In-Situ Stresses and Permeability Measurements from Testings in Injection Well 16A(78)-32 at Utah FORGE Site

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Keywords

Utah FORGE, In-situ stresses, Stress measurement, Permeability, DFIT, Flowback

ABSTRACT

A highly deviated injection well, 16A(78)-32, was completed with a total depth 10,987 ft at Utah FORGE site. A series of injection tests, including microhydraulic fracturing test, DFIT (Diagnostic Fracture Injection Test) and pump-in/flowback testing, were carried out in a 200 ft openhole section at the toe of the well. Various methods have been used to interpret closure stress and permeability from the pump-in/shut-in and pump-in/flowback tests. The closure stresses inferred from the three different testing types are consistent with each other. Closure stress interpretation from pump-in/flowback test is a success because of the improvements implemented, such as starting flowback early, maintaining same choke size, reducing flowback time, and more sub-cycles. Inferred closure stress gradients range from 0.71 to 0.75 psi/ft, which are within the range of those inferred from the openhole section of an offset well, well 58-32. Matrix permeability inferred from the DFIT testing is about 20 μD, which is approximately the maximum value measured on core from offset well 58-32. The inferred permeability thickness product is about 4 to 20 mD·ft.

1. Introduction

In January 2021, a highly deviated injection well, 16A(78)-32, was completed at a total depth 10,987 ft. This well is the first of a pair of inclined wells at the Frontier Observatory for Research in Geothermal Energy (FORGE) site near Milford, Utah. A series of injection tests, including microhydraulic fracturing test, DFIT (Diagnostic Fracture Injection Test) and pump-in/flowback testing, were carried out in a 200 ft openhole section at the toe of the well.

Especially, the pump-in/flowback test was improved based on the flowback tests conducted in the pilot well 58-32 (Xing et al., 2021).

In-situ stresses and reservoir permeability are important parameters for the hydraulic stimulation design and reservoir performance analysis for Enhanced Geothermal System (EGS). In 2017 and 2019, a series of injection tests were conducted in the pilot well 58-32 and closure stress associated with minimum horizontal principal stress was evaluated (Xing et al., 2020). A basic information of the reservoir information of FORGE site was acquired through the interpretations of injection tests in well 58-32. In this study, we have analyzed the injection tests directly from the injection well 16A(78)-32, which will be stimulated in the future. The inferred closure stresses are compared with those from injection tests in well 58-32. The inferred permeability is also compared with that measured on core from well 58-32. These inferred closure stress and permeability from well 16A(78)-32 enhanced our understanding of the FORGE reservoir.

2. Injection Tests Conducted in Well 16A(78)-32

2.1 Overview of Well 16A(78)-32

The injection well, 16A(78)-32, is highly deviated and is the first of its kind in granitic rock. Drilling of the well was completed in January 2021. The trajectory of well 16A(78)-32 is shown in Figure 1. This well was drilled on an azimuth of 105° (relative to true north) at a tangent of 65° to the vertical. The well kicked off (location where directional drilling operations commence) at 5892 ft measured depth (MD) and started to build 5°/100 ft until it reached 65°. The production casing shoe is at 10,787 ft MD, and there is a 200 ft openhole section behind it. Total depth (TD) of the well is 10,987 ft. True vertical depth (TVD) at the toe is 8560 ft and the temperature at the bottomhole is on the order of 446 °F (230 °C). The horizontal offset is 4074 ft.

2.2 Injection Tests

Before cementing, 200 ft of 100 mesh sand was spotted at the toe. The casing was run to a setting depth of 10,787 ft MD. A liner hanger was run but failed to set. The liner was pulled, the cement program was redesigned, and the casing was cemented from 10,787’ back to the surface, as a long string. The float equipment was drilled out and the sand washed out of the hole, leaving 200 ft of hole available for stress testing.

Upon dropping the ball, the packer did not properly set. The planned test procedure was continued using the full annual volume as a dead string. The stages pumped were a low rate microfrac (Figure 2), a diagnostic fracture injection test (DFIT) with shut-in (Figures 2 and 3), a pump-in with flowback (Figure 4), and a DFIT with annulus open to the atmosphere. The first three test cycles provided reliable in situ information. *The fourth cycle confirmed that the packer had not sealed.* Different test methods will provide robust results about the reservoir.

Cycle 1 was a microhydraulic fracturing test with a low pumping rate (less than 0.6 bpm). During the test, the pumping rate was gradually increased from 0.2 bpm to 0.5 bpm. The shut-in time was relative short, only 0.5 hour.

Cycle 2 was a DFIT with a relative high pumping rate of 5.0 bpm for 2.5 minutes after rate stabilization. The injected volume is 18.1 bbl. The shut-in time was 17.5 hour.

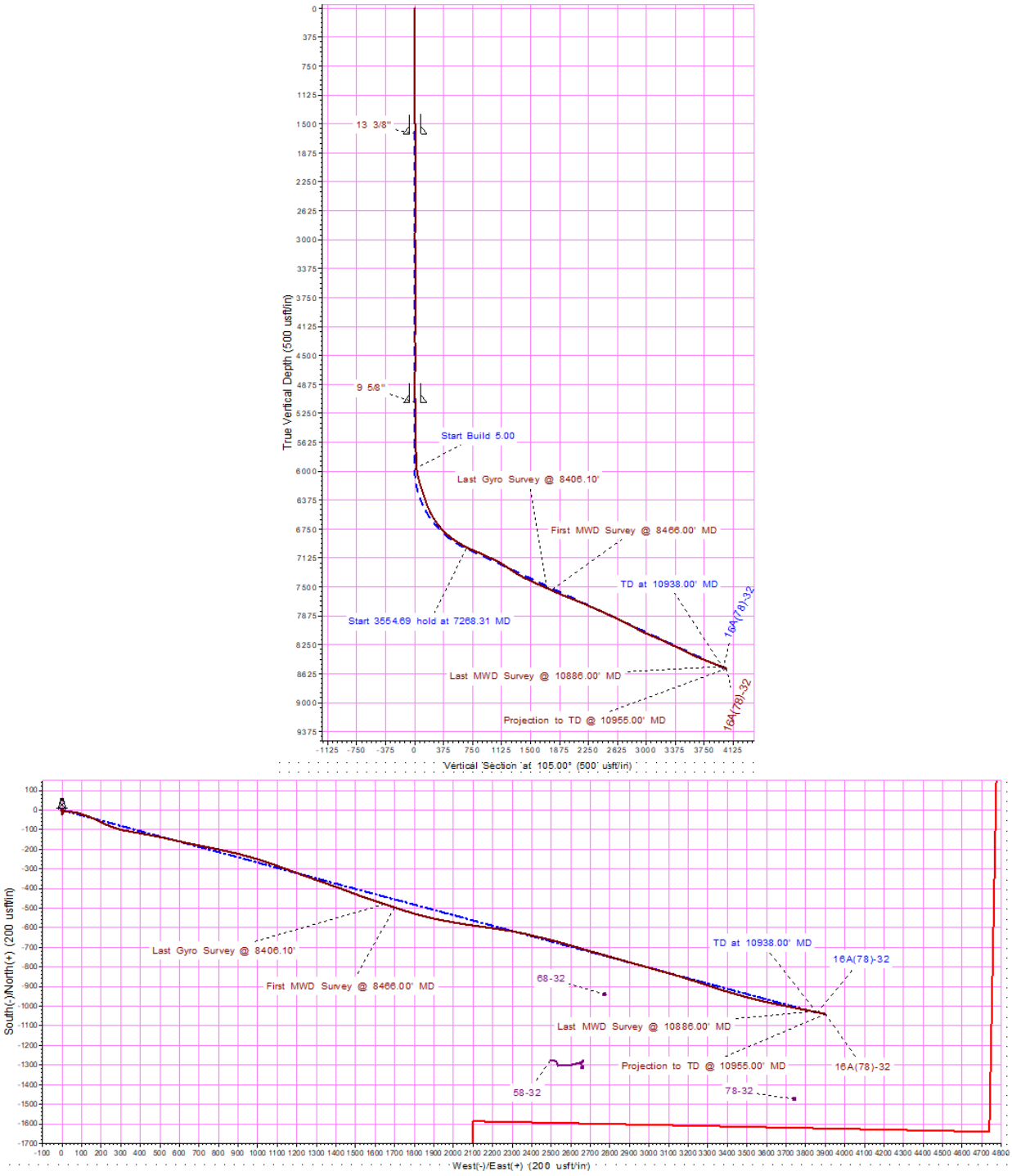

Figure 1. Trajectory of well 16A(78)-32. Top is the directional profile (approximate elevation view) and bottom is the plan view of trajectory at TD before coring.

Cycle 3 was pump-in/flowback test. Flowback test has the advantage over extended shut-in test, because it can reduce the operation time from days to hours. The pumping procedure of Cycle 3 is similar to Cycle 2, which is injection at 5.0 bpm for about 3 minutes. Immediately after pumping, there was a flowback with a through a 1/64" choke size instead of prolonged shut-in. After 30 seconds flowback, a three-minute shut-in followed. Then this flowback/shut-in sub-cycle was repeated until the surface pressure was reduced below 500 psi. There are four improvements in the flowback test conducted in well 16A(78)-32 compared to those in well 58-32 (Xing et al., 2021): 1) started flowback immediately after injection; 2) the choke size was kept the same through the test; 3) the flowback time was reduced to 30 seconds; 4) more sub-cycles were conducted. These improvements helped to interpret the closure stress and reduce the transient flow during flowback test (Savitski and Dudley, 2011).

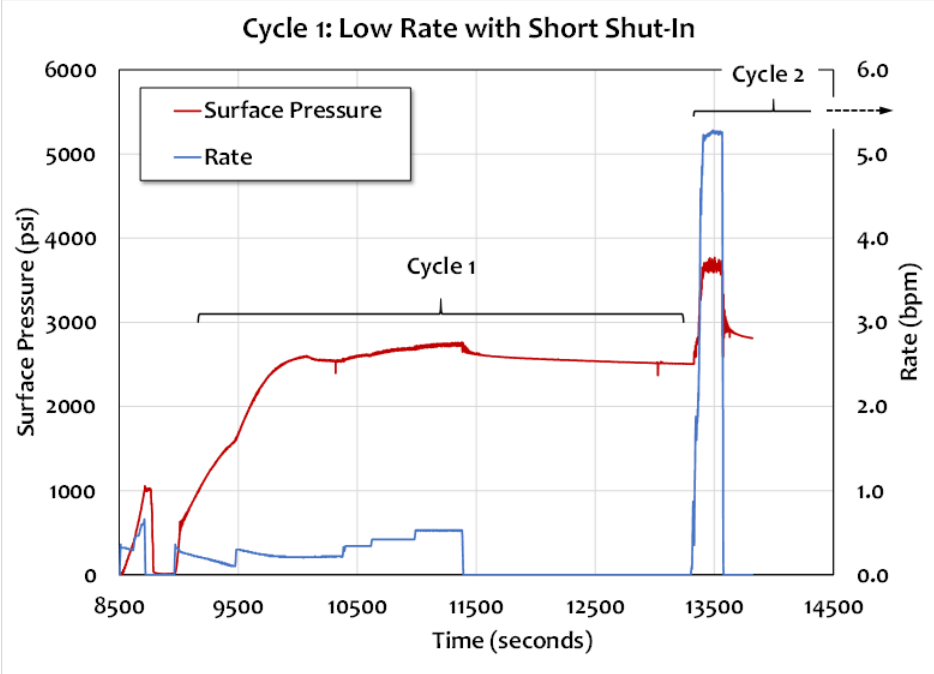

Figure 2. This is a plot of surface pressure and rate for the first cycle (at rates up to 0.5 bpm), followed by a brief shut in and then the injection portion of the standard DFIT test and the first part of the shut-in for that cycle. The entirety of Cycle 2 is shown in Figure 5.

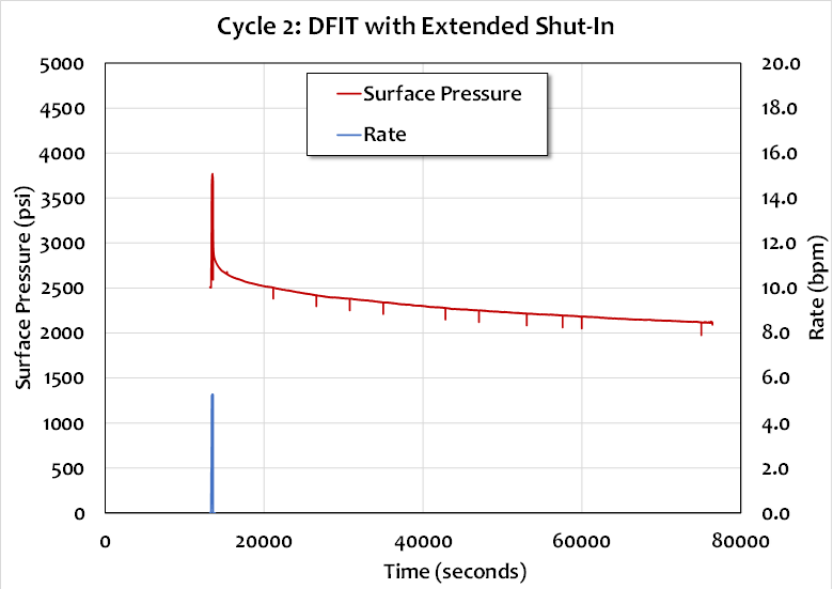

Figure 3. This is a plot of surface pressure and rate for Cycle 2 (pumping at 5 bpm for 2.5 minutes after rate stabilization), followed by a prolonged shut in (about 17.5 hr).

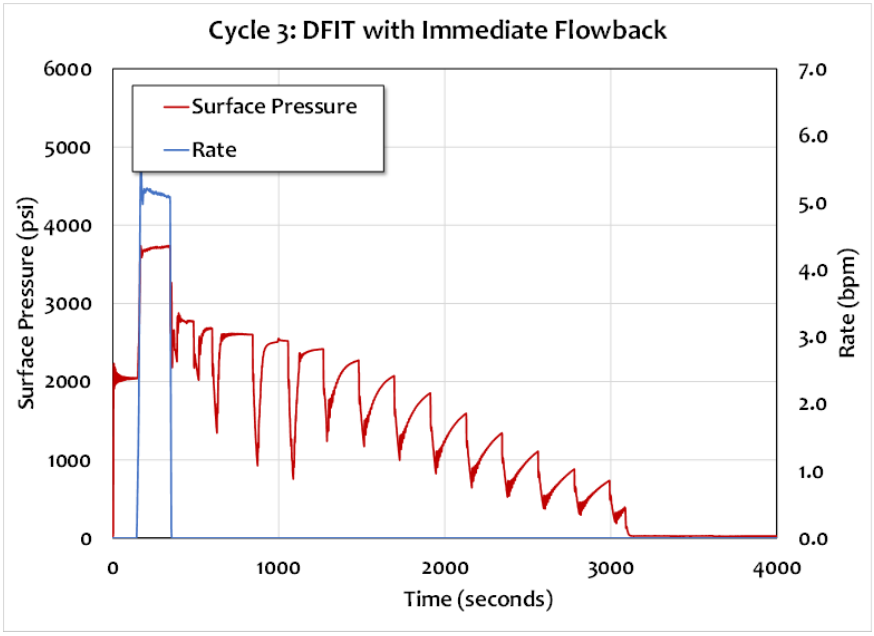

Figure 4. This is a plot of surface pressure and rate for the third cycle (pumping at 5 bpm for 3 minutes after rate stabilization), followed by a flowback sequence through a 1/64-inch choke (flow for 30 seconds followed by a three-minute shut-in, repeatedly).

3. Interpretation Results

The injection activities conducted include three different test methods: microhydraulic fracturing test, DFIT, and pump-in/flowback test. Closure stress and permeability are obtained through the interpretations of these injection tests.

3.1 In-situ Stresses (Closure Stresses) Interpretations

Closure stresses can be inferred from each of the injection methods. The results inferred from different methods can crosscheck with each other. There was only surface pressure recorded during the injection testing. The corresponding bottomhole pressure associated with fracture closure can be calculated by adding hydrostatic pressure to the surface pressure. The hydrostatic pressure gradient is 0.433 psi/ft and TVD is 8490 ft corresponding to beginning of openhole. Hence, the hydrostatic pressure is 3676 psi.

3.1.1 Cycle 1, microhydraulic fracturing test

For the microhydraulic fracturing test, various methods have been used to interpret the closure stress, including reopening pressure, ISIP, a plot of pressure vs. $\sqrt{t}$, and a plot of pressure vs. incremental pumping rates. Other methods based on shut-in data, including G-function plot and diagnostic log-log plot are not able to identify the fracture closure because the shut-in time is relatively short (only 0.5 hr).

Reopening Pressure and ISIP

This injection suggested reopening (refer to Figure 5). Reopening pressure inflection can be taken as an indication of closure stress. Reopening surface pressure can be taken as an estimate for closure pressure since pipe friction is negligible with a pumping rate of 0.2 bpm. The surface pressure at reopening is 2481 psi. By adding the hydrostatic pressure, the corresponding closure stress is 6157 psi (stress gradient is 0.73 psi/ft given TVD 8490 ft). Another interpretation is that at these low rates, the fracture(s) was(were) barely open and would close almost instantaneously. Presuming that this was the case, ISIP would be a rational estimate of the closure stress (refer to Figure 5). The closure stress inferred from ISIP is 6330 psi (stress gradient 0.75 psi/ft).

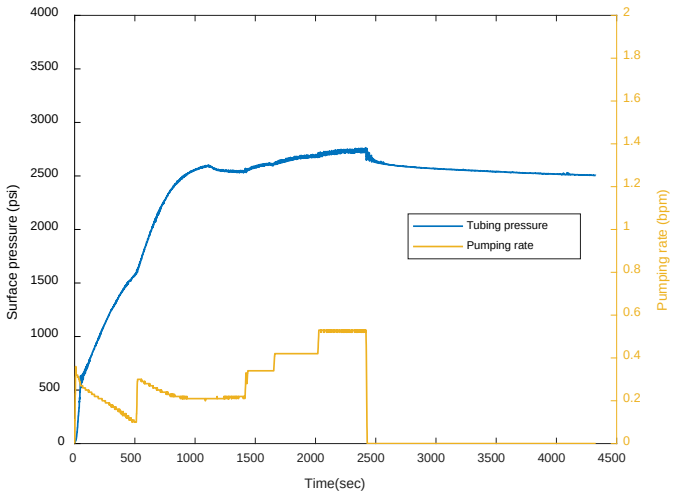

Figure 5. Surface pressure vs. pumping rate for Cycle 1. Shut-in time is only 0.5 hr. The surface pressure at reopening is 2481 psi and the corresponding closure stress is 6157 psi (stress gradient 0.73 psi/ft). The ISIP is 2654 psi and the corresponding closure stress is 6330 psi (stress gradient 0.75 psi/ft).

Pressure vs $\sqrt{t}$

Figure 6 indicates a square root of time representation of the post-shut-in data. The surface pressure at fracture closure is 2536 psi and the corresponding closure stress is 6212 psi (stress gradient is 0.73 psi/ft).

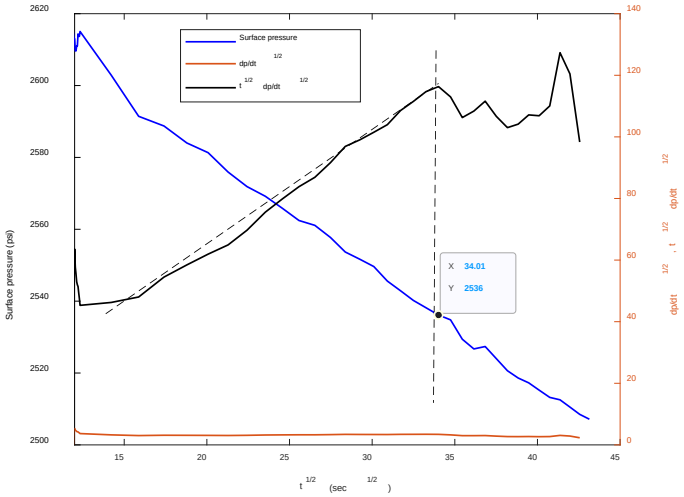

Figure 6. Pressure vs. square root of time for Cycle 1. The fracture closure is picked at the point deviating from the linear section in the $\sqrt{t}$ dp/d$\sqrt{t}$ curve. The surface pressure at fracture closure is 2536 psi and the corresponding closure is 6212 psi (stress gradient 0.73 psi/ft).

Step rate plot

Figure 7 shows the relation between surface tubing pressure and various pumping rates. The intercept of the upper linear fitting suggests the closure pressure. Surface pressure at fracture closure is 2432 psi and the corresponding closure stress is 6108 psi (stress gradient 0.72 psi/ft).

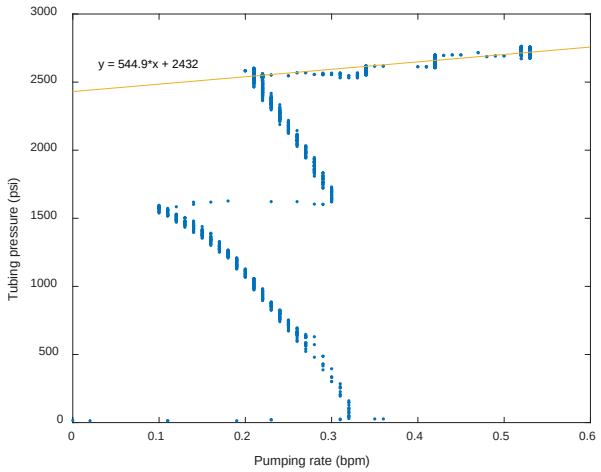

Figure 7. Surface pressure vs pumping rate for Cycle 1. Closure pressure can be picked as the intercept of the linear fitting of the upper section of the curve. Surface pressure at closure is 2432 psi and the corresponding closure stress is 6108 psi (stress gradient 0.72 psi/ft).

3.1.2 Cycle 2, DFIT

Cycle 2 is a typical DFIT. A diagnostic log-log plot and the G-function method based on shut-in data were employed to infer the closure stress. The inferred closure stress is 0.74 – 0.75 psi/ft for Cycle 2.

Diagnostic log-log plot

Figure 8 is a diagnostic plot of the shut-in data from Cycle 2. The fracture closure was picked at the end of 1/2 slope in the log-log plot of pressure drop vs. time since shut-in. The surface pressure at fracture closure is 2613 psi. The corresponding closure stress is 6289 psi (stress gradient 0.74 psi/ft).

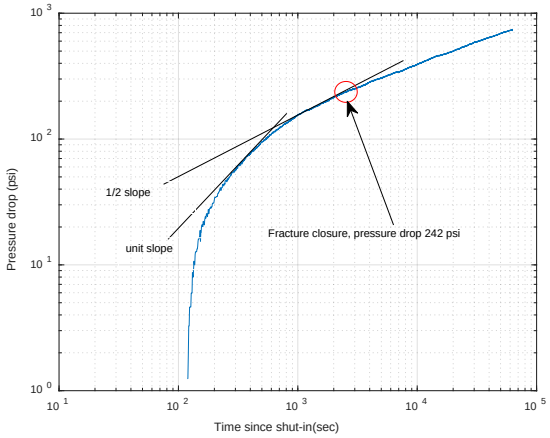

Figure 8. Diagnostic log-log plot of Cycle 2. The surface pressure at fracture closure is 2855-242=2613 psi. The corresponding closure stress is 6289 psi (stress gradient 0.74 psi/ft).

G function plot

Figure 9 shows a G-function plot of the data from Cycle 2. The fracture closure was picked at the point deviating from initial linear section on Gdp/dG curve. The corresponding closure stress is 6338 psi (stress gradient 0.75 psi/ft).

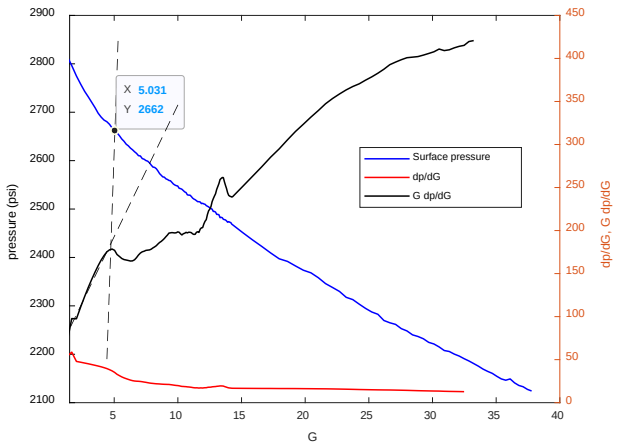

Figure 9. G function plot of Cycle 2. The surface pressure at fracture closure is 2662 psi. The corresponding closure stress is 6338 psi (stress gradient is 0.75 psi/ft).

3.1.3 Cycle 3, pump-in/flowback test

Cycle 3 is a pump-in/flowback test. Compared to the flowback tests for well 58-32, this flowback test for well 16A(78)-32 was improved by starting the flowback immediately after injection, maintaining the same choke size, reducing the flowback time, and conducting more flowback/shut-in sub-cycles. These improvements were helpful to minimize the transient flow and make the closure stress interpretation feasible. Both a stiffness method and a material balance time method were used to interpret the closure stress. The inferred closure stress gradients are 0.71 – 0.73 psi/ft.

Stiffness method

Figure 10 shows the stiffness change during flowback. Fracture closure is picked at the intersection of the two linear sections for the curve. As it is shown, the system stiffness increased after fracture closure as expected. Moreover, the system stiffness after fracture closure (595 psi/bbl) is close to the stiffness during injection (701 psi/bbl), which validates that the fractures were closed. The corresponding closure stress is 6018 psi (stress gradient 0.71 psi/ft).

Material balance method

Rate normalized pressure is plotted against material balance time in Figure 12 following Zanganeh et al (2020). Fracture closure is picked at the intersection of 1/2 slope and unit slope, which is between sub-cycle 4 and sub-cycle 5. The surface pressure at fracture closure is 2543 psi. The corresponding closure stress is 6219 psi (stress gradient 0.73 psi/ft).

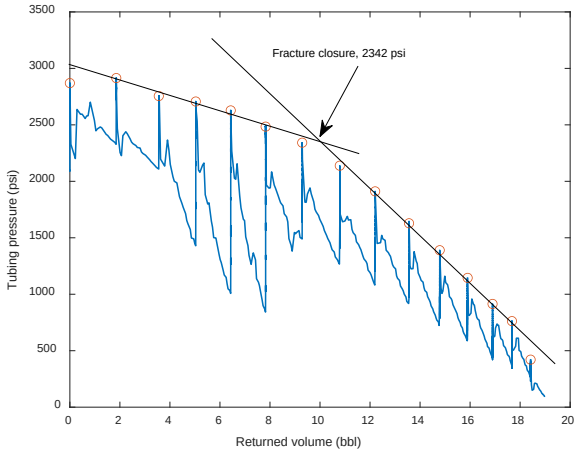

Figure 10. Surface pressure vs. returned volume for the flowback test. Fracture closure is picked at the intersection of the two linear sections for the curve. The surface pressure at closure is 2342 (corresponds to rebound pressure of sub-cycle 6). The closure stress is 6018 psi (stress gradient 0.71 psi/ft). The stiffness after closure is 595 psi/bbl, which is close to the injection stiffness of Cycle 1 (701 psi/bbl, shown in Figure 11).

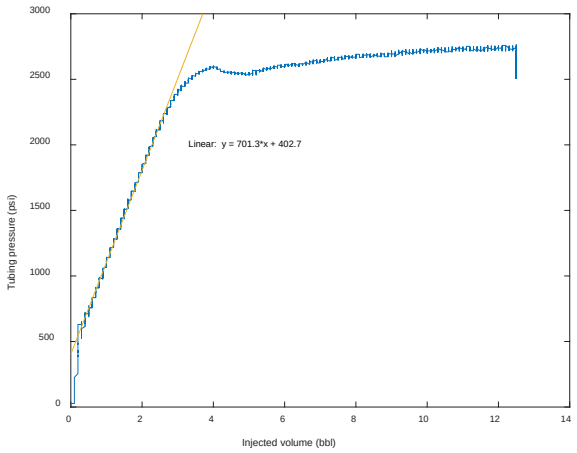

Figure 11. Surface pressure vs. injected volume for Cycle 1. Stiffness is 701 psi/bbl during injection.

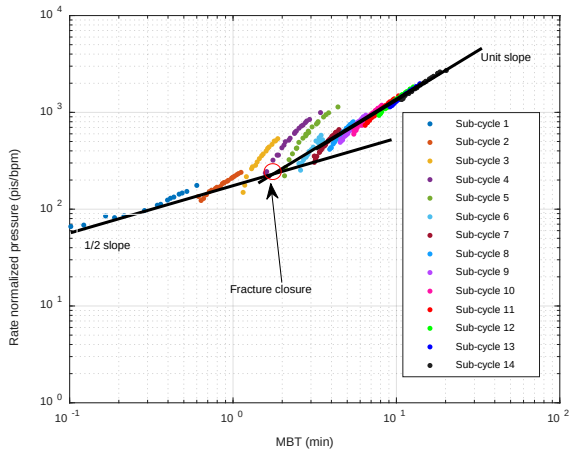

Figure 12. RNP vs. MBT for the flowback test. Fracture closure is picked between sub-cycle 4 and sub-cycle 5, which is 2543 psi of surface pressure. The corresponding closure stress is 6219 psi (stress gradient 0.73 psi/ft).

3.2 Permeability Interpretations

Permeability or permeability thickness product is inferred from both the DFIT (Cycle 2) and pump-in/flowback test (Cycle 3).

3.2.1 Cycle 2, DFIT

Ideally, for a DFIT, permeability can be inferred from both the before closure analysis and after closure analysis. However, due to the relative short shut-in period in this cycle, permeability interpretation from after closure analysis is not viable.

Before closure analysis

Presuming a radially-shaped hydraulic fracture, a leakoff coefficient inferred from the G function curve (refer to Figure 9) can be expressed as (McClure et al., 2019):

$$C_L = -\frac{dp}{dG}\frac{C_w + \frac{16R_f^3}{3E'}}{0.5\pi^2 R_f^2\sqrt{t_e}} \quad (1)$$

Permeability can be calculation by the definition of leakoff coefficient:

$$C_L = \sqrt{\frac{kc_f\phi}{\pi\mu}}\Delta p \quad (2)$$

Parameters and calculation of the permeability using before-closure-analysis for Cycle 2 are shown in Table 1. The inferred permeability is 21 μD, which is close to the result measured on the core from well 58-32. The calculated permeability thickness product kh is 4.0 mD·ft.

Table 1. Calculation of permeability through before-closure-analysis for Cycle 2.

Parameters	Oilfield Units	SI Units
Fluid compressibility c_f (1/Pa)	6.0e-6 1/psi	8.7e-10 1/Pa
Porosity ϕ	0.01	0.01
Viscosity μ	0.15 cp	1.5e-4 Pa.m
Fracture toughness	1600 psi.in^0.5	1.76 MPa.m^0.5
Pressure difference Δp	(0.75-0.433)·8490+200=2891 psi	2.0e7 Pa
pnet	200 psi	1.38e6 Pa
Fracture radius R_f	108 ft	33 m
Young's modulus	7.25e6 psi	5e10 Pa
Poisson's ratio	0.25	0.25
Wellbore storage coefficient C_w	1/600 bbl/psi	3.84e-8 m^3/Pa
Duration of pumping t_e	250 sec	250 sec
Pumping rate	5 bpm	1.3e-2 m^3/s
Pumping volume	18.1 bbl	2.88 m^3
dp/dG	42 psi	2.9e5 Pa
Calculated permeability k	21 μD	2.1e-17 m^2
Calculated kh	21 $\mu D \times \sqrt{\pi} R_f$ =4.0 mD.ft	1.2e-15 m^3

After closure analysis

Figure 13 describes the pressure difference and its derivative with time vs. time after shut-in. From this figure, neither after-closure linear flow nor radial flow can be identified. Therefore, permeability interpretation from after-closure analysis is not available for this cycle probably because the shut-in time was not long enough.

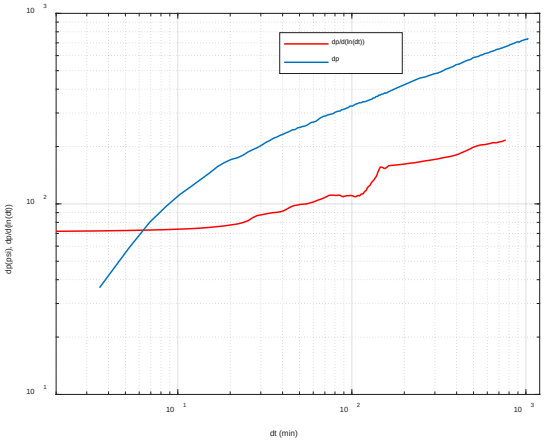

Figure 13. dp and dp/d(ln(dt)) vs dt for Cycle 2 well 16A(78)-32. Neither after closure linear flow nor radial flow can be identified.

3.2.2 Cycle 3, pump-in/flowback

The permeability-thickness product, kh, from the flowback test can be evaluated using the "two flow rates" method (Xing et al., 2021). Figure 14 shows permeability-thickness product, kh, estimation from the flowback test in Well 16A(78)-32. As shown in the figure, kh decreased as the pressure drop increased until fracture closure. kh then remained almost constant at 20 mD·ft after fracture closure, which is larger than that inferred from before closure analysis of Cycle 2.

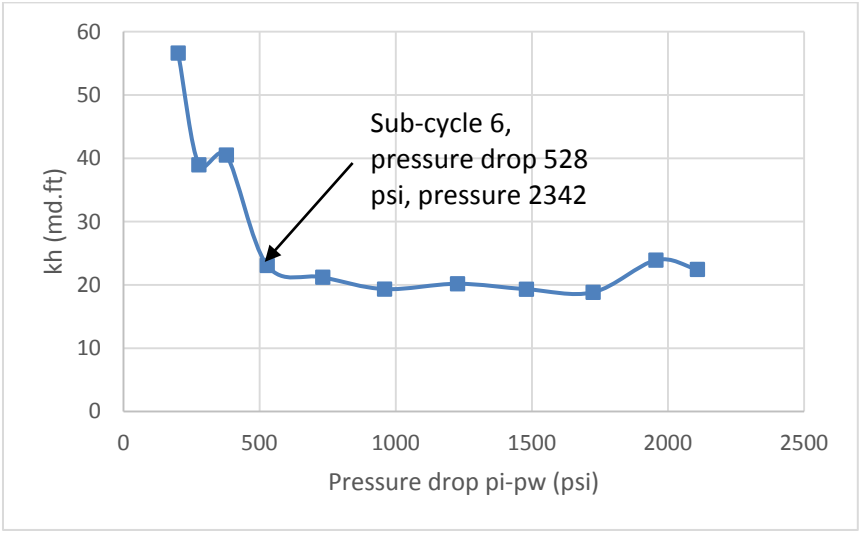

Figure 14. Permeability-thickness product, kh, estimation from the flowback test in Well 16A(78)-32. Sub-cycle 6 is when the fracture closed. After fracture closure, the estimated kh is almost constant, with a value of around 20 mD·ft.

3.3 Summary

A summary of the closure stress interpretations from the three cycles is provided in Table 2. The inferred closure stress gradients range from 0.71 to 0.75 psi/ft. These values are in the range of those inferred from Zone 1 (openhole) in well 58-32, 0.67 – 0.83 psi/ft, but with a smaller variation.

Table 2. Summary of closure stress interpretations for the openhole section of well 16A(78)-32 (TVD 8490 ft)

Cycle	Test Type	Interpretation method	Surface pressure (psi)	Closure stress (psi)	Closure stress gradient (psi/ft)
C1	Microhydraulic fracturing	Reopening pressure	2481	6157	0.73
C1	Microhydraulic fracturing	ISIP	2654	6330	0.75
C1	Microhydraulic fracturing	p vs $\sqrt{t}$	2536	6212	0.73
C1	Microhydraulic fracturing	Step rate	2432	6108	0.72
C2	DFIT	log-log	2613	6289	0.74
C2	DFIT	G-function	2662	6338	0.75
C3	Pump-in/flowback	Flowback stiffness	2342	6018	0.71
C3	Pump-in/flowback	RNP vs MBT	2543	6219	0.73

Permeability, inferred from before closure analysis of Cycle 2 (DFIT), is 21 μD, which is approximately the maximum value measured on core from offset well 58-32. The permeability-thickness product estimated from Cycle 2 is 4 mD·ft and from Cycle 3, it is 20 mD·ft.

4. Conclusions

For the injection well 16A(78)-32 of FORGE project, a series of injection tests, including microhydraulic fracturing test, DFIT and pump-in/flowback testing, were carried out in the openhole section at the toe of the well. The pump-in/flowback testing in well 16A(78)-32 was improved by starting the flowback immediately after injection, maintaining the same choke size, reducing the flowback time, and conducting more flowback/shut-in sub-cycles. Pump-in/flowback potentially has advantages over pump-in/shut-in because of the reduced time to closure.

Various criteria have been used to interpret the pump-in/shut-in tests (both the microhydraulic fracturing test cycle and the DFIT). These evaluation criteria included reopening pressure, ISIP, G-function, plotting pressure vs. square root of time, etc. For pump-in/flowback test, stiffness method and material balance time method are used to interpret the closure stress. Results inferred from the three different testing types are consistent with each other. Inferred closure stress gradients range from 0.71 to 0.75 psi/ft, which are within the range of those inferred from the openhole section of an offset well, well 58-32.

Matrix permeability inferred from the DFIT testing through before closure analysis is about 20 μD, which is approximately the maximum value measured on core from offset well 58-32. The permeability thickness product from DFIT is about 4 mD·ft. For pump-in/flowback test, inferred permeability thickness product is about 20 mD·ft. The matrix permeability inferred from these two methods have the same order of magnitude.

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