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Analysis of the 2024 Circulation Tests at Utah FORGE and the Response of Fiber Optic Sensing Data

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ABSTRACT

The 2024 circulation tests at the Utah FORGE site demonstrated a significant improvement in reservoir conductivity and fluid recovery following commercial-scale hydraulic stimulation. A nine-hour circulation test conducted in April 2024 was followed by a one-month test from August to September 2024. The results confirmed that hydraulic stimulation with proppant effectively enhanced permeability, leading to a substantial increase in production rate—from 7 gpm (0.17bpm) in 2023 to 378 gpm (9.0 bpm) in 2024—with a wellhead temperature of 385°F. This study investigates the behavior of the reservoir using the wellhead data (e.g., injection pressure, injection rate, production pressure, production rate, production temperature), downhole PT gauge, and the fiber optic sensing data. During the one-month circulation test, the injectivity (injection rate over pressure) gradually increased as the circulation continued. The injectivity increase could be due to the thermal cooling effect. The strain rate change pattern interpreted from the fiber optic cable corresponds to sudden flow of hotter water, as confirmed by the surface temperature gauge. The results highlight the benefits of proppant-supported fractures and the potential for sustained commercial geothermal energy production at Utah FORGE. These findings underscore the importance of continued circulation testing and advanced monitoring techniques for optimizing Enhanced Geothermal Systems (EGS) performance.

1. INTRODUCTION

Utah FORGE (Frontier Observatory for Research in Geothermal Energy) is an Enhanced Geothermal System project supported by the U.S. Department of Energy (Moore et al., 2023). A lot activities were completed at Utah FORGE site from 2017 to 2023, including 1) drill of an injection well and a production well, 2) conduction of three stages of hydraulic stimulation at the injection well, and 3) a circulation test based on these initial three stages of hydraulic stimulation. The circulation test conducted in July 2023 indicates that there is a connection between the injection well and production well. However, the production rate was in the order of 10 bph (barrel per hour) or 0.17 bpm (barrel per minute), which is only 3% - 5% of the injection rate (Xing, et al., 2024a). The low production rate was due to the absence of proppant during that earlier stimulation stages in April 2022 (only a small amount of microproppant was used in Stage 3).

In April 2024, a commercial-scale hydraulic stimulation was conducted at both the injection well and production well at the Utah FORGE. During most of these stages, proppant (100-mesh and 40/70-mesh silica sand) were used. Firstly, the initial three stages performed in April 2022 were retreated with water containing proppant. Then, additional seven stages of hydraulic stimulations were conducted at the section above the initial three stages in the injection well 16A(78)-32. Among those seven stages, four stages were treated with normal proppant – sand, while only one stage (Stage 10) was treated with ultra-light weight proppant (refer to England et al., 2025). In addition to the treatments in the injection well 16A(78)-32, four stages of hydraulic stimulation were conducted with proppant in the production well 16B(78)-32. The details of the April 2024 hydraulic stimulation can be found in England et al., 2025. Immediately after the stimulation on April 27, 2024, a nine-hour circulation test was performed. Several months later, from August to September 2024, a one-month long circulation test was conducted.

This paper first describes these two circulation tests in 2024. Then, the results of these two circulation test are compared, and they are also compared to the circulation test in July 2023. Finally, the injectivity, stiffness, injection efficiency, flow distribution among different stages, fiber optic data response, and the thermal cooling effect are analyzed.

2. DESCRIPTION OF CIRCULATION TESTS IN 2024

There are two circulation tests conducted between injection well 16A(78)-32 and production well 16B(78)-32 in 2024. The first one is conducted right after the commercial-scale hydraulic stimulation, and it lasted only for nine hours on April 27, 2024. The second one is conducted several months later, which lasted about one-month (26.8 days) from August to September 2024.

For both of the circulation tests, cold water with ambient temperature was pumped into the injection well 16A(78)-32. For April 2024 circulation test, the injected water temperature is around 47 °F (8.3 °C), while for August-September 2024 the water temperature is around 80 °F (26.7 °C). The injection pressure was controlled under the fracturing pressure to avoid any further fracture propagation.

A lot data was collected and recorded during the circulation tests, including both surface and downhole equipment. Pumping rate and pumping pressure was recorded from the pump trucks. Inline transducers collected the wellhead pressure, flow rate, and temperature. A pressure/temperature (PT) gauge was deployed at the heel (7050 ft MD, 6730 ft TVD) of well 16B(78)-32. Fiber optic cable in 16B(78)-32 provided the strain change and temperature change during the circulation tests. In addition, spinner tests (production logging) was conducted in both the injection well 16A(78)-32 and production well 16B(78)-32 during the circulation tests.

2.1 April 2024 (nine hour) circulation test

The circulation test started at about 13:00 pm, April 27, 2024, and last about nine hours to 9:50 pm, April 27, 2024. Figure 1 shows the injection pressure, injection rate, production wellhead pressure, and production surface temperature. During the nine-hour circulation test, the maximum injection rate is 15.5 bpm, and was reduced to 13.0 bpm after about 4 hours. The final production rate is 8.1 bpm (fluid efficiency is 62%), and the final temperature is 283 ^{o}F. The trend suggests that if circulation continued, the production rate and temperature would keep increasing.

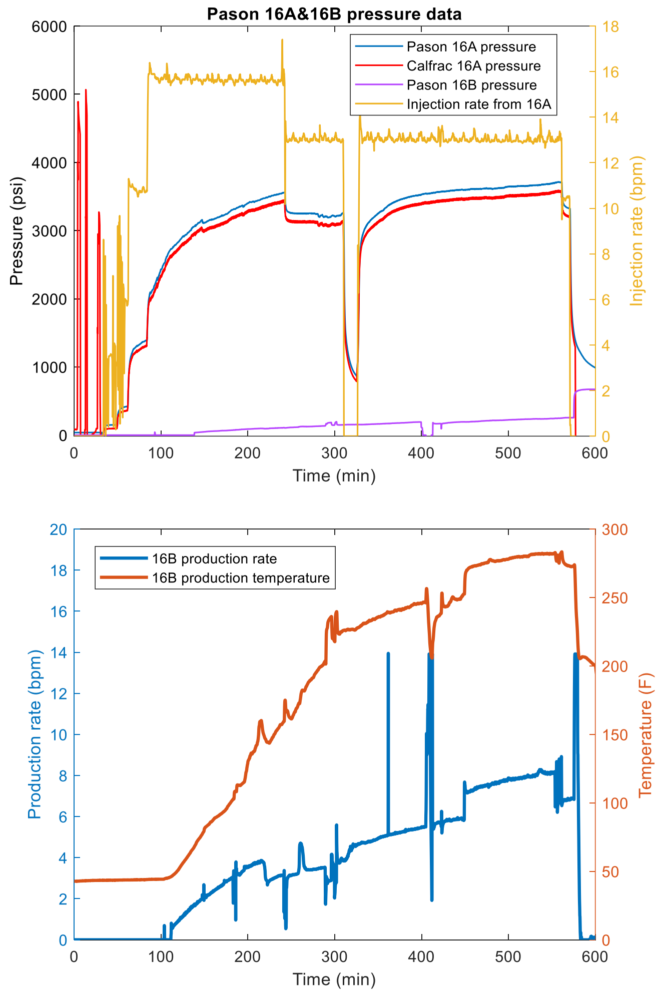


Figure 1: Data for the nine-hour circulation in April 27, 2024, including injection rate, injection pressure, production rate, production wellhead pressure, the production temperature.

2.2 August-September 2024 (one month) circulation test

The one-month circulation test started at 9:30 am August 8, 2024, and lasted 26.8 days till 5:54 am, September 4, 2024. The initial injection rate is 2.5 bpm, and gradually increased into 10 bpm within three days. Figure 2 shows the injection wellhead pressure, injection rate, production wellhead pressure, production surface temperature, downhole PT gauge pressure and temperature during the August-September 2024 circulation test. As shown in Figure 3, the final production flow rate of the one-month circulation test was approximately 378 gpm (9.0 bpm or 26.5 kg/s) with a temperature of 385 ^{o}F (196 ^{o}C). The electricity generation capacity is about 2 MW, considered as commercially viable.

The static temperature at the location of PT gauge is about 353 ^{o}F, and the PT gauge temperature at the end of circulation increased to 385 ^{o}F (refer to Figure 2). The temperature difference between the surface temperature transducer and downhole PT gauge narrowed down as circulation continued. On August 15, 2024, the temperature difference is 26 ^{o}F, while the difference is reduced to 21 ^{o}F on September 3, 2024 (close to the end of the circulation test).

Please note that the data shown in Figure 2 is directly from the sensor/transducer without any correction/calibration. However, the thermocouple in production line did not extend fully into the flow stream and read less. A temperature gun was used to measure the temperature at the wellhead, yielding higher temperature than the in-line thermocouple. The data from the temperature gun was recorded periodically and shown in Figure 3 as "corrected produce fluid temperature" (McLennan et al., 2024).

The production rate also needs to be corrected for two reasons: 1) the flow meter needs to be calibrated; 2) the flow meter was located at the downstream of the separator, and hence a fraction of fluid was lost to the atmosphere through steam before it entered the downstream flow meter. To account for these two factors: 1) the flow meter was calibrated by the Liberty Oilfield Services pumping equipment, 2) the steam loss was added to the final production rate. The corrected fluid efficiency is also shown in Figure 3. Finally, the production efficiency reached 90% (production rate 9 bpm), with wellhead temperature as 385 °F.

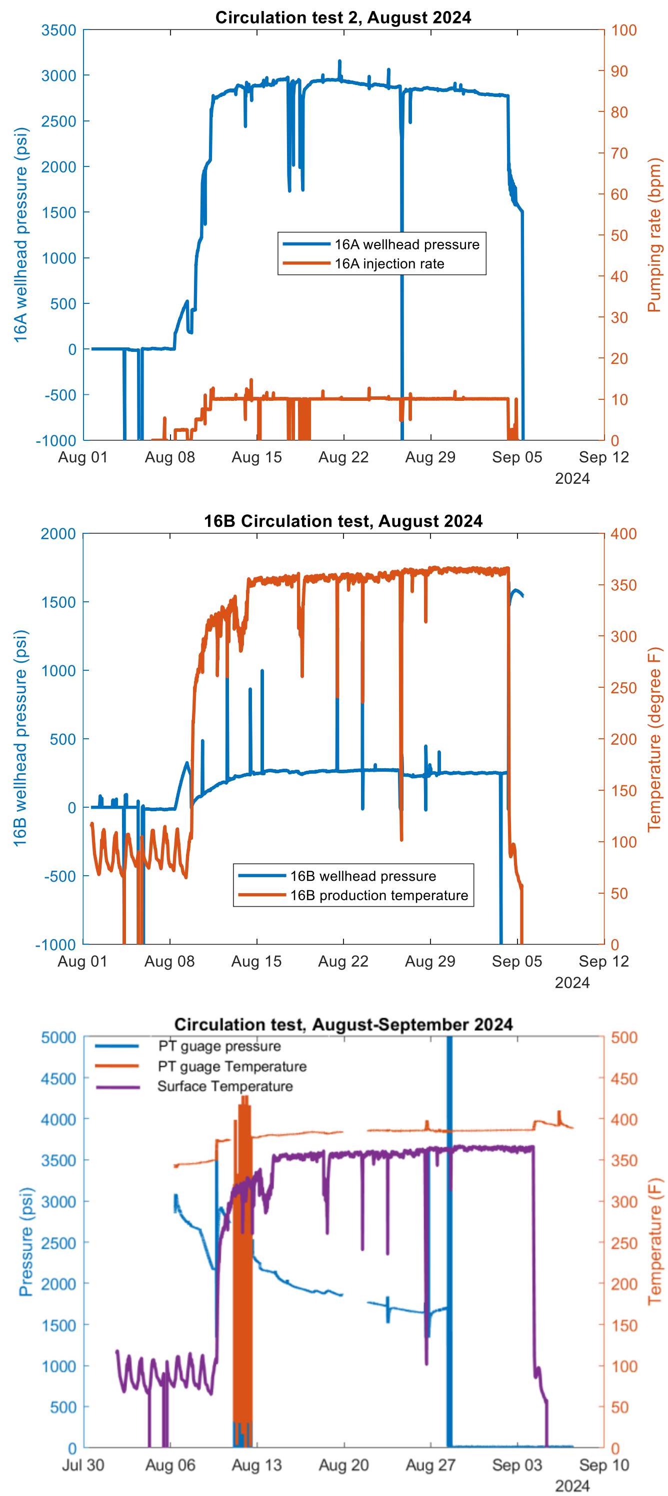


Figure 2: Data for the one-month circulation test in August-September, 2024, including injection rate, injection pressure, production wellhead pressure, the production temperature, and downhole PT gauge data.

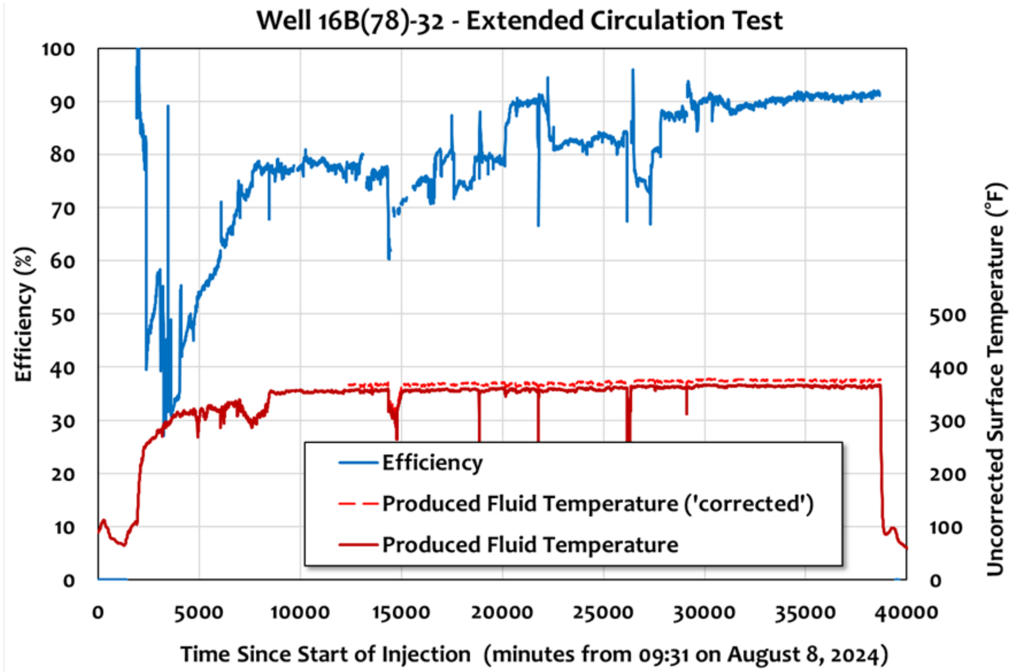


Figure 3: Calibrated production rate and corrected temperature of well 16B(78)-32 during August-September 2024 (one-month) circulation, adapted from McLennan et al., 2024.

3. ANALYSIS OF CIRCULATION TEST DATA

3.1 Communication between the injection well and production well

For the nine-hour circulation test in April 2024, initially the production well 16B(78)-32 was open. the temperature increased, and fluid began to flow out from the production well 16B(78)-32. After 105 minutes of pumping, the pressure of well 16B increased from 0 to 36.5 psi, and continued climbing to 250 psi.

During the one-month circulation test in August–September 2024, the production well 16B(78)-32 was initially closed. Immediately after pumping began in the injection well 16A(78)-32, the pressure in well 16B(78)-32 started to rise. After 31.5 hours of pumping, at 17:05 on August 9, well 16B(78)-32 was opened, allowing fluid to flow out. 25 minutes later, at 17:30 on August 9, the wellhead temperature of 16B(78)-32 began increasing.

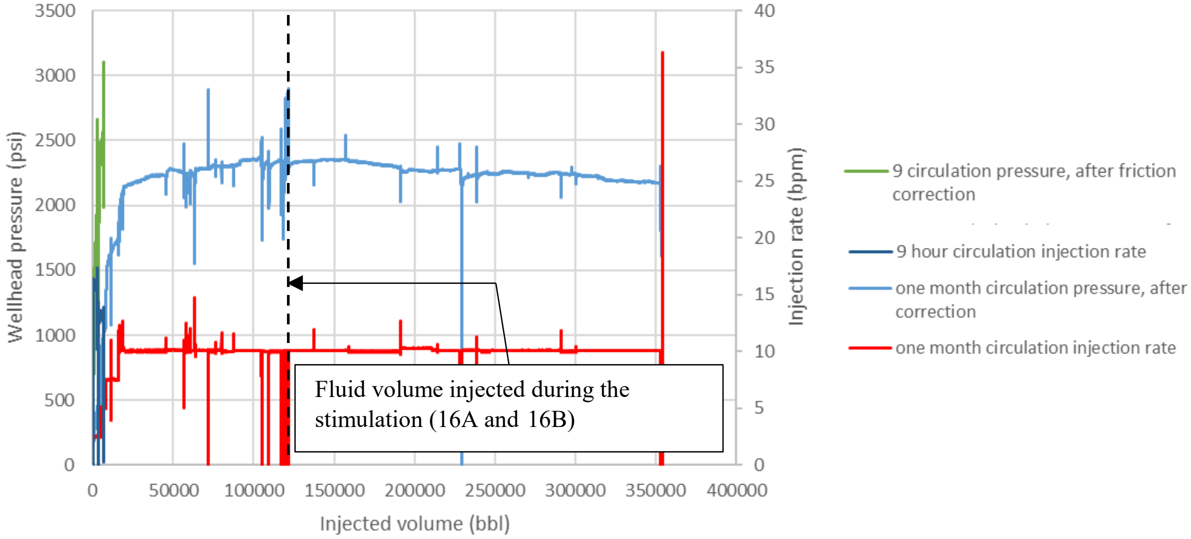
3.2 Comparison between April 2024 (nine hour) and August-September 2024 (one month) circulation test

The stiffness, injectivity, production rate, recovery rate, production temperature, and spinner test data are compared between these two circulation tests in 2024. The system stiffness here refers to the ratio of pressure over injected volume at the early stage of injection (Raaen et al., 2001). The injectivity is defined as the result of injection rate divided by injection pressure.

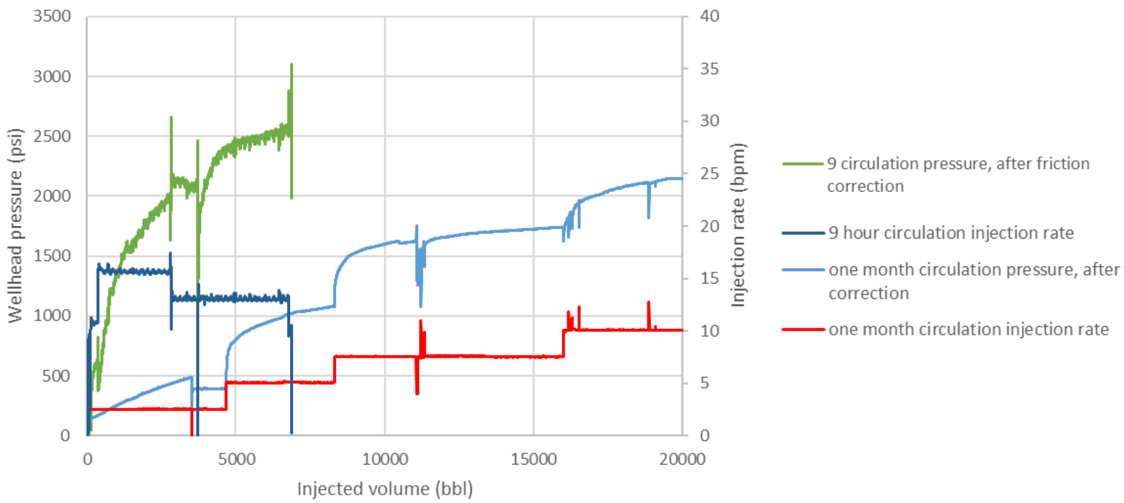
3.2.1 Stiffness and injectivity

The wellhead pressure vs. injected volume for the two circulation tests in 2024 is shown in Figure 4. The stiffness is calculated at the early stage of pumping before the curve slope changes. The stiffness of the different circulation tests is summarized in Table 1. For both the stiffness and injectivity calculation, the wellhead pressure of 16A(78) was corrected by subtraction of friction pressure. The friction pressure (unit psi) is estimated as $5.917Q^2$, where Q is the injection rate. The stiffness of two 2024 circulation tests is much smaller than that of the July 2023 circulation test. The smaller stiffness in 2024 is due to the commercial-scale hydraulic stimulation conducted in April 2024 before these two circulation tests. The April 2024 hydraulic stimulation has created more fractures, and a lot of them are filled with proppant. The circulation test in April 2024 has larger stiffness than that of August-September 2024 because there was more fluid in the reservoir before the April 2024 nine-hour circulation test. The total water volume injected during the April 2024 hydraulic stimulation is around 120,000 bbl. After the hydraulic stimulation, 82% of the injected fluid was flowed back. Hence, there was approximately 21,000 bbl of fluid remaining in the reservoir before the nine-hour circulation test. During the nine-hour circulation, about 6, 870 bbl of water was injected, but approximately 63% of injected fluid was circulated out through production well 16B(78)-32. After approximately three months, at the start of the August–September 2024 circulation test, the "tank" (fracture volume) created during the hydraulic stimulation in April 2024 was nearly empty, or the fluid volume in the reservoir was lower than that of the nine-hour circulation test. This is likely why the reservoir stiffness is lower during the one-month circulation test.

As shown in Figure 4(a), during the August-September 2024 circulation test, the injection pressure keeps increasing until the volume injected reached the 120,000 bbl on August 18, 2024—the same volume injected during the April 2024 hydraulic stimulation. After reaching this point, the pressure stabilized for three days. This suggests that pressure stabilization would not occur unless the fracture volume created during the hydraulic stimulation was fully recharged.



(a) Overall view



(b) Early stage

Figure 4: Wellhead pressure vs. injected volume for April 2024 (nine-hour circulation) and August-September 2024 (one-month circulation). The wellhead pressure was corrected by subtracting the friction pressure.

Figure 5 shows the injectivity vs. injected volume for April 2024 (nine-hour) and August-September 2024 (one-month) circulation tests. At the beginning, it is not the real injectivity since it is still in the process of building pressure. For both the nine-hour and one-month circulation tests, the injectivity all converged to 0.005 bpm/psi after 5,000 bbl water injected. The injectivity of the two circulation tests in 2024 is 2.5 times of the injectivity for the circulation test in July 2023 because there are more proppant supported fractures in 2024.

Table 1. Comparison of stiffness, injectivity, and production rate among the circulation test

Circulation Test	Stiffness	Injectivity	Maximum injection rate	Total injected volume	Production rate	Recovery rate	Production temperature
July 2023	~200 psi/bbl @5 bpm	0.002 bpm/psi	7.5 bpm	7,750 bbl	0.17 bpm	3% - 5%	N/A
April 2024	15 psi/bbl @ 10 bpm	0.005 bpm/psi	15.5 bpm	6,870 bbl	8.2 bpm	63%	283 °F
August-September 2024	0.4 psi/bbl @ 10 bpm	0.005 bpm/psi	10 bpm	354,500 bbl	9.0 bpm	90%	385 °F

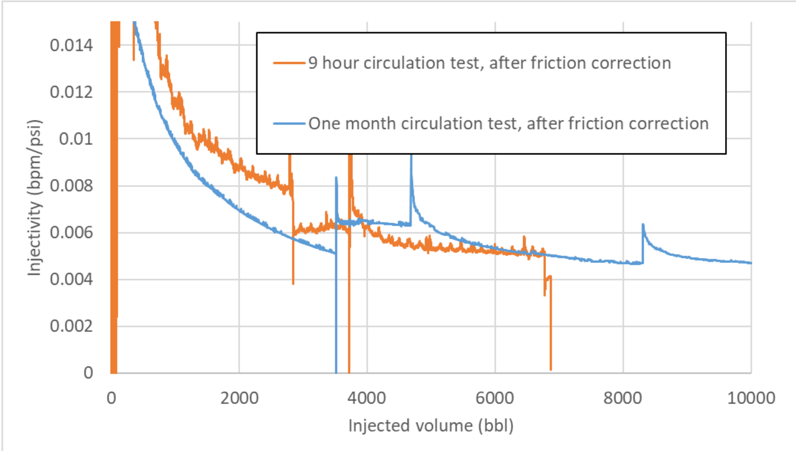


Figure 5: Injectivity vs. injected volume for April 2024 (nine-hour circulation) and August-September 2024 (one-month circulation). The wellhead pressure was corrected by subtracting the friction pressure.

3.2.2 Flow distribution (spinner test)

Spinner tests have been conducted in well 16A(78)-32 and 16B(78)-32 during both April 2024 and August-September 2024 circulation tests. The first spinner test was conducted in April 27, 2024 during the nine-hour circulation test. The second spinner test was done on August 17, 2024, 9 days after initiation of the one-month circulation test. The comparison of fluid flow distribution in well 16A(78)-32 for these two circulation tests is shown in Table 2. Most of the flow distribution occurred in Stages 1 to 5 and Stages 8 to 10. Stages 6 and 7 did not take fluid, as proppant was not used in these stages. The flow distribution in Stage 7 and below remained largely unchanged between the two circulation tests. However, in Stages 8, 9, and 10, the flow was more evenly distributed in August 2024 compared to April 2024, with increased fluid flow in Stages 8 and 10 and a decrease in Stage 9.

Table 2. Comparison of flow distribution in well 16A(78)-32 for the spinner tests for two circulation tests in 2024

Stage	Perforations (ft MD)		Cluster	April 2024		August-September 2024	
				Distribution in cluster	Distribution in stage	Distribution in cluster	Distribution in stage
10	9270	9276	10	9.2%	9.2%	25.8%	25.8%
9	9320	9323	9-8	4.7%	38.8%	1.4%	17.6%
	9345	9348	9-7	3.2%		2.5%	
	9370	9373	9-6	9.1%		4.5%	
	9395	9398	9-5	12.4%		5.0%	
	9420	9423	9-4	4.4%		1.0%	
	9445	9448	9-3	0.0%		0.6%	
	9470	9473	9-2	4.9%		0.7%	
	9490	9493	9-1	0.0%		1.8%	
8	9545	9548	8-8	N/a	16.2%	0.7%	26.1%
	9570	9573	8-7			0.7%	
	9595	9598	8-6			0.6%	
	9620	9623	8-5			1.4%	
	9645	9648	8-4			9.8%	
	9670	9673	8-3			7.0%	
	9695	9698	8-2			3.1%	
	9720	9723	8-1			2.9%	
7	9798	9801	7-3	N/a	1.8%	0.0%	0.0%
	9850	9853	7-2			0.0%	
	9898	9901	7-1			0.0%	
6	9959	9962	6-2	N/a	0.0%	0.0%	0.0%
	9970	9976	6-1			0.0%	
5-3R	Below 9976			N/a	34.0%	N/a	30.6%

3.2.3 Summary of the comparisons

As summarized in Table 1, the production rate, recovery rate, and injectivity of the two 2024 circulation tests are significantly higher than those of the July 2023 circulation test, while the system stiffness is considerably lower. The primary reason is the extensive use of proppant during the April 2024 hydraulic stimulation, unlike the April 2022 hydraulic stimulation test. Additionally, more stages were conducted in April 2024, resulting in the creation of more proppant supported fractures, providing significantly higher conductivity compared to that resulted by 2022 hydraulic stimulation.

The stiffness of April 2024 circulation is higher than that of August-September 2024 test because more fluid was stored in the reservoir at the start of April test. The injectivity for these two circulation tests in 2024 is the same, but the recovery rate and production temperature is larger for the August-September 2024 circulation test due to its significantly longer duration (26.8 days vs. 9 hours). As shown in Figure 3, for the August-September circulation test, the recovery started to increase after 10 days of pumping when the injected water volume equaled to the total volume injected during the April 2024 hydraulic stimulation, as the reservoir was fully recharged at that time. Regarding spinner test results, flow was more evenly distributed among Stage 8 9, and 10 in August 2024 compared to April 2024.

3.3 Fiber optic sensing data

The distributed strain sensing data was also recorded by the fiber optic cable in well 16B(78)-32 during the first 10 days of August-September 2024 circulation test. Figure 6 shows the strain change along the well on August 12, 2024 during the circulation test (Jurick et al., 2024). The strain change pattern indicates that there was hotter water flowing out from the bottom of the production well 16A(78)-32 to the surface. This can be confirmed by the surface temperature transducers. As shown in Figure 7, when the hot water arrived at the surface, the temperature started to increase. The final production surface temperature increased about 10 ^{o}F during this process.

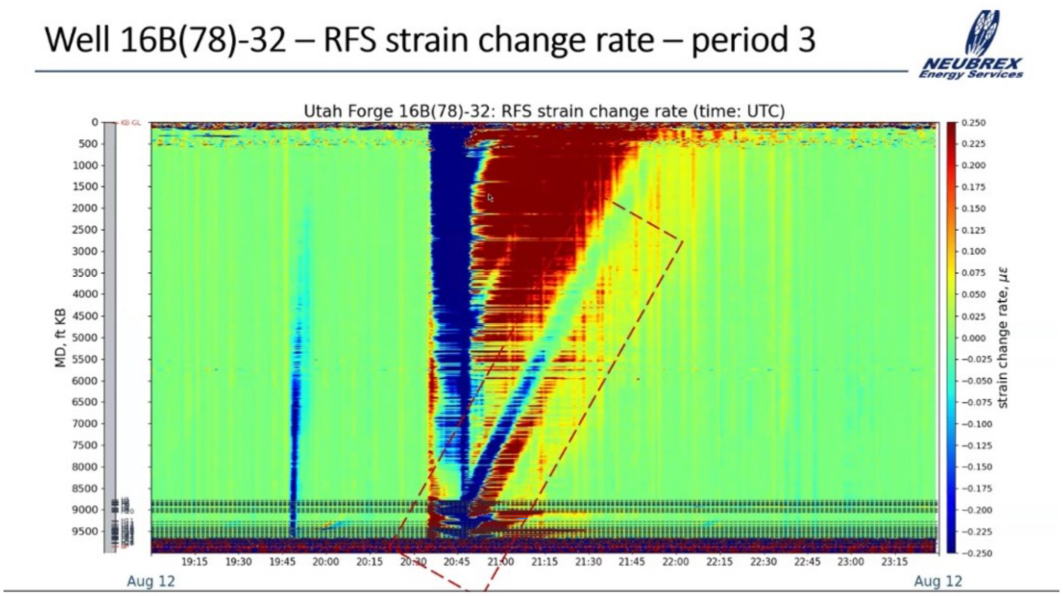


Figure 6: Fiber optic sensing strain data on August 12, 2024 during the circulation test (adapted from Jurick et al., 2024).

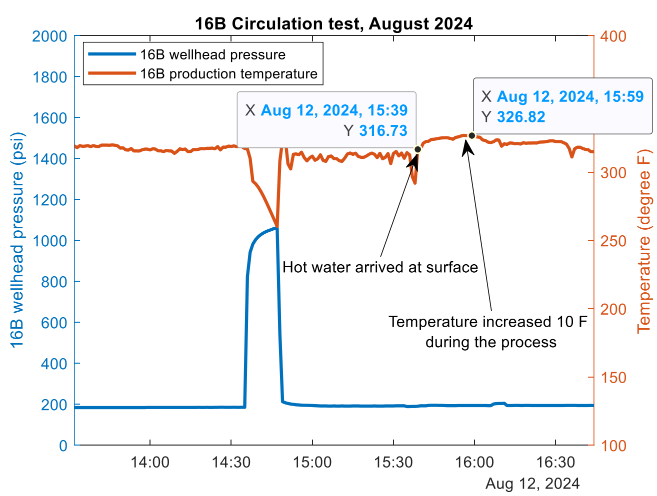


Figure 7: Surface temperature at the production pipe and well head pressure for well 16B(78)-32 on August 12, 2024, corresponding to the period of the strain pattern in Figure 6.

3.4 Thermal cooling effect – injectivity change

As shown in Figure 2, the injection pressure started to decrease after August 21, 2024 during the one-month circulation test. Under the same pumping rate, it means the injectivity increased. This could be due to the thermal cooling effect (Xing et al., 2024b; Ghassemi et al., 2008; Perkins and Gonzalez,1985; Koning, 1985).

The pressure difference between the inlet and outlet of a fracture can be approximately expressed as (cubic law):

$$P_{in} - P_{out} = Q\frac{12\mu}{w^3}\frac{L}{H} \tag{1}$$

where P_{in} is the pressure at the entering point, P_{out} is the pressure at the exit point, Q is the injection rate, μ is the fluid viscosity, w is the fracture aperture, L is the fracture length (the direction of fluid flow), and H is the fracture height. Here Stage 3 is taken as an example. During August-September 2024 circulation test, Stage 3 took about 7.7% of the fluid, estimated by the similar proportion in the July 2023 circulation test, suggesting an injection rate of 0.77 bpm (refer to Table 3). The fracture height and length are both assumed as 300 m based on the microseismicity cloud. If we assume the initial fracture aperture is 0.18 mm (the proppant size), then $P_{in} - P_{out}$ is around 600 psi according Equation (1). P_{out} is 200 psi in the production well (refer to Figure 2). Therefore, without any friction, the ideal injection pressure P_{in} will be around 800 psi.

Over one-month circulation, the injection pressure dropped about 200 psi (refer to Figure 2). Then, the final pressure difference $P_{in} - P_{out}$ is reduced to about 400 psi. By substituting $P_{in} - P_{out}$ as 400 psi into Equation (1), the aperture at the end of circulation test is calculated to be 0.21 mm. Therefore, the aperture increased about 0.03 mm during the one-month circulation due to the thermal cooling effect.

Table 3: Parameters for the thermal cooling analysis

Parameter	Magnitude
Fracture height	~300 m
Fracture length	~300 m
Viscosity	1e-3 Pa.s
Injection rate	0.77 bpm, 0.002 m3/s
Initial injection pressure	2973 psi
Production pressure	200 psi
Assumed initial aperture	0.18 mm
Final injection pressure	2769 psi
Pressure drop	204 psi
Final aperture	0.21 mm
Aperture increase	0.03 mm

4. CONCLUSIONS

The 2024 circulation tests at the Utah FORGE site demonstrated a significant improvement in reservoir conductivity following commercial-scale hydraulic stimulation in April 2024. The results indicate that the use of proppant and an increased number of stimulation stages contributed to a substantial enhancement in fluid recovery and thermal performance. The one-month circulation test in August-September 2024 showed a production rate of 9.0 bpm (recovery rate 90%) and a wellhead temperature of 385°F, a stark contrast to the limited flow observed in circulation test in July 2023.

Analysis of wellhead, downhole PT gauge, and fiber optic sensing data provided insights into injectivity trends, reservoir stiffness, and thermal cooling effects. The injectivity gradually increased over the test duration, likely due to thermal contraction effects enhancing fracture conductivity. Additionally, fiber optic strain data shows a strain change pattern caused by a flow of hotter water, confirmed by the surface temperature data. Comparison between the nine-hour and one-month circulation tests highlighted the long-term benefits of proppant-supported fractures in maintaining enhanced permeability. Furthermore, the observed increase in injectivity due to thermal effects underscores the importance of long-term circulation studies in optimizing Enhanced Geothermal Systems (EGS) performance.

These findings reinforce the potential for commercial-scale geothermal energy production at Utah FORGE. Future work should focus on extended circulation testing, continued refinement of stimulation strategies, and further integration of fiber optic sensing to enhance reservoir monitoring and management.

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