Macon CarbonSAFE

Analyses of Well Testing at T.R. McMillen#2 Drilled in CarbonSAFE Illinois - Macon County

Task 7

Technical Report

April 1, 2017 through March 31, 2022

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I. Introduction: McMillen Well Testing Program

As part of the CarbonSAFE Illinois – Macon County Project, the Illinois State Geological Survey (ISGS) at the University of Illinois at Urbana-Champaign designed, conducted, and analyzed production and injection testing of the T.R. McMillen #2 (TRM2) well, located in the Mt. Auburn Oil Field in Christian County, IL. The Eau Claire, Mt. Simon Sandstone, and Precambrian formations were tested. The ISGS contracted with Geostock Sandia and Projeo Corporation to support and manage field testing operations and with Podolsky Oil Company, who was the well owner. Projeo Corporation completed an operations report for the TRM2 (attached).

II. Testing Procedure

Multiple single-well, multirate well tests of the TRM2 were conducted between June 7, 2019, and October 31, 2019. These included Step Rate Tests (SRT), Vertical Interference Tests (VIT) (or Pulse Tests, PT), Pressure Falloff Tests (PFO), and Pressure Buildup Tests (PBU). (Minifrac tests [MFT] were attempted but either failed or gave no results differing from other tests and are not included in this report.) The pre-frac steps of each SRT can be analyzed as a Multirate test (MRT) but are representative of very near-wellbore characteristics. All analyses require formation pressure (i.e., bottomhole pressure, bhp) and flow rate (injection and production) data measurements.

The test program was designed for permeability, initial pressure, fracture gradient, and any large-scale geologic features affecting rate and pressure. VITs were used to determine vertical communication and vertical permeability between perforated intervals above (AZ) and/or below (BZ) the injection zone (IZ). SRTs were used to determine fracture gradient. PFO tests were used for permeability, initial pressure, and large-scale geologic features. Multirate tests (MRT) were used for permeability when other analyses were inconclusive.

Porous and permeable test intervals were chosen based on project interest, porosity logs, permeability estimates (from core and permeability transform), cement bond logs, and formation microimager (FMI) logs. Small, 5-ft perforated intervals were chosen for all tests; this allowed use of smaller volume pumps that were lower in cost and afforded week-long tests for each injection test interval. Moreover, a 5-ft *perforated* interval into a much larger *test* interval causes a partial penetration pressure transient effect that can be analyzed for vertical permeability *within* the test interval (**Table 1**). (Note that vertical interference testing was designed to record data that could be analyzed for vertical permeability *between* perforated intervals.)

After the test interval was perforated, so that each test could start at near initial pressure, no swabbing (i.e., fluid production) was done. Consequently, the first injection into each perforated interval was expected to have low communication initially with the test interval. The exception was MtSA2, which first had a production (or flowing) test before its injection test. For short-term tests (SRT and VIT), a liquid-filled tubing string was desirable to reduce wellbore storage (WBS) effects and increase discernable reservoir pressure response from each test. As such, for test intervals that could not support test brine to surface following overnight or longer shut-ins, additional test brine was added to the tubing under no direct pressure, so that the bottomhole pressure increase was due to increase in hydrostatic head of test brine and not increase in pressure due to resistance of test fluid entering the perforated interval. The addition of test brine to fill the injection tubing is identifiable on pressure-time graph as a linear increase in pressure vs. time, as the hydrostatic head of test brine increases pressure without additional increase due to resistance of the test interval.

A mixture of Mt. Simon brine (9.3 lb/gal) and freshwater (8.3 lb/gal) was used as the test brine. The mixed density was measured as 8.6 lb/gal. The Mt. Simon brine density and salinity were 9.3 lb/gal and salinity of 180,000 ppm, respectively. Using measured density of each fluid, a 30-70 mixture of brine-freshwater was calculated. Based on this mixture, a salinity of 54,300 ppm was estimated. All injection tests used a mixture of freshwater and Mt. Simon brine.

Table 1: Summary of test intervals. Because of uncertainty in well log measurements in crystalline basement rock, the perforated interval and test interval were equal.

Formation Name	Abbreviation	Perforation interval, feet	Test interval depth and thickness, feet	Average porosity from log, %
Eau Claire	EC	5,098-5,103 5.0	5,098-5,103 5	8.0
Mt. Simon E	MtSE	5,190-5,195 5.0	5,175-5,219 44	13.4
Mt. Simon A2	MtSA2	6,219-6,224 5.0	6,193-6,250 47	20.2
Mt. Simon A1	MtSA1	6,260-6,265 5.0	6,252-6,300 48	23.8
Precambrian 2	PC2	6,370-6,375 5.0	6,363-6,386 23	~5
Precambrian 1	PC1	6,415-6,420 5.0	6,387-6,420 33	~3

To acquire VIT data during each injection test, memory gauges were placed outside of the tubing string for AZ testing and below a retrievable bridge plug for BZ testing. The IZ test data was from surface readout electric line gauge and an IZ memory gauge placed outside of the tubing string (**Figure 1**).

Because the testing program for each test interval included an SRT and/or MFT that was designed to induce a small vertical fracture, it is possible that VITs for adjacent perforated intervals may not follow the principle of reciprocity. In other words, the k_v/k_h between two intervals may be different because for the first VIT, the fracture may not exist, and for the second VIT, the fracture may exist. Therefore, the chronological order of the intervals tested is important (**Table 2**).

Table 2: Chronological order of TRM2 well testing.

Testing order	Test Intervals	Injection / Production
1	MtSA2	Production
2	MtSE	Injection
3	EC	Injection
4	MtSA1	Injection
5	MtSA2	Injection
6	PC2	Injection
7	MtSA1-A2	Test fluid disposal (injection)

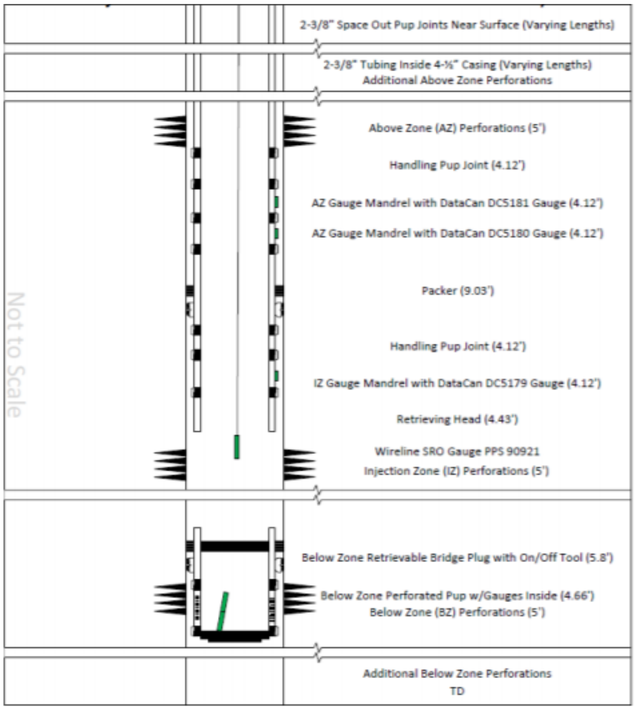

Figure 1: General description of the pressure gauge and packer locations for IZ, BZ, and AZ testing (from Projeo report).

III. Production Test Interval: Mt. Simon A2

A. MtSA2-Production Test Interval Overview

A 5-ft interval (6,219-6,224 ft MD) was perforated to test a 47-ft sub-interval (**Figure 2**) of the Mt. Simon Sandstone–A. (For this well test program, this interval was MtSA2 because another Mt. Simon Sandstone–A was tested, MtSA1; see **Table 1**.)

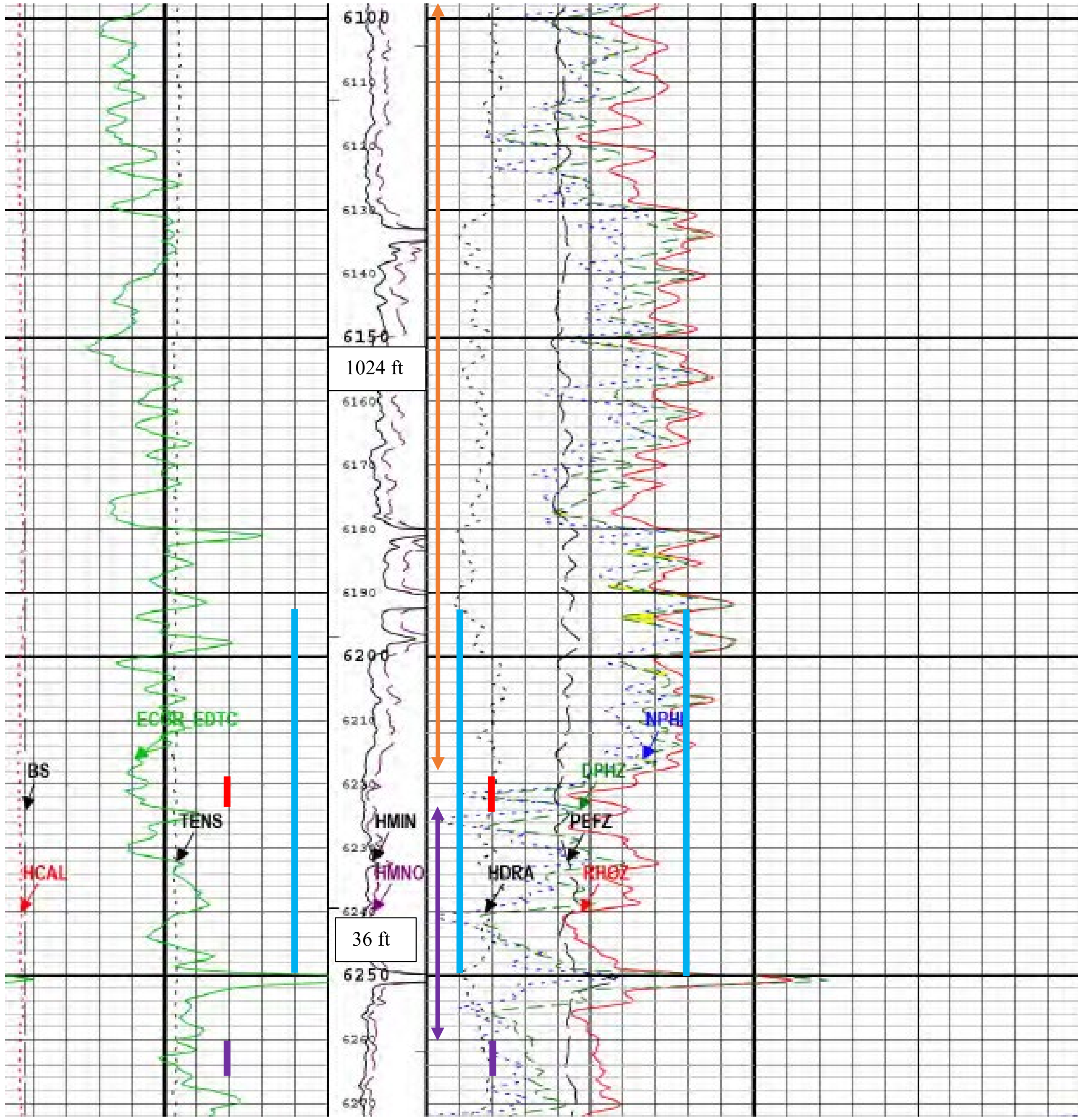

Figure 2: MtSA2 test interval (6,193-6,250 - blue vertical bar) and perforated interval (6,219-6,224 - red vertical bar): Track 1: Gamma ray (green); Depth track-calculated microlog; Track 2 and 3: Porosity log (scale 0.3 to -0.1, left to right); Neutron (blue) and density (green). AZ perforated interval (5,190-5,195 - orange arrow) and BZ perforated interval (6,260-6,265 - purple vertical bar) included. Distance between perforations shown by arrows.

The production well test program had two components: 1) well flowing to surface and 2) well pumping, in this order. As part of the perforation and swabbing process of MtSA2 only, the casing was filled with freshwater. The hydrostatic pressure of the freshwater was inadequate to balance the pressure of the MtSA2. Consequently, while waiting for formal testing to begin, the well was opened and shut-in periodically to provide buildup data for analyses.

Initially, the sole purpose of flowing the well was to kill the well prior to running a pump into the casing for production well testing using a submersible pump. Because the flow periods were planned during the daytime when staff were on location, the well was planned for shut-in (SI) overnight or until the next time staff was on location. This provided a unique opportunity to collect surface pressure data and conduct informal pressure transient analyses. A flow meter was not used, but the well was flowed into a container, and cumulative production for each time period was recorded so that a single, constant rate could be calculated for each flow period. Because the flow periods were of short duration (10 mins to 3.5 hrs), the primary objectives of the MtSA2 production well tests were to detect the partial penetration effect and estimate vertical and horizontal permeability.

Because the primary objectives of the MtSA2 production well tests were permeability, identify presence of outer boundary, and measure data to make rate-pressure relationships, flow periods of several weeks were planned during pumping tests. (Another objective was to produce water for use in subsequent injection tests.) Several flow meters were used, and rate data was recorded as frequently as the pressure data was recorded.

B. MtSA2-Production Vertical Interference Tests (Pulse test)

Only MtSA2 was perforated. No VIT was possible.

C. MtSA2-Production Step Rate Tests

No SRT was conducted during the production tests of MtSA2.

D. MtSA2-Production Pressure Falloff Tests

Flowing well: Flow periods varied from 10 mins to 3.5 hrs. Shut-in periods varied from 2 to 4 days. Five of the six SIs were analyzed. (One test failed to measure pressure during SI). Three of the four tests analyzed had very short flow periods and were not interpretable. An example derivative plot (**Figure 3**) of one of the two interpretable tests shows an initial unit slope over a ½ log cycle of time followed by a ¼ log cycle of time with a zero slope; this is likely WBS but may be early radial flow across the perforations. From 36 secs and 1 hr, two log cycles of time exhibit a definitive partial penetration effect (-½ slope from which k_v/k_h can be estimated). From 1 hr through the end of the test, nearly two log cycles of zero slope are present, exhibiting radial flow from which k_h can be calculated.

Vertical thickness is required to estimate permeability. Because the separation in the pressure and derivative curves is not too large and radial flow starts early and is extended over one log cycle (time), the vertical thickness of the formation tested is likely not very large or k_v/k_h (ratio of vertical to horizontal permeability) is high. The permeability-thickness product (k-h) is about 2,400-5,400 md-ft. As typical with well testing, to estimate permeability, an assumption must be made for the thickness of the interval tested. For effective thickness of 47 ft, the k_h is 50 to 110 md, and k_v/k_h is 0.0061 to 0.030.

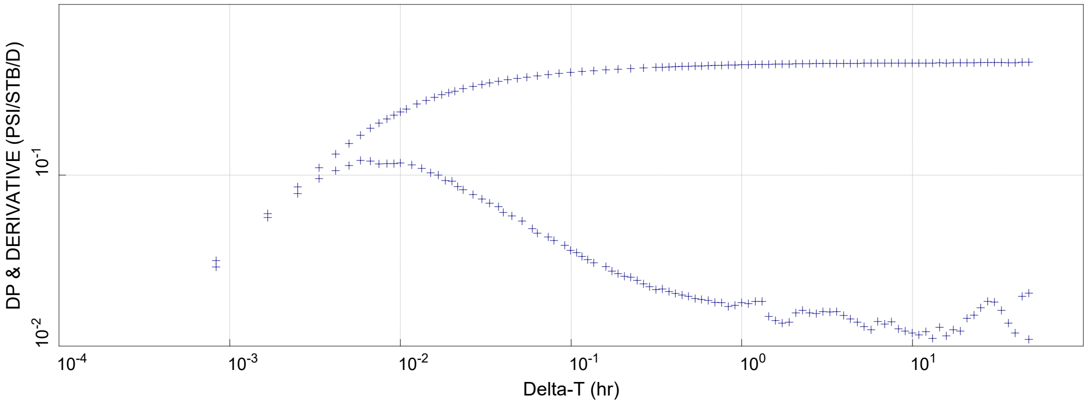

Figure 3: Example of MtSA2 derivative plot of an SI period test following the well flowing to surface SI period. (Upper curve is pressure, and lower curve is derivative.) Derivative plots of SI periods following flowing well conditions had similar appearances: a unit slope through about 20 seconds, followed by a short zero (0) slope (30 secs to 1 min). From 1 min to 1 hr (nearly two log cycles of time), a negative half-slope is present, which indicates partial penetration from which k_v/k_h ratio is calculated. The stabilization after 1 hr is indicative of a radial flow from which permeability is calculated; the small fluctuations are due to pressure gauge resolution in which pressure changed less than 1 psi in the last 60 hrs. The separation between the pressure and derivative curves indicates positive apparent skin, which is expected due to the partial penetration effect. (A logarithmic smoothing factor of 0.08 was used to calculate the derivative.)

Pumping well: Following a series of MRT, a PBU was conducted. A rate of 2.0 gpm (~70 bpd) was maintained for ~10 days, at which time injection stopped and a 4-day SI period of the buildup test started. The rate of 2.0 gpm was chosen based on the maximum pump speed available for this long-term project.

The derivative plot (**Figure 4**) shows a unit slope over 2 log cycles of time (<0.3 hrs), which indicates WBS dominated pressure. This is expected immediately after SI, when the maximum rate of increase in

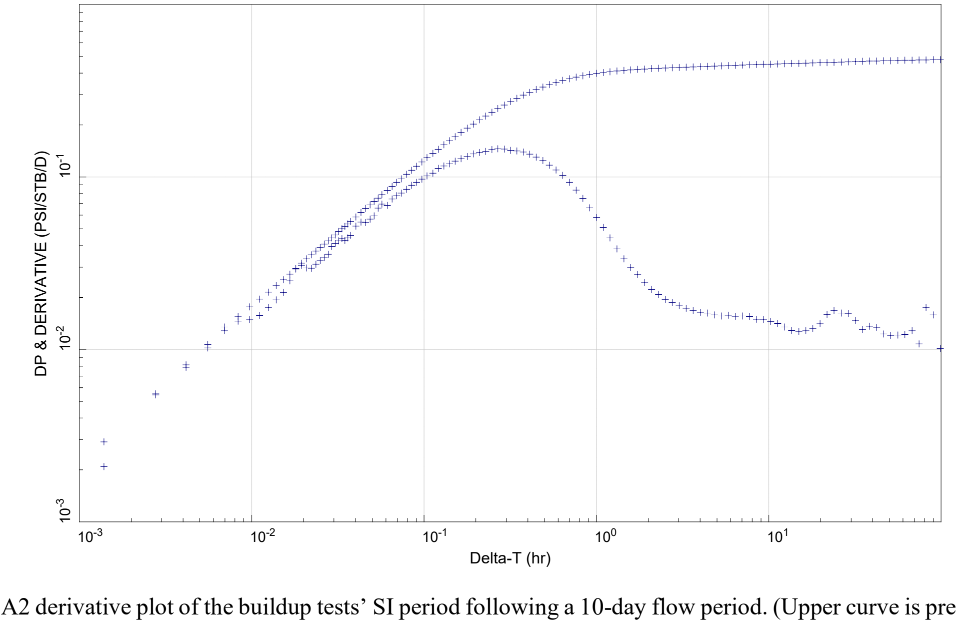

Figure 4: MtSA2 derivative plot of the buildup tests' SI period following a 10-day flow period. (Upper curve is pressure, and lower curve is derivative.) Through about 2 hrs, WBS dominates and influences the pressure, which is expected for a pumping well that lowers the fluid level. Beyond 2 hrs, the nearly zero slope trend indicates reservoir response from which permeability can be calculated. A half-slope indicative of partial penetration is not present and likely dominated by WBS, so no k_v/k_h ratio is calculated. The separation between the pressure and derivative curves indicates positive apparent skin, which is expected due to the partial penetration effect. (A logarithmic smoothing factor of 0.01 was used to calculate the derivative.)

fluid level (above the pressure gauge) occurs. WBS-influenced derivative continues until the derivative slope is nearly zero at 2 hrs. (A zero [0] slope is indicative of radial flow from which horizontal permeability is calculated.) No -½ slope is present. Therefore, the derivative of the buildup test does not show partial penetration, and there is no data from which to estimate k_v/k_h. The permeability-thickness product (k-h) from the radial flow period is about 4,900 md-ft over the entire test interval.

IV. Injection Test Interval: Mt. Simon E

A. MtSE Test Interval Overview

The primary objectives of the MtSE well tests were fracture gradient and permeability (horizontal and vertical). A 5-ft interval (5,190-5,195 ft MD) was perforated to test a 44-ft sub-interval (**Figure 5**) of the Mt. Simon Sandstone–E.

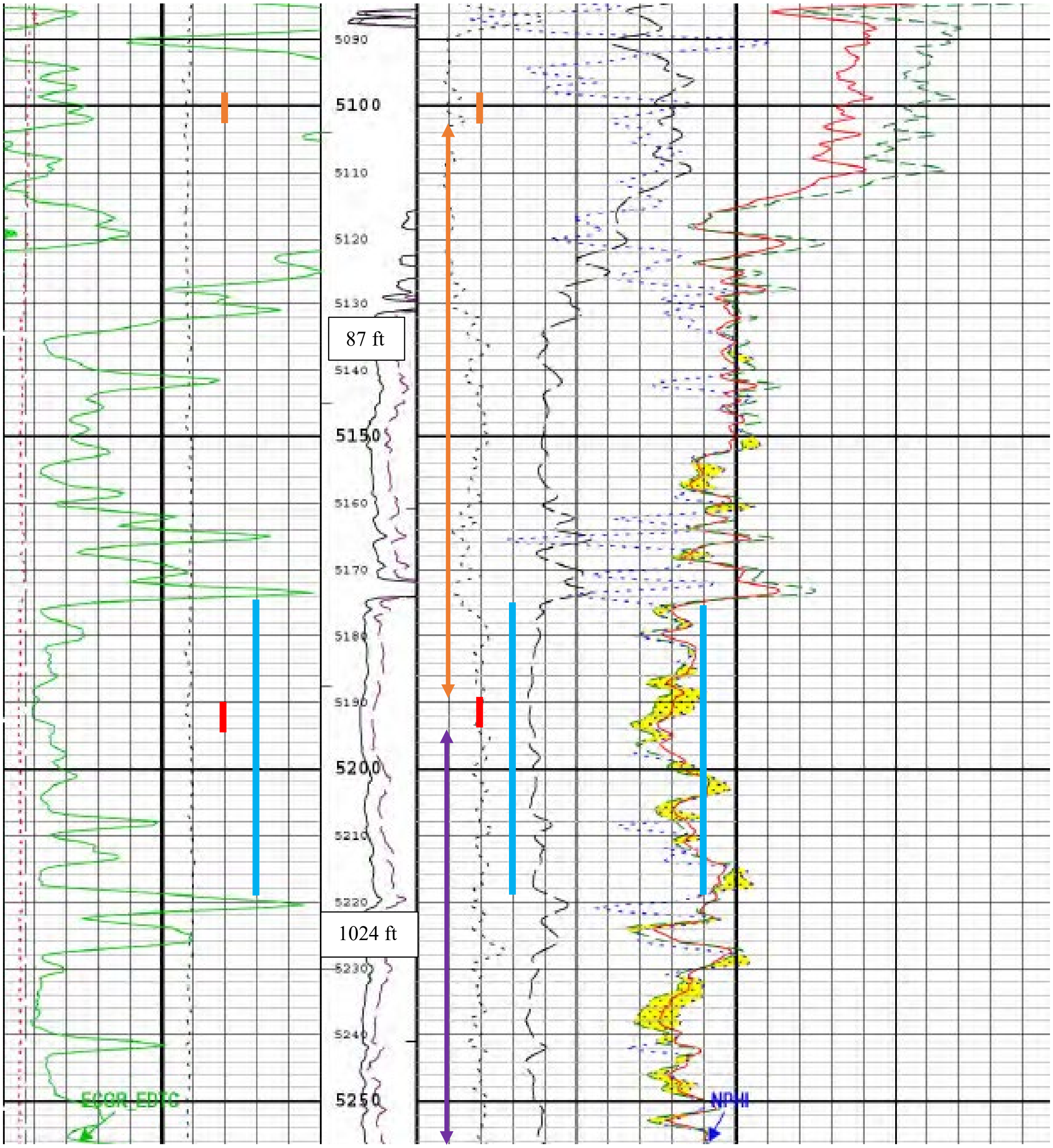

Figure 5: MtSE test interval (5,175-5,219 - blue vertical bar) and perforated interval (5,190-5,195 - red vertical bar). Track 1: Gamma ray (green); Depth track-calculated microlog; Track 2 and 3: Porosity log (scale 0.3 to -0.1, left to right); Neutron (blue) and density (green). AZ perforated interval (5,098-5,103 - orange vertical bar) and BZ perforated interval (6,219-6,224 - purple arrow) included. Distance between perforations shown by arrows.

The MtSE test interval was not able to sustain liquid level to surface overnight or during longer SI periods; consequently, test brine was added to the top of the tubing prior to short-term tests, which caused a very short period of linear pressure increase with time.

For the MtSE test interval, the AZ was EC, and the BZ was the MtSA2 (**Table 3**). Pressure transient analyses requires specific rock and fluid properties unique to each test interval's temperature and initial pressure. The salinity of the injected brine was used to estimate the test brine properties (**Table 4**).

Table 3: MtSE injection test of 5,190 to 5,195 ft from September 25 to October 2, 2019. Identification of gauge and formation included in the test. The BZ gauge failed for the MtSE injection tests, so VIT was not possible between MtSE and MtSA2.

Test Component	Formation Abbreviation	Gauge Depth	Gauge Number
IZ	MtSE	5,157	DC 5179
IZ	MtSE	5,190	SN 90921
AZ	EC	5,140	DC 5180
AZ	EC	5,136	DC 5181
BZ*	MtSA2	5,285	SN 9677

* BZ gauge failed; no VIT between MtSE and MtSA2 possible.

Table 4: MtSE test interval properties used in analyses.

Property*, units	Value	Source
Initial Pressure, psia	2,319	SN 90921 @ 5,190 MD
Temperature, F	98.9 (98.6)	SN 90921 @ 5,190 MD (DC 5179 @ 5,157 ft MD)
Porosity, %	13.4	Neutron-density log
Saturation, %	100	Assumed brine saturated
Pore Compressibility, psi^{-1}	4.586E-06	Newman's Correlation
Water Compressibility†, psi^{-1}	2.167E-06	Numbere et al.
Water Viscosity†, cp	1.028	Numbere et al.
Water Volume Factor†, rb/stb	1.007	Numbere et al.
Wellbore radius, ft	0.28125	Well log heading (6.75" bit)
Perforated height, ft	5	Projeo report
Sub-interval height, ft	44	Neutron-density log

*fluid properties are injected water properties.
†from online tool by Plano Research Corporation (planoresearch.com)

B. MtSE Vertical Interference Tests (Pulse test)

A three-pulse VIT followed the long SI period (~ 4 days) of a falloff test. A rate of 0.19 bpm was chosen to test below the fracture pressure determined by the SRT. Each injection period was 15 mins, followed by 15 mins SI. Unfortunately, the BZ gauge failed, so no VIT was possible with MtSA2—the BZ for the MtSE injection tests. The AZ gauge did not show any reservoir indication of communication between the MtSE and EC perforated intervals. Consequently, there was no analyses for vertical permeability between the MtSE and EC perforated intervals.

C. MtSE Step Rate Tests

SRTs were the first of the injection tests of the MtSE. The example SRT shown in (**Figure 6**) used 0.062 bpm in 30 min increments up to 0.43 bpm. The final pressure at the end of the final rate of this SRT was lower than the previous pressure, which indicated continued fracture growth. Therefore, this point was not used to select the line representing fracture flow. The test shows the fracture pressure as 3,713 psia at 5,190 ft MD, which is 0.712 psi/ft fracture pressure gradient, which was similar to the other two SRTs.

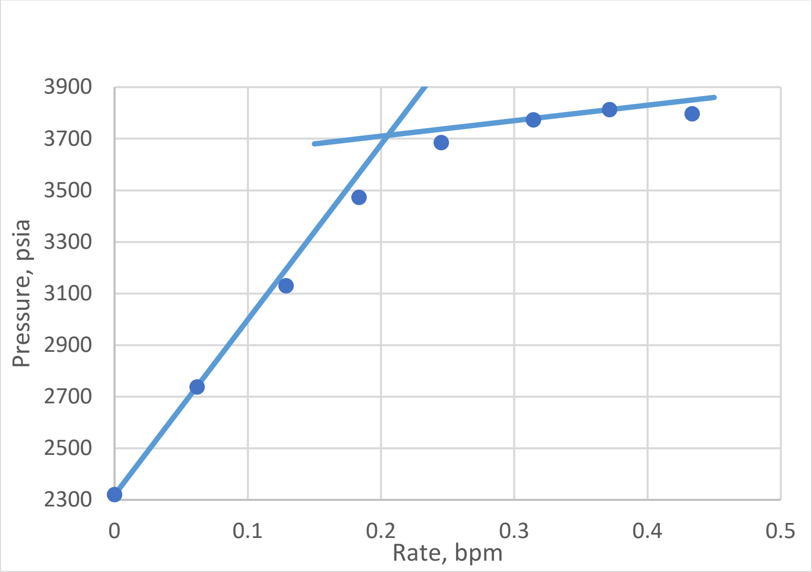

Figure 6: MtSE step rate test. E-line pressure gauge data (SN 90921) at 5,190 ft MD, the depth of the top perforation. The intersection of the two lines is interpreted as the fracture propagation pressure (3,713 psia). The initial pressure (2,319 psia) is the y-axis value at 0 bpm. The pressure at the last rate started to decrease, which is indicative that the fracture is increasing with the additional rate change. Therefore, the final point was not used.

D. MtSE Pressure Falloff Tests

Immediately following one of the SRTs, a 20-hr injection period was started, followed by a 4-day SI. A rate of 6 gpm was chosen to avoid exceeding the fracture gradient during the 20-hr injection. Pressure increased about 1,200 psi above the initial pressure, 200 psi below the fracture pressure.

The derivative plot (**Figure 7**) has an early unit slope (<0.01 hrs), which is interpreted as WBS. The zero slope and negative slope are transition from WBS (0.01-0.2 hrs). The near zero slope may be indicative of radial flow or a transition from WBS. Between 0.2 and 3 hrs, the derivative increase with about ½ slope could be linear flow from a hydraulic fracture. Because the well was not hydraulically fractured, this ½ slope may be related to the fracture created during the preceding SRTs; the calculated fracture half-length is estimated <10 ft, which is likely the dimension of a fracture created during the SRTs. However, because of the short duration of the ½ slope, it could be a transition from a higher to lower permeability for radial flow. From 2 to 3 hrs, a zero slope occurs that could be radial flow or another transition. After 3 hrs, the derivative decreases over 2½ log cycles (y-axis) across about one log cycle of time; this is indicative of a large increase in permeability-thickness. While noisy, the derivative appears to have a zero slope from 30 hrs to the end of the test. There is no distinctive, unique zero slope sustained over a log cycle of time indicative of radial flow.

Analyses of the second zero slope as radial flow gave 340 md-ft, which agreed with the MRT analyses of the pulse test injection data (280-420 md-ft). The large decrease in the derivative indicates higher permeability is being sensed by the test. This could be radial from the well or an adjacent layer with higher permeability. Analyses of this trend (>30 hrs) gives a permeability-thickness product of 10,000 md-ft, which seems very high for MtSE.

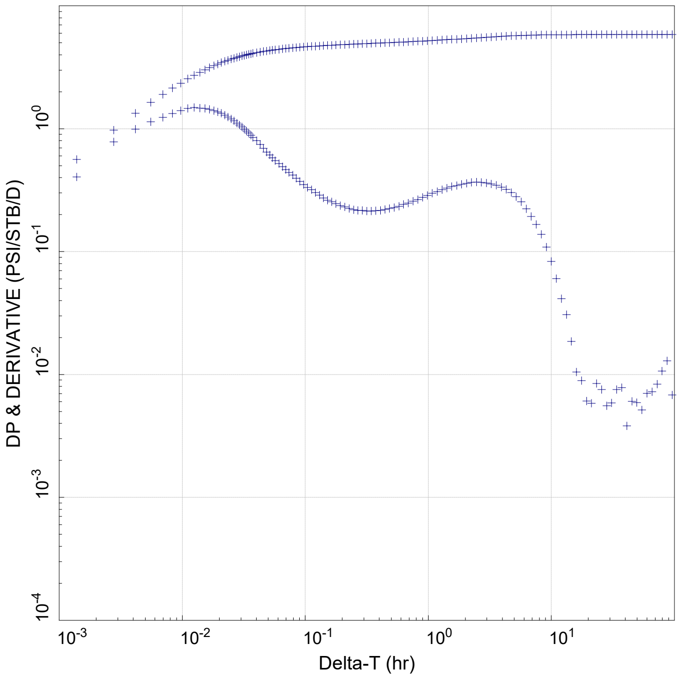

Figure 7: MtSE Derivative plot of falloff test's SI period. (Upper curve is pressure, and lower curve is derivative.) All derivative plots of SI periods had similar appearances: an initial unit slope through about 30 secs, followed by a zero (0) and a negative unit slope, indicative of WBS. The two zero slopes at about 0.3 and 3 hrs are across <½ log cycle time and not strong indication of radial flow. There is no -½ slope present and, thereby, no indication of partial penetration. During the final 1½ log cycles of time, the derivative decreases about 2 log cycles of pressure, which is indicative of a higher permeability than the permeability that influenced the earlier part of the test. (A logarithmic smoothing factor of 0.001 (pressure) was used to calculate the derivative.)

V. Injection Test Interval: Eau Claire

A. EC Test Interval Overview

The primary objective of the EC well tests was fracture gradient. A 5-ft interval (5,098-5,103 ft MD) was perforated to test a 5-ft sub-interval (**Figure 8**) of the Eau Claire Formation (**Table 6**). The EC test interval sustained liquid level to surface, and it was not necessary to add test brine prior to each test.

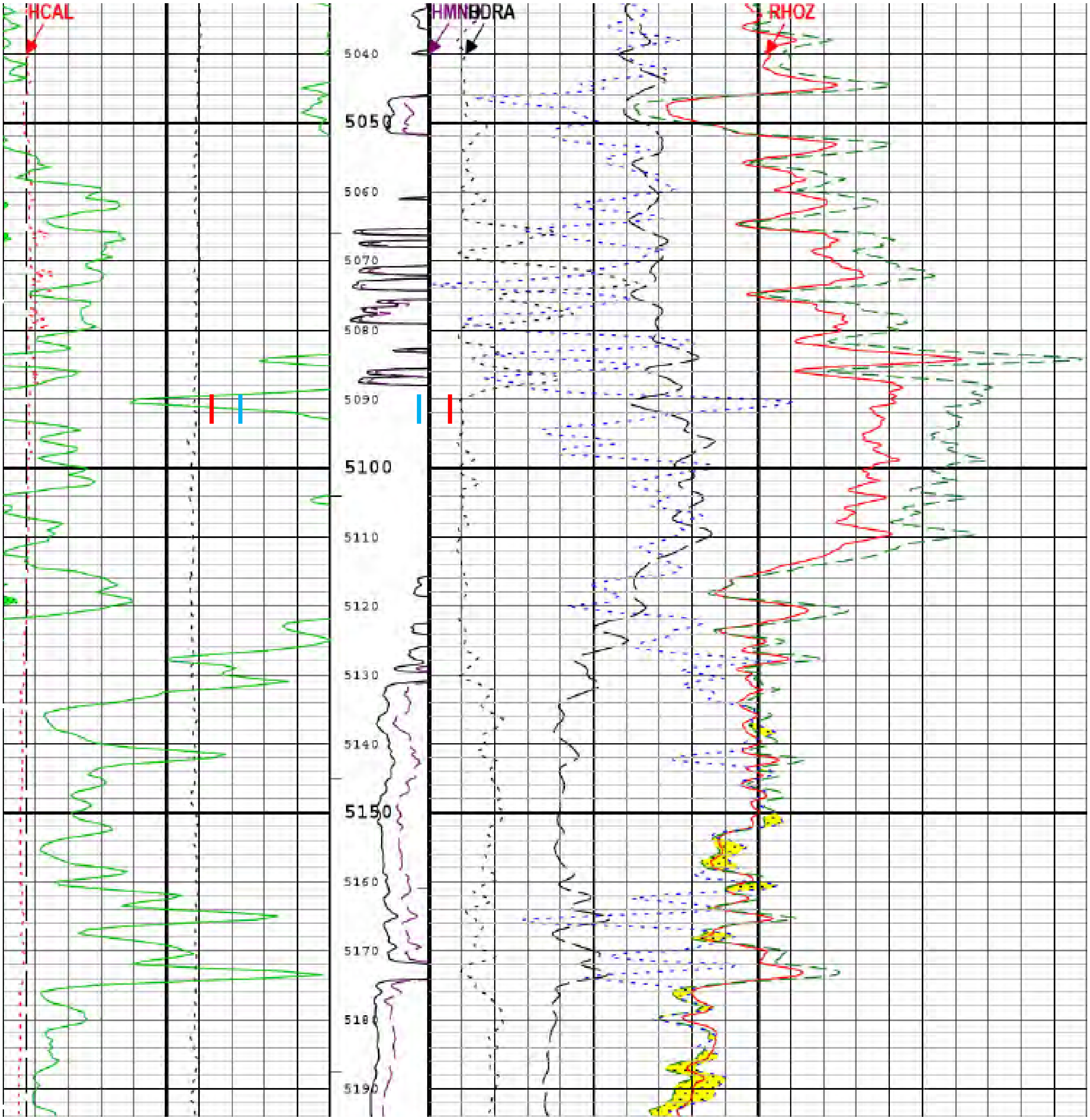

Figure 8: EC test interval (5,098-5,103 - blue vertical bar) and perforated interval (5,098-5,103 - red vertical bar). Track 1: Gamma ray (green); Depth track-calculated micrology; Track 2 and 3: Porosity log (scale 0.3 to -0.1, left to right); Neutron (blue) and density (green).

For the EC test interval, there was no AZ perforation. The BZ was the MtSE (**Table 5**). Pressure transient analyses require specific rock and fluid properties unique to each test interval's temperature and initial pressure. The salinity of the injected brine was used to estimate the test brine properties (**Table 6**).

Table 5: EC injection test of 5,098 ft to 5,103 ft from October 3 to October 14, 2019. Identification of gauge and formation included in the test. The BZ gauge failed for the EC2 injection tests, so VIT was not possible between EC and MtSE.

Test Component	Formation Abbreviation	Gauge Depth	Gauge Number
IZ	EC	5,035	DC 5179
IZ	EC	5,098	SN 90921
AZ*	N/A	5,018	DC 5180
AZ*	N/A	5,014	DC 5181
BZ	MtSE	5,155	SN 9677

*No AZ perforations. AZ gauges for quality assurance only.

Table 6: EC test interval properties used in analyses.

Property*, units	Value	Source
Initial Pressure, psia	2,483	SN 90921 @ 5,098 ft MD
Temperature, F	98.4 (97.5**)	SN 90921 @ 5,098 ft MD (DC 5179 @ 5,035 ft MD)
Porosity, %	8.0	Neutron-density log
Saturation, %	100	Assumed brine saturated
Pore Compressibility, psi^{-1}	8.589E-06	Newman's Correlation
Water Compressibility†, psi^{-1}	2.153E-06	Numbere et al.
Water Viscosity†, cp	1.044	Numbere et al.
Water Volume Factor†, rb/stb	1.007	Numbere et al.
Wellbore radius, ft	0.28125	Well log heading (6.75" bit)
Perforated height, ft	5	Projeo report
Sub-interval height, ft	5	Neutron-density log

*fluid properties are injected water properties. **Temperature used
†from online tool by Plano Research Corporation (planoresearch.com)

B. EC Vertical Interference Tests (Pulse test)

The VIT for the EC was limited to the MtSE (BZ) because there were no perforations above the EC. However, the BZ gauge failed to record pressure data, so there was no data to analyze for the VIT.

C. EC Step Rate Tests

The SRT followed VIT and MFT. Four SRT tests were completed using rates of 0.0071 to 0.012 bpm (0.3 to 0.5 gpm) for durations of 0.5 to 2 mins up to 0.079 to 0.083 bpm (3.30 to 3.75 gpm). Ideally, an SRT starts at the initial test interval pressure, but the VIT and MFT tests showed that the EC test interval would not return to initial pressure quickly (<1 hr). Therefore, none of the SRTs started at initial pressure. The four SRTs were sequential but separated by SI periods from 0.75 to 1.15 hrs.

Figure 9 is the final EC SRT, which was representative of all other EC SRTs. Due to the pressure increase from the previous tests and slow pressure falloff into the EC, this SRT does not start at initial pressure (i.e., the pressure at zero rate on **Figure 9**). Because the injection periods were short duration, the increase in formation pressure around the wellbore for the first three rate changes (<0.02 bpm) was of similar magnitude to the SRT start pressure (at rate of zero), and the rate of increase is relatively flat. Between rates of 0.02 and 0.05 bpm, a larger increase in pressure was seen and a straight line developed; this line intersected the initial (formation) pressure. Therefore, the analyses technique was to use the initial pressure as a valid point on the first straight line and ignore the data that was nearly horizontal for the first few injection periods (**Figure 9**, <0.02 bpm). Another unique feature to all EC SRTs was the second straight line. After only a single deviation (point) from the first line, the pressure trend decreased in pressure at each incremental increase in pressure (**Figure 9**, >0.06 bpm). Decreasing pressure points are indicative of the fracture increasing in size and extending into rock at initial pressure, hence the pressure decreases with each subsequent rate change. When the second straight line has a negative slope, this part of the SRT cannot be analyzed, so these points were excluded from the analyses.

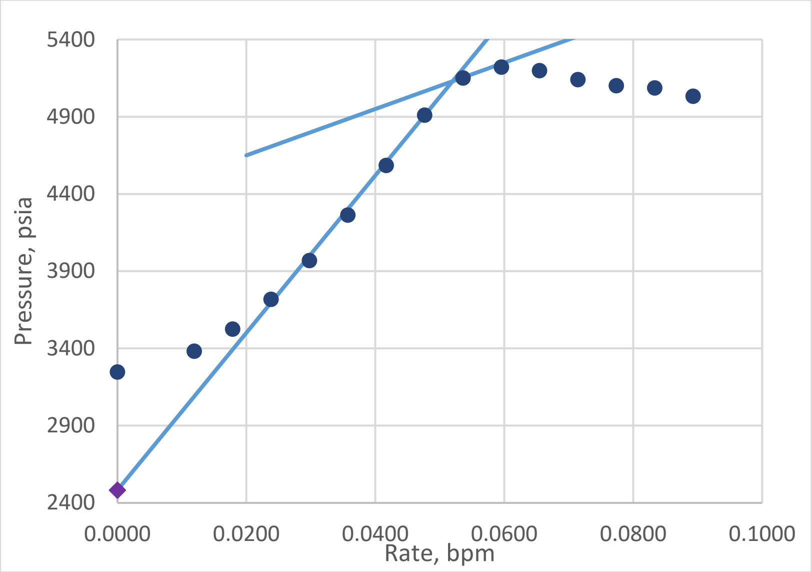

Figure 9: Final of four EC step rate tests. E-line pressure gauge data (SN 90921) at 5,098 ft MD, the depth of the top perforation. The intersection of the two lines is interpreted as the fracture propagation pressure (5,130 psia). The initial pressure (2,483 psia) is the y-axis value at 0 bpm, but it was not part of the SRT trend because no SRT started at the initial (formation) pressure. Because the later data at increasing rates (>0.06 bpm) resulted in decreasing pressure, these test points were not part of the analyses, and only the first two points breaking from the trend of the first straight line were used.

This analyses approach was used for all EC SRTs, resulting in fracture pressure ranges from 5,130 to 6,100 psia, and the fracture gradient was 1.00 to 1.19 psi/ft. Chronologically, the fracture pressure decreased with each subsequent SRT.

D. EC Pressure Falloff Tests

Because the primary objective of the EC was fracture gradient, no extended injection period was sustained for a formal pressure falloff test. Nevertheless, portions of SI periods were analyzed as falloff tests. Three SI periods of about 1, 4, and 5 days followed short (1 hr) constant rate injection periods that followed SRTs and MFTs.

The derivative plot (**Figure 10**) has an early unit slope (<0.1 hrs), which indicates WBS-dominated pressure data transitions to reservoir-dominated at about 0.8 hrs. A zero slope is present for nearly ½ log cycle time (0.8-2 hrs), which indicates radial flow, but has a very short duration due to a later feature. The last part of the test (>2 hrs) shows a sustained unit slope on the derivative, which is caused by the short injection period preceding the SI period.

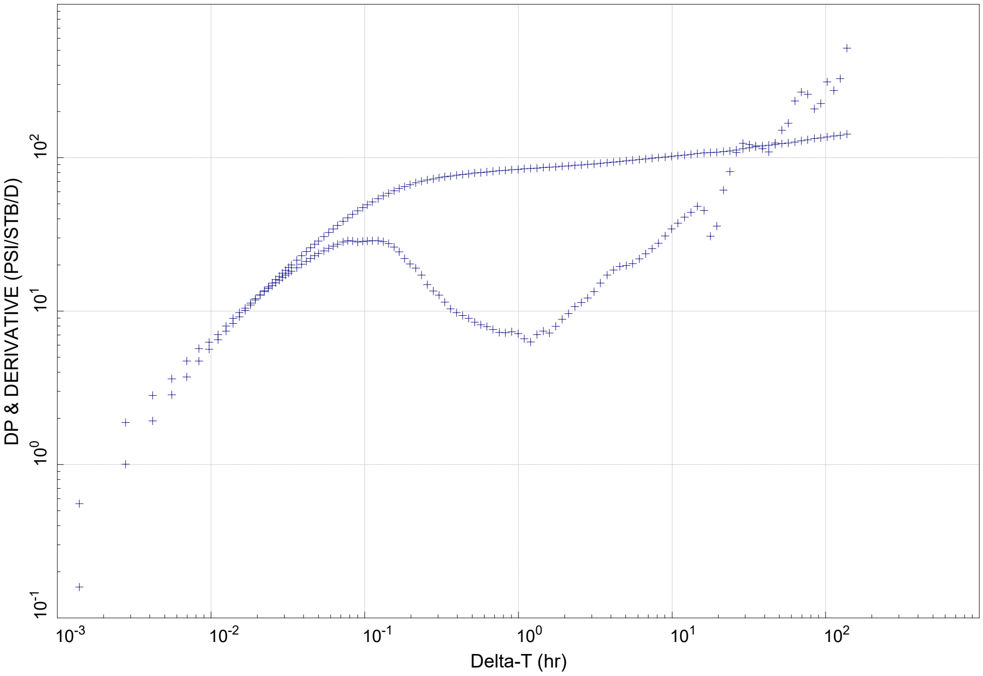

Figure 10: Derivative plot of falloff test's SI period. (Upper curve is pressure, and lower curve is derivative.) Two of the three EC derivative plots of SI periods had similar appearances: unit slope (0.08 hrs), zero slope (0.08 to 1.1 hrs), negative slope (1.1 to 0.8 hrs), a second zero slope (0.8 to 2 hrs), and a final unit slope (>2 hrs). WBS is the most likely cause of the first three slopes. The second zero slope is attributed to radial flow, and the final unit slope is caused by a short injection period preceding this SI period. The modest separation between the pressure and derivative curves (one log cycle) indicates small, positive apparent skin (+1). No partial penetration effect was present. (No logarithmic smoothing was used.)

The radial flow period (zero slope) for the EC SI periods gave a permeability-thickness product of 11 and 16 md-ft. Because the radial flow period on the derivative was relatively short, a simulation match of the derivative (>2 hrs) gave the permeability-thickness product as 15 md-ft. Because no partial penetration effect is present, the perforated interval of 5 ft may be the height of test interval, which gives permeability between 2 to 3 md. (The MRT analyses agreed with the PFO analyses showing permeability from 2 to 4 md.) Without presence of pressure data indicative of partial penetration (i.e., -½ slope), a vertical permeability estimate is not possible.

VI. Injection Test Interval: Mt. Simon A1

A. MtSA1 Test Interval Overview

The primary objective of the MtSA1 well tests was fracture gradient and permeability (vertical and horizontal). A 5-ft interval (6,260-6,265 ft MD) was perforated to test a 48-ft sub-interval (**Figure 11**) of the Mt. Simon Sandstone–A. (For this well test program, this interval was MtSA1 because another Mt. Simon Sandstone–A was tested; see **Table 8**.)

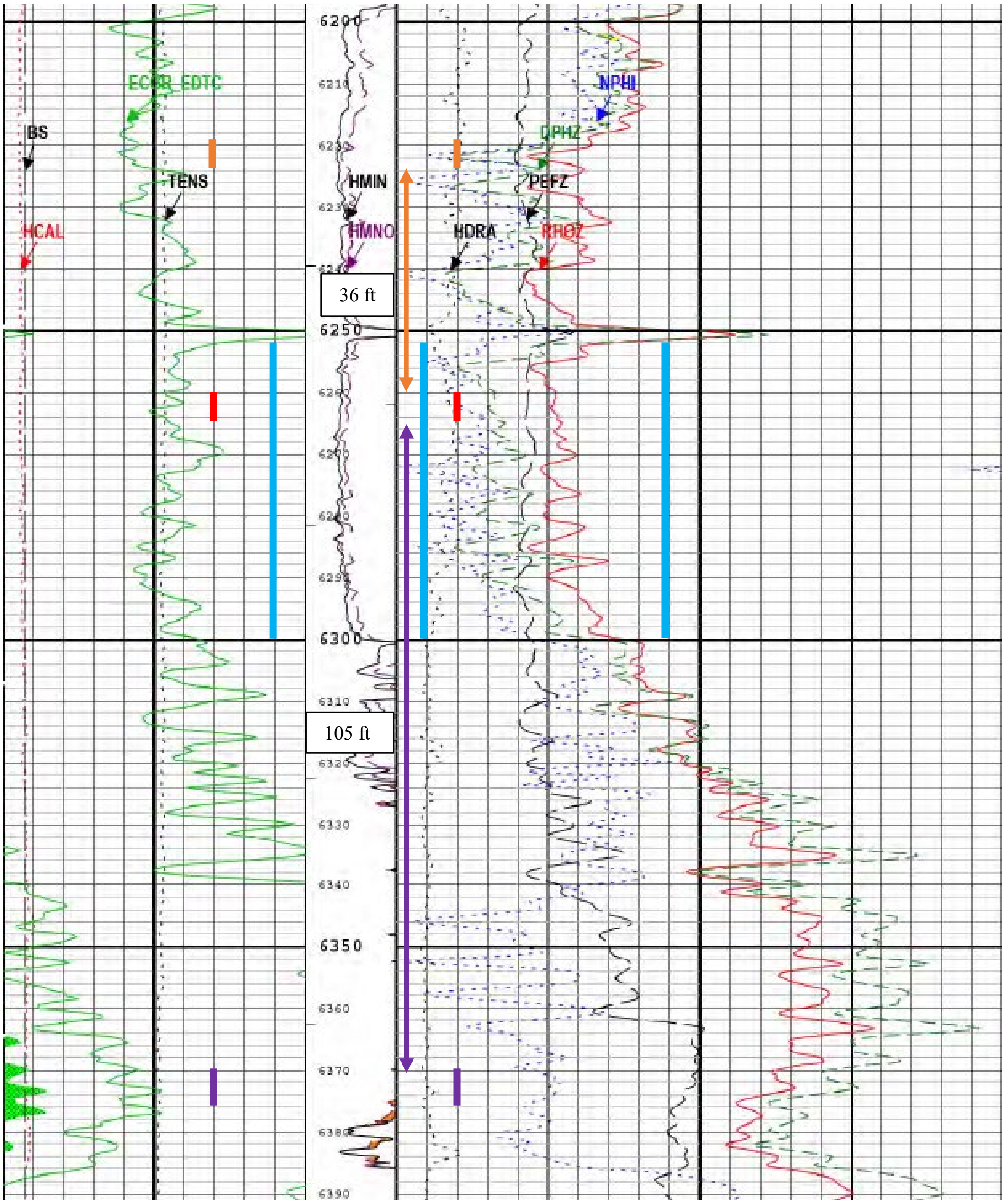

Figure 11: MtSA1 test interval (6,252-6,300 - blue vertical bar) and perforated interval (6,260-6,265 - red vertical bar). Track 1: Gamma ray (green); Depth track-calculated microlog; Track 2 and 3: Porosity log (scale 0.3 to -0.1, left to right); Neutron (blue) and density (green). AZ perforated interval (6,219-6,224 - orange vertical bar) and BZ perforated interval (6,370-6,375 - purple vertical bar) included. Distance between perforations shown by arrows.

For the MtSA1 injection test, the above zone (AZ) was MtSA2, and the below zone (BZ) was the PC2 (**Table 7**). Pressure transient analyses requires specific rock and fluid properties unique to each test interval's temperature and initial pressure. The salinity of the injected brine was used to estimate the test brine properties (**Table 8**).

Table 7: MtSA1 injection test of 6,260-6,265 ft from October 16 to October 21, 2019. Identification of gauge and formation included in the test.

Test Component	Formation Abbreviation	Gauge Depth	Gauge Number
IZ	MtSA1	6,246	DC 5179
IZ	MtSA1	6,260	SN 90921
AZ	MtSA2	6,232	DC 5180
AZ	MtSA2	6,228	DC 5181
BZ	PC2	6,334	DC 3834

Table 8: Test interval properties used in analyses. Differences between properties for each test interval are due to different temperatures and initial pressures.

Property*, units	Value	Source
Initial Pressure, psia	2,872	SN 90921@ 6,260 ft MD
Temperature, F	104.7 (104.8)	SN 90921 @ 6,260 ft MD (DC 5179 @ 6,246 ft MD)
Porosity, %	24.3	Neutron-density log
Saturation, %	100	Assumed brine saturated
Pore Compressibility†, psi^{-1}	2.2778E-06	Hall's correlation
Water Compressibility†, psi^{-1}	2.135E-6	Numbere et al.
Water Viscosity†, cp	0.9704	Numbere et al.
Water Volume Factor, rb/stb	1.009	Numbere et al.
Wellbore radius, ft	0.28125	Well log heading (6.75" bit)
Perforated height, ft	5	Projeo report
Sub-interval height, ft	48	Neutron-density log

*fluid properties are injected water properties.

†from online tool by Plano Research Corporation (planoresearch.com)

B. MtSA1 Vertical Interference Tests (Pulse test)

The MtSA2's (AZ) lowest perforation is 36 ft above the top perforation of the MtSA1, while the PC2 (BZ) upper perforation is 105 ft below the lowest perforation of the MtSA1. A VIT consisting of two pulses was the first test of the MtSA1. The injection rates of the pulse test were varied due to pressure response much higher than the estimated fracture pressure. While all injection transmits a pulse, the formal pulse test was atypical because of the varied rate to control the maximum injection pressure.

Figure 12 shows one of the two MtSA1 (IZ) pulses, which was over 3,500 psi pressure increase. The MtSA2 (AZ) and PC2 (BZ) gauges show an increase in maximum pressure of 70 and 80 psi, respectively, but were remarkably different in character. Both MtSA2 and PC2 pressure responses were low in comparison to the MtSA1 (<3%), which indicates communication is through rock and not the wellbore;

however, the PC2 response started before the MtSA1 pulse, which is impossible, and the PC2 response arrived in <40 sec, which indicates communication through a very high-permeability path like the wellbore.

The characteristics of the MtSA2 and PC2 pulses were very different. The PC2 showed rapid increase and slow decrease similar to the general trend of the MtSA1. The MtSA2 had a linear increase over the entire pulse of the MtSA1, with noticeable changes in slope near the time of the rate changes at MtSA1. MtSA2 reached a maximum about 45 secs after MtSA1 injection stopped.

To estimate vertical permeability, a VIT requires an arrival time and a pulse. This test had a pulse indicative of a successful VIT, but the arrival time indicated a failed test. At the time of this report, it was not possible to reconcile the cause of these analyzable arrival times.

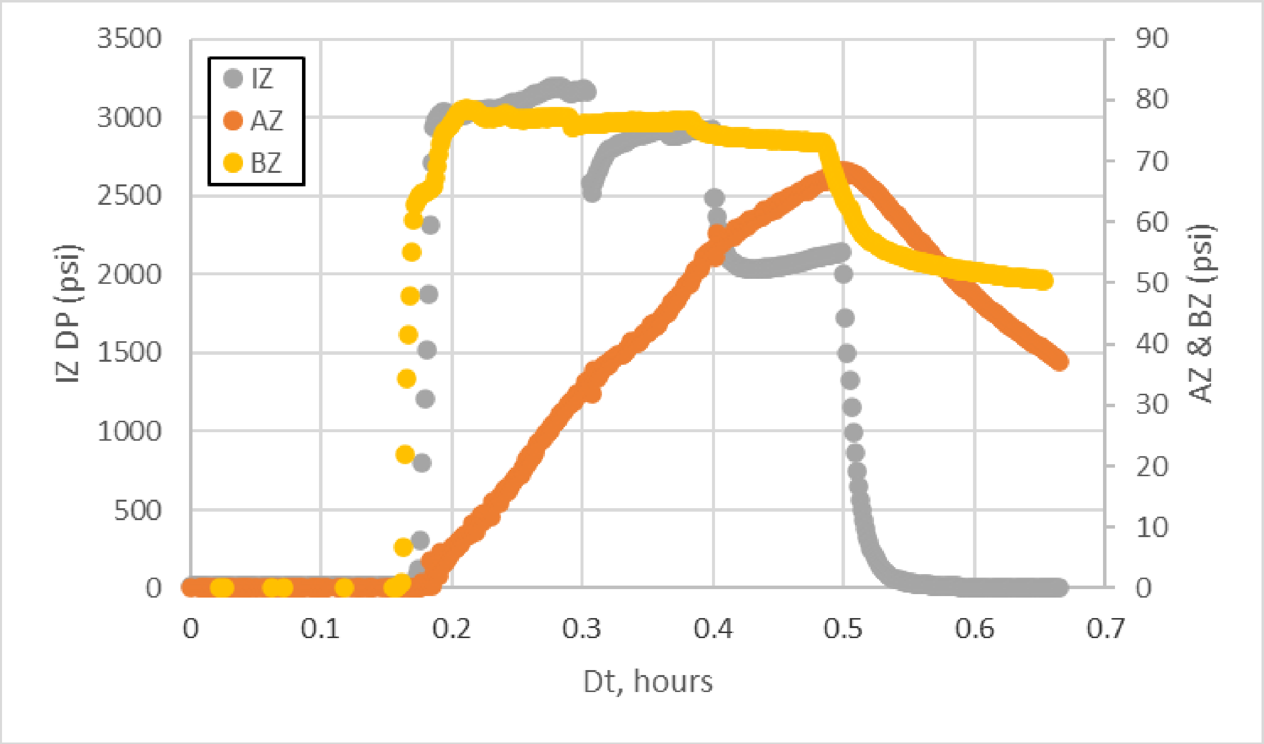

Figure 12: MtSA2 (AZ) and PC2 (BZ) pressure response to MtSA1 (IZ) injection. The pressure increase at the AZ and BZ gauges (70 and 80 psi, respectively) clearly shows communication with pressure increase of <3% of the IZ pressure increase (3,000 psi). The AZ gauge has <45 second delay in pressure change, but the BZ gauge is instantaneous. Qualitative interpretation of instantaneous arrival time communication through the wellbore and not the formation.

C. MtSA1 Step Rate Tests

Following the VIT, a single successful step rate test was completed using 0.1 bpm rate increments for 15 mins durations up to 0.6 bpm. The test shows the fracture pressure as 4,816 psia at 6,260 ft MD, which is 0.769 psi/ft fracture pressure gradient (**Figure 13**). The 0.5 bpm pressure was slightly off the trend because during the transition from 0.4 bpm to 0.5 bpm, operational problems occurred and injection ceased for a few seconds, causing the injection pressure to fall over 500 psi.

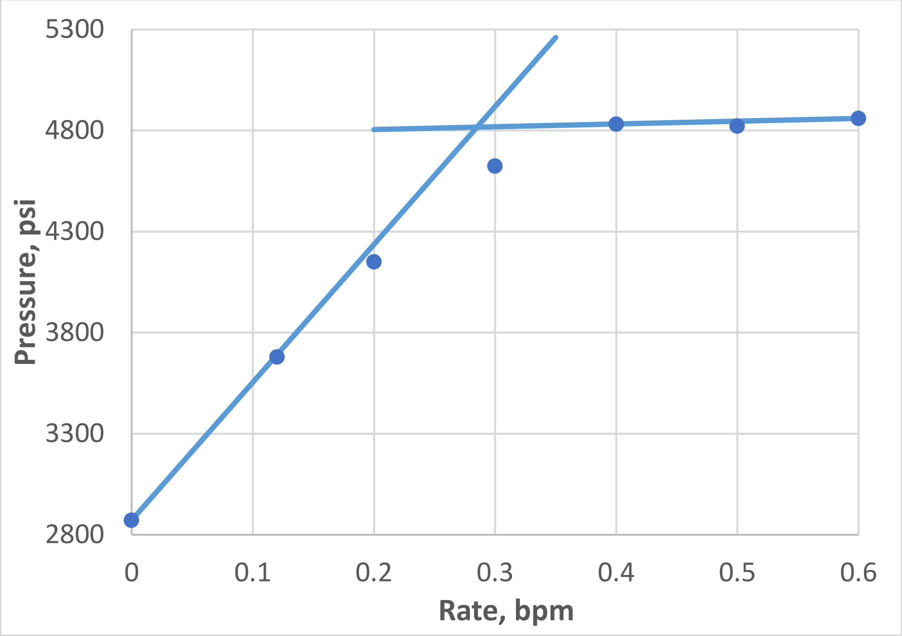

Figure 13: MtSA1 step rate test. E-line pressure gauge data (SN 90921) at 6,260 ft MD, the depth of the top perforation. The intersection of the two lines is interpreted as the fracture propagation pressure (4,816 psia). The initial pressure (2,872 psia) is the y-axis value at 0 bpm. During the rate change between 0.4 and 0.5 bpm, rate was unintentionally suspended, and pressure decreased, causing the 0.5 bpm pressure to fall slightly below the 0.4 and 0.6 bpm trend.

D. MtSA1 Pressure Falloff Tests

Immediately following an MFT, a 24-hr injection period was started, followed by a three-day SI. The flow period needed an injection rate that could be held constant for 24 hrs without reaching the fracture gradient. The initial injection rate was 432 bwpd (13 gpm), but this rate only increased pressure by about 800 psi after 20 hrs of injection. It was decided that to achieve a larger pressure increase, the rate would be increased to 1,570 bwpd (43 gpm) for the final four hrs of injection prior to SI for the falloff test.

The derivative plot (**Figure 14**) has an early ½ slope (0.03 to 0.2 hrs), which is typically interpreted as a linear flow from a hydraulic fracture. Because the well was not hydraulically fractured, this may be related to the fracture created during preceding SRTs. Fracture half-length is estimated at 20 ft using the ½ slope on the derivative plot. Following the ½ slope, the derivative reaches a maximum (zero slope), then decreases to a -½ slope (0.2 to 2 hrs), indicative of spherical flow due to partial penetration. Following the -½ slope is a -¼ slope, which is a long transition toward a zero slope, indicative of radial flow. However, by the end of the test, there is no zero slope indicative of radial flow.

The large separation between the pressure curve (upper) and derivative (lower) is caused by very high, positive apparent skin, which may or may not be mechanical skin. The partial penetration effect contributes to the apparent skin. This trend gave a permeability-thickness product of 14,000-15,000 md-ft. Because there is no radial flow on the derivative after 0.5 hrs, a simulation was attempted on the derivative after 0.8 hrs; simulation gave a permeability-thickness product of 16,000 md-ft. The MRT analyses results were very different from the derivative analyses of the PFO; the MRT gave a permeability-thickness product of 200-400 md-ft and likely representing the 5 ft perforated interval not the entire test interval. As typical with well testing of thick formations, to estimate permeability, assumptions must be made for the thickness of the interval tested. **Table 9** shows estimates for different values of thickness. The k_h and k_v/k_h ratio decreases with decreasing thickness.

Following the injection period of each VIT, SRT, and MFT, injection ceased for a short period (10 to 50 mins) prior to the next injection period. The derivative plot of each of these SI periods had a similar ½ slope as the derivative of the falloff. The longest two SIs followed an SRT; they showed a derivative that reached a maximum and started a negative unit slope that transitioned to a -½ slope that was repeatable on several tests.

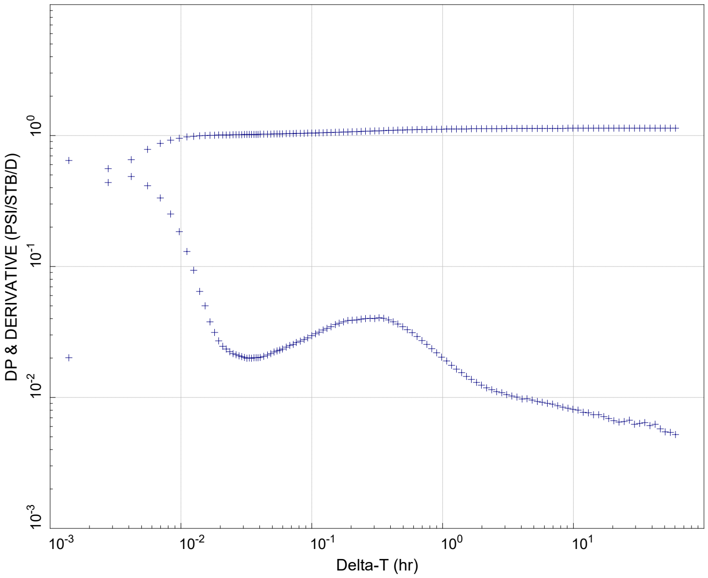

Figure 14: Derivative plot of falloff test's SI period. (Upper curve is pressure, and lower curve is derivative.) All MtSA1 derivative plots of SI periods had similar appearances: a sharp decrease (to 0.03 hrs), a very early ½ slope (0.03 to 0.2 hrs), a -½ slope 0.2 to 2 hrs), and -¼ slope (2 hrs to 60 hrs). Half-slope indicates linear flow very near the wellbore, which may be a single vertical fracture induced during the preceding SRT. The large separation between the pressure and derivative curves indicates very large, positive apparent skin, which is expected due to the partial penetration effect. (A logarithmic smoothing factor of 0.05 was used to calculate the derivative.)

Table 9: MtSA1 k_v/k_h and horizontal permeability estimates for assumed thicknesses.

	Well Test Analyses (Log-Log: Derivative)		
Thickness, feet	**k_h, md (k-h, md-ft)**	**k_v, md (k_h x k_v/k_h)**	**k_v/k_h**
6,252-6,300 ft 48 ft (maximum based on logs)	290 md (14,000 md-ft)	0.082	0.000281
6,252-6,269 17 ft (smallest based on logs)	770 md (14,000 md-ft)	0.013	0.0000163

VII. Injection Test Interval: Mt. Simon A2

A. MtSA2 Test Interval Overview

The primary objectives of the MtSA2 well tests were fracture gradient and permeability (horizontal and vertical). A 5-ft interval (6,219-6,224 ft MD) was perforated to test a 47-ft sub-interval (**Figure 2**) of the Mt. Simon Sandstone–A. (For this well test program, this interval was MtSA2 because another Mt. Simon Sandstone–A was tested; see **Table 1**.)

For the MtSA2 test interval, the AZ was MtSE, and the BZ was the MtSA1 (**Table 10**). Pressure transient analyses require specific rock and fluid properties unique to each test interval's temperature and initial pressure. The salinity of the injected brine was used to estimate the test brine properties (**Table 11**).

Table 10: MtSA2 injection test of 6,219-6,224 ft from October 21 to October 24, 2019. Identification of gauge and formation included in the test.

Test Component	Formation Abbreviation	Gauge Depth	Gauge Number
IZ	MtSA2	6,167	DC 5179
IZ	MtSA2	6,219	SN 90921
AZ	MtSE	6,150	DC 5180
AZ	MtSE	6,146	DC 5181
BZ	MtSA1	6,254	DC 3834

Table 11: MtSA2 test interval properties used in analyses.

Property*, units	Value	Source
Initial Pressure, psia	2,809	SN 90921 @ 6,219 ft MD
Temperature, F	102.8 (102.7)	SN 90921 @ 6,219 ft MD (DC 5179 @ 6,167 MD)
Porosity, %	20.2	Neutron-density log
Saturation, %	100	Assumed brine saturated
Pore Compressibility, psi^{-1}	2.278E-6	Newman's Correlation
Water Compressibility†, psi^{-1}	2.137E-6	Numbere et al.
Water Viscosity†, cp	0.9889	Numbere et al.
Water Volume Factor†, rb/stb	1.008	Numbere et al.
Wellbore radius, ft	0.28125	Well log heading (6.75" bit)
Perforated height, ft	5	Projeo report
Sub-interval height, ft	57	Neutron-density log

*fluid properties are injected water properties.
†from online tool by Plano Research Corporation (planoresearch.com)

B. MtSA2 Vertical Interference Tests (Pulse test)

During the formal VIT test of the MtSA2, a large instantaneous pressure increase in the casing/tubing annulus was detected. The test was discontinued, and the packer reset; a second formal VIT was *not* conducted. However, the injection from the SRT and PFO created adequate pressure to create a perturbation and to analyze the AZ and BZ test intervals as a VIT. Therefore, while the injection created a pulse, the VIT was atypical in design.

Figures 15 and 16 (MtSA1-BZ and MtSE-AZ, respectively) show a MtSA2 injection period used as a VIT pulse, which was ~1,000 psi pressure increase. The MtSE (AZ) lower perforation is 1,024 ft above the top perforation of the MtSA2, while the MtSA1 (BZ) upper perforation is 36 ft below the lowest perforation of the MtSA2.

The MtSE (AZ) and MtSA1 (BZ) gauges show an increase in maximum pressure of <10 and ~800 psi, respectively, but were remarkably different in character. MtSA1 (BZ) pressure response (**Figure 15**) was nearly 80% of the IZ pulse but arrived ~45 secs before the pulse was initiated, which is impossible. At the time of this report the problem with the clock times were not resolved. Because of the early arrival time, an analysis was not possible. Because the MtSA1 pressure was 80% of the MtSA2 pulse and 36 ft apart, it seems likely the pulse was through the rock formation, showing vertical communication between the MtSA1 and MtSA2. The general trend of MtSE (AZ) pressure (**Figure 16**) prior to the MtSA2 pulse was decreasing (presumably from the previous MtSE test) but noisy. During the pulse, a pressure change was detected, but it was quite random from -8 to 10 psi with no pulse through the formation nor through a leak. The exact mechanism of pressure transmission is not obvious.

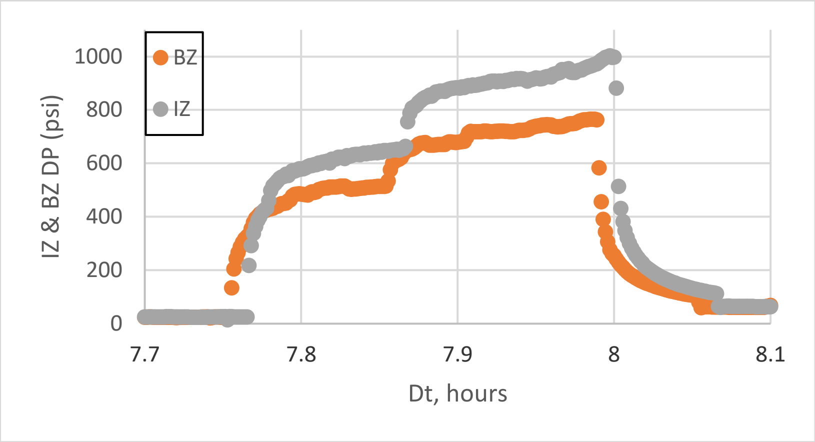

Figure 15: MtSA1 (BZ) pressure response to MtSA2 (IZ) injection. The pressure increase at the BZ gauge (800 psi) clearly shows communication with pressure increase of <80% of the IZ pressure increase (800 psi). The BZ gauge arrived about ~45 secs prior to the IZ pulse. Consequently, qualitative interpretation of the BZ gauge is not possible.

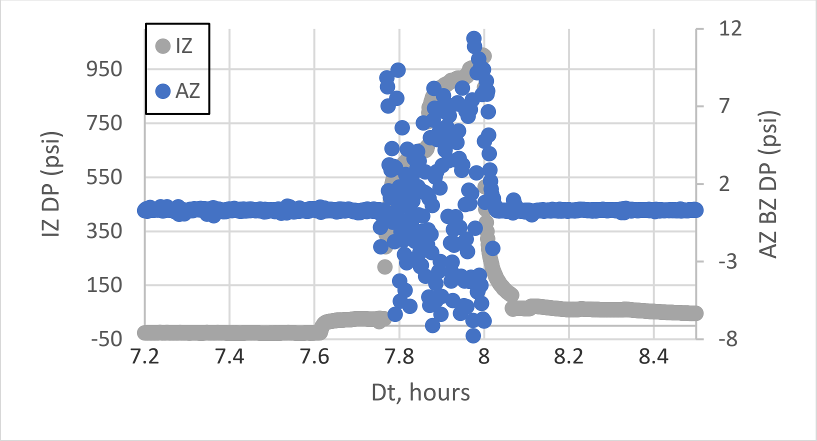

Figure 16: MtSE (AZ) pressure response to MtSA2 (IZ) injection. The pressure response at the AZ gauge (from -8 to +10 psi) clearly occurs during the injection period but has no characteristic signal of pressure transmission through rock. The AZ gauge's response is instantaneous to the IZ pulse. Qualitative interpretation of instantaneous arrival time communication indicates the pulse is through the wellbore and not the formation. Therefore, the test could not be analyzed.

C. MtSA2 Step Rate Tests

Following three failed SRT attempts (due to poorly seated packer and a wellhead flange) during the preceding day (and after pressure returned to static initial pressure), a single successful step rate test was completed using 0.4 bpm rate increments for 15 mins duration up to the maximum pump rate of 3.4 bpm. Only two rates indicate that the fracture pressure was reached; consequently, only two points could be used to approximate the post-fracture linear trend. Nevertheless, the SRT gave results similar to other SRTs for this well. The SRT gave the fracture pressure as 4,870 psia at 6,219 ft MD, which is 0.783 psi/ft fracture pressure gradient (**Figure 17**). (An SRT following the last PFO gave a lower fracture of 0.69 psi/ft, which was anomalous in comparison to the other MtSA2 and MtSA1 SRT results.)

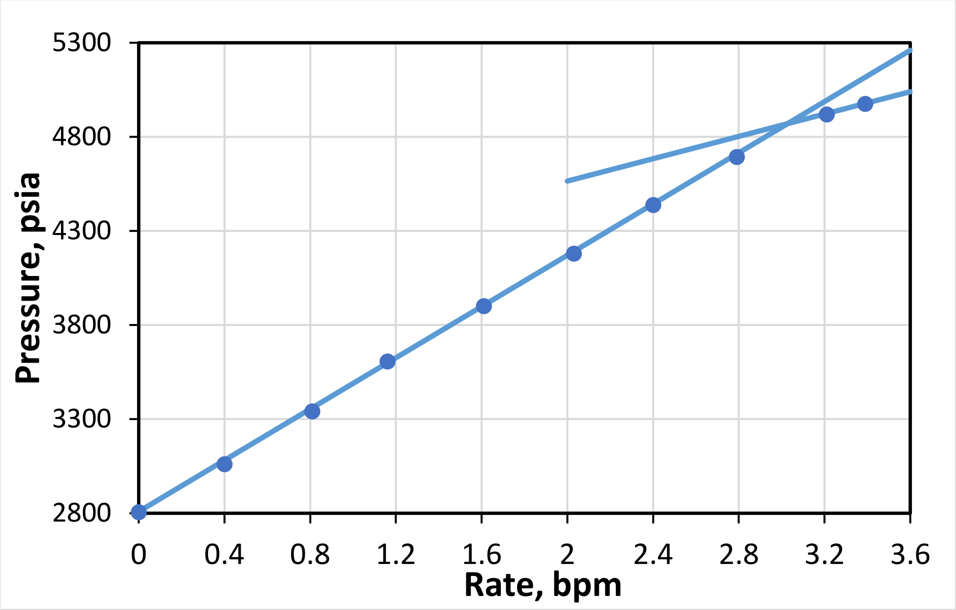

Figure 17: MtSA2 step rate test. E-line pressure gauge data (SN 90921) at 6,219 ft MD, the depth of the top perforation. The intersection of the two lines is interpreted as the fracture propagation pressure (4,870 psia). The initial pressure (2,809 psia) is the y-axis value at 0 bpm. The pump neared its maximum rate, and only two rates were attained that lead to two pressures exceeding the fracture pressure.

D. MtSA2 Pressure Falloff Tests

Following the last rate of SRT, a lower rate of 1.5 bpm was maintained for 12 hrs, at which time injection stopped and a 27-hr SI period of the falloff test started. The rate of 1.5 bpm was chosen because it was projected to provide the largest pressure increase without exceeding the fracture pressure determined by the preceding SRT during the 27-hr injection period.

The derivative plot (**Figure 18**) shows a negative slope over 3 log cycles of time (0.001 to 1.0 hrs), with about ½ log cycle between 0.06 and 0.15 hrs exhibiting negative ½ slope, indicative of spherical flow caused by partial penetration. From 1 to 27 hrs (about 1½ log cycles), the slope is zero (0), indicative of radial flow from which horizontal permeability is calculated. Vertical thickness is required to estimate permeability. Because the separation in the pressure and derivative curves is not too large and radial flow starts early and is extended over one log cycle (time), the vertical thickness of the formation tested is not likely very large. The permeability-thickness product (k-h) is about 4,200 md-ft over the entire test interval. (The MRT is generally supportive of this range, 2,000-2,200 md-ft, but would be over mostly the perforated interval, 5 ft). As typical with well testing of thick formations, to estimate permeability, assumptions must be made for the thickness of the interval tested. **Table 12** shows estimates for different values of thickness. The k_h and k_v/k_h ratio decreases with decreasing thickness.

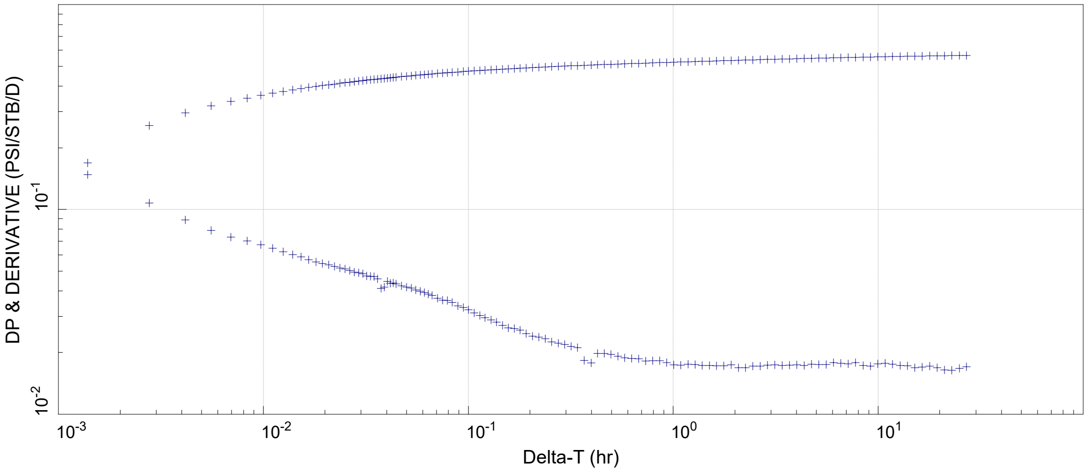

Figure 18: MtSA2 derivative plot of falloff tests' SI period. (Upper curve is pressure, and lower curve is derivative.) All derivative plots of SI periods had similar appearances: a negative slope through about 1 hr, followed by a zero (0) slope (1 to 27 hrs). From 0.06 to 0.14 hrs, a negative half-slope is present, which indicates partial penetration from which k_v/k_h ratio is calculated. The stabilization after 1 hr is indicative of a radial flow from which permeability is calculated. The separation between the pressure and derivative curves indicates positive apparent skin, which is expected due to the partial penetration effect. (A logarithmic smoothing factor of 0.05 was used to calculate the derivative.)

Table 12: MtSA2 k_v/k_h and horizontal permeability estimates for assumed thicknesses.

	Well Test Analyses (Log-Log: Derivative)		
Thickness, ft	k_h, md (k-h, md-ft)	k_v, md	k_v/k_h
6,199-6,249 **47 ft** **(maximum based on logs)**	89 md (4,200 md-ft)	1.5	0.0170
6,221-6,249 **28 ft** **(medium based on logs)**	150 md (4,200 md-ft)	0.54	0.0036
6,221-6,228 **7 ft** **(smallest based on logs)**	540 md (4,200 md-ft)	0.45	0.00084

VIII. Injection Test Interval: Precambrian 2

A. PC2 Test Interval Overview

The primary objectives of the PC2 well tests were fracture gradient and permeability (horizontal and vertical). A 5-ft interval (6,370-6,375 ft MD) was perforated to test a 5-ft sub-interval (**Figure 19**) of the Precambrian crystalline basement. (For this well test program, this interval was PC2 because another Precambrian perforated interval, PC1, was deeper to assess vertical permeability across 40 ft of the Precambrian crystalline basement rock; see **Table 1**.)

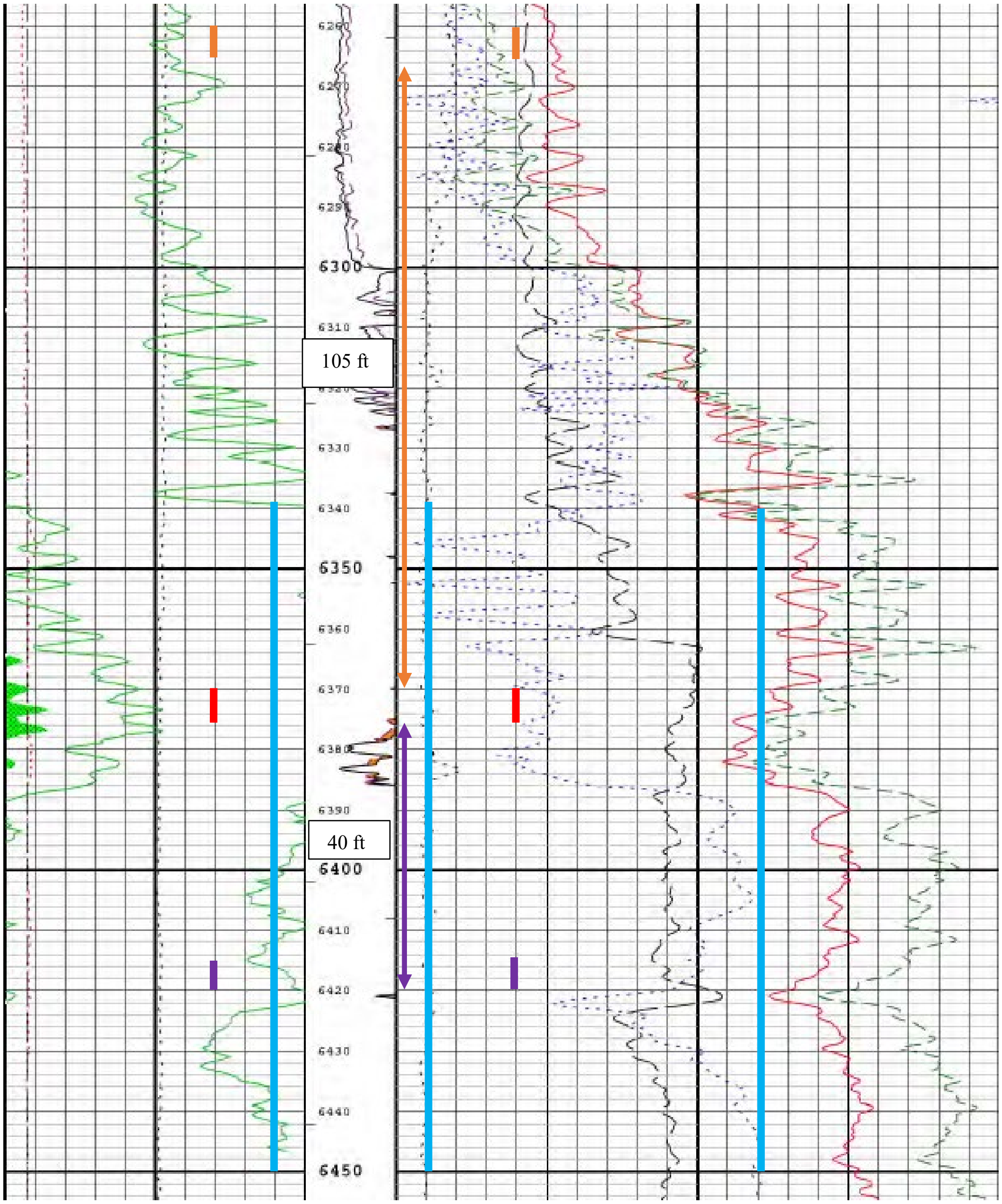

Figure 19: PC2 test interval (6,340-6,450 - blue vertical bar), PC2 perforated interval (6,370-6,375 - red vertical bar). Track 1: Gamma ray (green); Depth track-calculated microlog; Track 2 and 3: Porosity log (scale 0.3 to -0.1, left to right); Neutron (blue) and density (green). AZ perforated interval (6,260-6,265 - orange vertical bar) and BZ perforated interval (6,415-6,420 -purple vertical bar) included. Distance between perforations shown by arrows.

For the PC2 injection test, the AZ was MtSA1, and the BZ was the PC1 (**Table 13**). Pressure transient analyses require specific rock and fluid properties unique to each test interval's temperature and initial pressure. The salinity of the injected brine was used to estimate the test brine properties (**Table 14**).

Table 13: PC2 injection test of 6,370 ft to 6,375 ft from October 3 to October 14, 2019. Identification of gauge and formation included in the test.

Test Component	**Formation Abbreviation**	**Gauge Depth**	**Gauge Number**
IZ	PC2	6,337	DC 5179
IZ	PC2	6,370	SN 90921
AZ	MtSA1	6,320	DC 5180
AZ	MtSA1	6,316	DC 5181
BZ	PC1	6,394	DC 3832

Table 14: PC2 test interval properties used in analyses.

Property*, units	**Value**	**Source**
Initial Pressure, psia	2,948	SN 90921 @ 6,370 ft MD
Temperature, F	105.3 (105.2)	SN 90921 @ 6,370 ft MD (DC 5179 @ 6,337 ft MD)
Porosity, %	1	Estimate
Saturation, %	100	Assumed brine saturated
Pore Compressibility, psi^{-1}	33.324E-06	Newman's Correlation
Water Compressibility†, psi^{-1}	2.130E-06	Numbere et al.
Water Viscosity†, cp	0.9648	Numbere et al.
Water Volume Factor†, rb/stb	1.008	Numbere et al.
Wellbore radius, ft	0.28125	Well log heading (6.75" bit)
Perforated height, ft	5	Projeo report
Sub-interval height, ft	40	Neutron-density log

*fluid properties are injected water properties

†from online tool by Plano Research Corporation (planoresearch.com)

B. PC2 Vertical Interference Tests (Pulse test)

A formal VIT in the PC2 was not done due to the high injection pressures at lowest rates; nevertheless, pulses from other injections were used as a VIT test. **Figure 20** shows clear communication (~250 psi) between PC2 (IZ) and PC1 (BZ), which are 40 ft apart (vertically). **Figure 21** shows communication but much lower pressure response (~0.2 psi) between PC2 and MtSA1, which is 105 ft above PC2 perforations. Because the arrival time of the pulses were prior to the pulses being sent, quantitative analyses are not possible. The cause of the clocks showing this impossibility is unknown.

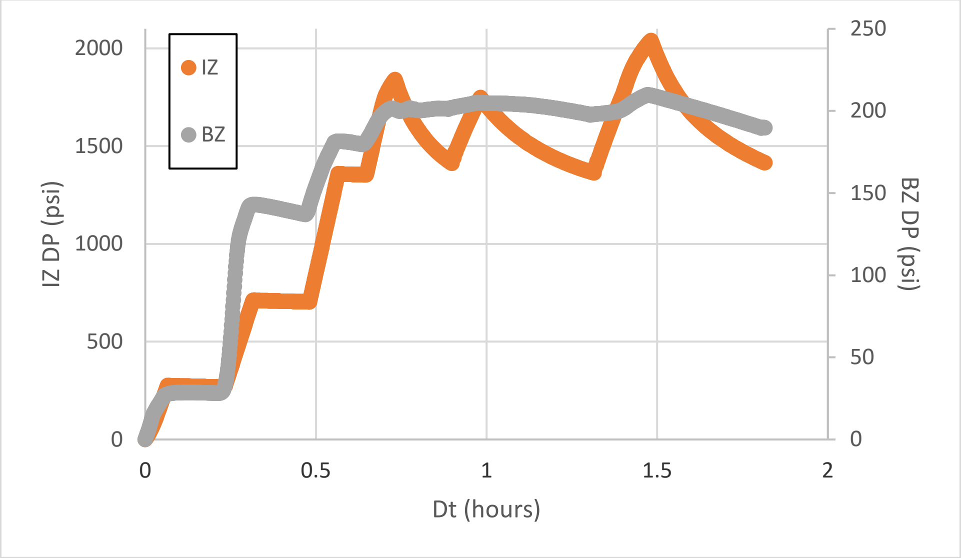

Figure 20: PC1 (BZ) pressure response to PC2 (IZ) injection. The pressure increase at the BZ gauge (~200 psi) clearly shows communication with pressure increase of ~10% of the IZ pressure increase (~2,000 psi). The IZ pulse arrives on the BZ gauge ~30 sec before the IZ pulse starts, which is impossible. While the pulse looks like it is through the formation, because of the arrival time, analysis is impossible.

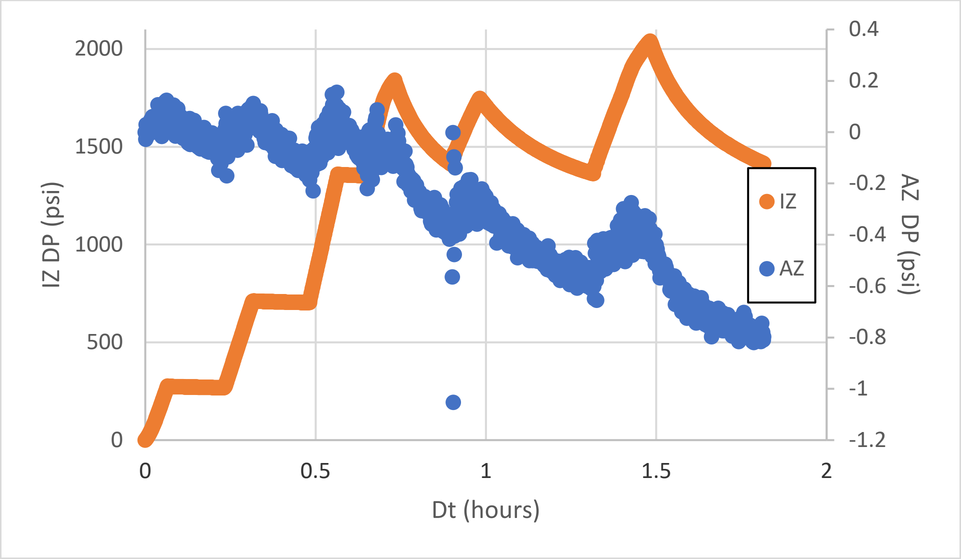

Figure 21: MtSA1 (AZ) pressure response to PC2 (IZ) injection. The pressure increase at the AZ gauge was only about 0.2 psi, but it increases and decreases with the IZ pulse; however, the general trend is decreasing. Additionally, the pulse arrives nearly instantaneously, which suggests wellbore communication. Because of this discrepancy, no analyses were possible.

C. <u>PC2 Step Rate Tests</u>

The PC2 SRTs followed the VIT. The pressures necessary to fracture the PC2 were very close to the maximum operating pressure of the wellhead. Consequently, one SRT had only one point that deviated downward from the first straight line, and the other SRTs did not reach the fracture pressure prior to reaching maximum surface injection pressure. The fracture pressure was 8,089 psia, and the fracture pressure gradient was 1.27 psi/ft (**Figure 22**).

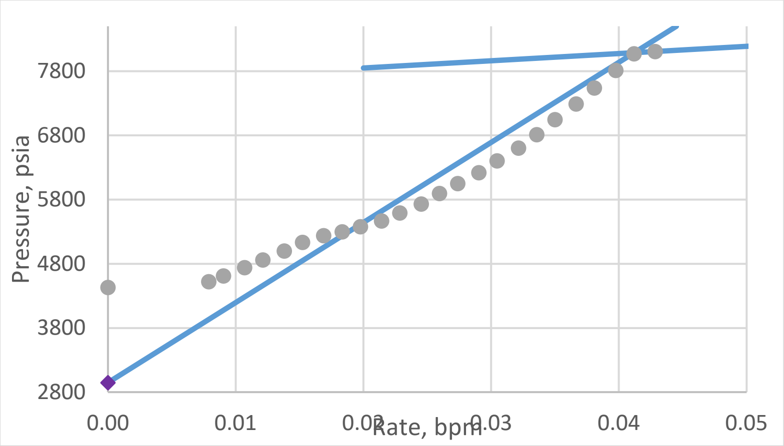

Figure 22: First of two PC2 step rate tests shown. E-line pressure gauge data (SN 90921) at 6,379 ft MD, the depth of the top perforation. The intersection of the two lines is interpreted as the fracture propagation pressure (8,089 psia). The initial pressure (2,948 psia) is the y-axis value at 0 bpm, but it was not part of the SRT trend because no SRT started at the initial (formation) pressure. Because only one rate could be achieved below the maximum wellhead operating pressure (5,000 psi), only one rate is shown exhibiting appearance that the PC2 test interval was fractured. Therefore, only two points are used for the second line representing the fracture part of the SRT. (Placement of the first line through the later points on this trend, 0.032 to 0.041 bpm, gave approximately the same fracture pressure.)

D. PC2 Pressure Falloff Tests

Following the last SRT, the lowest rate of the pump, 0.0080 bpm, was maintained for about 2.5 hrs, at which time the surface tubing pressure reached the maximum wellhead operating pressure. There was no alternative but to cease injection and start the SI period of the falloff test, which was nearly 4 days. The derivative plot (**Figure 23**) has a unit slope through 0.1 hrs, then a slight deviation to a nearly zero slope before it begins a ½ slope from 3 to 30 hrs. The ½ slope is indictive of a linear flow attributable to fracture flow, but it is more likely due to a short injection period preceding this SI. Two shorter SI periods (30 mins) preceding SRT and MFT had similarly shaped derivative.

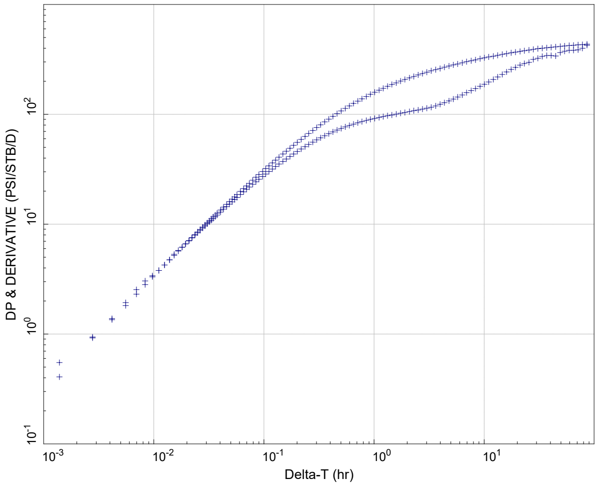

Figure 23: PC2 Derivative plot of falloff test's SI period. (Upper curve is pressure, and lower curve is derivative.) All derivative plots of SI periods had similar appearances: a negative slope through about 1 hr, followed by a zero (0) slope (1 hr to 27 hrs). From 0.06 to 0.14 hrs, a negative half-slope is present, which indicates partial penetration from which k_v/k_h ratio is calculated. The stabilization after 1 hr is indicative of a radial flow from which permeability is calculated. The separation between the pressure and derivative curves indicates positive apparent skin, which is expected due to the partial penetration effect. (A logarithmic smoothing factor of 0.05 was used to calculate the derivative.)

The very small separation (<0.5 log cycle of pressure) between the pressure curve (upper) and derivative (lower) is caused by negative skin (-2). This trend gave a permeability-thickness product of 0.53 to 6.3 md-ft. There is no partial penetration effect apparent on the derivative. Because there is no partial penetration effect present in the trend of the derivative, a test interval thickness equal to the perforated interval was assumed (5 ft), and an estimate of vertical permeability within the test interval was not possible. This gives a permeability of 0.13 to 0.20 md. The MRT analyses supported the lower part of this range: 0.04 to 0.07 md.

IX. Injection Test Interval: Mt. Simon A1-A2

A. MtSA1-A2 Test Interval Overview

At the end of the McMillen #2 well test program, test water remained. To avoid offsite disposal costs, the downhole test assembly was configured to inject into two 5-ft intervals (6,260-6,265 ft and 6,219-6,224 ft MD): the MtSA1 and MtSA2. Injection into these two zones tested a 95-ft sub-interval (**Figure 24**) of the Mt. Simon Sandstone–A. While disposal occurred, wireline pressure gauges were deployed to record data that might be used for a combined test of the MtSA1 and A2 (MtSA1-A2).

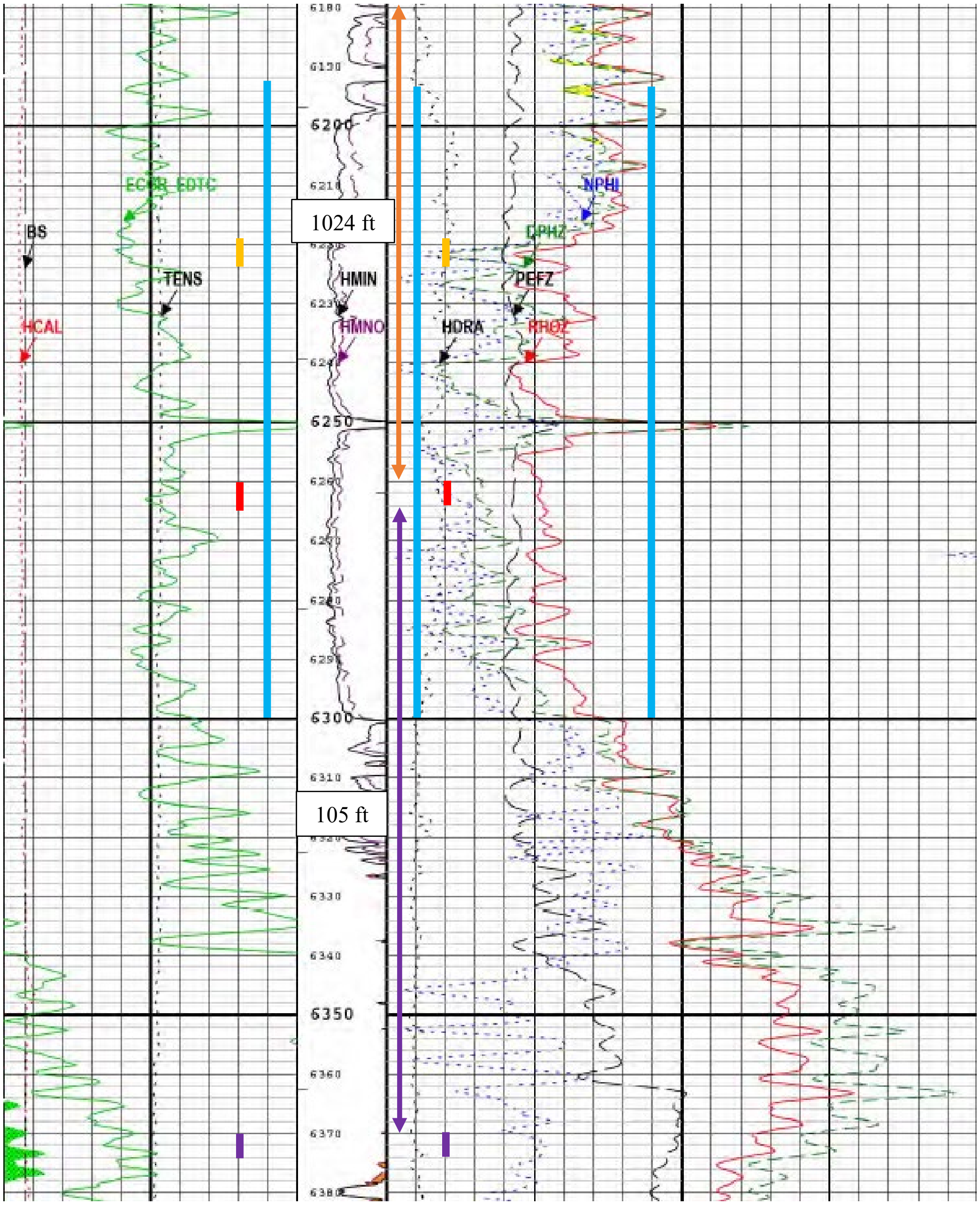

Figure 24: MtSA1-A2 test interval (6,193-6,300 - blue vertical bar), MtSA1 perforated interval (6,260-6,265 - red vertical bar), and MtSA2 perforated interval (6,219-6,224 - yellow vertical bar). Track 1: Gamma ray (green); Depth track-calculated microlog; Track 2 and 3: Porosity log (scale 0.3 to -0.1, left to right); Neutron (blue) and density (green). AZ perforated interval (not shown) and BZ perforated interval (6,370-6,375 - purple vertical bar) included.

For the MtSA1-A2 test interval, the AZ was the MtSE, and the BZ was the PC2 (**Table 15**). Pressure transient analyses require specific rock and fluid properties unique to each test interval's temperature and initial pressure. A combination of the MtSA1 and MtSA2 properties (**Table 8 and 11**) were used.

Table 15: MtSA1-A2 injection test of 6,193 to 6,300 ft from October 29 to October 31, 2019. Identification of gauge and formation included in the test.

Test Component	Formation Abbreviation	Gauge Depth	Gauge Number
IZ	MtSA1-A2	6,157*	DC 5179
IZ	MtSA1-A2	6,157*	SN 90921
AZ	MtSE	6,143	DC 5180
AZ	MtSE	6,139	DC 5181
BZ	PC2	6,334	DC 3834

* This depth was recorded incorrectly in the Projeo report as 6300 ft. The correction was made based on the packer depth and depth of upper perforation of the MtSA2 perforated interval.

B. MtSA1-A2 Vertical Interference Tests (Pulse test)

A formal VIT, consisting of two, 15-min pulses separated by 15-min SI, was the first injection into the combined MtSA1 and MtSA2 perforated intervals. Because it was uncertain how quickly pressure would increase into the combined interval injection, the first pulse had two rates and the second only one: 1.0 bpm (5 mins)/1.5 bpm (10 mins) and 1.5 bpm (15 mins), respectively. The IZ pressure increased ~1,200 psi. The MtSE (AZ) lower perforation is 1,024 ft above the top perforation of the MtSA2, while the PC2 (BZ) upper perforation is 105 ft below the lowest perforation of the MtSA1. The PC2 (BZ) pressure gauge had a general decrease in pressure, with the pulses superimposed on this trend, which showed a ~30 psi increase, but it arrived prior to the IZ pulse being initiated (**Figure 25**). The trend between 1.0 and 1.2 hrs was atypical with a local minimum instead of an exponential decrease. Due to pulse arrival time and the atypical trend, the pulse could not be analyzed for vertical permeability. The MtSE (AZ) did not show an analyzable response (**Figure 26**).

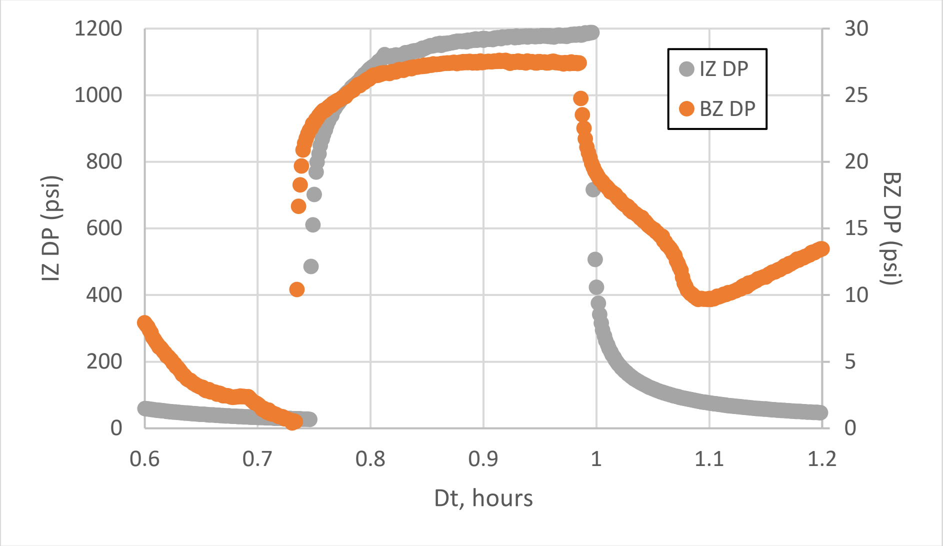

Figure 25: PC2 (BZ) pressure response to MtSA1-A2 (IZ) injection. The overall trend of BZ pressure was decreasing, causing calculation of net negative pressure change, even when a clear and obvious pressure change (~28 psi) was detected. The pressure increase at the BZ gauge is likely through the formation, but the cause of the atypical response between 1.0 and 1.2 hrs (local

minimum when IZ injection stopped) is unknown. The BZ gauge arrived about ~45 secs prior to the IZ pulse. Consequently, qualitative interpretation of the BZ gauge is not possible.

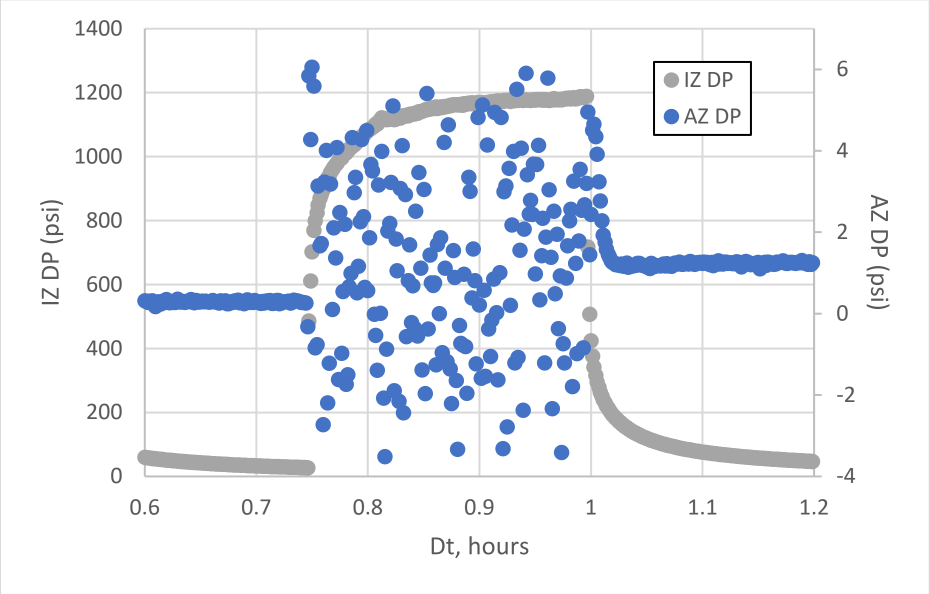

Figure 26: MtSE (AZ) pressure response to MtA1-A2 (IZ) injection. The pressure response at the AZ gauge (from -4 to +6 psi) clearly occurs during the injection period but has no characteristic signal of pressure transmission through rock. The AZ gauge's response is instantaneous to the IZ pulse. Qualitative interpretation of instantaneous arrival time communication indicates the pulse is through the wellbore and not the formation. Therefore, the test could not be analyzed.

C. MtSA1-A2 Step Rate Tests

Following the VIT, a single successful SRT was conducted using 0.5 bpm rate increments for 4 mins duration up to 3.5 bpm (**Figure 27**). The estimated fracture pressure, the intersection of the two lines, is 4,160 psia at depth of 6,157 ft MD. This is a fracture gradient of 0.67 psi/ft, which is low compared to the fracture gradient from the SRT of the MtSA1 and MtSA2 separately. However, it does compare well with the final SRT of the MtSA2 (0.69 psi/ft), which was an outlier of all other SRTs of the MtSA2.

D. MtSA1-A2 Pressure Falloff Tests

At the end of the brine disposal process, a 20-hr SI provided data for informal PFO. The rates prior to SI were highly variable from a minimum of 53 gpm to a maximum of 126 gpm.

The derivative plot (**Figure 28**) shows no unit slope (no WBS), which is expected for injection with test fluid to surface. However, WBS-influenced derivative is present through 0.01 hrs, followed by a transition to -½ slope from 0.5 to 1 hr, indicative of partial penetration from which k_v/k_h is estimated (0.0019). A zero (0) slope, indicative of radial flow, starts to develop near the end of the SI. The permeability-thickness product (k-h) estimated near the end of the test is about 4,600 md-ft over the entire test interval. The derivative shape and calculated permeability agree with the MtSA2 injection only, even though the MtSA1 perforations were open during this disposal process.

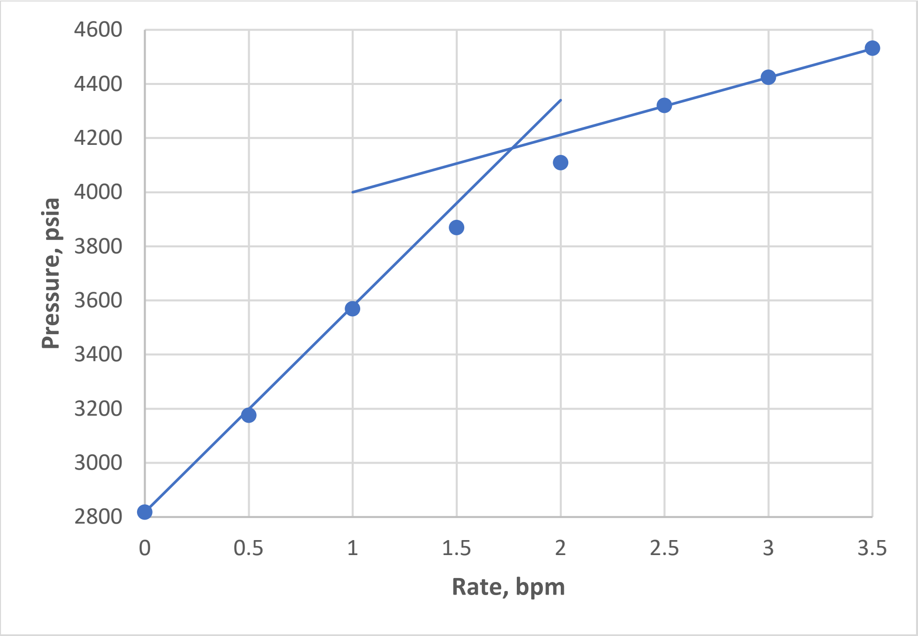

Figure 27: MtSA1-A2 step rate test. E-line pressure gauge data (DC5179) at 6,157 ft MD. The intersection of the two lines is interpreted as the fracture propagation pressure (4,160 psia). The initial gauge pressure (2,818 psia) is the y-axis value at 0 bpm.

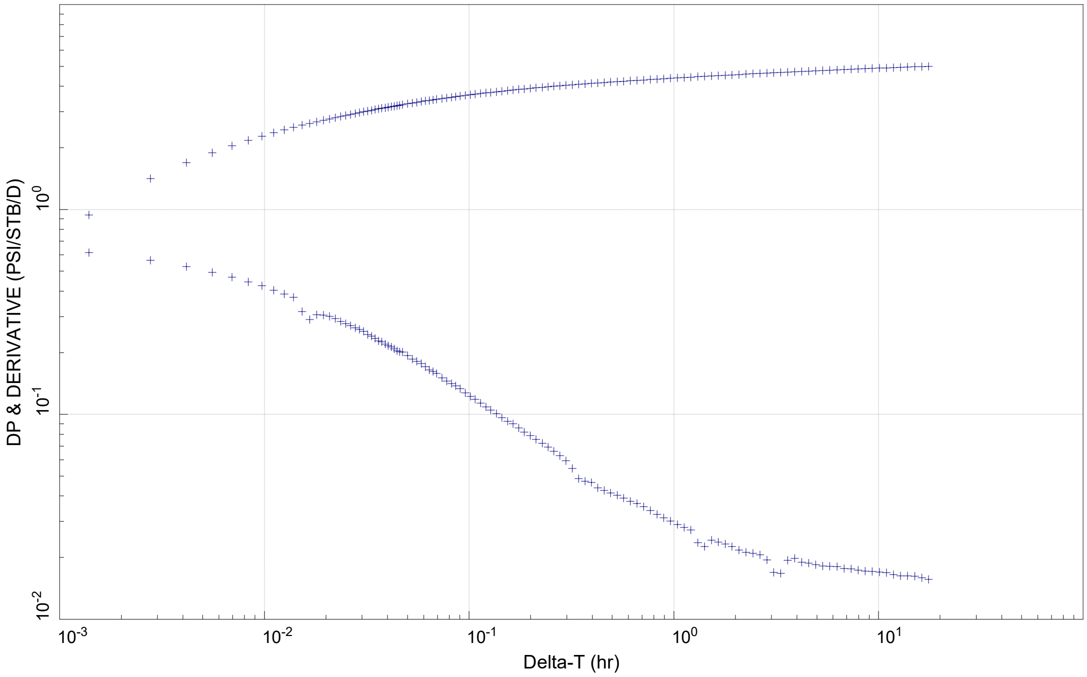

Figure 28: MtSA1-A2 derivative plot of the buildup tests' SI period at the end of the process of disposing the remaining test brine. (Upper curve is pressure, and lower curve is derivative.). No WBS-dominated derivative is present, but WBS influence is in the first log cycle of time (< 0.01 hrs). Between 0.5 and 1 hr is a half-slope indicative of partial penetration from which k_v/k_h ratio is calculated. The separation between the pressure and derivative curves indicates large, positive apparent skin, which is expected due to the partial penetration effect. (No logarithmic smoothing factor was used to calculate the derivative.)

X. Summary:

Table 16 tabulates the fracture pressure gradient, permeability-thickness, and k_v/k_h of each test interval from which test data could be analyzed for each petrophysical property.

Table 16: Tabulation of petrophysical properties for each test interval.

Attribute	MtSA2-Prod	EC	MtSE	MtSA2	MtSA1	PC2	MtSA1-A2
Initial Pressure/ Fluid Gradient	-	2483 (0.487)	2319 (0.444)	2809 (0.449)	2872 (0.456)	2948 (0.460)	-
Fracture Gradient	-	1.00 - 1.19	0.712	0.783	0.769	1.27	0.69
k-h*, md-ft	2,400-5,400 (flowing) 4,900 (pumping)	11-16	10,000 (280-420)	4,200 (2000-2200)	14,700 - 10,000 (200-400)	0.13-0.20	4,600
k_v/k_h	0.0061-0.030 (flowing) - (pumping)	-	-	0.0084-0.017	0.000016-0.00028	-	0.0019

*Numbers in parenthesis are from MFT and are most representative of the 5-ft perforated interval. The number above the parenthesis is over the entire test interval.