

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 CO₂ 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 CO₂ 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: Todd Davis
Todd.E.Davis@adm.com

Well location: Decatur, Macon County, IL

Well coordinates: 39° 53' 09.32835" N, 88° 53' 16.68306" W

Permit number: IL-115-6A-0001

Report date: January 31, 2024

Report period: January 1, 2023 @ 00:00 hrs - January 1, 2024 @ 00:00 hrs

Report number: 33

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 01/01/2023 @ 00:00 hours and ending at 01/01/2024 @ 00:00 hours. During the 12-month period, 545,560 metric tons (Mt) of CO₂ was injected at an average rate of 1,494 Mt/day resulting in a total mass of 3,498,636 Mt being injected into CCS#2 (See Figure 2). A coiled tubing cleanout operation using solvent and acid stimulation was performed in January 2023. This has resulted in lower injection pressure and higher injection rates at CCS#2 compared to the previous reporting period (2022). The average downhole injection zone pressure during this monitoring period was 3,473 psig versus the pre-injection pressure of 2,841 psig (prior to 04/08/2017) equating to an increase in reservoir pressure of 632 psi. The actual injection pressure has been tracking with the forecast injection pressure with a <5% bias versus the reservoir model. The above confining zone (ACZ) monitoring data at VW#1 show no movement of fluids or CO₂ above the confining zone. This is also supported by the injection zone pressure and temperature data which indicate the CO₂ 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 CO₂ out of the injection zone.

The injectate stream analysis shows no change in the CO₂ quality when compared to the baseline data. The unit's corrosion monitoring system showed much lower corrosion rate on the 13CR-L80 coupon during Q4 of 2023 compared to the previous reporting period and observed rates are similar compared to the rates for the carbon steel coupons. Continuous DTS monitoring of CCS#2 is ongoing and we do not observe any well integrity issues or evidence for movement of fluid or CO₂ behind the casing. The attenuation ratio of the new DTS interrogator unit was modified During Q3 2023, to resolve the instrument bias. Therefore, continuing injection operation does not present an endangerment to the St. Peter Sandstone, the lower most USDW.

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	0	0	NA	NA
DH Tubing/Annulus ΔP	1	5	Communications failure	2/25/2023 04:00 - 09:00
Annulus Pressure	0	0	NA	NA
Trip Auto S/D System	1	8	Communications failure	02/25/2023 3:10 - 10:00

Note 1: Detailed description provided in Section 3.

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. As previously reported, ADM had detected completion equipment malfunctioning at VW#2. Completion flow control valves in the Mt. Simon

formation and multiple downhole pressure and temperature gauges had failed. ADM retrieved parts of the failed completion assembly in Q4 2023 including control lines but could not retrieve the clamps. Due to inclement weather conditions and having reached a good stopping point, two plugs were set in the 5.5” casing to isolate Ironton-Galesville from the lower Mt. Simon zones (Figure 1). Meanwhile, current site above-zone and in-zone monitoring will continue at VW#1. ADM plans to continue with VW#2 recompletion once weather permits. ADM is working on the next steps for the recompletion and plans to submit the same to the EPA separately.

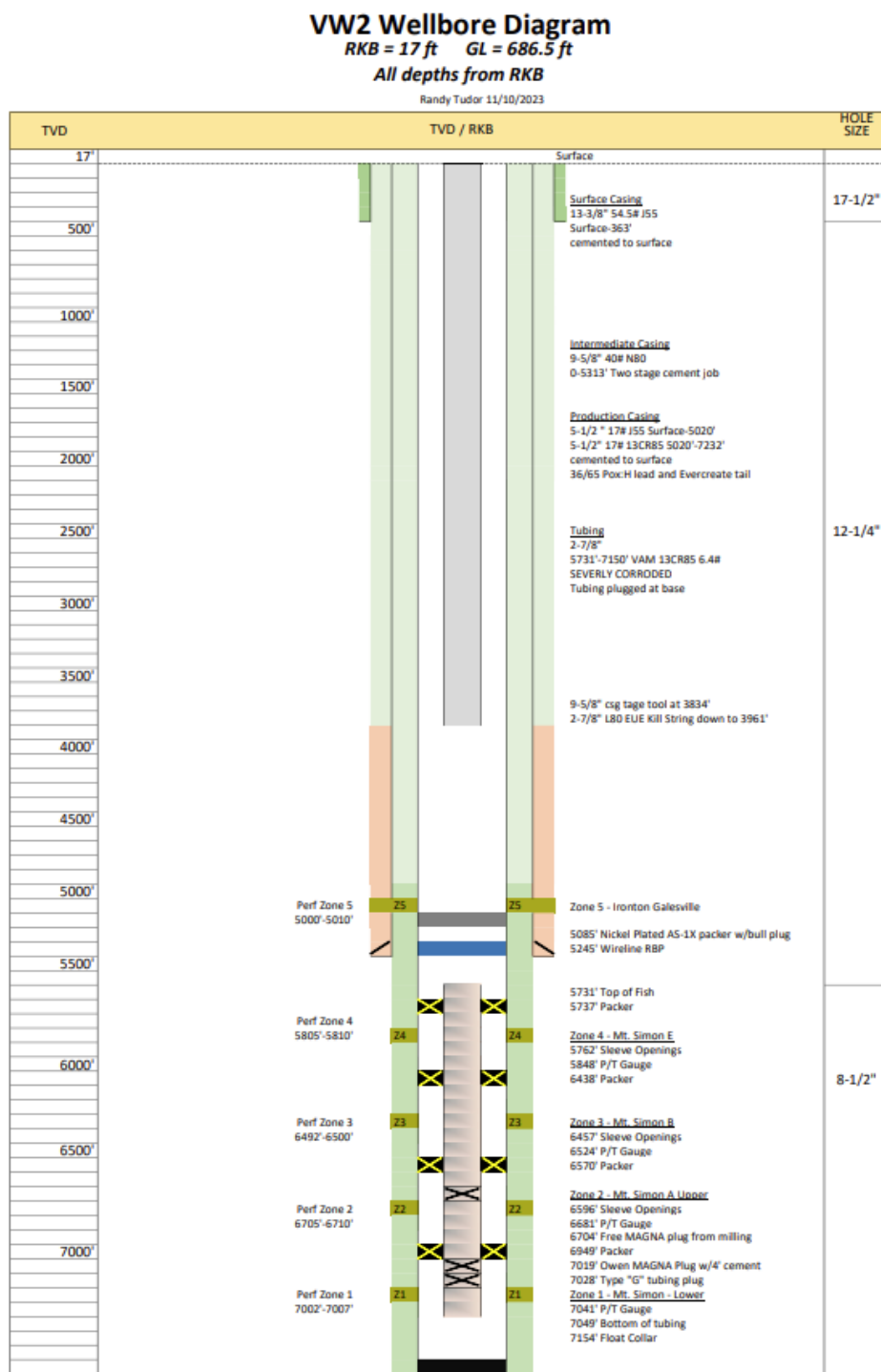


Figure 1: Current VW#2 wellbore schematic post workover and plugging operations.

Table 2. Recording frequency of VW#2 downhole gauges. Zone 1, 2, 3, 4 and 5 gauges have stopped functioning. The completion above zone 4 has been retrieved and plugs have been set below zone 5 for

now. VW#1 gauges continue to be used for monitoring relevant formations above and in the injection zone.

Well	Zone	Depth	Formation	Gauge	Recording Frequency
VW#2	Zone 5	5,027	Ironton Galesville	Pressure	0.00%
				Temperature	0.00%
	Zone 4	5,848	Mt Simon E	Pressure	3.24%
				Temperature	3.24%
	Zone 3	6,524	Mt Simon B	Pressure	3.24%
				Temperature	3.24%
	Zone 2	6,881	Mt Simon A - Upper	Pressure	53.61%
				Temperature	53.61%
	Zone 1	7,041	Mt Simon A - Lower	Pressure	3.24%
				Temperature	3.24%

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

Table 3. Schedule and status for 2023 annual reservoir fluid sampling and MIT activities.

Dates	Well	Activity	Status
Mar 24, 2023	CCS#2	T/P Calibration of DH Gauges	Completed
Apr 19-21, 2023 Oct 17-18, 2023	G101, G102, G103, G104, 10LG, 11LG, 12LG, 13LG	Shallow groundwater sampling	Completed
Mar 22-23, 2023 ⁽¹⁾	VW#1	Sample Zone - 3 (Ironton Galesville)	Completed
Mar 22-23, 2023	VW#1	Sample Zones - 2 (Mt Simon B)	Completed
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 ⁽²⁾	VW#2	Sample Zone - 2 (Mt Simon A Upper)	Suspended
Mar 29, 2023	GM#2	Sample St Peter (Lowermost USDW)	Completed
Mar 21 - Apr 4, 2023	CCS#2	T/P Calibration of Surface Gauges	Completed
Mar 21, 2023	CCS#2	Testing of the Automatic S/D System	Completed

Note 1: Reservoir fluids are produced until representative native fluids are produced (zone purging).

Note 2: The VW#2 well is currently offline as ADM works through recompleting the well and VW#1 well sampling will continue in place of VW#2 sampling.

Maintenance, Inspection, & Annual Sampling

The annual deep groundwater sampling and the MIT activities were completed during Q1 and Q2 2023. Since the last reporting period, an additional round of shallow ground water sampling was completed in Q4 2023. The schedule and status for 2023 annual MIT and groundwater sampling activities are shown in Table 3. As previously reported, we continued to experience failing performance of the downhole gauges at VW#2. All downhole gauges are offline with <3.5% recording frequency for this reporting period for Zone 1, Zone 3, Zone 4 and Zone 5 gauges. As mentioned previously, ADM is currently working through recompletion process for VW#2. In the interim, we continue to use VW#1 to monitor the Ironton Galesville and the Mt Simon A/B formations. This should provide enough downhole surveillance to

detect any anomalies that would indicate the movement of fluids or CO₂ out of the injection zone. During the current reporting period, sampling from VW#2 did not occur due to mechanical issues affecting well operation at multiple sampling intervals. Work is ongoing to resolve the mechanical issues in VW#2. Once we reach a resolution, we expect to be able to obtain representative fluid samples from the monitored formations for this project. Meanwhile, sampling from VW#1 well has demonstrated continued containment of CO₂ within the injection zone.

2. Analysis of CO₂ Injectate Stream

Discussion of Results

Table 4 presents the CO₂ injectate analytical results for the last four quarters (Q1-Q4 2023). 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 overall analytical results for both the quarterly analysis indicate no trend or change in the quality of the CO₂ injectate and is consistent with historic sample data generated during ICCS and IBDP projects. Although we note that the Q3 and Q4, 2023 samples appear to have been slightly contaminated with air.

Table 4. Analytical results for CO₂ injectate stream.

Parameter	Q1 2023 2/17/23	Q2 2023 5/30/23	Q3 2023 9/8/23	Q4 2023 12/4/23	Unit (LOQ)	Analytical method
Carbon Dioxide	Positive 99.9	Positive 99.9	Positive 99.8	Positive 99.7	% v/v (5.0)	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID)
Nitrogen	350	330	1000	1900	ppm v/v (10)	ISBT 4.0 (GC/DID)
Oxygen	29	43	210	700	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	440	250	340	180	ppm v/v (0.1)	ISBT 10.0 THA (FID)
Methane	trace	0.4	nd	nd	ppm v/v (0.1)	ISBT 10.1 (GC/FID)
Acetaldehyde	100	30	150	45	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	16	6.6	5.3	33	ppm v/v (0.01)	ISBT 14.0 (GC/SCD)
Ethanol	200	120	90	44	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. Trace = unquantified amount observed between MDL and LOQ.*

Supplemental Material

The analytical reports for the samples have been uploaded to the GSDT as follows:

Q1 2023 CO₂ Analytical Report: [***20230217_Q1_2023_CO2_Analysis.pdf***](#)

Q2 2023 CO₂ Analytical Report: [***20230530_Q2_2023_CO2_Analysis.pdf***](#)

Q3 2023 CO₂ Analytical Report: [***20230908_Q3_2023_CO2_Analysis.pdf***](#)

3. Continuous Recording of Injection Pressure, Rate, 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 545,560 metric tons (Mt) of CO₂ was injected at an average rate of 1,494 Mt/day. This contrasts with the average rate of 1,421 Mt/day during the previous reporting period (1/1/23 – 06/30/23). The maximum flowrate achieved was 3,300 Mt/day during which the wellhead pressure reached 1,473 psig. The fluctuations seen in the injection flowrate are due to plant slowdowns and shutdown of injection during the period which ADM conducted chemical stimulation maintenance in January of 2023 as well as backflow operations of CCS#2. Figure 3 trends the CCS#2 wellhead temperature and pressure data. During this period, the wellhead temperature and pressure averaged 58 °F and 1,348 psig, respectively. This contrasts with the average wellhead pressure of 1,420 psig observed during the previous reporting period and indicates that significant positive injection response from the chemical stimulation maintenance carried out at CCS#2 in January 2023 continued over the last six months of the reporting period.

Due to improved injectivity from the stimulation maintenance activity at CCS#2, higher injection rates were maintained throughout this reporting period while maintaining lower average downhole pressure (3473 psig). Therefore, we did not observe any downhole pressure exceedance over the maximum limit of 4,125 psia (90% of the calculated reservoir fracture pressure) as reported in Table 1. Table 1 details other monitored operating condition exceedances for the maximum surface pressure, minimum annulus pressure, minimum annulus, and tubing pressure differential as well as all automatic shut-down trips during the reporting period. We note that other than well workovers, the identified exceedance was associated with a communication failure incident in February as reported previously. Tabulation of daily parameters is provided with the supplemental data file as required.

Figure 4 trends the pressure maintained on the CCS#2 injection well annulus. During this period, the annulus pressure averaged 816 psig and approximately 60 gallons of annular fluid was removed from the system in January 2023. 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 3,473 psia corresponding to a ΔP of 632 psi versus the baseline. The downhole injection temperature averaged 121 °F or a ΔT of 4.9 °F. Figure 6 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 745 psi.

On February 25, 2023, the automatic shutdown system was activated due to a communications failure with the downhole instrumentation. The system was rebooted, and measurements were brought back online. Since the observed pressures before and after the automatic shutdown indicate similar values (Figure 6), we believe that the mechanical integrity across the packer has not been impacted in any manner.

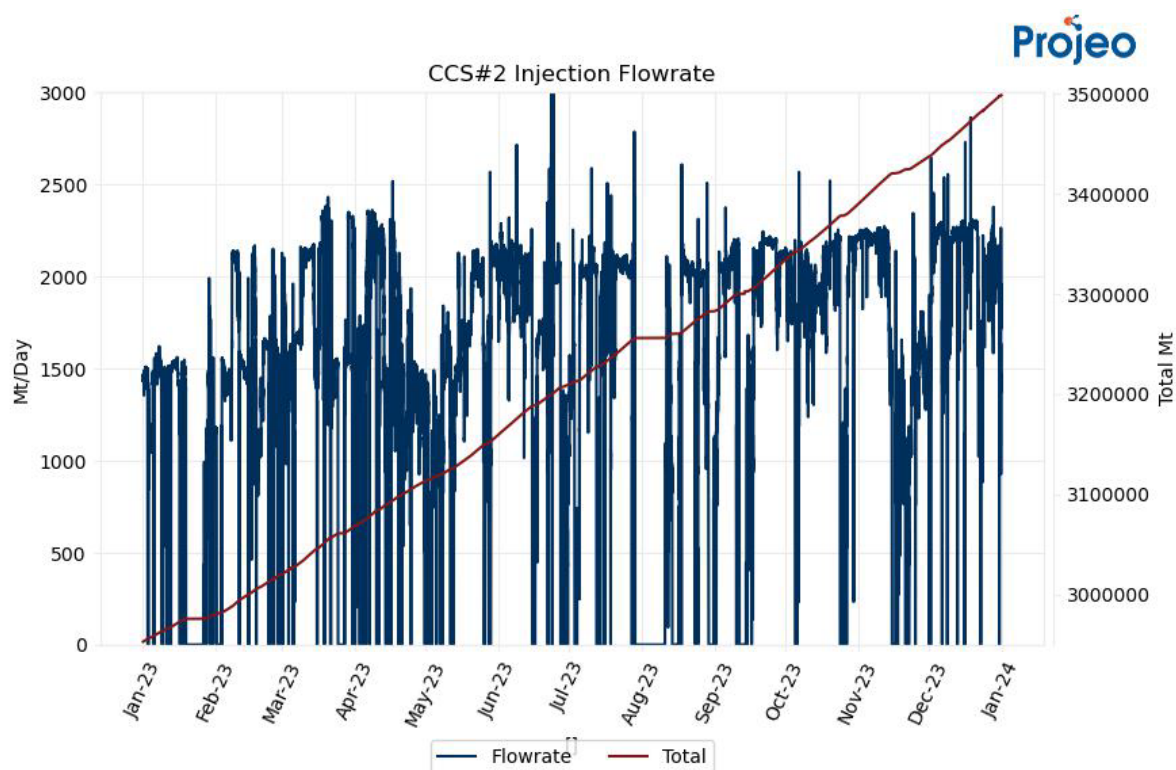


Figure 2: CCS#2 - Injection rate monitoring data for Jan-Dec 2023.

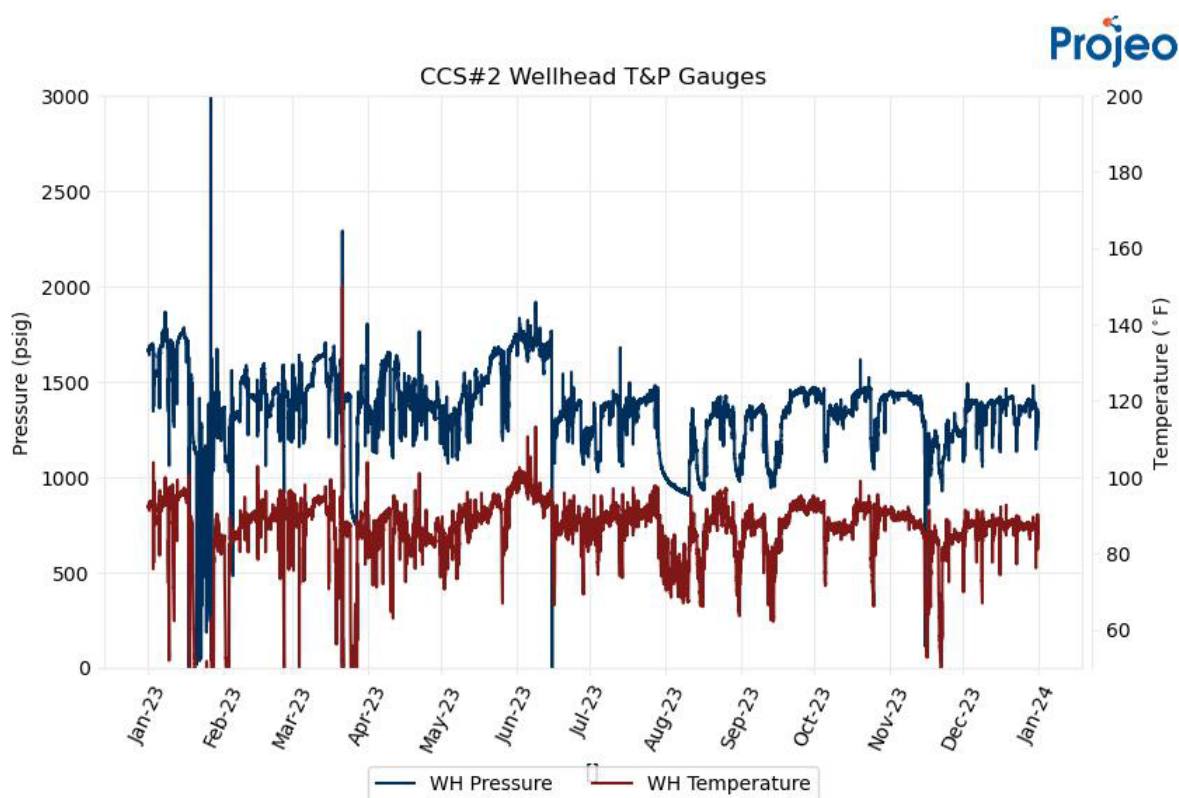


Figure 3: CCS#2 wellhead temperature and pressure monitoring data for Jan-Dec 2023.

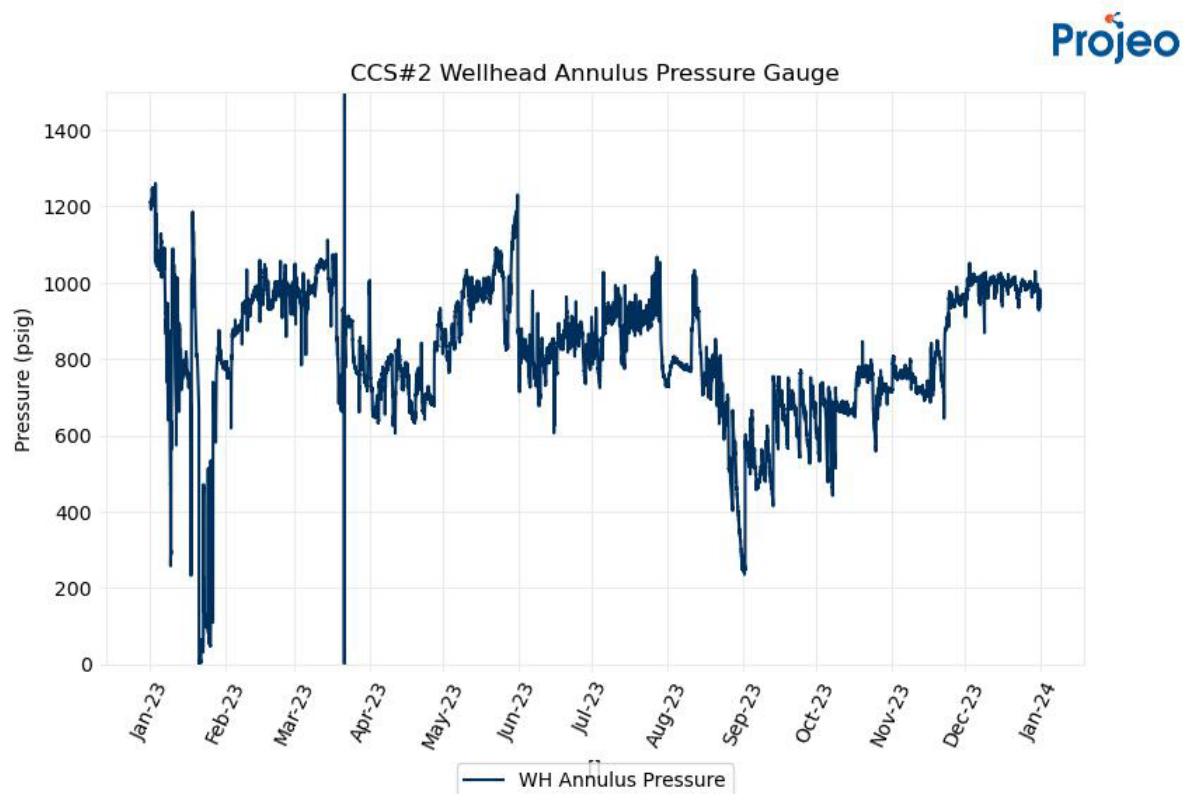


Figure 4: CCS#2 wellhead annulus pressure monitoring data for Jan-Dec 2023.

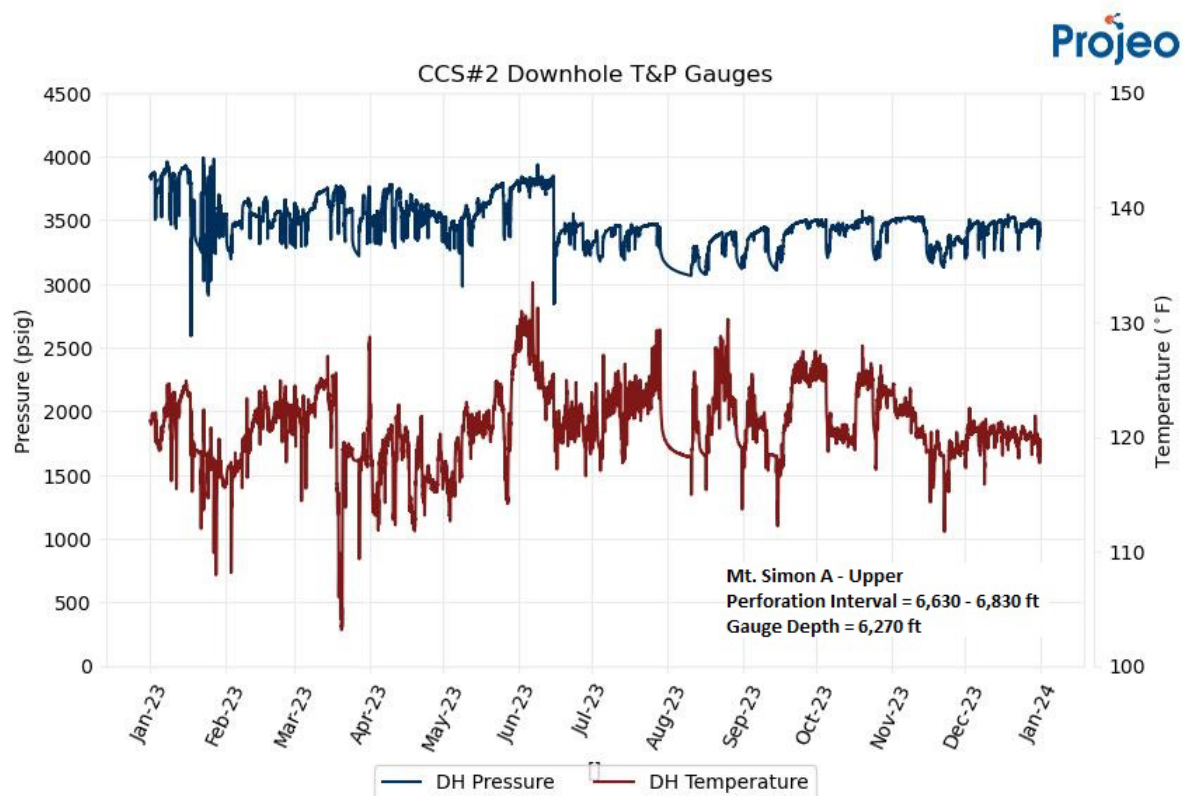


Figure 5: CCS#2 downhole temperature and pressure monitoring data for Jan-Dec 2023.

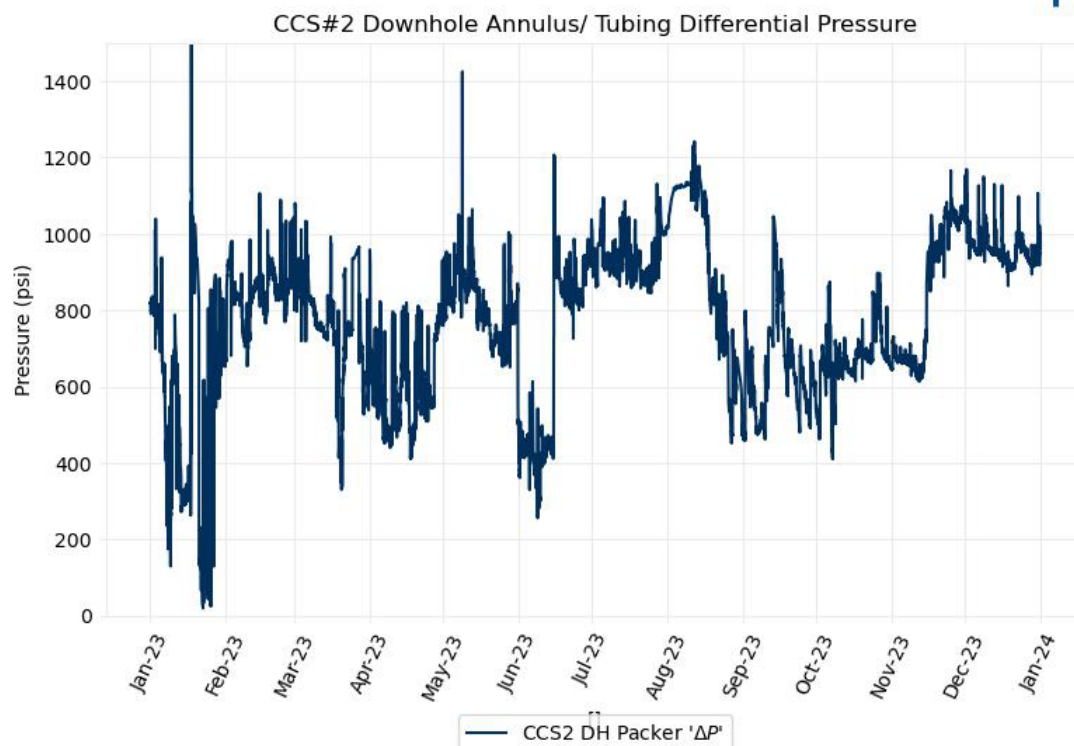


Figure 6: CCS#2 downhole annulus and tubing differential pressure monitoring data for Jan-Dec 2023. Table 5 provides a monthly summary of several important operational limits for CCS#2 and details the parameter's minimum, maximum and average value for each month. During the reporting period, none of the operating limits were exceeded and a single downhole instrument communication failure event was recorded.

Table 5. CCS#2 summary of injection parameters for continuous operational monitoring. Elevated maximum injection pressure (3000 psi) and low minimum annular pressure (3 psi) in January were observed during well workover operations.

Parameter (Unit)	Reporting Period	Monthly Summary Values		
		Average	Minimum	Maximum
Injection Pressure (psig)	January 2023	1335	0	3000
	February 2023	1380	915	1595
	March 2023	1416	0	1703
	April 2023	1408	1099	1751
	May 2023	1453	1072	1743
	June 2023	1478	0	1848
	July 2023	1302	995	1677
	August 2023	1123	905	1425
	September 2023	1299	943	1471
	October 2023	1358	1039	1615
	November 2023	1279	112	1451

	December 2023	1351	1053	1490
Injection Rate (Mt/day)	January 2023	902	0	1560
	February 2023	1410	0	2160
	March 2023	1547	0	2369
	April 2023	1496	0	2456
	May 2023	1497	0	2371
	June 2023	1669	0	2293
	July 2023	1495	0	2782
	August 2023	878	0	2605
	September 2023	1701	0	2372
	October 2023	1798	0	2564
	November 2023	1572	0	2341
	December 2023	1992	0	2860
Injection Volume Based on DH Reservoir T/P (ft ³ /day)	January 2023	44820	0	77852
	February 2023	70207	0	108236
	March 2023	76928	0	119828
	April 2023	74859	0	122105
	May 2023	67779	0	116396
	June 2023	74752	0	100460
	July 2023	67329	0	131761
	August 2023	39894	0	131667
	September 2023	76610	0	118358
	October 2023	80531	0	115055
	November 2023	70121	0	114007
	December 2023	88440	0	144149
Annular Pressure (psig)	January 2023	735	3	1247
	February 2023	935	644	1059
	March 2023	915	664	1110
	April 2023	740	610	930
	May 2023	964	766	1229
	June 2023	817	635	976
	July 2023	886	724	1067
	August 2023	713	248	1032
	September 2023	600	235	770
	October 2023	686	442	846
	November 2023	806	644	988
	December 2023	990	868	1051

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: **202312_ADM_IL-115-6A-0001_Data.xlsx**

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 45,413 Mt and the total amount injected was 545,560 Mt. At the end of the reporting period, the total mass of CO₂ injected into CCS#2 was 3,498,636 Mt. As reported previously, during the chemical stimulation activity in January, approximately 60 gallons of brine (annular fluid) was removed from the system as part of the operations. Barring said instance, no brine 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 CO₂ injected and annular fluid maintenance.

Reporting Period	CO₂ Injected (Mt)	Cumulative CO₂ Injected (Mt)	Annulus Fluid Volume +/- Added or Removed (Gallons)
January 2023	27,949	2,981,025	-60
February 2023	39,479	3,020,505	0
March 2023	47,946	3,068,450	0
April 2023	44,836	3,113,286	0
May 2023	46,207	3,159,493	0
June 2023	49,334	3,208,827	0
July 2023	46,325	3,255,704	0
August 2023	27,224	3,282,920	0
September 2023	51,028	3,333,954	0
October 2023	55,727	3,389,684	0
November 2023	47,149	3,436,851	0
December 2023	61,756	3,498,636	0

Supplemental Material

No supplemental information to be provided.

5. Corrosion Monitoring

Summary of Results

The results of the corrosion monitoring program are shown in Table 7. Review of the data shows that the earlier observed increase in corrosion rates on the 13CR-L80 coupon during Q2 of 2023 has subsequently dropped to more reasonable rates which are considered low and much closer to the baseline. 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.

Table 7. CCS#2 corrosion monitoring results¹.

Coupon Material Equipment Service	Coupon Number	Monitoring Period	Corrosion Rate (mpy)	Corrosion Categorization	Corrosion Type
A106-B Transport pipeline	6	Q1 2023	0.016	Low	Generalized
	5	Q2 2023	0.079	Low	Generalized
	6	Q3 2023	0.077	Low	Generalized
	5	Q4 2023	0.037	Low	Generalized
L-80 Long string casing <4,800 ft	6	Q1 2023	0.029	Low	Generalized
	5	Q2 2023	0.030	Low	Generalized
	6	Q3 2023	0.043	Low	Generalized
	5	Q4 2023	0.038	Low	Generalized
13CR-L80 Long string casing >4,800 ft, injection tubing, and packer	6	Q1 2023	0.477	Low	MD
	5	Q2 2023	1.665	Moderate	Generalized
	6	Q3 2023	0.338	Low	Generalized
	5	Q4 2023	0.028	Low	Generalized

Note 1: Corrosion categorization is based on NACE: SP0775-2018 "Preparation, Installation, Analysis, And Interpretation of Corrosion Coupons in Oilfield Operations". MD=Mechanical Damage

Supplemental Materials

The coupon photos, measurements, and corrosion calculations have been uploaded to the GSDT as follows:

Q1-Q2 2023 Coupons: [2023_ADM_Corrosion_Coupon_Photos_Q1-Q4.pdf](#)

Corrosion Calculations: [202311_CCS#2_Corrosion_Monitoring_Results.xlsx](#)

6. Above Confining Zone (ACZ) Monitoring

Discussion of Results – Pressure and Temperature Monitoring

The pre-injection reservoir parameters and the observed reservoir parameters for the ACZ monitoring zones in GM#2 (St. Peter Formation), and VW#1 (Ironton Galesville Formation) are compared in Table 8. While the VW#2 gauges cannot be used for monitoring due to gauge failure, examination of the data from the VW#1 and GM#2 shows no significant change to have occurred during the monitoring period (pre-injection vs. current) thus indicating no movement of fluids or CO₂ above the confining zone. This indicates that the operation does not present an endangerment to the St. Peter Sandstone, the lower most USDW.

The downhole pressure and temperature for the Ironton Galesville, i.e., the formation directly above the injection zone seal (Eau Claire Shale) at VW#1 are shown in Figure 7. As already mentioned, VW#2 data is not shared since the gauges were non-operational and we do not have enough data to make any determination from the pressure or temperature profiles for that well. Figure 8 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 CO₂ above the seal formation. The spikes observed in the GM#2 trend data are associated with the retrieval and subsequent deployment (4/18/2023) of downhole gauges post repair. The reported data during this period was essentially constant (stale) gauge values and can be disregarded. The steady pressure and temperature values before these anomalies indicate that the reservoir conditions remain like what we had observed before the gauge repair.

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	VW#1
Gauge Depth ⁽²⁾	3450 ft - St Peter Sandstone	5027 ft - Ironton Galesville	4989 ft - Ironton Galesville	3450 ft - St Peter Sandstone	5027 ft - Ironton Galesville	4989 ft - Ironton Galesville
Pre-Injection	1,396.7	2,112.1	2,086.0	94.8	103.6	104.4
Average	1,392.1	Fail	2,077.4	94.9	Fail	104.4
Δ	-4.6	Fail	-8.6	0.05	Fail	0.0
% Change	-0.33%	Fail	-0.41%	0.05%	Fail	0.03%

Note 1: Data Collection Time Period = 1/1/23 - 12/31/23. Pressure reported as reservoir=psia & ΔP =psi.

Note 2: Depths reported are gauge depths.

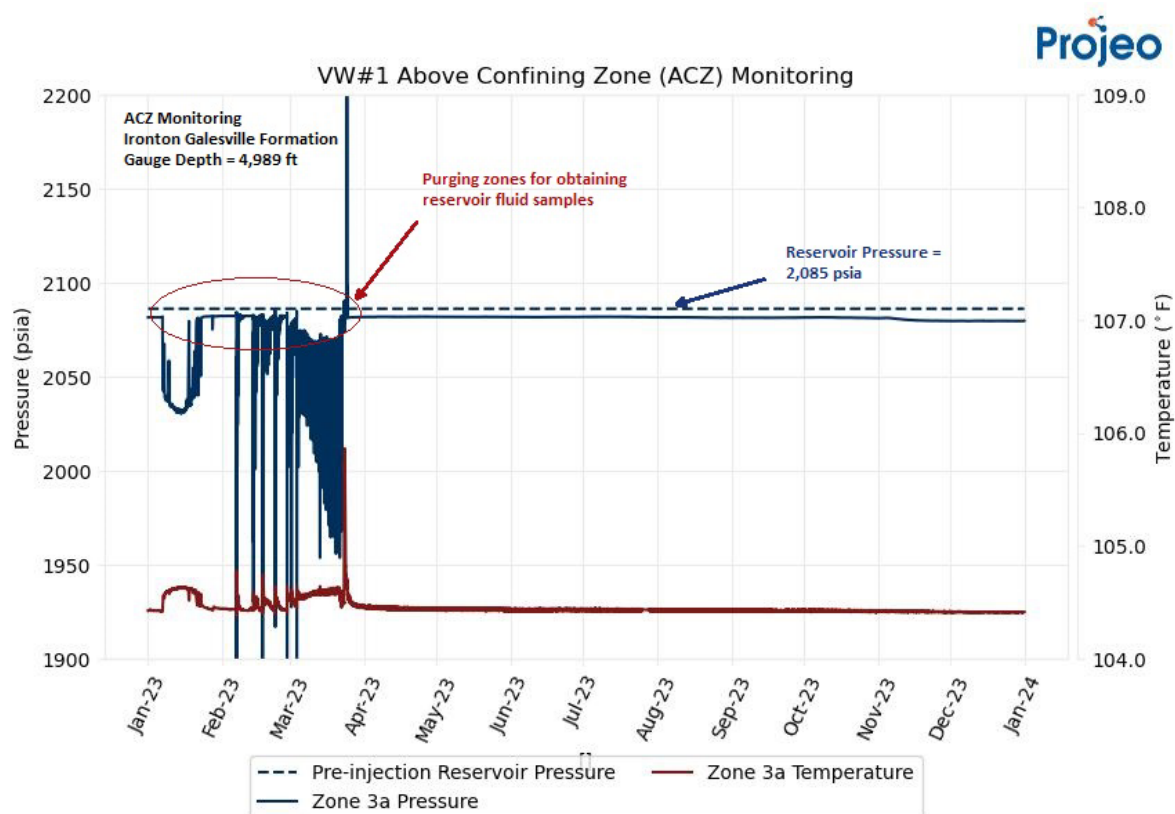


Figure 7: VW#1 ACZ monitoring of the Ironton Galesville Formation for Jan-Dec 2023.

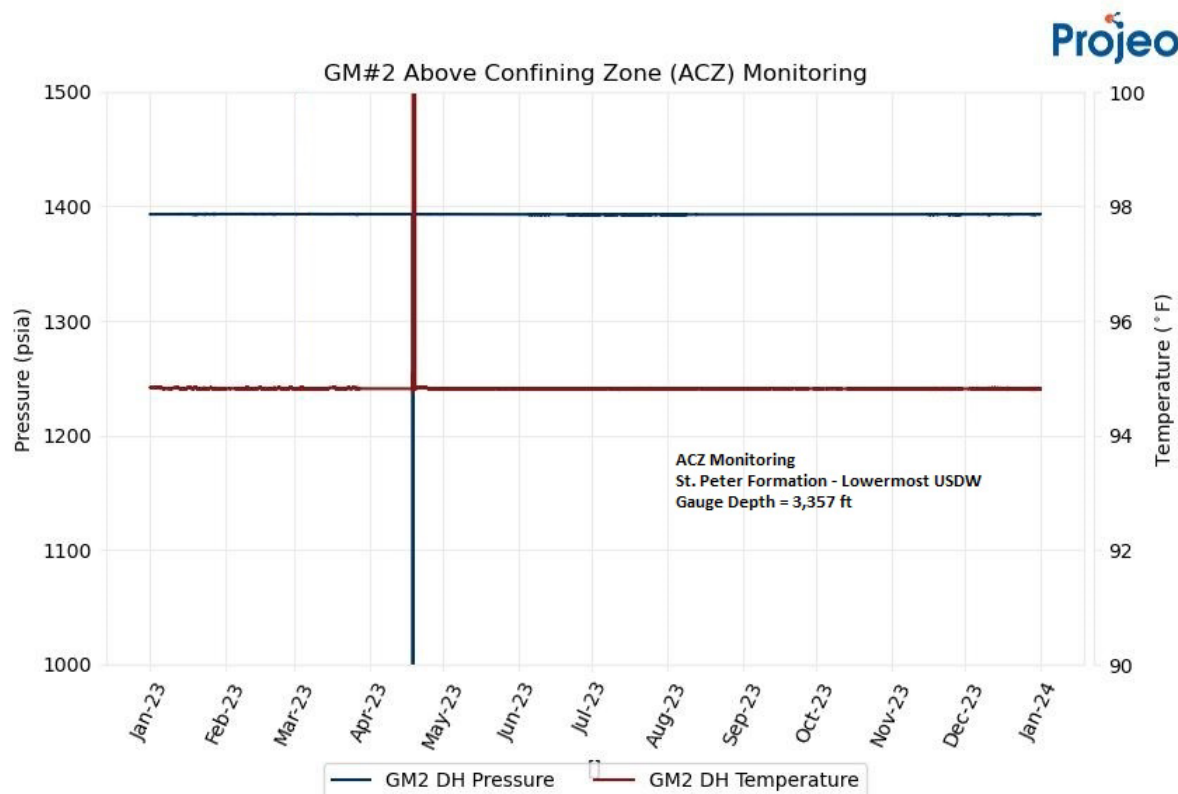


Figure 8: GM#2 ACZ monitoring of the St. Peter Formation for Jan-Dec 2023.

In previous reports, ADM has discussed issues surrounding downhole gauges in VW#2 including the intermittent shorting of the communications line as well as minor CO₂ leakage into the tubing from VW#2 Zone 2 sliding sleeve. As mentioned previously, ADM is currently working through recompletion process for VW#2. Meanwhile, VW#1 well is currently being used for above-zone and in-zone monitoring.

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 (CO₂) 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 CO₂ 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 3,498,636 metric tons of CO₂ had been injected as of December 31, 2023. Because of the report's size, it is being submitted as supplemental material.

Since the last report (submitted in July 2023), additional sampling events have occurred. Between July 1, 2023, and December 31, 2023, one shallow groundwater sampling event (October 2023) has occurred. For deep well sampling, as has already been reported, due to mechanical issues with well VW#2 collection of samples has been suspended. Instead, as reported during the prior reporting period, samples

were collected from the Mt. Simon and Ironton-Galesville formations at well VW#1. As mentioned previously, ADM is currently working through recompletion process for VW#2. Meanwhile, VW#1 well is currently being used for above-zone and in-zone monitoring at the site including for injection zone groundwater monitoring.

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 5, 2023, 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 because 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: ***202307_IL-115-6A-0001-0002_GWM_Report.pdf***

202401_IL-115-6A-0001-0002_GWM_Report.pdf

GW COAs: ***202303_IL-115-6A-0001-0002_Deep_GWM_COA.pdf***

202304_IL-115-6A-0001-0002_Shallow_GWM_COA.pdf

202310_IL-115-6A-0001-0002_Shallow_GWM_COA.pdf

7. External Mechanical Integrity Testing

Discussion of Results

The CCS#2 annual external MIT was conducted during the reporting period with results submitted on April 13, 2023 (*20230414_CCS2_Mechanical_Integrity_Testing_Report.pdf*). As discussed in the referenced MIT report, a new DTS interrogator was installed which has resulted in a temperature measurement bias between the old and the new measurements. However, the profile trends are comparable (similar temperature features and transitions are observed in both the baseline data and data analyzed for the MIT). The identified bias is a result of difference in attenuation ratios used in the DTS processing. The attenuation ratio of the new interrogator unit was modified During Q3 2023, and the observed bias has been resolved. Both the post-shutdown temperature profile and the pre-shutdown temperature profile using DTS measurements show no anomalies in the profiles and indicate good well mechanical integrity of the CCS#2 injection well casing and tubing. Continuous DTS monitoring of CCS#2 is ongoing and the 24-hour period for October 4, 2023, is shown in Figure 9. This observation period is chosen due to constant flow rate and no operational activity at CCS#2.

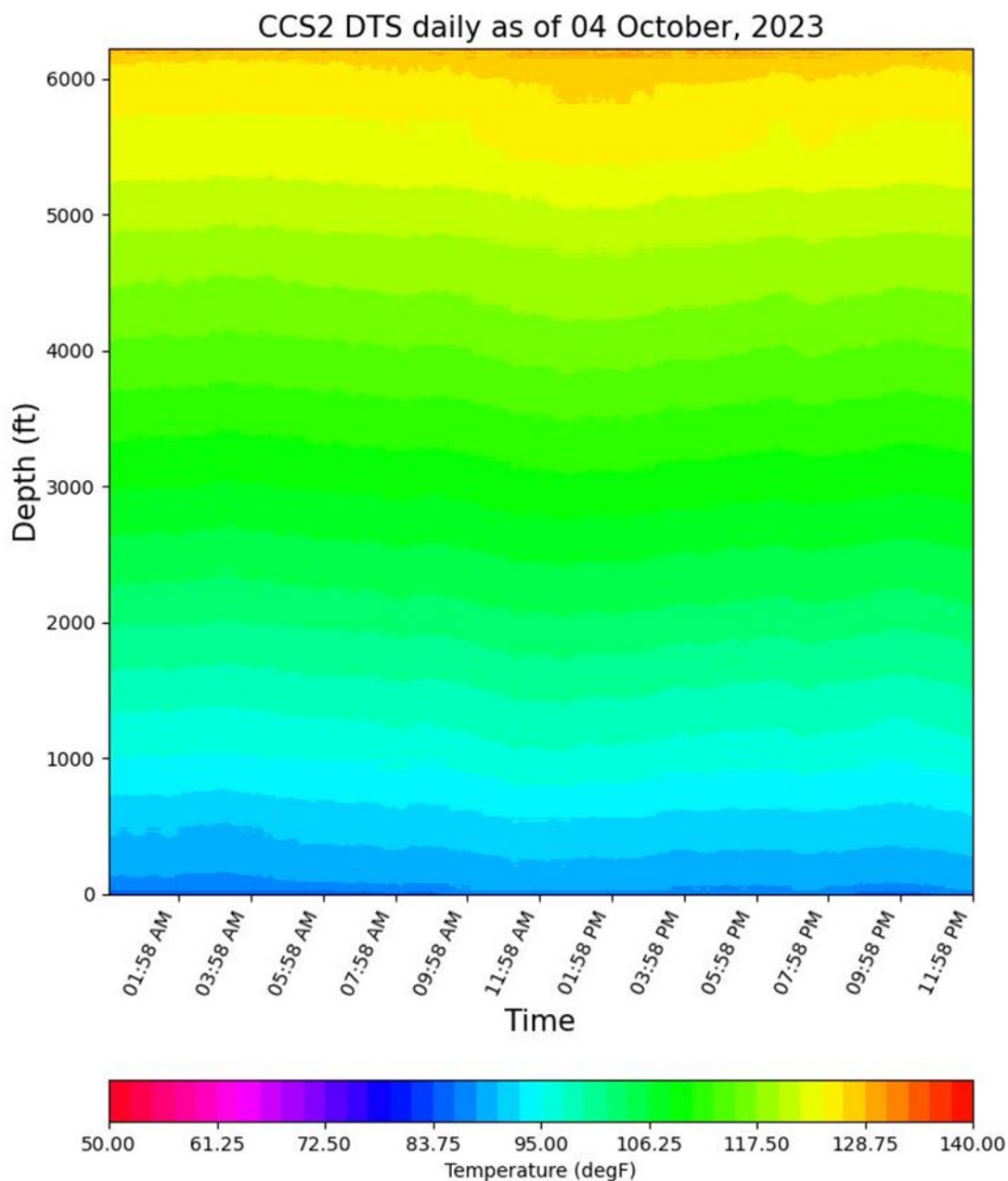


Figure 9: CCS#2 DTS data in 3-dimensional view for 10/04/2023.

8. Pressure Fall-Off Testing

Discussion of Results

No pressure fall-off testing was conducted during the reporting period. The permit specifies a pressure fall-off test for CCS#2 at approximately halfway through the injection period or after 2.75 million Mt of

CO₂ have been injected. The threshold was met in 2022 and results were submitted in accordance with the UIC Class VI Requirements.

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 CO₂ pressure and plume fronts are developing in a manner that is reasonably consistent with the results forecasted by the updated (2020) Eclipse reservoir flow model. Table 9 compares the actual reservoir pressure with the pressure forecast by the Eclipse model. While some zones show a good correlation between the actual and forecast data, the correlation fails for injections zone at CCS#1 and VW#1 Zone 2. CCS#1 is showing a recorded pressure which is 8.5% below the forecast and the CCS#2 bottom hole pressure is more than 5%, or 171 psi higher than the projected pressure. The significant change observed is due to the use of an updated 2020 reservoir model for our analysis compared to the 2018 model used during the prior reporting period.

The 2020 model was re-history matched from the ground up in 2020 at the completion of the IBDP project to incorporate all of the latest data. The main changes in the new model include incorporating structural information from seismic data reprocessed in 2019; updated porosity, permeability and facies model incorporating baffle facies; and a DFN model implemented in the Precambrian for better permeability modeling. Much of the deviations from the current model and actual data can be attributed to the lack of additional history match cycles over the past year. ADM plans to go through a new history matching exercise and update the model accordingly in 2024. The significant variations in CCS#1 and CCS#2 injection pressures are due to the simulated pressure depths and the gauge depths being at significant offsets (665 ft for CCS#1 and 551 ft for CCS#2).

Previous reports (2022) had communicated the observed build-up of foreign material around the perforated interval in CCS#2 injection well. This manifested in higher downhole injection pressures at the injection well with reduced injectivity. Figure 10 compares the predicted injection zone pressure 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 deviate during the subsequent injection finally reaching a ~500 psi differential at 2.0 million tons. The bias between the actual and the forecast pressure was identified to be mainly driven by downhole fouling. As already mentioned in this report, a coiled tubing cleanout operation using solvent and acid stimulation was performed in January 2023 (20230223_ADM_CCS2_Solvent_Stimulation_Report.pdf). Post cleanout operation, the injection pressure is now trending much closer to the predicted pressure from the reservoir model. Specifically, the current downhole pressure is trending at or below the forecast pressure suggesting that the cleanout operation was successful. Additional routine backflow operations have been and may be conducted as required to maintain injectivity over the longer term and prevent future fouling.

Figure 11 - Figure 16 trends the actual versus the forecast differential pressure within the injection zone for each monitoring well. As already mentioned, additional history matching exercises will be taken up in 2024 to improve the forecast moving forward. Figure 11 and Figure 13 only provide partial forecast data due to the use of partial historic pressure data in the history matching process for corresponding monitoring locations (VW1 Zone 1 and Zone 2).

Table 9: Comparison of actual reservoir pressure versus 2020 Eclipse model forecast¹.

Well	CCS#1	CCS#2	VW#1		VW#2		
Depth ²	7,015 ft	6,725 ft	6,970 ft	6,420 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 A Lower	Mt Simon B	Mt Simon E
Zone	Injection	Injection	Zone 1	Zone 2	Zone 1	Zone 2	Zone 3
Actual P	3,062	3,772	3,214	3,186	3,241	3,252	3,118
Forecast P	3,334	3,601	3,235	3,023	3,262	3,188	3,031
ΔP	272	171	21	163	21	63	87
% Delta	8.5%	4.6%	0.7%	5.3%	0.7%	2%	2.8%

Note 1: Data Collection Time Period = 1/1/23 - 12/31/23. Pressure reported as reservoir=psia ΔP =psi

Note 2: Monitoring well depths are reported as gauge depths while CCS#1 & CCS#2 depths are the middle of the perforated interval.

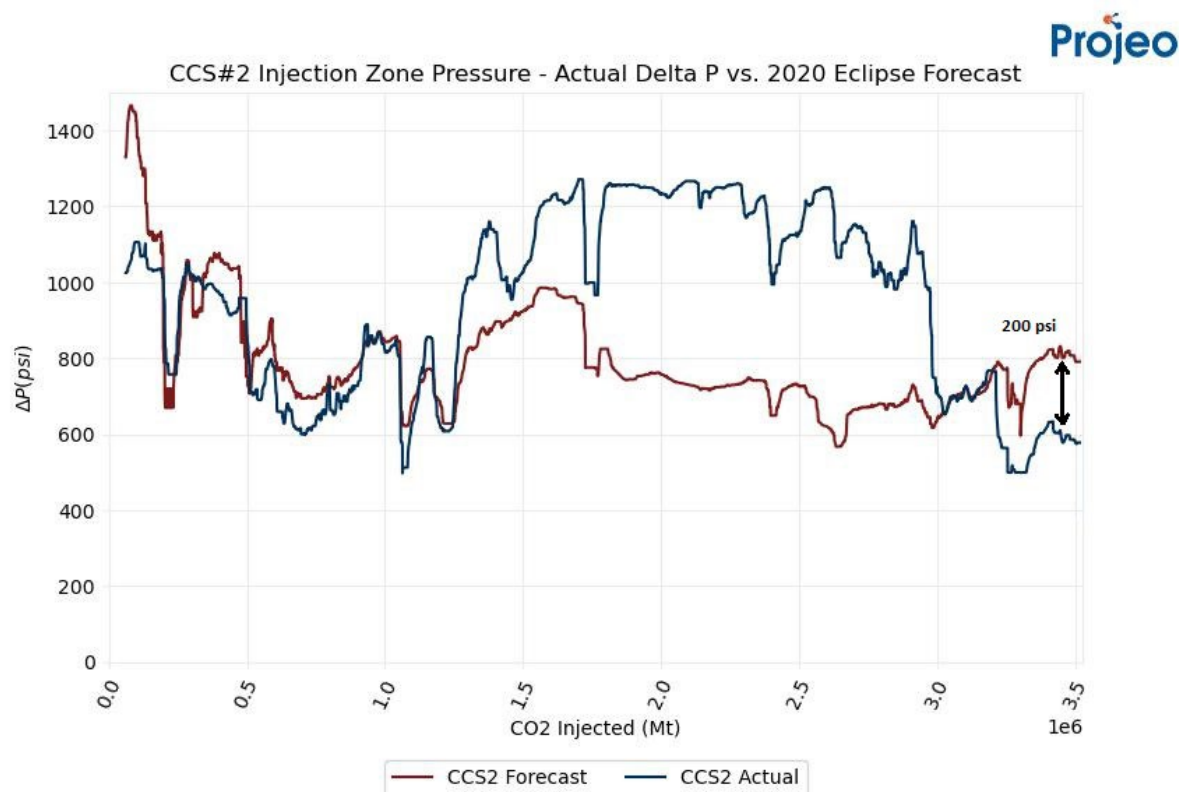


Figure 10: CCS#2 comparison of the downhole injection pressure versus the forecast pressure generated by the 2020 Eclipse reservoir model.

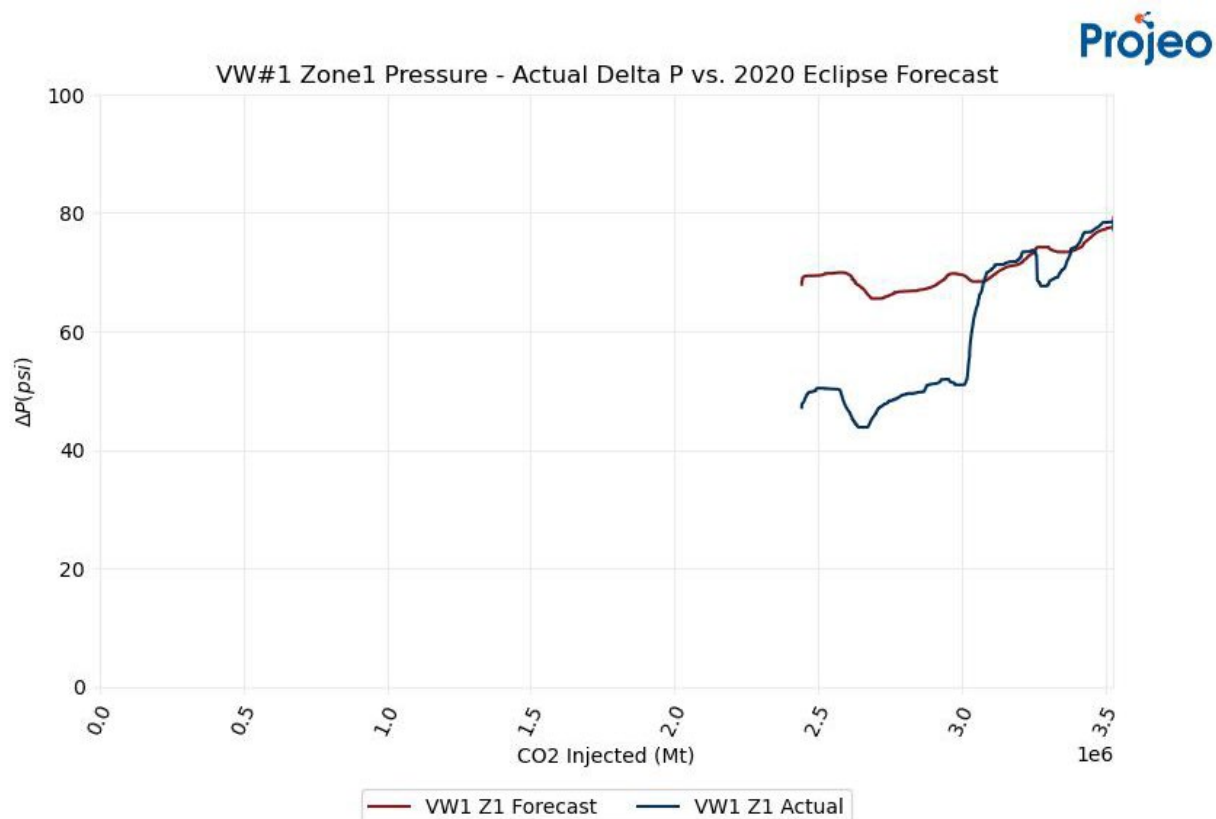


Figure 11: VW#1 Zone 1 differential pressure comparison of actual versus 2020 Eclipse model forecast.

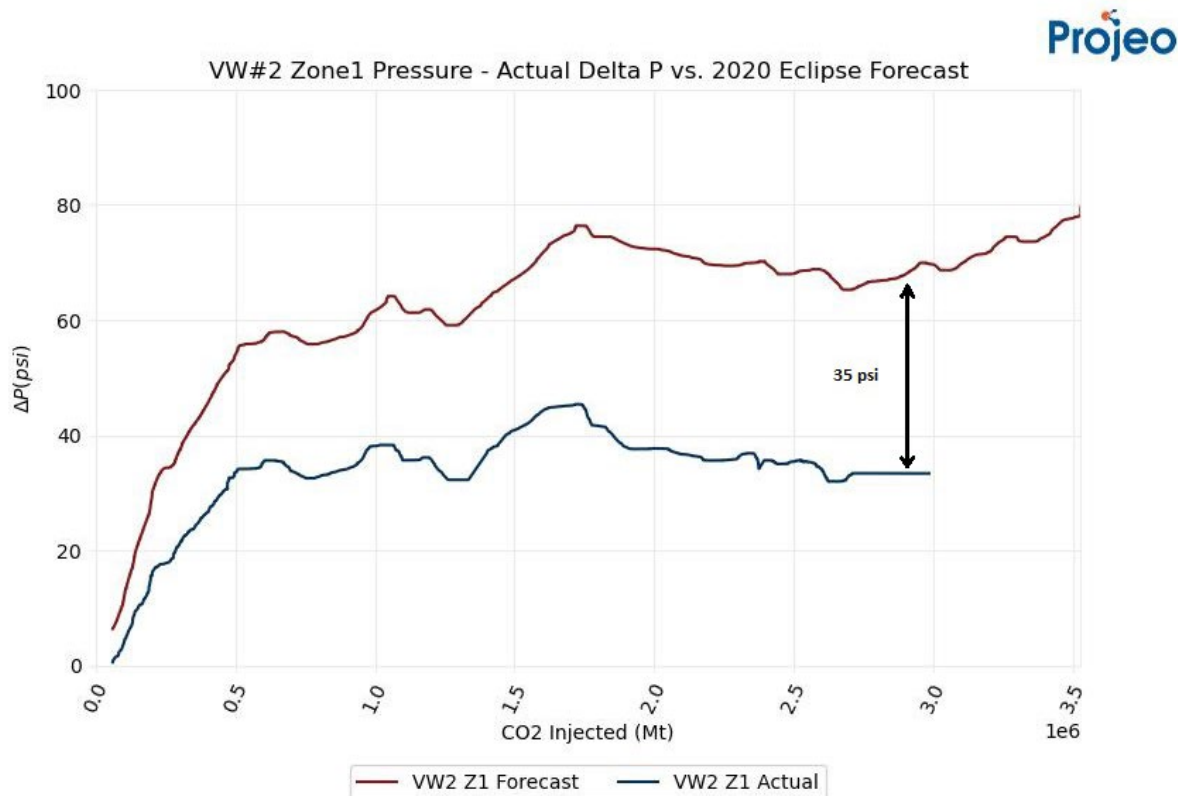


Figure 12: VW#2 Zone 1 differential pressure comparison of actual versus 2020 Eclipse model forecast.

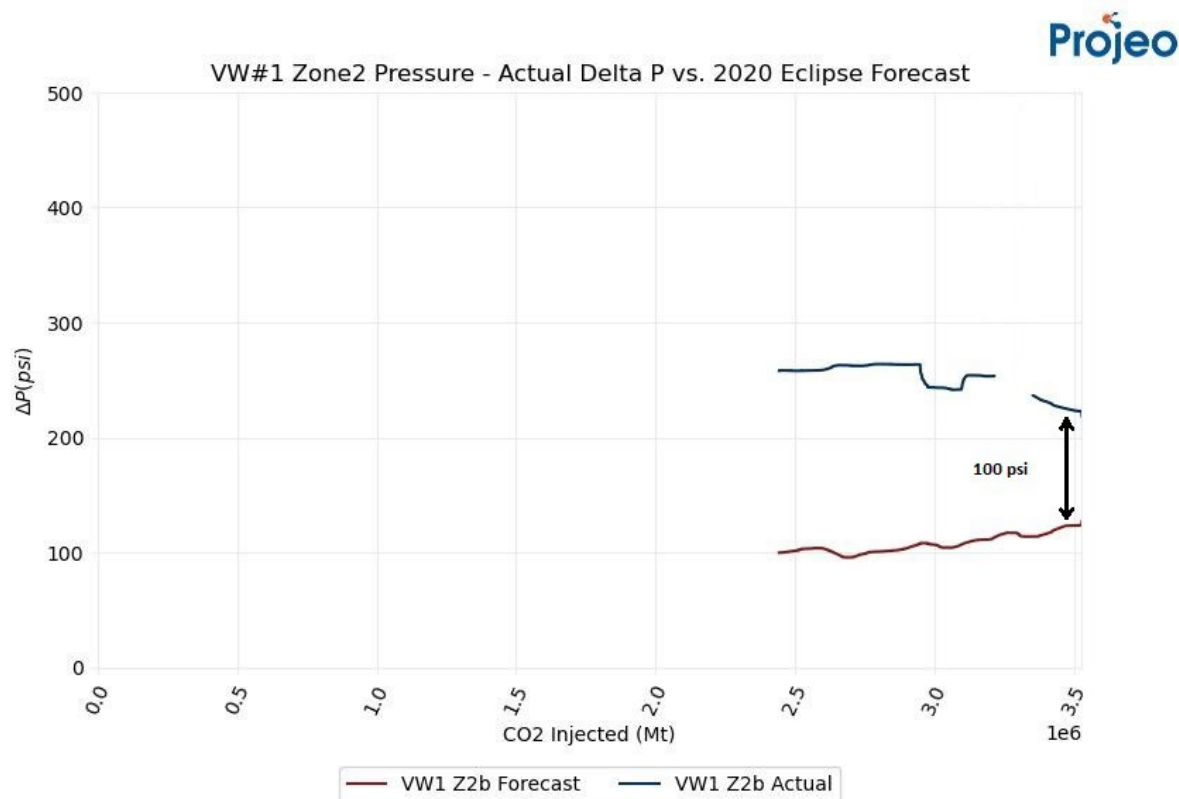


Figure 13: VW#1 Zone 2a actual reservoir differential pressure versus 2020 Eclipse model forecast.

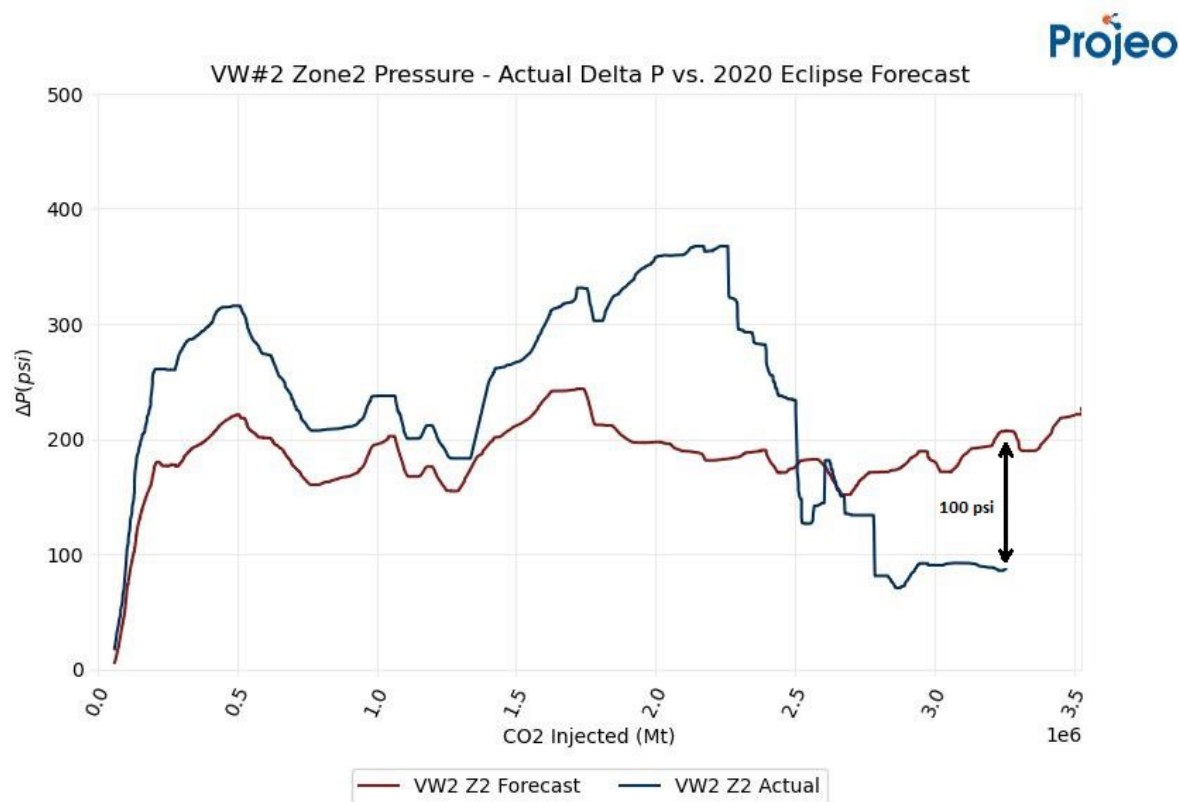


Figure 14: VW#2 Zone 2 actual reservoir differential pressure versus 2020 Eclipse model forecast.

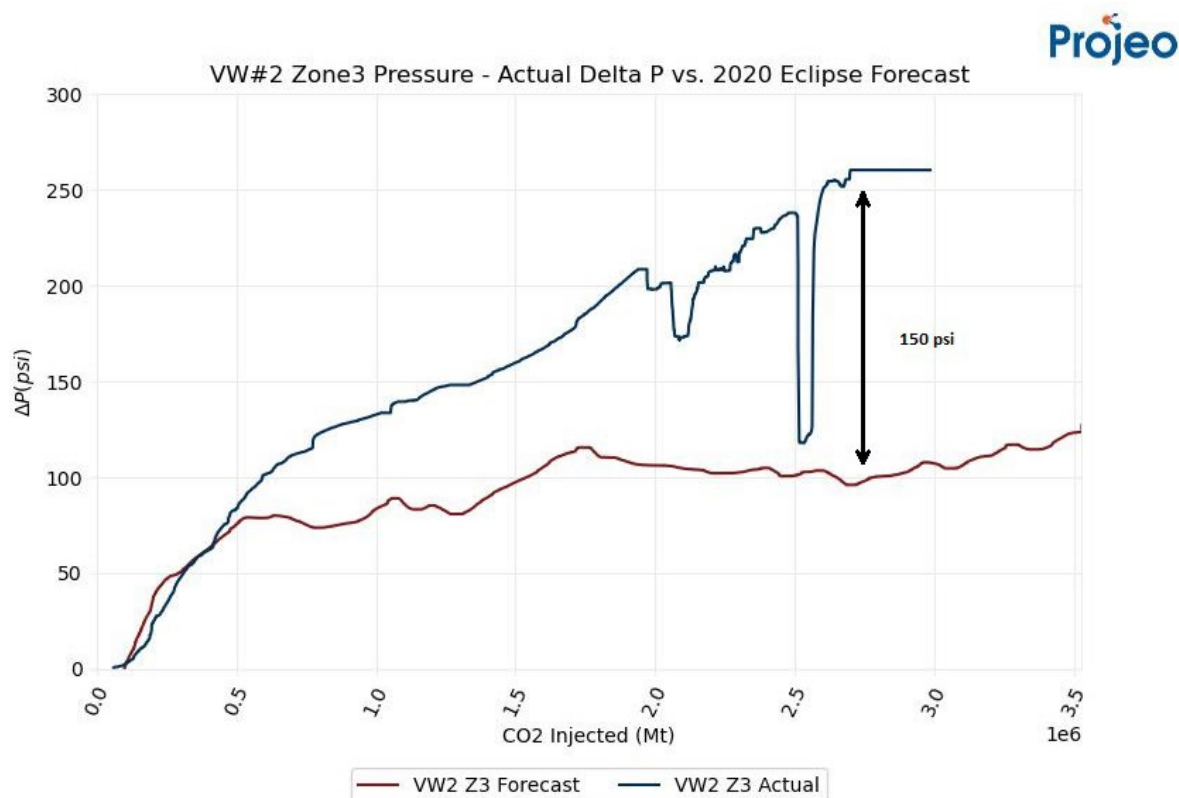


Figure 15: VW#2 Zone 3 actual reservoir differential pressure versus 2020 Eclipse model forecast.

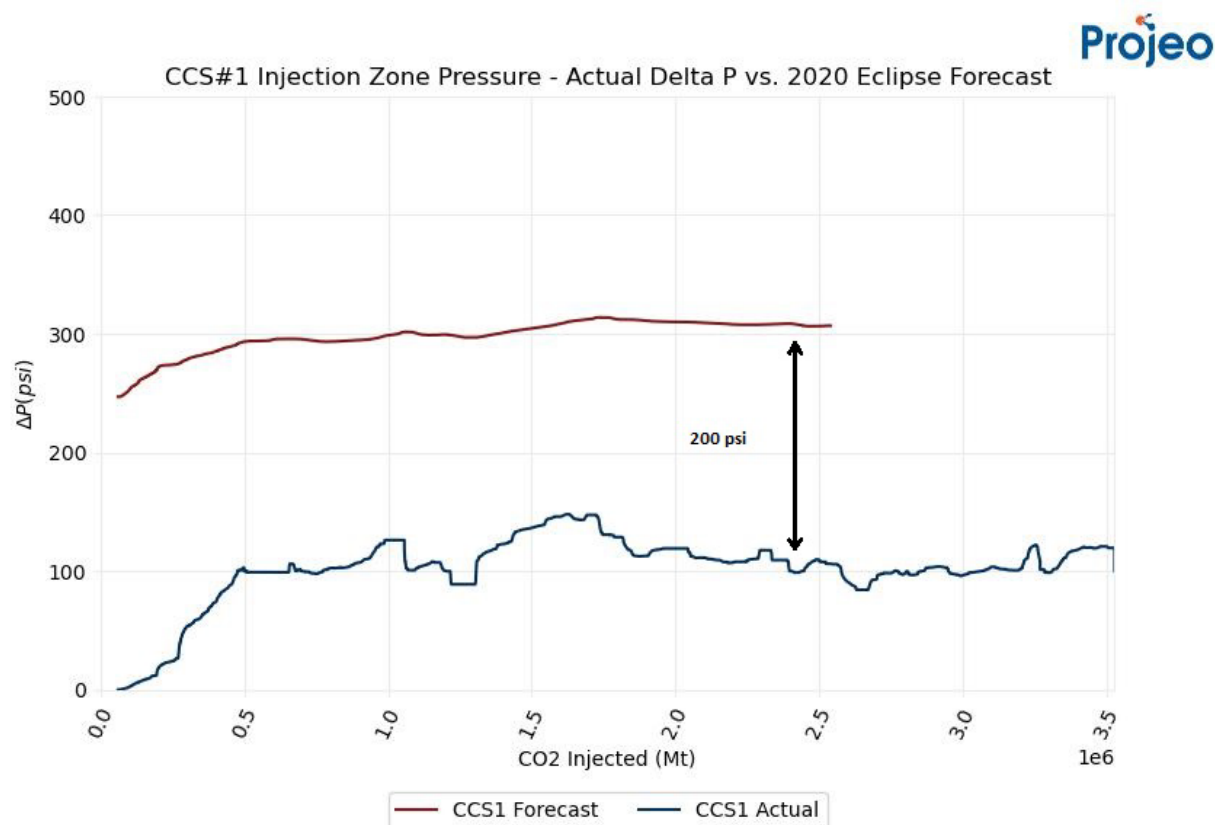


Figure 16: CCS#1 injection zone reservoir differential pressure versus 2020 Eclipse model forecast.

Discussion of Results – Pressure-Front Tracking

Table 10 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 had the greatest pressure response increasing 8.26% ($\Delta P=241$ psi) in VW#1 and 8.8% ($\Delta P=260$ 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 VW#2 parameters may not be representative since the recording frequency was limited to < 3.5% during this period (Table 2). 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. For the VW#2 injection zone (Zone 2) gauge, the deviation observed during this monitoring period was 3.85% ($\Delta P = 117$ psi), slightly higher than the corresponding value conveyed in the previous reporting period above the baseline pressure. For the VW#1, Zone 2 gauge, the deviation observed during the monitoring period was 7.80% ($\Delta P = 228$ psi) which is slightly lower than the deviation observed in the previous reporting period (234 psi). 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 2.20% ($\Delta P = 70$ psi) at VW#1 and 1.04% ($\Delta P = 33$ psi) at VW#2. The recorded average pressure increase in the previous reporting period for VW#1 Zone 1 and Zone 2 gauges are broadly consistent with the values reported in the current period.

Table 10: VW#1 and VW#2 injection zone pressure monitoring.¹

	VW#2 (2,600 ft) ²				VW#1 (2,700 ft) ²	
Gauge Depth	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	3,148	3,214	2,729	3,235	3,149
Maximum	3,241	3,218	3,214	2,729	3,246	3,163
Avg ΔP	33	117	260	109	69.6	228
% Change	1.04%	3.85%	8.80%	4.17%	2.20%	7.80%
Max ΔP	33	187	260	109	81	241
% Change	1.04%	6.17%	8.80%	4.17%	2.56%	8.26%

Note 1: Data Collection Time Period = 1/1/23 - 12/31/23. Pressure reported as reservoir=psia & ΔP =psi.

Note 2: Approximate distance from injection well (CCS#2).

Figure 17 and Figure 18 chart the pressure and temperature of the four injection monitoring zones in VW#2 during the reporting period. We can clearly observe the lack of data for all the monitoring intervals outside of the injection zone due to instrumentation failure. As mentioned previously, ADM is currently working through recompletion process for VW#2. Meanwhile, VW#1 well is currently being used for both above-zone as well as in-zone monitoring purposes.

Figure 19 and Figure 20 show the downhole pressure and temperature for the two Mt. Simon monitoring zones in VW#1. These figures show a relatively flat pressure and temperature profile over the monitoring period and are consistent with the historic monitoring data. The spike in pressure observed from June is due to the VW#1 Zone 2b gauge malfunctioning. After reviewing with the vendor and a thorough root cause analysis, a modified SDA databox may have to be installed to gather relevant diagnostic information to rectify the issue with Zone 2b gauge. However, Zone 2a gauge had been functioning properly during these periods of erroneous data and they confirm far-field pressure response at the offset verification well location for reporting purposes. Figure 21 shows the downhole pressure and temperature for CCS#1. Greater fluctuations in reservoir pressure (Mt. Simon A – Lower unit) are observed unlike in

either VW#1 or VW#2 wells. Despite this artifact, the overall pressure response generally trends with the other Zone 1 gauges. Figure 22 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 22 where CCS#1 has a significantly higher-pressure response when compared to the closer monitoring well, VW#1. This indicates 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 23 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 trend highlighted in the previous reporting period (2022), this effect continues to be slightly more pronounced and is likely due to the higher CCS#2 injection rates post the chemical stimulation maintenance activity in January 2023 (Figure 2).

Figure 24 delineates the MESPOP (pressure front – 62.2 psi) predicted by the updated 2020 Eclipse model. The current pressure front extends approximately 9,790 feet from the injection well and covers an area of approximately 301 million ft². We expect the pressure and plume fronts to change after the history matching exercise planned in 2024.

Discussion of Results – Plume Tracking

Figure 25 delineates the current and final position of the estimated plume front as predicted by the 2020 Eclipse model. The current plume front has an area of 29.6 million ft² with an estimated boundary extending about 3,100 ft from the injection well. The figure also shows that the plume front passed VW#2 after injecting approximately 1.8 million Mt of CO₂.

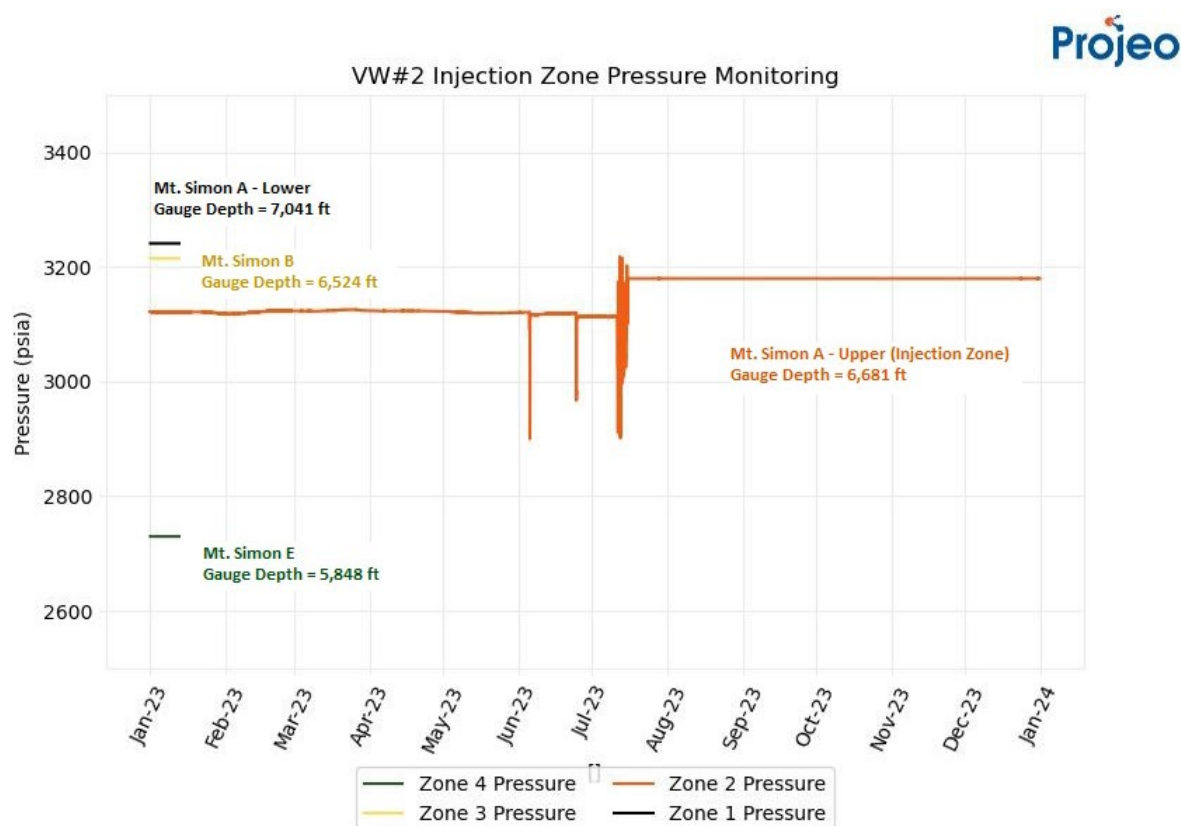


Figure 17: VW#2 injection zone pressure monitoring data for Jan-Dec 2023.

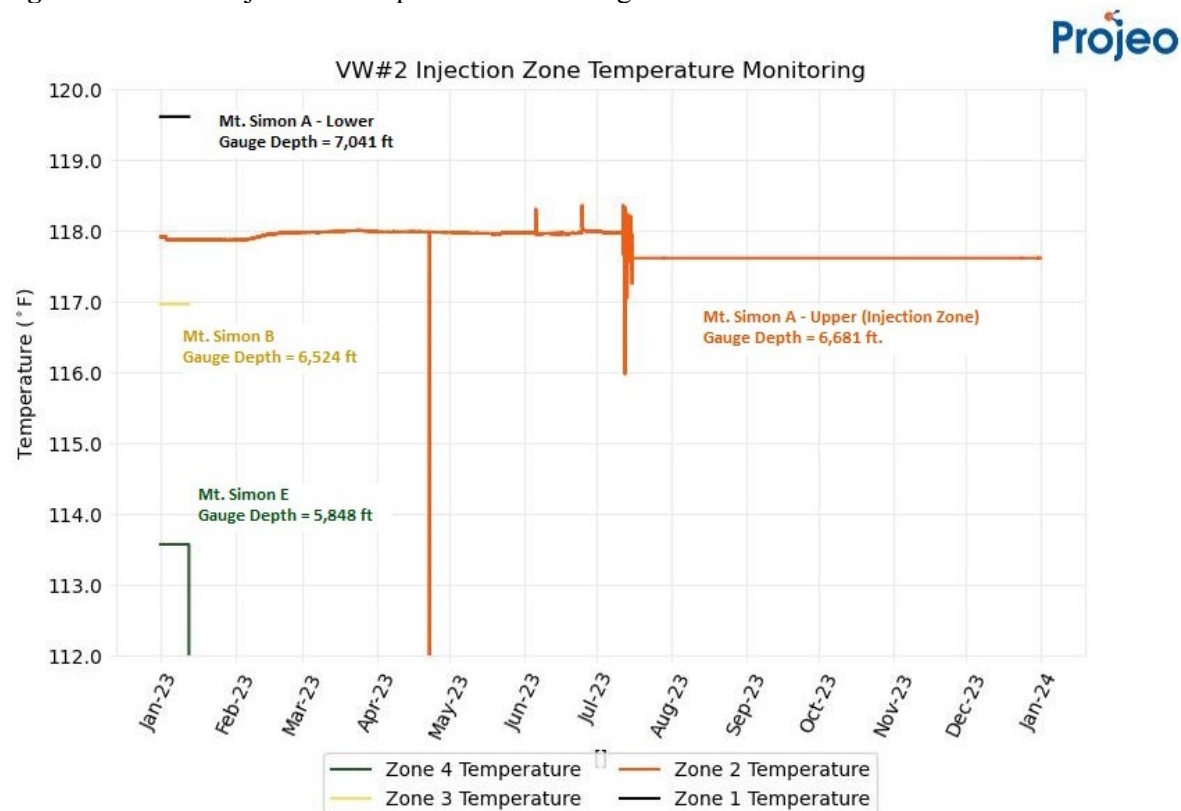


Figure 18: VW#2 injection zone temperature monitoring data for Jan-Jun 2023.

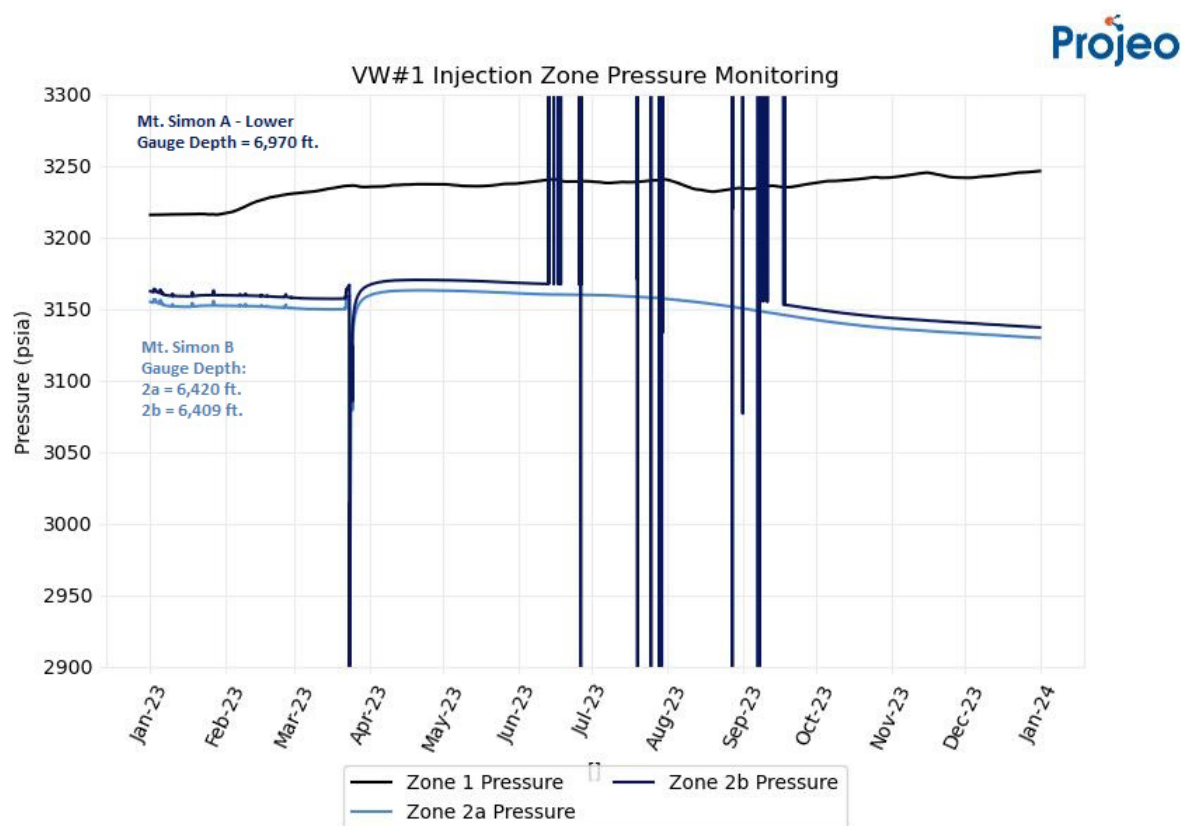


Figure 19: VW#1 injection zone pressure monitoring data for Jan-Dec 2023.

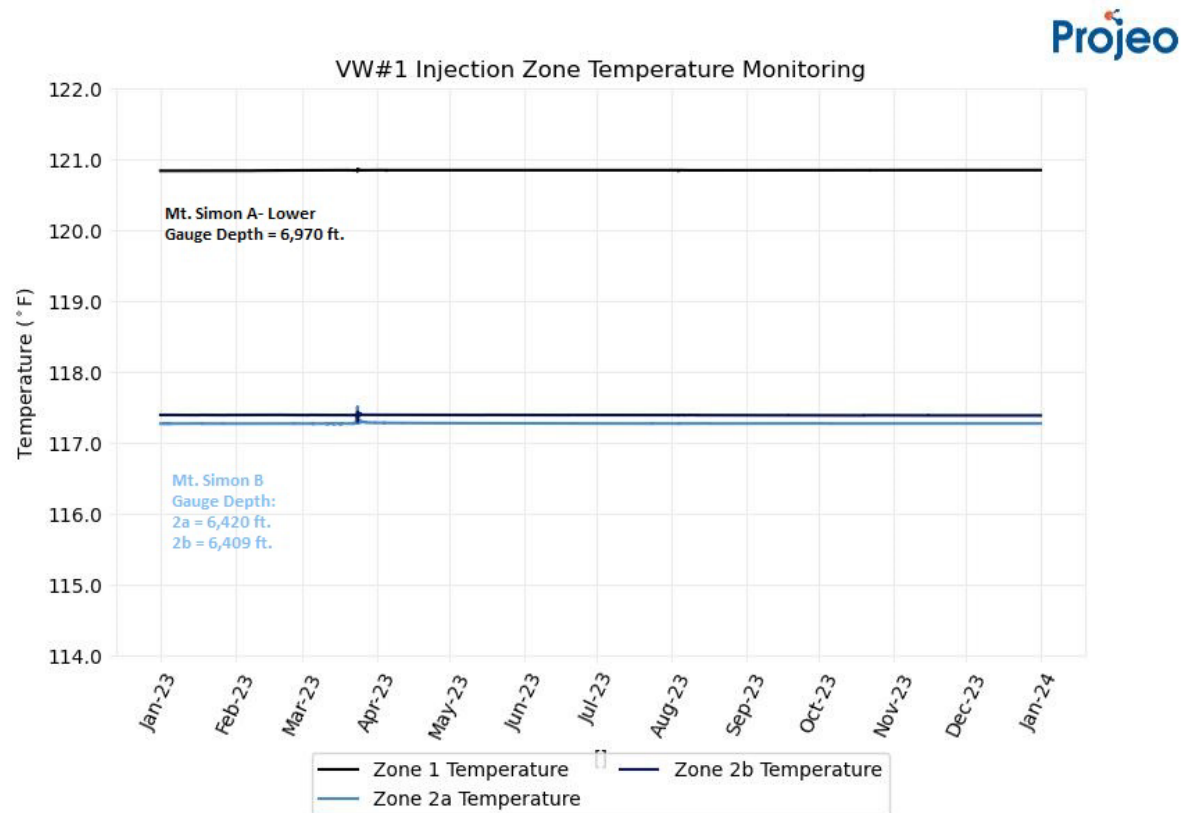


Figure 20: VW#1 injection zone temperature monitoring data for Jan-Dec 2023.

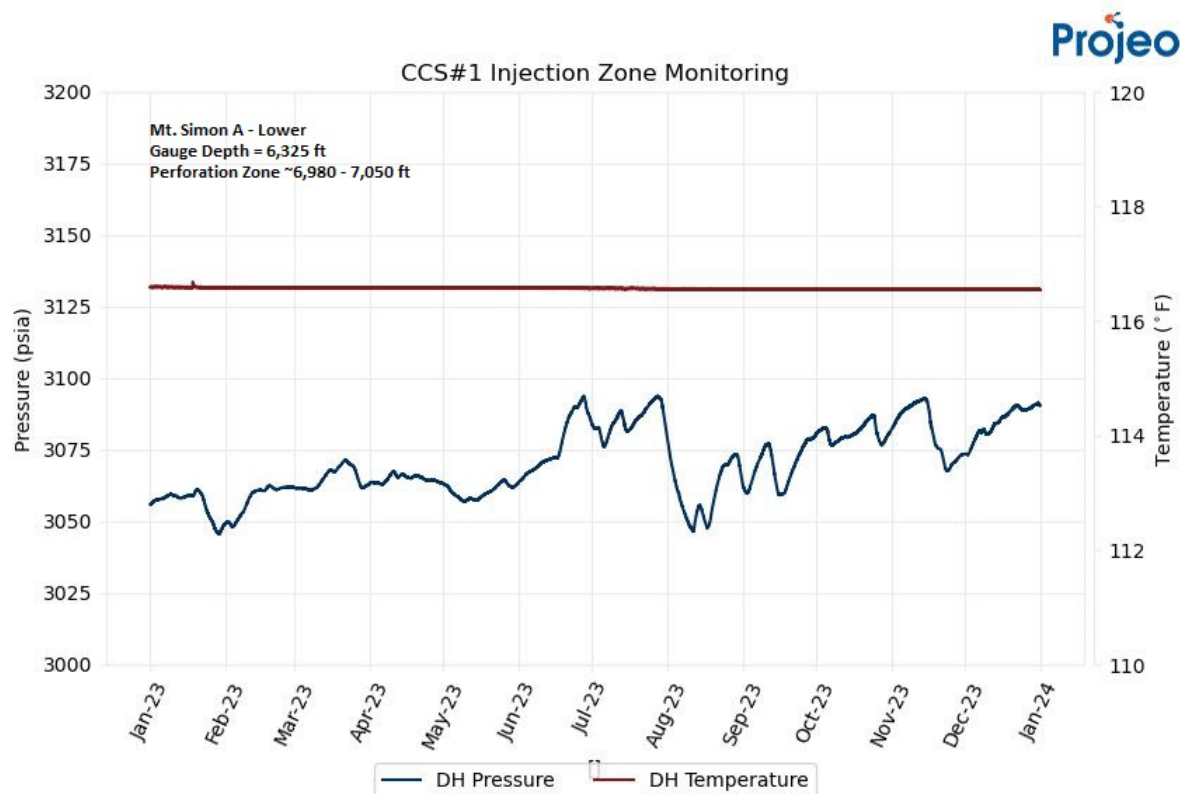


Figure 21: CCS#1 injection zone temperature & pressure monitoring data for Jan-Dec 2023.

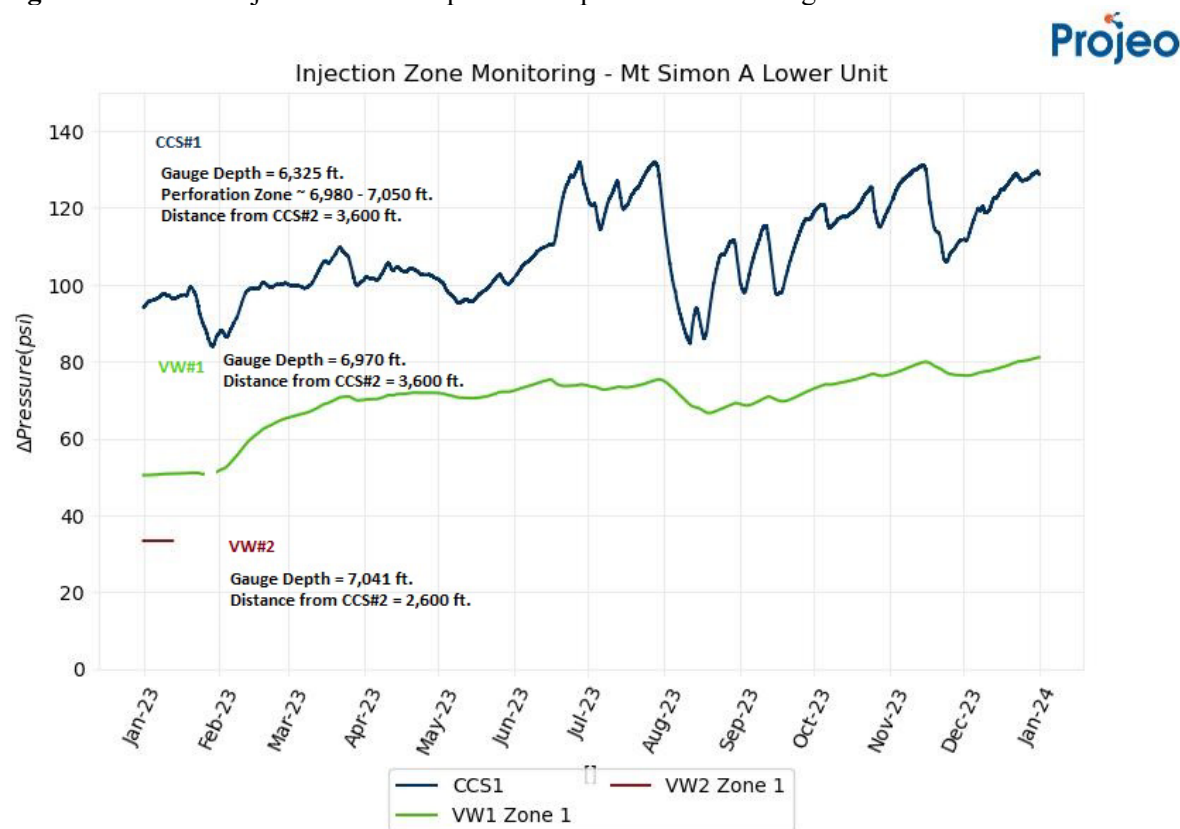


Figure 22: Comparison of the pressure change in the Mt. Simon A Lower at CCS#1, VW#1, and VW#2.

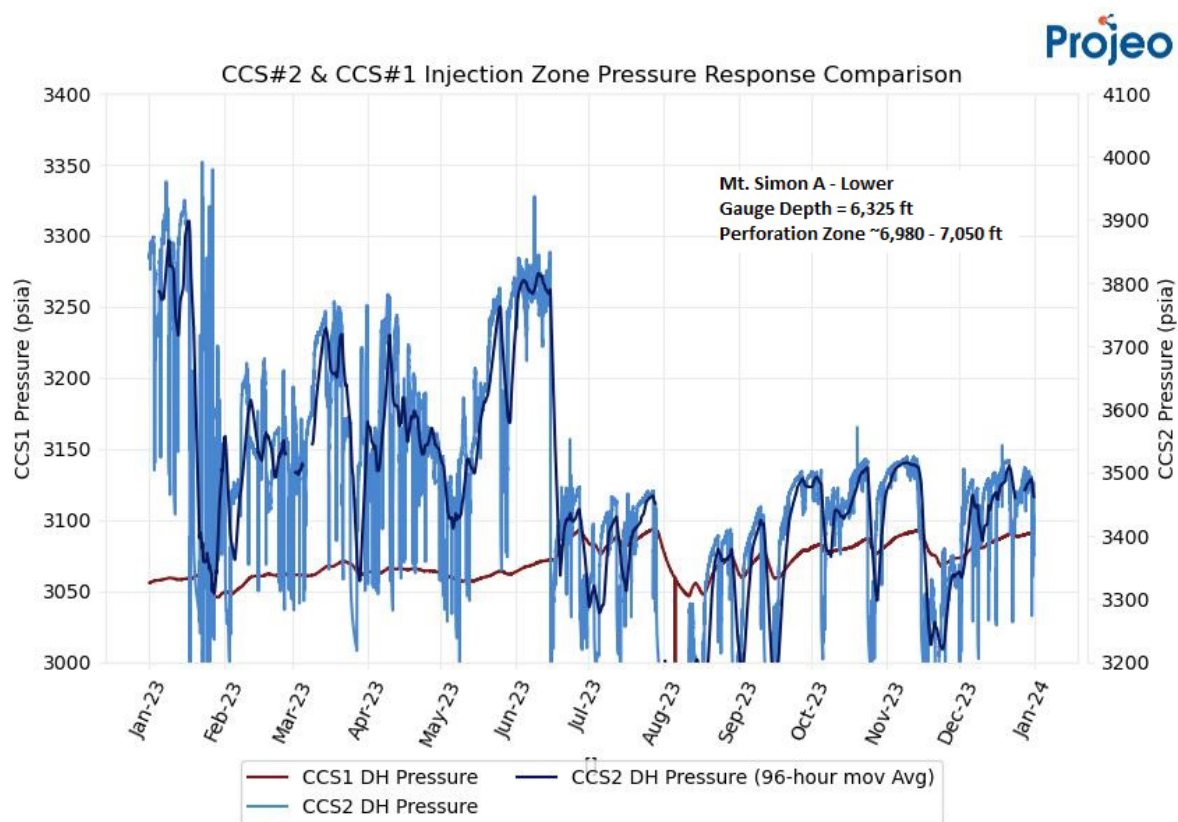


Figure 23: Comparison of the CCS#1 pressure response to CCS#2 injection pressure.

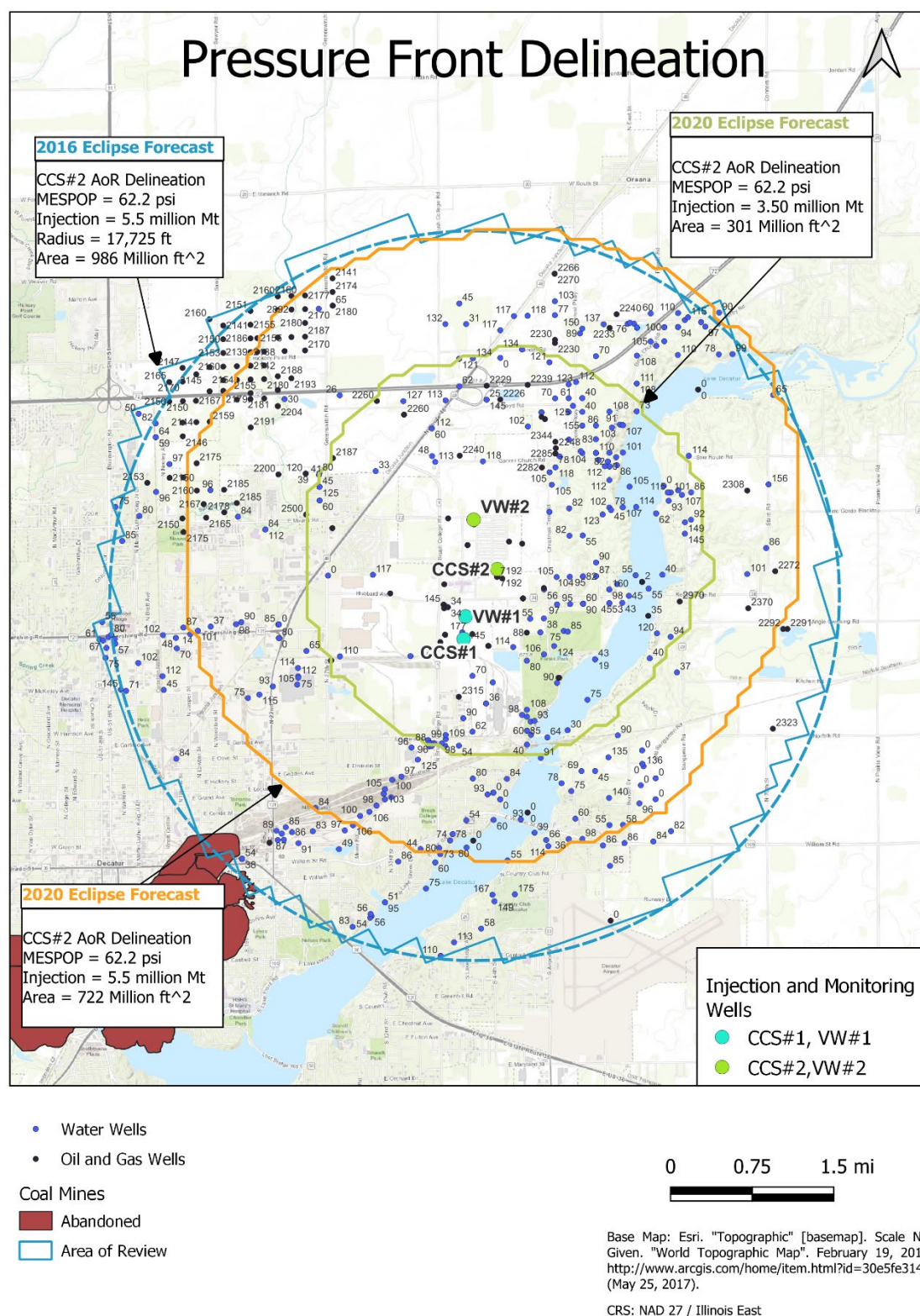


Figure 24: 2020 Eclipse model's pressure front delineation for December 31, 2023 and after the total injection of 6.5 million Mt (CCS#1=1.0 million Mt and CCS#2=5.5 million Mt).

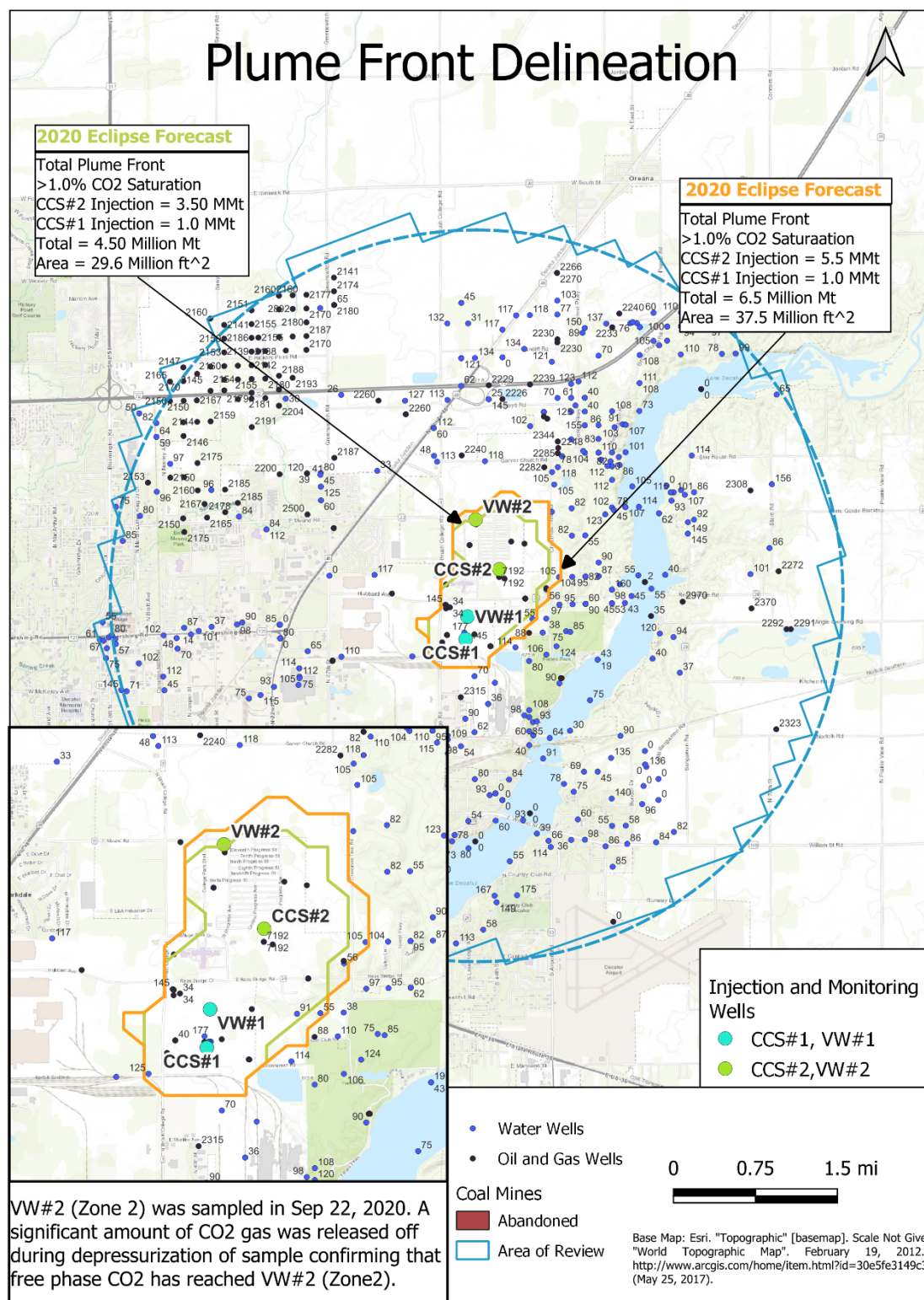


Figure 25: 2020 Eclipse model's plume front delineation for December 31, 2023 and after the total injection of 6.5 million Mt (CCS#1=1.0 million Mt and CCS#2=5.5 million Mt).

Supplemental Material

No supplemental information to be provided.

10. Other Testing and Monitoring

On March 24, 2023, the CCS#2 down hole pressure and temperature gauges were checked against a Pioneer Petrotech Services (PPS) quartz memory gauge (Model# PPS25) that was deployed into the well using slickline. Both the downhole tubing pressures and temperatures recorded on the quartz memory gauge and the CCS#2 downhole gauge are within the required accuracy range. The calibration report along with calibration data and certificate is submitted as supplemental information.

Calibration of the CCS#2 surface instruments was also conducted during the reporting period and the calibration certificates are submitted as supplemental information.

Testing of the CCS#2 automatic shutdown system was done on April 4, 2023, and the results were submitted to EPA in April 2023.

(20230414_CCS2_Automatic_Shutoff_Functionality_Demonstration.pdf).

Supplemental Materials

The gauge calibration reports have been uploaded to the GSDDT as follows:

DH Calibration Report:	202304_CCS#2_BHPT_Cert_Rpt.pdf
DH Calibration Data:	202304_CCS#2_BHPT_Cert_Data.xlsx
DH Calibration Certification:	202307_CCS2_DH_Gauge_Cal_Inst_Cert.pdf
Surface Calibration Certification:	202307_CCS2_Surface_Gauge_Cal_Inst_Cert.pdf