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:	Jason Stahr jason.stahr@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, 2021
Report period:	January 1, 2021 @ 00:00 hrs - July 1, 2021 @ 00:00 hrs
Report number:	28

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 Results

This report covers the CCS#2 injection monitoring period beginning 01/01/2021 @ 00:00 hours and ending at 07/01/2021 @ 00:00 hours. During the 6 month reporting period, 224,406 metric tons (Mt) of CO_2 was injected at an average rate of 1,240 Mt/day resulting in a total mass of 2,300,702 Mt being injected into CCS#2 (See Figure 1). Review of the monitoring data shows the injection zone reservoir pressure and temperature readings correspond with the CCS#2 operational parameters. No anomalous operating or reservoir parameters were observed.

During the period, the reservoir pressure changed as a function of injection rate and the total mass of CO_2 injected. The average reservoir pressure was 4,022 psia versus the pre-injection pressure of 2,841 psia equating to an increase in reservoir pressure of 1,180 psi. The actual reservoir pressure tracked with the forecast reservoir pressure with the deviation averaging about 3.4%.

The injectate stream analysis shows no change in the CO_2 quality when compared to the baseline data. However, the Q1 and Q2 2021 samples appear to have been slightly contaminated with air. System corrosion monitoring results show a slight increase in corrosion rates on the 13CR-L80 coupon during Q1 2021. Close examination of the coupon indicates that it was damaged during installation or removal. Other than the mechanical damage to the Q1 coupon, the 13CR-L80 coupons lacked any unusual corrosion patterns such as pitting, that would indicate operational problems which is also confirmed by the lack of unusual or accelerated corrosion patterns observed on the less resistant A106B or the L80 coupons. Regarding well mechanical integrity, continuous DTS monitoring of CCS#2 is ongoing and the well's smooth temperature profile indicates good mechanical integrity and no movement of fluid or CO_2 behind the casing. Currently, there is no monitoring data indicating a failure of the injection and monitoring well's external mechanical integrity. Regarding the shallow and deep groundwater monitoring program, the data show no changes in groundwater chemistry that would indicate movement of fluids or CO_2 out of the injection zone.

The above confining zone (ACZ) monitoring data at VW#1 and VW#2 show no movement of fluids or CO_2 above the confining zone. This is also supported by the injection zone pressure and temperature data which indicate the CO_2 is moving along the injection horizon. No changes were observed in the reservoir pressure of the St. Peter Sandstone. Based on the current monitoring data, no brine or CO_2 have moved above the confining zone and continuing injection into the CCS#2 well does not present an endangerment to the St. Peter Sandstone, the lower most USDW.

On January 21, 2021@ 09:00 hrs, the CCS#2 automatic shut-down system was triggered when the downhole tubing/annulus differential pressure dropped below 100 psig. ADM was conducting maintenance to change out a leaking pressure relief valve. To safely conduct this maintenance, ADM had to isolate the annulus tank from the well head. During the maintenance procedure, the automatic shutdown valve was disengaged to prevent inadvertent valve closure and shutdown of the CO_2 compression facility. Once the well head was isolated from the annulus tank, the annulus pressure on the well head slowly began to decrease which inadvertently resulted in a drop in the down hole tubing differential pressure. There is no data indicating well mechanical integrity has been affected by this event. To avoid future inadvertent initiation of the automatic shutdown system, ADM plans to manually pressurize the annulus system when preventative maintenance is conducted on the annulus system.

On May 21, 2021, we conducted a well backflow on CCS#2. This maintenance activity was conducted as detailed in the standard operating procedures (SOPs) and went as planned. Initial results indicate a partial recovery of well injectability. The report covering this activity is submitted as supplemental information.

The annual deep groundwater sampling and the remaining MIT activities were completed during Q2 2021. The schedule of MIT and groundwater sampling activities is shown in Table 1. Prior to sampling GM#2, on April 6, 2021, the St. Peter reservoir T/P monitoring gauge was pulled from the well and underwent annual maintenance and testing. The gauge has not been redeployed due to failure of the cable to meet the specified ductility test. Deploying the gauges utilizing this cable would add significant risk regarding cable failure and losing the gauges downhole. We have ordered replacement cable and plan to redeploy the gauges in August 2021. In order to monitor the pressure in the St Peter Sandstone (USDW), the well is being water gauged weekly and the results are shown in Figure 8.

During the last reporting period an issue arose affecting the performance of the downhole gauges at VW#2, specifically the above confining zone (Zone 5 – Ironton Galesville) and the injection zone, (Zone 3 – Mt. Simon B) monitoring gauges. During the beginning of this reporting period, the Zone 5 gauge completely failed and no data is being received from the instrument. Zone 3 continues to operate but still has an intermittent fault that is affecting data transmission to the surface junction box. We are closely watching the instrument's fault frequency to gauge the rate of deterioration and we are reviewing the deployment of retrievable acoustic and electric line down hole gauges. We continue to use VW#1 to continuously monitor the Ironton Galesville and the Mt Simon B. This should provide enough downhole surveillance to detect any anomaly's that would indicate the movement of fluids or CO_2 out of the injection zone.

Table 1. Annual reservoir fluid sampling and MIT activities.

Date	Well	Activity
Jun 17, 2021	VW#1	Sample Zone - 3 (Ironton Galesville)
Jun 18, 2021	VW#1	Sample Zones - 2 (Mt Simon B)
May 14, 2021	VW#2	Sample Zone - 5 (Ironton Galesville)
Jun 15, 2021	VW#2	Sample Zone - 4 (Mt Simon E)
Jun 16, 2021	VW#2	Sample Zone - 3 (Mt Simon B)
Suspended	VW#2	Sample Zone - 2 (Mt Simon A Upper)
Apr 6, 2021	GM#2	Sample St Peter (Lowermost USDW)
Apr 7, 2021	CCS#2	T/P Calibration of DH Gauges
Apr 6, 2021	CCS#2	Testing of the Automatic S/D System

2. Analysis of CO_2 Injectate Stream

Discussion of Results

Table 2 presents the CO_2 injectate analytical results for the last four quarters (Q3 2020 – Q2 2021). 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 analytical results indicate no trend or change in the quality of the CO_2 injectate and is consistent with the historic sample data generated during the ICCS and IBDP projects. Although the 2021 samples appear to have been slightly contaminated with air.

Table 2. Analytical results for CO_2 injectate stream.

Parameter	Q3 2020 8/7/20	Q4 2020 11/17/20	Q1 2021 2/16/21	Q2 2021 4/28/21	Unit (LOQ)	Analytical method
Carbon Dioxide	Positive 99.9	Positive 99.9	Positive 99.5	Positive 99.8	% v/v (5.0)	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID)
Nitrogen	390	350	3000	820	ppm v/v (10)	ISBT 4.0 (GC/DID)
Oxygen	6.6	32	1000	260	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	70	180	120	96	ppm v/v (0.1)	ISBT 10.0 THA (FID)
Methane	nd	0.2	0.2	0.5	ppm v/v (0.1)	ISBT 10.1 (GC/FID)
Acetaldehyde	15	62	5.9	5.3	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	11	28	73	34	ppm v/v (0.01)	ISBT 14.0 (GC/SCD)
Ethanol	15	14	1.3	2.9	ppm v/v (0.1)	ISBT 11.0 (GC/FID)

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

Supplemental Material

The analytical reports for the samples have been uploaded to the GSDT as follows:
Q3 2020 CO_2 Analytical Report: ***20210216_Q1_2021_CO2_Analysis.pdf***
Q4 2020 CO_2 Analytical Report: ***20210428_Q2_2021_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 224,406 Mt of CO_2 was injected at an average rate of 1,240 Mt/day. The maximum flowrate achieved was 2,053 Mt/day during which the maximum wellhead pressure reached 1,906 psig. The fluctuations seen in the injection flowrate are due to plant slowdowns as well as being injection rate limited due to the downhole fouling which occurred during the previous 12 months. Figure 2 shows the CCS#2 wellhead temperature and pressure data. During this period, the wellhead temperature and pressure averaged 91 °F and 1,806 psig respectively. In an effort to maximize the injection rate, the downhole pressure was maintained near the maximum downhole limit of 4,125 psia (90% of the calculated reservoir fracture pressure). There were no exceedances above the 4,125 psia pressure limit.

Figure 3 trends the pressure maintained on the CCS#2 injection well annulus. During this period, the annulus pressure averaged 834 psig and 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 4,017 psia corresponding to a ΔP of 1,175 psi versus the baseline. The downhole injection temperature averaged 120 °F or a ΔT of 4 °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 261 psi and only dropped below the 100-psi minimum limit on January 21, 2021.

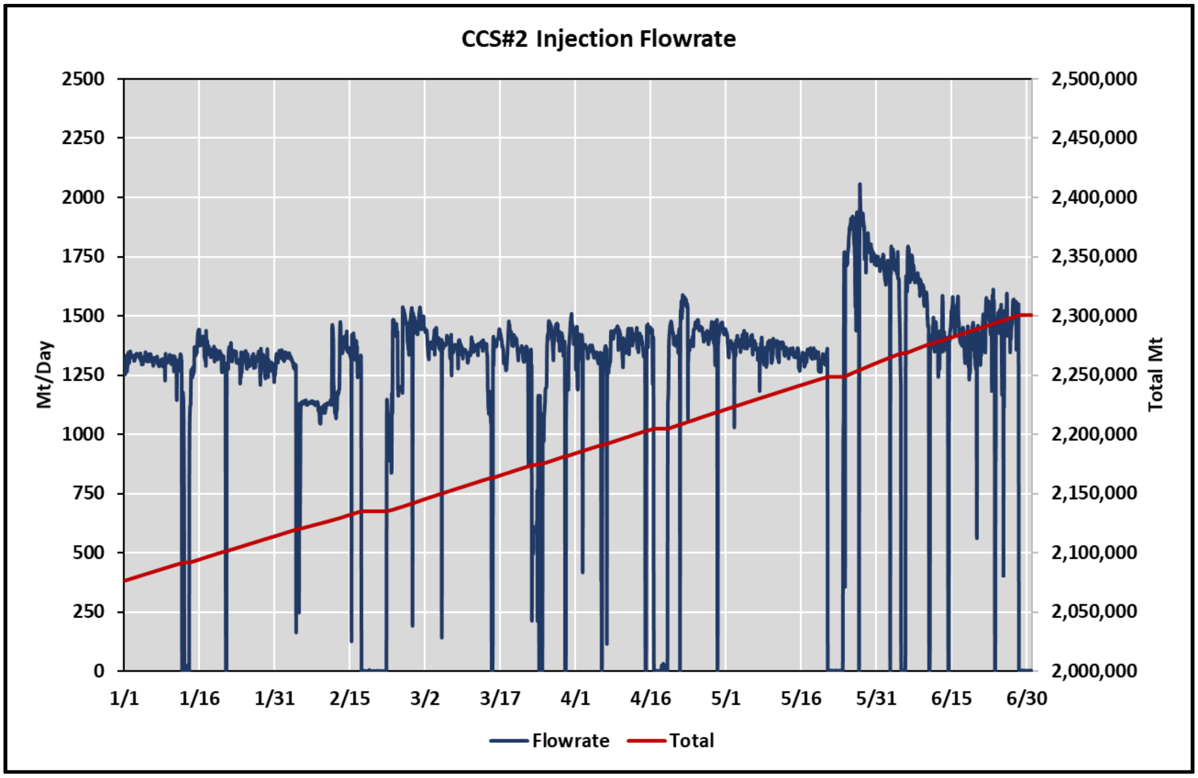

Figure 1: CCS#2 - Injection rate monitoring data for Jan-Jun 2021.

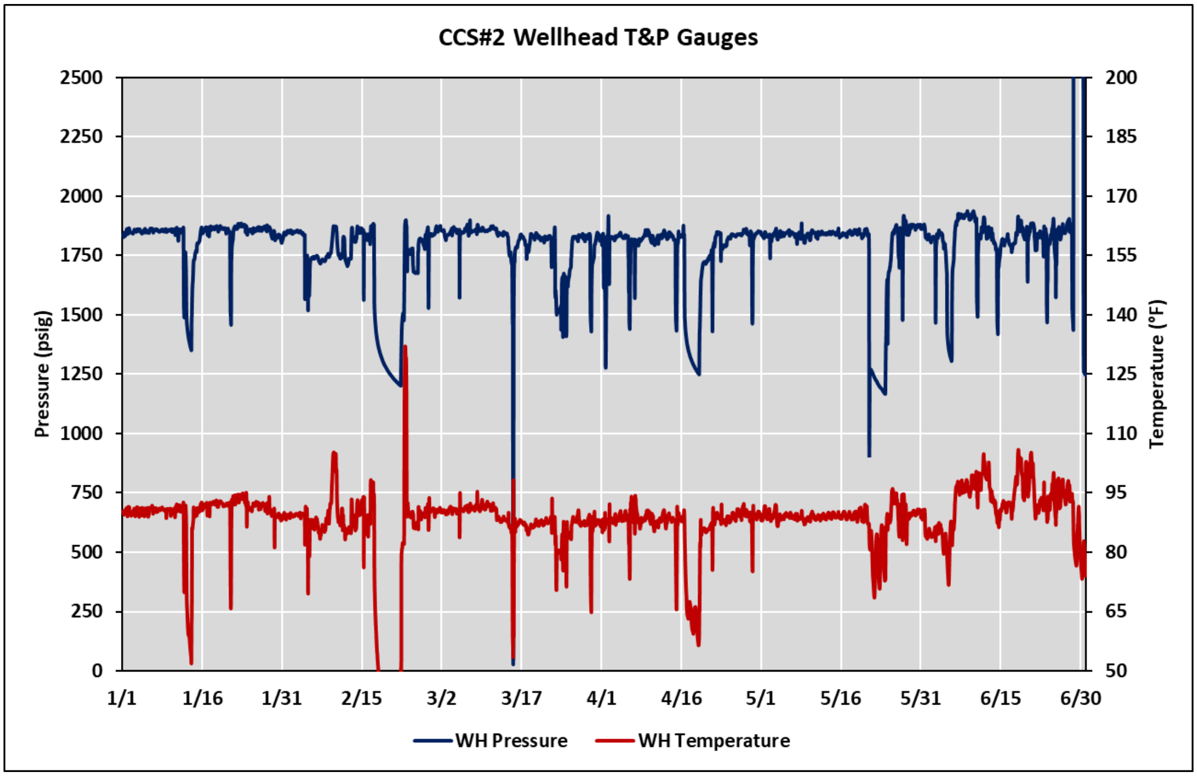

Figure 2: CCS#2 wellhead temperature and pressure monitoring data for Jan-Jun 2021.

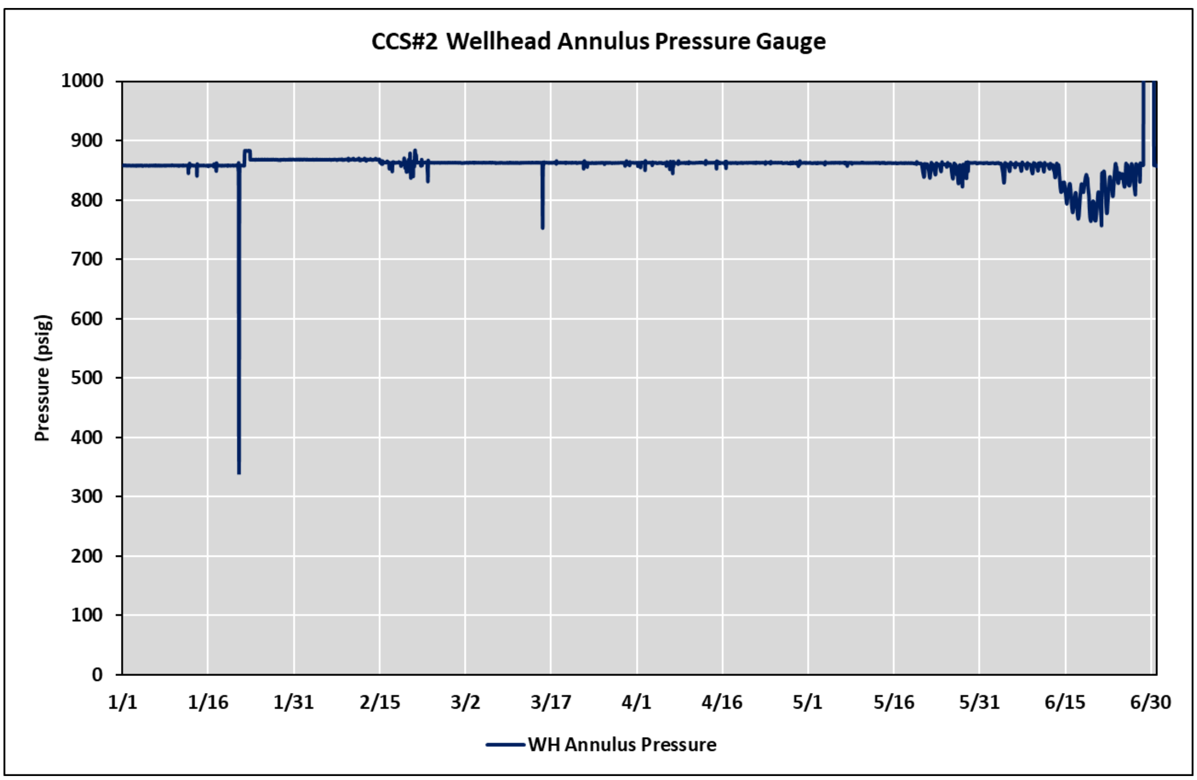

Figure 3: CCS#2 wellhead annulus pressure monitoring data for Jan-Jun 2021.

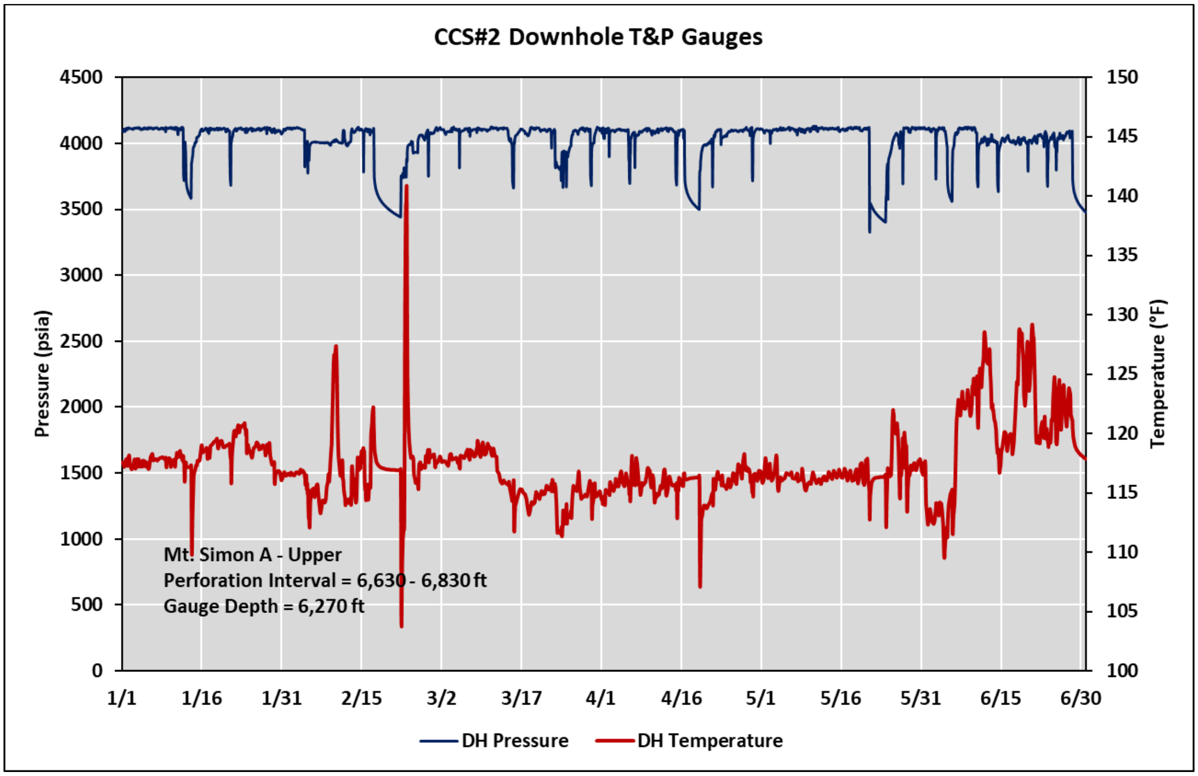

Figure 4: CCS#2 downhole temperature and pressure monitoring data for Jan-Jun 2021.

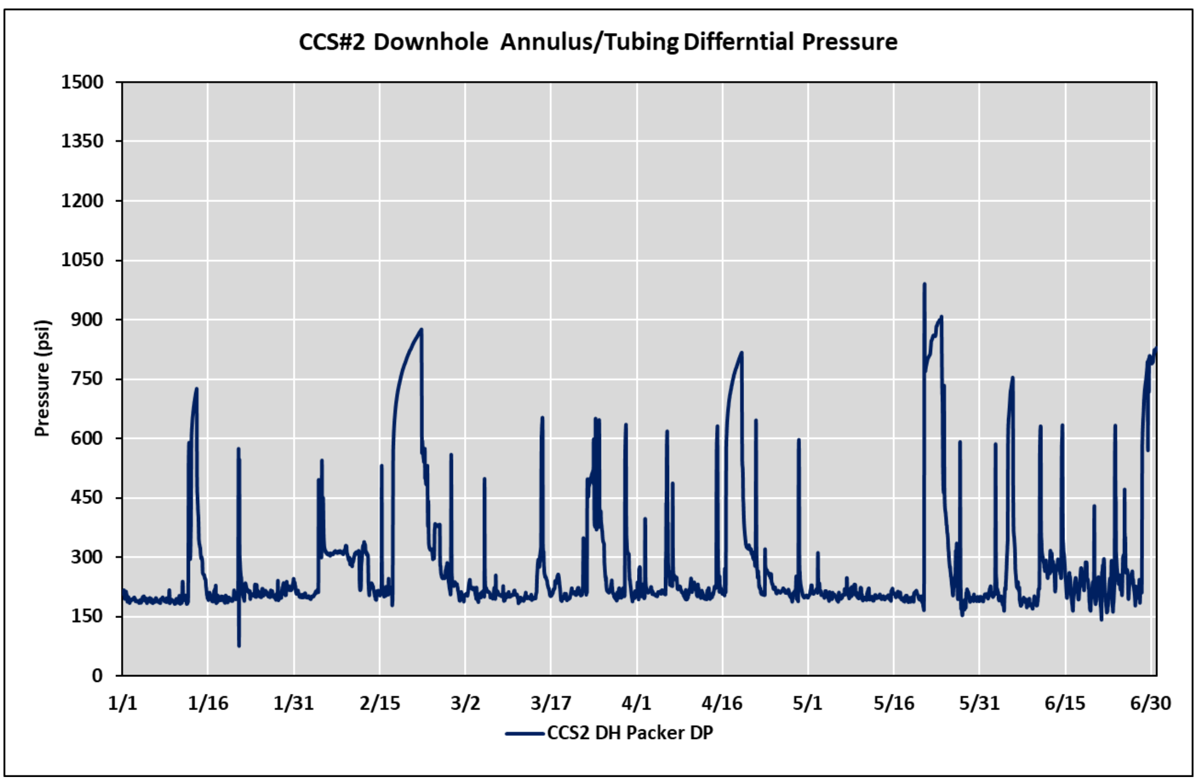

Figure 5: CCS#2 downhole annulus and tubing differential pressure monitoring data for Jan-Jun 2021.

Table 3 provides a monthly summary of several important operational limits for CCS#2 and details the parameter's minimum, maximum and average value for the month. Beginning on June 29, 2021 @ 07:00 hrs ending June 30, 2021 @ 10:00 hrs (28 hours), the wellhead tubing and annulus pressure reached 3,000 psig during a period when injection was shut down and the well was blocked in. The downhole pressure never exceeded the 4,125 psia limit. There is no data indicating well mechanical integrity has been affected by this event.

Table 3. CCS#2 summary of injection parameters for continuous operational monitoring.

Parameter (Unit)	Reporting Period	Monthly Summary Values		
		Average	Minimum	Maximum
Injection Pressure (psig)	January 2021	1,828	1,349	1,886
	February 2021	1,695	1,201	1,900
	March 2021	1,796	0	1,886
	April 2021	1,756	1,228	1,980
	May 2021	1,771	96	1,918
	June 2021	1,878	1,246	3,000
Injection Rate (Mt/day)	January 2021	1,913	2	2,281
	February 2021	1,831	0	2,307
	March 2021	1,687	28	2,087
	April 2021	1,044	0	2,219
	May 2021	1,582	0	2,244
	June 2021	1,269	0	1,629
Injection Volume *Based on DH Reservoir T/P* (ft^3/day)	January 2021	83,802	67	100,062
	February 2021	80,189	0	101,690
	March 2021	74,123	1,219	91,077
	April 2021	46,320	0	99,568
	May 2021	69,841	0	98,905
	June 2021	56,458	0	72,679
Annular Pressure (psig)	January 2021	879	346	886
	February 2021	865	817	883
	March 2021	862	62	869
	April 2021	863	844	881
	May 2021	860	820	872
	June 2021	964	754	3,000

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: ***202106_ADM_IL-115-6A-0001_Data.xlsm***

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

Summary of Results

Table 4 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 37,401 Mt and the total amount injected was 224,406 Mt. At the end of the reporting period, the total mass of CO_2 injected into CCS#2 was 2,300,702 Mt. No brine (annular fluid) was added or removed from the annulus system confirming the downhole mechanical integrity of the tubing, casing, and packer.

Table 4. 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 2021	38,929	2,115,225	0
February 2021	28,663	2,143,888	0
March 2021	40,086	2,183,974	0
April 2021	37,103	2,221,077	0
May 2021	40,794	2,261,870	0
June 2021	38,831	2,300,702	0

Supplemental Material

No supplemental information to be provided.

5. Corrosion Monitoring

Summary of Results

Table 5 shows the results of the corrosion monitoring program. System corrosion monitoring results show a slight increase in corrosion rates on the 13CR-L80 coupon during Q1. The coupon appears to have been damaged during installation or removal. Other than the mechanical damage, the coupon lacked any unusual corrosion patterns such as pitting, that would indicate operational problems which is also confirmed by the lack of unusual or accelerated corrosion patterns observed on the less resistant A106B or the L-08 coupons. The coupon lacked any unusual corrosion patterns, such as pitting, that would indicate a generalized corrosion problem. This conclusion is confirmed by the lack of unusual or accelerated corrosion patterns observed on the less resistant A106B or the L-08 coupons. Overall, the corrosion monitoring data indicates minimal injectate induced corrosion in the transportation pipeline and injection well. This data is consistent with the historic corrosion data generated during the IBDP's (CCS#1) three-year operational period. The coupons were prepared by EnhanceCo and assessed for corrosion using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). The coupons were photographed, visually inspected at 20x power, dimensionally measured to within 0.0001 inches, and weighed to within 0.0001 grams. During the reporting period, there was no deviation from the testing and monitoring plan that would indicate quality assurance/quality control (QA/QC) problems.

Supplemental Materials

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

Q1&Q2 2021 Coupons:	***2021_ADM_Corrosion_Coupon_Photos_Q1_Q2.pdf***
Corrosion Calculations:	***202106_CCS#2_Corrosion_Monitoring_Results.xlsx***

Table 5. 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	Q3 2020	0.050	Low	Generalized
	5	Q4 2020	0.022	Low	Generalized
	6	Q1 2021	0.127	Low	Generalized
	5	Q2 2021	0.041	Low	Generalized
L-80 Long string casing <4,800 ft	6	Q3 2020	0.046	Low	Generalized
	5	Q4 2020	0.015	Low	Generalized
	6	Q1 2021	0.181	Low	Generalized
	5	Q2 2021	0.057	Low	Generalized
13CR-L80 Long string casing >4,800 ft, injection tubing, and packer	6	Q3 2020	0.090	Low	Generalized
	5	Q4 2020	0.266	Low	Generalized
	6	Q1 2021	1.093	Moderate	MD
	5	Q2 2021	0.229	Low	Generalized

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

6. Above Confining Zone (ACZ) Monitoring

Discussion of Results – Pressure and Temperature Monitoring

Table 6 compares the pre-injection reservoir parameters versus the observed reservoir parameters for the ACZ monitoring zones in GM#2 (St. Peter Formation), VW#2 (Ironton Galesville Formation), and VW#1 (Ironton Galesville Formation). Examination of the data shows no significant change occurred during the monitoring period (pre-injection vs. current) thus indicating no movement of fluids or CO_2 above the confining zone and therefore indicates that the operation does not present an endangerment to the St. Peter Sandstone, the lower most USDW.

Table 6: 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
Depth[2]	3,450 ft	5,027 ft	4,989 ft	3,450 ft	5,027 ft	4,989 ft
Formation	St Peter Sandstone	Ironton Galesville	Ironton Galesville	St Peter Sandstone	Ironton Galesville	Ironton Galesville
Pre-Injection	1,397	2,112	2,086	N/A	N/A	104
Average	1,398	2,145	2,084	N/A	N/A	104
Delta P	1.0	32.7	-1.6	N/A	N/A	0.1
% Change	0.1%	1.5%	-0.1%	N/A	N/A	0.1%

Note 1: Data Collection Time Period = 1/1/21 - 7/1/21. Pressure reported as reservoir=psia & dP=psi.
Note 2: Depths reported are gauge depths.

Figure 6 and Figure 7 trend the downhole pressure and temperature for the Ironton Galesville, the formation directly above the injection zone seal (Eau Claire Shale) at VW#2 and VW#1 respectively. Figure 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. These figures also denote the time period in which there was unstable behavior with the instruments (VW#2) or the period during which the GM#2 gauges were out of the well. Regarding GM#2, the well was water gauged weekly during this period. The well's water level was equivalent to the 1,400 psia hydrostatic pressure of reservoir.

As discussed in the summary section and denoted in Figure 6, since September 14, 2020, an intermittent short on VW#2's downhole communications line is affecting the ability to continuously monitor the reservoir conditions of Ironton Galesville (ACZ) at VW#2. The data indicates there is an intermittent fault in the communication line between the downhole gauges and the surface junction box. During the instrument's energization and data transmission cycle, the line is subject to shorting. If the fault occurs during the data transmission cycle, the signal is corrupted and the ARCCON data acquisition unit reports null values. Electrical checks taken from the VW#2 junction box to the downhole cable showed a reverse resistance of 7.05 kilo-ohms, which is indicative of a short or leak. Unfortunately, there is no means to institute repairs without pulling the complete downhole assembly, essentially a complete well workover. Therefore, we are closely watching the instrument's fault frequency to gauge the rate of deterioration. In the event of an instrument failure, we are reviewing the deployment of retrievable down hole gauges that are compatible with our existing data acquisition system. Using a single or multiple level system, we could park the gauges at the appropriate levels and sequentially cycle the sliding ports (opening and closing the ports). This would allow periodic data acquisition from the failed monitoring zones. This combined with VW#1's continuous monitoring of the Ironton Galesville and the Mt Simon B, should provide enough downhole surveillance to detect any anomaly's that would indicate the movement of fluids or CO_2 out of the injection zone.

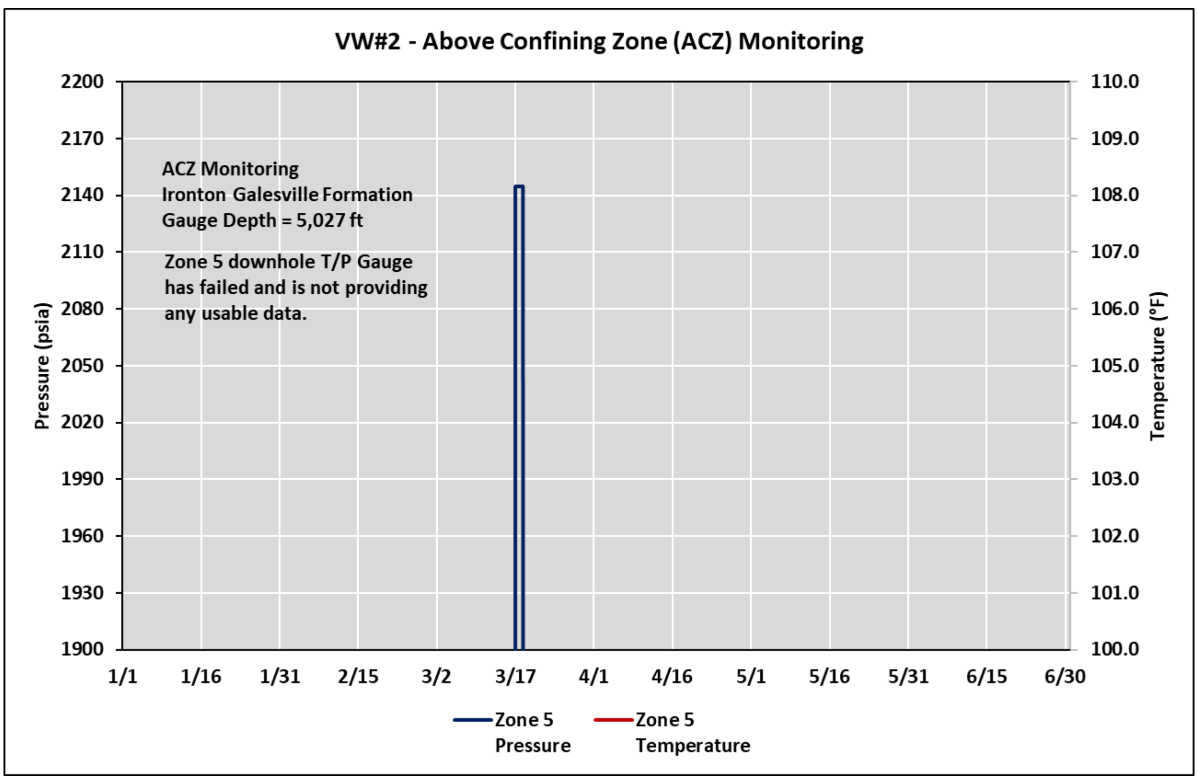

Figure 6: VW#2 ACZ monitoring of the Ironton Galesville Formation for Jan-Jun 2021.

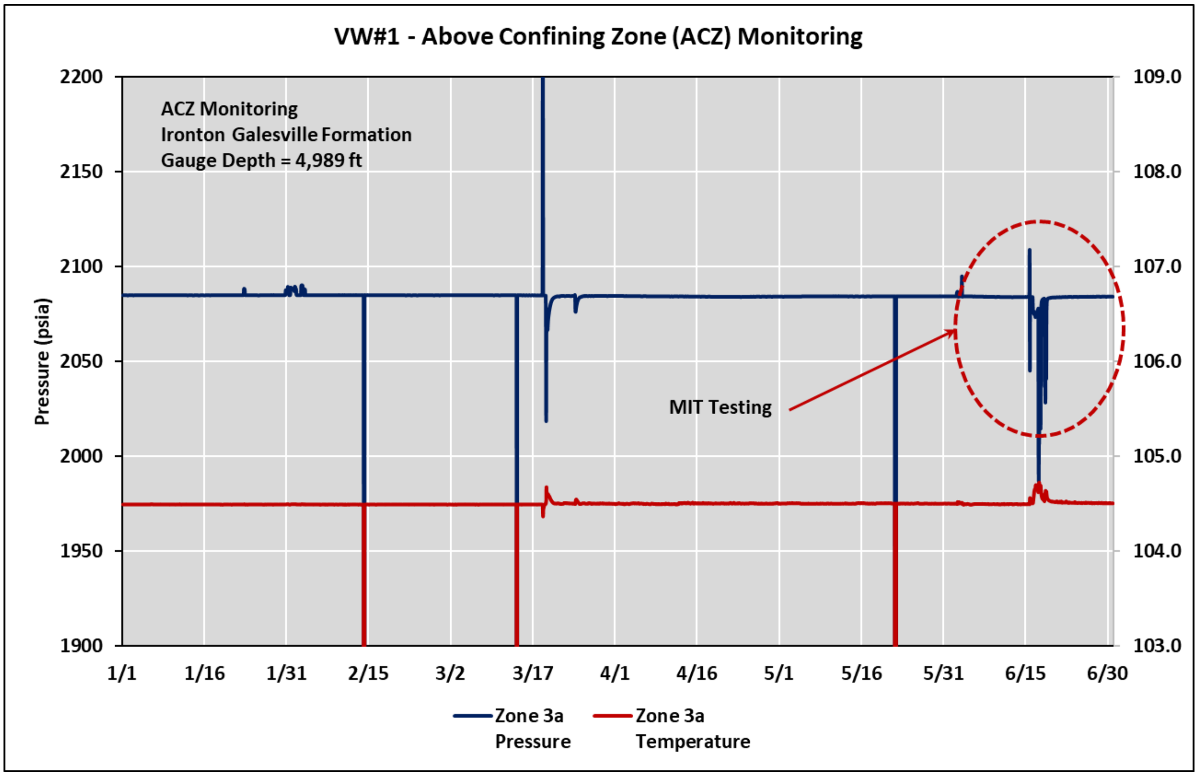

Figure 7: VW#1 ACZ monitoring of the Ironton Galesville Formation for Jan-Jun 2021.

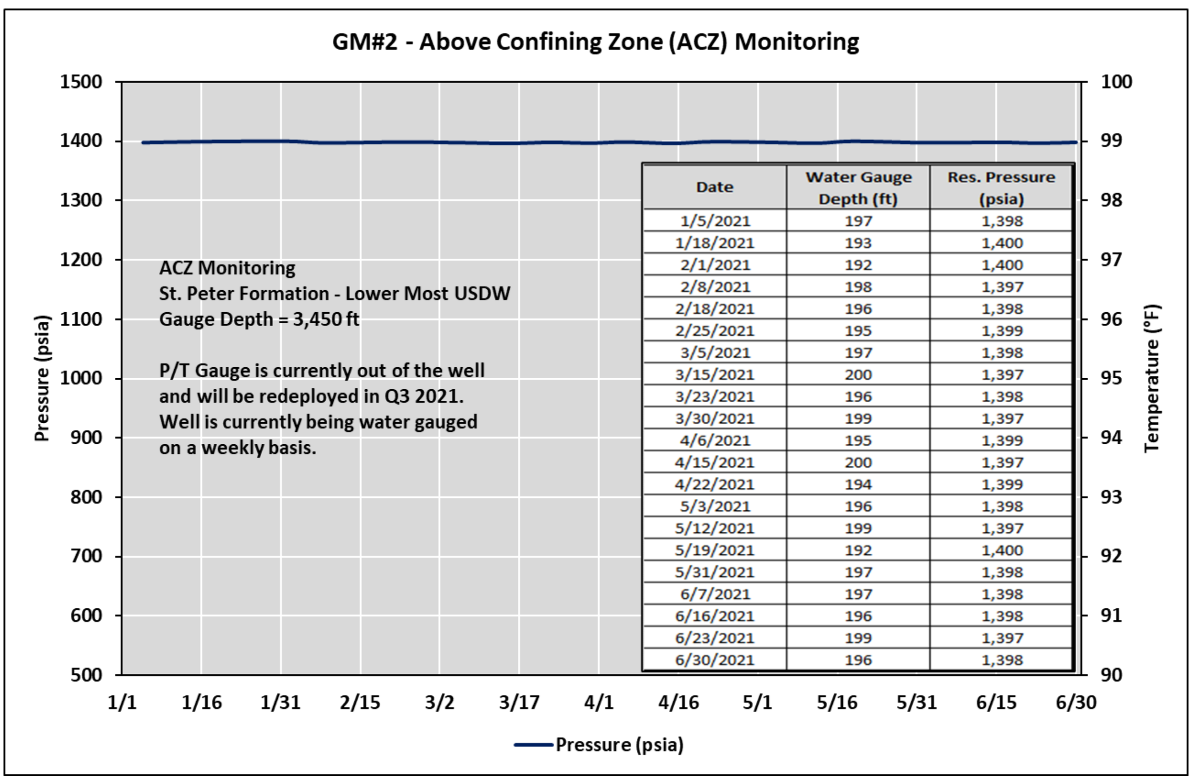

Figure 8: GM#2 ACZ monitoring of the St. Peter Formation for Jan-Jun 2021.

Discussion of Results – Groundwater Monitoring

The purpose of this 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 Mt of CO_2 into the lower Mt. Simon Sandstone under an Illinois EPA UIC Class I (non-hazardous) permit from November 2011 through November 2014. Injection for the IL-ICCS project started on April 7, 2017, and 2,204,784 metric tons of CO_2 had been injected as of April 16, 2021. Because of the report's size, it is being submitted as supplemental material.

Since the last report (dated January 20, 2021), additional sampling events have occurred. Between October 8, 2020 and June 17, 2021, two quarterly shallow groundwater sampling events (January 2021 and April 2021) and two deep fluid sampling events occurred. The new results are included 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 20, 2021 report, and the major conclusion remains the same. Specifically, interpretations of all shallow groundwater data to date indicate that no trends or changes in shallow groundwater chemistry have occurred as a result of CO_2 injection in Decatur. The variability observed in shallow water quality data are attributed to factors including natural groundwater heterogeneity, seasonal groundwater variability, initial effects of well installation, and equipment performance. No changes in water quality were observed that would indicate brine or injected CO_2 were introduced into the shallow groundwater environment. Further, there are natural differences between the chemistry of groundwater from wells screened in the shallow Pennsylvanian bedrock (i.e., the G-series wells used for the IBDP) and wells screened in the glacial materials of the Lower Glasford Formation (i.e., the LG wells used for the IL-ICCS project). In general, the concentration of alkalinity, dissolved carbon dioxide, barium, calcium, iron, magnesium, manganese, and silicon from LG wells are greater than in the bedrock wells, whereas specific conductance and the concentrations of total dissolved solids, bromide, chloride, fluoride, and sodium are lower than the bedrock wells. These concentration variations are interpreted as the result of mineralization by natural water-rock interactions and groundwater movement within the strata being monitored.

Supplemental Materials

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

GW Report Name:	***202106_IL-115-6A-0001-0002_GWM_Report.pdf***
GW COAs:	***202106_IL-115-6A-0001-0002_Shallow_Deep_GWM_COAs.pdf***

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

Discussion of Results

The CCS#2 annual external MIT was conducted during the reporting period. In February 2021, the DTS data generated during a 119-hour shutdown of CCS#2 was utilized to validate the annual mechanical integrity of the well via a DTS temperature log. The results of the temperature log indicate no fluid movement is occurring behind the casing indicating good well mechanical integrity. Continuous DTS monitoring of CCS#2 is ongoing and the 24-hour period for December 31, 2020 (end of the reporting period) is shown in Figure 9. The smooth temperature profile indicates good well integrity and no movement of fluids/CO_2 behind the casing.

Supplemental Material

CCS#2 DTS Tabular Data: ***20210631_CCS#2_DTS_Data.xls***
CCS#2 Annual DTS Log: ***20210426_CCS#2_MIT_DTS_Log.xlsx***

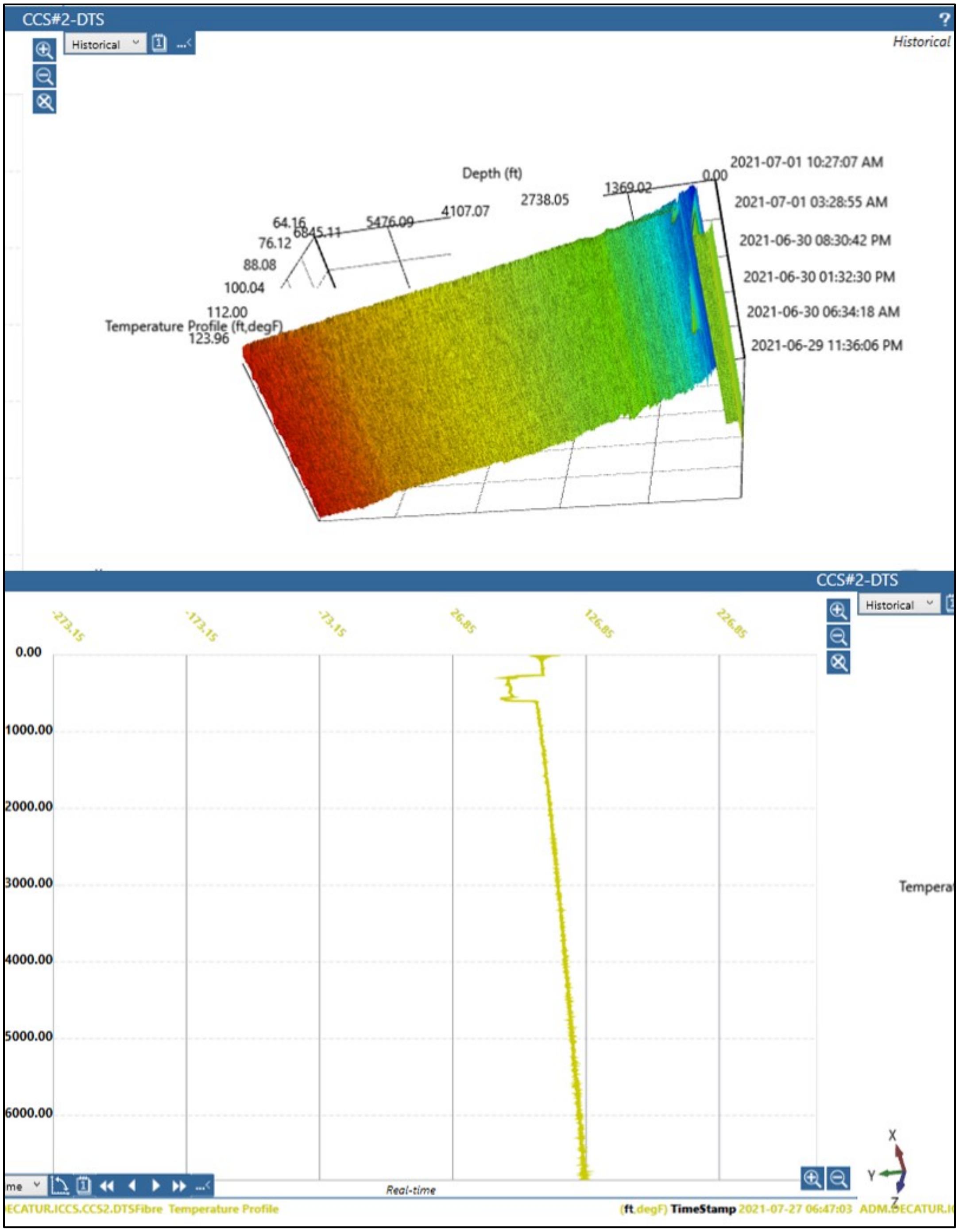

Figure 9: CCS#2 DTS data in 3-dimensional view for last day of reporting period 6/30/2021.

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. Based on current injection rates, this threshold should be met in November 2022. The project team will plan, schedule, and notify the Agency, 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 7 compares the actual reservoir pressure with the pressure forecast by the Eclipse model. The actual and forecast data correlate well. The monitoring wells are within 2.5% of the predicted pressures. CCS#1 is within 3.5% of the forecast, but CCS#2 deviates from the forecast by 10.1% or 386 psi higher than projected. To better understand why CCS#2 is significantly different from the forecast one must look at the spinner logs we conducted over the past 3 years.

Table 8 details the results of the logs and compares the injectate flow distribution observed during each run. From this data, it appears that a significant portion of the injectate flow shifted from the upper to the lowest set of perforations. This shift in the well's flow distribution as well as the casing diameter reduction shown by the tool's caliper readings (not shown), confirms the buildup of foreign material around the upper perforated interval. Figure 10 compares the predicted injection zone pressure predicted versus the actual pressure recorded at CCS#2. One can observe that the two pressures correlate closely during the first million tons of injection but deviates during the subsequent injection finally reaching about 350 psi differential at 2.3 million tons. The bias between the actual and the forecast pressure is due mainly to the downhole fouling we are experiencing at CCS#2. The backflow procedure conducted on May 21, 2021 appears to have reduced the fouling reducing the bias shown in the previous months. If the fouling remains, modification of reservoir model parameters (i.e. skin factor) will be needed to better align the model with the observed pressure.

Figure 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. This strongly support that the static geophysical (Petrel) and the dynamic reservoir flow (Eclipse) models well characterize our storage site and the pressure and plume fronts are behaving as forecast in the model. One exception can be seen with regard to Figure 16. This chart trends the CCS#1 injection zone pressure versus the model pressure. Clearly there is an unknown artifact that is causing a significant bias one does not see in the other monitoring wells. One theory is that unresolved faults proximate to the interface of the Precambrian with the Mt Simon (Argenta) are channeling pressure. These faults would not present a leakage risk but could provide a conduit to transmit pressure more directly from the CCS#2 injection well to CCS#1. The results of the recently conducted 3D seismic survey may shed additional light on this phenomenon.

Table 7: 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	3,073	3,997	3,216	3,167	3160	3243	3,364	3,174
Forecast P	3,181	3,611	3,232	3,106	3100	3271	3,321	3,101
Delta P	108	386	16	61	60	27	43	73
% Delta	3.4%	10.1%	0.5%	1.9%	1.9%	0.8%	1.3%	2.3%

Note 1: Data Collection Time Period = 1/1/21 - 7/1/21. Pressure reported as reservoir=psia dP=psi
Note 2: Monitoring well depths are reported as gauge depths while tCCS#1 & CCS#2 depths are the average of the perforated interval.

Table 8: Comparison of 2017, 2018, and 2019 Spinner Logs

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

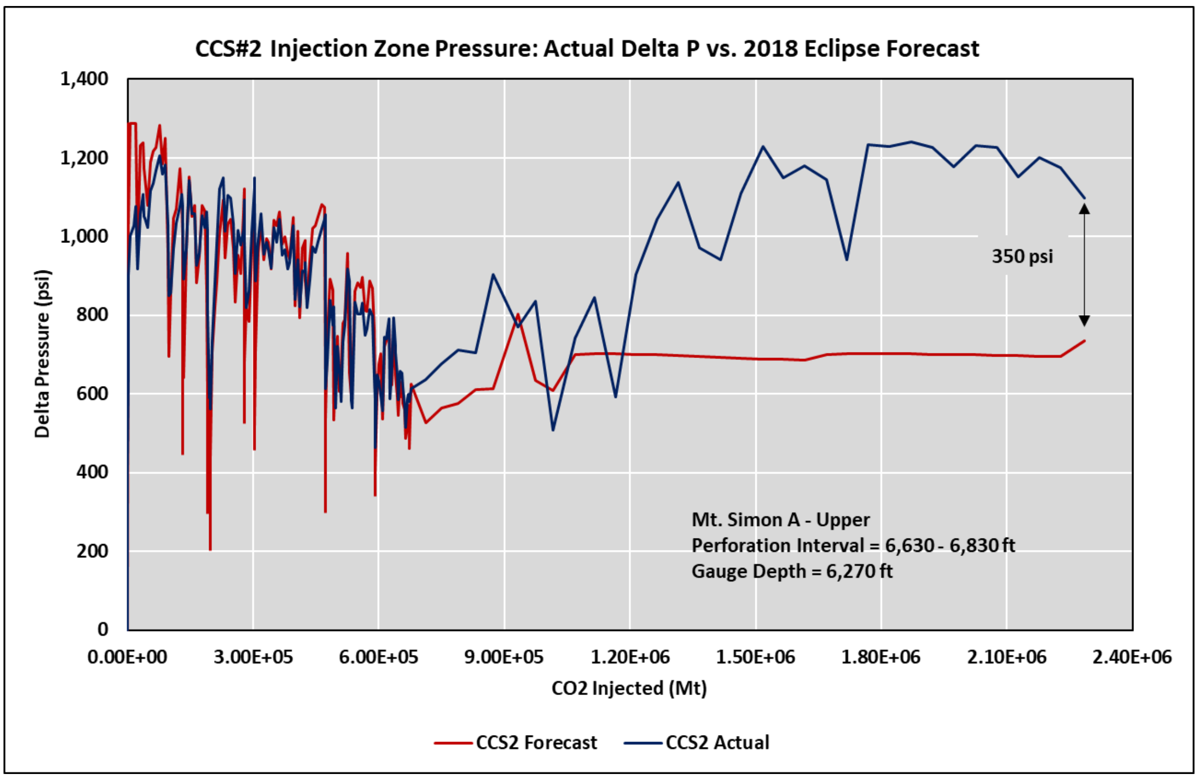

Figure 10: CCS#2 comparison of the downhole injection pressure versus the forecast pressure generated by the 2018 Eclipse reservoir model.

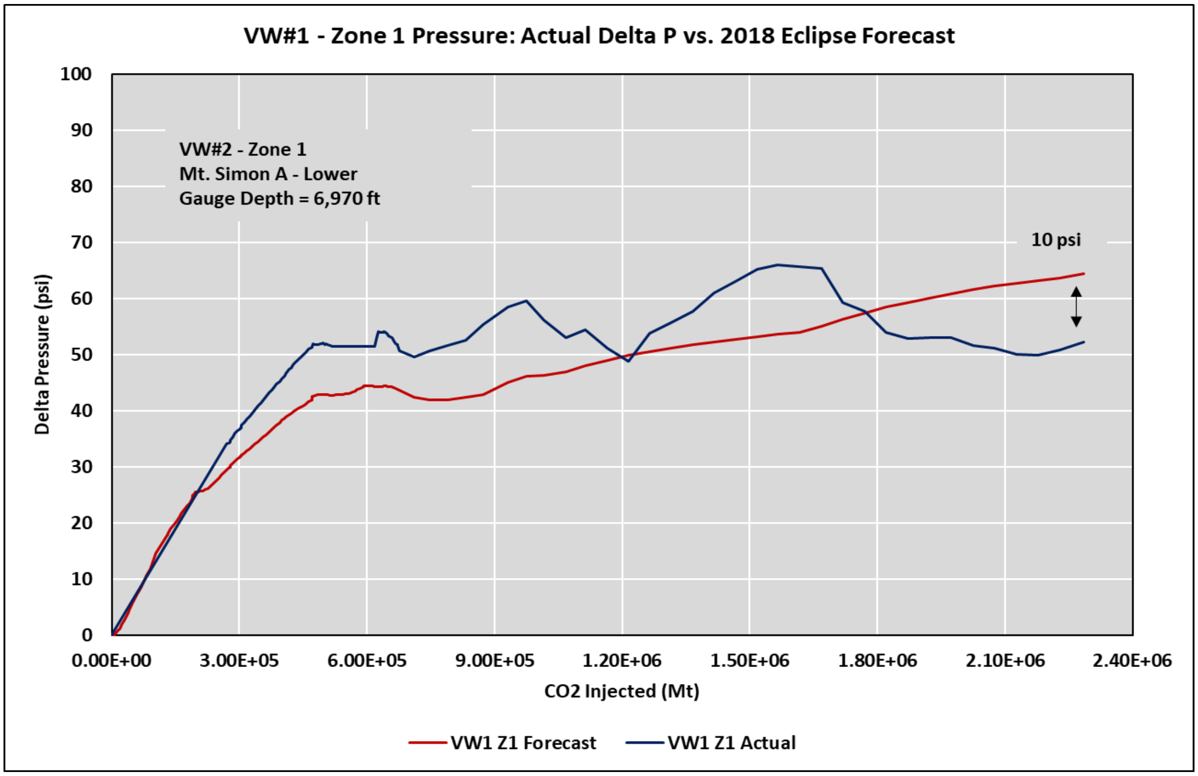

Figure 11: VW#2 Zone 1 differential pressure comparison of actual versus 2018 Eclipse forecast.

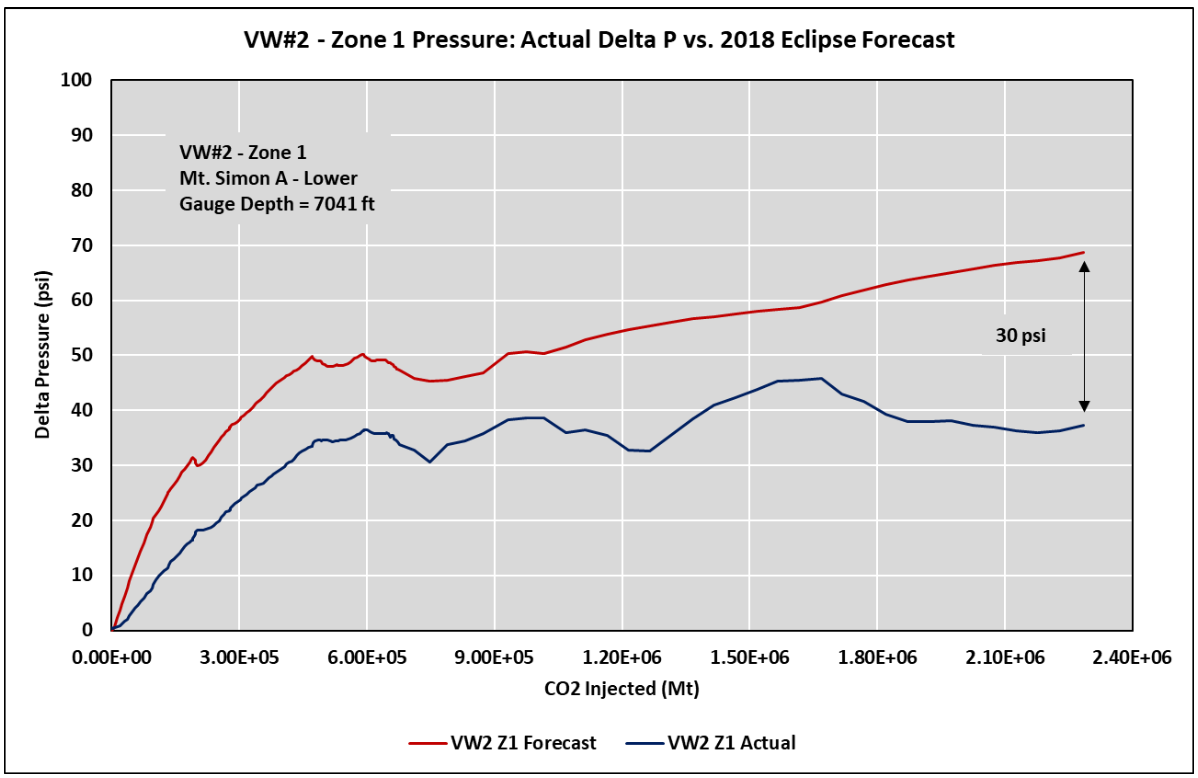

Figure 12: VW#1 Zone 1 differential pressure comparison of actual versus 2018 Eclipse forecast.

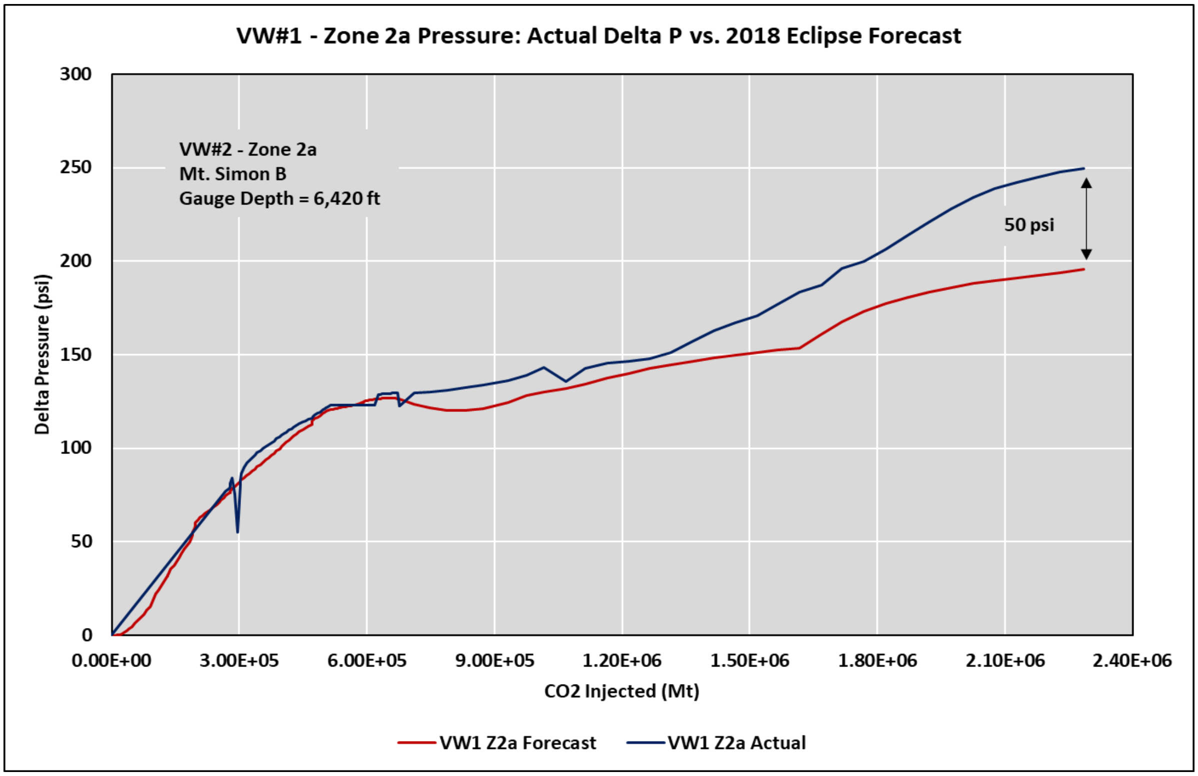

Figure 13: VW#1 Zone 2a actual reservoir differential pressure versus 2018 Eclipse forecast.

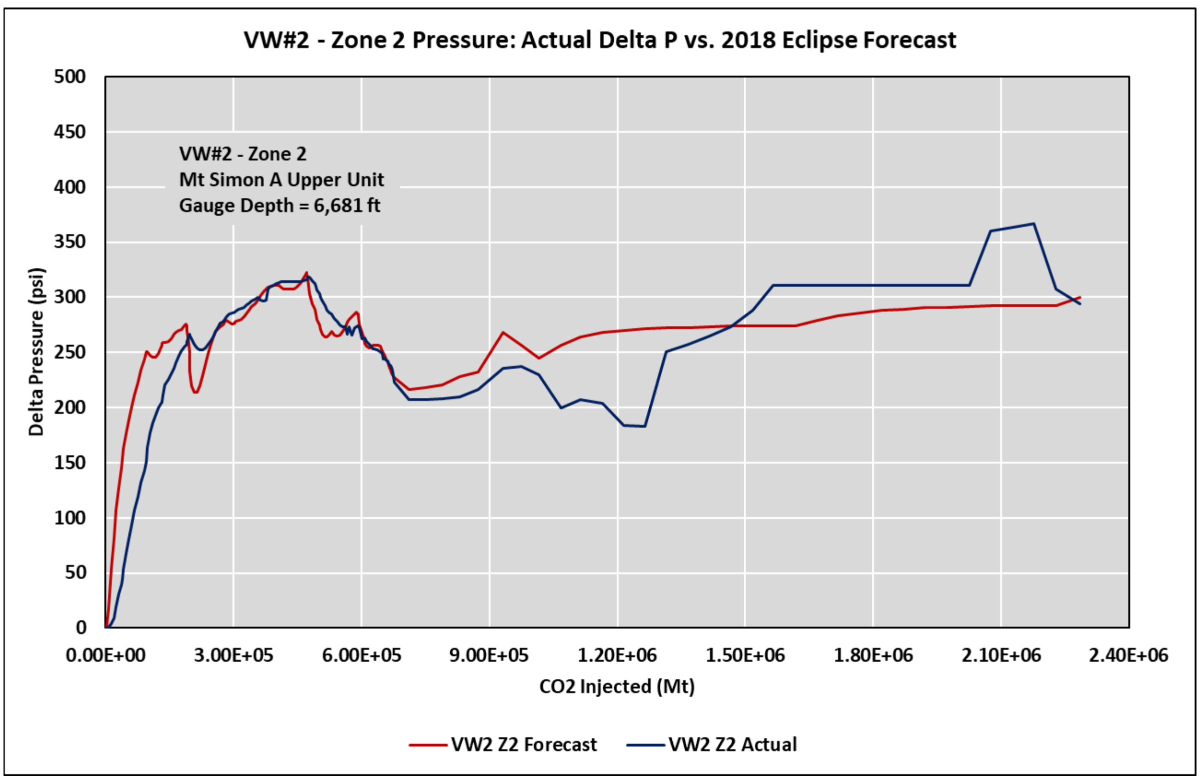

Figure 14: VW#2 Zone 2 actual reservoir differential pressure versus 2018 Eclipse forecast.

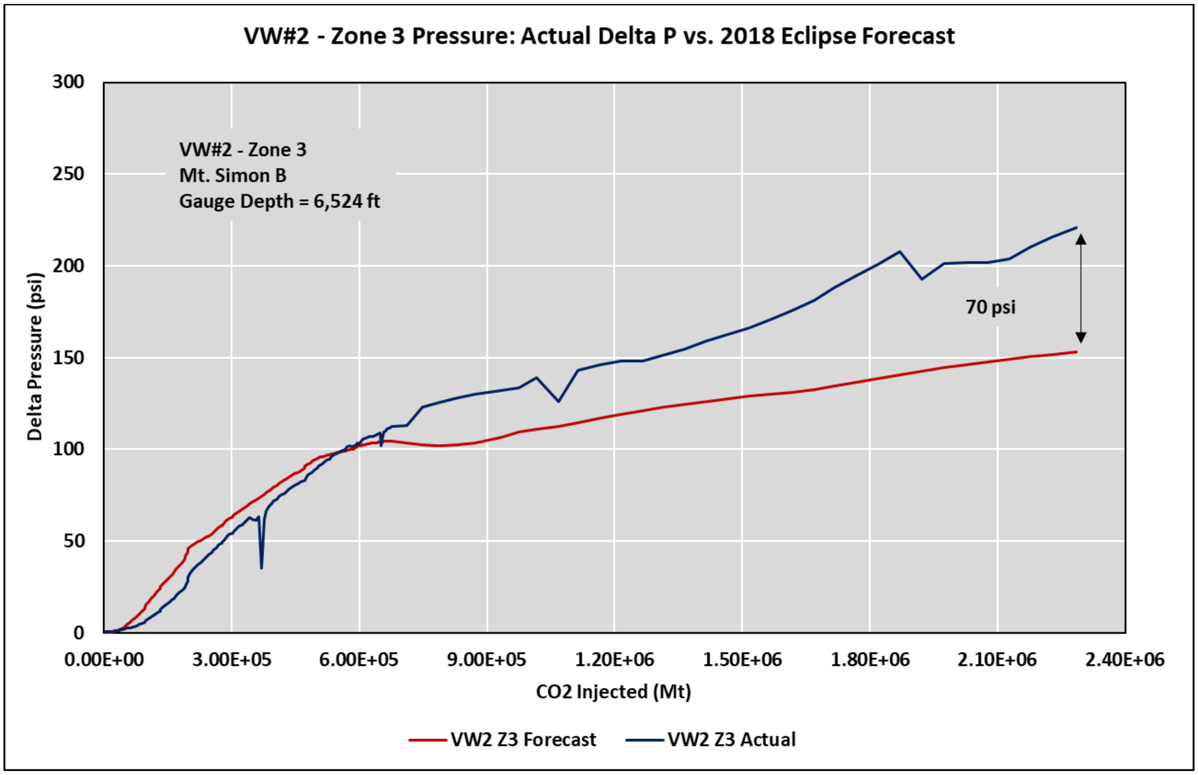

Figure 15: VW#2 Zone 3 actual reservoir differential pressure versus 2018 Eclipse forecast.

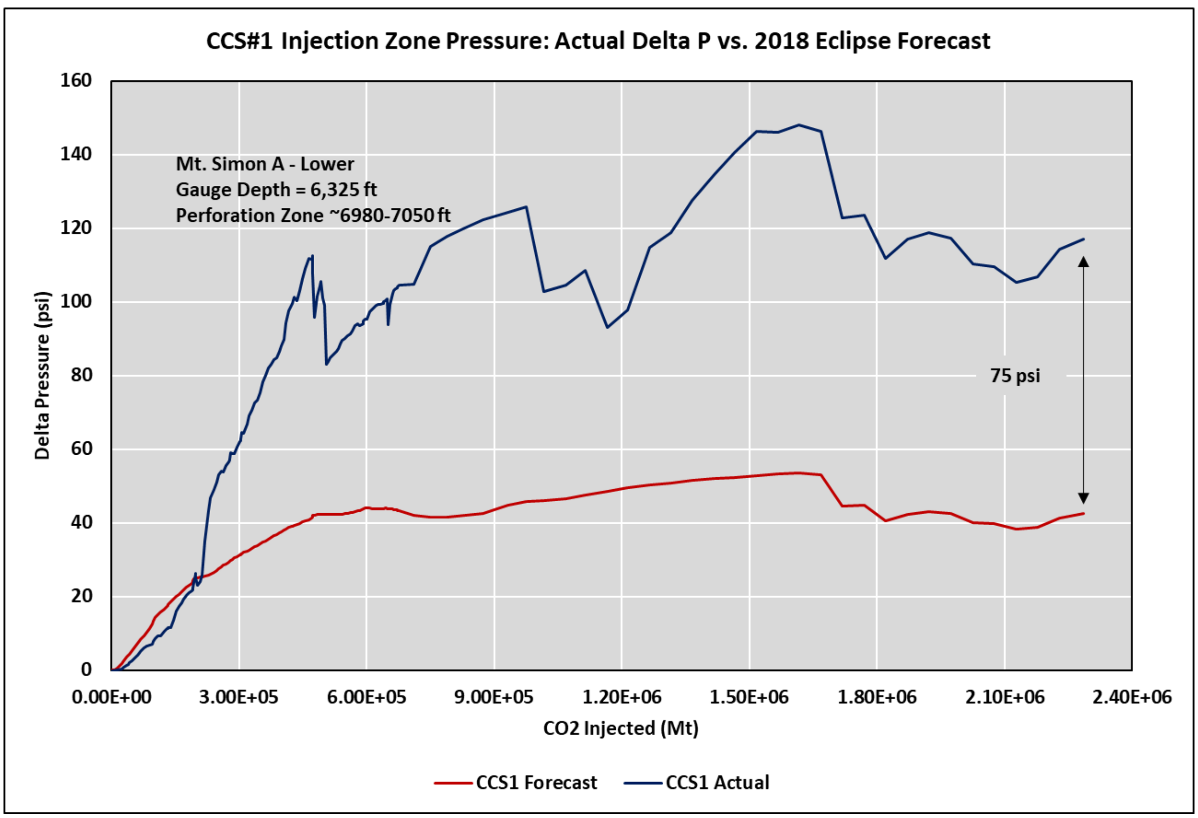

Figure 16: CCS#1 injection zone actual reservoir differential pressure versus 2018 Eclipse forecast.

Discussion of Results – Pressure-Front Tracking

Table 9 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 VW#2-Zone 2 pressure had the greatest pressure response. The zonal pressure increased approximately 14.8% (ΔP=447 psi) over the baseline pressure. VW#2-Zone 2 monitors the Mt. Simon A Upper unit at a depth that matches the CCS#2 injection interval. VW#1-Zone 2 and VW#2-Zone 3 monitor the pressure in the Mt. Simon B unit. VW#1-Zone 2 monitors the top of the Mt. Simon B while VW#2-Zone 3 monitors conditions in the middle of the unit. The pressure responses in these zones are consistent with the development of a uniform pressure gradient. VW#2-Zone 4 monitors the Mt. Simon E unit and this zone's pressure response is consistent with the other monitoring zones. The pressure response in the Mt. Simon A Lower unit is monitored in Zone 1 for VW#1 and VW#2 and these readings appear consistent with the other data.

Table 9: VW#1 and VW#2 injection zone pressure monitoring.[1]

	VW#2 (2,600 ft)[3]				VW#1 (2,700 ft)[3]	
Depth[2]	7,041 ft	6,681 ft	6,524 ft	5,848 ft	6,970 ft	6,420 ft
Formation	Mt Simon A Lower	Mt Simon A Upper	Mt Simon B	Mt Simon E	Mt Simon A Lower	Mt Simon B
Zone	Zone 1	Zone 2	Zone 3	Zone 4	Zone 1	Zone 2
Pre-Injection	3,207	3,031	2,954	2,620	3,165	2,922
Average	3,243	3,378	3,173	2,652	3,216	3,165
Maximum	3,244	3,478	3,200	2,654	3,217	3,235
Max Delta P	37	447	245	34	52	313
% Change	1.15%	14.75%	8.30%	1.30%	1.64%	10.71%

Note 1: Data Collection Time Period = 7/1/20 - 1/1/21. 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. Observation the Upper Mt. Simon A (VW#2 - Zone 2) shows the pressure was steady at 3,400 psia and dropped off in two steps in May 2021. This occurred as a result of the deep groundwater sampling that occurred in VW#2. The native wellbore fluids had a significant amount of dissolved CO_2 which was a result of the last round of groundwater sampling (specifically Zone 2) which occurred in December 2020. Zone 2 has free phase CO_2 at the wellbore and any cycling of Zone 2 or 3 will result in CO2 leaking into the wellbore. Because of the difficulty in cleaning up this fluid normally done by purging the upper zones, fresh water was injected into the wellbore and the native fluids were displaced into Zone 2. This was done prior to sampling VW#2 and after sampling Zone 3 (last zone to be sampled). When sampling Zone 3, Zone 2 is cycled (open and closed) as part of the closing sequence therefore it is very difficult to prevent free phase CO_2 from entering the wellbore. All future groundwater sampling of VW#2 will be concluded by displacing the wellbore fluids into Zone 2.

Regarding the other monitoring zones, only modest changes in pressure are observed. No significant changes in the zonal temperatures are observed. These figures also illustrate the unstable operation of the Zone 3 gauges. The gauges raw (discrete) data was extracted and subjected to extensive filtering to remove any null value. Even with these values removed, one can see variation in the temperature not observed in the other instruments. As discussed previously, we are examining options to mitigate any reduction or loss of data and maintain the fidelity of our monitoring system. Figure 19 and Figure 20 show the downhole pressure and temperature for the two Mt. Simon monitoring zones in VW#1. From these figures, a modest increase in injection zone (Zone 2a and 2b) reservoir pressure (25 psia) is seen during the monitoring period, while no change in reservoir temperature is evident.

Figure 21 shows the downhole pressure and temperature for CCS#1. From this figure, one observes greater fluctuations in reservoir pressure (Mt. Simon A – Lower unit) not observed in the other monitoring wells. Despite this artifact, the overall pressure response generally trends with the other Zone 1 gauges. Figure 22 compares the CCS#1 pressure with the zonal 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 wells (VW#1 & VW#2). As previously mentioned, this seems to indicate that proximate to CCS#1, the pressure is being transmitted from the Mt. Simon A Upper (injection interval) to the Mt. Simon A Lower.

Figure 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 the 96 hours (4 days) moving average of the CCS#2 injection pressure. When compared to historical trends, this effect is significantly less pronounced at the currently lower CCS#2 injection rates. This indicates that the injection pressure from CCS#2 is readily transmitted to CCS#1 with a four-day lag. The following discussion is provided to explain the pressure response observed within this unit.

As previously reported in the site's core and petrophysical logging data, a thin impermeable (mudstone) layer separates these two geologic units and retards the pressure transmission between the injection interval and the lower units. This layer is extremely thin having a thickness measured in inches and was thought to be extensive at our site. But a review of the petrophysical logs reveal some differences that indicate this layer may not exist proximate to CCS#1. Figure 24 shows the site's petrophysical data acquired from the well logs. This figure details the position of the mudstone layer at each well location. Reviewing the CCS#2, VW#1, and VW#2 data, a sharp decrease (spike) in permeability is seen and this feature helps defines the existence and position of this layer. This permeability artifact is not apparent in the CCS#1 well data. This indicates that the layer is pinching out creating an area of greater vertical permeability proximate to the CCS#1 well bore. As the pressure flux develops in the Upper Mt. Simon A, these areas of higher vertical permeability allow localized pressure transmission to the Lower Mt. Simon A producing a localized pressure flux within this unit. This would explain the Lower Mt. Simon A pressure monitoring data that shows the development of a localized pressure gradient at CCS#1 that corresponds to the pressure gradient in the injection zone (Mt. Simon A – Upper Unit). Several other factors, not mentioned above, may also be contributing to the pressure effect observed in CCS#1. The project's geotechnical team has reviewed the data and recommended additional changes to the site's static geologic (Petrel) model to account for these observations. The updated 2018 model included these changes, but further evaluation of the site data may be needed to better understand this effect.

Figure 25 delineates the MESPOP (pressure front = 62.2 psi) predicted by the original 2016 Eclipse model as well as the updated 2018 Eclipse model. From this figure, one observes that the 2016 model's pressure front area is about 100% greater than the pressure front predicted by the updated 2018 model. Several factors account for this change and will not be reviewed in this report. Please refer to *Technical_Report_Ref_CS1903-001-SYL.pdf* submitted as supplemental information in the last semi-annual report #26. The current pressure front extends approximately 10,725 feet from the injection well and covers an area of approximately 361 million square feet.

Discussion of Results – Plume Tracking

During the reporting period, no geophysical monitoring (pulsed neutron or surface seismic) was conducted to monitor the movement of the CO_2 plume. However, it is evident that CO2 arrived at the monitoring well during the last reporting period (Sep 22, 2020) when it was determined that the Zone 2 sample was saturated with CO_2. Figure 26 delineates the current and final position of the plume front and as predicted by the 2018 Eclipse model. The current plume front has an area of 36.5 million ft^2 with an estimated boundary extending about 3,600 ft from the injection well. The figure also shows that the plume front has passed VW#2. Using the updated model, the plume front passed VW#2 after injecting approximately 1.8 million Mt of CO_2; confirmed by the Sep 2020 round of deep ground water sampling.

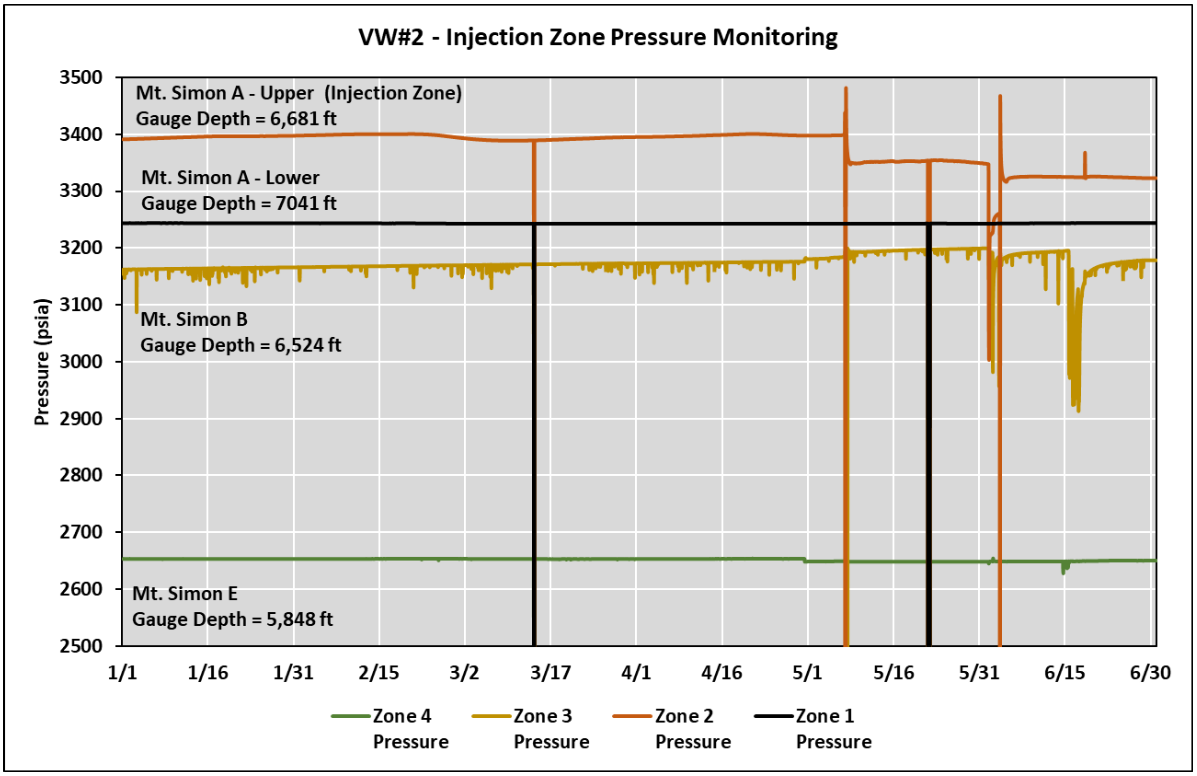

Figure 17: VW#2 injection zone pressure monitoring data for Jan-Jun 2021.

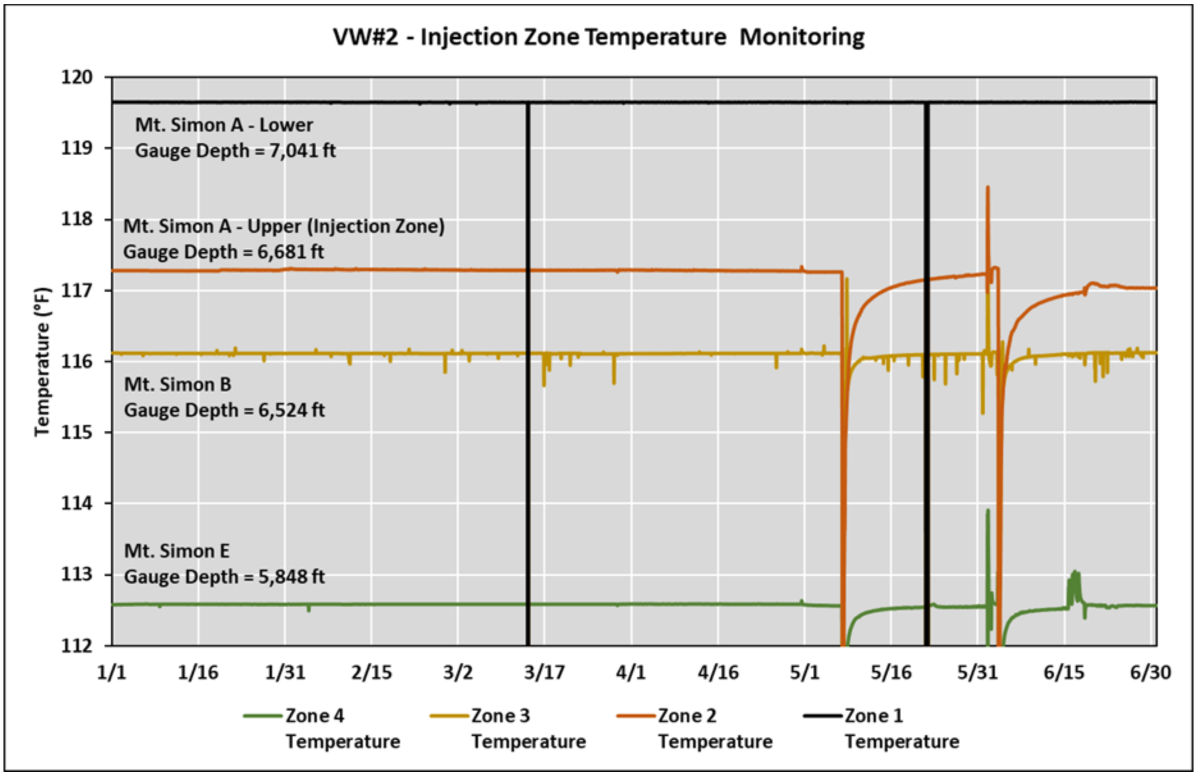

Figure 18: VW#2 injection zone temperature monitoring data for Jan-Jun 2021.

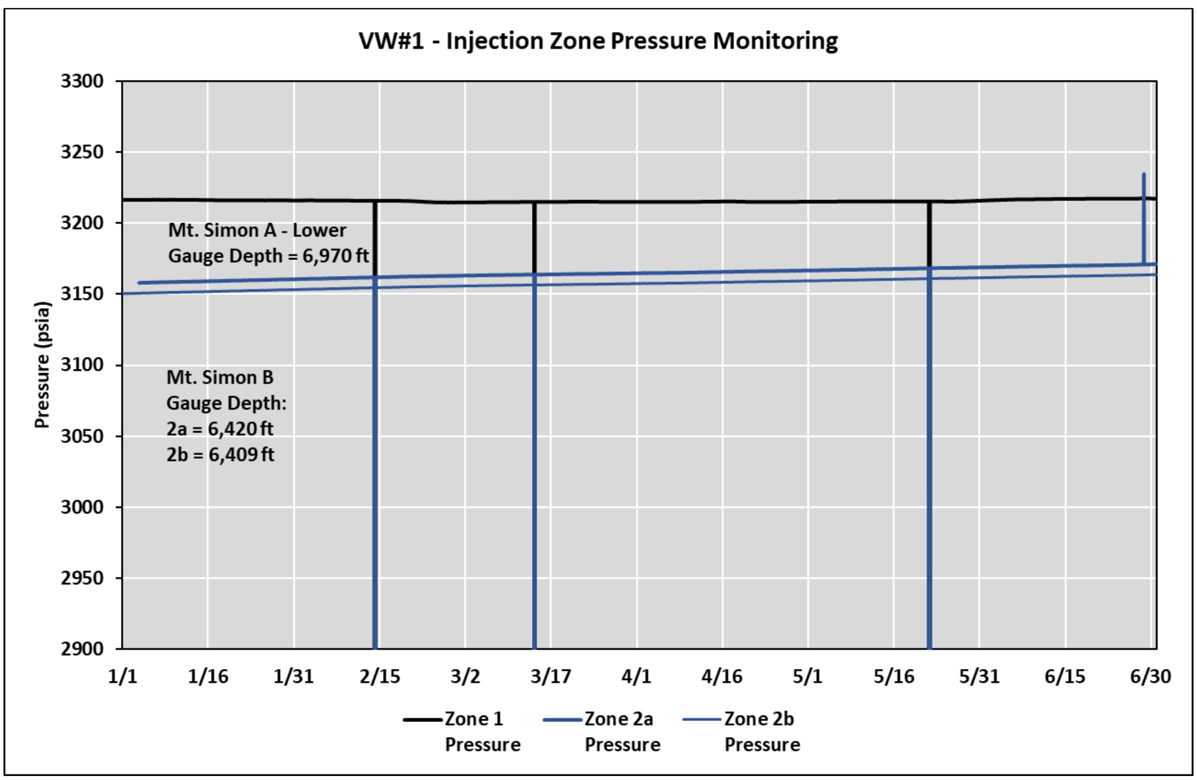

Figure 19: VW#1 injection zone pressure monitoring data for Jan-Jun 2021.

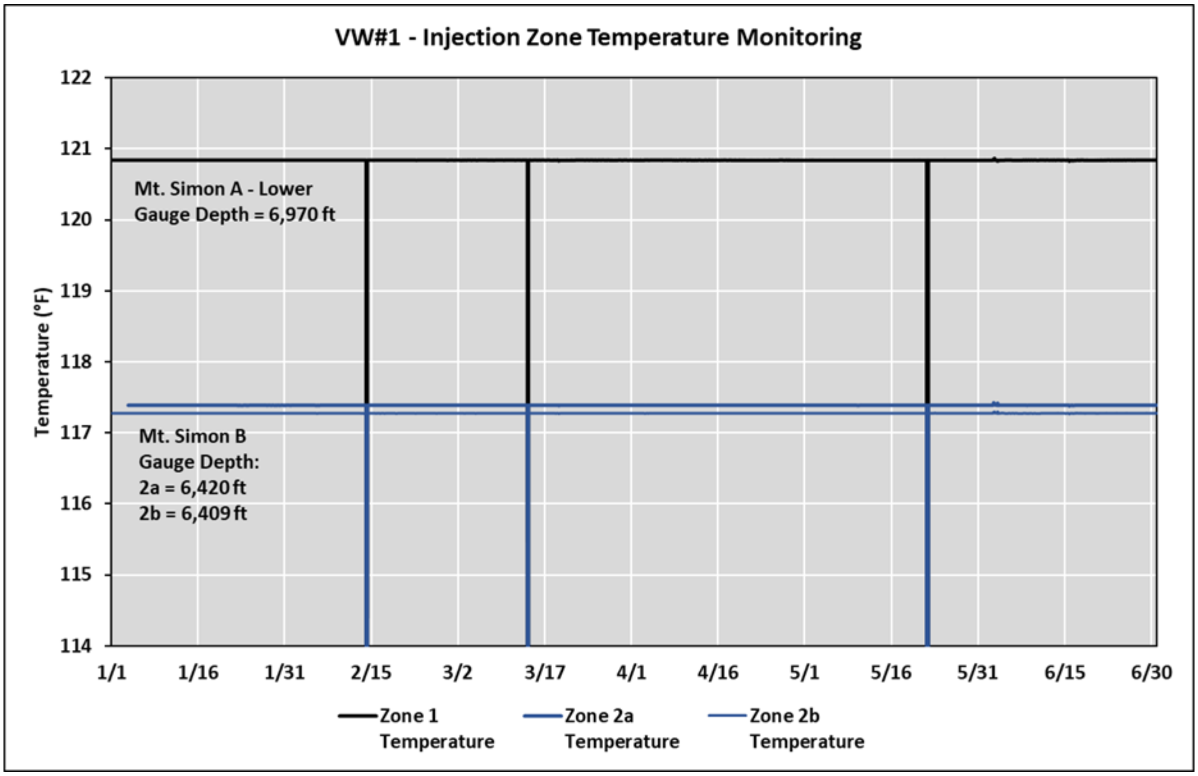

Figure 20: VW#1 injection zone temperature monitoring data for Jan-Jun 2021.

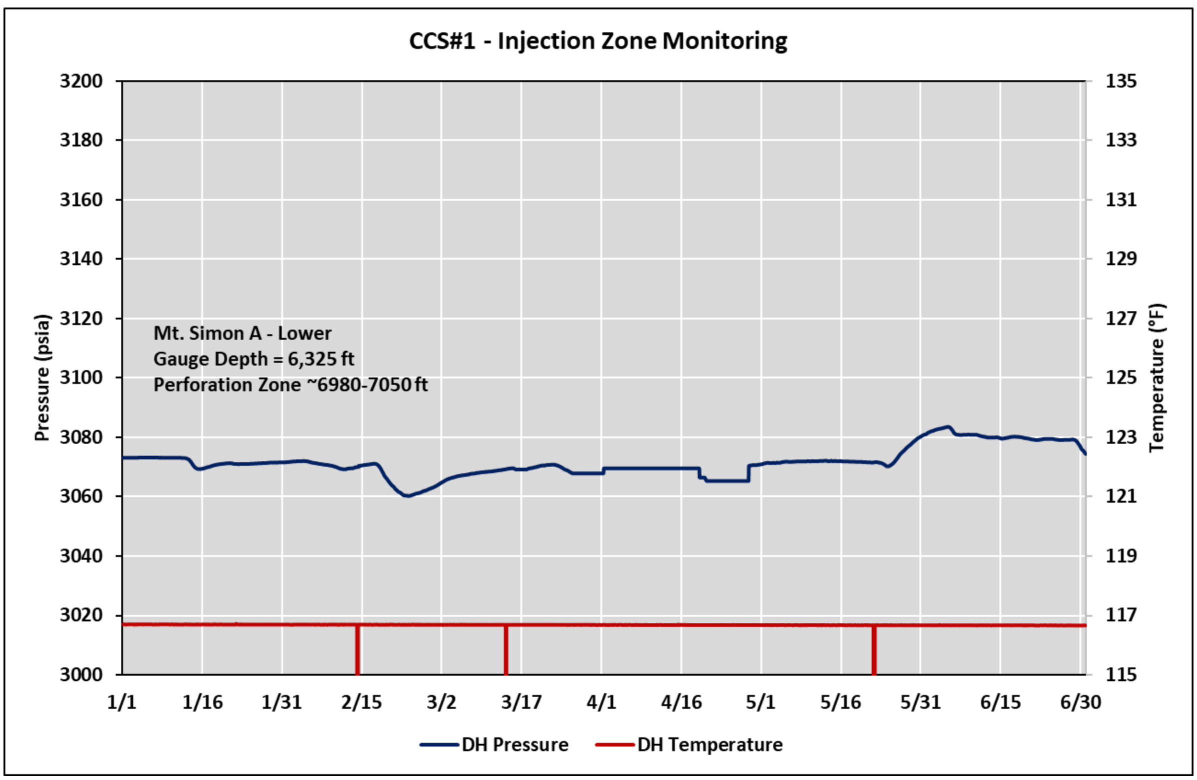

Figure 21: CCS#1 injection zone temperature & pressure monitoring data for Jan-Jun 2021.

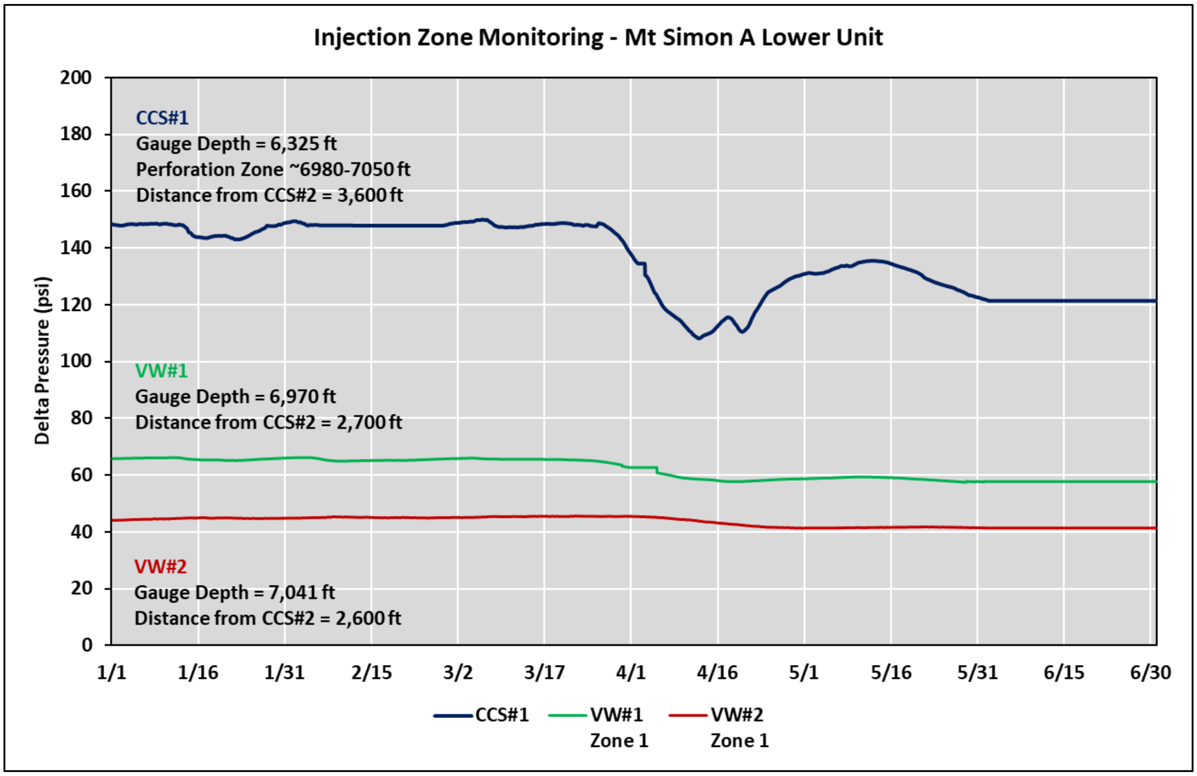

Figure 22: Comparison of the pressure change in the Mt. Simon A Lower at CCS#1, VW#1, and VW#2.

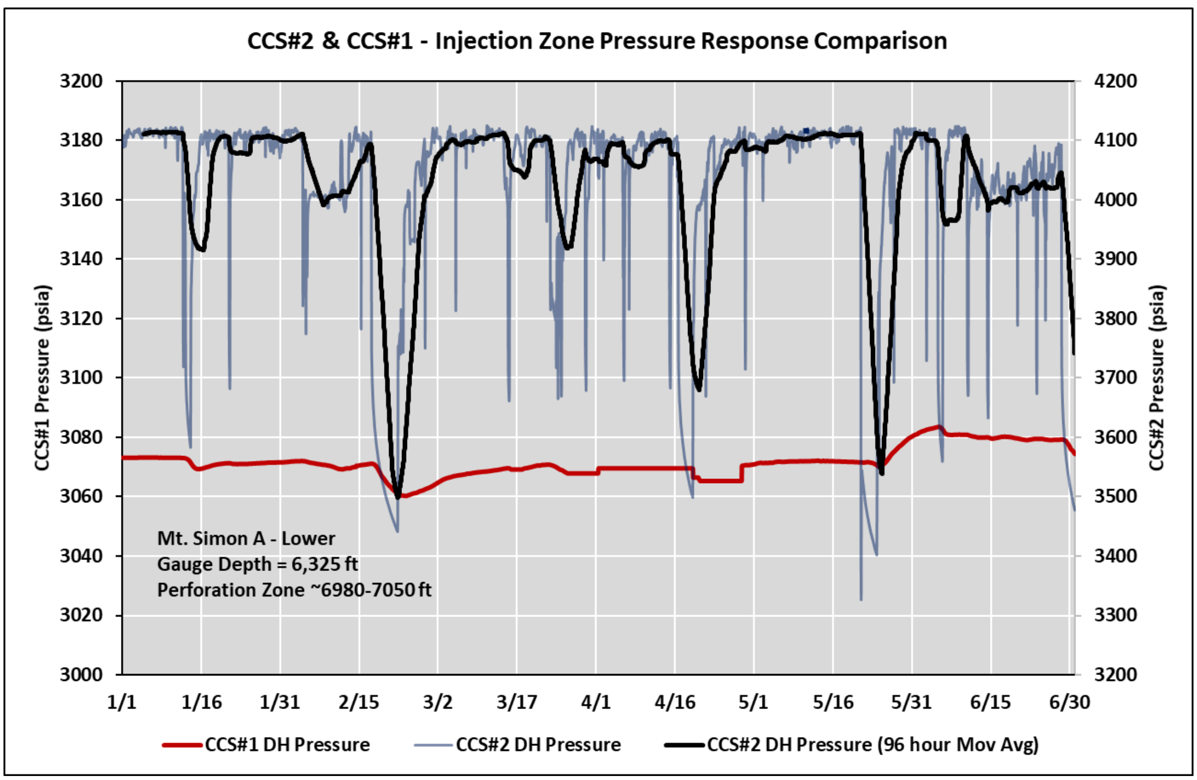

Figure 23: Comparison of the CCS#1 pressure response to CCS#2 injection pressure.

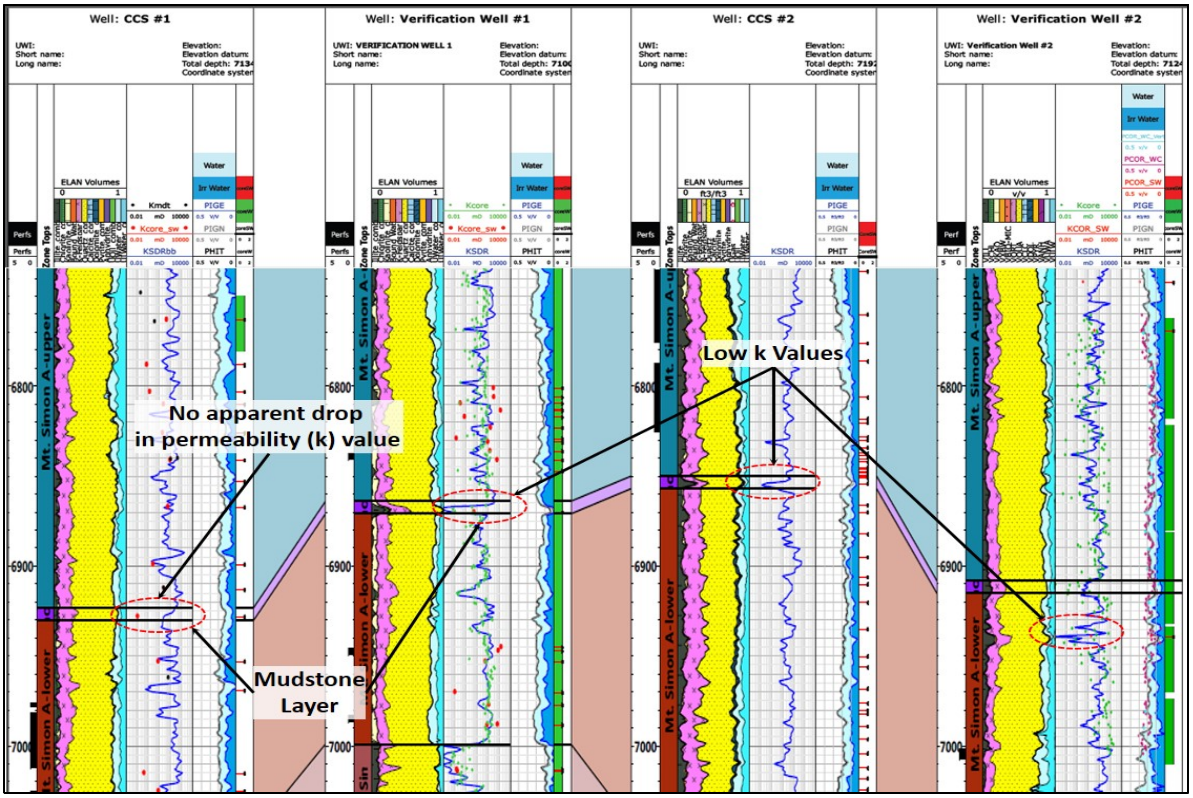

Figure 24: Geophysical logs detailing the location and properties of the mudstone layer separating the Upper Mt. Simon A from the Lower Mt. Simon A.

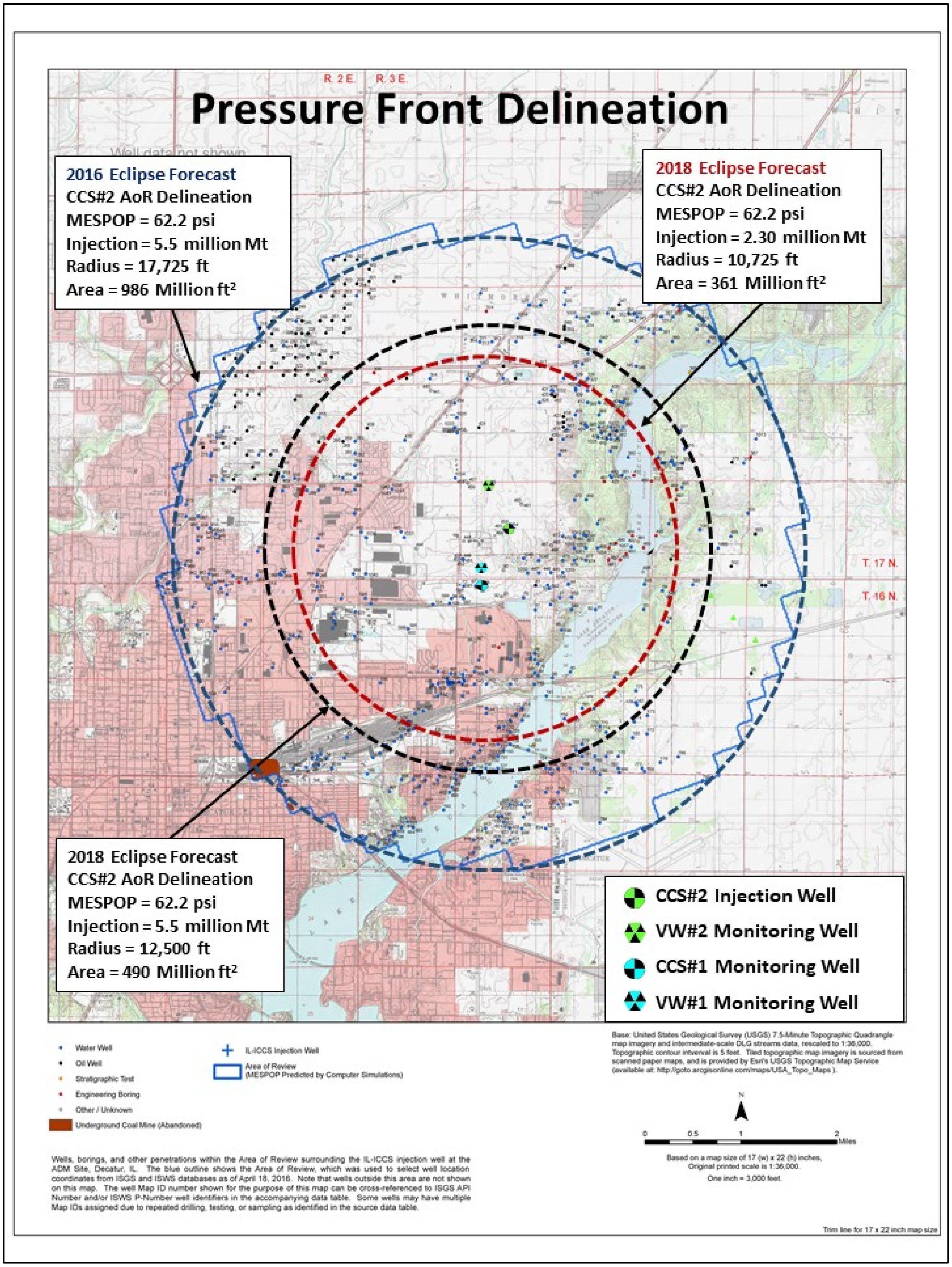

Figure 25: Pressure front delineation of the 2018 Eclipse model versus the 2016 Eclipse model.

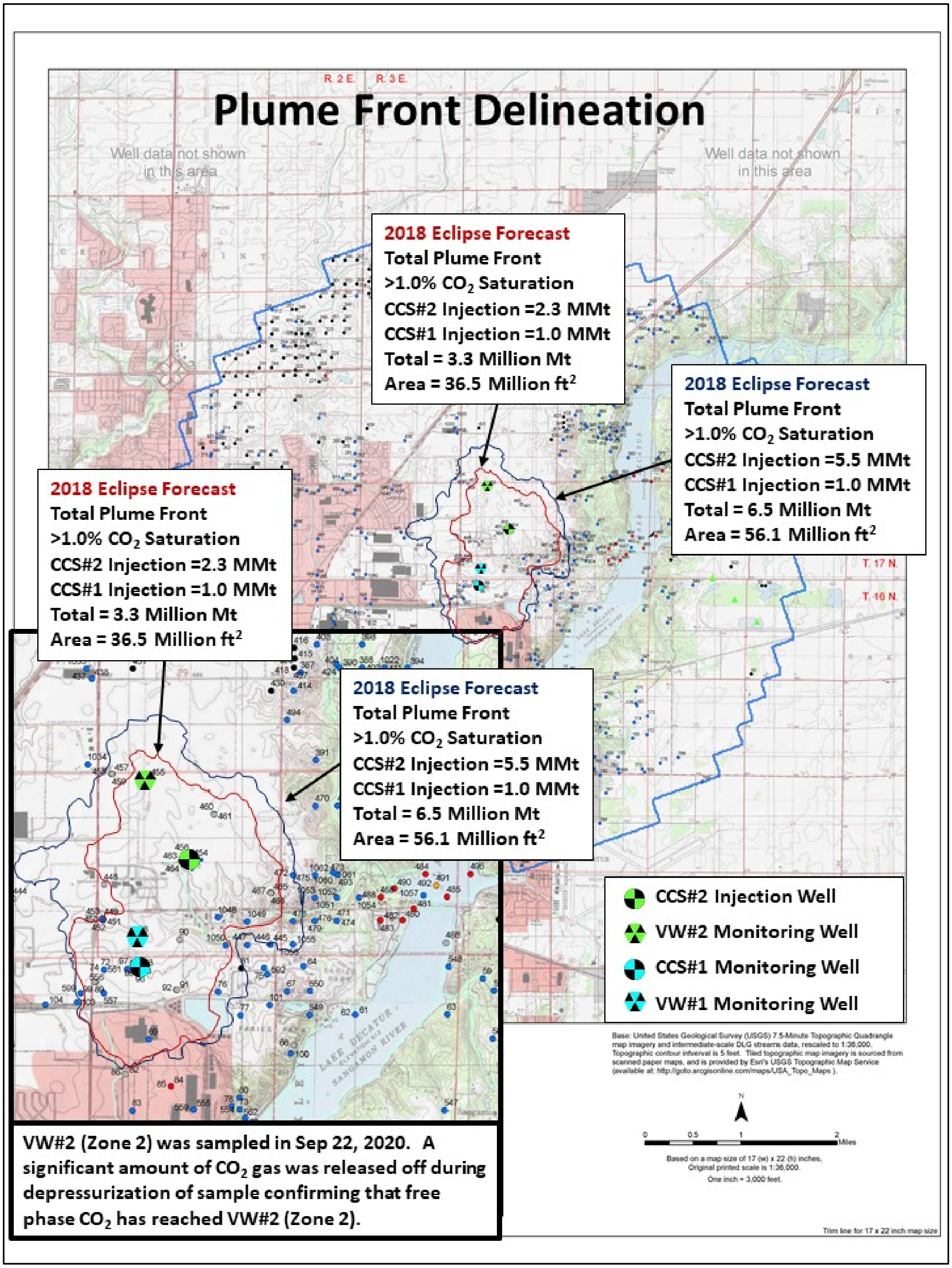

Figure 26: 2018 Eclipse model's plume front delineation for July 1, 2021 and after the total injection of 6.5 million Mt (CCS#1=1.0 million Mt and CCS#2=5.5 million Mt).

Supplemental Material
No supplemental information to be provided.

10. Other Testing and Monitoring

On April 7, 2021, the CCS#2 down hole pressure and temperature gauges were checked against a calibrated set of retrievable temperature and pressure gauges. The downhole gauges were within tolerance and the results are submitted as supplemental information.

Supplemental Material

DH Gauge Calibration Report:	***20210407_CCS#2_BHPT_Cert_Rpt.pdf***
DH Gauge Calibration Data:	***20210407_CCS#2_BHPT_Cert_Data.xlsx***
DH Gauge Tool Instrument Certification:	***20210407_Tool_#4261_Calibration_Cert.pdf***
CCS#2 Backflow Report:	***20210521_ADM_IL-115-6A-0001_CCS#2_Well_Back_Flow_Rpt.pdf***