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:	July 28, 2023
Report period:	January 1, 2023 @ 00:00 hrs - July 1, 2023 @ 00:00 hrs
Report number:	32

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 07/01/2023 @ 00:00 hours. During the 12-month period, 255,751 metric tons (Mt) of CO_2 was injected at an average rate of 1,421 Mt/day resulting in a total mass of 3,208,827 Mt being injected into CCS#2 (See Figure 1). 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. The average downhole injection zone pressure was 3,576 psia versus the pre-injection pressure of 2,841 psia equating to an increase in reservoir pressure of 735 psi. The actual injection pressure has been tracking with the forecast injection pressure with a 3% bias versus the reservoir model. The above confining zone (ACZ) monitoring data at VW#1 and 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 a moderately elevated corrosion rate on the 13CR-L80 coupon during Q2 of 2023. This is inconsistent because the carbon steel coupons had low corrosion rates. The project team will further investigate this matter with our mechanical integrity group. 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.

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. ADM has detected completion equipment malfunctioning at the VW#2. As already reported, completion flow control valves in the Mt. Simon formation and multiple downhole pressure and temperature gauges have failed. ADM is currently in the process of recompleting this well and replacing the damaged gauges.

Maintenance, Inspection, & Annual Sampling

The annual deep groundwater sampling and the MIT activities were completed during Q1 and Q2 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. The Zone 1 (Mt. Simon A Lower), Zone 3 (Mt. Simon B), Zone 4 (Mt. Simon E), and Zone 5 (Ironton Galesville) gauges have essentially failed with <7% recording frequency for this reporting period. ADM is in the process of recompleting the VW#2 well to maintain the well's testing and monitoring requirements in accordance with USEPA Permit Number IL-115-6A-0001 Attachment C: Testing and Monitoring Plan. 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 CO_2 out of the injection zone. Zone 2 sliding sleeve has developed a leak but as reported previously, this leakage was a confined event. Temporary measures have been implemented by ADM to isolate the CO_2 leakage including installation of tubing and cement plugs, and closure of a downhole flow control valve and two wellhead valves at surface. 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 and after the workover , we expect to be able to obtain representative fluid samples from the monitored formations.

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 Differential Pressure	1	5	Communications Failure	2/25/2023 04:00 – 2/25/2023 09:00
Annulus Pressure	0	0	NA	NA
Trip Auto Shutdown System	1	7	Communications Failure	2/25/2023 03:10 – 2/25/2023 10:00

Note 1: Detailed description provided in Section 3.

Table 2. Recording frequency of VW#2 downhole gauges. Zone 1, 3, 4 and 5 gauges have stopped functioning and a recompletion is currently in progress.

Well	Zone	Depth	Formation	Gauge	Recording Frequency[1]
VW#2	Zone 5	5,027	Ironton Galesville	Pressure Temperature	0.00% 0.00%
	Zone 4	5,848	Mt Simon E	Pressure Temperature	6.42% 6.42%
	Zone 3	6,524	Mt Simon B	Pressure Temperature	6.42% 6.42%
	Zone 2	6,881	Mt Simon A – Upper *Injection Zone*	Pressure Temperature	100.00% 100.00%
	Zone 1	7,041	Mt Simon A - Lower	Pressure Temperature	6.42% 6.42%

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

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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	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(3)	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: Sampling of Zones 3 & 4 was suspended due to equipment failure. 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 two quarters (Q1-Q2 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 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 2023 2/17/23	Q2 2023 5/30/23	Unit (LOQ)	Analytical method
Carbon Dioxide	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	350	330	ppm v/v (10)	ISBT 4.0 (GC/DID)
Oxygen	29	43	ppm v/v (1.0)	ISBT 4.0 (GC/DID)
Carbon Monoxide	nd	nd	ppm v/v (2.0)	ISBT 4.0 (GC/DID)
Oxides of Nitrogen	nd	nd	ppm v/v (0.5)	ISBT 7.0 Colorimetric
Total Hydrocarbons	440	250	ppm v/v (0.1)	ISBT 10.0 THA (FID)
Methane	trace	0.4	ppm v/v (0.1)	ISBT 10.1 (GC/FID)
Acetaldehyde	100	30	ppm v/v (0.05)	ISBT 11.0 (GC/FID)
Sulfur Dioxide	nd	nd	ppm v/v (0.05)	ISBT 14.0 (GC/SCD)
Hydrogen Sulfide	16	6.6	ppm v/v (0.01)	ISBT 14.0 (GC/SCD)
Ethanol	200	120	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 CO_2 Analytical Report: ***20230217_Q1_2023_CO2_Analysis.pdf***
Q2 2023 CO_2 Analytical Report: ***20230530_Q2_2023_CO2_Analysis.pdf***

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

Discussion of Results
Figure 1 shows the injection rate monitoring data for the reporting period. During this period, a total of 255,751 metric tons (Mt) of CO_2 was injected at an average rate of 1,421 Mt/day. This contrasts with the average rate of 1,180 Mt/day during the previous reporting period (1/1/22 – 12/31/22). The maximum flowrate achieved was 2,456 Mt/day during which the wellhead pressure reached 1,477 psig. The fluctuations seen in the injection flowrate are due to plant slowdowns and shutdown of injection during the period which the operator conducted chemical stimulation maintenance in January of 2023 as well as backflow operations of CCS#2. Figure 2 trends the CCS#2 wellhead temperature and pressure data. During this period, the wellhead temperature and pressure averaged 85 °F and 1,412 psig, respectively. This contrasts with the average wellhead pressure of 1,720 psig observed during the previous reporting period indicating significant positive injection response from the chemical stimulation maintenance carried out at CCS#2.

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 (3575 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 operating condition exceedances monitoring 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 the identified exceedance was associated with a communication failure incidence in February.

Figure 3 trends the pressure maintained on the CCS#2 injection well annulus. During this period, the annulus pressure averaged 851 psig no annular fluid was added to the system. Figure 4 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 734 psi versus the baseline. The downhole injection temperature averaged 120 °F or a ΔT of 4.5 °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 698 psi.

On 25 February 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 failure indicate similar values (Figure 5), we believe that the mechanical integrity across the packer has not been impacted in any manner.

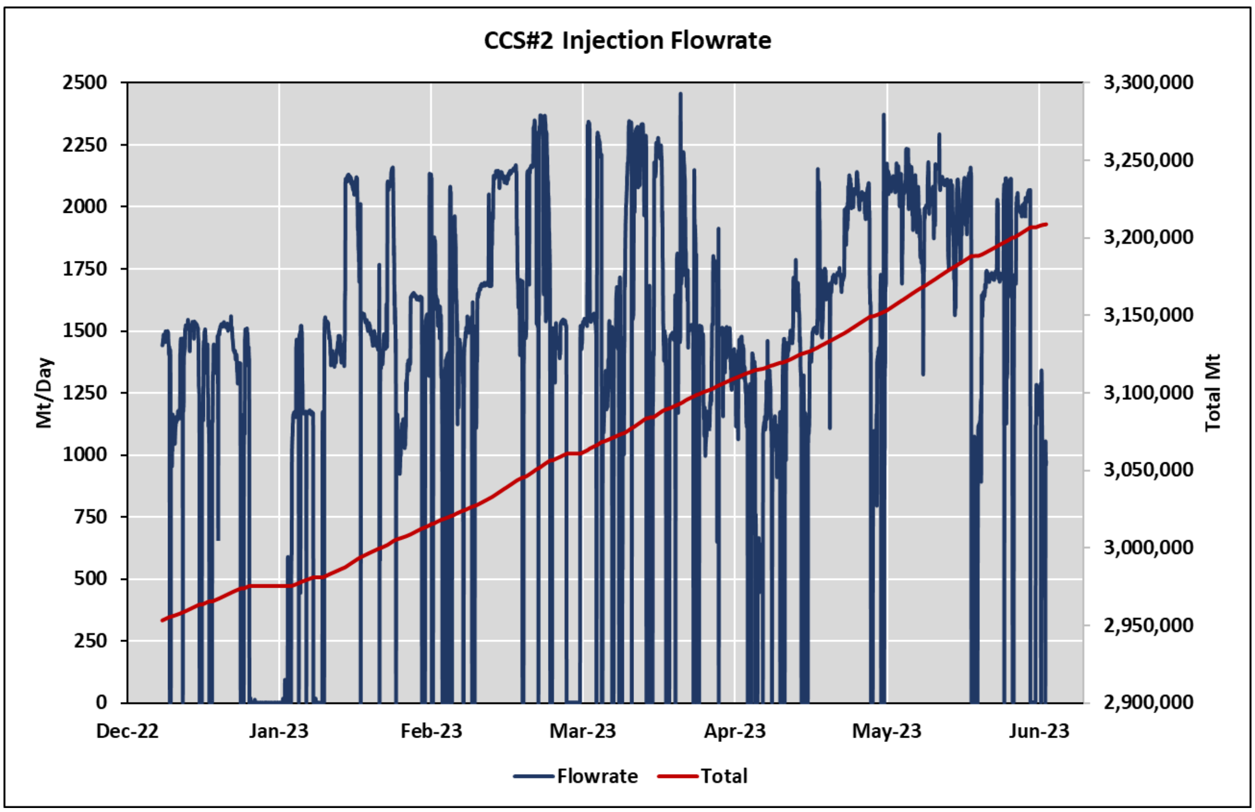

Figure 1: CCS#2 - Injection rate monitoring data for Jan-Jun 2023.

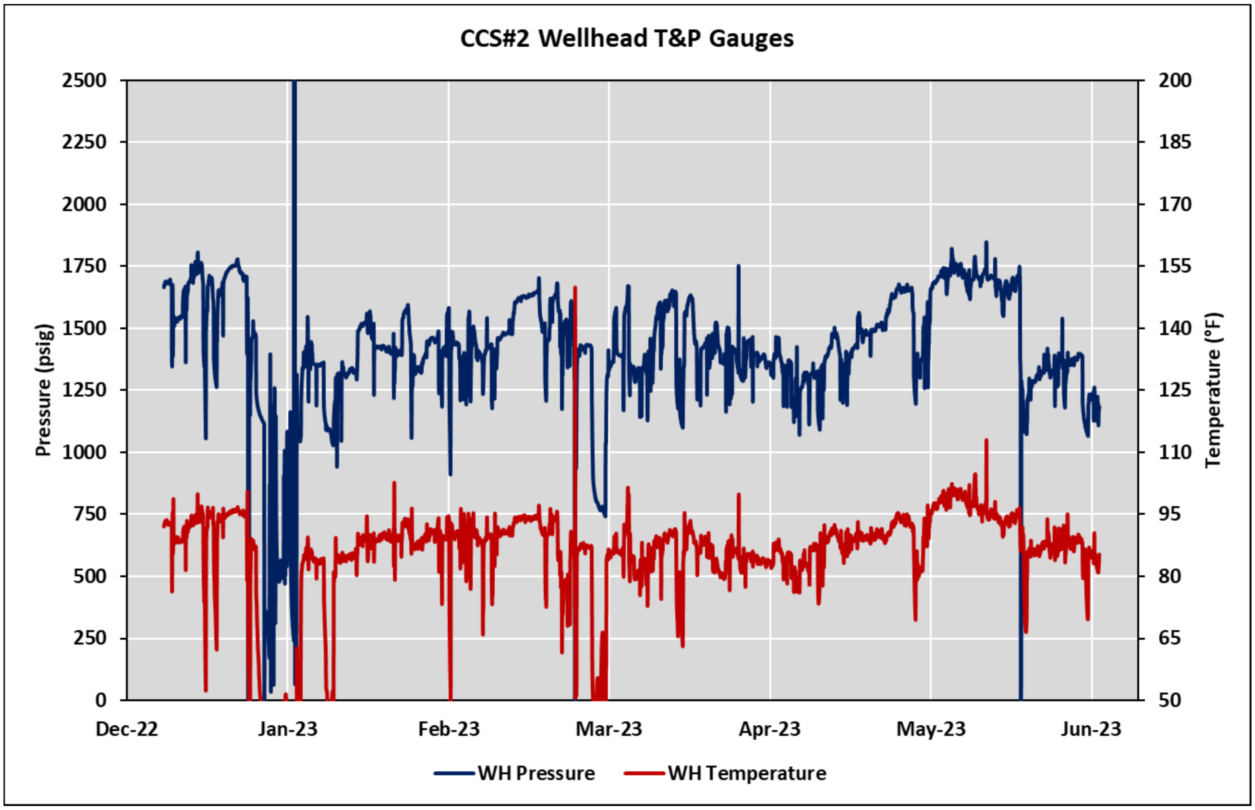

Figure 2: CCS#2 wellhead temperature and pressure monitoring data for Jan-Jun 2023.

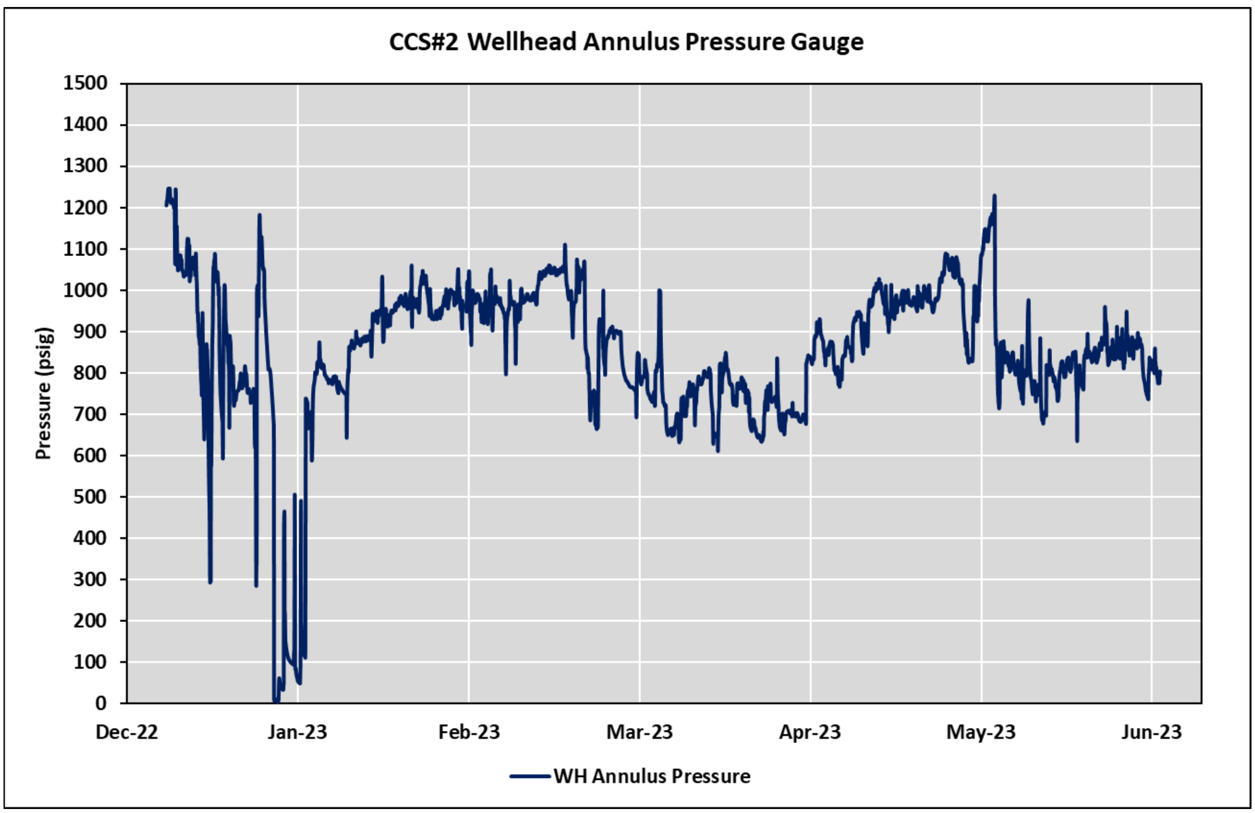

Figure 3: CCS#2 wellhead annulus pressure monitoring data for Jan-Jun 2023.

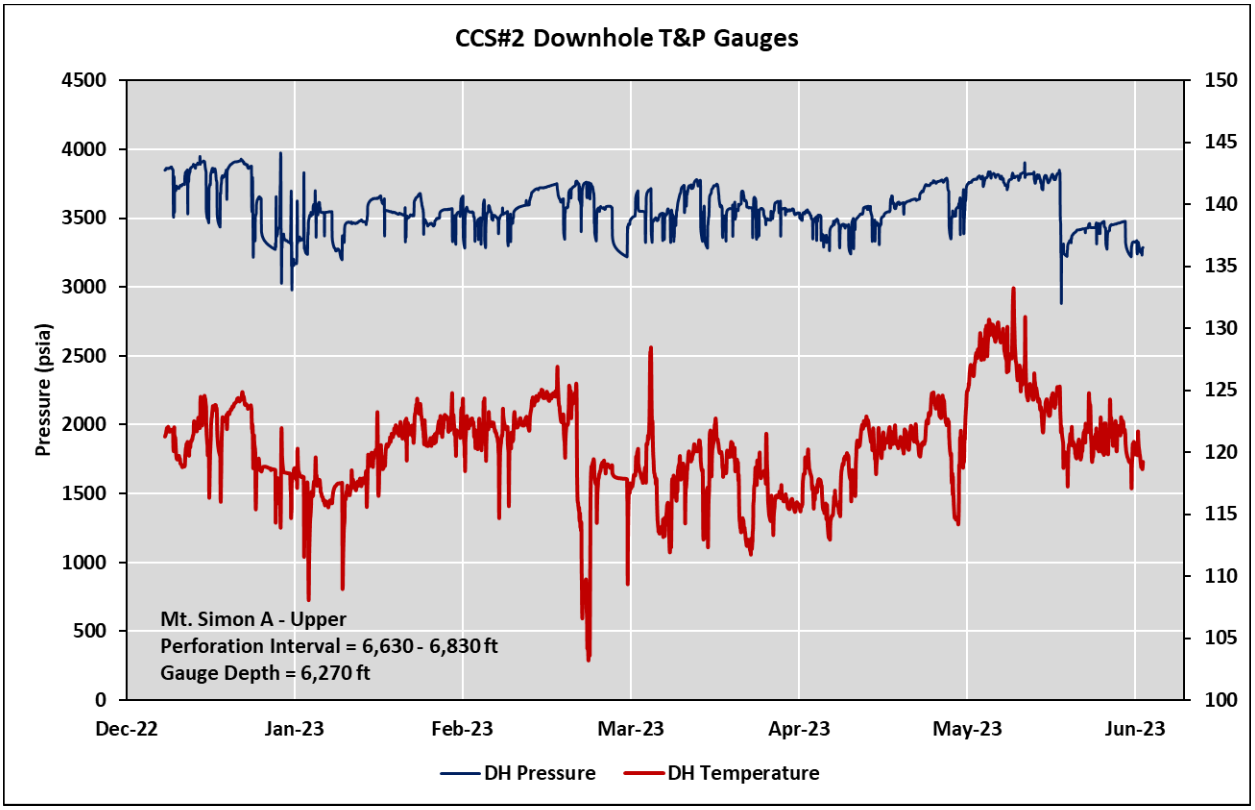

Figure 4: CCS#2 downhole temperature and pressure monitoring data for Jan-Jun 2023.

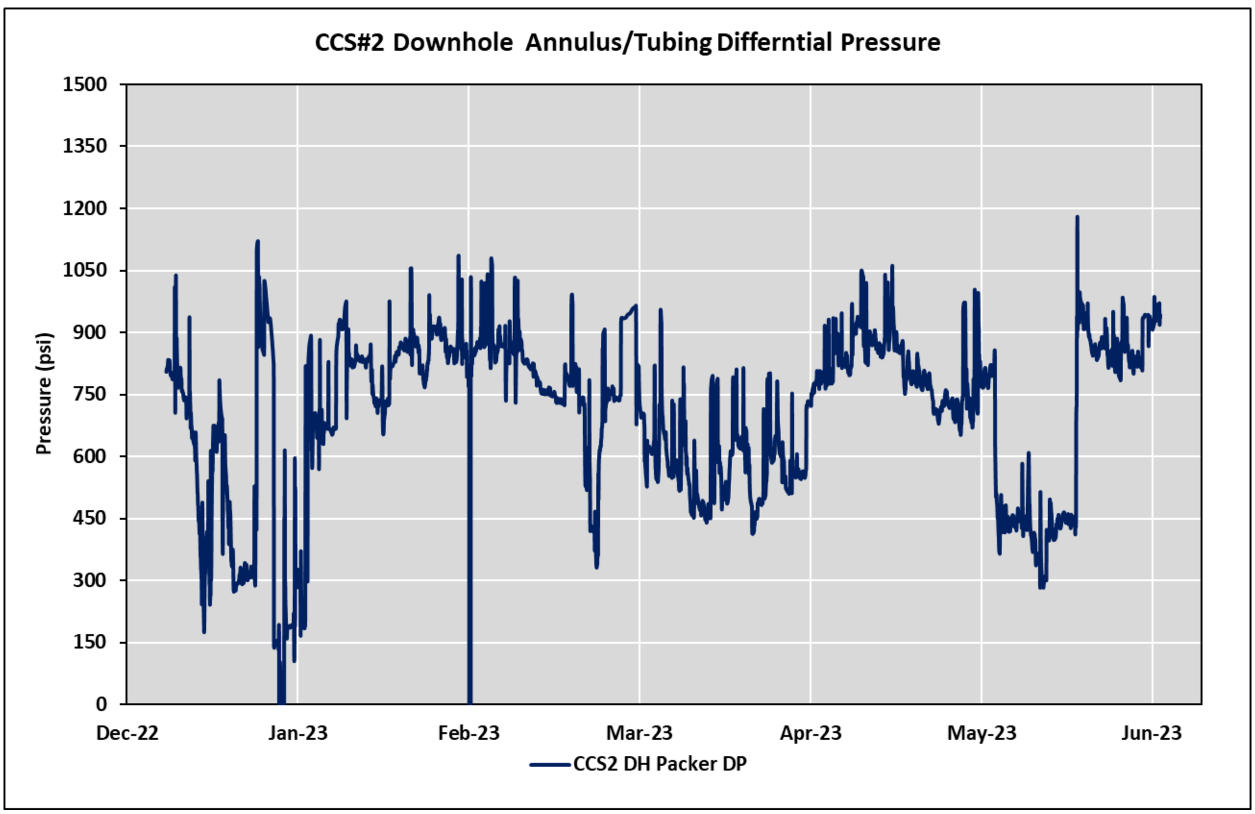

Figure 5: CCS#2 downhole annulus and tubing differential pressure monitoring data for Jan-Jun 2023.

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.

Parameter (Unit)	Reporting Period	Monthly Summary Values		
		Average	Minimum	Maximum
Injection Pressure (psig)	January 2023	1,335	0	3,000
	February 2023	1,380	915	1,595
	March 2023	1,416	0	1,703
	April 2023	1,408	1,099	1,751
	May 2023	1,453	1,072	1,743
	June 2023	1,478	0	1,848
Injection Rate (Mt/day)	January 2023	902	0	1,560
	February 2023	1,410	0	2,160
	March 2023	1,547	0	2,369
	April 2023	1,496	0	2,456
	May 2023	1,497	0	2,371
	June 2023	1,669	0	2,293
Injection Volume *Based on DH Reservoir T/P* (ft^3/day)	January 2023	40,259	0	70,527
	February 2023	65,672	0	107,048
	March 2023	76,731	0	117,118
	April 2023	74,104	0	121,447
	May 2023	69,909	0	117,562
	June 2023	86,486	0	120,296
Annular Pressure (psig)	January 2023	735	3	1,247
	February 2023	935	644	1,059
	March 2023	915	664	1,110
	April 2023	740	610	930
	May 2023	964	766	1,229
	June 2023	817	635	976

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: ***202306_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 42,625 Mt and the total amount injected was 255,751 Mt. At the end of the reporting period, the total mass of CO_2 injected into CCS#2 was 3,208,827 Mt. 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 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 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

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 an increase in corrosion rates on the 13CR-L80 coupon during Q2 of 2023. The coupons had visible signs of particulate formation (see Figure 6). After a review of the operations of the dehydration unit and onstream water analyzer, we believe that the elevated corrosion and particulates observed are likely a result of the coupon being hit with tar-like particulates of heavy oil components generated after the trans-critical phase of compression. 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.

Figure 6: Corrosion Coupon 13CR-L80 Q1-2023 (top figure) and Q2-2023 (bottom figure) shows particulates adhering to coupons.

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-Q2.pdf***
Corrosion Calculations: ***202305_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 2023	0.016	Low	Generalized
	5	Q2 2023	0.079	Low	Generalized
L-80 Long string casing <4,800 ft	6	Q1 2023	0.029	Low	Generalized
	5	Q2 2023	0.030	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

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

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 CO_2 above the confining zone. This

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
Gauge Depth[2]	3,450 ft - St Peter Sandstone	5,027 ft - Ironton Galesville	4,989 ft - Ironton Galesville	3,450 ft - St Peter Sandstone	5,027 ft - Ironton Galesville	4,989 ft - Ironton Galesville
Pre-Injection	1,396.7	2,112.1	2,086.0	94.8	103.6	104.4
Average	1,390.9	Fail	2,074.4	94.9	Fail	104.5
Delta	-5.8	Fail	-11.6	0.08	Fail	0.1
% Change	-0.4%	Fail	-0.6%	0.09%	Fail	0.1%

Note 1: Data Collection Time Period = 1/1/23 - 6/30/23. Pressure reported as reservoir=psia & dP=psi.
Note 2: Depths reported are gauge depths.
Note 3: Based on VW#2 DTS data.

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 CO_2 above the seal formation. The spike observed in the GM#2 trend data during the deployment of downhole pressure gauge on 4/18/23 is a false reading as suggested by the steady pressure and temperature values before and after the anomaly.

In previous reports, we have discussed issues surrounding downhole gauges in VW#2 including the intermittent shorting of the communications line as well as minor CO_2 leakage into the tubing from VW#2 Zone 2 sliding sleeve. This leakage was a confined event and temporary measures have been implemented by ADM to isolate the CO_2 leakage. Specifically, these measures included installation of tubing and cement plugs to prevent further leakage. Furthermore, a downhole flow control valve and two wellhead valves at surface were also closed to prevent further leakage. ADM is recompleting the well and will replace the damaged completion to allow accurate monitoring of the injection intervals.

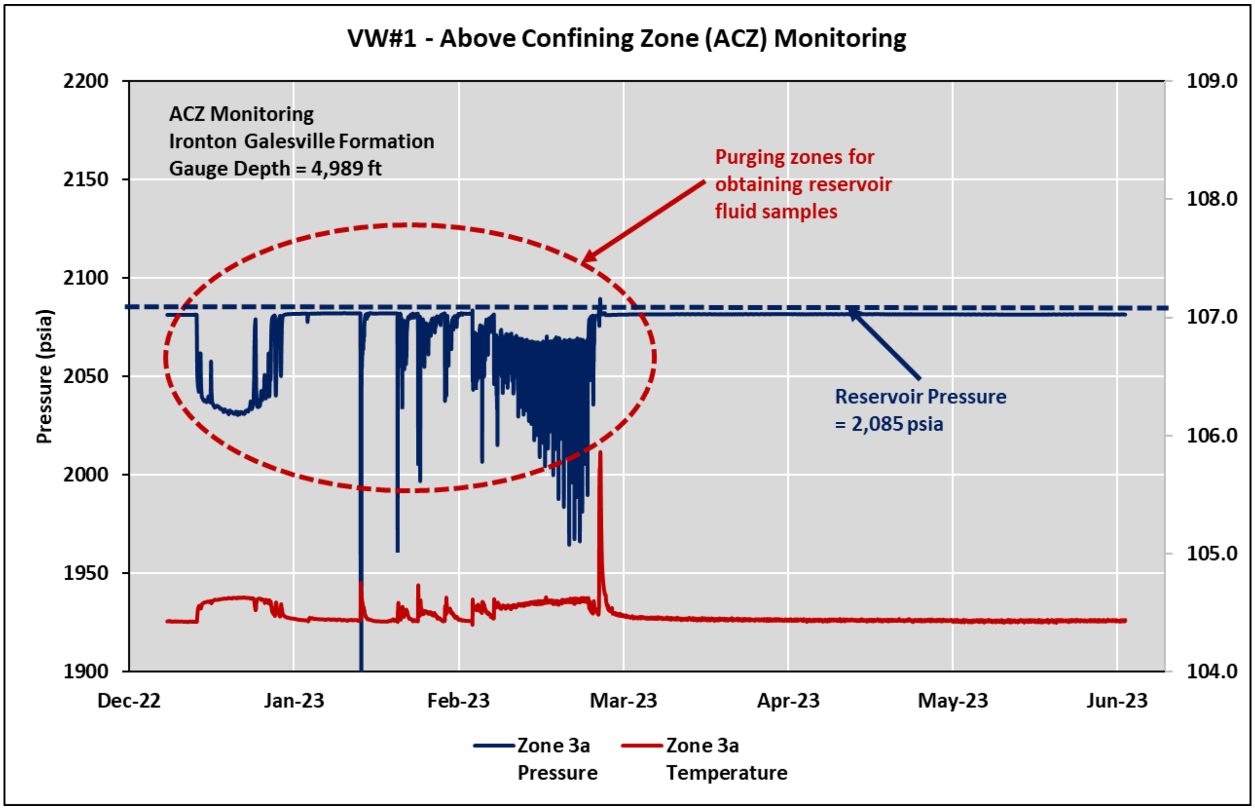

Figure 7: VW#1 ACZ monitoring of the Ironton Galesville Formation for Jan-Jun 2023.

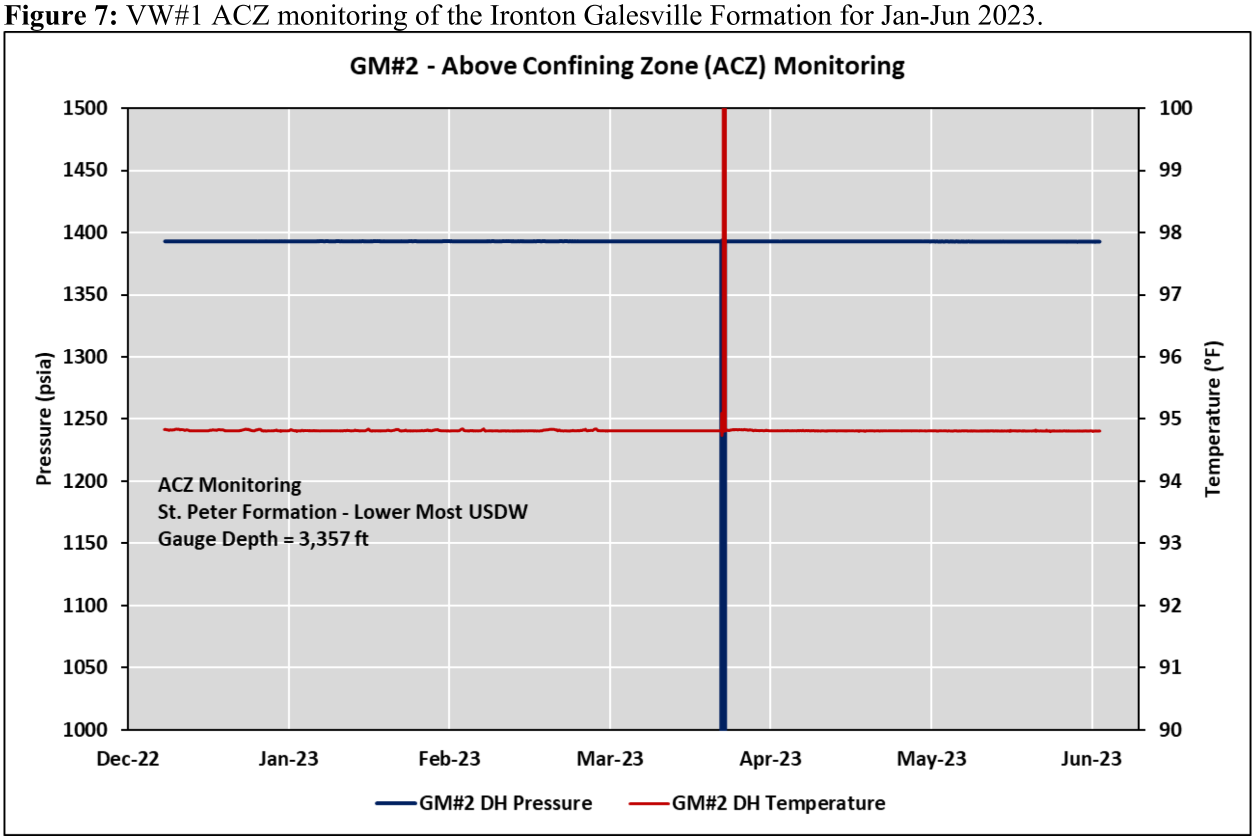

Figure 8: GM#2 ACZ monitoring of the St. Peter Formation for Jan-Jun 2023.

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 3,208,827 metric tons of CO_2 had been injected as of June 30, 2023. Because of the report's size, it is being submitted as supplemental material.

Since the last report (dated January 9, 2023), additional sampling events have occurred. Between October 19, 2022, and April 21, 2023, one shallow groundwater sampling event (April 2023) occurred. For deep well sampling, mechanical issues were encountered with well VW#2 that prevented the collection of samples that were representative of the formations being monitored. Instead, samples were collected from the Mt. Simon and Ironton-Galesville formations at well VW#1. To address the mechanical issues at VW#2, ADM is recompleting the well and will replace the damaged completion to allow accurate pressure and temperature monitoring as well as fluid sampling at the injection intervals. 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 January 9, 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 CO_2 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 CO_2 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***
GW COAs:	***202303_IL-115-6A-0001-0002_Deep_GWM_COA.pdf***
	202304_IL-115-6A-0001-0002_Shallow_GWM_COA.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 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 which will be resolved in future by re-calibrating the new interrogator. 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 June 25, 2023, is shown in Figure 9. This observation period is chosen due to constant flow rate and no operational activity at CCS#2. The smooth temperature profile indicates good well integrity and no movement of fluids/CO_2 behind the casing.

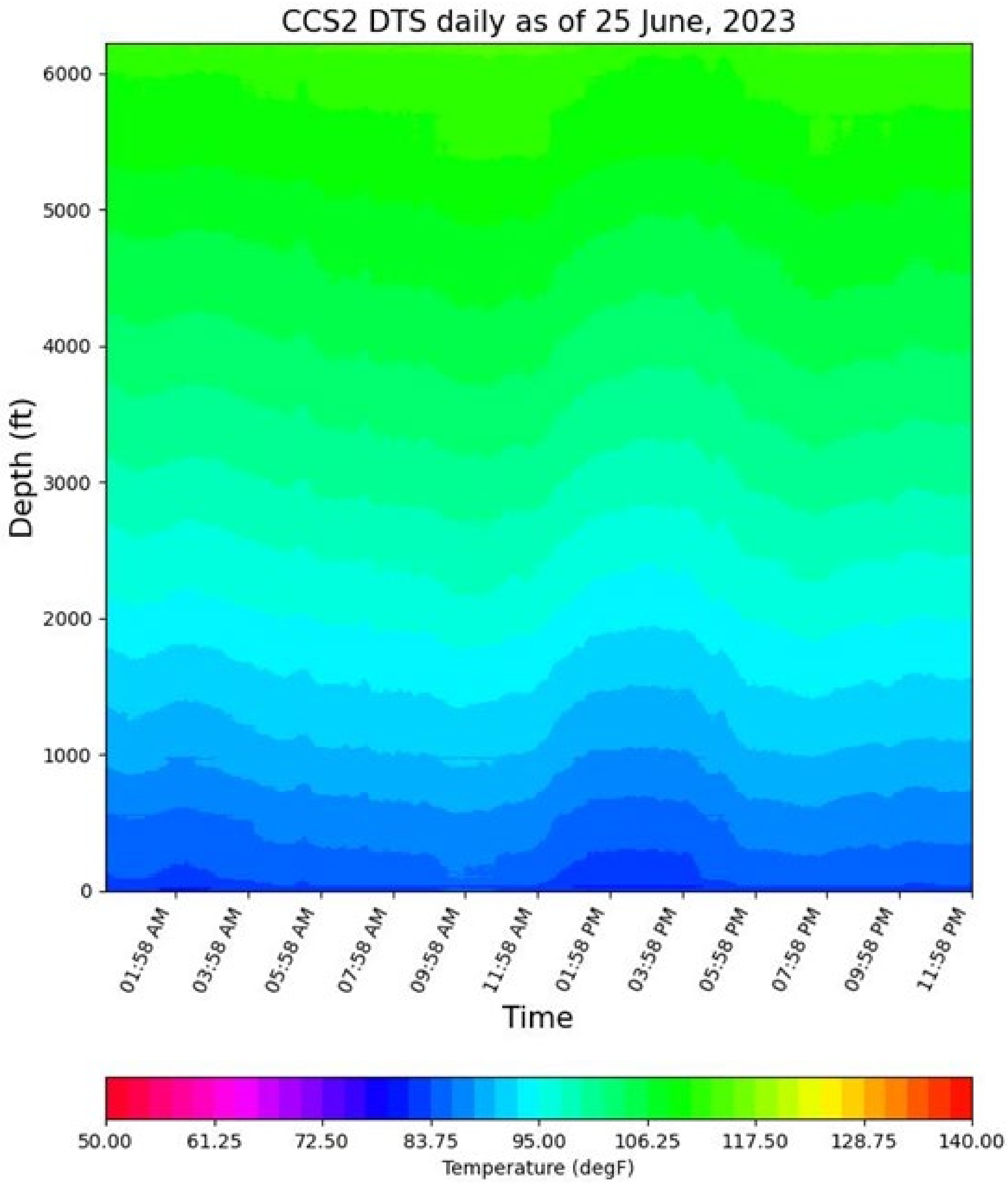

Figure 9: CCS#2 DTS data in 3-dimensional view for 06/25/2023.

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 CO_2 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 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 9 compares the actual reservoir pressure with the pressure forecast by the Eclipse model. The actual and forecast data have a good correlation. Except for VW#2 Zone 2 and Zone 3, the monitoring wells are within ~2% of the predicted pressures. The VW#2 Zone 2 and Zone 3 pressure gauges have a recording frequency of < 7% and this could be the likely cause of 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 3%, or 96 psi lower than the projected pressure. While in the past, we had observed higher pressures due to fouling at CCS#2 injection zone, the chemical stimulation performed in January 2023 has led to higher injectivity and lower bottom hole pressures.

Previous reports 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. From these figures, one can see close correlation between the predicted reservoir pressure response versus the actual response. These observations strongly support that the static geophysical (Petrel) and the dynamic reservoir flow (Eclipse) models well characterize the storage site, and the pressure and plume fronts are behaving as forecast in the model. Figure 12, Figure 14, and Figure 15 highlight bias that has developed in these gauges due to the equipment failure. Another bias is shown in Figure 16 which trends the CCS#1 injection zone pressure versus the model pressure. This bias can be due to unknown baffles or due to unresolved faults proximate to the interface of the Precambrian with the Mt Simon (Argenta) which is 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 and 4D seismic interpretation did not provide any additional insights into

this phenomenon. We hypothesize that the geological features may be thin enough to be below the detection threshold of seismic at depth and therefore, were not observable with the latest survey.

Table 9: 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	3,065	3,571	3,232	3,156	3163	3241	3,120	3,214
Forecast P	3,191	3,667	3,240	3,128	3122	3280	3,345	3,122
Delta P	125	96	8	28	40	39	224	92
% Delta	4.0%	2.7%	0.3%	0.9%	1.3%	1.2%	6.9%	2.9%

Note 1: Data Collection Time Period = 1/1/23 - 6/30/23. 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.

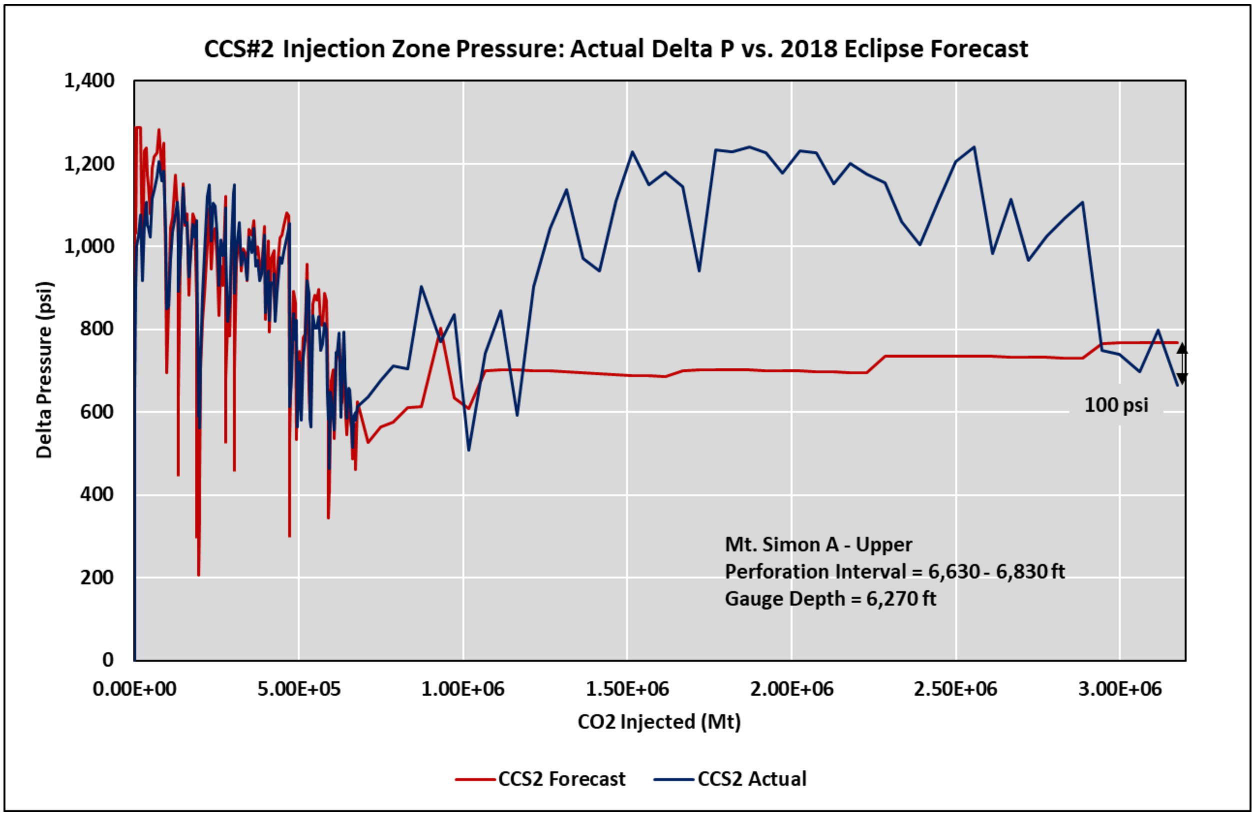

Figure 10: CCS#2 comparison of the downhole injection pressure versus the forecast pressure generated by the 2018 Eclipse reservoir model.

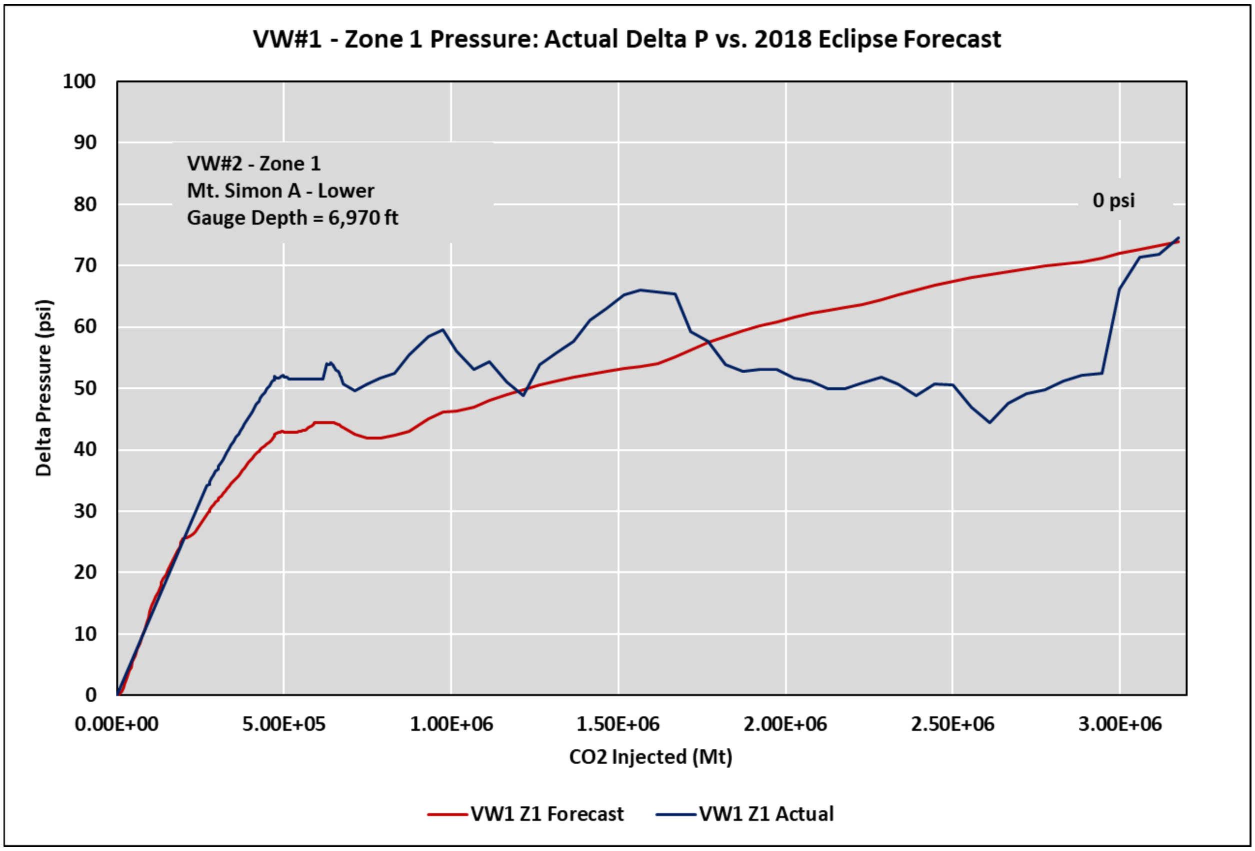

Figure 11: VW#1 Zone 1 differential pressure comparison of actual versus 2018 Eclipse model forecast.

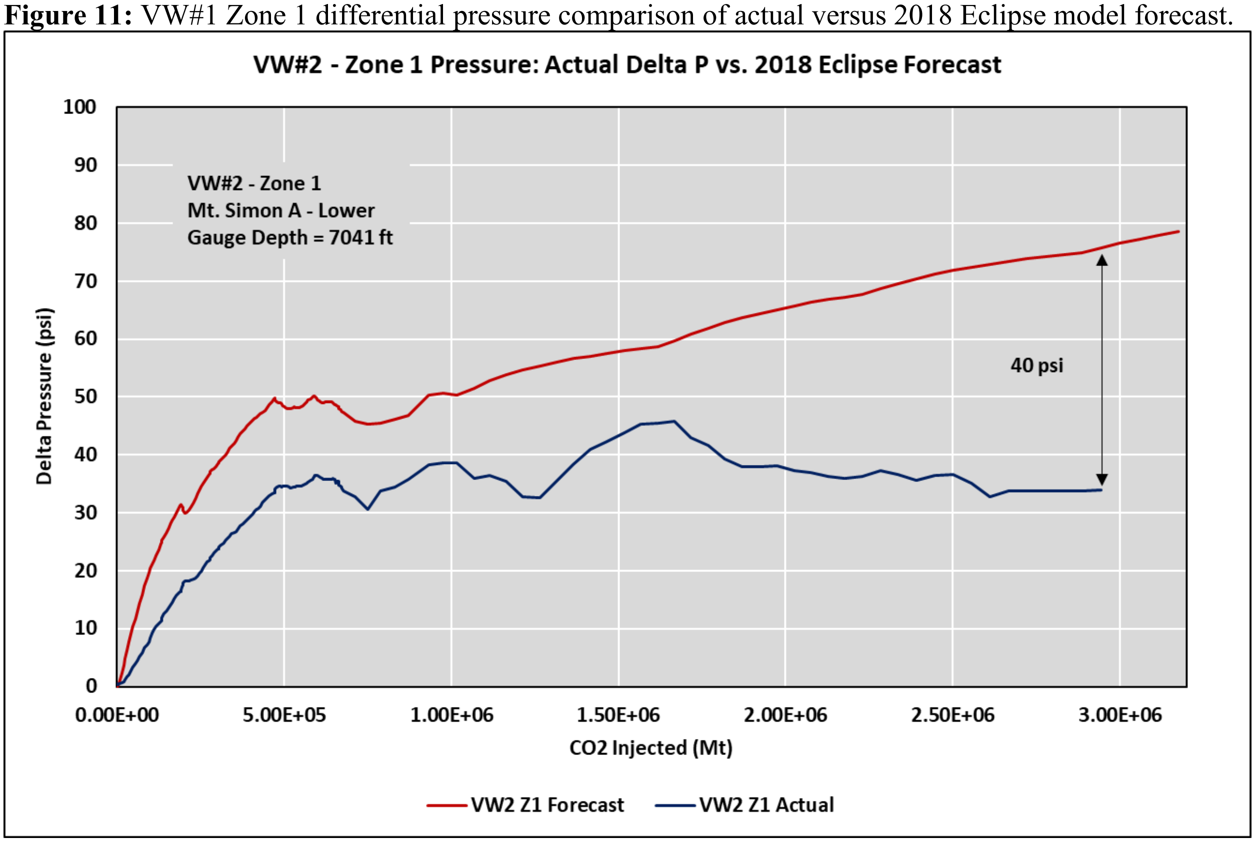

Figure 12: VW#2 Zone 1 differential pressure comparison of actual versus 2018 Eclipse model forecast.

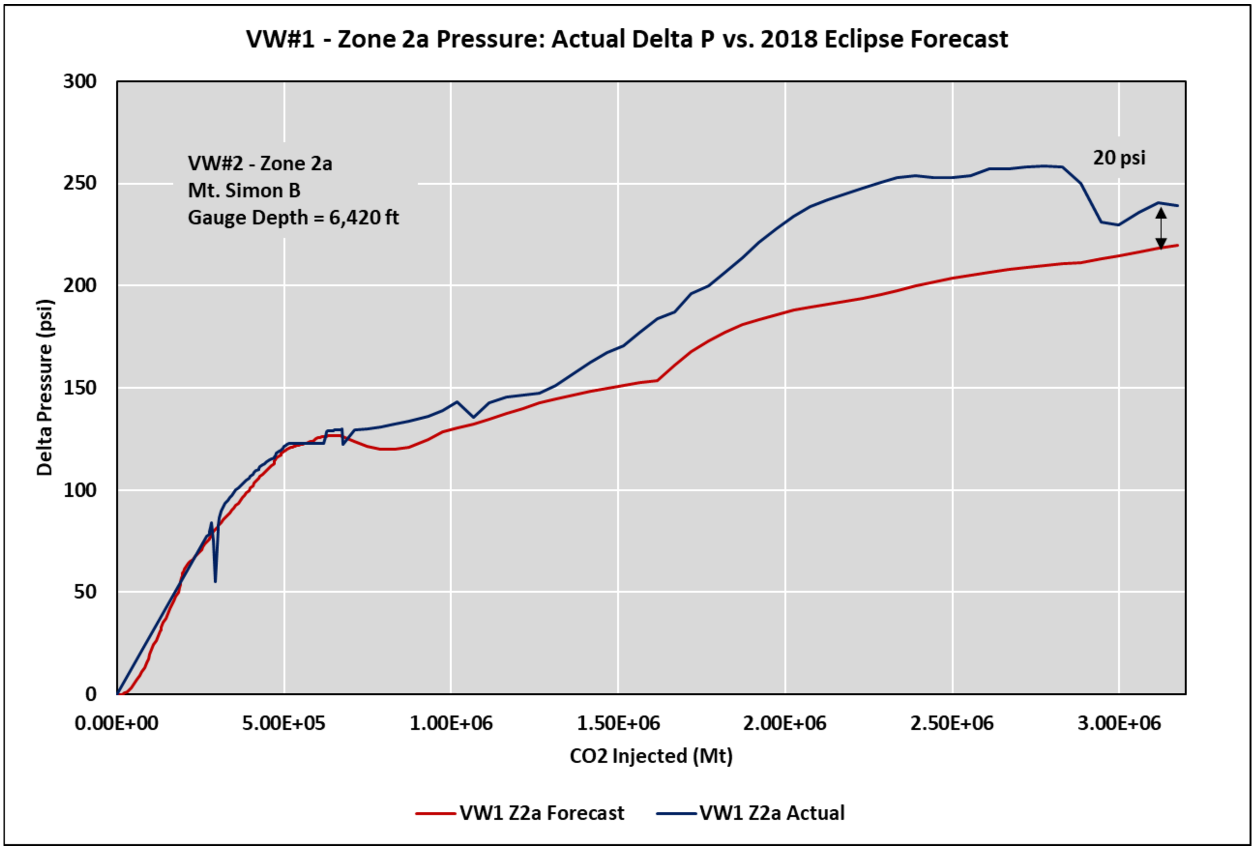

Figure 13: VW#1 Zone 2a actual reservoir differential pressure versus 2018 Eclipse model forecast.

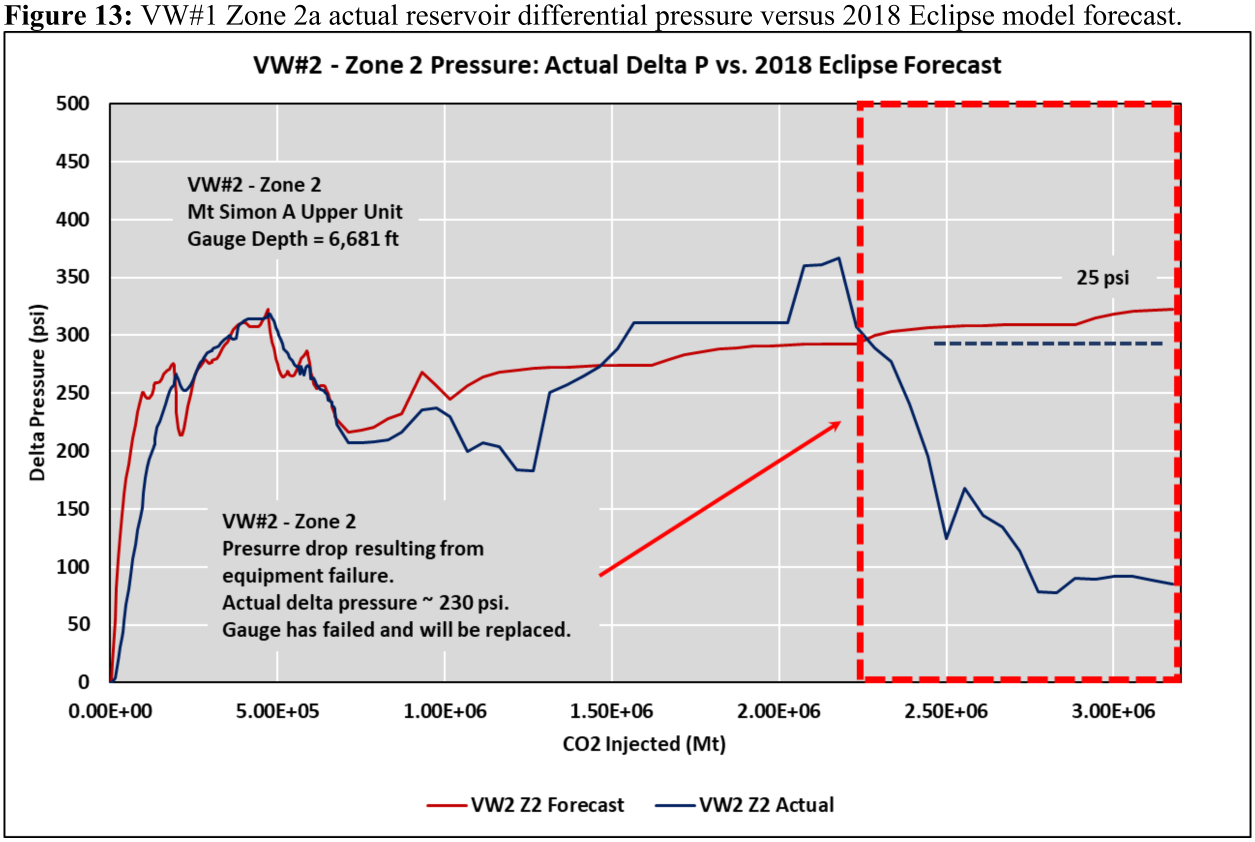

Figure 14: VW#2 Zone 2 actual reservoir differential pressure versus 2018 Eclipse model forecast.

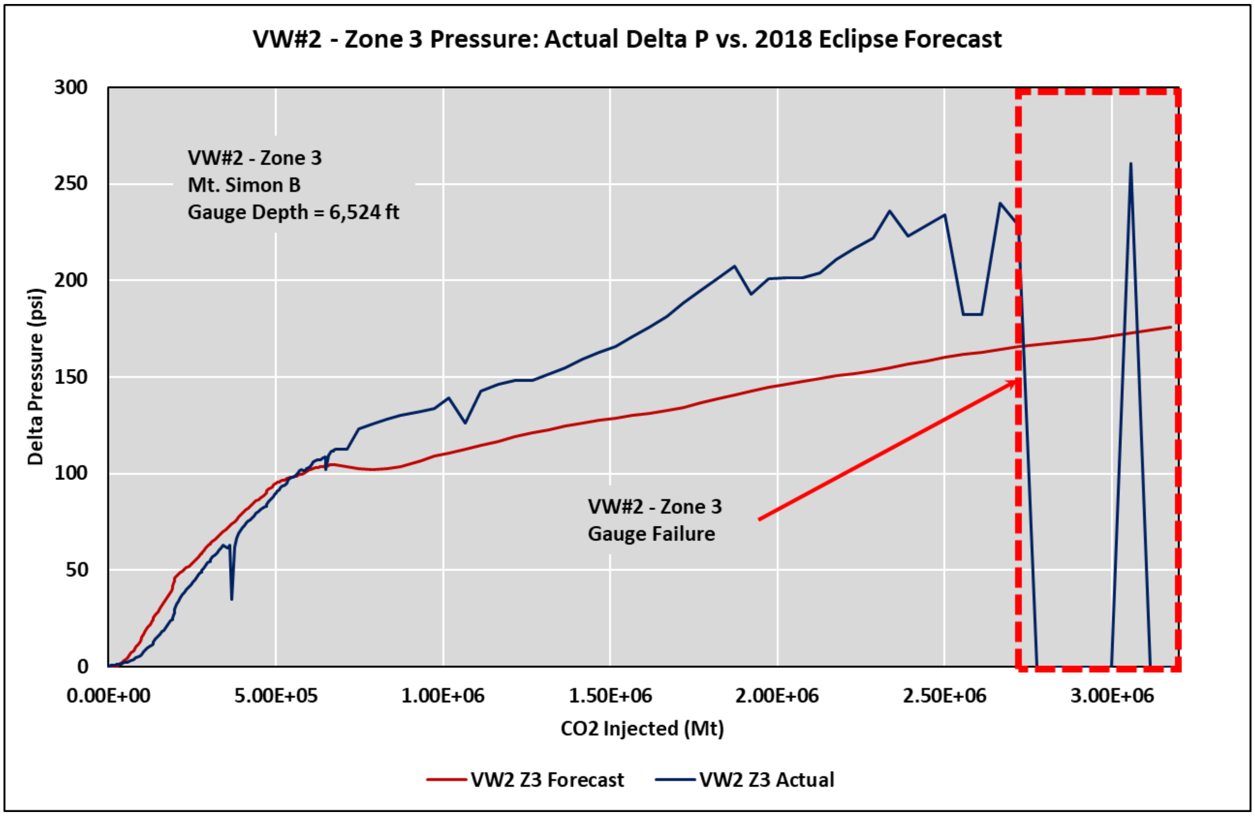

Figure 15: VW#2 Zone 3 actual reservoir differential pressure versus 2018 Eclipse model forecast.

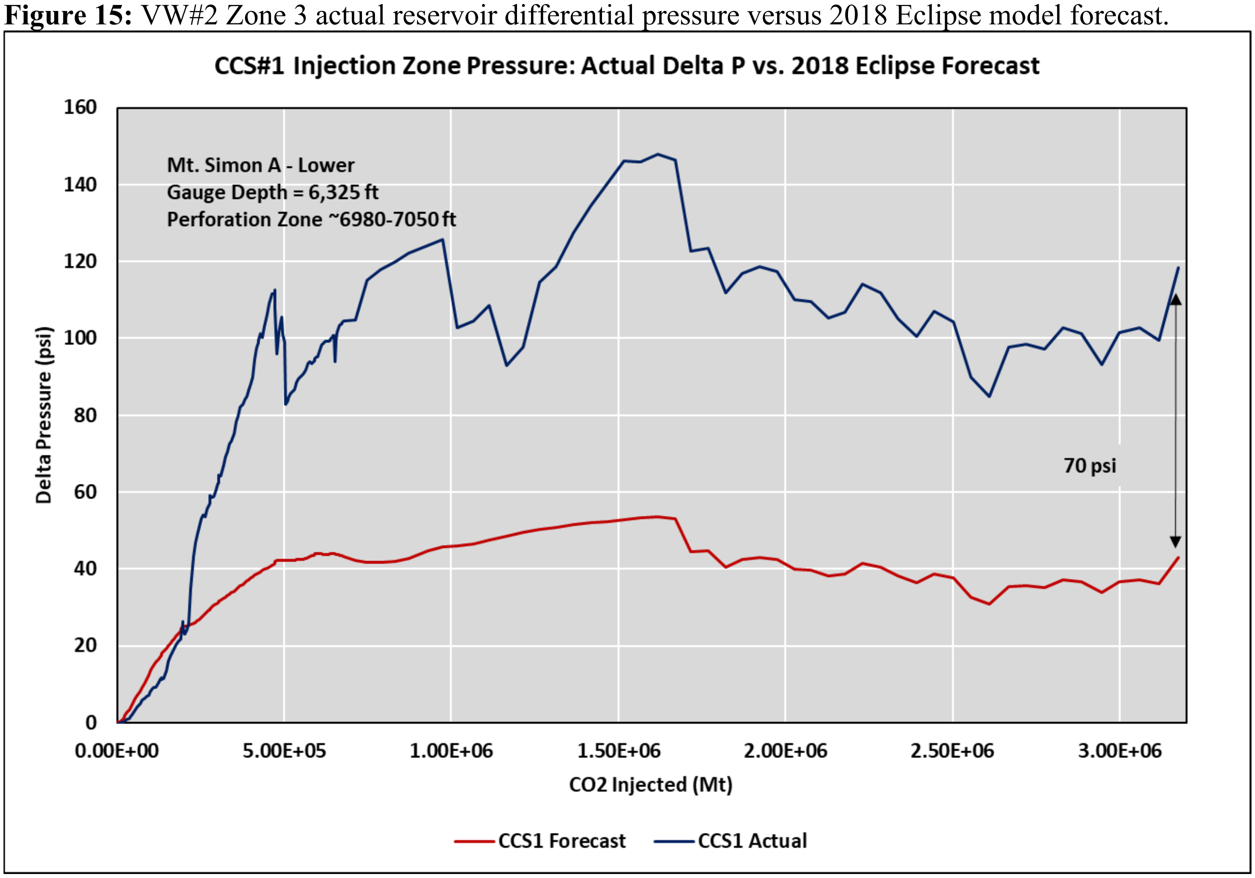

Figure 16: CCS#1 injection zone reservoir differential pressure versus 2018 Eclipse model forecast.

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 8.02% (ΔP=234 psi) in VW#1 and 8.8% (ΔP=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 < 7% 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 2.97% (ΔP = 90 psi). The corresponding value conveyed in the previous reporting period was 4.8% (ΔP = 145 psi) above the baseline pressure. The reduction in pressure could be due to the higher injection rate but the other monitoring zones do not support this conclusion. The change in the average pressure as observed is likely due to the intermittent electrical faults as has been discussed in previous reporting periods. 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 2.08% (ΔP = 66 psi) at VW#1 and 1.04% (ΔP = 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)[3]				VW#1 (2,700 ft)[3]	
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	3,121	3,214	2,729	3,231	3,156
Maximum	3,241	3,126	3,214	2,729	3,241	3,163
Avg ΔP	33	90	260	109	66	234
% Change	1.04%	2.97%	8.80%	4.17%	2.08%	8.02%
Max ΔP	33	95	260	109	75	241
% Change	1.04%	3.13%	8.80%	4.17%	2.38%	8.26%

Note 1: Data Collection Time Period = 1/1/23 - 6/30/23. Pressure reported as reservoir=psia & dP=psi.
Note 2: Depths reported are gauge depths.
Note 3: Approximate distance from injection well (CCS#2).

Figure 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 most of the monitoring intervals outside of the injection zone due to instrumentation failure. ADM is recompleting the well and will replace the damaged completion to allow accurate monitoring at the injection intervals.

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 and is currently being reviewed. 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, this effect is slightly more pronounced and is likely due to the higher CCS#2 injection rates post the chemical stimulation maintenance activity in January 2023 (Figure 1).

Figure 25 delineates the MESPOP (pressure front – 62.2 psi) predicted by the updated 2018 Eclipse model. The current pressure front extends approximately 11,450 feet from the injection well and covers an area of approximately 411 million square feet. Note that this assumes that the pressure front is symmetrical away from the injection zone.

Discussion of Results – Plume Tracking

Figure 25 delineates the current and final position of the estimated plume front as predicted by the 2018 Eclipse model. The current plume front has an area of 42.8 million ft^2 with an estimated boundary extending about 3,690 ft from the injection well. The figure also shows that the plume front passed VW#2 after injecting approximately 1.8 million Mt of CO_2.

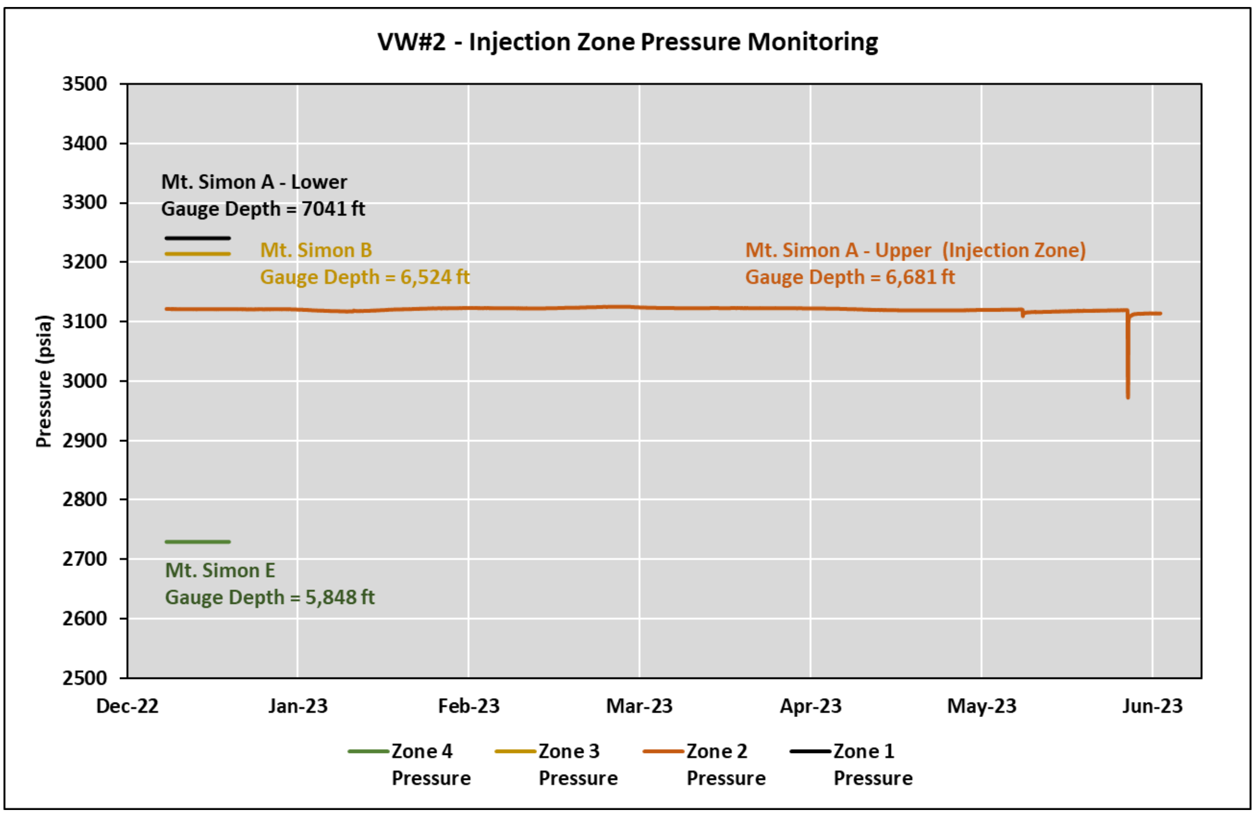

Figure 17: VW#2 injection zone pressure monitoring data for Jan-Jun 2023.

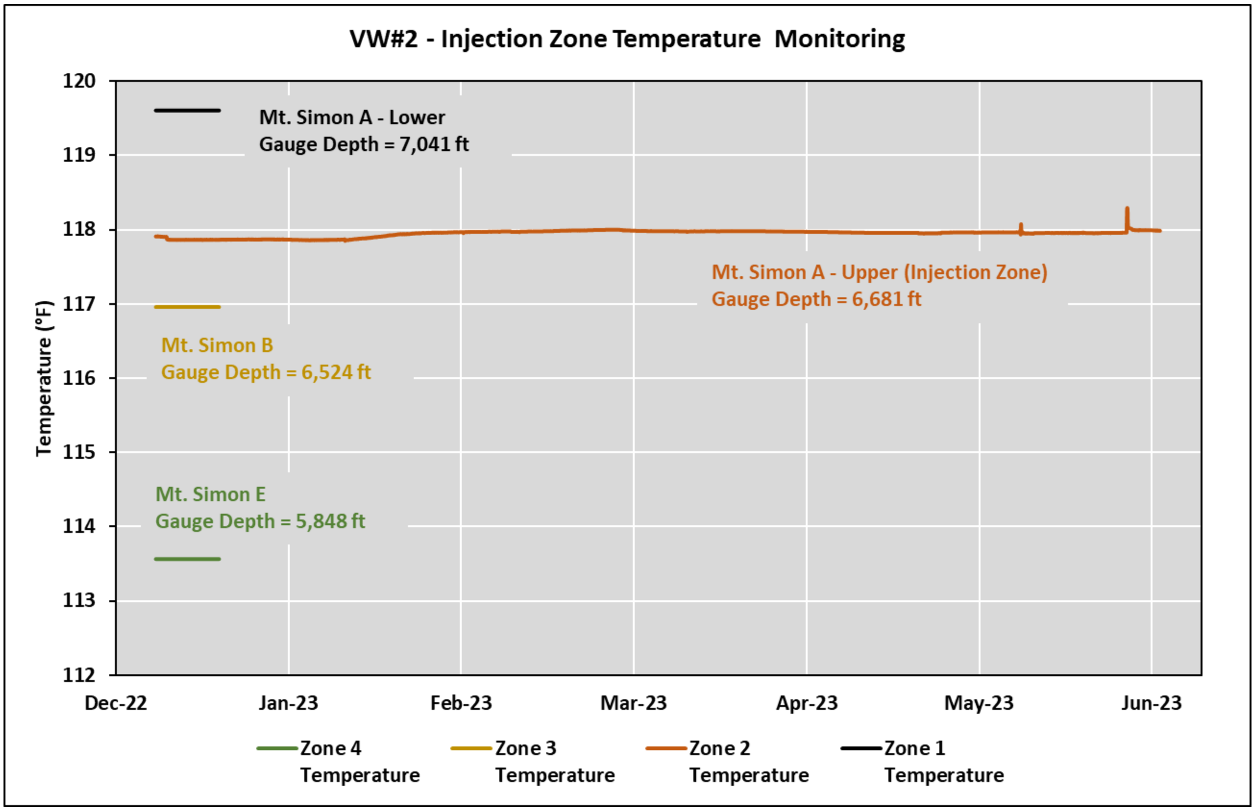

Figure 18: VW#2 injection zone temperature monitoring data for Jan-Jun 2023.

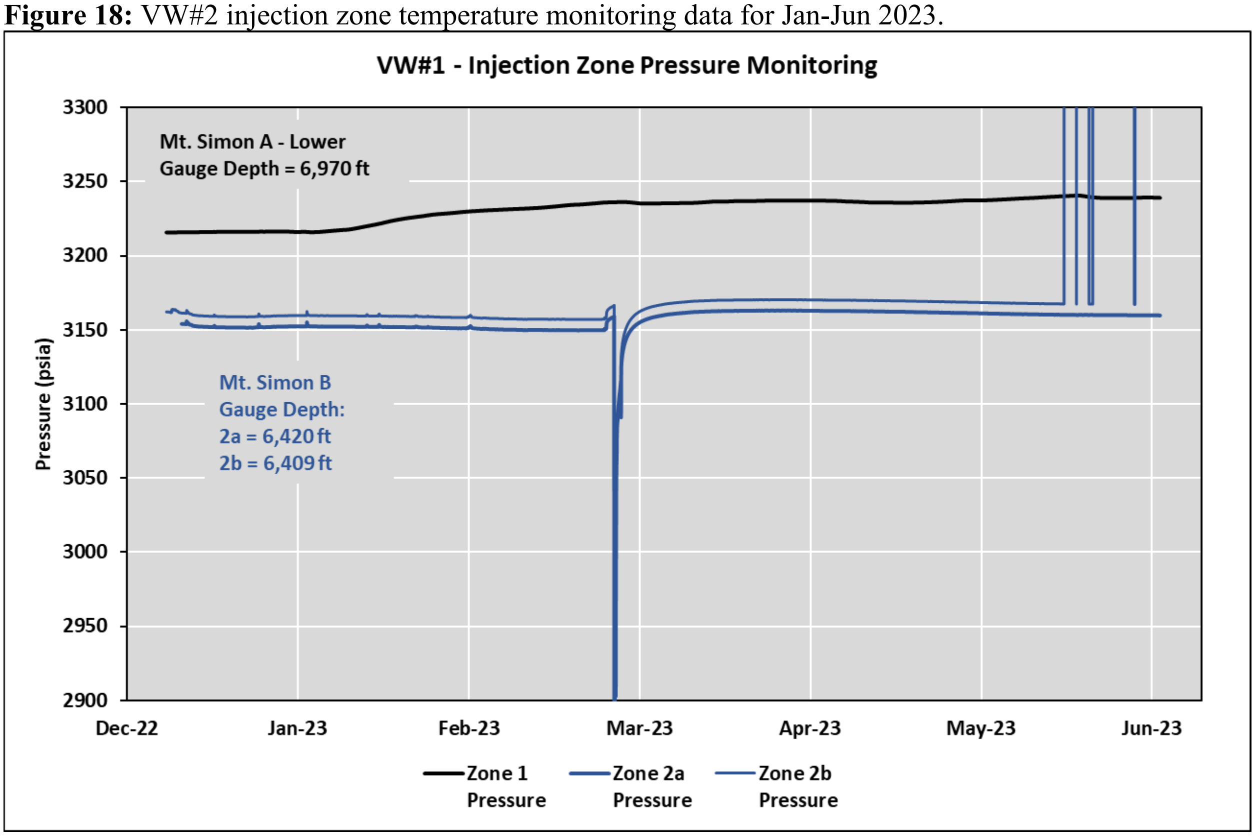

Figure 19: VW#1 injection zone pressure monitoring data for Jan-Jun 2023.

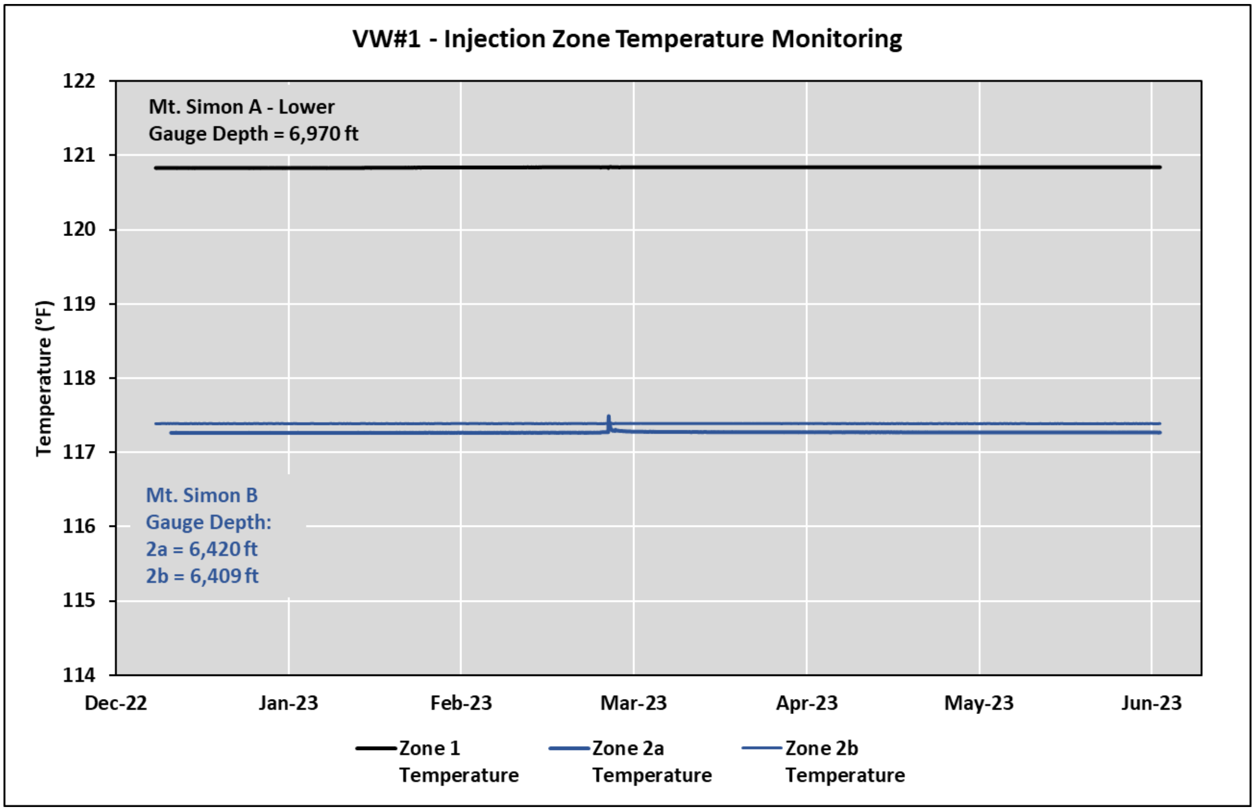

Figure 20: VW#1 injection zone temperature monitoring data for Jan-Jun 2023.

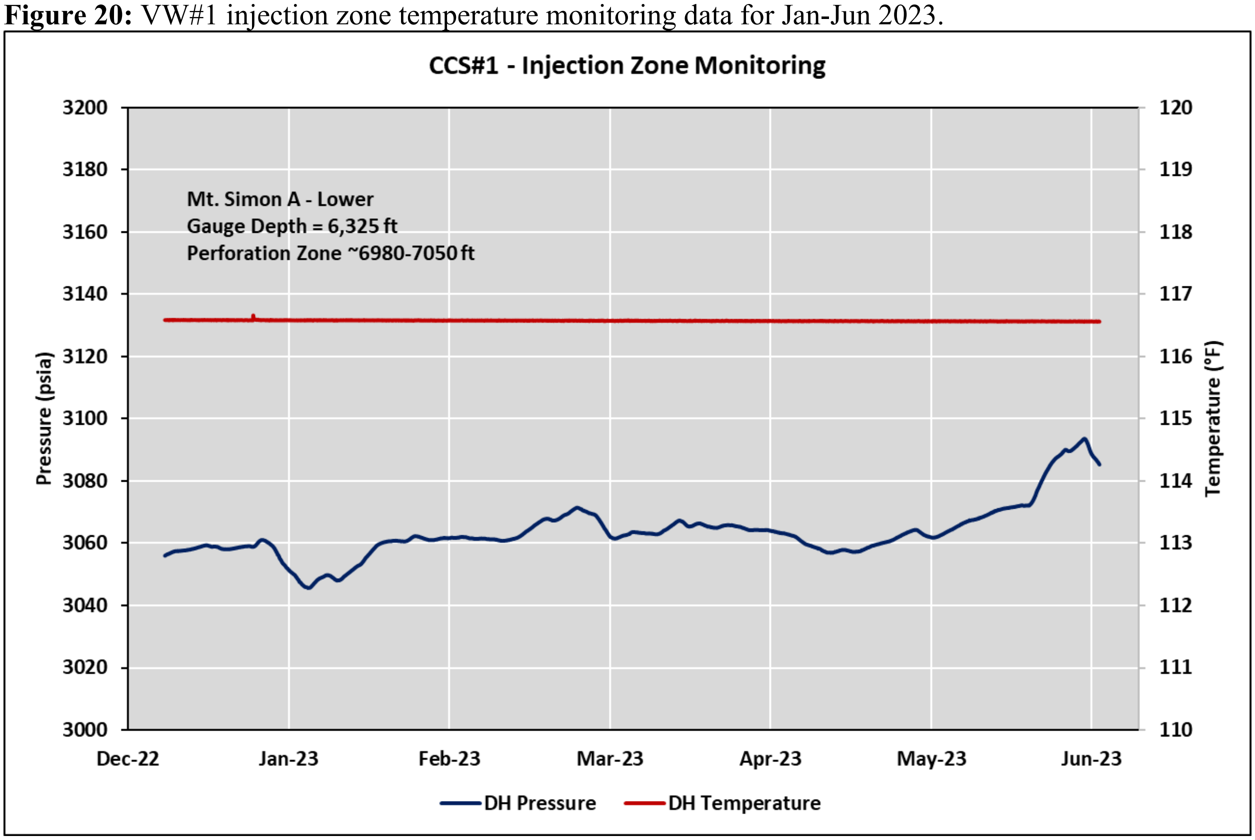

Figure 21: CCS#1 injection zone temperature & pressure monitoring data for Jan-Jun 2023.

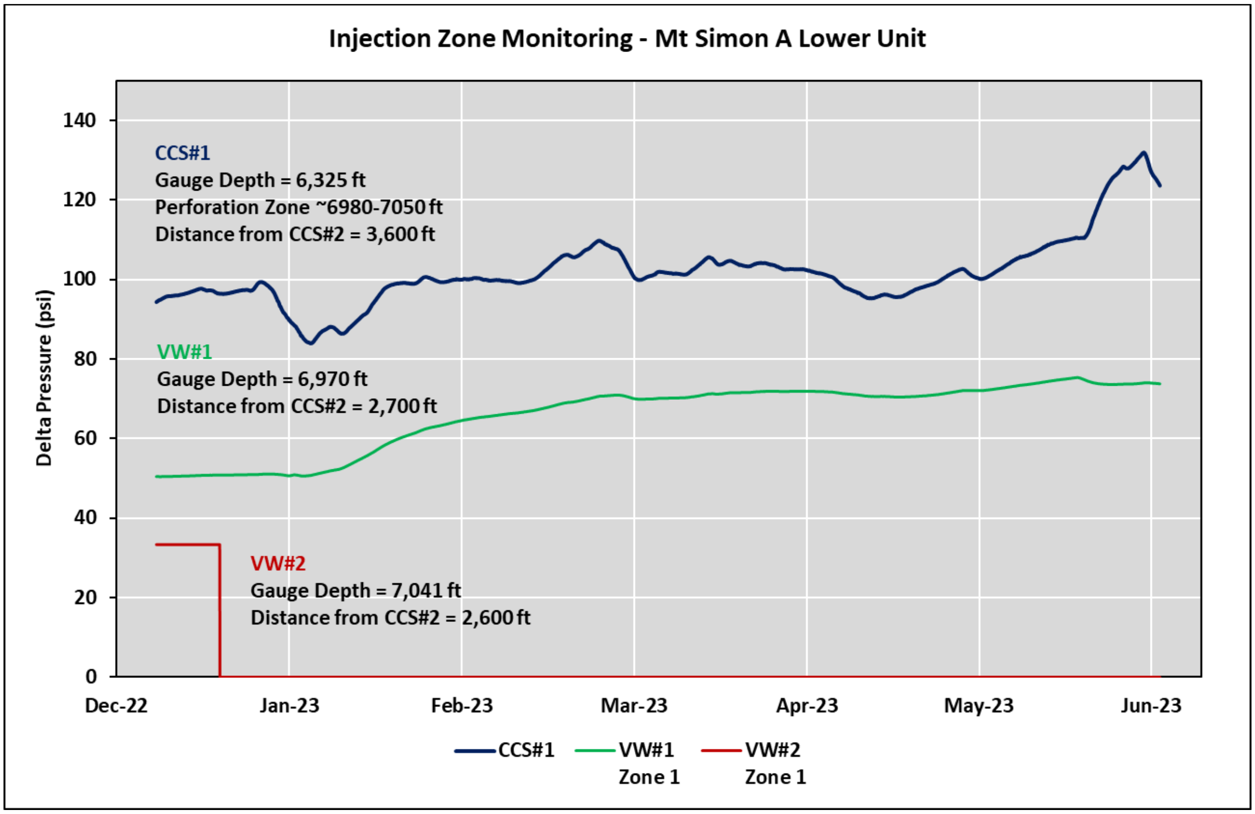

Figure 22: Comparison of the pressure change in the Mt. Simon A Lower at CCS#1, VW#1, and VW#2.

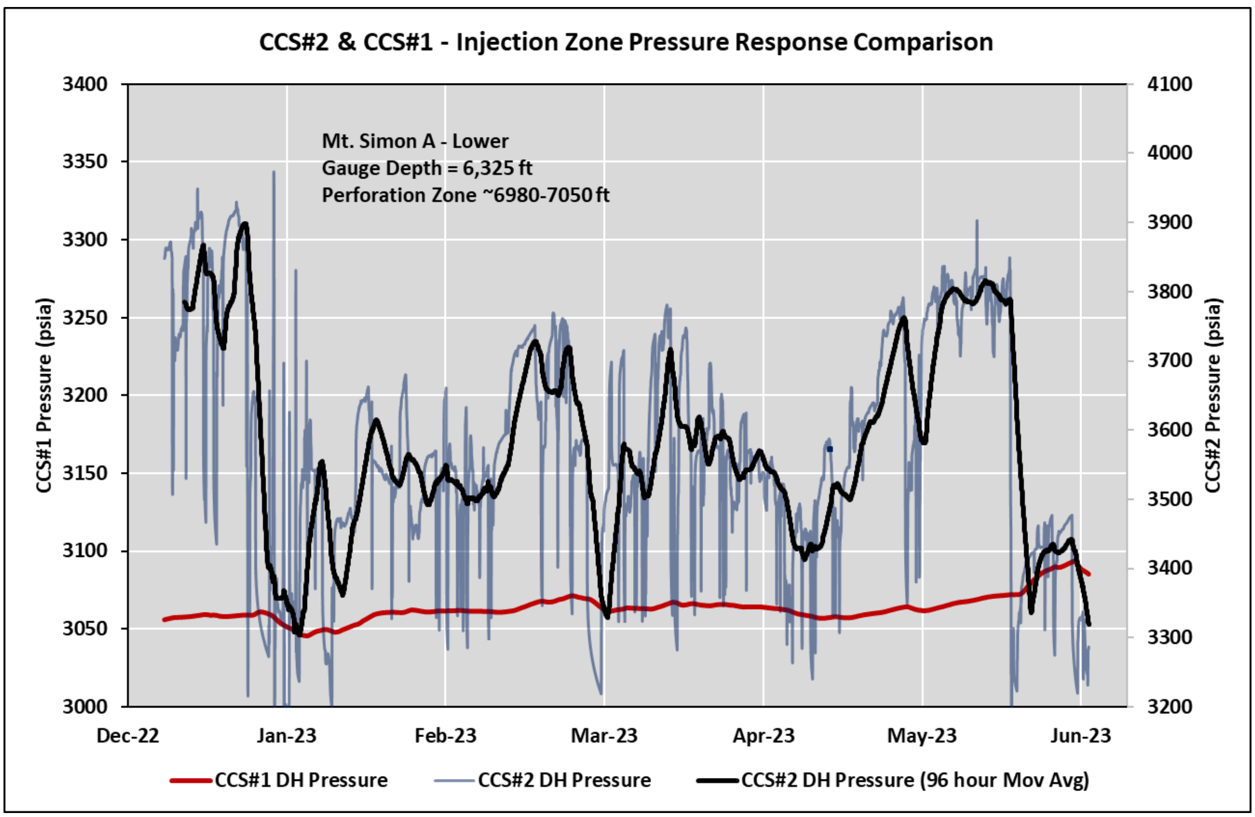

Figure 23: Comparison of the CCS#1 pressure response to CCS#2 injection pressure.

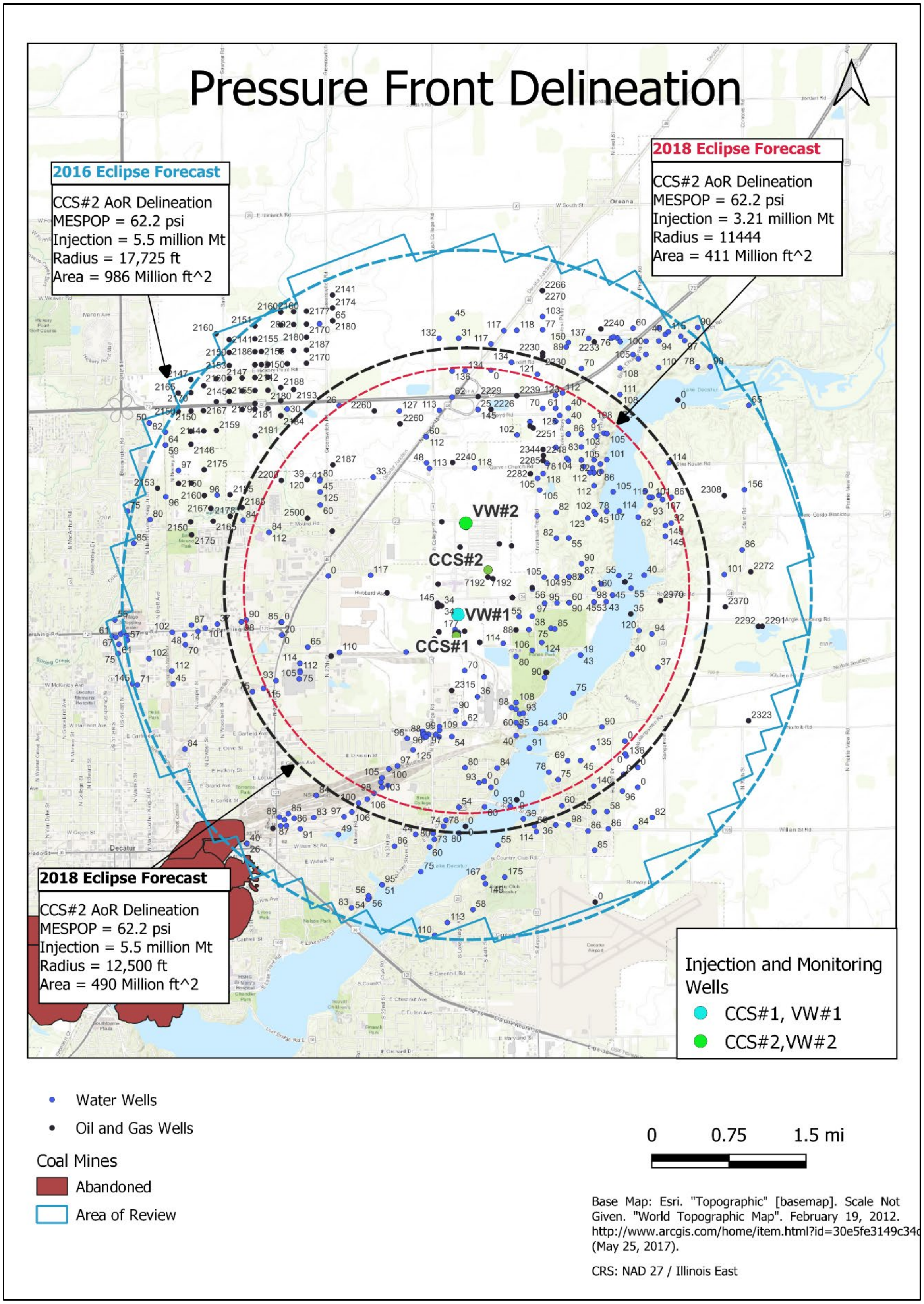

Figure 24: 2018 Eclipse model's pressure front delineation for June 30, 2023 and after the total injection of 6.5 million Mt (CCS#1=1.0 million Mt and CCS#2=5.5 million Mt).

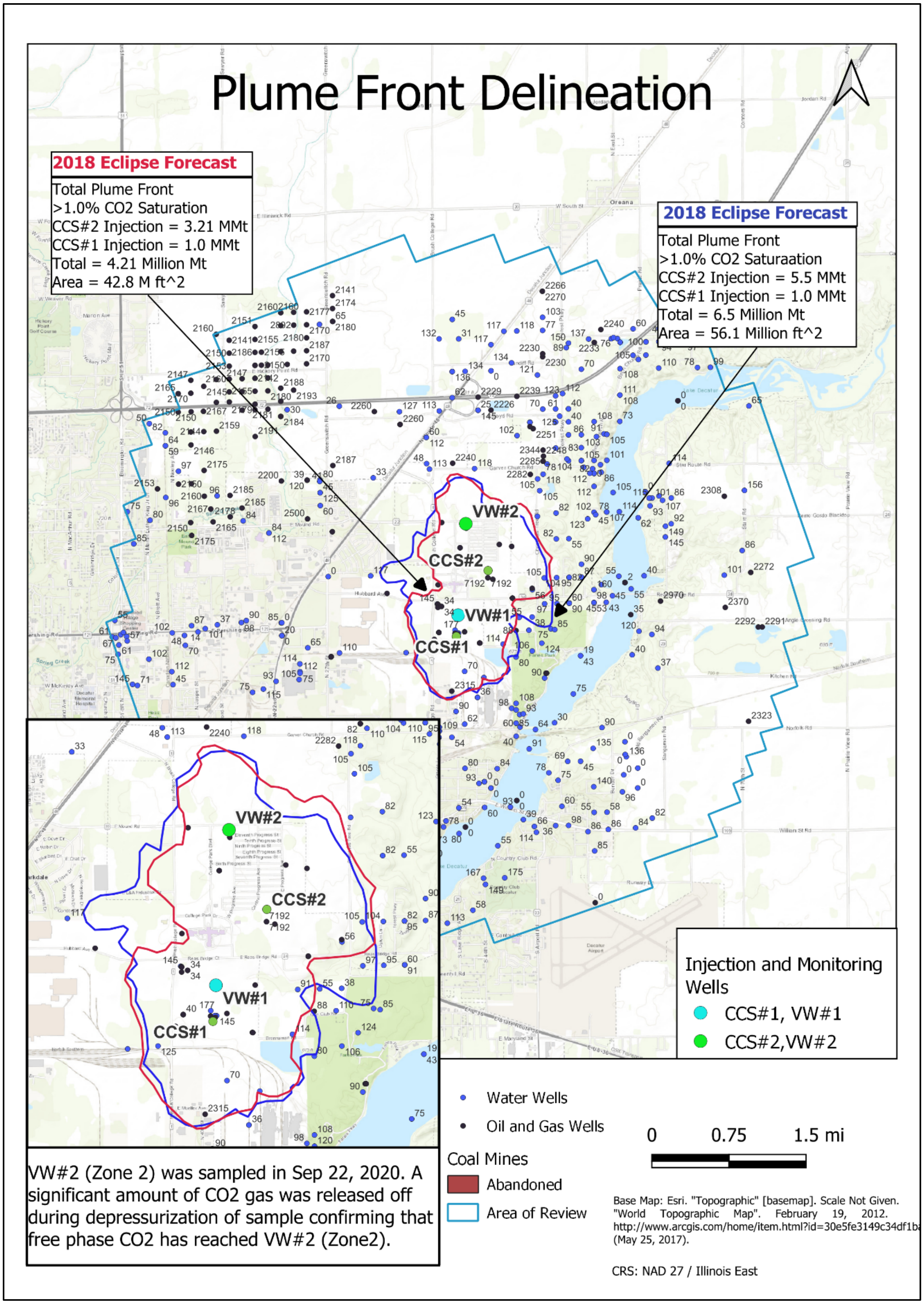

Figure 25: 2018 Eclipse model's plume front delineation for June 30, 2023 and after the total injection of 6.5 million Mt (CCS#1=1.0 million Mt and CCS#2=5.5 million Mt).

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*).

In January 2021 IL-ICCS Project acquired a time-lapse (4D) seismic monitor survey covering 5.8 square miles in the Illinois Basin for the purpose of monitoring the CO_2 plume from injection well CCS_2. This survey was processed along with the existing 2011 baseline survey by Earth Signal Processing Ltd for time-lapse analysis. The corresponding monitoring report is being submitted as supplemental information.

Supplemental Materials
The gauge calibration reports have been uploaded to the GSDT 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
4D Time Lapse Seismic Report:	202302_CCS#2_4D_Seismic_Report.pdf