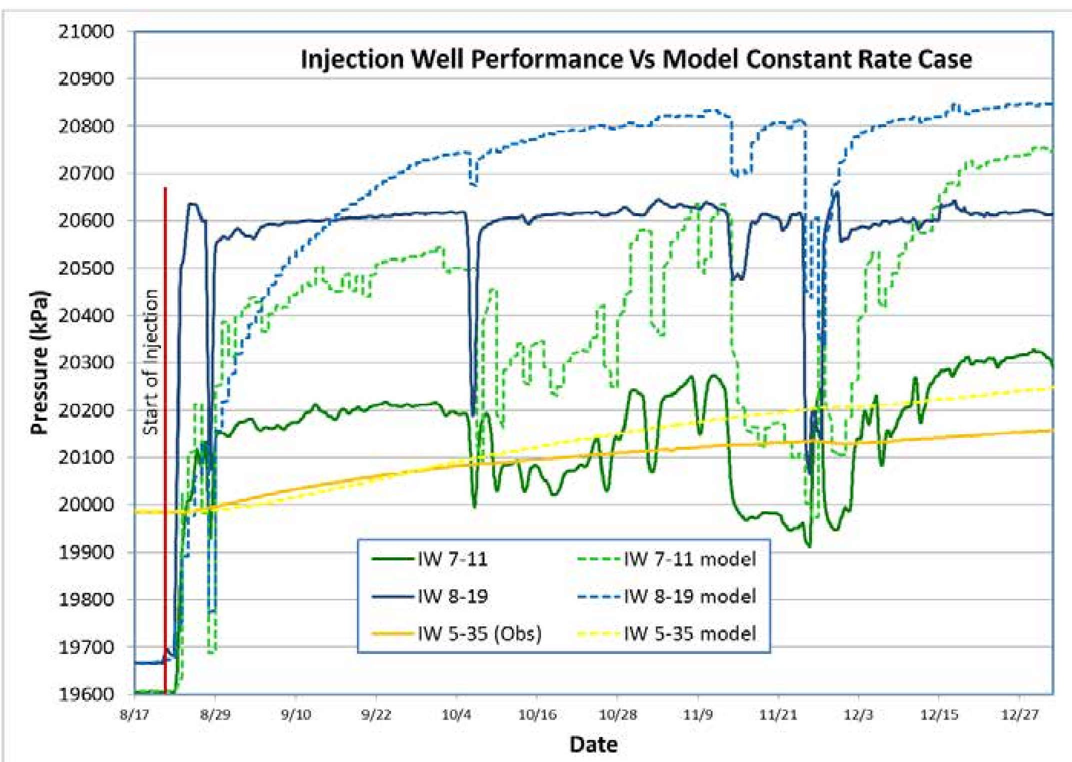


Figure 3-3: Actual BH Gauge Response vs Modeled Pressure Response.

3.4. **Reservoir Modelling**

3.4.1. Modelling Updates

No significant update to the reservoir model occurred in 2015 as no new wells were drilled, and the early performance was close to our expectation case. The actual daily well rate history has been incorporated into the model controls as illustrated in Figure 3-3; currently IW 5-35 is in observation mode. Work in 2016 will include tuning the model to a growing performance data set which includes the first monitor VSP in Q1 2016.

3.4.2. Pressure Prediction

The pressure build-up in the BCS is forecasted to be less than 2 MPa of differential pressure (DeltaP) at the injection wells by the end of the project life (Figure 3-4).The assumption for the 2016 forecast below is that from 2017 onward an equal amount of CO_2 will be injected in each well for the remainder of the life of the project.

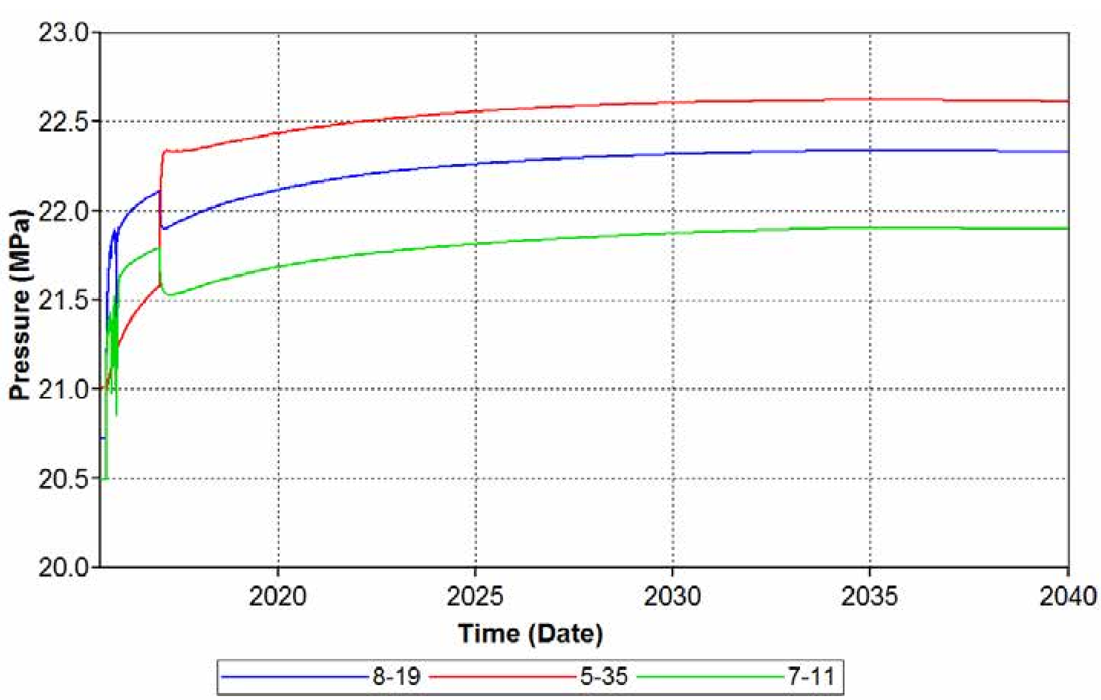


Figure 3-4: Well by well expected pressure build forecast.

3.4.3. Plume Prediction

Detailed Gen-4 CO_2 plume modelling of a three injection well scheme concluded a P50 CO_2 plume length of 4.1 km at the end of injection in 2040 for a random average type-well [4]. The range of uncertainty was large and was heavily driven by uncertainty in the relative permeability of the CO_2.

The Gen-5 model incorporates new well control and estimates well specific CO_2 plume migration [6], as illustrated in Figure 3-5. Remaining uncertainty on relative permeability will be reduced in 2016 as the model is tuned to pressure history and the 1st monitor VSP interpretation, further refining the forecast and predictions.

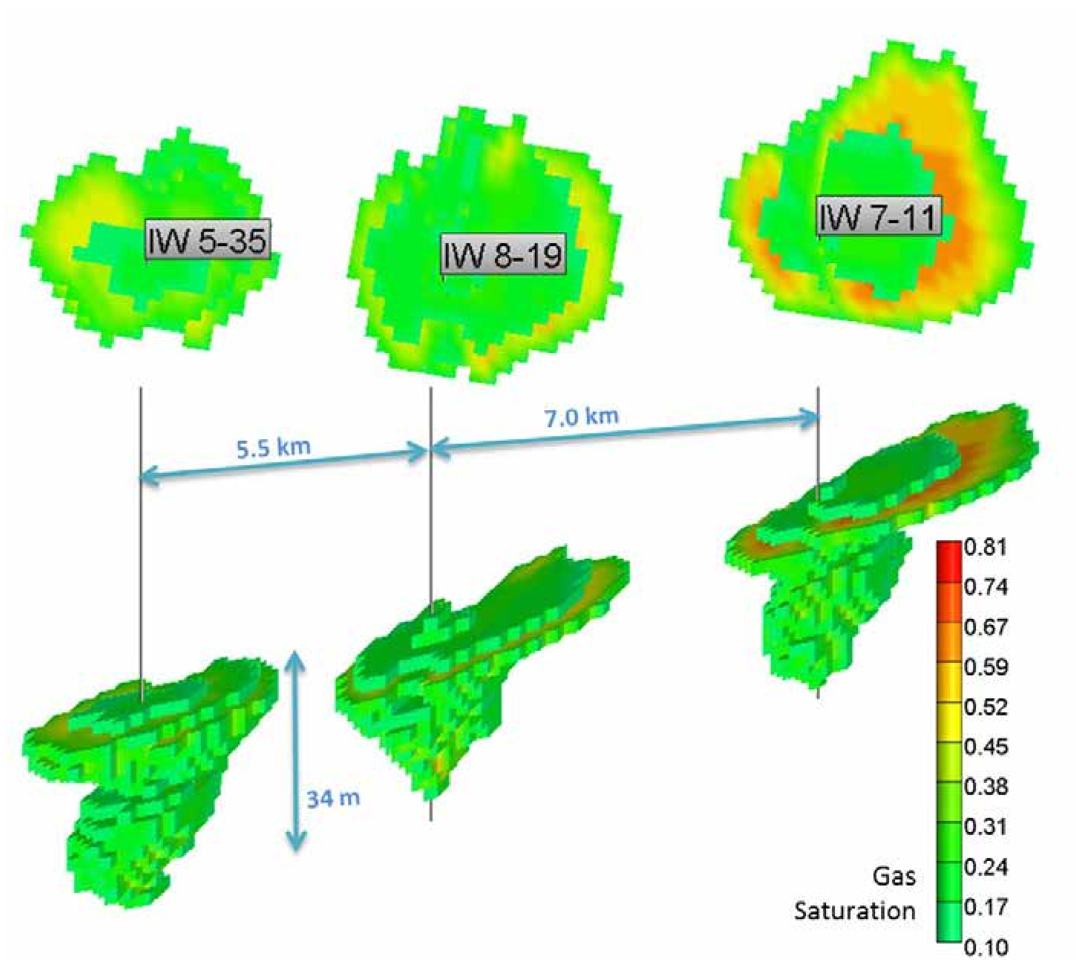


Figure 3-5: Map view and 3D views of the CO_2 plume in 2040.

Current modelling shows similar maximum plume lengths in 2040 of 2.5 to 4.2 km. Figure 3-6 is an approximation of the maximum plume length expansion per well over time, based on 2016 rate forecasts (Figure 3-4) and a high-relative permeability scenario.

Figure 3-7 illustrates the size of the CO_2 plumes with respect to the SLA.

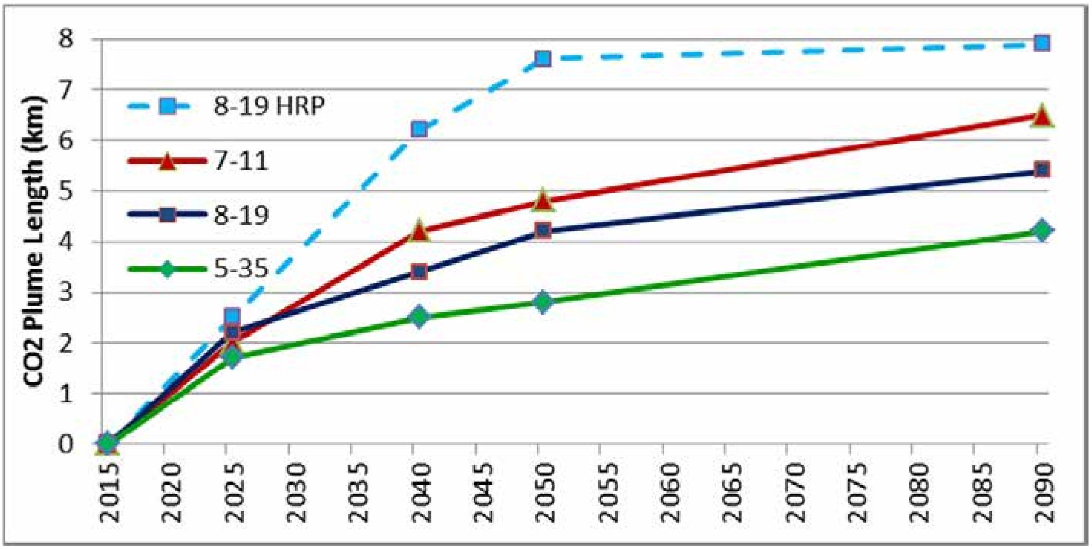


Figure 3-6: Maximum CO_2 plume length per well over time.

3.5. **Reservoir Capacity**

Current operating conditions and analysis indicate that the Quest project has more than sufficient storage capacity for the project volume of 27 Mt of CO_2.

Uncertainty in the capacity of the BCS storage complex has been further reduced since commencement of injection as pressures have been lower than the expectation case (Figure 3-4)

The full 27 Mt of CO_2 is expected to be sequestered without ever approaching the limit specified in clause 5) a) of the Approval [1]. The 2013 First Annual Status Report [4] states that the Quest project will not raise the stabilized reservoir pressure at any injector beyond the AER approved 26 MPa limit within the life of the project. This has not changed as there is no expectation for the flowing bottomhole pressure to ever approach the 26 MPa maximum shut-in formation pressure.

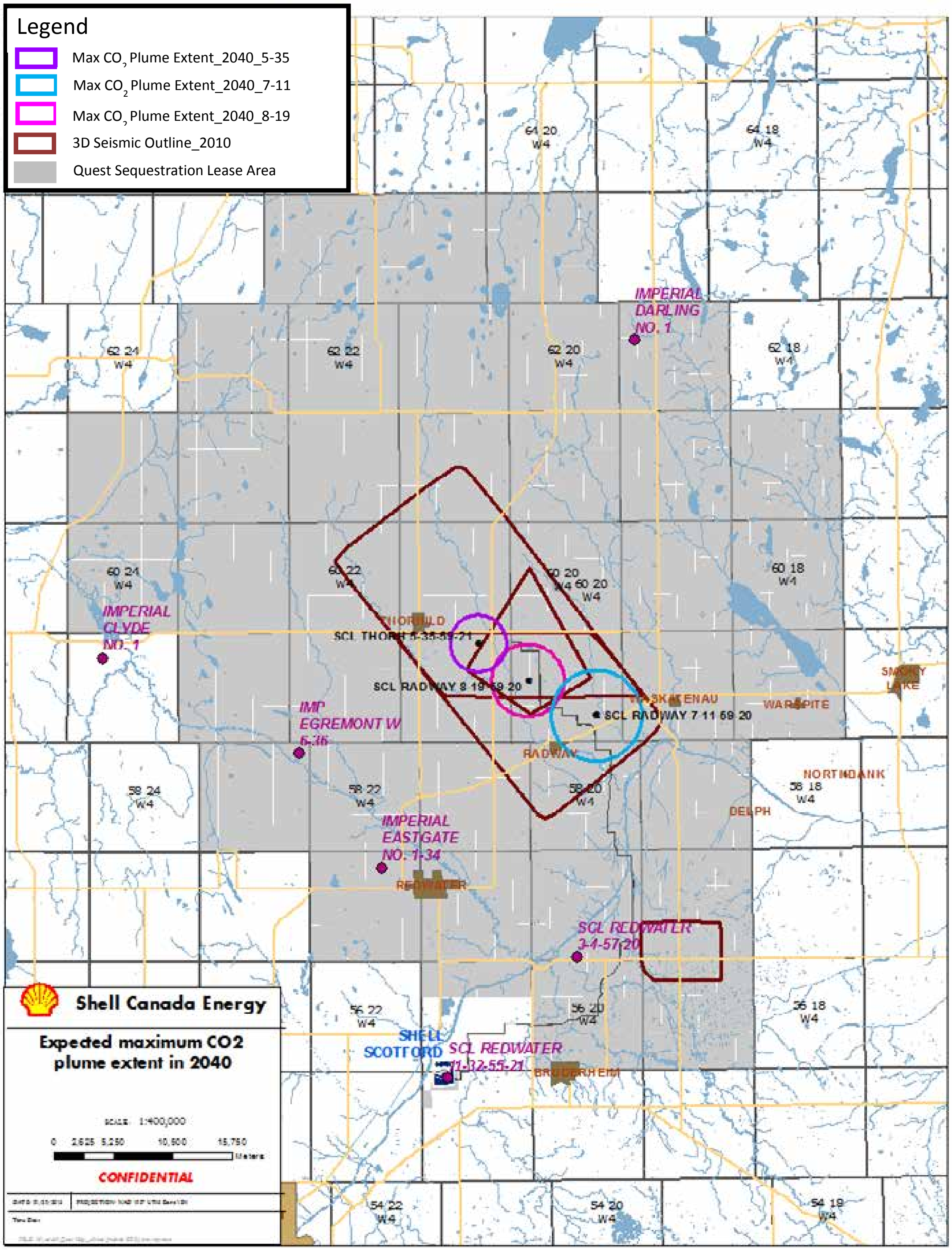


Figure 3-7: Maximum CO_2 Plume extent in 2040.

4. PRE-INJECTION MMV PLAN ACTIVITIES

4.1. Summary of Pre-Injection MMV Activities in 2015

2015 pre-injection MMV activities included: atmosphere, biosphere, hydrosphere, geosphere, and well-based monitoring. Table 4-1 provides an overview of the planned monitoring activities as per MMV plan submitted in January 2015 [6] and an assessment of whether these activities were executed as per plan. Additional details about the activities listed in Table 4-1 are provided in Section 4.2.

Two manuscripts on the isotopic composition of CO2 were submitted to the peer-reviewed journal International Journal of Greenhouse Gas Control in 2014, in conjunction with the University of Calgary, and published in 2015 [7][8].

4.2. Pre-Injection MMV Operations and Maintenance Activities

4.2.1. Atmospheric Monitoring

A CO_2 field release test was successfully completed in June 2015 at pad 8-19 prior to start of injection to support the development of the LightSource technology. The tests demonstrated the detectability of all controlled releases. In addition to the LightSource system, EC data collection continued at pad 8-19 until the end of 2015.

4.2.2. Hydrosphere Biosphere Monitoring Activities

2015 pre-injection HBMP (Hydrosphere Biosphere Monitoring Plan) monitoring activities included:

- Quarterly groundwater well sampling of the project groundwater wells located on the 3 injection well pads
- Quarterly groundwater well sampling of landowner groundwater wells
- A single shallow soil sampling (down to about 90cm depth) event on plots with a 6 km radius of the injection well pads
- A single soil gas (using probes installed at a depth of 0.8 to 1.0 m) and soil surface CO_2 flux (using chambers placed on soil surface) sampling event around each injection well.

Further details on the HBMP activities can be found in Appendix A.

Additional groundwater well testing/sampling was undertaken in conjunction with the February 2015 baseline VSP campaign (Appendix A).

Table 4-1: Summary of MMV activities planned and executed in 2015

Domain	Activity planned for 2015 ^	Executed	Comment
Atmopshere			
	LightSource measurements at pads 8-19, 7-11, & 5-35	✓	controlled CO_2 release test successfully executed in June 2015 instead of May 2015
	Eddy covariance measurements at pad 8-19	✓	measurements were extended beyond June 2015 to end of year 2015
Biosphere			
	Soil sampling event at existing and new plots with a 6 km radius of the injection well pads	✓	completed prior to start of injection
	Targeted soil gas and soil surface CO_2 flux measurements at each of the injection well pads	✓	completed two sampling events: one prior to and one post start of injection
Hydrosphere			
	Downhole pH & EC monitoring at Project groundwater wells	✓	
	Quarterly discrete sampling at Project groundwater wells	✓	three sampling events took place prior to start of injection; one sampling event took place post start of injection
	Quarterly discrete sampling at landowner wells within 1km of each injection well pad	✓	three sampling events took place prior to start of injection; one sampling event took place post start of injection
	Once per year for landowner wells located within expected CO_2 plume size	✓	covered under 'landowner wells within 1km of each injection well pad', as CO_2 plume size < 1km
	Landowner wells associated with VSP surveys: pre- and post-campaign	✓	occurred prior to start of injection
Geopshere			
	Injection rate monitoring	✓	
	Annulus pressure monitoring	✓	
	DHPT monitoring at all 3 DMWs	✓	
	DHPT monitoring at all 3 IWs	✓	
	DHP monitoring at Redwater 3-4	✓	
	WHPT monitoring at all 3 IWs	✓	
	Mechanical well integrity testing (packer isolation test) and tubing caliper log of IWs		to be completed within about 6 months after start of injection, expected to take place in Q1-2 2016
	Routine well maintenance, including Temperature & RST logs and measurement of hold-up depths (HUD) of IWs at which injection started		to be completed within about 6 months after start of injection, expected to take place in Q1-2 2016
	MSM at DMW 8-19	✓	
	DTS monitoring at IWs	✓	work in progress to move towards automated data download; currently, field visits required to download data
	DAS monitoring at IWs	✓, ✗	used for VSP survey data collection; no continuous data collection implemented yet
	8 walkaway VSP surveys around each injection well using DAS fibers in Q1	✓	
	InSAR: monthly satellite image collection	✓	
corrosion coupons	corrosion coupons at injection skids		
SCVF/GM	annually by June 30^{th}	✓	
Injected CO_2	analysis of captured CO_2 at Scotford Upgrader	✓	

Note: List of MMV activities as per MMV plan update [6]

4.2.3. Geosphere Monitoring Activities

4.2.3.1. Distributed Acoustic Sensing

During 2015, the DAS system was used for recording data during the pre-injection VSP survey completed in Q1 2015. For further details, please refer to Section 4.2.3.4.

4.2.3.2. Distributed Temperature Sensing

Three DTS lightboxes, installed prior to start of injection, one on each injection site, have been used to record DTS profiles with a current sampling rate of a 10 minutes sample every 30 minutes.

SageRider and Lawrence Berkley National Laboratories (LBNL) were contracted to assess the detectability limits and feasibility of using DTS for real-time leak detection. This work was completed in Q1 2015.

4.2.3.3. Microseismic Monitoring

As per Section 2.3.2, a microseismic array was installed in DMW 8-19 and began recording baseline microseismicity on November 2014 as per the MMV Plan (Appendix A). A new array was installed in April 2015. The sensor orientations were then re-calibrated using Vibroseis surface shots at four different locations surrounding well DMW 8-19 (Figure 4-1). The brief workflow of sensor orientation QC procedure includes:

- QC of the geophone geometry.
- QC of the vibe shots geometry and waveform data.
- QMS-6 was selected to redo sensor orientation by using Shell's sensor orientation procedure.
- Comparison between ESG's and Shell's results was completed.

As a result, both sensor orientations are consistent with each other (Figure 4-2).

Trigger files are created when a specified threshold criteria is met on multiple geophones. These files are sent for trigger categorization and processing. Currently, Shell receives a daily report from ESG with the date, number of triggers, and breakdown of trigger type (Table 4-2). There were no locatable events recorded in 2015, either before or after injection started. Figure 4-2 shows the daily statistics for major categorized events in 2015.

The acquisition system event triggering parameters was initially designed as listed in Table 4-3. In order to catch more potential event candidates, the event detection thresholds were further refined on June 3, 2015 with feedback from the AER. The triggered files are treated as event candidates and are manually reviewed.

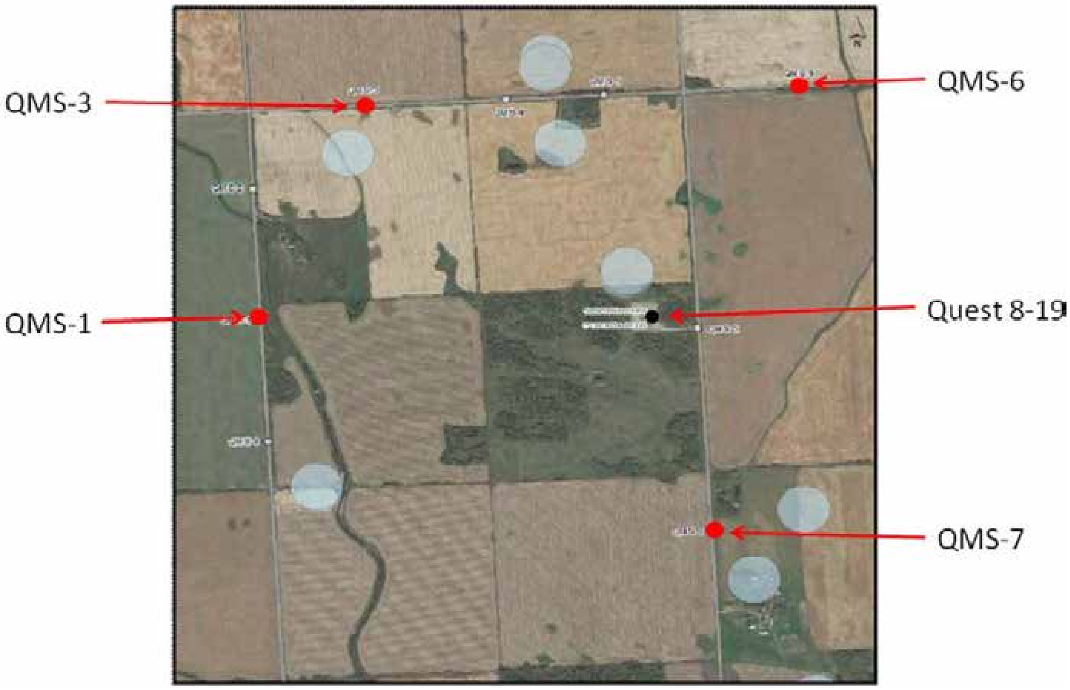


Figure 4-1: Vibroseis shot locations for sensor orientation around well DMW 8-19.

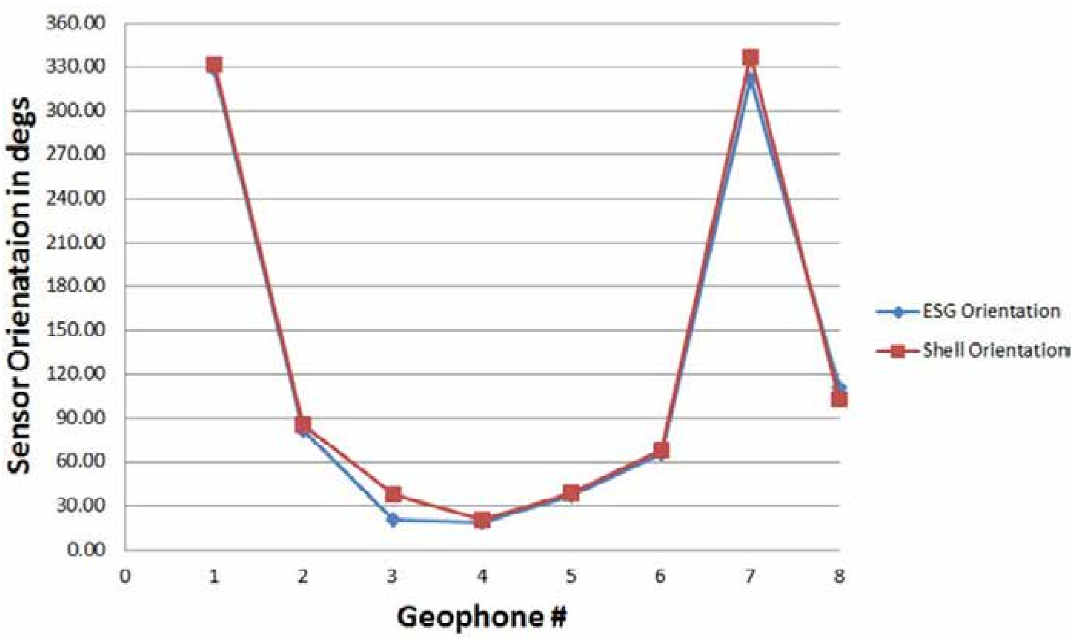


Figure 4-2: Sensor orientation result comparing the contractor's (ESG) orientation and the Shell in-house orientation.

Table 4-2: Trigger classifications used for the Quest Project and trigger totals from January 1st, 2015 to December 31st, 2015.

Trigger Type	Description	Total
Automatic	Hourly triggering intended to ensure health of the system	8630
High Frequency Noise	Caused by elevated, high frequency background noise	35675
Acoustic	Caused by energy travelling up and down the wellbore	1583
Hammer Tap Test	Tap test on the wellhead to test geophone functionality	1
Locatable Events	Events with clear P- and S-wave arrivals exhibiting waveform characteristics typical of microseismic events	0
Single-Phase Events	Seismic signals that lack significant P- and S-wave arrivals and cannot be located	19
Surface	Events that originate at the surface	7842
Electrical	Caused by electrical interference	0
Orientation Shots	Induced events such as surface-based seismic sources that are used to orient the geophones	23
Potential Regional Events	Far offset earthquake events that occur beyond the AOR	1213
Total		54986

Table 4-3: Event detection trigger parameters.

Before Jun. 3, 2015

Description	Parameters
Pre-triggering Length	500 ms
Post-Triggering Length	1000 ms
Trigger Window	200 ms
LTA	50 ms
STA	15 ms
STA/LTA Ratio	3
# of Channels to Trigger	7 out of 24

After Jun. 3, 2015

Description	Parameters
Pre-triggering Length	2000 ms
Post-triggering Length	4000 ms
Trigger Window	200 ms
LTA	50 ms
STA	15 ms
STA/LTA Ratio	2
# of Channels to Trigger	7 out of 24

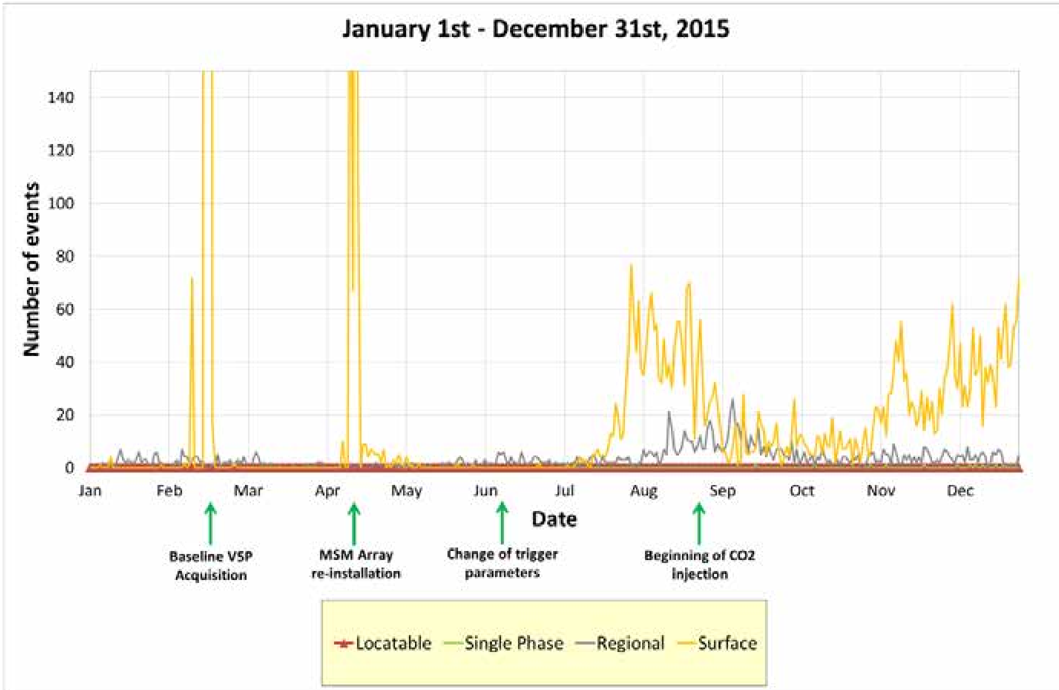


Figure 4-3: Statistics of major microseismic categorized events in 2015.

4.2.3.4. Baseline Walkaway VSP Surveys

The baseline VSP was acquired in Q1 2015 to allow for frozen ground and prior to first CO_2 injection at the sites. Eight walk-away VSP lines were acquired at each injection well location. The survey used the DAS fibers in each well to record the data and the ODH4i lightsource box.

The results of the processed and migrated VSP datasets demonstrate that the storage complex and BCS reflectors were successfully imaged to considerable offset from the receiver well, in some lines beyond 1km. The distance to which a CO_2 plume can be imaged will not be confirmed until the 4D data is processed in 2016.

An example of the raw VSP data from the 8-19 location is shown in Figure 4-4. The VSP data have been processed in-house and the migrated results are shown in Figure 4-5.

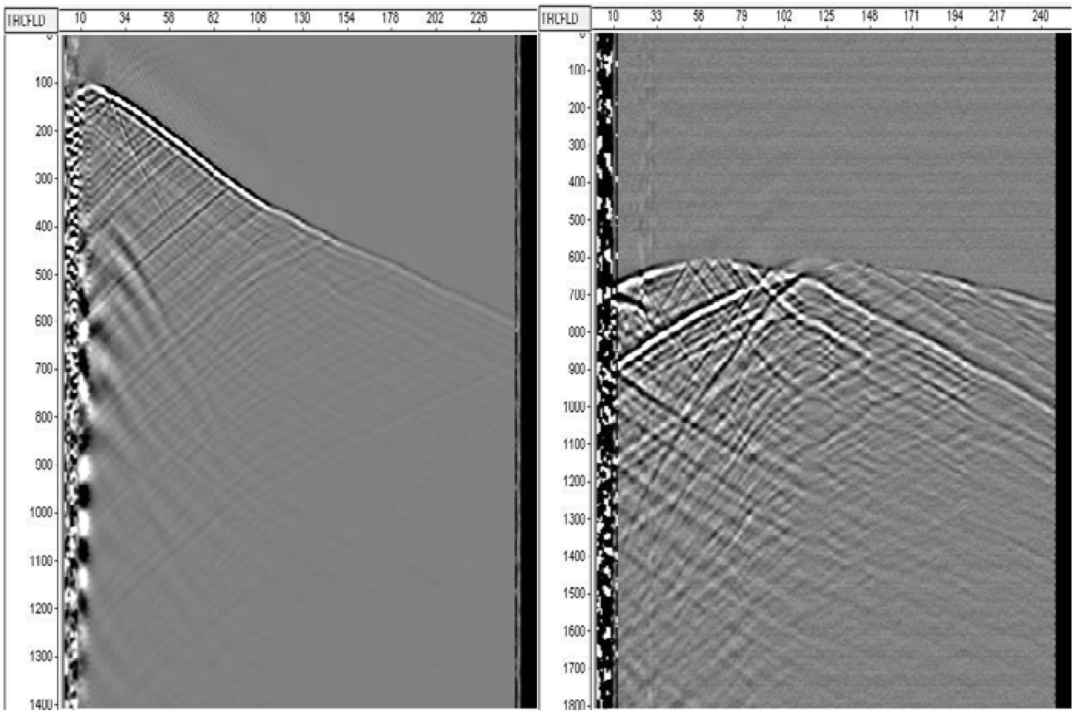


Figure 4-4: Raw field data from one walkaway line at 8-19. Near offset shot (left) and Far offset shot(right).

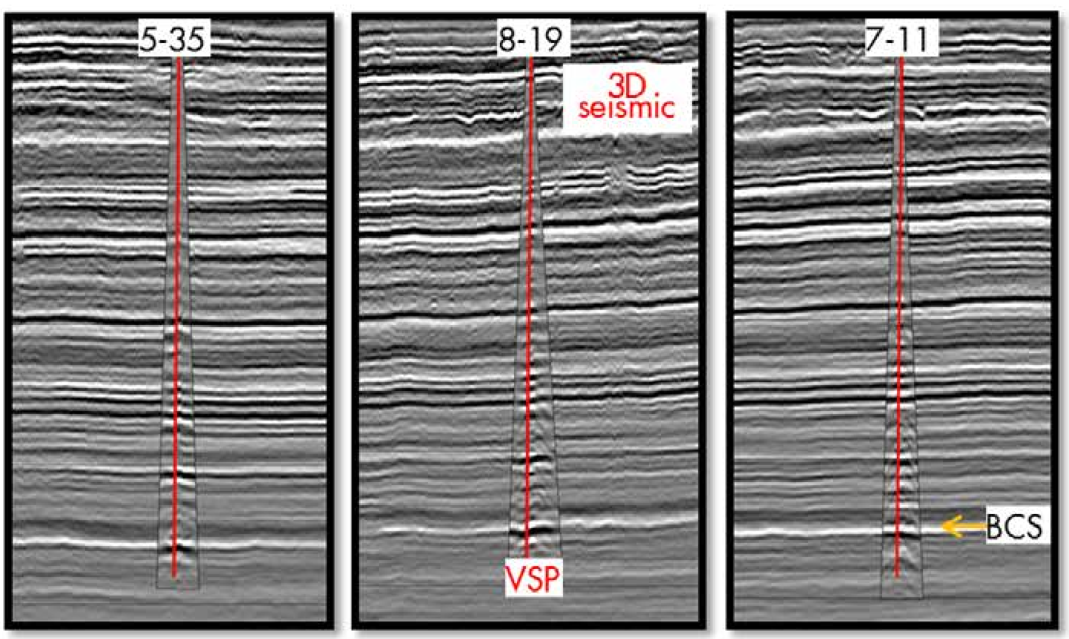


Figure 4-5: Comparison between VSP and 3D seismic images for all three wells. Note that the VSP events correlate with the 3D seismic events.

4.2.3.5. InSAR

The programming and acquisition of RADARSAT-2 satellite imagery continued during 2015. These data will be used alongside previously collected data to assess the efficacy of the InSAR program. An extension of the InSAR Efficacy Report to March 31st, 2017 has been granted.

4.2.4. DMW Pressure Monitoring

Continuous pressure data in the Cooking Lake Formation via three monitoring wells, DMW 7-11, DMW 8-19, and DMW 5-35 are plotted in Figure 4-6 for a few months before injection until end 2015. The pressure data have been very steady, providing reasonable evidence that a leak path from the BCS to the Cooking Lake near the 7-11 and 8-19 injection wells does not exist. A pressure fluctuation greater than 200 kPa is the threshold for indication of a leak in the 2015 MMV Plan.

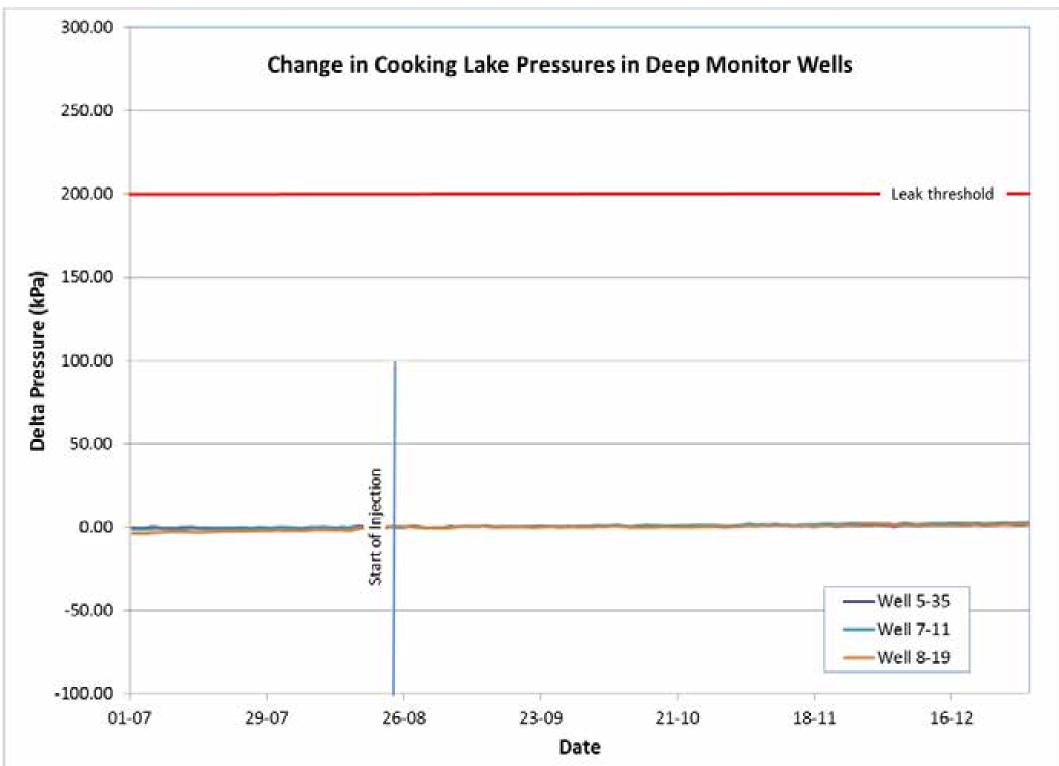


Figure 4-6: Quest deep monitoring well pressure history before and after injection

The pressure in the Cooking Lake Formation is not at equilibrium due to offset production from the Leduc Reef, which is connected to the Cooking Lake Formation as illustrated in Figure 4-8. These pressure transients in the Cooking Lake Formation could lead to misinterpretation of the observed data.

The Redwater 3-4 well is located considerably closer to the Leduc Reef and the CKLK pressure data is being used as a proxy for the Leduc Reef pressure response. The Cooking Lake Formation was perforated and a pressure gauge installed. Given the length of the pressure response time between 3-4 and the Quest DMWs, the utility of the 3-4 well pressure data will be assessed in a few years' time.

The reservoir pressure in the 3-4 well was supercharged due the overbalance hydrostatic of the completion fluid. This left the well near 12 MPa, which fell off exponentially to stabilize at about 10.5 MPa by year end (Figure 4-7).

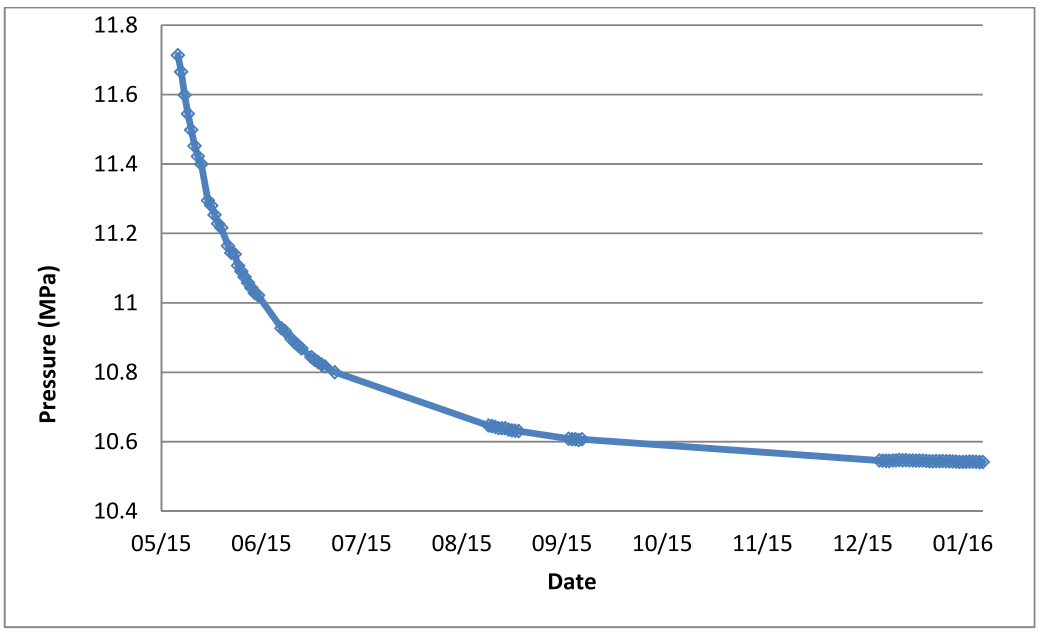


Figure 4-7: Quest 3-4 DMW pressure history before and after injection.

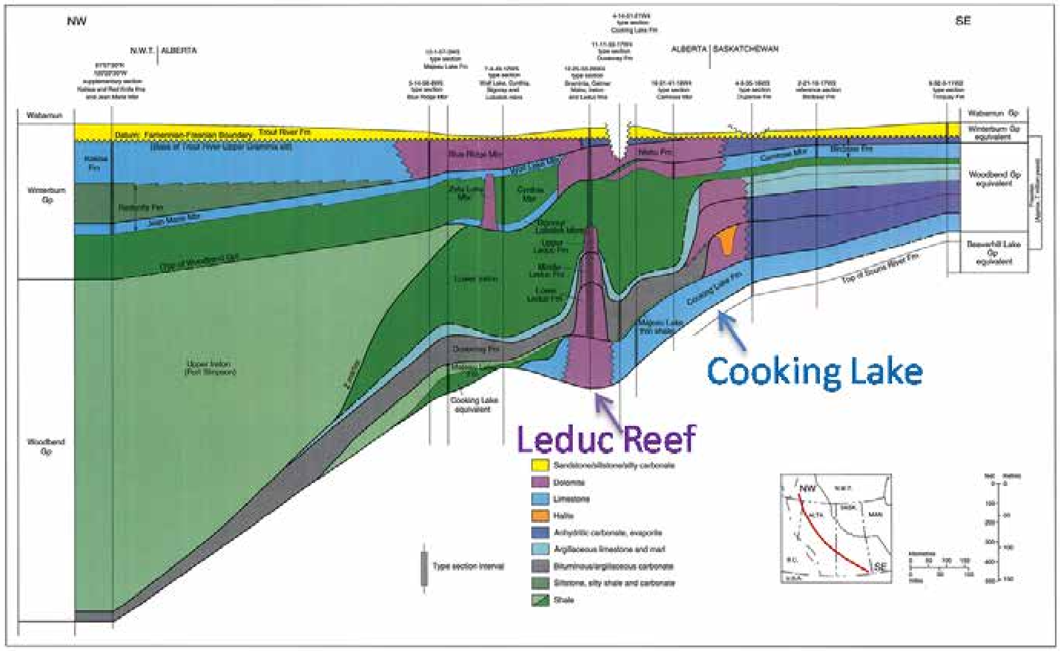


Figure 4-8: Schematic cross section illustrating Cooking Lake Formation connection to the Leduc Reef connection (http://www.ags.gov.ab.ca/graphics/atlas/fg12_07.jpg)

4.2.5. MMV Infrastructure

A private, secure network was developed and installed to transmit all data types between well sites, the Scotford Upgrader, the Calgary office, and relevant external parties. This system was operational in 2015 ahead of first injection.

A web-based toolkit was implemented which interfaces directly with the PI database and displays these data online in real-time at any Shell location. The system was fully operational in Q1 2015; changes to this system are expected in 2016 related to software upgrades.

DTS data are currently stored locally at a pad, and data retrieval requires a field visit. Work is progress to move towards an automated – online data access/retrieval. To this end, three computer systems were purchased in 2015.

All remaining equipment installations associated with the LightSource technology were completed at the three injection well pads in 2015 prior to start of injection at two of the pads.

A total of 20 semi-permanent soil gas probes were installed in a radial fashion around each injector well, with 5 probes each along a north, south, west, east direction.

5. OPERATIONAL MMV PLAN ACTIVITIES AND PERFOMANCE

5.1. Summary of Operational MMV Activities in 2015

In 2015, post start of injection MMV activities included: atmosphere, biosphere, hydrosphere, geosphere, and well-based monitoring. Please refer to Table 4-1 for a list of the various monitoring activities that took place. Additional details about the activities listed in Table 4-1 are provided in Section 4.2.

- Atmosphere Monitoring: Monitoring of CO_2 levels within the atmosphere continued using the LightSource and EC systems.
- Hydrosphere Monitoring: One discrete sampling event took place post start of injection at the project groundwater wells located on the 3 injection well pads, and landowner groundwater wells within 1 km of the injection well pads.
- Biosphere Monitoring: One sampling event of soil gas and soil surface CO_2 flux measurements was undertaken on each injection pad.
- Geosphere Monitoring: monthly satellite image collection
- Well based Monitoring: ongoing data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes.

5.2. Assessment of MMV objective 'Containment'

No trigger events were identified that indicate a loss of containment (Table 5-1), indicating that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir during this reporting period.

Reasons for this observation are described below for the technologies that were used as part of the assessment for this reporting period.

As the project progresses it is expected that based on current performance the focus of assessing 'containment trigger events' will be on a limited and/or reduced number of monitoring technologies.

- LightSource

Installed on each well pad, the LightSource system includes: one laser beam located in one of the pad's corners which can scan across the pad and three reflectors located in the three remaining corners of the pad. In 2015 no evidence was found of a trigger event indicative of leakage (Figure 5-1).

- Soil Gas

Soil gas CO_2 concentrations on the injection well pads were established in June 2015 (prior to start of injection) and in October 2015 (post start of injection). The data between both sampling events were very similar (Figure 5-2).

Table 5-1: Overall assessment of trigger events.

Domain	Technology ^	Trigger Event	23 Aug to 31 Dec 2015	Comment
Atmosphere	LightSource	Sustained locatable anomaly above background levels		impact of inclement weather on system response being investigated
Biosphere	Soil Gas	Outside established baseline range		
Biosphere	Surface CO2 Flux	Outside established baseline range		
Hydrosphere	Tracer	Outside established baseline range		
Hydrosphere	WPH	Sustained decrease in baseline pH values		
Hydrosphere	WEC	Sustained increase in baseline WEC values		
Hydrosphere	Geochemical Analyses	Outside established baseline range		
Geosphere	DHPT CKLK	Pressure increase 200 Kpa above background levels		
Geosphere	DHMS	Sustained clustering of events with a spatial pattern indicative of fracturing upwards		
Geosphere	DTS	Sustained temperature anomaly outside casing		currently manual data retrieval; work in progress to finalize data assessment approach
Geosphere	VSP2D	Identification of a coherent and continuous amplitude anomaly above the storage complex		1st VSP monitor after injection to be executed in Q1 2016
Geosphere	SEIS3D	Identification of a coherent and continuous amplitude anomaly above the storage complex		not applicable yet
Geosphere	InSAR	Unexpected localized surface heave		data collection monthly, but first assessement of data since start of injection will occur after about 1 year of injection

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

Legend:
- *no trigger event*
- *trigger event*
- *not evoluated*

- Surface CO_2 Flux

On the injection well pads, soil surface CO_2 flux measurements were taken in June 2015 (prior to start of injection) and in October 2015 (post start of injection). The data between both sampling events were very similar (Figure 5-3).

- Tracer

$\delta^{13}C\text{-}CO_2$ values were established for soil gas CO_2 during the sampling campaigns for soil surface CO_2 flux measurements in June 2015 (prior to start of injection) and in October 2015 (post start of injection). Results obtained between both sampling campaigns were similar (Figure 5-4).

- WPH (water pH)

Groundwater pH values above the base of the groundwater protection zone at the injection well pads are measured using downhole gauges deployed within the project groundwater wells. No trigger event occurred in 2015; i.e. no indication of a sustained decrease in pH values between pre- and post-injection (Figure 5-5).

- WEC (Water electrical conductivity)

Groundwater EC values above the base of the groundwater protection zone at the injection well pads are measured using downhole gauges deployed within the project groundwater wells. No trigger event occurred in 2015, as would be indicated by a sustained increase in EC values between pre- and post-injection (Figure 5-5).

- Geochemical Analyses

One groundwater sampling event took place in Q4 2015 after start of injection, including the sampling of the 9 project groundwater wells and 9 landowner wells within a 1km radius of an injection well. Over half of the landowner wells were located around pad 5-35 where no injection occurred in 2015. There is no indication of leakage from the storage complex in 2015.

When reviewing the Q4-2015 data on a well by well basis, some values were found to be outside the range observed during previous sampling campaigns. This was observed for wells associated with any of the three areas (around all 3 pads) where sampling took place.

- DHPT Cooking Lake

No indication of communication from the injection wells in 2015; see Section 4.2.4.

a)

b)

c)

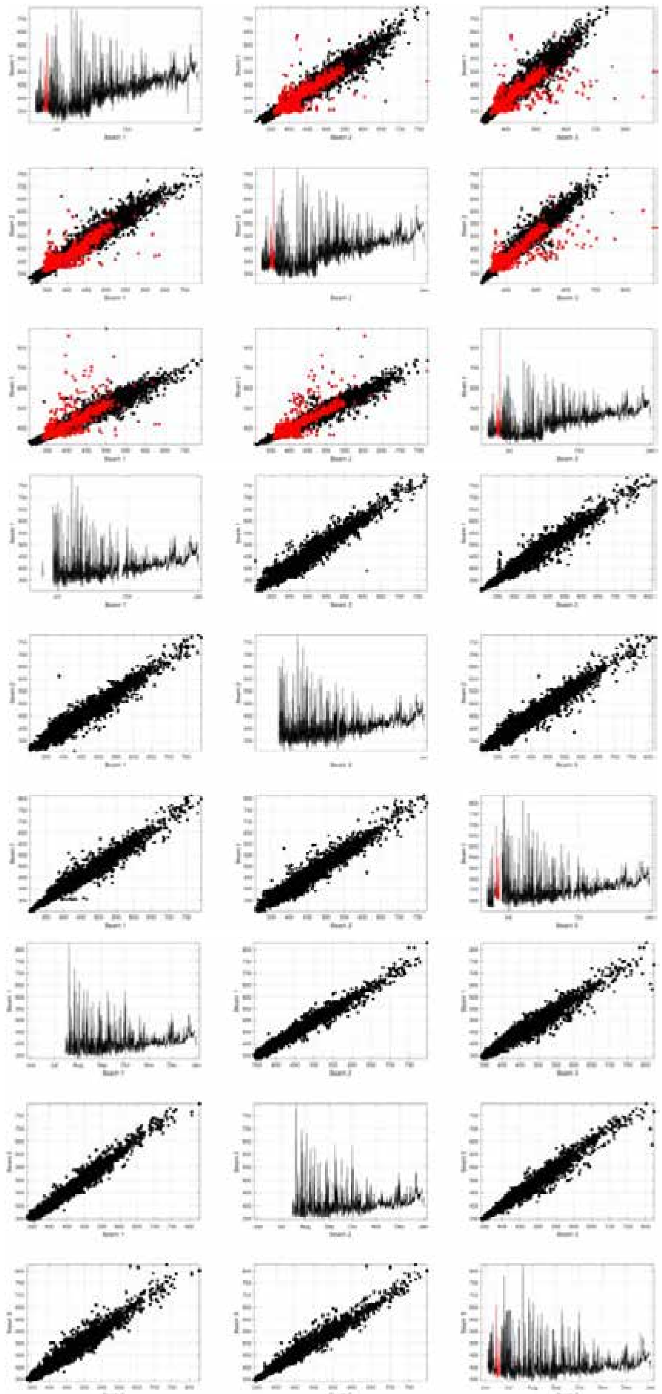


Figure 5-1: Cross-plots of times series (June to December 2015) of path averaged CO_2 concentrations and cross-plots of path averaged CO_2 concentrations for one beam versus another beam; a) for pad 8-19; b) for pad 7-11; c) for pad 5-35.

The figure illustrates the type of data being collected as part of the LightSource system. Red highlighted data were collected during a CO_2 release test that was completed in 2015 prior to start of injection.

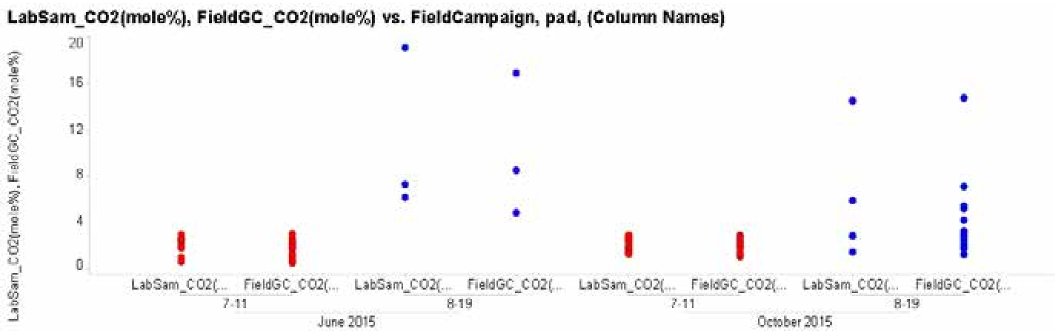


Figure 5-2: Soil gas CO_2 concentrations measured on pads 7-11 and 8-19 in June 2015 (pre-injection) and October 2015 (post start of injection) for laboratory and in-field analyses

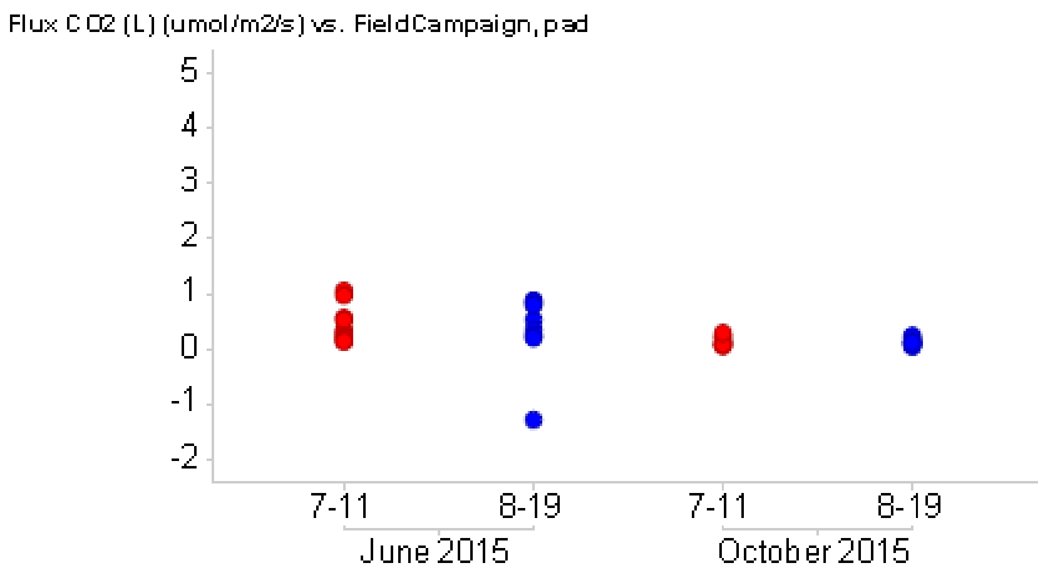
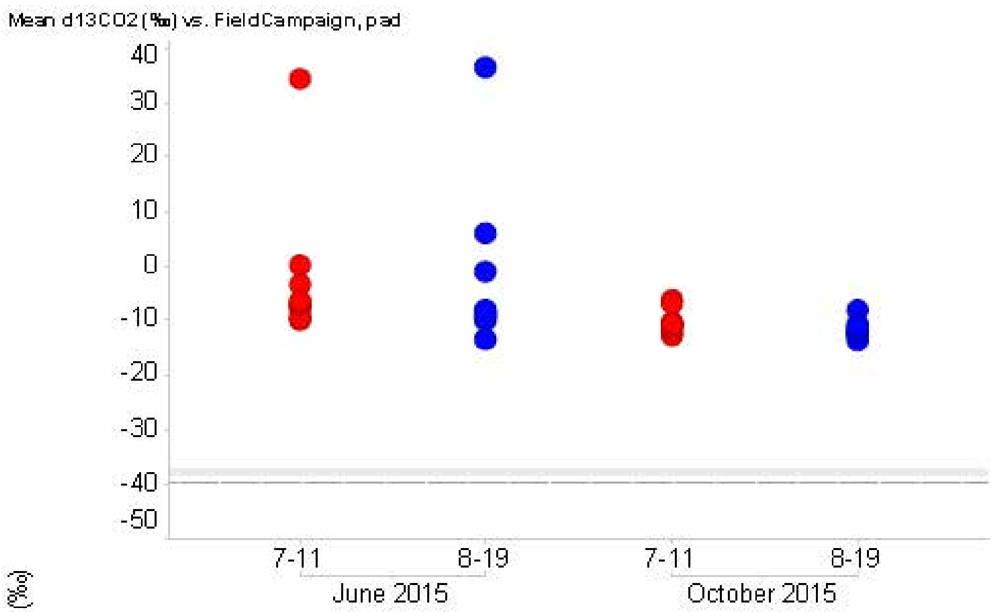


Figure 5-3: Soil surface CO_2 flux (μmol m^{-2} s^{-1}) measured on pads 7-11 and 8-19 in June 2015 (pre-injection) and October 2015 (post start of injection)

a)



b)

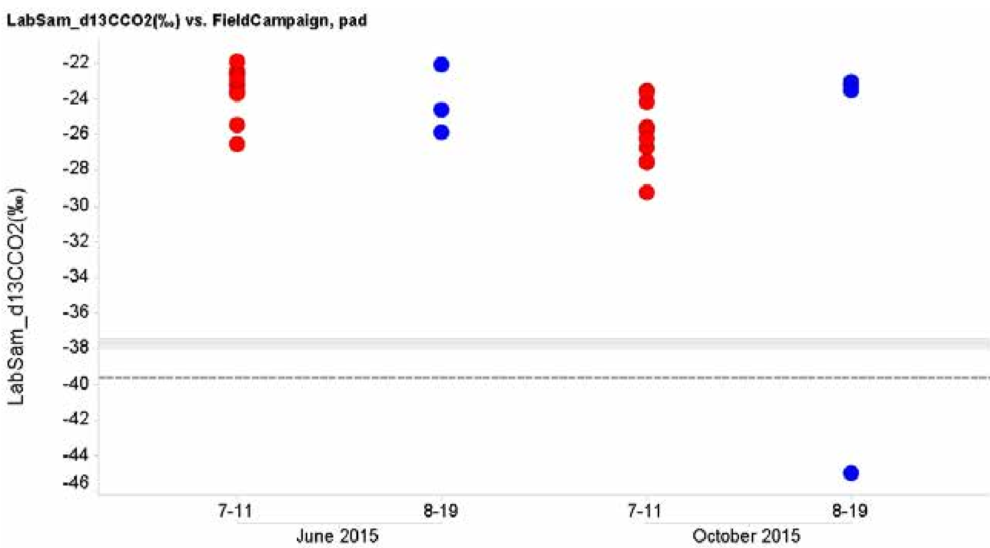


Figure 5-4: $\delta^{13}C\text{-}CO_2$ values for pads 7-11 and 8-19 in June 2015 (pre-injection) and October 2015 (post start of injection) for a) soil surface CO_2 and b) soil gas CO_2.

Notes: gray band represents estimated $\delta^{13}C\text{-}CO_2$ value of injected CO_2 based on $\delta^{13}C\text{-}CO_2$ values of gas sample which is closest to the injected CO_2 collected at Scotford prior to completion of capture facility. It takes into consideration potential isotope fractionation effects due to adsorption and desorption. Gray dashed line represents 'October 2015' $\delta^{13}C\text{-}CO_2$ value of captured CO_2. One outlier within the October 2015 sample set of pad 8-19 can be identified, suggesting potential contribution of CO_2 from methane oxidation (CH_4 was measured within this sample), and/or loss of sample integrity.

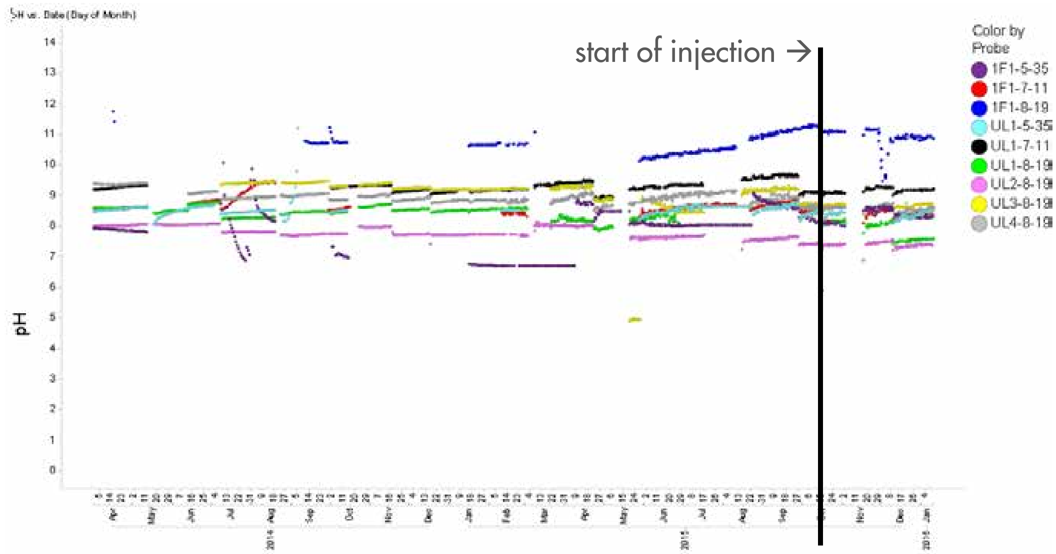


Figure 5-5: pH values recorded between April 2014 and December 2015 using the downhole gauges deployed within the project groundwater wells at pads 8-19, 7-11, and 5-35.

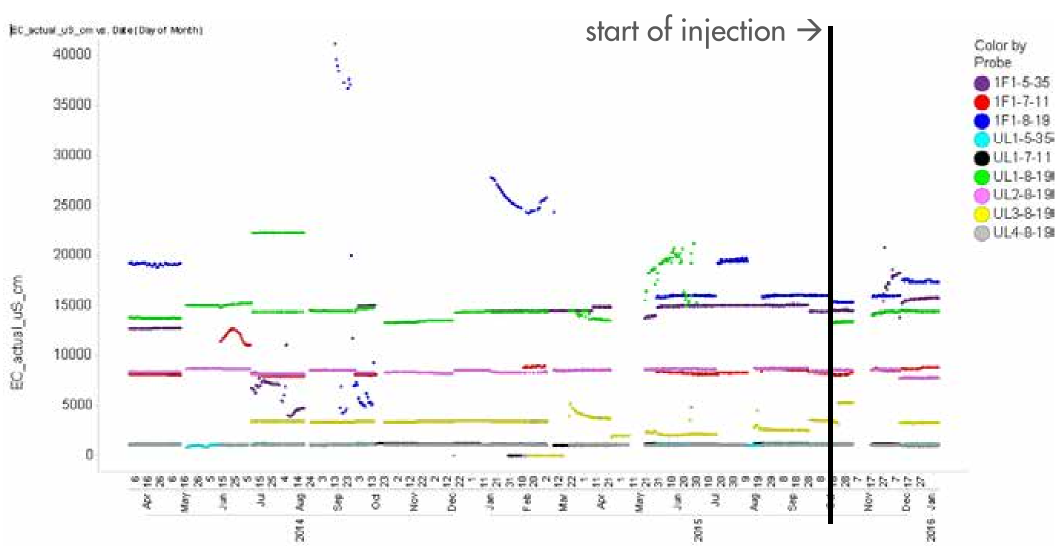


Figure 5-6: EC values recorded between April 2014 and December 2015 using the downhole gauges deployed with the project groundwater wells at pads 8-19, 7-11, and 5-35.

- DHMS (downhole microseismic monitoring)

No locatable micro-seismic events were detected in 2015 by the geophone array deployed within DMW 8-19located on same pad as IW8-19(Figure 4-3).

- DTS (Distributed Temperature Sensing):

The DTS traces collected from each injection well in 2015 demonstrate the absence of a leak within the well. The temperature changes are within the range expected for standard thermal stabilization resulting from steady CO_2 injection ('cooling' of geothermal gradient). An expected warm-back occurred at cessation of injection, demonstrating the functioning of the DTS equipment.

All DTS traces are similar in general profile, notwithstanding the various differences in rock thermal properties from injection site to injection site.

No expected 'leak' profiles, or identifiable deviations from the norm, have been identified within the data in 2015.

An example of a DTS trace collected on September 25th 2015 (post start of injection), as well as the geothermal gradient on August 20th 2015 (prior to injection) is shown in Figure 5-7.

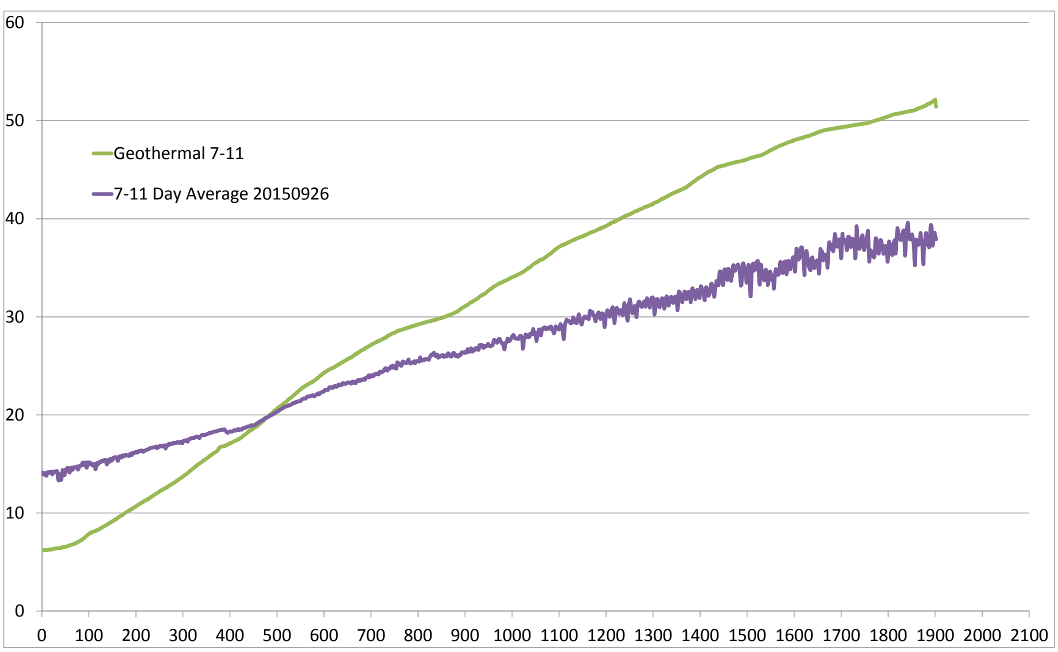


Figure 5-7: DTS trace (temperature [°C] versus depth [m]) collected on September 26, 2015 (post start of injection), as well as the geothermal gradient on (prior to injection) at pad 7-11.

5.3. **Assessment of MMV objective 'Conformance'**

- Time-lapse seismic data:

First monitor VSP survey to take place in Q1 2016.

- Downhole Pressure Temperature Gauges:

Pressures behaving as expected; discussed in Section 3.3

- InSAR:

First assessment planned after approximately 1 year of injection. A request has been submitted to extend the submission of the special report on InSAR efficacy (Condition 16 of AER Approval 11837C) to March 31st, 2017 in order to allow for sufficient injection history to be able to assess the efficacy of the InSAR program.

5.4. **MMV Performance and Plan Issues**

MMV performance and plan issues for the year of 2015 have been identified as follows:

i. Work in progress regarding the capability and approach to be used for real-time leak detection based on the DTS fiber optics' system.
ii. Investigation of the impact of inclement weather on the LightSource system response.
iii. Steps taken to address challenges with the Troll groundwater gauges that have been encountered regarding sensors and calibration (some data loggers needed to be returned to the manufacturer).
iv. The Third Annual Status Report [6] referred to a delay in the installation of pressure gauges in the DMW 8-19 and at the Redwater 3-4 wells. These were installed prior to start of injection in 2015.
v. The Third Annual Status Report [6] referred to a delay from 2014 to 2015 with regards to executing a 2nd controlled release test related to the LightSource technology. This was executed in 2015 prior to start of injection.

6. FUTURE MMV ACTIVTIES

6.1. Changes to currently approved MMV Plan

6.1.1. DAS (Distributed Acoustic Sensing)

The current approved MMV plan [6] included reference to the evaluation of potential applications of DAS monitoring based on the optical fibers installed within the injection wells:

- acoustic monitoring for leak detection
- detection of small temperature changes
- continuous microseismic acquisition and data analysis
- determine mechanical integrity of cement

Assessment of these potential applications ceased for the moment. For instance, as no microseismic activity has been detected in the storage complex using the DMW 8-19 'conventional' geophone array, the current impetus is low for developing any novel DAS technologies for detecting microseimic events. As MMV activities continue, the decision to cease assessment of potential DAS applications will be reviewed.

6.1.2. VSP (vertical seismic profile) survey

The first monitor time-lapse walkaway VSP survey will be executed in Q1 2016, and not in December 2015 as proposed in the January 2015 MMV plan [6]. Since CO_2 has not yet been injected at pad 5-35, a monitor survey will not be acquired at that well site in 2015.

6.1.3. Groundwater well sampling

To-date, CO_2 has not been injected at pad 5-35; hence, the groundwater sampling program around pad 5-35 may be reduced in 2016 compared to what was proposed in the January 2015 MMV plan [6].

6.2. Time-Lapse Seismic Surveys

All monitor VSPs will be acquired in Q1 of each year to align with the acquisition timing of the baseline VSP in February 2015. This is because ground condition is a significant variable in the repeatability, and thus quality, of the time-lapse signature.

The need for a second monitor survey in Q1/2017 will be evaluated once the results of the first monitor survey are processed and interpreted in 2016. The size and growth rate of the CO_2 plume will determine the utilization of subsequent monitor VSPs.

As outlined in the current MMV Plan, once the plume growth exceeds the imaging capability of VSP technology, surface seismic surveys will be employed. The footprint of future time-lapse surveys will be adjusted to cover the expected plume size as the project moves forward [6].

6.3. **Monitoring Wells**

6.3.1. Need for Monitoring Wells Near Periphery of Pressure Build-up

Approval No. 11837C Condition 10i, requires that each annual status report address the need for additional monitoring wells towards the periphery of the pressure build-up area later in the project life.

Shell considers the current pressure monitoring program adequate. There has been no change since submission of the 2013 First Annual Report [4]. At this time, Shell considers additional monitoring wells (BCS wells, deep monitoring wells, or groundwater wells) situated towards the periphery of the pressure build-up zone and near legacy wells unnecessary. There is no indication from injection or well data that BCS pressure will increase to levels that would provide a threat to containment (Section 3.4.2: Pressure Prediction).

6.3.2. Need for Additional Monitoring Wells Near Legacy Wells

At present Shell considers monitoring wells near the legacy wells to be unnecessary, as there is no indication from the injection and well data that the BCS pressure will increase to levels that would provide a threat to containment near the legacy wells (Section 3.4.3: Plume Prediction).

6.3.3. Monitoring at Injection Wells

In accordance with the Approval, Shell will use each of the three injection wells as pressure monitoring wells when feasible. IW 5-35 has been monitoring pressures in the BCS throughout the 2015 injection period. [1]

7. STAKEHOLDER ENGAGEMENTS

Stakeholder engagement activities for Quest continued throughout 2015. Activities fell into three main categories:

1) Updates to town, city, and county councils through regularly scheduled meetings,

2) Project information sessions to the public, and

3) Community involvement in the MMV Plan development and communication of results through participation in the Community Advisory Panel (CAP).

7.1. Government Authority Updates

Annual updates were given to town and county authorities at their council sessions to provide the most recent project progress information. Specifically, updates were provided to the following municipalities:

- April 8, 2015 – Thorhild County
- November 10, 2015 – Thorhild County
- November 24, 2015 – Fort Saskatchewan

Shell's updates to the above councils were well received. No major issues were raised and all questions posed by each of the councils were general in nature and answered immediately at the council sessions.

7.2. Public Information Sessions

To provide the broader public with the opportunity to hear the most recent updates on the project and to provide a forum for questions and answers, open houses were held in the Quest impacted areas. These sessions were as follows:

- May 12, 2015 – Thorhild Community Center
- May 20, 2015 – Radway Agricentre

The open houses were advertised to the greater public through local advertising.

The Quest Launch in November comprised both Scotford on-site and offsite celebration. Key community stakeholders were also invited to the on-site Quest Launch..

- November 6, 2015 - Quest launch event (on-site)
- November 14, 2015 - Quest launch community celebration (Radway Agricentre)

These public information sessions were generally well received with the attendees primarily looking for updates to the project. No major concerns or objections were raised with respect to the project at any of these public information sessions and any concerns that were raised have been addressed. There are no outstanding issues

7.3. MMV plan community involvement through CAP

To involve the greater public in the development of the MMV plan, a CAP was formed in 2012. The CAP comprises local community members including educators, business owners, emergency responders, and medical professionals as well as academics and AER representation. The mandate of the panel is to provide input to the Quest Project on the design and implementation of the MMV Plan on behalf of the broader community and to help ensure that results from the program are communicated in a clear and transparent manner.

In 2015 each meeting started with a project update followed by specific topics summarized below:

- April 9, 2015 – Update on MMV baseline program progress to date, construction update
- December 14, 2015 – Overview of operational MMV monitoring data and results, overview of commercial tests, sharing results of the first 90 days of injection.

In addition, a lunch meeting was held with CAP members and Shell Vice Presidents July 16, 2015.

8. CONSTRUCTION AND IMPLEMENTATION TEST RESULTS

The project was substantially completed in by January 2015. The main activities as related to construction and implementation of the Quest Project in 2015 included:

- Testing of the instrumentation loops
- Documentation quality checks
- Commissioning and Startup

Testing results that are relevant to this stage are (Table 8-1):

- Tests of instrumentation systems to check functionality

Some 119 operational procedures have been developed as part of the testing. Efforts have been focused on walking down each process and utilities system in order to identify punch list items that needed to be fixed before readiness for commissioning and start-up was declared in 2015.

Table 8-1: Summary of construction and implementation tests completed in 2015 for Quest CCS Project.

Test	Capture	ModYard	Pipeline
Functional Tests	233 Loop Checks	N/A	N/A

REFERENCES

[1] Carbon Dioxide Disposal Approval No. 11837C, AER, May 12th, 2015.

[2] Shell Quest Carbon Capture and Storage Project: 2015 Annual Summary Report: Section 8 Regulatory and Funding. Submitted to GOA March 31, 2015 as per CCS Funding Agreement – Quest Project (June, 2011).

[3] Shell Quest Carbon Capture and Storage Project: Second Annual Status Report. Submitted to AER January 31, 2015 as per Carbon Dioxide Disposal Approval 11837A Conditions 10 and 14.

[4] Shell Quest Carbon Capture and Storage Project: First Annual Status Report. Submitted to AER January 31, 2013 as per Carbon Dioxide Disposal Approval 11837A Conditions 10 and 11.

[5] Annual Surface Casing Vent Flow and Gas Migration submission to AER. June 30th, 2015.

[6] Shell Quest Carbon Capture and Storage Project: Third Annual Status Report. Submitted to AER January 31, 2015 as per Carbon Dioxide Disposal Approval 11837A Conditions 10 and 11.

[7] V Becker, A Myrttinen, M Nightingale, M Shevalier, L Rock, B Mayer, JAC Barth, 2015, Stable carbon and oxygen equilibrium isotope fractionation of supercritical and subcritical CO2 with DIC and H2O in saline reservoir fluids, International Journal of Greenhouse Gas Control, 39: 215-224.

[8] B Mayer, P Humez, V Becker, C Dalkhaa, L Rock, A Myrttinen, JAC Barth, 2015, Assessing the usefulness of the isotopic composition of CO2 for leakage monitoring at CO2 storage sites: A review, International Journal of Greenhouse Gas Control, 37: 46-60.

[9] Surveillance Analysis Theory, Fekete Associates Inc. (2016, March). Retrieved from http://www.fekete.com/SAN/WebHelp/FeketeHarmony/Harmony_WebHelp/Content/HTML_Files/Reference_Material/Analysis_Method_Theory/Surveillance_Theory.htm

APPENDIX A: GOLDER REPORT ON 2015 HBMP SAMPLING PROGRAM

REPORT

March 2016

2015 HBMP SUMMARY REPORT

Shell Quest CCS Hydrosphere Biosphere Monitoring Program

Submitted to:
Shell Canada Limited
400 4th Avenue SW
Calgary, AB
T2P 2H5

Report Number: 1523491_RP004_V2

Distribution:

Shell - 1 ecopy
Golder - 1 ecopy

Golder Associates

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APPENDICES

1.0 INTRODUCTION

The purpose of the Shell Canada Limited (Shell) Quest Carbon Capture and Storage Project (the Project) is to capture up to 1.2 million tonnes (Mt) of carbon dioxide (CO_2) per year from the Scotford Upgrader, compress and then transport the CO_2 by pipeline to the injection and storage facility located near Thorhild, Alberta, where it will be injected.

During 2015, biosphere field programs were conducted within the Project area to characterize pre-injection conditions based on soil chemistry in the vicinity of the injection well sites. Soil gas probes were also installed to provide sampling points for future testing. The Hydrosphere field programs included sampling of 24 wells during the Q1 2015 to Q4 2015 sampling events. This report outlines the sampling methodologies, field activities and results for each of these programs.

2.0 BIOSPHERE

2.1 Soils Surveys

The focus of the 2015 soil sampling program was to establish long-term soil monitoring plots and characterize Year 0 soil chemical properties that may be used as baseline values for future soil monitoring occurring over the life of the Project.

2.1.1 Field Methods

The 2015 soil sampling program was completed between May 23 and May 28, 2015 and on July 30, 2015. Soil samples were collected from nine locations north of Radway, Alberta in the County of Thorhild (Figure 2.1-1). A collection of 15 samples was taken at each location from five randomly chosen sites. Soil was collected from 0 to 30 cm, 30 to 60 cm, and 60 to 90 cm depth ranges with a Dutch auger and submitted to Exova Laboratories in Edmonton, Alberta for analysis of pH, electrical conductivity (EC), sodium adsorption ratio (SAR), and percent saturation. Sampling locations were marked using a Trimble R1 sub-metre accurate GPS.

Two distinct soil sampling procedures were established to collect soil data; one to sample soils on the constructed injection well pads, and the other to sample soil at plots on agricultural land.

Injection Well Pads Plots

Construction of injection well pads involved salvaging topsoil and subsoil and stockpiling them on site. The remaining material was levelled, if necessary, and gravel was placed in a tear drop shape around the centre and along the main access to the well head.

Pre-injection (or baseline) soil samples were collected at five randomly chosen sites on the constructed pad within the fenced area. Though randomly selected, soil sample sites were situated at least 3 m away from the soil gas monitoring probes, which were installed in a “cross” pattern radiating from the well head, to minimize the potential for introduction of atmospheric air into soil near the probes.

Generally, samples collected on the injection well sites were taken at the standard depth ranges of 0 to 30 cm, 30 to 60 cm, and 60 to 90 cm. However, when soils were sampled adjacent to the well head or access path, gravel was encountered at the surface. In these cases, sampling depths were altered slightly so as not to collect gravel and to remain within 90 cm of the pad surface grade to prevent contact with the utilities installed at 1 m or greater below the pad.

Monitoring Plots on Agricultural Land

Monitoring plots were established on annual crop and pasture land. A total of six monitoring plots were established during the 2015 soil sampling program. Single monitoring plots were established adjacent to each of the three injection wells and another three monitoring plots were established at previously established semi-permanent plots (Figure 2.1-1). Eighteen (18) metre (m) by 15 m monitoring plots were set up at each location in an area representative of the local landscape and at a relatively level site to ensure homogeneity of soil types within the plot. The monitoring plot was split into cells with six cells across and five cells down the rectangular plot (Figure 2.1-2). GPS accuracy ranged from 60 cm to 90 cm during the field program. A 3 m x 3 m cell dimension was chosen to ensure samples were taken and marked within the cells, and to maximize the homogeneity of the soils within each cell.

Sampling sites were randomly chosen at the centre of five of the 30 cells in the monitoring plot and sampled at the standard depth ranges of 0 to 30 cm, 30 to 60 cm, and 60 to 90 cm. Soil sampling locations and corner points of the monitoring plots were marked using the sub-metre accurate GPS in order to re-establish the same plots and ensure continuity for future soil sampling events.The rows were labelled from A to E and the columns were numbered from 1 to 6 starting from the northwest corner (Figure 2.1-2). For example, the cell located in the third row and second column would be labelled C2.

Figure 2.1-1: Soil Sample Location Overview

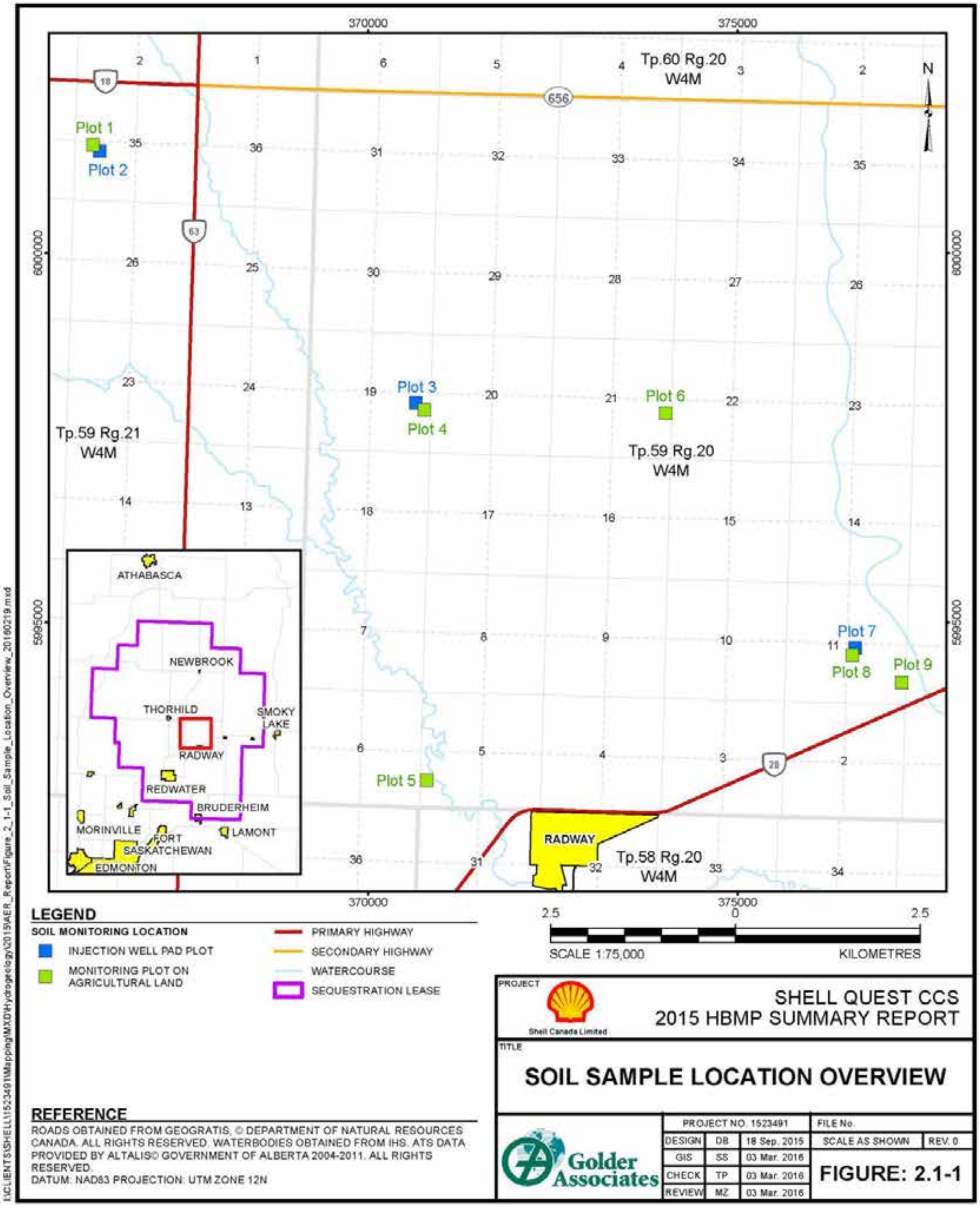


Figure 2.1-2: Monitoring Plot Setup and Site Naming Convention

	1	2	3	4	5	6
A	*A1*	*A2*	*A3*	*A4*	*A5*	*A6*
B	*B1*	*B2*	*B3*	*B4*	*B5*	*B6*
C	*C1*	*C2*	*C3*	*C4*	*C5*	*C6*
D	*D1*	*D2*	*D3*	*D4*	*D5*	*D6*
E	*E1*	*E2*	*E3*	*E4*	*E5*	*E6*

Before entering and exiting each plot on agricultural land, bio-hazard control procedures recommended by the Alberta Clubroot Management Committee (ACMC, 2010) were completed by field personnel to control the potential spread of clubroot spores.

2.1.2 Laboratory Analytical Methods

The analytical methods implemented by Exova Laboratories are listed in Table 2.1-1.

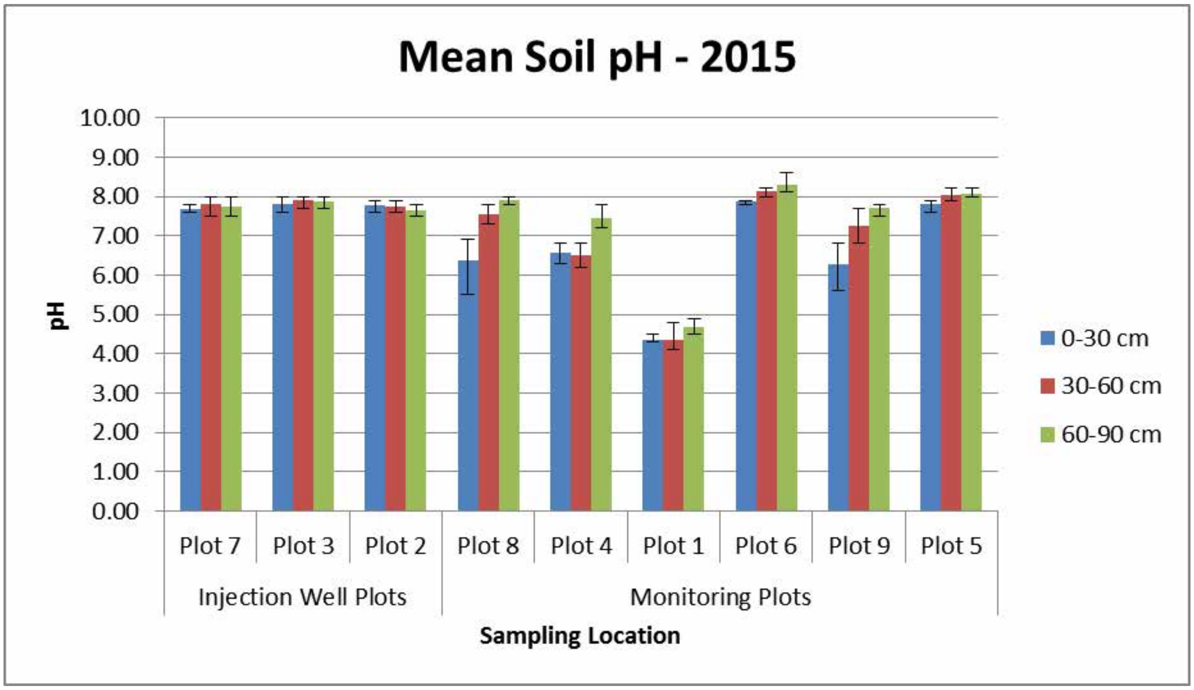
Table 2.1-1: Exova Soil Analytical Methods

Analysis	Reference	Method
Percent saturation (% saturation)	Carter and Gregorich, 2008	saturated paste with gravimetric method and oven drying, 51.2
Salinity	Carter and Gregorich, 2008	saturated paste method

2.1.3 Results and Key Findings

A total of 135 soil samples were collected in 2015. Sample results were used to calculate the mean pH, EC, SAR, and percent saturation values for each sampling location under pre-injection conditions. For example, calculated mean, maximum, minimum, and standard deviation values for soil pH are presented in Figure 2.1-3.

Figure 2.1-3: Mean Soil pH by Sampling Location and Depth – 2015

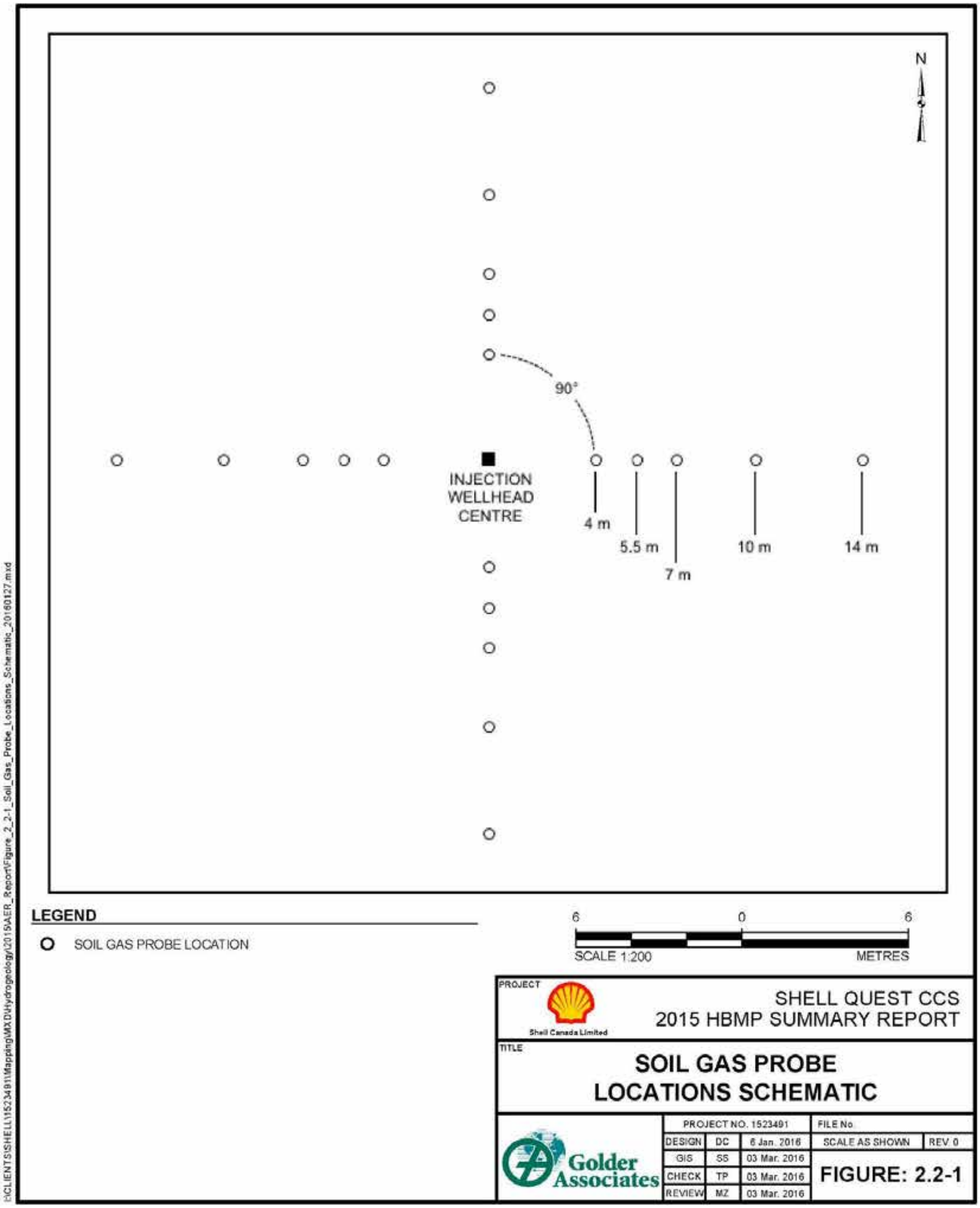


Results of the 2015 soil sampling program are consistent with previous soil information collected at these plots and are within the natural range of variability for soils in this region (Pedocan 1993). The study design is comparable to previous long-term soil monitoring programs (Abboud et al. 2012; Metz 1958; Morrison et al. 1996) and accounts for both temporal and spatial changes in the measured soil parameters.

2.2 Soil Gas Probe Installation

From May 23, 2015 to May 27, 2015, Golder field personnel installed 20 semi-permanent soil gas sampling probes at each of the three Shell Quest injection well sites located at 07-11-59-20 W4M, 05-35-59-21 W4M, and 08-19-59-20 W4M. Sampling probes were installed at a depth of 0.8 to 1.0 m around each injection well, radiating from the centre in four distinct 'arms' generally to the north, east, south and west. In each arm, five sampling probes were installed at prescribed distances from the centre of the Injection well head. Figure 2.2-1 shows the typical formation and approximate spacing between soil gas probes around each of the injection wells.

Figure 2.2-1: Soil Gas Probe Installation Schematic



3.0 HYDROSPHERE

The 2015 hydrosphere component of the HBMP for the Project included four quarterly groundwater and gas sampling events conducted as a component of the overall Shell Quest MMV Plan (Shell Canada Limited, 2012). The Q1, Q2 and Q3 sampling/data collection events were conducted prior to start of injection (pre-injection). Q4 sampling/data collection, conducted in early November, occurred after the start of injection and is referred to as operational monitoring.

The wells sampled for groundwater and gas analyses are located within the Quest Sequestration Lease Area. Samples were collected from two types of wells: Project wells and Landowner wells. Landowner wells included participating private Landowners. Project wells are monitoring wells located at one of Shell's three injection well sites. In addition to groundwater and gas sampling, downloads of pressure and basic water quality data from In-Situ® Multi-Parameter TROLL 9500 data loggers installed in the Project wells were performed on a quarterly basis.

Additional groundwater sampling and flow testing, separate from the HBMP sampling, was conducted in conjunction with Shell's 2015 Vertical Seismic Profiling program. A summary of this work is provided in Appendix A.

The sections below provide a summary of field work activities completed and analytical results obtained from the HBMP sampling events completed in 2015.

3.1 Monitoring Well Network

3.1.1 Landowner Wells

Landowner wells sampled in 2015 included privately owned wells located within 1 kilometre of an injection well site, and/or wells identified by Shell for sampling/testing. A total of 15 unique Landowner Wells were included in the planned 2015 sampling program.

3.1.2 Project Wells

The Project wells are Shell-owned groundwater monitoring wells located at the three injection sites:

- 07-11-59-20 W4M (07-11);
- 08-19-59-20 W4M (08-19); and
- 05-35-59-21 W4M (05-35).

A total of nine Project groundwater monitoring wells are installed; five are located at the 08-19 injection well site and two wells each are located at the 05-35 and 07-11 injection well sites.

3.1.3 Laboratory Analyses

3.1.3.1 Groundwater Analyses

Laboratory analyses of groundwater samples collected for the HBMP are listed in Table 3.1-1. Sample analyses included routine parameters and dissolved metals (Tier 1 & 2 analytes) and isotopes (Tier 3 analytes). Routine chemistry and metals analyses were performed by AGAT Laboratories (AGAT); and isotope analyses were performed by the University of Calgary.

Table 3.1-1: 2015 Laboratory Analyses – Groundwater

Analysis Type	Laboratory	Method
Tier 1 & 2		
Routine water[a]	AGAT Laboratories	Various
Low level metals[b]	AGAT Laboratories	Various[c]
Tier 3 - Isotopes		
$\delta^{13}C$-dissolved inorganic carbon	University of Calgary	Isotope-Ratio Mass Spectrometry

Notes:

(a) = Includes pH, electrical conductivity, TDS, TSS, alkalinity, ion balance, total hardness, Br, I, F, Cl, Na, K, Ca, Fe, Mg, Mn, HCO_3, CO_3, OH, SO_4, NO_2, NO_3, P, dissolved inorganic carbon, reactive silica, sodium adsorption ratio.

(b) = Low level dissolved metals: includes Al, Sb, As, Ba, B, Cd, Cr, Cu, Fe, Pb, Mn, Mo, Ni, Se, Ag, Ti, U, Zn.

(c) = Inductively Coupled Plasma Mass Spectrometry, Inductively Coupled Plasma Atomic Emission Spectrometry, or Cold Vapour Atomic Absorption depending upon analyte.

3.1.3.2 Gas Analyses

During 2015, free gas (gas that readily comes out of solution at atmospheric pressure) in groundwater was collected using a flow-through (FT) gas separator during well purging. The gas samples were collected into Tedlar® bags and submitted to AGAT for analyses. Laboratory gas analyses conducted as part the HBMP are listed in Table 3.1-2. Sample analyses included standard gas composition and isotopic analyses. Compositional analyses were conducted by AGAT and isotope analyses were performed by the University of Alberta.

In addition to the compositional and isotopic analyses noted above, gas samples were also collected in 2015 for noble gas analysis (Table 3.1-2). Samples were collected from Project wells in Q1 and from Landowner wells in Q3. The samples were analyzed for noble gas composition by the University of Utah.

Table 3.1-2: 2015 Laboratory Analyses – Free Gas

Analysis Type	Laboratory	Method
Composition He, H_2, O_2, N_2, CO_2, H_2S, C_1 to C_{10} hydrocarbons	AGAT Laboratories	GC-TCD-FID[a]
Isotopes $\delta^{13}C_{CO2}$, $\delta^{13}C_{CH4}$, $\delta^{13}C_{C2}$, and $\delta^{2}H_{CH4}$	University of Alberta	GC-C-IRMS[b]
Noble Gases		
Ar, Ne, Kr, Xe, He	Univiversity of Utah	Various

Notes:

(a) = Gas Chromatography-Thermal Conduction Detector-Flame Ionisation Detector

(b) = Gas Chromatography–Combustion–Isotope Ratio Mass Spectrometry

3.1.4 2015 Sampling Schedule

The planned 2015 groundwater and gas sampling schedule is presented in Table 3.1-3. A total of four quarterly sampling events were conducted in 2015. Where possible, both groundwater and free gas samples from scheduled Project and Landowner wells were collected during each sampling event.

Table 3.1-3: 2015 Planned Groundwater and Free Gas Sampling Schedule

Sampling Quarter	Planned Sampling	Number of Planned Wells	
		Landowner Wells	Project Wells
Q1	Groundwater	14	9
	Gas	14	9
	Noble Gas	0	9
Q2	Groundwater	10	9
	Gas	10	9
Q3	Groundwater	11	9
	Gas	11	9
	Noble Gas	11	0
Q4	Groundwater	10	9
	Gas	10	9

As much as possible, samples were collected from all 15 unique Landowner and 9 Project wells for sampling in each given quarter. However, in some circumstances (e.g., Landowner refusal or absence), it was not always possible to collect the total number of samples indicated in Table 3.1-3 during a given quarter.

3.2 Methodology

Prior to starting each quarterly sampling event, Landowners were contacted for permission to access their property and conduct groundwater sampling. The sampling procedures used to collect groundwater and gas samples from Landowner and Project wells are described below.

Groundwater and gas samples collected from Landowner/Project wells were placed in an ice chest and submitted under chain of custody to AGAT in Edmonton. As much as possible, samples were collected and delivered to the laboratory on the same day. In certain cases, same-day delivery was not possible due to scheduling, availability of Edmonton staff and/or weather conditions. In cases where same-day delivery of samples was not possible, samples were submitted the following day. Analyses for gas composition and Tier 1 & 2 groundwater chemistry were conducted by AGAT. Groundwater isotope samples were submitted to AGAT, and subsequently forwarded to the University of Calgary for analysis. Gas isotope samples were submitted to AGAT, and subsequently forwarded to the University of Alberta for isotope analysis. Gas samples collected for noble gas analysis were shipped directly to the University of Utah.

3.2.1 Groundwater Sampling

3.2.1.1 Landowner Wells

Groundwater samples were collected from Landowner wells via a raw water sampling outlet (e.g., an outdoor spigot or kitchen tap), upstream of any water treatment or softening systems. The water was first run through the tap for approximately 25 to 30 minutes. Field parameters (pH, conductivity, temperature and dissolved oxygen) were monitored and recorded during the purge time. Once parameters stabilized, indicating representative groundwater conditions, gas samples were collected if possible, and water samples were collected directly into laboratory-supplied bottles.

3.2.1.2 Project Wells

Groundwater samples from Project wells were collected using a portable bladder pump, following a low-flow sampling protocol. Low-flow sampling is an alternative approach to traditional sampling that reduces the need for large purge volumes by minimizing mixing and dilution within the wellbore, thereby minimizing alteration in water chemistry during the sampling process. Before conducting the low-flow groundwater sampling, manual water level measurement and data logger removal and download were performed.

The Project wells were purged at a low-flow rate (between 0.1 to 0.5 litres per minute), with the water intake placed at the approximate mid-point of the well screen. Field parameters and water levels were monitored and recorded during purging. Once field parameters had stabilized, indicating representative groundwater conditions, gas samples were collected if possible, and water samples were collected directly into laboratory-supplied bottles.

3.2.2 Gas Sampling

Gas sampling was attempted at all Project wells and Landowner wells sampled in 2015. Gas samples were collected for compositional and isotopic analysis on a quarterly basis. Additional samples at Project and Landowner wells were collected once in 2015 for noble gas analysis.

3.2.2.1 Flow-Through Gas Sampling

Gas composition and isotope samples were collected using a flow-through gas separator (FT). The FT is used in separating free gas from groundwater and is described in detail by Jones et al. (2009). Although gas collection was attempted at all Project and Landowner wells in 2015, samples could not always be collected, particularly in shallower and unconfined wells, where gas concentrations were minimal or the pressure differential was insufficient to allow gas to build up above the surface saturation levels. Where gas was collected in insufficient volume to analyze for both composition and isotopes, the sample was submitted for isotope analysis only.

3.2.2.2 Noble Gas Sampling

Noble gas samples were collected once in 2015 at all Project wells in Q1 and at Landowner wells in Q3. Samples were collected from Project wells using an advanced passive diffusion sampler (Gardner and Solomon 2009). The sampler was left in each well for 24 to 48 hours to allow gas to fill the sample chamber. The entire sampler, containing the gas, was submitted to the University of Utah for analysis.

The advanced passive diffusion sampler requires a relatively long sample collection time and detailed well installation information, neither of which were typically available at Landowner wells. Consequently, groundwater samples were collected (for gas analysis) from Landowner wells using a sealable ¼-inch diameter copper tube sampler supplied by the University of Utah. Samples were collected via a raw water sampling outlet (e.g., an outdoor spigot or kitchen tap), upstream of water treatment or softening systems. The tubes were connected in-line with a multi-parameter field probe used to monitor water quality field parameters (pH, conductivity, temperature). Once field parameters had stabilized, indicating representative formation water, the copper tubes were sealed at both ends with clamps. The copper tubes were then submitted directly to the University of Utah for analysis.

3.2.3 Water Quality Data Loggers

In addition to groundwater and gas sampling, the water quality data loggers installed in each of the nine Project wells were checked and calibrated monthly, with extended maintenance checks every quarter.

3.2.4 Well-ID Tag Installation

To facilitate the identification of Landowner wells that were sampled as part of the HBMP 2012-2014 Baseline Program, well identification (ID) tags were installed. This involved installing metal well ID tags, supplied by Shell, on approximately 130 Landowner Wells throughout the 2015 Q2, Q3 and Q4 sampling events. The well IDs are unique values and represent either the corresponding ID number found in the Alberta Water Well Information Database (AWWDB), or (where AWWDB IDs were unavailable) were provided by Shell.

3.2.5 Quality Assurance/Quality Control

Industry-standard methods and equipment were used in the sampling process to ensure representative samples were collected. This included low flow sampling techniques as described by Puls and Barcelona (1996), among others, used at the Project wells. Collection methods as outlined in Nielsen and Nielsen (2007) were employed in collecting samples from Landowner wells.

The groundwater quality assurance/quality control (QA/QC) program consisted of collecting duplicate samples, field blanks and equipment blanks during each quarterly sampling event. Field duplicates were collected for every 10 wells sampled; and relative percent differences (RPD) between the original and duplicate were compared to monitor reproducibility of sampling and analysis (Mitchell, 2006).

Field and equipment blanks were collected to assess potential contamination resulting from field and ambient conditions during sampling. Theoretically, sample concentrations in blank samples should be below reportable detection limits. The blank samples were generated in the field using laboratory-supplied distilled water.

3.3 Results

3.3.1 Groundwater Sampling

Groundwater samples collected in 2015 are summarized below in Table 3.3-1. Quarterly samples were collected from all nine Project wells in 2015, with the exception of one sample in Q2. Samples collected from Landowner wells varied between quarters, due primarily to Landowner availability (i.e., well access). A total of 24 wells (9 Project and 15 Landowner wells) were sampled at least once in 2015.

Table 3.3-1: 2015 Groundwater Samples Collected

Sampling Quarter	Groundwater Analysis	Number of Wells Sampled	
		Landowner Wells	Project Wells
Q1	Tier 1 & 2 / Tier 3	14	9
Q2	Tier 1 & 2 / Tier 3	10	8
Q3	Tier 1 & 2 / Tier 3	10	9
Q4	Tier 1 & 2 / Tier 3	9	9

As noted previously, not all wells planned for sampling could be sampled each quarter. Wells not sampled in 2015 were primarily due to the unavailabity of the Landowner. In two cases, access to the property/well was refused by the Landowner.

3.3.1.1 Groundwater Laboratory Results

A summary of the analytical results (including isotope data) from groundwater samples collected in 2015, including total number of samples, concentrations above the reported detection limit (RDL) and maximum concentrations observed for each analyte, is presented in Table 3.3-2. The data are presented as pre-injection (Q1, Q2 and Q3) and operational monitoring (Q4) data, with the composition and isotope data results from both Project and Landowner wells combined.

Table 3.3-2: 2015 Groundwater Chemical Analysis Summary

Parameter	Unit	Health Canada DWG [(a)]		Results Summary					
				Q1 to Q3 Data (Pre-Injection)			Q4 Data (Operational Monitoring)		
		MAC [(b)]	AO [(b)]	Average Observed Concentration	Total # of Analyses	Drinking Water Exceedances	Average Observed Concentration	Total # of Analyses	Drinking Water Exceedances
Conventional Parameters									
pH	-	-	6.5 - 8.5	7.98	60	8	7.82	18	2
Hardness, as $CaCO_3$	mg/L	-	-	353.6	60	-	364	18	-
Total Dissolved Solids (calculated)	mg/L	-	-	4123	60	-	4656	18	-
Total Suspended Solids	mg/L	-	-	39.06	34	-	31.71	18	-
Electrical Conductivity	µS/cm	-	-	6753	60	-	7707	18	-
Alkalinity, Total (as $CaCO_3$)	mg/L	-	-	579.8	60	-	523.8	18	-
Alkalinity, phenolphthalein (as $CaCO_3$)	mg/L	-	-	33.64	60	-	22.67	18	-
Dissolved Inorganic Carbon	mg/L	-	-	127.15	60	-	105.06	18	-
Reactive Silica	mg/L	-	-	9.57	37	-	9.3	18	-
Major Ions									
Calcium	mg/L	-	-	102.2	60	-	108.1	18	-
Magnesium	mg/L	-	-	23.9	60	-	22.9	18	-
Potassium	mg/L	-	-	16.3	60	-	13.4	18	-
Sodium	mg/L	-	200	1353	60	59	1566	18	18
Bicarbonate	mg/L	-	-	717.4	60	-	669.1	18	-
Carbonate	mg/L	-	-	30.58	60	-	15	18	-
Chloride	mg/L	-	250	2002	60	22	2217	18	7
Fluoride	mg/L	1.5	-	0.64	60	0	0.27	18	0
Sulphate	mg/L	-	500	390.2	60	14	549.6	18	7
Hydroxide	mg/L	-	-	24	60	-	10	18	-
Bromide	mg/L	-	-	19.16	37	-	25.28	18	-

Table 3.3-2: 2015 Groundwater Chemical Analysis Summary con't

Parameter	Unit	Health Canada DWG (a)		Results Summary					
				Q1 to Q3 Data (Pre-Injection)			Q4 Data (Operational Monitoring)		
		MAC (b)	AO (b)	Average Observed Concentration	Total # of Analyses	Drinking Water Exceedances	Average Observed Concentration	Total # of Analyses	Drinking Water Exceedances
Major Ions									
Iodide	mg/L	-	-	9.9	37	-	13.7	18	-
Ion Balance	%	-	-	95.1	60	-	95.6	18	-
Nutrients and Biological Indicators									
Dissolved Phosphorus (as P)	mg/L	-	-	0.218	43	-	0.286	18	-
Nitrate as N	mg/L	10	-	6.35	60	2	4.41	18	0
Nitrate	mg/L	45	-	28.13	52	2	19.5	18	0
Nitrite as N	mg/L	1	-	n.d.	60		n.d.	18	0
Nitrite	mg/L	3	-	n.d.	52		n.d.	18	0
Dissolved Metals									
Aluminum	mg/L	-	0.1	0.05	60	4	0.006	18	0
Antimony	mg/L	0.006	-	0.003	60	2	0.002	18	0
Arsenic	mg/L	0.01	-	0.002	60	0	0.002	18	0
Barium	mg/L	1.0	-	5.7	60	16	7.187	18	6
Boron	mg/L	5.0	-	0.83	60	0	0.94	18	0
Cadmium	mg/L	0.005	-	0.00003	60	0	0.00004	18	0
Chromium	mg/L	0.05	-	0.0076	60	0	n.d.	18	0
Copper	mg/L	-	1.0	0.007	60	0	0.0025	18	0
Iron	mg/L	-	0.3	2.1	60	16	1.138	18	10
Lead	mg/L	0.01	-	0.0014	60	0	n.d.	18	0
Manganese	mg/L	-	0.05	0.101	60	35	0.12	18	13
Molybdenum	mg/L	-	-	0.008	60	-	0.008	18	-
Nickel	mg/L	-	-	0.013	60	-	0.03	18	-
Selenium	mg/L	0.05	-	0.02	60	3	0.005	18	0
Silver	mg/L	-	-	0.00076	60	-	0.00008	18	-
Thallium	mg/L	-	-	n.d.	60	-	n.d.	18	0
Uranium	mg/L	0.02	-	0.008	60	1	0.005	18	0
Zinc	mg/L	-	5.0	0.198	60	0	0.21	18	0

Notes:

[a] Health Canada (2014). Guidelines for Canadian Drinking Water Quality - Summary Table. Water and Air Quality Bureau, Healthy Environments and Consumer Safety Branch, Health Canada, Ottawa, Ontario.

[b] Health Canada's Maximum Acceptable Concentration (MAC) for Drinking Water.

[c] Health Canada's Aesthetic Objectives (AO) or Operational Guidelines (OG) for Drinking Water.

n.d.= not detected; no concentrations observed above RDL.

'-' = no data/guideline

RDL = reportable detection limit

δ^{13}C-DIC isotope results ranged from -19.1‰ to +13.1‰.

3.3.1.2 Data Logger Results

Daily pressure and water quality data collected from the nine In-Situ® Multi-Parameter TROLL 9500 installed in Project wells were downloaded during each quarterly sampling event in 2015. Logger data currently available for 2015 extends from January 1, 2015 to November 3, 2015 (Table 3.3-3). Data from the remainder of 2015 will be downloaded in the upcoming 2016 Q1 event.

Offsite maintenance and calibration were completed on the nine data loggers quarterly in 2015; and additional calibration and equipment/sensor inspections were performed monthly at the well site. Sensor and calibration issues continued to occur in 2015, requiring different data loggers to be returned to the manufacturer for major repairs on six occasions.

Table 3.3-3: 2015 TROLL 9500 Data Logger Summary

Project Well-ID	2015 Date Range [(a)]	2015 Data Points Collected [(b)]
1F1-08-19-059-20W4-00	01-Jan-2015 to 03-Nov-2015	78
UL1-08-19-059-20W4-00	01-Jan-2015 to 03-Nov-2015	126
UL2-08-19-059-20W4-00	01-Jan-2015 to 03-Nov-2015	265
UL3-08-19-059-20W4-00	01-Jan-2015 to 03-Nov-2015	253
UL4-08-19-059-20W4-00	01-Jan-2015 to 03-Nov-2015	271
1F1-05-35-059-21W4-00	01-Jan-2015 to 03-Nov-2015	148
UL1-05-35-059-21W4-00	01-Jan-2015 to 03-Nov-2015	140
1F1-07-11-059-20W4-00	01-Jan-2015 to 03-Nov-2015	141
UL1-07-11-059-20W4-00	01-Jan-2015 to 03-Nov-2015	247

Notes:
[(a)] 2015 dataset was included as part of the 2015 quarterly download events. The remaining 2015 data will be downloaded in Q1 of 2016.
[(b)] Represents number of pressure data points collected; actual number of points for each water quality parameter (temperature, pH, ORP, conductivity) will vary.

3.3.2 Gas Sampling

The gas results for samples collected during the four quarterly 2015 sampling events are summarized in Table 3.3-4.

As noted previously, gas sampling was attempted at all Project and Landowner wells in 2015; however, samples could not be collected at all wells, particularly in shallower and unconfined wells.

Table 3.3-4: 2015 Gas Sampling Summary

Sampling Quarter	Gas Analysis	Number of Wells Sampled	
		Landowner Wells	Project Wells
Q1	Composition	1	4
	Isotopes	1	4
	Noble Gas	0	9
Q2	Composition	1	3
	Isotopes	1	3
Q3	Composition	1	5
	Isotopes	3	6
	Noble Gas	7	0
Q4	Composition	1	3
	Isotopes	1	5

3.3.2.1 Gas Analytical Results

A summary of the gas composition and isotope results from samples collected in 2015, representing both Project and Landowner wells, is presented in Table 3.3-5 and Table 3.3-6, respectively, including total number of samples, concentrations above the reported detection limit (RDL), average concentration (composition), and minimum/maximum concentrations (isotopes) observed for each analyte. The data are presented as pre-injection (Q1, Q2 and Q3) and operational monitoring (Q4) data, with the composition and isotope data results from both Project and Landowner wells combined.

Table 3.3-5: 2015 Gas Chemical Analysis Summary

Parameter	Units	Q1 to Q3 Data (Pre-Injection)			Q4 Data (Operational Monitoring)		
		Average Observed Concentration	Number of Samples	Samples Above RDL	Average Observed Concentration	Number of Samples	Samples Above RDL
Helium (He)	%	0.011	15	14	0.010	4	4
Hydrogen (H_2)	%	0.033	15	15	0.041	4	4
Oxygen (O_2)	%	3.864	15	15	4.029	4	4
Nitrogen (N_2)	%	17.367	15	15	15.603	4	4
Carbon Dioxide (CO_2)	%	0.058	15	15	0.047	4	4
Hydrogen Sulphide (H_2S)	%	n.d.	15	0	n.d.	4	0
Methane (C_1)	%	78.578	15	15	80.194	4	4
Ethane (C_2)	%	0.051	15	15	0.065	4	4
Propane (C_3)	%	0.006	15	2	0.006	4	2
I-Butane (IC_4)	%	0.0015	15	2	0.002	4	2
N-Butane (NC_4)	%	0.001	15	1	0.001	4	3
I-Pentane (IC_5)	%	0.001	15	1	0.001	4	3
N-Pentane (NC_5)	%	0.001	15	1	0.002	4	3
Hexanes (C_6)	%	0.001	15	1	0.0035	4	2
Heptanes (C_7)	%	0.003	15	1	0.007.	4	1
Octanes (C_8)	%	0.001	15	1	0.004	4	1
Nonanes (C_9)	%	n.d.	15	0	n.d.	4	0
Decanes+ (C_{10+})	%	n.d.	15	0	n.d.	4	0

Notes:
n.d.= not detected; no concentrations observed above parameter RDL.
RDL = reportable detection limit

Table 3.3-6: 2015 Gas Isotope Analysis Summary

Isotope	Units	Standard	Q1 to Q3 Data (Pre-Injection)			Q4 Data (Operational Monitoring)		
			Minimum	Maximum	Number of Analyses[1]	Minimum	Maximum	Number of Analyses[1]
$\delta^{13}C_{CO2}$	‰	V-PDB	-25.6	+1.7	14	-24.7	-24.7	1
$\delta^{2}H_{CH4}$	‰	V-PDB	-368	-257	14	-317	-297	4
$\delta^{13}C_{CH4}$	‰	V-PDB	-87.4	-51.4	17	-74.7	-54.2	6
$\delta^{13}C_{C2}$	‰	V-PDB	-53.2	-47.8	13	-52.7	-49.5	6

Notes:
n.d. = not detected; no concentrations observed above reportable detection limit (RDL).
[1] 17 gas isotope samples were submitted in Q1-Q3; 6 in Q4. “Number of Analyses” in this table refers to the number of samples that could be successfully analyzed for each isotope.

3.3.3 Quality Assurance/Quality Control

Blanks and duplicate samples were collected during each sampling event to assess precision of field sampling procedures and the quality of reported analytical results. The Quality Assurance/Quality Control (QA/QC) samples collected are summarized in Table 3.3-7. A total of 16 groundwater duplicate samples and 11 groundwater blanks were collected in 2015.

Results from nine of the 11 groundwater blank samples collected in 2015 indicated concentrations below the detection limit for all parameters. A chloride concentration above the acceptable RDL was observed in one blank sample collected in Q2; and one for sodium and chloride in Q4.

Parameter RPD exceedances for were noted in 2 groundwater duplicate samples in 2015, including dissolved inorganic carbon and bismuth (in Q1) and zinc (in Q3). Single parameter RPD exceedances were noted for n-butane, ethane and butane in 2015 gas samples. Nitrogen and oxygen RPD exceedances were noted 3 and 4 times, respectively, in 2015.

Table 3.3-7: Quality Assurance/Quality Control Sampling

Sampling Quarter	Analysis	Number of QA/QC Samples Collected					
		Groundwater QA/QC			Gas QA/QC		
		Duplicate Samples	Field Blanks	Equipment Blank	Duplicate Samples	Field Blanks	Equipment Blank
Q1	Chemical	2	2	1	2	0	0
	Isotopes	2	0	0	3	0	0
Q2	Chemical	2	2	0	2	0	0
	Isotopes	2	0	0	2	0	0
Q3	Chemical	2	2	1	2	0	0
	Isotopes	2	0	0	2	0	0
Q4	Chemical	2	2	1	2	0	0
	Isotopes	2	0	0	2	0	0

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5.0 ABBREVIATIONS

%	percent
µS/cm	microsiemens per centimetre
Ag	silver
Al	aluminum
As	arsenic
B	boron
Ba	barium
Br	bromine
Ca	calcium
Cd	cadmium
CH_4	methane
Cl	chlorine
cm	centimetre
CO_2	carbon dioxide
CO_3	carbonate
Cr	chromium
Cu	copper
EC	electrical conductivity
F	florine
Fe	iron
Golder	Golder Associates Ltd.
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulphide
HCO_3	bicarbonate
HBMP	Hydrosphere and Biosphere Monitoring Program
He	Helium
I	iodine
K	potassium
Mg	magnesium
mL	millilitre
MMV	Measurement, Monitoring and Verification
Mn	manganese
Mo	molybdenum

N_2	nitrogen
Na	sodium
Ni	nickel
NO_2	nitrogen dioxide
NO_3	nitrate
O_2	oxygen (gas)
OH	hydroxide
P	phosphorus
Pb	lead
Q	quarter (i.e., three months of a year)
QA/QC	Quality Assurance and Quality Control
RDL	Reported Detection Limit
SAR	Sodium Adsorption Ratio
Sb	antimony
Se	selenium
Shell	Shell Canada Limited
SO_4	sulphate
TDS	Total Dissolved Solids
Ti	titanium
TSS	Total Suspended Solids
the Project	Quest Carbon Capture and Storage Project
U	uranium
W4M	West of the Fourth Meridian
Zn	zinc

Report Signature Page

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APEGA PERMIT TO PRACTICE 05122

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APPENDIX A

VSP Memo

MEMORANDUM

TO	Celina Duong	**DATE**	March 9, 2016
CC			
FROM	Doreen Chan	**REFERENCE No.**	152341_ME002

2015 VSP PROGRAM

Introduction

As requested by Shell Canada Energy (Shell), Golder Associates Ltd. (Golder) performed water quality sampling and flow testing at designated landowner wells prior to Vertical Seismic Profie (VSP 1) and following (VSP 2) testing in early 2015. Chemical analyses were similar to those conducted for the Quest Hydrosphere Biosphere Monitoring Program (HBMP) quarterly monitoring program, with the addition of total iron and coliform bacteria analyses. Flow testing consisted of placing a pressure transducer into the well and opening a tap for 30-60 minutes to draw the water level down in the well.

Wells

Shell provided a list of wells to be sampled; most of the wells were already included in the quarterly monitoring program. The intent was to include wells within a specific distance of the proposed seismic line.

VSP 1

Pre-seismic testing was performed from January 12 to January 26, 2015. A total of 11 wells were flow tested, and 14 wells were sampled for chemistry. Three wells could not be flow tested due to insufficient access to the well for the pressure sensor.

At each well, the water level was measured and recorded, then an InSitu® Level TROLL 700 datalogger was placed in the well, deep enough to accommodate expected drawdown but safely above the pump intake. The normal water sampling equipment was prepared, including flow-through cell, gas separator, and associated tubing. The datalogger was started and set to a recording interval of five seconds, and the tap was opened fully. Manual measurements of depth to water were also collected at specific intervals, and field chemistry parameters were recorded periodically during the test. Chemistry samples were collected near the end of the pumping period. At the end of the pumping test, the tap was closed and recovery was monitored for an equal period of time.

VSP 2

Post-seismic testing was combined with the Q1 2015 HBMP monitoring event, from March 2 to March 10, 2015. Nine wells were flow tested, and 11 chemistry samples were collected. The same procedures were used as for the VSP 1 testing.

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