CLASS VI SEMI-ANNUAL REPORT
40 CFR 146.91(a)

Illinois Industrial Carbon Capture and Storage Project

INSTRUCTIONS

This template provides an outline and recommendations for the Semi-Annual Reports.

In this template, examples or suggestions appear in **blue text**. These are provided as general recommendations to assist with site- and project-specific document development. The recommendations are not required elements of the Class VI Rule. This document does not substitute for those provisions or regulations, nor is it a regulation itself, and it does not impose legally-binding requirements on the EPA, states, or the regulated community.

Please delete the **blue text** and replace the yellow highlighted text before submitting your document. Similarly, please adjust the example tables as necessary (e.g., by adding or removing rows or columns). Appropriate maps, figures, references, etc. should also be included to support the text. Throughout this report, please compare monitoring results to computational model inputs and outputs wherever applicable.

Pursuant to 40 CFR 146.91(a), each semi-annual report must contain:

(1) Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data;
(2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;
(3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;
(4) A description of any event which triggers a shut-off device required pursuant to 40 CFR 146.88(e) and the response taken;
(5) The monthly volume and/or mass of the CO_2 stream injected over the reporting period and the volume injected cumulatively over the life of the project;
(6) Monthly annulus fluid volume added; and
(7) The results of monitoring prescribed under 40 CFR 146.90.

The semi-annual report must cover all activities included in the approved Testing and Monitoring Plan. Remember that, pursuant to 40 CFR 146.90, the requirement to maintain and implement an approved Testing and Monitoring Plan is directly enforceable regardless of whether the requirement is a condition of the permit. For more information, see the Class VI guidance documents at https://www.epa.gov/uic/class-vi-guidance-documents.

To avoid duplicative reporting, you are encouraged to provide relevant cross-references to other submissions made with the GSDT.

Facility Information

Facility name:	Archer Daniels Midland Company
Well Name:	CCS#2
Facility contact:	Douglas Kirk douglas.kirk@adm.com
Well location:	Decatur, Macon County, IL
Well Coordinates:	39º 53' 09.32835" N, 88º 53' 16.68306" W
Permit number:	IL-115-6A-0001
Report date:	January 30, 2023
Report period:	January 1, 2022 @ 00:00 hrs - January 1, 2023 @ 00:00 hrs
Report number:	31

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons that manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

1. Overview

Summary of Operating Parameters

This report covers the CCS#2 injection monitoring period beginning 01/01/2022 @ 00:00 hours and ending at 01/01/2023 @ 00:00 hours. During the 12-month period, 430,522 metric tons (Mt) of CO_2 was injected at an average rate of 1,180 Mt/day resulting in a total mass of 2,953,076 Mt being injected into CCS#2 (See Figure 1). The reservoir pressure changed as a function of injection rate and the total mass of CO_2 injected. The average downhole tubing injection pressure (reservoir pressure) was 3,915 psia versus the pre-injection pressure of 2,841 psia equating to an increase in reservoir pressure of 1,073 psi. The actual injection pressure tracked with the forecast injection pressure but due to fouling of the perforated interval there is a 6.9% bias versus the reservoir model. The above confining zone (ACZ) monitoring data at VW#1 and VW#2 show no movement of fluids or CO_2 above the confining zone. This is also supported by the injection zone pressure and temperature data which indicate the CO_2 is moving along the injection horizon within the CCS#2 operational parameters. No anomalous operating or reservoir parameters were observed. No changes were observed in GM#2's downhole pressure and temperature monitoring of the St. Peter Sandstone and the shallow and deep groundwater monitoring data show no changes in groundwater chemistry that would indicate movement of fluids or CO_2 out of the injection zone.

The injectate stream analysis shows no change in the CO_2 quality when compared to the baseline data. The unit's corrosion monitoring system showed an increase in corrosion rates on the A106-B & 13CR-L80 coupon during Q3 and Q4 of 2022. The coupons had visible signs of particulate formation indicating upstream corrosion (see Figure 1). Project team is reviewing the operation of the dehydration unit and onstream water analyzer. Continuous DTS monitoring of CCS#2 is ongoing and the well's smooth temperature profile indicates good well integrity and no movement of fluid or CO_2 behind the casing. Therefore, continuing injection operation does not present an endangerment to the St. Peter Sandstone, the lower most USDW.

Figure 1: Corrosion Coupon A106-B Q3-2022 (top figure) and Q4-2022 (bottom figure) shows particulates adhering to coupons indicative of upstream corrosion.

Summary of Operational Deviations

A summary of the periods in which the operational parameters exceeded the maximum or minimum limits is provided in Table 1. Detailed descriptions of each event are provided in Section 3. Table 2 shows the recording frequency for VW#2's downhole gauges.

Maintenance, Inspection, & Annual Sampling

The annual deep groundwater sampling and the remaining MIT activities were completed during Q1-2022. Prior to sampling GM#2, the St. Peter reservoir T/P monitoring gauge was pulled from the well and underwent annual maintenance and testing. The GM#2 gauges were deployed in Q3-2022. The pulse neutron logging of CCS#1, CCS#2, VW#1, and VW#2 was conducted in January 17-23, 2022 and the log interpretation was submitted to the agency. The schedule and status for 2022 annual MIT and groundwater sampling activities is shown in Table 3.

As previously reported, we continue to experience failing performance of the downhole gauges at VW#2, specifically the above confining zone (Zone 5 – Ironton Galesville) and within the injection zone, (Zones 2 & 3 – Mt. Simon A & B) monitoring gauges. The Zone 5 gauge essentially failed in July 2021 and little data (1.32%) is being received from the instrument. The Zone 4 gauges are operating at a recording frequency of Pressure (P)-71% and Temperature (T)-71%. The Zone 3 gauges are recording at P-13% and T-100%. The Zone 2 gauges are recording at P-97% and T-100% and the Zone 1 gauges are recording at P-100% and T-100%. We are closely watching the instrument's fault frequency to gauge the rate of deterioration. We continue to use VW#1 to continuously monitor the Ironton Galesville and the Mt Simon A/B. This should provide enough downhole surveillance to detect any anomaly's that would indicate the movement of fluids or CO_2 out of the injection zone. Zone 2 sliding sleeve developed a leak and the operator installed a bridge plug above Zone 4. This bridge plug isolated the leaking zone within the injection zone but does not allow reservoir fluid sampling below Zone 5. To be clear, this leakage is confined to the production tubing and does not impact the well's external mechanical integrity. The operator attempted to sample the Zone 5 (Ironton Galesville) interval but was unable to obtain a representative sample of the reservoir fluid. The project team conducted a spinner log on the well and determined Zone 2 fluid was leaking through the bridge plug. Therefore, sampling of this zone was discontinued and a recompletion plan for VW#2 is being developed. Recompletion of the monitoring well is planned for Q3-2023.

Table 1. Summary of deviations from operational control limits.

Monitoring Condition	No. Events	Total hours	Description of Event(s)[1]	Date/Time
Wellhead Pressure	0	0	NA	NA
DH Tubing Pressure	13	13	Operational – 4,125.4 psia (0.01% over limit) Operational – 4,126.4 psia (0.03% over limit) Operational – 4,129.6 psia (0.11% over limit) Operational – 4,130.6 psia (0.14% over limit) Operational – 4,126.0 psia (0.03% over limit) Operational – 4,125.5 psia (0.01% over limit) Operational – 4,132.4 psia (0.18% over limit) Operational – 4,125.3 psia (0.01% over limit) Operational – 4,127.4 psia (0.06% over limit) Operational – 4,125.6 psia (0.01% over limit) Operational – 4,160.6 psia (0.86% over limit) Operational – 4,126.1 psia (0.03% over limit) Operational – 4,125.5 psia (0.01% over limit)	01/09/2022 08:00 01/09/2022 11:00 01/20/2022 00:00 01/25/2022 00:00 01/25/2022 02:00 02/12/2022 00:00 02/19/2022 08:00 07/18/2022 17:00 07/18/2022 18:00 10/17/2022 21:00 10/20/2022 00:00 10/21/2022 23:00 11/17/2022 09:00
DH Tubing/Annulus ΔP	0	0	NA	NA
Annulus Pressure	0	0	NA	NA
Trip Auto S/D System	0	0	NA	NA

Note 1: Detailed description provided in Section 3.

Table 2. Recording frequency of VW#2 downhole gauges**.**

Well	Zone	Depth	Formation	Gauge	Recording Frequency[1]
VW#2	Zone 5	5,027	Ironton Galesville	Pressure	1.32%
				Temperature	0.00%
	Zone 4	5,848	Mt Simon E	Pressure	70.75%
				Temperature	70.78%
	Zone 3	6,524	Mt Simon B	Pressure	13.17%
				Temperature	99.90%
	Zone 2	6,881	Mt Simon A – Upper *Injection Zone*	Pressure	97.00%
				Temperature	99.90%
	Zone 1	7,041	Mt Simon A - Lower	Pressure	99.70%
				Temperature	99.70%

Note 1: Fully functional gauge with compliant recording frequency = 100%

.

Table 3. Schedule and status for 2022 annual reservoir fluid sampling and MIT activities.

Dates	Well	Activity	Status
Jan 17-23, 2022	CCS#1&2	Pulse Neutron Logging	Completed
Jan 17-23, 2022	VW#1&2	Pulse Neutron Logging	Completed
Jan 21, 2022	CCS#2	T/P Calibration of DH Gauges	Completed
TBD[1]	VW#1	Sample Zone - 3 (Ironton Galesville)	Purging Zone
TBD[1]	VW#1	Sample Zones - 2 (Mt Simon B)	Purging Zone
Suspended[2]	VW#2	Sample Zone - 5 (Ironton Galesville)	Suspended
Suspended[2]	VW#2	Sample Zone - 4 (Mt Simon E)	Suspended
Suspended[2]	VW#2	Sample Zone - 3 (Mt Simon B)	Suspended
Suspended[3]	VW#2	Sample Zone - 2 (Mt Simon A Upper)	Suspended
Apr 6, 2022	GM#2	Sample St Peter (Lowermost USDW)	Completed
Feb 22, 2022	CCS#2	T/P Calibration of Surface Gauges	Completed
Feb 22, 2022	CCS#2	Testing of the Automatic S/D System	Completed

Note 1: Reservoir fluids are being produced until representative native fluids are produced (zone purging).
Note 2: Sampling of Zones 3 & 4 was suspended due to leakage of the Zone 2 sliding sleeve. The operator set a bridge plug above Zone 4; therefore, no fluid sampling can occur below Zone 5.
Note 3: Sampling of Zone 2 was suspended due to CO_2 break through.

2. Analysis of CO_2 Injectate Stream

Discussion of Results

Table 4 presents the CO_2 injectate analytical results for the last four quarters (Q1-Q4 2022). The samples were analyzed by Airborne Labs International using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photoionization. The sample chain-of-custody procedures described in the Quality Assurance and Surveillance Plan (QASP) were employed with no reported deviations. The Q1-2022 sample appear to have some minor air contamination which can occur during sampling, but the overall analytical results indicate no trend or change in the quality of the CO_2 injectate and is consistent with the historic sample data generated during the ICCS and IBDP projects.

Table 4. Analytical results for CO_2 injectate stream.

Parameter	Q1 2022 2/25/22	Q2 2022 5/24/22	Q3 2022 8/19/22	Q4 2022 11/18/22	Unit (LOQ)	Analytical method
Carbon Dioxide	Positive 99.8	Positive 99.9	Positive 99.9	Positive 99.9	% v/v (5.0)	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID)
Nitrogen	700	320	320	480	ppm v/v (10)	ISBT 4.0 (GC/DID)
Oxygen	110	27	nd	50	ppm v/v (1.0)	ISBT 4.0 (GC/DID)
Carbon Monoxide	nd	nd	nd	nd	ppm v/v (2.0)	ISBT 4.0 (GC/DID)
Oxides of Nitrogen	nd	nd	nd	nd	ppm v/v (0.5)	ISBT 7.0 Colorimetric
Total Hydrocarbons	210	200	660	270	ppm v/v (0.1)	ISBT 10.0 THA (FID)
Methane	trace	0.2	nd	0.2	ppm v/v (0.1)	ISBT 10.1 (GC/FID)
Acetaldehyde	6.2	18	41	53	ppm v/v (0.05)	ISBT 11.0 (GC/FID)
Sulfur Dioxide	nd	nd	nd	nd	ppm v/v (0.05)	ISBT 14.0 (GC/SCD)
Hydrogen Sulfide	25	21	2.1	23	ppm v/v (0.01)	ISBT 14.0 (GC/SCD)
Ethanol	84	65	420	100	ppm v/v (0.1)	ISBT 11.0 (GC/FID)

LOQ = Limit of Quantitation is the lowest amount of analyte quantitatively determined with suitable precision and accuracy.
nd = indicates the impurity was not detected and was below method detection limit.

Supplemental Material
The analytical reports for the samples have been uploaded to the GSDT as follows:
Q1 2022 CO_2 Analytical Report: ***20220225_Q1_2022_CO2_Analysis.pdf***
Q2 2022 CO_2 Analytical Report: ***20220524_Q2_2022_CO2_Analysis.pdf***
Q3 2022 CO_2 Analytical Report: ***20220819_Q3_2022_CO2_Analysis.pdf***
Q4 2022 CO_2 Analytical Report: ***20221118_Q4_2022_CO2_Analysis.pdf***

3. Continuous Recording of Injection Pressure, Rate, and Volume and Annular Pressure

Discussion of Results
Figure 2 shows the injection rate monitoring data for the reporting period. During this period, a total of 430,522 metric tons (Mt) of CO_2 was injected at an average rate of 1,180 Mt/day. The maximum flowrate achieved was 2,183 Mt/day during which the wellhead pressure reached 2,108 psig. The fluctuations seen in the injection flowrate are due to plant slowdowns and shutdown of injection during the period which the operator conducted a backflow of CCS#2. Figure 3 trends the CCS#2 wellhead temperature and pressure data. During this period, the wellhead temperature and pressure averaged 93 °F and 1,720 psig respectively.

In an effort to maximize the injection rate, the downhole pressure was maintained near the maximum downhole limit of 4,125 psia (90% of the calculated reservoir fracture pressure). Operating near this constraint, resulted in thirteen 1-hour periods in which the downhole tubing pressure exceeded this limit. Table 1 details these exceedances and shows that all are significantly below the reservoir's fracture pressure and the current operating data indicates that no formation or well damage occurred.

Figure 4 trends the pressure maintained on the CCS#2 injection well annulus. During this period, the annulus pressure averaged 863 psig and no annular fluid was added to the system. Figure 5 shows the CCS#2 injection zone temperature and pressure monitoring data for the gauges set at 6,270 ft. The baseline (pre-injection) reservoir pressure and temperature was 2,841 psia and 116 °F respectively. As injection progressed through the period, the pressure trended with the injectate flow averaging 3,915 psia corresponding to a ΔP of 1,073 psi versus the baseline. The downhole injection temperature averaged 123 °F or a ΔT of 7 °F. Figure 5 charts the difference between the downhole annulus pressure and the tubing pressure thus providing delta pressure (ΔP) monitoring across the downhole packer. During the reporting period, the packer ΔP averaged 395 psi. The automatic shutdown system was not activated during the reporting period.

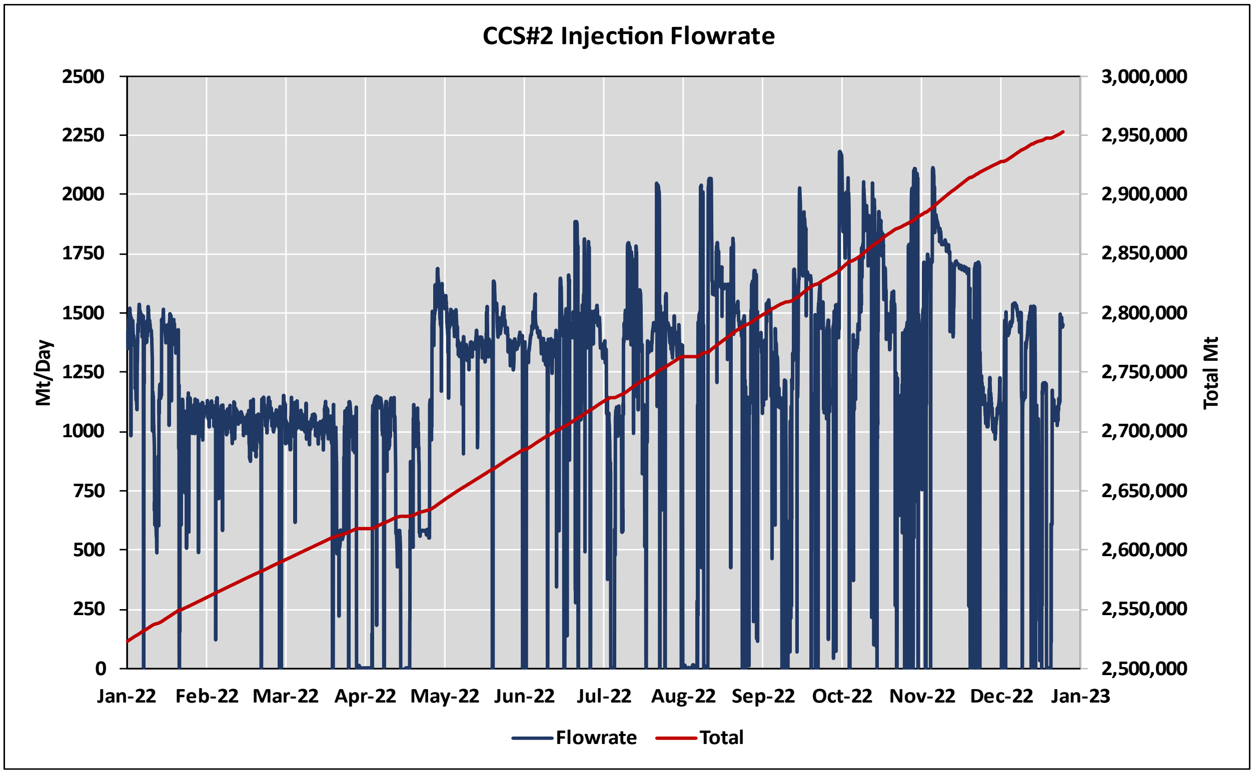

Figure 2: CCS#2 - Injection rate monitoring data for Jan-Dec 2022.

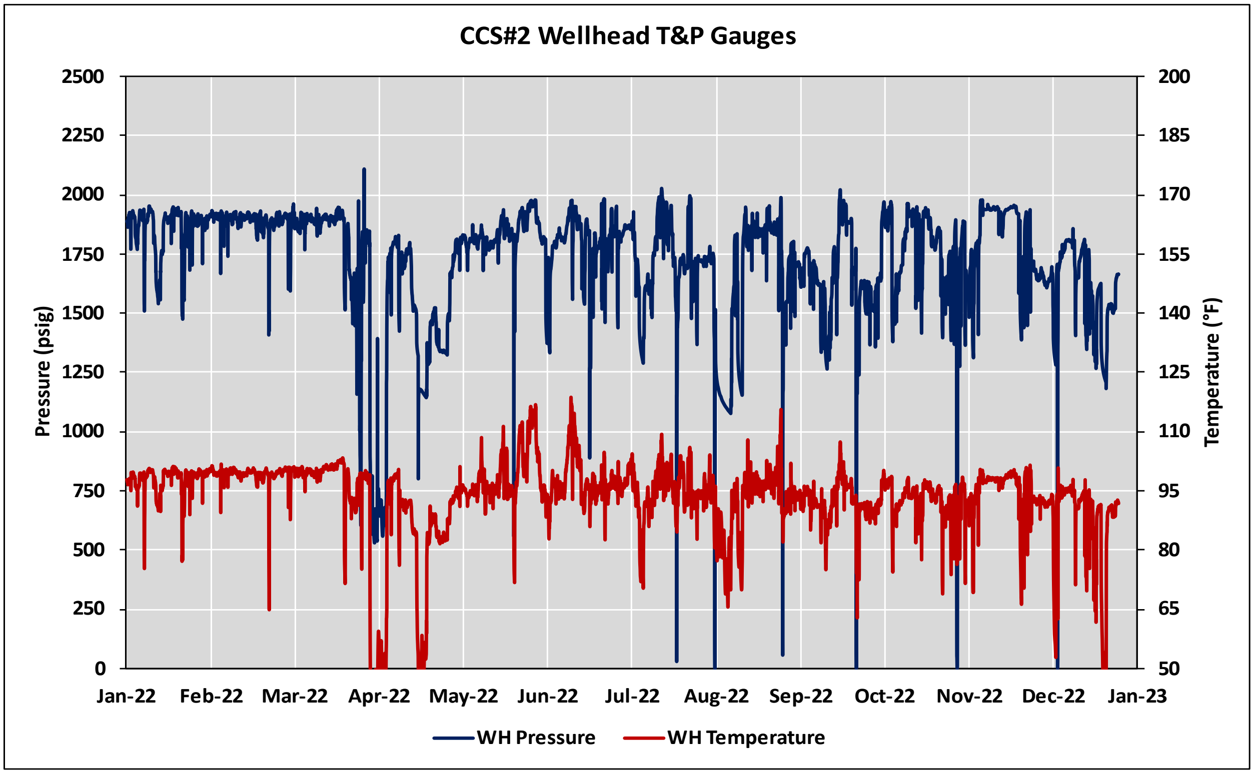

Figure 3: CCS#2 wellhead temperature and pressure monitoring data for Jan-Dec 2022.

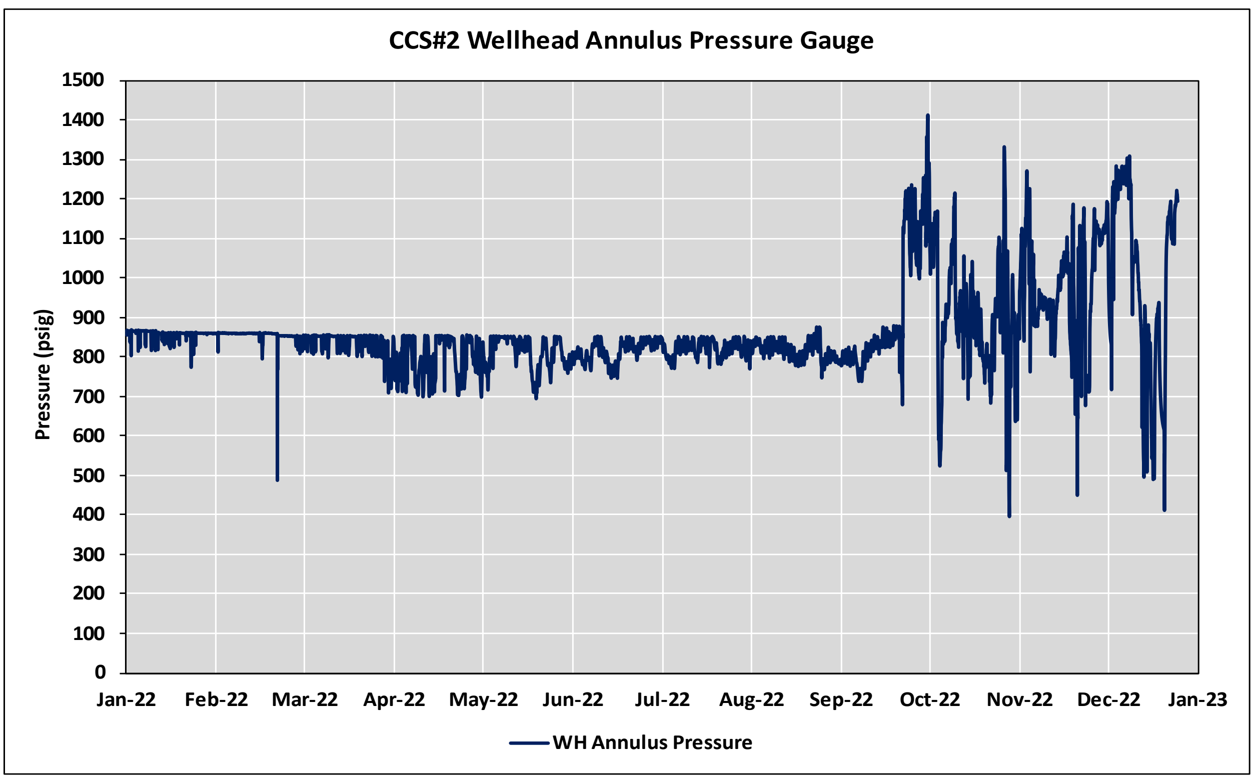

Figure 4: CCS#2 wellhead annulus pressure monitoring data for Jan-Dec 2022.

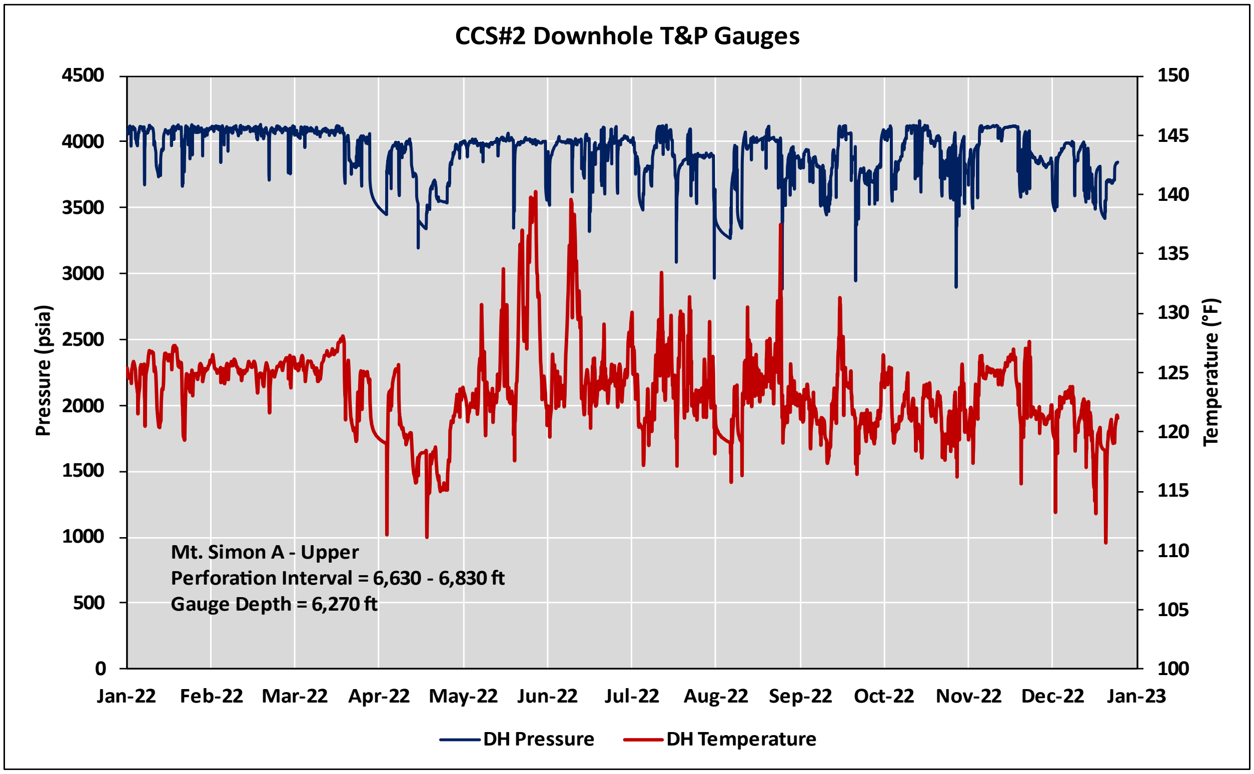

Figure 5: CCS#2 downhole temperature and pressure monitoring data for Jan-Dec 2022.

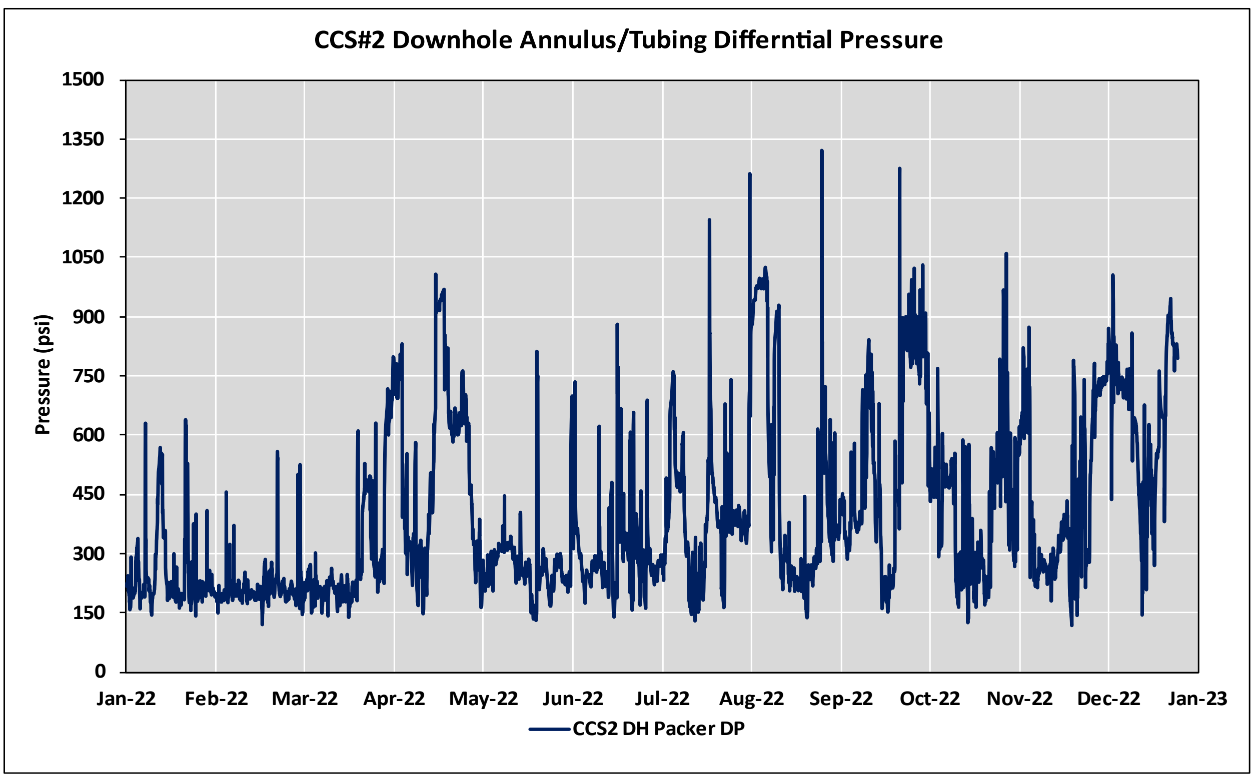

Figure 6: CCS#2 downhole annulus and tubing differential pressure monitoring data for Jan-Dec 2022.

Table 5 provides a monthly summary of several important operational limits for CCS#2 and details the parameter's minimum, maximum and average value for each month. Except for the thirteen events in which the downhole tubing pressure slightly exceeded 4,125 psia limit, no other operating limits were exceeded during the monitoring period.

Table 5. CCS#2 summary of injection parameters for continuous operational monitoring.

Parameter (Unit)	Reporting Period	Monthly Summary Values		
		Average	Minimum	Maximum
Injection Pressure (psig)	January 2022	1,857	1,458	1,957
	February 2022	1,892	1,433	1,938
	March 2022	1,798	608	2,132
	April 2022	1,347	93	1,833
	May 2022	1,829	90	1,978
	June 2022	1,789	1,234	1,986
	July 2022	1,732	0	2,029
	August 2022	1,603	0	1,991
	September 2022	1,658	0	2,028
	October 2022	1,753	1,314	1,978
	November 2022	1,792	0	1,981
	December 2022	1,601	0	1,896
Injection Rate (Mt/day)	January 2022	1,199	1	1,537
	February 2022	1,042	2	1,146
	March 2022	941	0	1,153
	April 2022	613	0	1,508
	May 2022	1,401	0	1,688
	June 2022	1,286	0	1,887
	July 2022	1,255	3	2,049
	August 2022	1,107	0	2,069
	September 2022	1,265	0	2,029
	October 2022	1,474	0	2,183
	November 2022	1,507	0	2,114
	December 2022	1,050	0	1,543
Injection Volume *Based on DH Reservoir T/P* (ft^3/day)	January 2022	53,572	61	68,882
	February 2022	48,499	74	57,490
	March 2022	46,663	0	57,091
	April 2022	30,401	0	74,819
	May 2022	65,315	0	83,612
	June 2022	66,824	0	102,302
	July 2022	65,932	149	107,886
	August 2022	57,560	0	108,909
	September 2022	64,686	0	112,883

Parameter (Unit)	Reporting Period	Monthly Summary Values		
		Average	Minimum	Maximum
	October 2022	73,532	0	112,522
	November 2022	75,362	0	111,203
	December 2022	52,842	0	78,622
Annular Pressure (psig)	January 2022	828	771	890
	February 2022	856	358	870
	March 2022	841	732	870
	April 2022	798	696	862
	May 2022	811	683	864
	June 2022	808	740	854
	July 2022	823	752	854
	August 2022	819	740	879
	September 2022	850	666	1,241
	October 2022	952	524	1,416
	November 2022	936	390	1,330
	December 2022	1,005	417	1,321

Supplemental Material
The operational data file which includes the raw monitoring data, tables, and figures used in this report have been uploaded to the GSDT as follows:
Operational Data File: ***202212_ADM_IL-115-6A-0001_Data.xlsm***

4. Carbon Dioxide Volume/Mass Injected and Annular Fluid Added

Summary of Results
Table 6 summarizes the monthly injection rate, cumulative mass injected, and the amount of annular fluid added or removed from CCS#2's annulus pressure system. During the reporting period, the monthly amount injected into CCS#2 averaged 36,976 Mt and the total amount injected was 430,522 Mt. At the end of the reporting period, the total mass of CO_2 injected into CCS#2 was 2,953,076 Mt. No brine (annular fluid) was added or removed from the annulus system confirming the downhole mechanical integrity of the well's tubing, casing, and packer.

Table 6. Summary of CO_2 injected and annular fluid maintenance.

Reporting Period	CO_2 Injected (Mt)	Cumulative CO_2 Injected (Mt)	Annulus Fluid Volume +/- Added or Removed (Gallons)
January 2022	37,164	2,559,719	0
February 2022	29,167	2,588,886	0
March 2022	29,131	2,618,017	0
April 2022	18,400	2,636,417	0
May 2022	43,426	2,679,842	0

Reporting Period	CO_2 Injected (Mt)	Cumulative CO_2 Injected (Mt)	Annulus Fluid Volume +/- Added or Removed (Gallons)
June 2022	38,585	2,718,428	0
July 2022	38,871	2,757,298	0
August 2022	34,288	2,791,586	0
September 2022	37,968	2,829,554	0
October 2022	45,694	2,875,248	0
November 2022	45,281	2,920,529	0
December 2022	32,547	2,953,076	0

Supplemental Material
No supplemental information to be provided.

5. Corrosion Monitoring

Summary of Results
Table 7 shows the results of the corrosion monitoring program. Review of the data shows an increase in corrosion rates on the A106-B and 13CR-L80 coupon during Q3 & Q4 of 2022. The coupons had visible signs of particulate formation indicating upstream corrosion (see Figure 1). Project team is reviewing the operation of the dehydration unit and onstream water analyzer. The coupons were prepared by EnhanceCo and assessed for corrosion using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). The coupons were photographed, visually inspected at 20x power, dimensionally measured to within 0.0001 inches, and weighed to within 0.0001 grams. During the reporting period, there was no deviation from the testing and monitoring plan that would indicate quality assurance/quality control (QA/QC) problems.

Supplemental Materials
The coupon photos, measurements, and corrosion calculations have been uploaded to the GSDT as follows:
Q1-Q4 2022 Coupons: ***2022_ADM_Corrosion_Coupon_Photos_Q1-Q4.pdf***
Corrosion Calculations: ***202211_CCS#2_Corrosion_Monitoring_Results.xlsx***

Table 7. CCS#2 corrosion monitoring results[1].

Coupon Material Equipment Service	Coupon Number	Monitoring Period	Corrosion Rate (mpy)	Corrosion Categorization	Corrosion Type
A106-B Transport pipeline	6	Q1 2022	0.036	Low	Generalized
	5	Q2 2022	0.071	Low	Generalized
	6	Q3 2022	0.146	Low	Generalized
	5	Q4 2022	0.497	Low	Generalized
L-80 Long string casing <4,800 ft	6	Q1 2022	0.009	Low	Generalized
	5	Q2 2022	0.046	Low	Generalized
	6	Q3 2022	0.047	Low	Generalized
	5	Q4 2022	0.079	Low	Generalized
13CR-L80 Long string casing >4,800 ft, injection tubing, and packer	6	Q1 2022	0.048	Low	MD
	5	Q2 2022	0.135	Low	MD
	6	Q3 2022	0.674	Low	MD
	5	Q4 2022	1.973	Moderate	Generalized

Note 1: Corrosion categorization is based on NACE: SP0775-2013 "Qualitative Categorization of Carbon Steel Corrosion Rates for Oil Production Systems". MD=Mechanical Damage

6. Above Confining Zone (ACZ) Monitoring

Discussion of Results – Pressure and Temperature Monitoring

Table 8 compares the pre-injection reservoir parameters versus the observed reservoir parameters for the ACZ monitoring zones in GM#2 (St. Peter Formation), VW#2 (Ironton Galesville Formation), and VW#1 (Ironton Galesville Formation). Examination of the data shows no significant change occurred during the monitoring period (pre-injection vs. current) thus indicating no movement of fluids or CO_2 above the confining zone and therefore indicates that the operation does not present an endangerment to the St. Peter Sandstone, the lower most USDW.

Table 8: GM#2, VW#2, & VW#1 ACZ pressure and temperature monitoring.[(1)]

Parameter	Pressure (psia/psi)			Temperature (°F)		
Well	GM#2	VW#2	VW#1	GM#2	VW#2[(3)]	VW#1
Depth[(2)]	3,450 ft	5,027 ft	4,989 ft	3,450 ft	5,027 ft	4,989 ft
Formation	St Peter Sandstone	Ironton Galesville	Ironton Galesville	St Peter Sandstone	Ironton Galesville	Ironton Galesville
Pre-Injection	1,397	2,112	2,086	95	104	104
Average	1,398	Fail	2,093	103	107	105
Delta P	1.5	Fail	7.4	8.2	3.7	0.1
% Change	0.1%	Fail	0.4%	8.6%	3.6%	0.1%

Note 1: Data Collection Time Period = 1/1/22 - 1/1/23. Pressure reported as reservoir=psia & dP=psi.
Note 2: Depths reported are gauge depths.
Note 3: Based on VW#2 DTS data.

Figure 7 and Figure 8 trend the downhole pressure and temperature for the Ironton Galesville, the formation directly above the injection zone seal (Eau Claire Shale) at VW#2 and VW#1 respectively.

Figure 9 trends GM#2's downhole pressure and temperature for the St. Peter Sandstone, the lower most USDW. From these figures, one observes no significant change in reservoir temperature or pressure that would indicate the movement of brine or CO_2 above the seal formation. Figure 7 shows the time period in which the alternative pressure monitoring method was employed at VW#2. The monitoring was effective until October when CO_2 began leaking through the Zone 2 sliding sleeve slowing increasing the wellhead pressure. Because the downhole gauges were out of GM#2 during Q1 & Q2 of 2022, Figure 9 plots the results of the weekly water gauge conducted during this period. The tabular data used to generate the figure is shown in Table 9. The well's water level is consistent with the hydrostatic level needed for the 1,400 psia reservoir pressure.

As discussed in the summary section and denoted in Figure 7, since September 14, 2020, an intermittent short on VW#2's downhole communications line is affecting the ability to continuously monitor the reservoir conditions of Ironton Galesville (ACZ) at VW#2. The data indicates there is an intermittent fault in the communication line between the downhole gauges and the surface junction box. During the instrument's energization and data transmission cycle, the line is subject to shorting. If the fault occurs during the data transmission cycle, the signal is corrupted and the ARCCON data acquisition unit reports null values. Electrical checks taken from the VW#2 junction box to the downhole cable showed a reverse resistance of 7.05 kilo-ohms, which is indicative of a short or leak. Unfortunately, there is no means to institute repairs without pulling the complete downhole assembly, essentially a complete well workover. Therefore, we are closely watching the instrument's fault frequency to gauge the rate of deterioration.

In Q3-2021, we installed an alternative method to monitor VW#2 Zone 5. For description of this monitoring method, please see document named *"20210818 MOC VW#2 Tubing Pressure Mod"* in the supplemental information of semi-annual report 29. This method was effective for 6-8 weeks but minor CO_2 leakage into the tubing from the Zone 2 sliding sleeve forced suspension of this monitoring system. To mitigate the CO_2 leakage, we plan to inject fluid into Zone 2 in order to displace the free phase CO_2 away from the wellbore. This has been proven effective in stopping CO_2 leakage through the sleeve. To be clear, this leakage is confined to the production tubing and does not impact the well's external mechanical integrity.

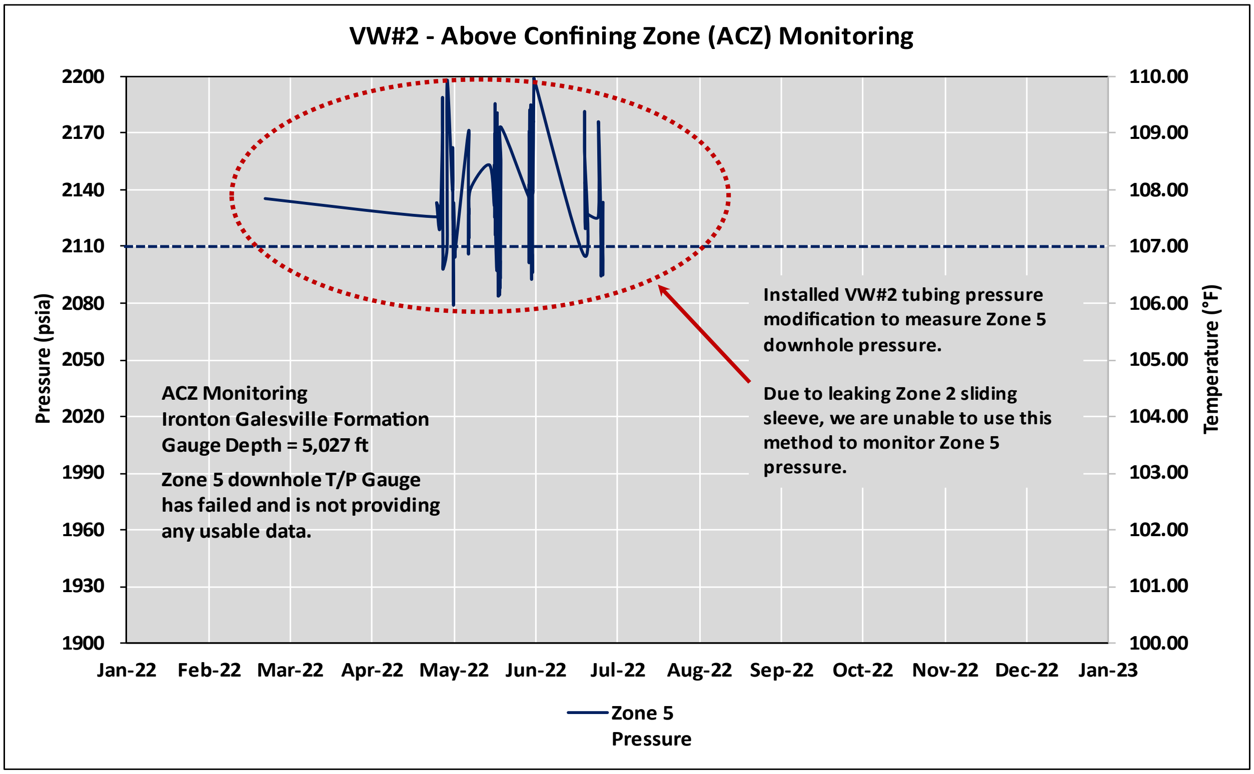

Figure 7: VW#2 ACZ monitoring of the Ironton Galesville Formation for Jan-Dec 2022.

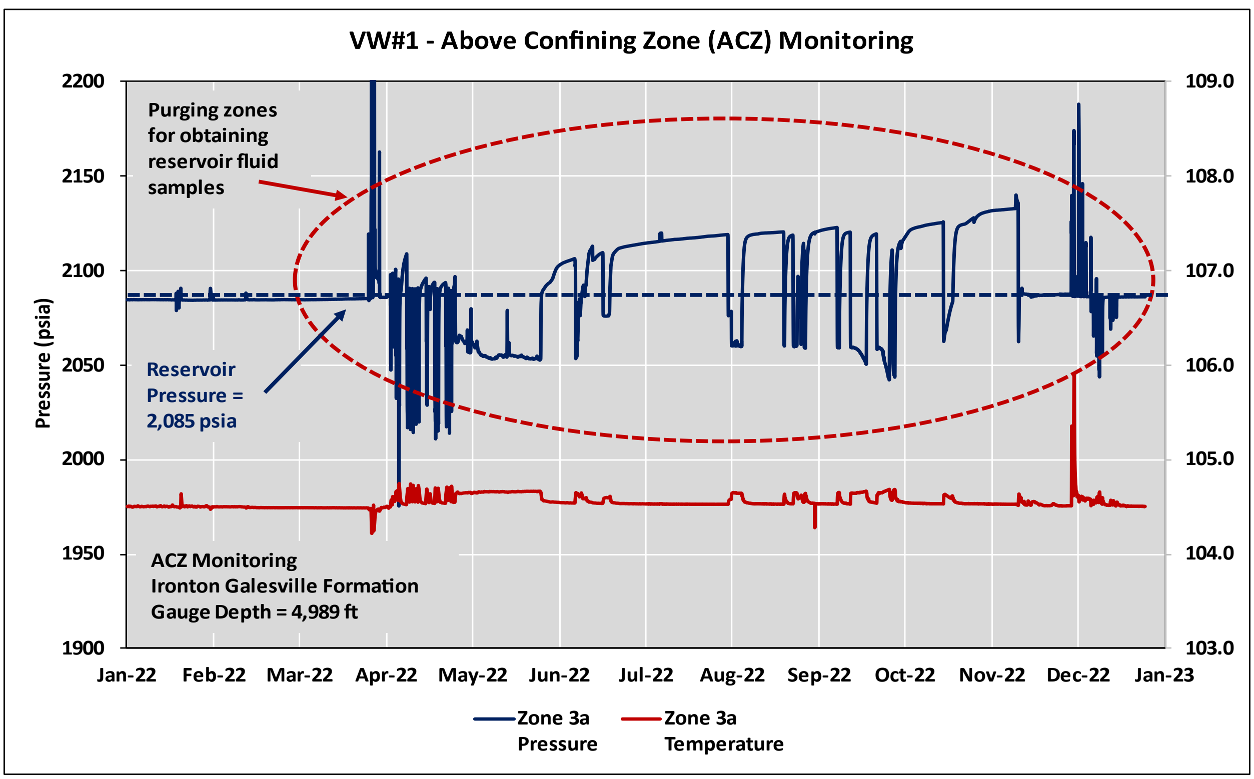

Figure 8: VW#1 ACZ monitoring of the Ironton Galesville Formation for Jan-Dec 2022.

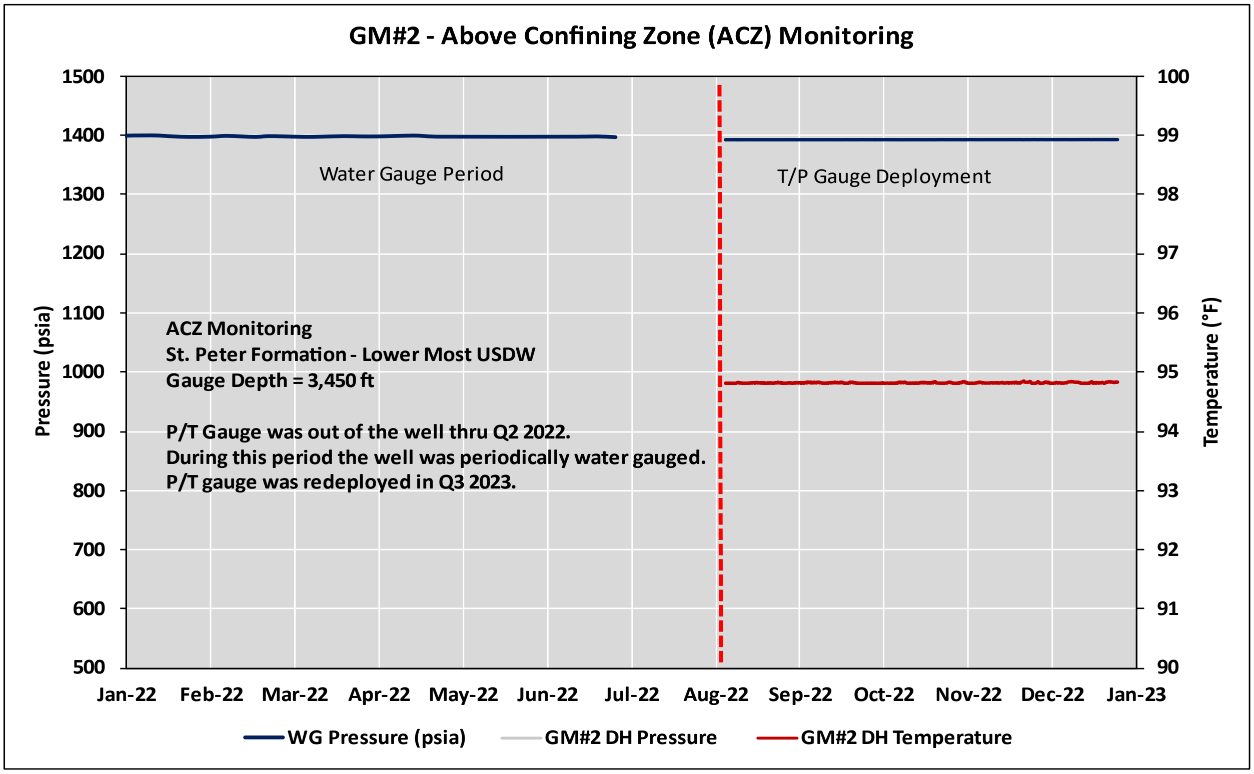

Figure 9: GM#2 ACZ monitoring of the St. Peter Formation for Jan-Dec 2022.

Table 9: GM#2 Water Gauge Tabular Data.

Date	Water Gauge Depth (ft)	Pressure (psia)	Date	Water Gauge Depth (ft)	Pressure (psia)
12/27/2021	194	1,399	5/3/2022	195	1,399
1/10/2022	192	1,400	5/9/2022	194	1,399
1/18/2022	196	1,398	5/17/2022	192	1,400
1/24/2022	198	1,397	5/23/2022	195	1,399
2/1/2022	197	1,398	5/31/2022	196	1,398
2/7/2022	194	1,399	6/7/2022	194	1,399
2/17/2022	198	1,397	6/13/2022	193	1,400
2/22/2022	195	1,399	6/20/2022	197	1,398
2/28/2022	196	1,398	6/27/2022	194	1,399
3/8/2022	198	1,397			
3/14/2022	197	1,398			
3/22/2022	195	1,399			
3/28/2022	196	1,398			
4/4/2022	196	1,398			
4/11/2022	194	1,399			
4/18/2022	193	1,400			
4/26/2022	197	1,398			

Discussion of Results – Groundwater Monitoring

The purpose of the groundwater monitoring report is to provide groundwater monitoring data collected for two USEPA Underground Injection Control (UIC) Class VI permits for two carbon dioxide (CO_2) injection wells located in Decatur, Illinois: CCS1 (permit IL-115-6A-0002) and CCS2 (permit IL-115-6A-0001). The injection wells were installed as part of two U.S. Department of Energy funded demonstration projects: 1) The Illinois Basin – Decatur Project (IBDP), and 2) The Illinois Industrial Carbon Capture and Storage (IL-ICCS) Project. Permit requirements for each project were aligned because the projects are in very close proximity and are both using the Mt. Simon Sandstone as a storage reservoir. Groundwater compliance information for both projects is coordinated in this single report in order to provide an integrated groundwater quality data assessment. The IBDP injected over 999,000 tonnes of CO_2 into the lower Mt. Simon Sandstone under an Illinois EPA UIC Class I (non-hazardous) permit from November 2011 through November 2014. Injection for the IL-ICCS project started on April 7, 2017, and 2,857,752 metric tons of CO_2 had been injected as of October 19, 2022. Because of the report's size, it is being submitted as supplemental material.

Since the last report (dated July 22, 2022), additional sampling events have occurred. Between April 22, 2022 and October 19, 2022, one shallow groundwater sampling event (October 2022) occurred. For deep well sampling, mechanical issues were encountered with wells VW1 and VW2 that prevented the collection of samples that were representative of the formations being monitored. Additional work is underway to continue to address mechanical issues at wells VW1 and VW2 so representative samples can be collected in the future. New water quality results are provided in this report.

Time series graphs for shallow groundwater compliance parameters were updated and the corresponding interpretations were reviewed. The newly obtained data are consistent with all historical data cited in the July 22, 2022 report, and the major conclusion remains the same. Specifically, interpretations of all shallow groundwater data to date indicate that no trends or changes in shallow groundwater chemistry have occurred as a result of CO2 injection in Decatur. The variability observed in shallow groundwater quality data are attributed to factors including natural groundwater heterogeneity, seasonal groundwater variability, initial effects of well installation, and equipment performance. No changes in groundwater quality were observed that would indicate brine or injected CO2 were introduced into the shallow groundwater environment.

Supplemental Materials

The groundwater monitoring report has been uploaded to the GSDT as follows:

GW Report Name: ***202212_IL-115-6A-0001-0002_GWM_Report.pdf***

GW COAs: ***202212_IL-115-6A-0001-0002_Shallow_Deep_GWM_COAs.pdf***

7. <u>External Mechanical Integrity Testing</u>

Discussion of Results

The CCS#2 annual external MIT was conducted during the reporting period with results submitted on March 30, 2022. The results of the temperature log indicate no fluid movement is occurring behind the casing indicating good well mechanical integrity. Continuous DTS monitoring of CCS#2 is ongoing and Continuous DTS monitoring of CCS#2 is ongoing and the 24-hour period for June 30, 2022 is shown in Figure 10. The smooth temperature profile indicates good well integrity and no movement of fluids/CO_2 behind the casing.

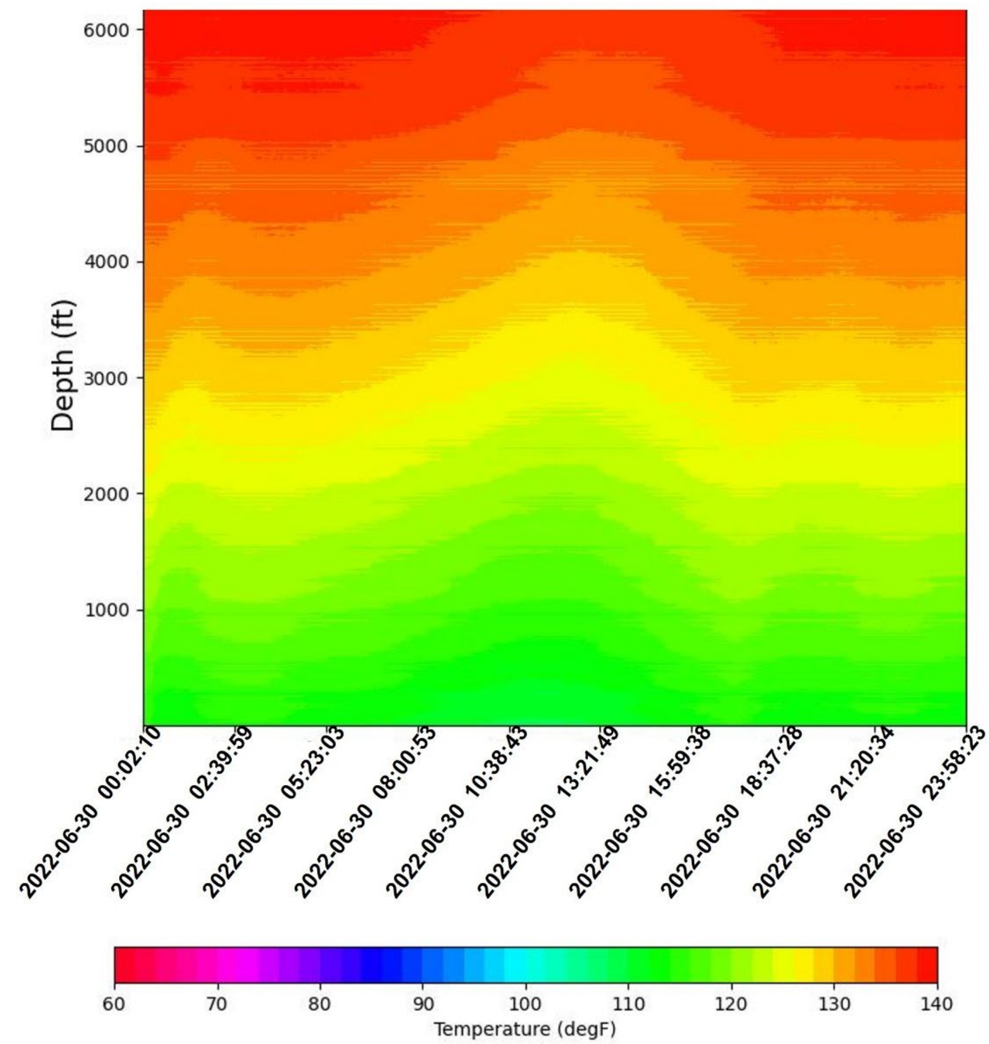

Figure 10: CCS#2 DTS data in 3-dimensional view for last day of reporting period 06/30/2022.

8. <u>Pressure Fall-Off Testing</u>

Discussion of Results

A pressure fall-off test was conducted March 31- April 6, 2022 following a period of stable injection over four perforated intervals in the Mt. Simon Sandstone. The pressure transient was monitored during the shut-in period and no anomalous behavior noted during that period using real-time bottomhole pressure data. A near-zero skin factor was interpreted along with an average permeability of 38.9 mD during radial flow and two possible no-flow boundaries consistent with the previously identified reservoir architecture. The complete pressure fall-off testing report was submitted to the agency on July 5, 2022.

Supplemental Material
No supplemental information to be provided.

9. Carbon Dioxide Pressure-Front and Plume Tracking

Summary of Results and Comparison to Reservoir Model
The subsurface monitoring data indicate the CO_2 pressure and plume fronts are developing in a manner that is consistent with the results forecasted by the updated (2018) Eclipse reservoir flow model. Table 10 compares the actual reservoir pressure with the pressure forecast by the Eclipse model. The actual and forecast data have a good correlation. With the exception of VW#2 Zone 2, the monitoring wells are within ~2% of the predicted pressures. The VW#2 Zone 2 pressure gauge has a recording frequency of 29% and this is the likely cause of the bias that has developed over the reporting period. CCS#1 is maintaining a recorded pressure within 4% of the forecast and the CCS#2 bottom hole pressure remains within a 6.9% or 261 psi higher than the projected pressure. As discussed in the prior reports, this bias is due to downhole fouling of the perforated interval.

Table 11 details the results of the spinner logs and compares the injectate flow distribution observed during each run. From this data, it appears that a significant portion of the injectate flow shifted from the upper to the lowest set of perforations. This shift in the well's flow distribution as well as the casing diameter reduction shown by the tool's caliper readings (not shown), confirms the buildup of foreign material around the upper perforated interval. From the last spinner log conducted on January 22, 2022, it appears we have regained some injectability at the second set of perforations. This is likely due to the well back flows that were conducted prior to the log. Figure 11 compares the predicted injection zone pressure predicted versus the actual pressure recorded at CCS#2. One can observe that the two pressures correlate closely during the first million tons of injection but deviates during the subsequent injection finally reaching a ~500 psi differential at 2.0 million tons. Well back flows were subsequently conducted and the figure shows bias between the actual versus the forecast downhole pressure narrowing and is currently 70 psi. The bias between the actual and the forecast pressure is due mainly to the downhole fouling we are experiencing at CCS#2. Eliminating the fouling should correct the observed model bias. If the fouling remains, modification of reservoir model parameters (i.e. skin factor) will be needed to better align the model with the observed pressure.

Figure 12 - Figure 17 trends the actual versus the forecast differential pressure within the injection zone for each monitoring well. From these figures, one can see close correlation between the predicted reservoir pressure response versus the actual response. This strongly support that the static geophysical (Petrel) and the dynamic reservoir flow (Eclipse) models well characterize our storage site and the pressure and plume fronts are behaving as forecast in the model. Figure 15 and Figure 16 have developed a bias due to the instruments failing. Another bias is shown in Figure 17. This chart trends the CCS#1 injection zone pressure versus the model pressure. Clearly there is an unknown artifact that is causing a significant bias one does not see in the other monitoring wells. One theory is that unresolved faults proximate to the interface of the Precambrian with the Mt Simon (Argenta) are channeling pressure. These faults would not present a leakage risk but could provide a conduit to transmit pressure more directly from the CCS#2 injection well to CCS#1. The results of the 2021 3D seismic survey may shed additional light on this phenomenon. Results of this survey will be presented in the next semi-annual report.

Table 10: Comparison of actual reservoir pressure versus 2018 Eclipse model forecast[1].

Well	CCS#1	CCS#2	VW#1			VW#2		
Depth[2]	7,015 ft	6,725 ft	6,970 ft	6,420 ft	6,409 ft	7,041 ft	6,681 ft	6,524 ft
Formation	Argenta	Mt Simon A Lower	Mt Simon A Lower	Mt Simon B	Mt Simon B	Mt Simon A Lower	Mt Simon B	Mt Simon E
Zone	Injection	Injection	Zone 1	Zone 2	Zone 3	Zone 1	Zone 2	Zone 3
Actual P	3,059	3,900	3,214	3,175	3168	3241	3,145	3,162
Forecast P	3,184	3,639	3,237	3,121	3115	3277	3,335	3,115
Delta P	125	261	23	54	53	36	191	47
% Delta	4.0%	6.9%	0.7%	1.7%	1.7%	1.1%	5.9%	1.5%

Note 1: Data Collection Time Period = 1/1/22 - 1/1/23. Pressure reported as reservoir=psia dP=psi
Note 2: Monitoring well depths are reported as gauge depths while CCS#1 & CCS#2 depths are the middle of the perforated interval.

Table 11: Comparison of 2017, 2018, and 2019 Spinner Logs

Perforation Interval (ft)[(1)]	Perforation Interval Thickness (ft)	04/08/2017 Rate = 1050 Mt/day	03/29/2018 Rate = 1040 Mt/day	03/08/2019 Rate = 1121	01/22/2022 Rate = 1043
6,630-6,670	40	19%	0%	0%	0%
6,680-6,725	45	8%	0%	0%	37.6%
6,735-6,775	40	3%	5%	6.5%	18.2%
6,787-6,825	38	70%	95%	93.5%	44.2%

Note 1: Yellow shading denotes perforations that are fouled with approximately 2 inches of material.

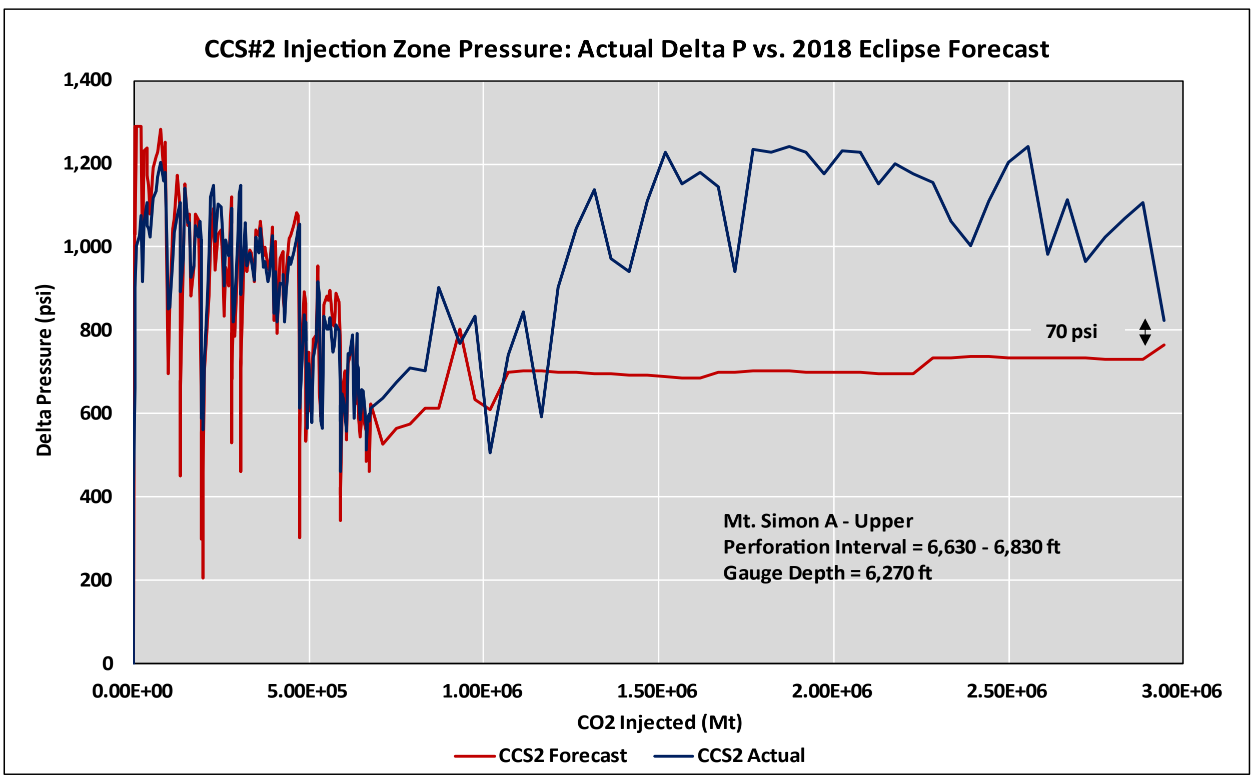

Figure 11: CCS#2 comparison of the downhole injection pressure versus the forecast pressure generated by the 2018 Eclipse reservoir model.

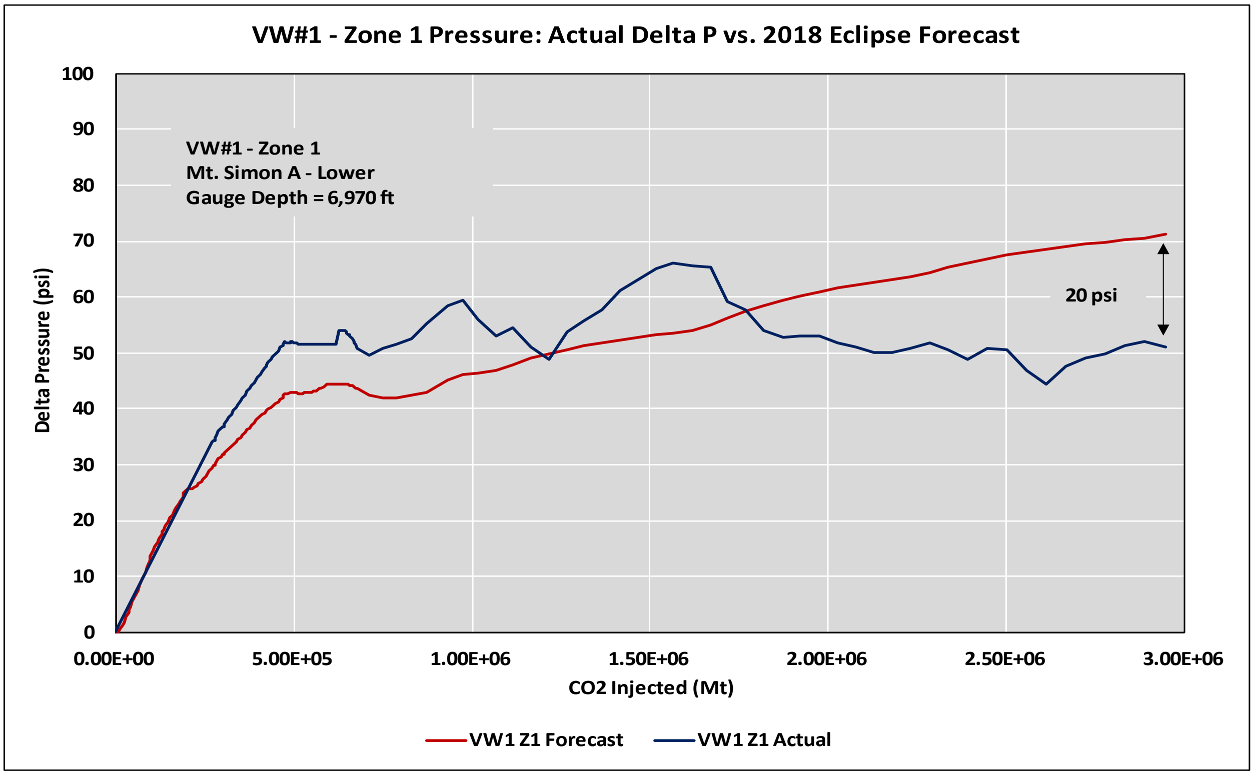

Figure 12: VW#1 Zone 1 differential pressure comparison of actual versus 2018 Eclipse forecast.

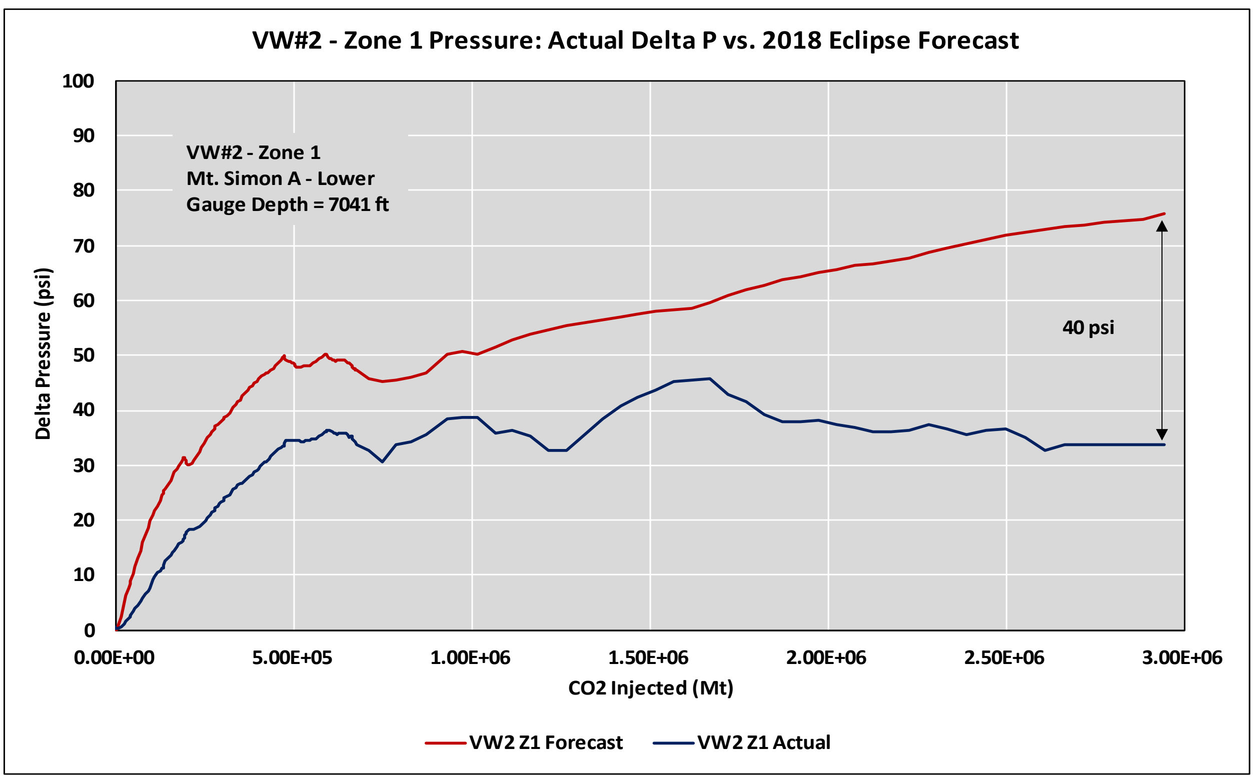

Figure 13: VW#2 Zone 1 differential pressure comparison of actual versus 2018 Eclipse forecast.

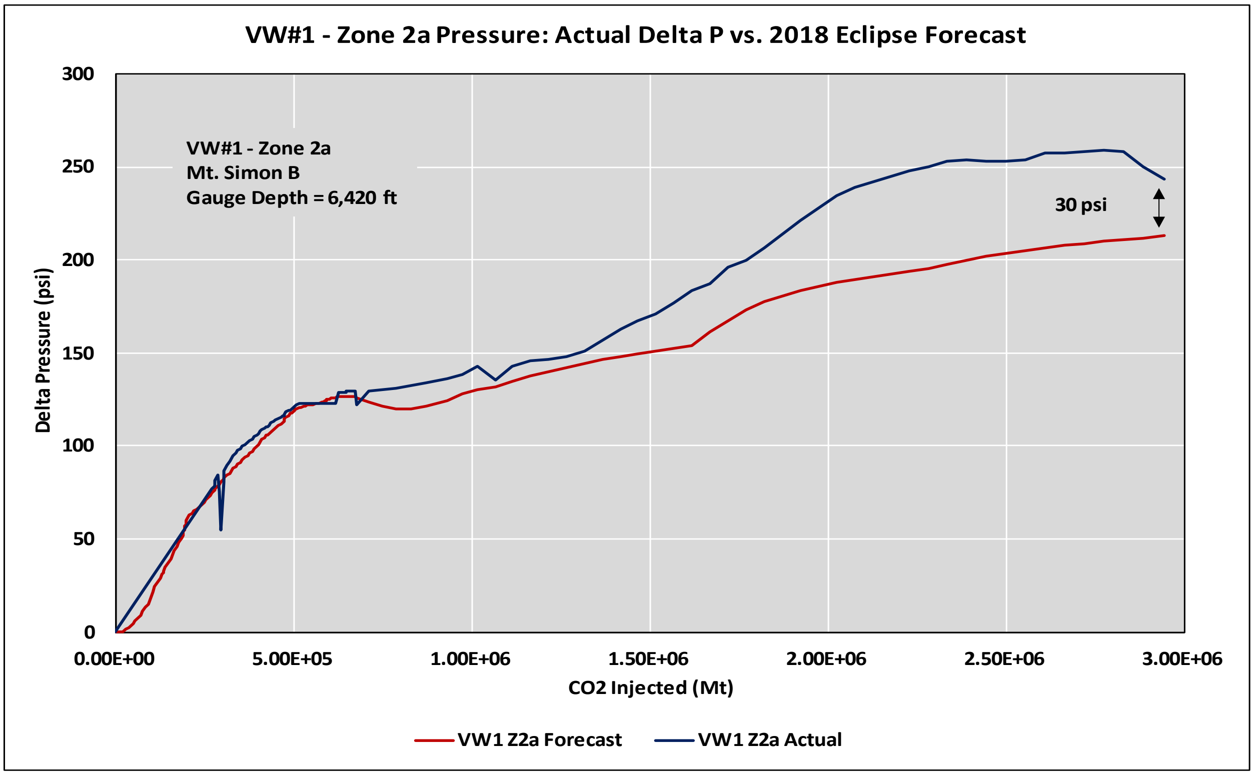

Figure 14: VW#1 Zone 2a actual reservoir differential pressure versus 2018 Eclipse forecast.

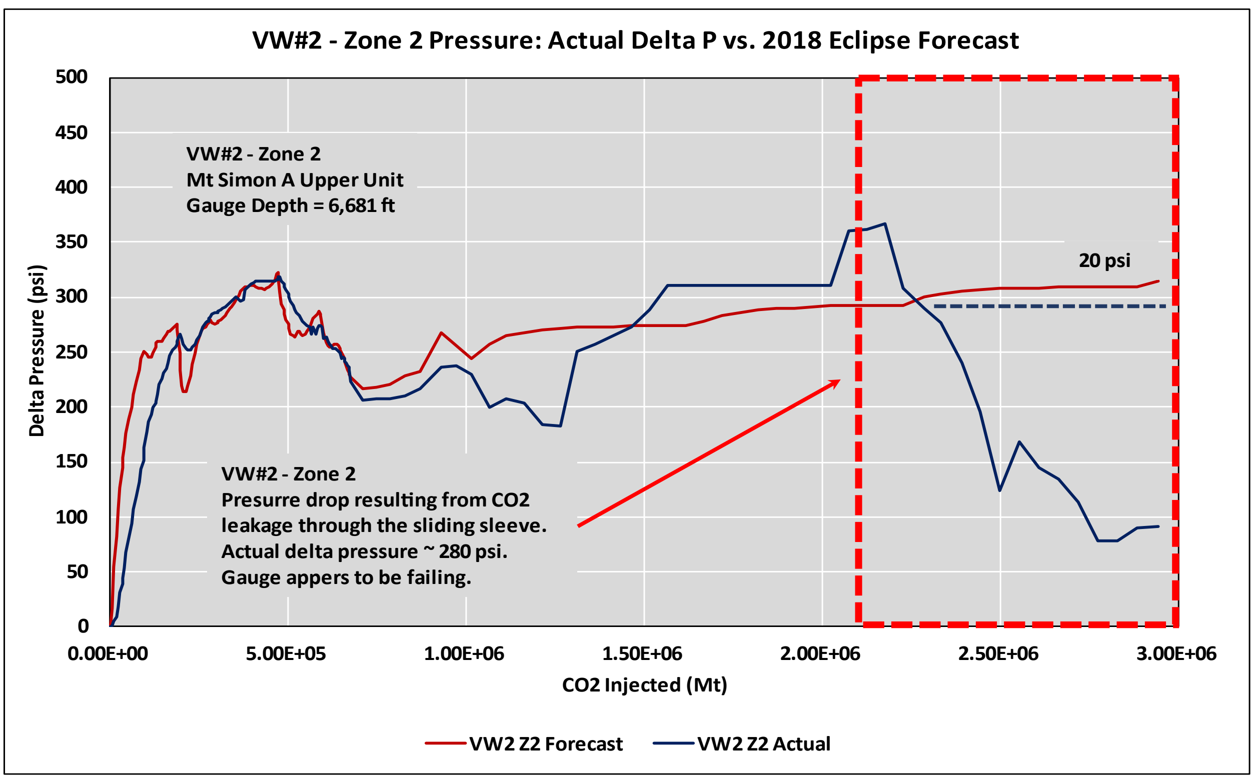

Figure 15: VW#2 Zone 2 actual reservoir differential pressure versus 2018 Eclipse forecast.

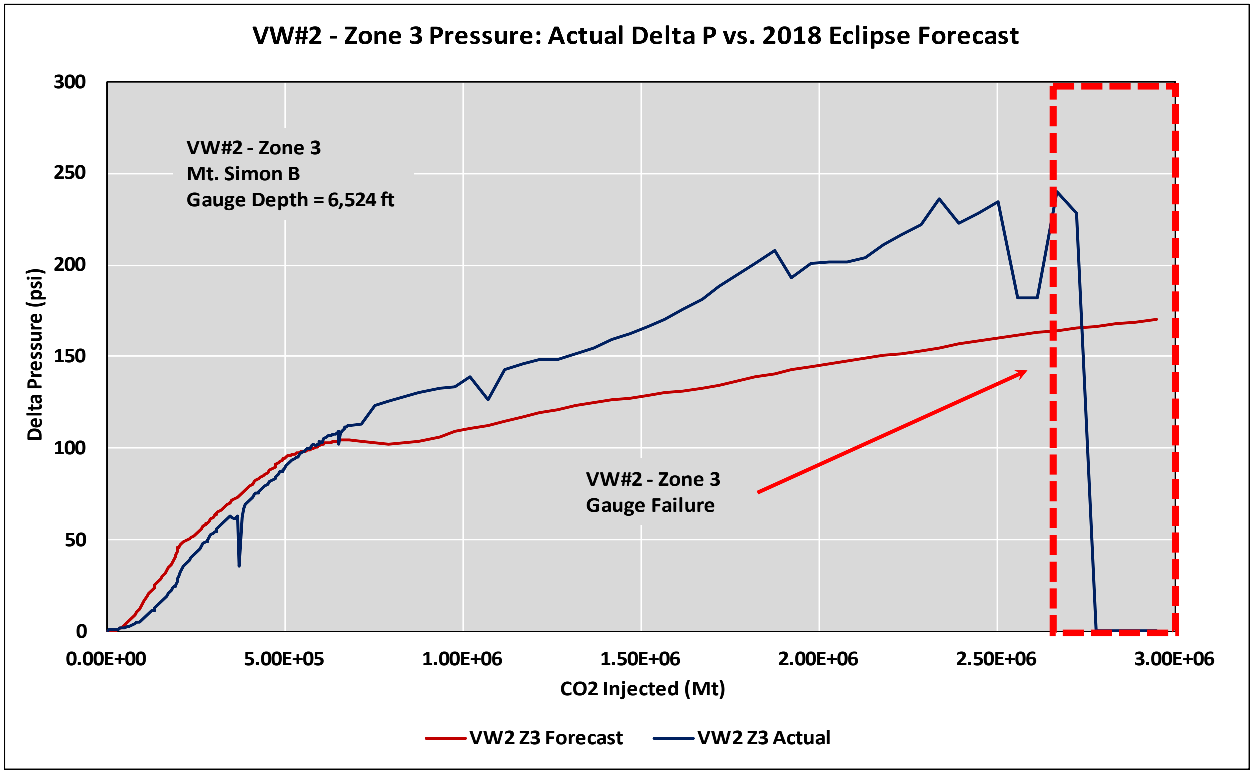

Figure 16: VW#2 Zone 3 actual reservoir differential pressure versus 2018 Eclipse forecast.

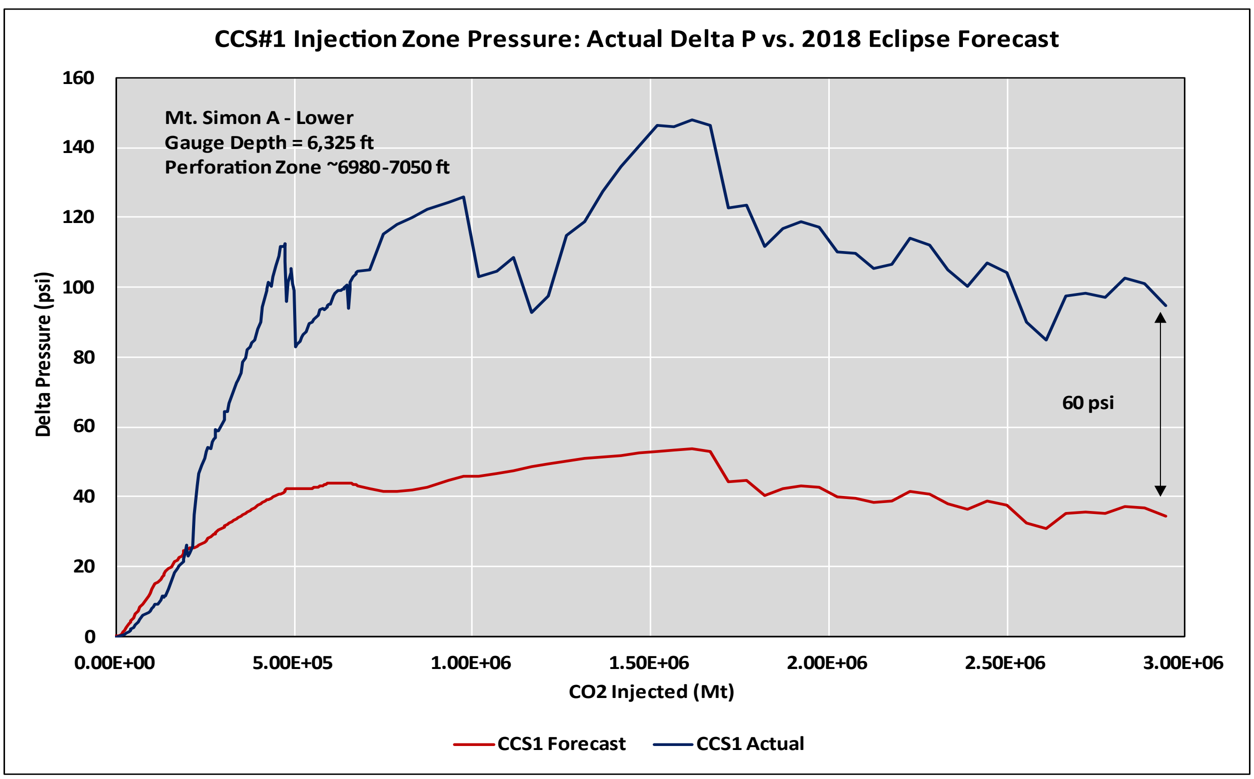

Figure 17: CCS#1 injection zone actual reservoir differential pressure versus 2018 Eclipse forecast.

Discussion of Results – Pressure-Front Tracking

Table 12 shows the injection zone pressure gradient by comparing VW#1 and VW#2's zone pressures against the pre-injection pressures. Inspection of the data shows that the Mt Simon B (Zone 3) had the greatest pressure response increasing 8.7% (ΔP=255 psi) in VW#1 and 6.8% (ΔP=201 psi) in VW#2. VW#1 gauge monitors the top of the Mt. Simon B while VW#2 gauge monitors conditions in the middle of the unit. The pressure responses in these zones are consistent with the readings during the last reporting period and indicate the development of a uniform pressure gradient. The injection zone (Mt Simon A Upper) is monitored in VW#2 at Zone 2 and this zone had the second highest pressure response averaging 4.8% (ΔP=145 psi) over the baseline pressure. The average pressure recorded during the last reporting period was 7.8% (ΔP=236 psi) above the baseline pressure. The reduction in pressure could be due to the lower injection rate but the other monitoring zones do not support this conclusion. The change in the average pressure is likely due to the intermittent electrical faults. The Zone 4 gauge in VW#2 monitors the Mt. Simon E. This gauge recorded and average pressure increase of 4.3% (ΔP=127 psi) over the baseline. The pressure increase reported in the last period was only 1.6% (ΔP=42 psi). This change is likely due to the deterioration of the instrument. The Mt Simon A Lower is monitored in VW#1 and VW#2 at Zone 1. Both gauges were consistent and recorded an average pressure increase of 1.5% (ΔP=46 psi) at VW#1 and 1.1% (ΔP=35 psi) at VW#2.

Table 12: VW#1 and VW#2 injection zone pressure monitoring.[1]

	VW#2 (2,600 ft)[3]				VW#1 (2,700 ft)[3]	
Depth[2]	7,041 ft	6,681 ft	6,524 ft	5,848 ft	6,970 ft	6,420 ft
Formation	Mt Simon A Lower	Mt Simon A Upper	Mt Simon B	Mt Simon E	Mt Simon A Lower	Mt Simon B
Zone	Zone 1	Zone 2	Zone 3	Zone 4	Zone 1	Zone 2
Pre-Injection	3,207	3,031	2,954	2,620	3,165	2,922
Average	3,241	3,152	3,160	2,730	3,214	3,177
Maximum	3,244	3,359	3,200	2,930	3,218	3,180
ΔP vs. Avg	34	121	205	110	48	255
% Avg ΔP	1.05%	4.00%	6.95%	4.20%	1.53%	8.73%
ΔP vs. Max	36	328	246	310	52	259
% Max ΔP	1.14%	10.83%	8.31%	11.82%	1.66%	8.86%

Note 1: Data Collection Time Period = 1/1/22 - 1/1/23. Pressure reported as reservoir=psia & dP=psi.
Note 2: Depths reported are gauge depths.
Note 3: Approximate distance from injection well (CCS#2).

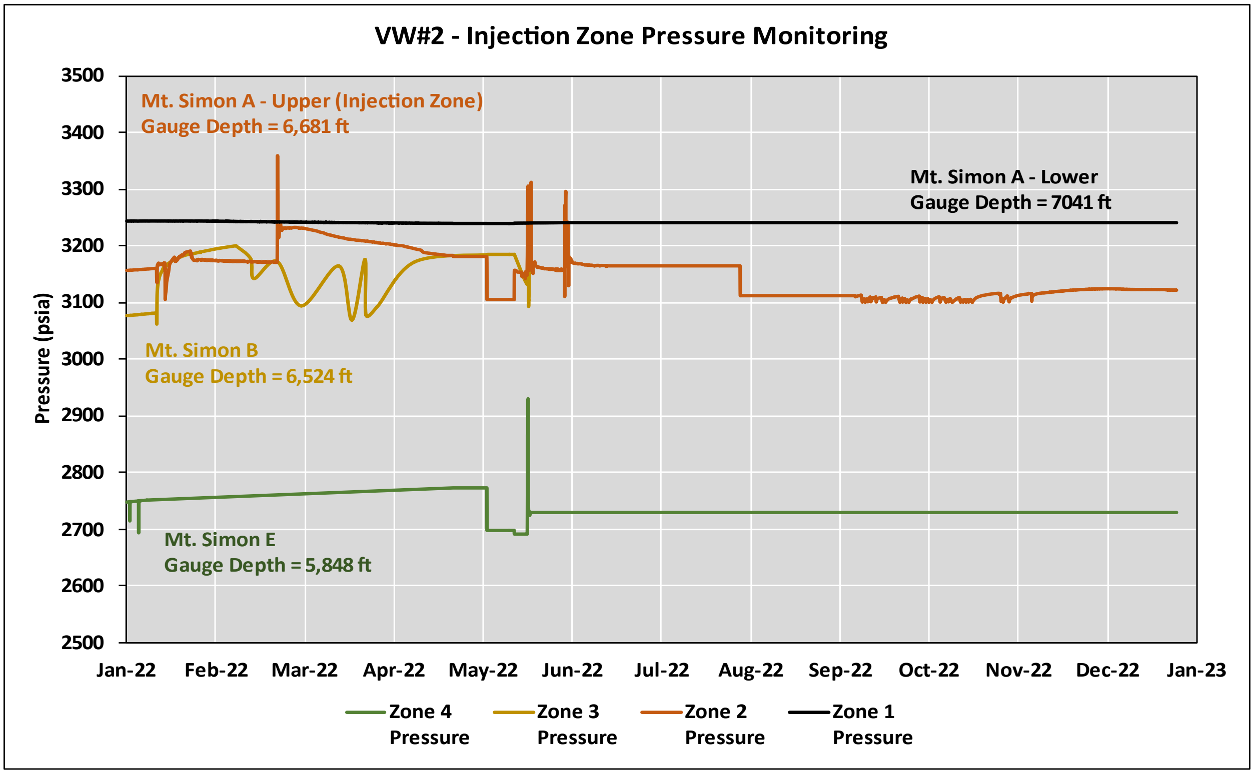

Figure 18: and Figure 19 chart the pressure and temperature of the four injection monitoring zones in VW#2 during the reporting period. Observation the Upper Mt. Simon A (VW#2 - Zone 2) shows the pressure began at 3,150 psia and spiked up to 3250 psia in February and then gradually fell back to 3,150 psia during the remaining period. The falling pressure is jointly attributed to lower injection rates and deterioration in instrument performance. Additionally, the spikes seen in the data are the result of pumping into this zone while setting retrievable bridge plugs to isolate the leaking sliding sleeve. The operator was unable to successfully set a retrievable plug and subsequently set a permanent bridge plug above Zone 4.

Regarding the other monitoring zones, only modest changes in pressure are observed Zone 1 while the other zones (Zones 3&4) show inconsistent changes in pressure. The zonal temperatures had some moderate changes and are generally consistent with the historic monitoring data. These figures also illustrate the unstable operation of the Zone 3 and 4 gauges. The gauges raw (discrete) data was extracted and subjected to extensive filtering to remove any null value. Even with these values removed, one can see variation in the temperature not observed in the other instruments. As discussed previously, we are examining options to mitigate any reduction or loss of data and maintain the fidelity of our monitoring system. Figure 20 and Figure 21 show the downhole pressure and temperature for the two Mt. Simon monitoring zones in VW#1. These figures show a relatively flat pressure profile over the monitoring period and are consistent with the historic monitoring data.

Figure 22 shows the downhole pressure and temperature for CCS#1. From this figure, one observes greater fluctuations in reservoir pressure (Mt. Simon A – Lower unit) not observed in either VW#1 or VW#2. Despite this artifact, the overall pressure response generally trends with the other Zone 1 gauges. Figure 23 compares the CCS#1 delta pressure with the zonal delta pressures observed in VW#1 and VW#2. CCS#1 is almost 3,600 ft from CCS#2 while VW#1 and VW#2 are only 2,700 ft and 2,600 ft respectively. Because pressure attenuates as a logarithmic function with respect to the distance from the source, one would expect a decreasing pressure gradient as you move further away from the CCS#2. This behavior is not observed in Figure 23 where CCS#1 has a significantly higher-pressure response when compared to the closer monitoring wells (VW#1 & VW#2). As previously mentioned, this seems to indicate that proximate to CCS#1, the pressure is being transmitted from the Mt. Simon A Upper (injection interval) to the Mt. Simon A Lower.

Figure 24 compares the CCS#1 pressure response against the CCS#2 injection pressure. From this figure, one can see that the CCS#1 pressure response trends with the CCS#2 injection pressure. When compared to historical trends, this effect is significantly less pronounced and is likely due to the lower CCS#2 injection rates.

Figure 25 delineates the MESPOP (pressure front = 62.2 psi) predicted by the original 2016 Eclipse model as well as the updated 2018 Eclipse model. From this figure, one observes that the 2016 model's pressure front area is about 100% greater than the pressure front predicted by the updated 2018 model. Several factors account for this change and will not be reviewed in this report. Please refer to *Technical_Report_Ref_CS1903-001-SYL.pdf* submitted as supplemental information in the CCS#2 semi-annual report #26. The current pressure front extends approximately 11,269 feet from the injection well and covers an area of approximately 399 million square feet.

Discussion of Results – Plume Tracking

During the reporting period, pulse neutron logging was conducted at the two injection wells (CCS#1&2) and the two deep monitoring wells (VW#1&2) in January 2022. The results from the well logs were submitted to the agency on June 17, 2022. For an evaluation of the logging results, please refer to these reports. Figure 26 delineates the current and final position of the plume front and as predicted by the 2018 Eclipse model. The current plume front has an area of 40.4 million ft^2 with an estimated boundary extending about 3,500 ft from the injection well. The figure also shows that the plume front has passed VW#2. Using the updated model, the plume front passed VW#2 after injecting approximately 1.8 million Mt of CO_2.

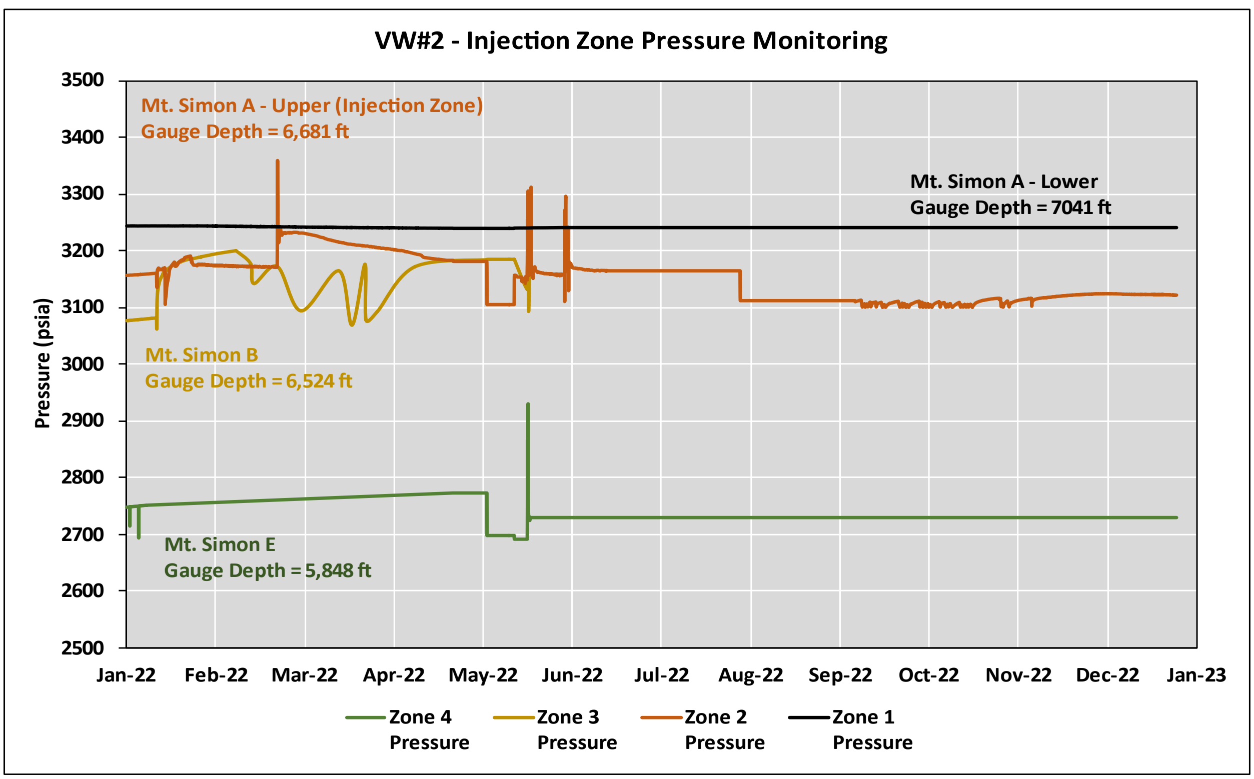

Figure 18: VW#2 injection zone pressure monitoring data for Jan-Dec 2022.

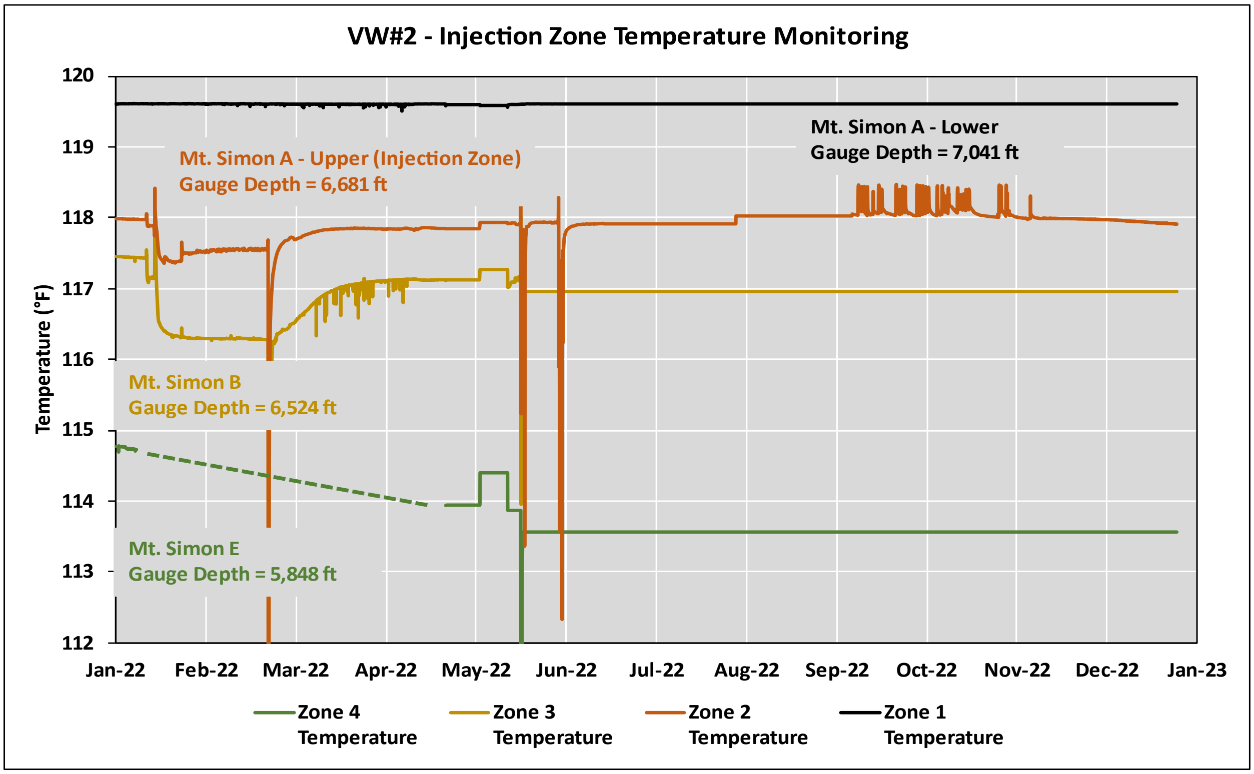

Figure 19: VW#2 injection zone temperature monitoring data for Jan-Dec 2022.

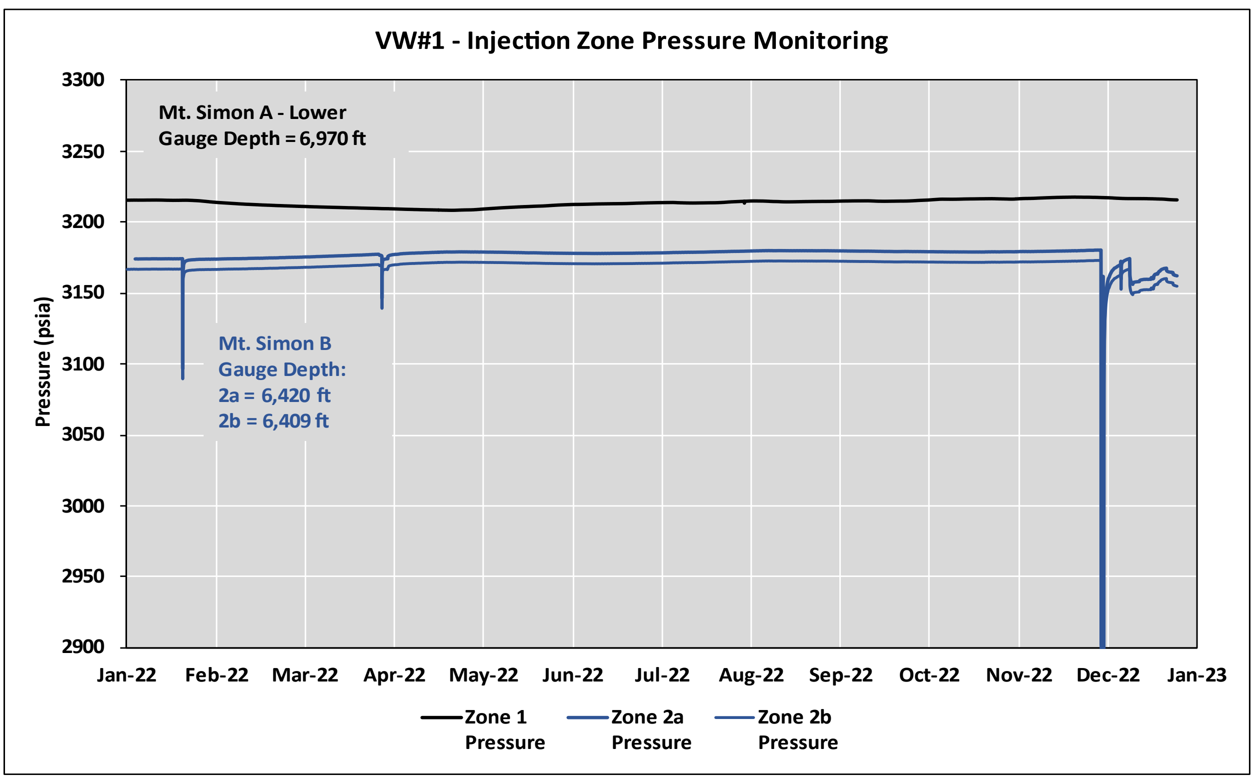

Figure 20: VW#1 injection zone pressure monitoring data for Jan-Dec 2022.

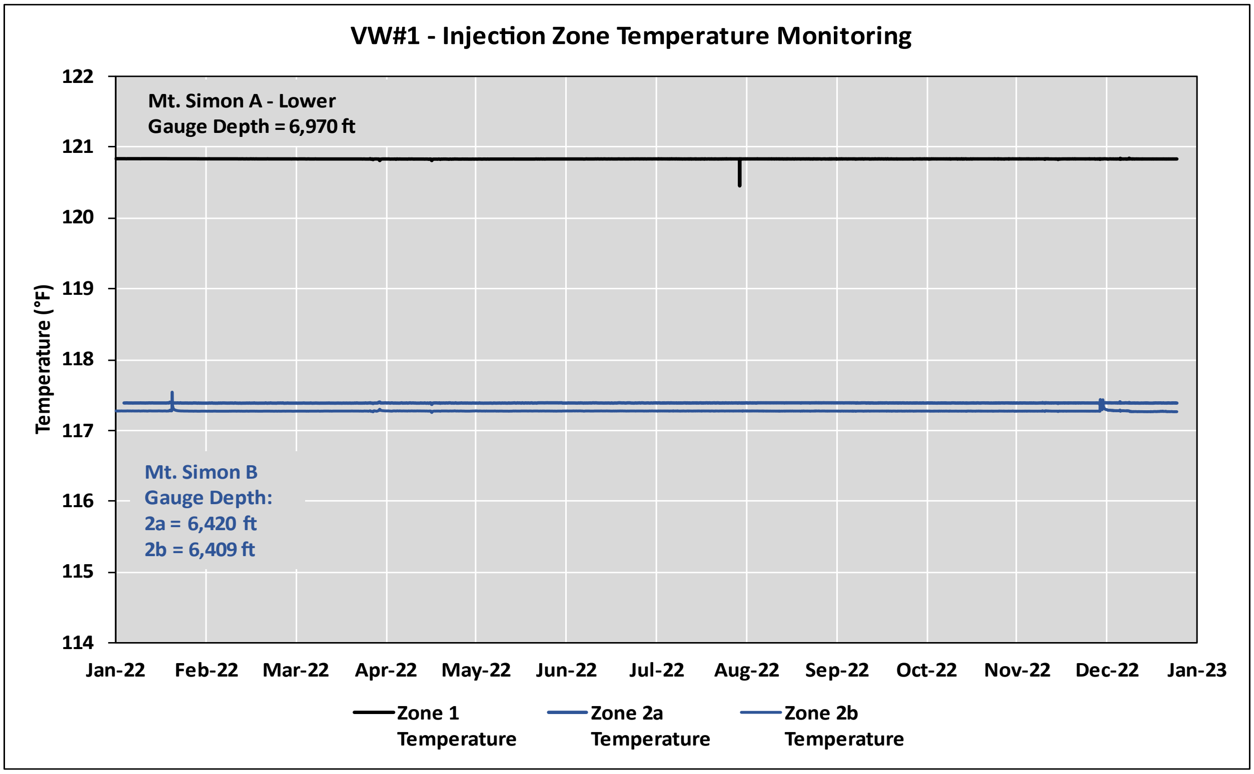

Figure 21: VW#1 injection zone temperature monitoring data for Jan-Dec 2022.

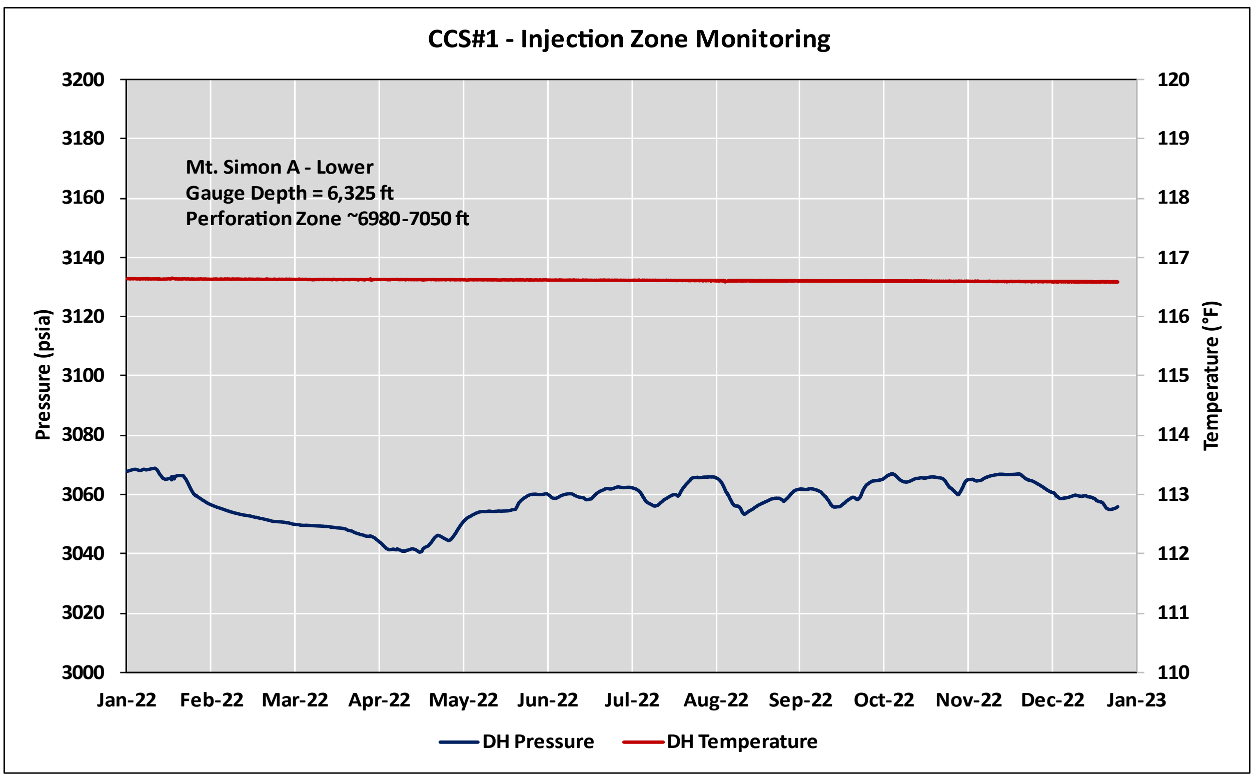

Figure 22: CCS#1 injection zone temperature & pressure monitoring data for Jan-Dec 2022.

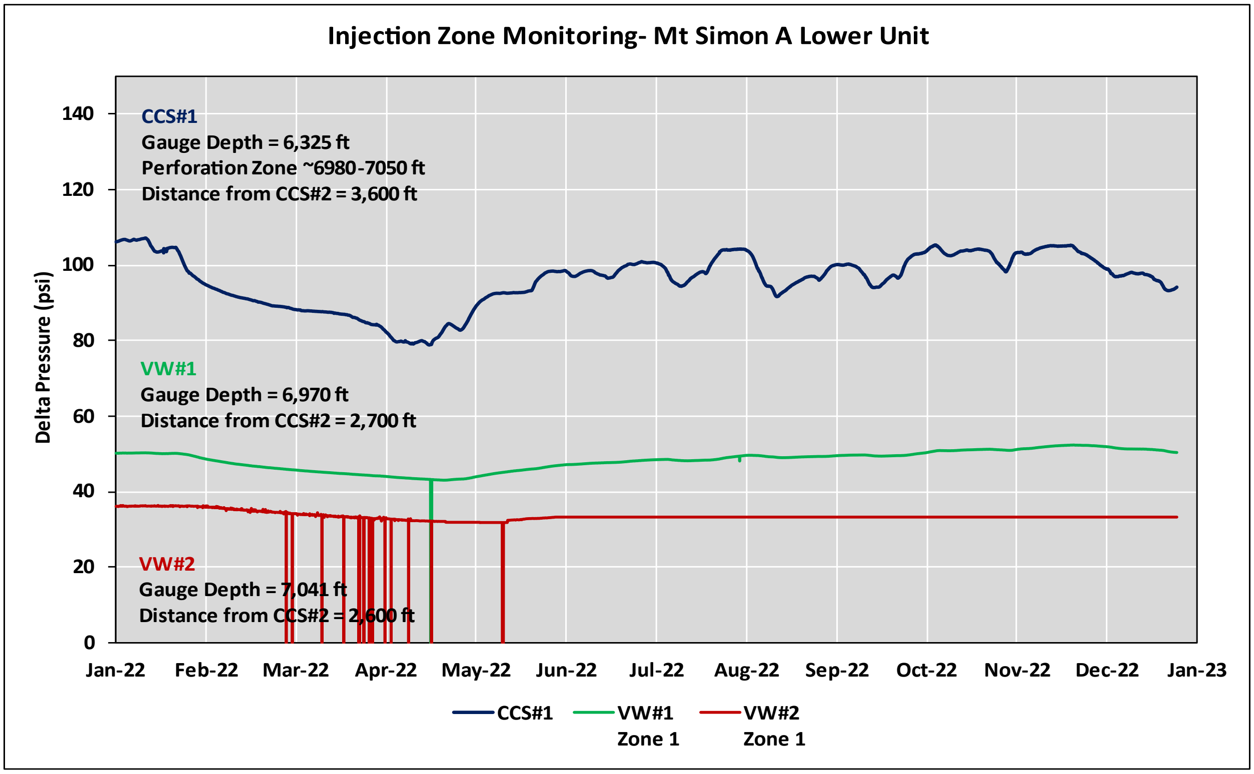

Figure 23: Comparison of the pressure change in the Mt. Simon A Lower at CCS#1, VW#1, and VW#2.

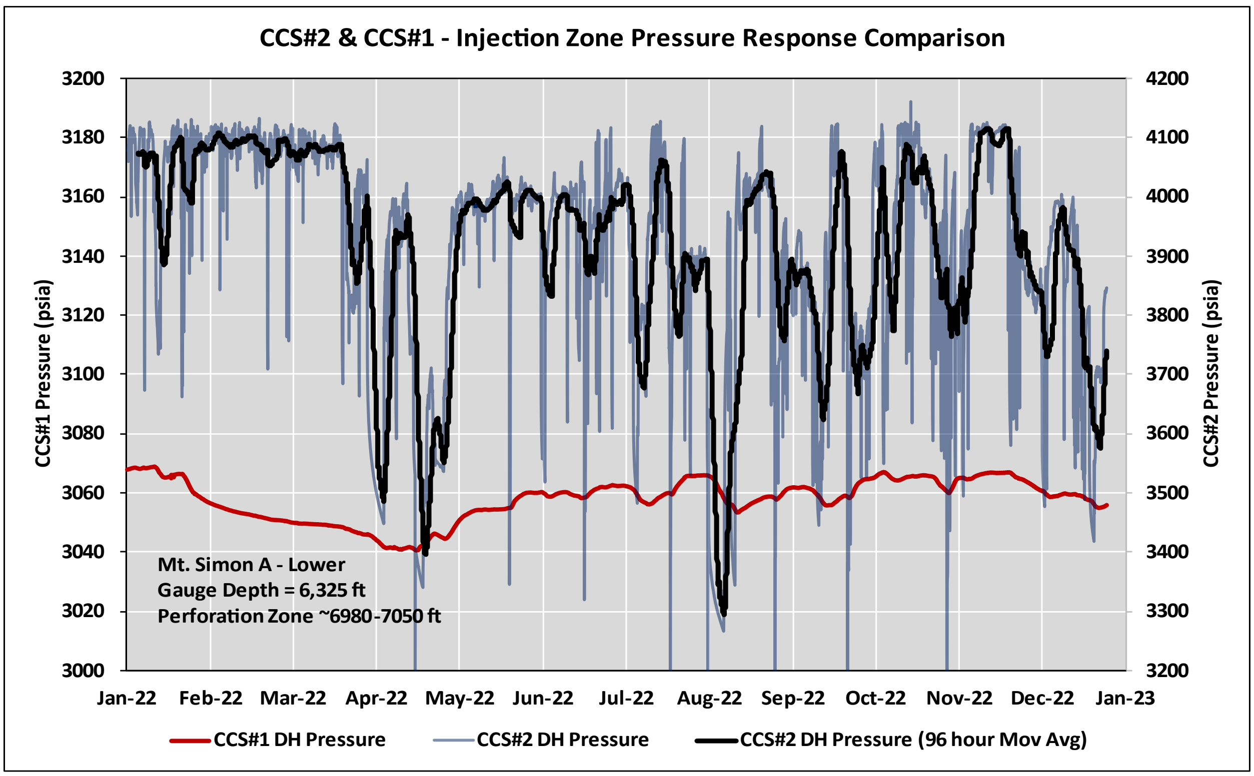

Figure 24: Comparison of the CCS#1 pressure response to CCS#2 injection pressure.

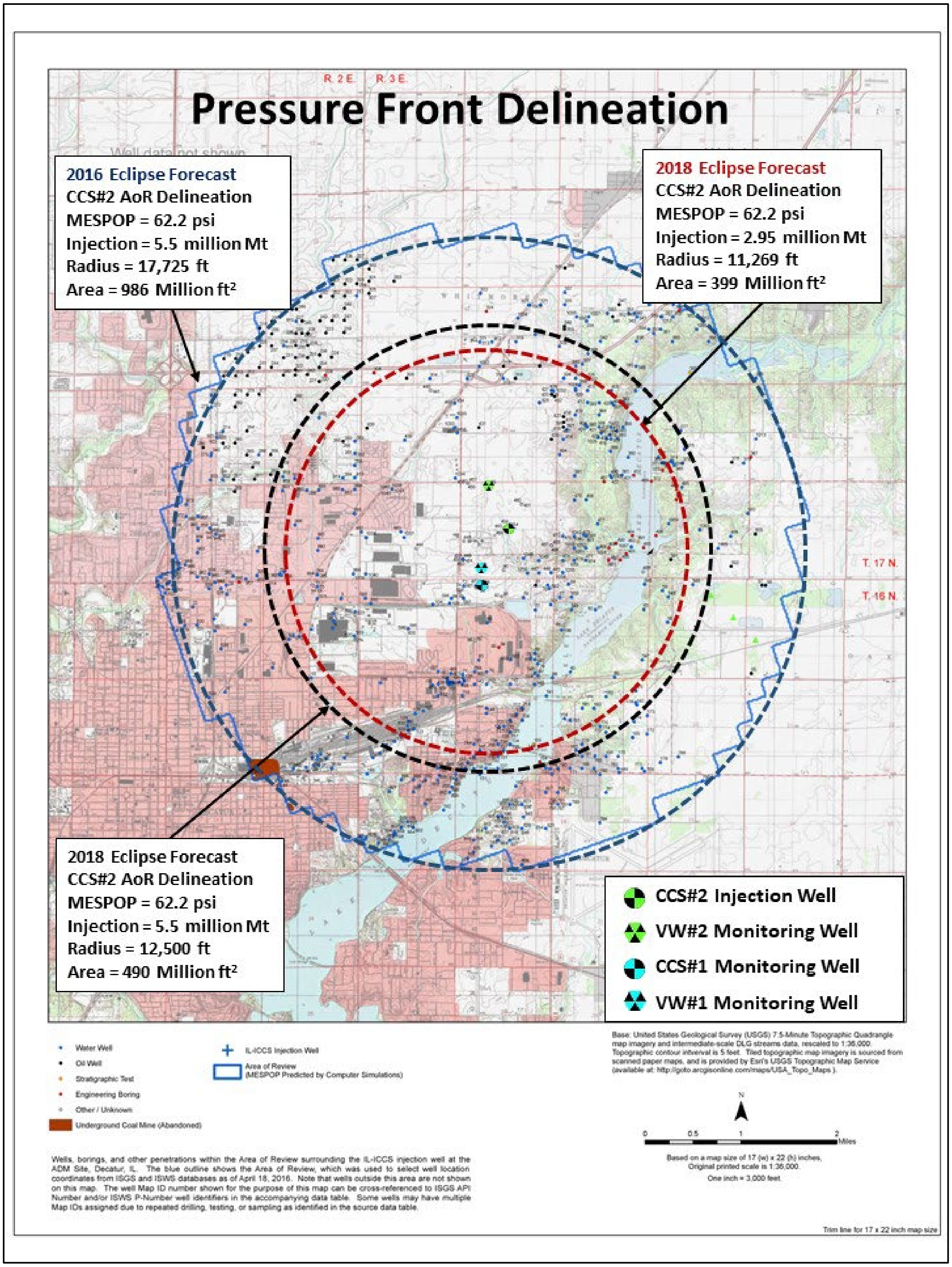

Figure 25: 2018 Eclipse model's pressure front delineation for June 30, 2022 and after the total injection of 6.5 million Mt (CCS#1=1.0 million Mt and CCS#2=5.5 million Mt).

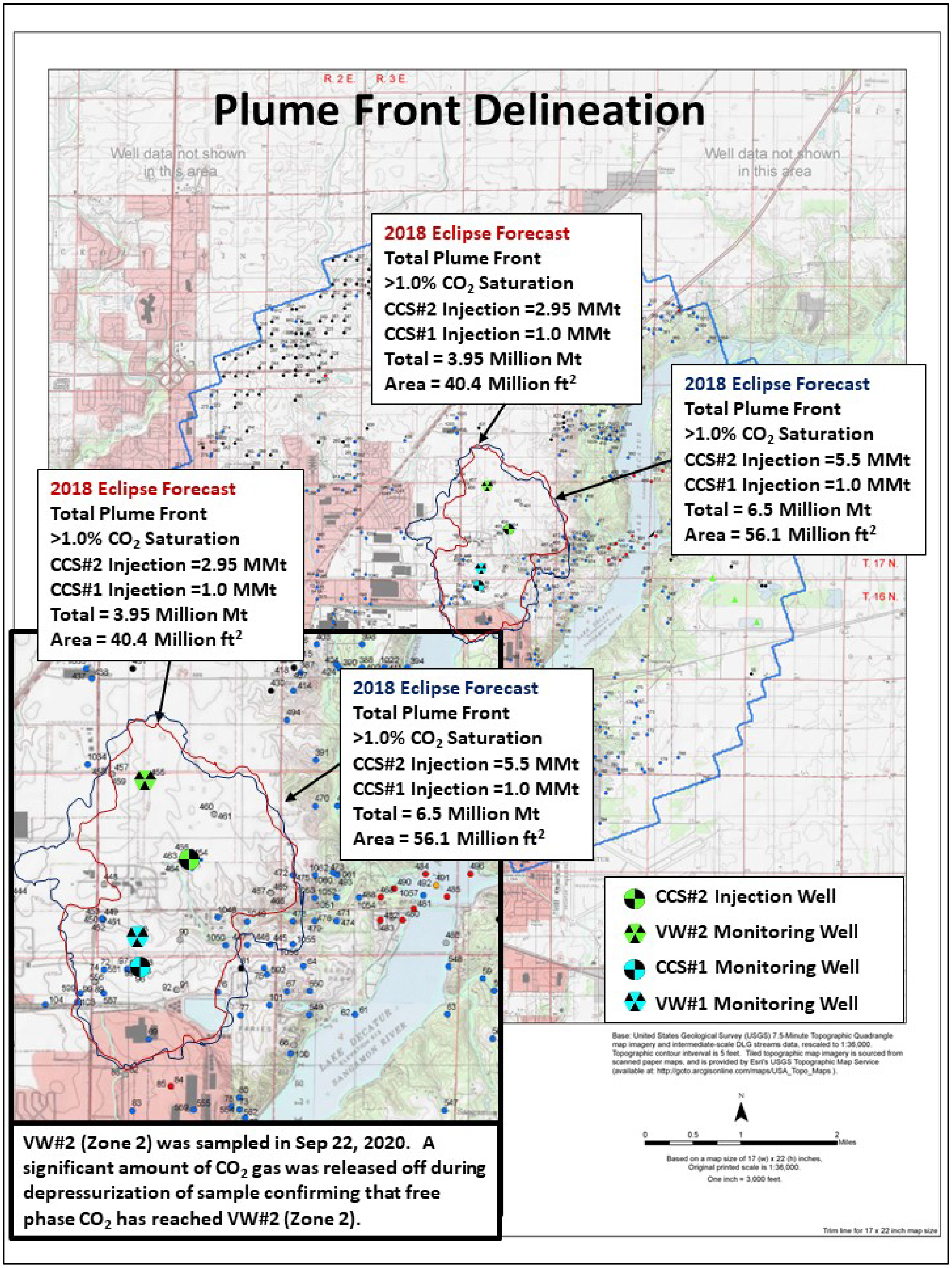

Figure 26: 2018 Eclipse model's plume front delineation for June 30, 2022 and after the total injection of 6.5 million Mt (CCS#1=1.0 million Mt and CCS#2=5.5 million Mt).

Supplemental Material
No supplemental information to be provided.

10. Other Testing and Monitoring
On January 21-22, 2022, the CCS#2 down hole pressure and temperature gauges were checked against a calibrated set of retrievable temperature and pressure gauges by conducting spinner logs as part of the pulse neutron activities. The downhole gauges were within tolerance and the results are included in this report.

Other Supplemental Materials
ADM_CCS_2_PRESSURE_TEMP_21_JAN_2022.pdf
ADM_CCS_2_SPINNER_22_JAN_2022.pdf
ADM_CCS_2_InjLog_CO2_Final_Report.pdf