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Fiber Optic Model Based Flow Quantification Enhancing Geothermal Systems

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ABSTRACT

Fervo Energy is at the forefront of geothermal innovation with its pioneering pilot project located in northern Nevada. This initiative focuses on harnessing geothermal energy through the drilling of two horizontal wells, which have been stimulated using hydraulic fracturing techniques. The primary objective of the project is to inject water into a horizontal injector well, extract it from a horizontal producer well, and subsequently capture the heat transferred to the water for sustainable power generation. This approach aims to provide 24/7 carbon-free energy, addressing the growing global demand for renewable energy sources. To achieve optimal performance, Fervo Energy employs an Enhanced Geothermal Systems (EGS) methodology, which involves the strategic pairing of horizontal producer and injector wells. A critical challenge in this context is ensuring that water circulation occurs effectively across the full length of the injection interval. Short-circuiting in this process can lead to reduced efficiency in energy generation, making it essential to understand the injection profile within the injector well. Recognizing the importance of precise injection profiling, Fervo Energy has integrated fiber optic technology into its operational framework. Traditionally utilized in oil and gas applications, fiber optics have not been widely employed for injection profiling in geothermal wells. This project marks a significant shift as Fervo decided to run fiber optic cables for injection profiling. The fiber optic acquisition was performed as part of a larger-scale injection test, focusing on capturing data across various flow conditions with different tools. During the test, Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) data were recorded alongside Flow Scanner assessments at variable flow rates. The testing included three transitional flow periods: a transition from lower flow rates to higher and a step-down test returning to lower ones, followed by shut-in periods. This comprehensive transient dataset enabled a robust analysis of the injection dynamics, including model-based interpretation of fully transient data set and other approaches thus providing better insights into water injection and heat transfer efficiency, as compared to traditional warmback analysis. The fiber optic data acquisition not only facilitated a qualitative interpretation of the flow dynamics but also allowed for accurate quantitative assessments with fine resolution in depth. The analysis revealed a strong correlation between the fiber optic measurements and the traditional Flow Scanner Inversion (FSI) results. This validation confirms that fiber optic technology can accurately capture injection profiles, even in complex horizontal geothermal wells. The results of this test provide a significant advancement in geothermal technology, showcasing the potential of fiber optics as a reliable tool for improving operational efficiency in geothermal systems. Implementing fiber optic technology for injection profiling in future geothermal projects will allow Fervo Energy to enhance the precision of the data, ultimately leading to more efficient and sustainable geothermal energy generation. This pilot project serves as a first-of-its-kind industry example, demonstrating the feasibility and advantages of using fiber optic data for quantitative injection profiling in geothermal wells. The project results could advance the geothermal sector and contribute to a more sustainable energy landscape.

1. INTRODUCTION

Geothermal energy is becoming a vital and strategic source for baseload electrical and thermal power generation. While conventional geothermal sources, known as hydrothermal reservoirs, are limited and concentrated in specific geographic areas, the significant impact of geothermal energy on the energy portfolio necessitates the development of new production methods. Enhanced or engineered geothermal systems (EGS) represent one such technology, offering the potential for geothermal energy production in virtually any location on Earth. EGS involves hydraulic stimulation of the reservoir to enhance permeability, enabling heat extraction through a network of created cracks acting as a heat exchanger using injection and production wells. Fervo Energy has emerged as a leader in EGS technology, with ongoing projects in Nevada and Utah.

Distributed Fiber Optic Sensing (DFOS), encompassing technologies such as Distributed Acoustic Sensing (DAS), Distributed Temperature Sensing (DTS), and Distributed Strain Sensing (DSS), plays a crucial role in monitoring EGS systems. DFOS can be utilized throughout the entire lifecycle of a wellfield (e.g., Ajo-Franklin et al., 2023), including the acquisition of in-well and cross-well data during stimulation and production phases of EGS development (e.g., Titov et al., 2023). By deploying fiber optic cables, either temporarily or permanently, within the wellbore, DFOS provides valuable data on reservoir behavior. The glass fiber itself acts as a dense sensor array, exhibiting high sensitivity to minute variations in strain or temperature fields, enabling it to withstand the harsh conditions encountered in geothermal wells.

The application of DFOS for production surveys is particularly significant, as no other established technology can provide permanent, stage-level resolution of flow allocation in conditions exceeding 150°C. This study focuses on applying fiber optic technologies for production monitoring within an EGS system at Fervo Energy Project Red. This pioneering commercial project successfully utilized horizontal wells and multistage plug-and-perf stimulation (Norbeck et al., 2023). During crossflow testing of the wells (Norbeck and Latimer, 2023), SLB deployed spinner surveys and wireline fiber optic cables. DAS and DTS data were acquired for various injection rates, demonstrating a strong correlation with the results obtained from conventional spinner logs. DFOS-based flow quantification holds significant promise for future EGS projects, particularly for production wells where deploying conventional wireline tools may be challenging due to high temperatures. By leveraging the capabilities of permanent fiber optic installations, continuous monitoring of production parameters can be achieved, providing valuable data for optimizing reservoir management and maximizing energy production.

2. OPERATIONAL DETAILS

Executing the data acquisition plan required the integration of several fit for purpose technologies to enable a program expected to take approximately 48 hours in total.

Program requirements:

- Deployment of conventional production logging tool with real-time telemetry capable of sustained operation and multiple passes
- Deployment of a wireline cable suitable for cased hole operations with reservoir and surface induced pressure. The cable requires electrical and optical lines enabling the conventional wireline tools and distributed sensing.
- Method to reliably convey the logging tool and cable across the horizontal interval to perform multiple logging passes without pulling out of hole.
- Surface equipment to support operation and acquisition of production logging data and DTS and DAS data including real-time remote data acquisition and real time quality control.

The production logging tool selected is an advanced multiarray production logging tool designed specifically for use in horizontal wells. Key sensors for this application included the array of 5 high-sensitivity flowmeters to measure fluid velocity across the wellbore cross-section, a single axis caliper to measure the ID of the wellbore and high-resolution pressure and temperature sensors included as part of the BHA. The assembly also included gamma ray and casing collar locator for correlation purposes and a deviation sensor for enhanced understanding of the wellbore trajectory. The selected toolstring can operate in depth logging mode while performing up and down logging pass and in a station logging mode allowing time referenced data to be acquired when the cable was stationary during the DTS and DAS portion of the program.

The wireline cable selected is a specialty wireline intervention cable constructed with 3 integrated fiber optic lines and a coaxial electrical conductor. The coaxial conductor provides an electrical connection to the downhole wireline tools allowing for power and telemetry to the bottom hole assembly. The fiber optic bundle with 1 muti mode and 2 single mode fibers is tight coupled into the center conductor of the cable. The tight coupled fiber allows for a better signal to noise ratio for the distributed measurements and confident depth control relative to a fiber in metal tube construction. The outer layer of the cable is polymer coated, this coating simplifies the pressure control requirements as only a dual packoff is needed in place of grease injection which would be required for standard armored wireline cables. The polymer coating also decreases the friction between the cable and casing making it easier to reach total depth in the horizontal.

Conveyance method chosen to allow access to the lateral is a wireline tractor. The selected tractor is a slim 2-1/8” OD modular design. Tension and tractor force modelling indicated a 4 drive configuration would be suitable for the well profile. This design would provide sufficient tractor force to reach TD with a margin in case more challenging conditions were encountered. The tractor is capable of real-time control, allowing contingencies such as control of individual drive sections and ability to tractor in the uphole direction. The tractor allows for continuous real-time communication with the wireline toolstring allowing real-time data acquisition and tractor control while in depth or station logging mode. The ability to monitor the tractor condition in real-time is also instrumental in ensuring that the tractor is able to complete the multiple passes required for the operation.

Sequence of Events:

The program was designed to allow production logging data to be acquired at multiple rates with the well in a stable injection state and capture the transient behavior with DTS and DAS when the rates were being stepped up and down including 2 shut-in periods. The basic operation sequence was to wait for stable injection at the selected rate and then tractor down while logging with the production logging tool. Once on bottom begin recording DTS and DAS data and then proceed to change the injection rate. Once the injection appears stable at the new rate then proceed to perform the next up and down logging passes with the logging tool. Table XXX shows on overview of the sequence of events.

Table 1: Sequence of Events.

Step#	Operation	Rate (bpm)	Logging
1	Rig Up and Run in Hole	0	
2	Spinner Calibration	0	FSI

3	Logging Passes: Down1, Up1 and Down2	5	FSI
4	DTS and DAS, BHP & BHT	5 – 12.5	Fiber Optic
5	Logging Passes: Up2 and Down3	12.5	FSI
6	DTS and DAS, BHP & BHT	12.5 – 20	Fiber Optic
7	Logging Passes: Up3 and Down4	20	FSI
8	Step Down Test: DTS and DAS, BHP & BHT	20 – 12.5 – 5	Fiber Optic
9	Shut-ins: DTS and DAS, BHP & BHT	5 – 0 – 5 – 0	Fiber Optic
10	Logging Passes: Up4	15	FSI
11	Rig Down	0	

Total operating time not including rig-up and rig-down was 51 hours. There were 4 production logging passes completed across the lateral, a total of 27.5hrs of DAS data recorded and 26.75hrs of DTS data recorded. Data quality was excellent on both the production log and distributed measurements. The only operational problem which arose was a connection failure between the DTS interrogator and surface acquisition laptop which caused 45min of data to not be recorded. During all Fiber Optic acquisition periods the production logging tool was operating in station logging mode capturing data from all sensors, although primarily of interest was the bottom hole pressure and temperature measurement

3. INTERPRETATION METHOD

The sophisticated operational procedure described in the above section allowed to acquire a series of dynamic data sets with DTS and DAS data characterizing injection process during different transitional stages. This is important as steady-state injection data is not informative at high flow rates while long enough shut-in to conduct conventional interpretation of warm-back DTS data was not available operationally. Therefore in this work we focused on using a combination of traditional and well established techniques (like so called Hot Slug data analysis via thermal front tracking along wellbore) and advanced methods that are based on use of the joint interpretation of transient distributed temperature data with flow metering data (PTRA) that was previously successfully applied to quantitative interpretation of injection well DTS data (Kortukov et al., 2019; Al-Hashemi et al., 2021). Depending on the conducted operations, transient DTS data for injection wells can be split into three major groups.

First, it's a series of quasi-steady-state temperature profiles along wellbore during longer-term injection. This phase begins after pumping a sufficient amount of liquid, when rapid temperature changes no longer appear in the measurements. In this regime, at a relatively low to moderate injection flow rates, the established DTS temperature profile may exhibit some variations over depth that are caused by a difference between injected temperature at the sandface and mass-average temperature in the injected fluid flow. However, for vertical wells and in horizontal injectors with high to very high flow rates this regime exhibit temperature distribution that could not be recorded with sufficient signal-to-noise ratio using DTS to determine the characteristics of the injectivity profile. Depending on the volume of pumped fluid, length of injected interval, permeability distribution and formation thermal properties, DTS data in a quasi-steady-state regime may be used for interpretation in horizontal wells (Brown et al., 2003, Pimenov et al., 2005).

Second, traditional used warm-back data during well shut-ins with significant number of published results. The sequence of "injection – shut-in" is a common approach for characterizing injectivity profiling (Al-Gamber et al., 2013, Buhassan et al. 2015). In simple cases, without crossflow between reservoir zones, the highest injectivity corresponds to slower recovery of temperature to geothermal levels compared to zones with low injectivity. The rate of this temperature recovery can be used to quantitatively determine the injectivity profile. However, even this method come with known challenges, e.g. crossflow, at least during the early stages of shut-in, impact of variable injection temperatures, too short SI duration to establish an asymptotic temperature warm-back behavior and some others. Another limitation of this approach is that higher injection rates may require too long shut-in time, from many days to few weeks. These factors should be considered during operational planning.

Third, early-stage of injection or re-start of injection after shut-in. During this stage, fluid displacement resembles piston-like displacement and is seen on DTS data as temperature front propagation transients (Brown et al., 2005, Fahim et al., 2011, Malanya et al. 2016). This period is typically referred to as "hot slug" (or "thermal slug") propagating along the wellbore. This slug can be considered a thermal scanner of the injectivity profile, as its velocity depends on how much fluid is lost to the intake zone. One popular approach for utilizing data from the early stage is to track the slug's front (e.g. with a front mid-point location) and estimate its velocity. However, the actual interaction of the "hot slug" is more complex, as heat transfer with the formation alters and blurs the slug's shape. Proper modeling of early-stage transients could enable a much more detailed and accurate representation of the injectivity profile. It is important to note that early-stage injection or reinjection provides useful data even if a noticeable thermal slug is not formed and simplified front-tracking procedure is not applicable. This may occur under certain conditions, such as low injection rates or a small temperature difference between the upstream fluid and the injection interval. In such scenarios, sophisticated enough numerical simulation tools can be used for interpretation (Stone et al., 2013, Tardy et al., 2011).

In this paper, we utilize all regimes for interpretation using a fully transient numerical simulator (Kortukov and Shako, 2019). Specifically, we demonstrate how rapid temperature transients, combined with advanced simulation tools, can provide refined injectivity profiling.

We briefly describe the main features of the numerical model used in this study. Further details can be found in (Kortukov et al., 2019).

The wellbore models consist of two main components: a one-dimensional pressure quasi-steady momentum equation and a one-dimensional energy conservation equation. The first equation accounts for homogeneous multiphase fluid flow, incorporating friction, gravity, and convective acceleration terms. This formulation enables fast yet sufficiently accurate simulations of fluid flow to determine the pressure distribution inside the wellbore. The second equation computes the temperature distribution inside the wellbore and includes various thermal effects, such as conductive and convective heat transfers, frictional heating, adiabatic and Joule-Thomson effects, conductive heat exchange between the fluid flow and wellbore walls, and convective heat exchange between the fluid flow and the formation. As a result, the energy equation provides a sophisticated representation of the evolution of temperature over time and depth, enabling the analysis of field data, including rapid transients.

Similar to the wellbore model, the reservoir model is based on two main conservation equations: the mass conservation equation and the energy conservation equation. The mass conservation equation is formulated in terms of fluid pressure within the reservoir layer under consideration. At its core lies Darcy's law, which enables multiphase simulations when supplemented by relative permeability models. Our numerical engine supports two such models: the Brooks-Corey relations for three-phase fluids (Brooks and Corey, 1964) and Baker's saturation-weighted model (Baker, 1988). The energy conservation equation accounts for two-dimensional conductive heat transfer (in the radial direction and along the wellbore trajectory), convective heat transfer, adiabatic and Joule-Thomson effects, and degassing heat. For impermeable formation layers, the mass conservation equation is excluded, and only the conductive term is retained in the energy equation.

Thus, these equations solved jointly provide a detailed description of pressure and temperature distributions and their evolutions in time in a whole simulation domain. Numerical engine supports detailed specifications of material properties to represent features of particular completion. For example, casing properties, cement properties can be taken into account for accurate modelling of thermal exchange. User can specify cable deployment position for proper interpretation of modelled and measured temperature profiles. Thus, solving these equations jointly provides a detailed description of pressure and temperature distributions, as well as their evolution over time, across the entire simulation domain. The numerical engine supports detailed specifications of material properties to represent the characteristics of a particular completion. For example, casing and cement properties can be incorporated to accurately model thermal exchange. Additionally, users can specify the cable deployment position to ensure proper interpretation of the modeled and measured temperature profiles.

4. DATA OVERVIEW

In the further interpretation, we focus on the third flow period, as it provides the most informative data for temperature analysis. Figures 1, 2 and 3 present the DTS data for this period. In Figure 1, DTS profiles are shown separately for each change in pumping rate, with the color scheme indicating the sequence of traces: blue represents the initial traces, while red represents the final ones. Figure 2 displays a 2D plot of DTS measurements, where a sharp vertical line at the start of the first reinjection marks a communication failure lasting approximately 45 minutes. Figure 3 shows the same region using linear interpolation. In this figure the color scheme represents depth points: blue corresponds to smaller measured depths (MD), and red to larger MD values.

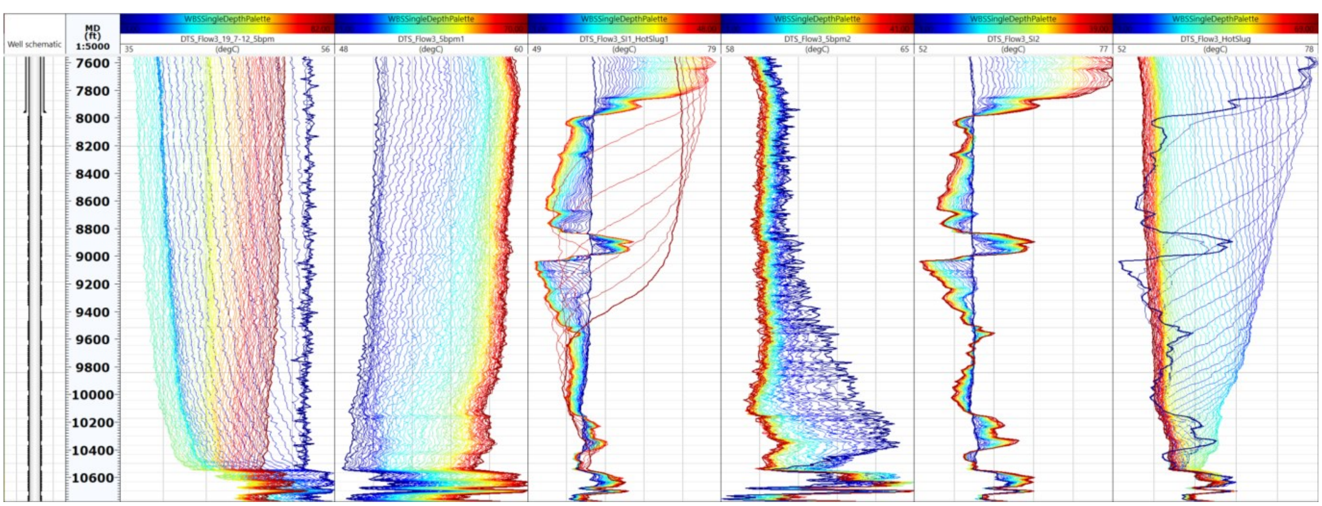

Figure 1. Track 1 – well schematic, track 2 – depth track, track 3 – DTS traces for pumping rate change from 19 to 12.5 bpm, track 4 – DTS traces for pumping rate change from 12.5 to 5 bpm, track 5 – DTS traces for first shut-in and the beginning of reinjection at 5 bpm before communication failure, track 6 – DTS traces for the reinjection at 5 bpm after restoring communication, track 7 – DTS traces for second shut-in, 8 – DTS traces for the reinjection at 5 bpm.

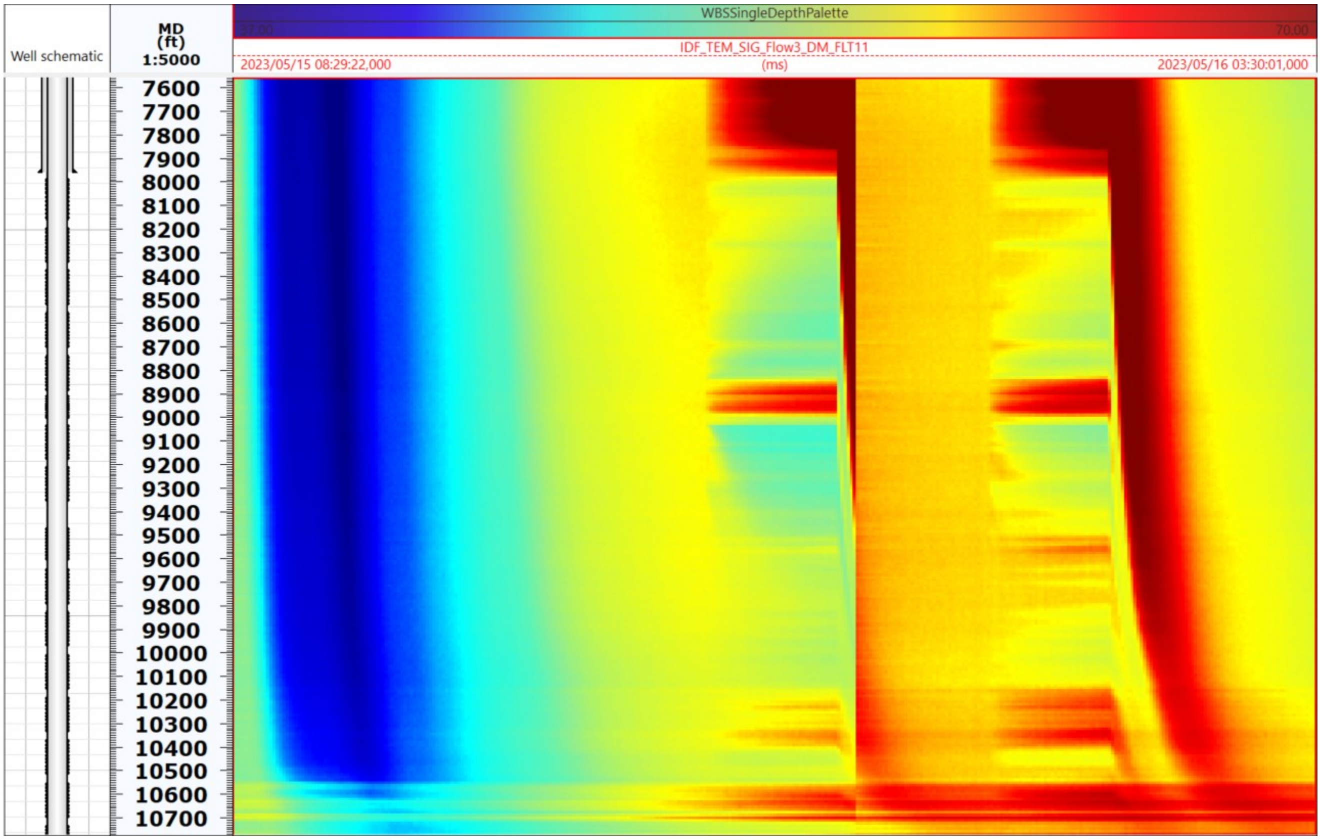

Figure 2. Track 1 – well schematic, track 2 – depth track, track 3 – DTS 2D plot for the third flow period.

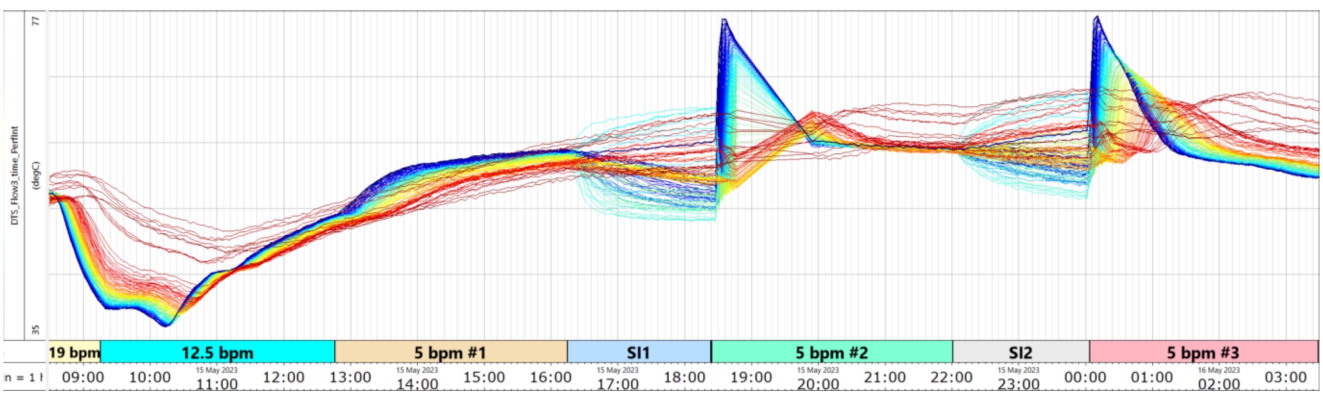

Figure 3. DTS traces for depth points within the injection interval as a function of time during the third flow period.

Let's provide a general overview of the measured temperature signal. The first two changes in injection rate (from 19 to 12.5 bpm and from 12.5 to 5 bpm) result in the formation of a thermal slug that propagates along the well, followed by a stabilized temperature distribution. These slugs propagate quickly, and we will not focus on them in the subsequent interpretation. Both shut-ins show similar behavior, with high-temperature recovery observed in intervals 8800-9000 ft and 10100-10400 ft. Conversely, other intervals, such as 8500-8800 ft and 9000-9400 ft, demonstrate cooling on the DTS data. Each shut-in is followed by reinjection at 5 bpm, which is observed as the propagation of a hot slug along the injection interval. As these slugs flow deeper toward the wellbore toe, their temperature perturbation diminishes and blurs. Eventually, the temperature distribution stabilizes.

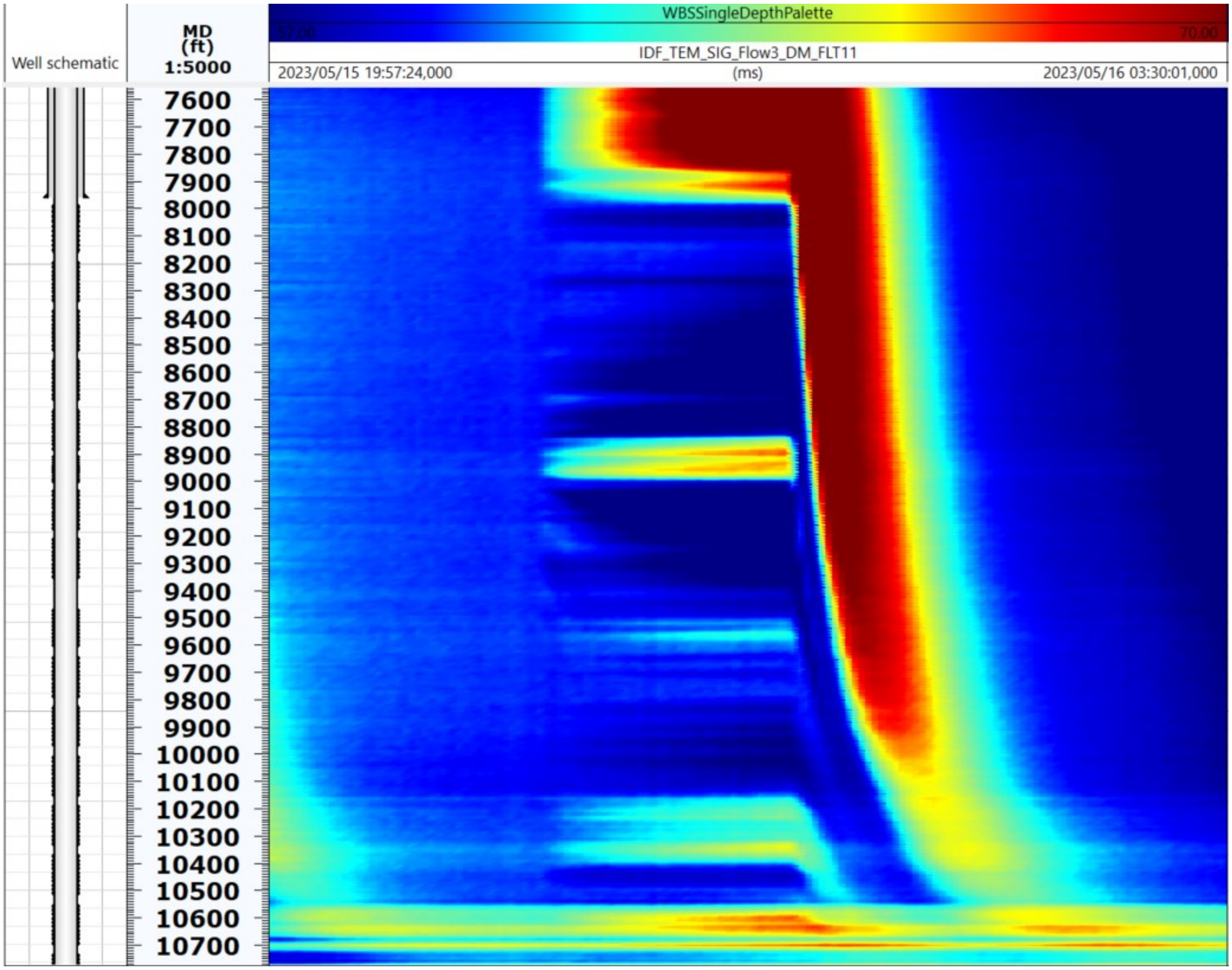

Figure 4. Track 1 – well schematic, track 2 – depth track, track 3 – DTS 2D plot for the second shut-in and the following reinjection.

To start, a qualitative assessment of potential injectivity profiling can be conducted using shut-in data. Figure 4 presents 2D DTS data for the second shut-in and the subsequent reinjection. Depth intervals that exhibit temperature recovery are likely to correspond to the smallest injectivity index, as the temperature rapidly returns to geothermal values. Conversely, some intervals show cooling compared to the previously stabilized temperature during injection. This cooling occurs if the previously injected water was colder, and its temperature affects DTS measurements during the initial stage of the shut-in. Consequently, cooler regions indicate higher intake.

The same qualitative behavior is observed during the first shut-in, as shown in Figure 4. The actual measured values depend on the prior conditions leading up to the shut-in. This is a critical consideration, as accurate numerical modeling of the initial stages of a shut-in requires proper specification of the preceding pumping rates and injection temperatures.

5. INTERPRETATION RESULTS

The comprehensive data set described above allows injectivity profile quantification using different data, methods and complimentary physical principles. In particular, the FSI data can be considered as a reliable source of flow profiling and thus enabling validation of the interpretation results based on the indirect flow-metering from DTS transients. Meanwhile, the interpretation of DTS data was performed without direct use of the FSI interpretation results, basing on DTS and flow-metering data only.

The results below are obtained from the most informative Flow3 stage. This is largely related to availability of two shut-in data and hot slug data sets covering the whole perforated interval with high signal-to-noise ratio in DTS profiles as can be seen in Figure 1, rightmost track. Resrpectively, in this study we put stronger focus on interpretation of the hot slug data. This data set was quantitatively interpreted with two complimentary approaches: 1) a traditional one, based of tracking of temperature front mid-point movement along wellbore as it is proportional to the local flow rate at a given depth and 2) numerical simulations of hot slug process with as accurate as possible match of the simulation results against real DTS data in depth domain for every time moment and temporal trends in time at all depths in the perforated interval.

Building numerical model and specifying initial guess for an effective permeability profile, we rely on quantitative analysis of DTS SI profiles. SI was not long enough for warm-back analysis, which is another tradition approach. There are also clear indications in DTS data of the crossflows through the wellbore. Meanwhile, we could reasonably assume that the principles of the warm-back analysis are qualitatively applicable: the colder zone is during SI, the more injected it likely is. And vice versa, the higher temperature in temperature profiles likely corresponds to lower injection. Constructed in such a way initial guess for the effective permeability profile was further tuned in order to provide the best possible match of DTS data in both depth and time domains. The specifics of the hydraulically fractured well was considered via specifically defined heat transfer correlation in the injected intervals assuming that during relatively short-term injection during hot slug (3h) only near vicinity of each perforated cluster/fractures is disturbed by the injection of the contrast temperature fluid, while the remaining (major) part of the wellbore is not affected by injection inro the reservoir. Instead, it is impacted by mostly heat conductive heat transfer with the wellbore flow. The zonation for simplicity was constructed with 36 zones of constant depth size.

The results of the hot slug data match using numerical model are shown in Figure 5 for the first 2 h of re-injection. The simulated and real DTS temperature profiles are shown for the same time moments with a constant time step about 3 min starting from the same initial temperature profile taken from the last moment of previous SI before re-start of injection (shown as thick lines). One can see that tuning the effective permeability profile only allowed to achieve a good match in depth domain.

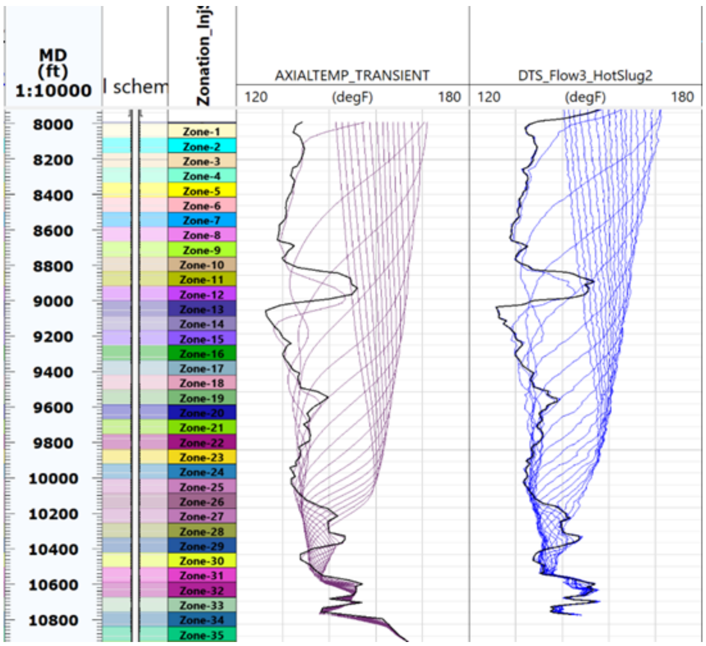

Figure 5. Match of hot slug DTS data in depth domain with numerical simulations: simulated profile (left track) and field DTS data (right).

The results of the hot slug data match in time domain for the simulation zones are shown in Figure 6 for the full duration of the second hot slug (more than 3h). It was achieved with the same model parameters and the same simulation runs that were used for the match in depth domain in Figure 5. The injection inlet temperature at the top of the simulation domain was taken from the DTS data.

It should be noted that in this study the time-domain DTS data match provided better accuracy and depth resolution of the final injectivity profile compared to the data match in depth domain. Therefore, it was important to ensure good enough match in time and depth domains simultaneously.

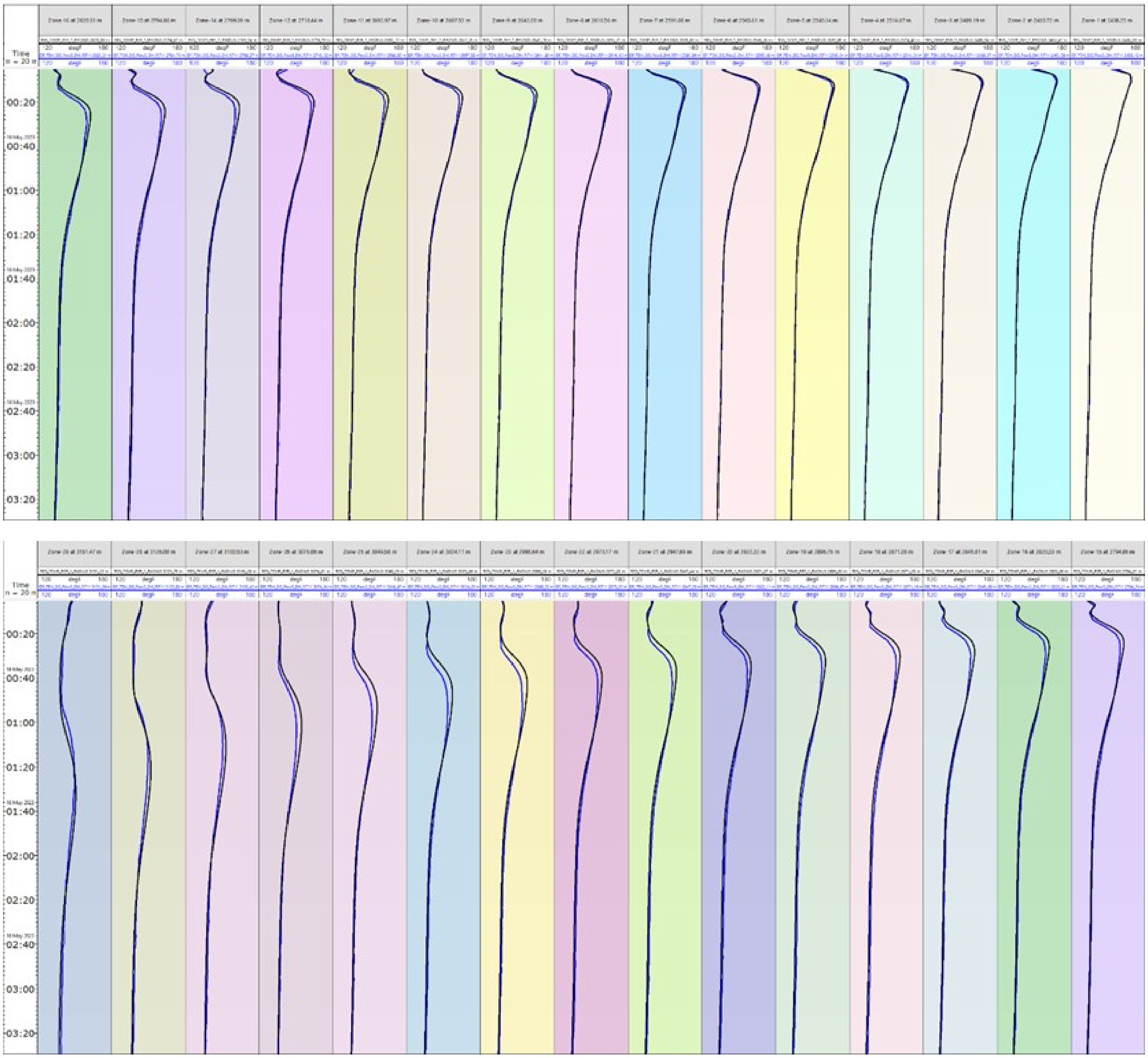

Figure 6. Match of hot slug DTS data in time domain with numerical simulations: simulated profile (black) and field DTS data (blue). The upper plot shows shallow zones, the lower – deeper ones.

The comparison of the estimated injectivity profiles from DTS data with 1) front-tracking and 3) fully transient numerical simulation and reference FSI interpretation results is shown in Figure 7. The left track illustrates the match of the cumulative flow rates, the right one – differential. The cumulative profiles are found to be very consistent between the FSI and full numerical-estimated ones, while the front-tracking profile is qualitatively looks reasonably representative but somewhat worse with respect to the quantitative representation of the results even after filtering in depth domain. Respectively, the comparison between FSI and numerical model results are shown in the right track with the differential injectivity profiles.

Despite slight mismatches in the zones where SI temperature data somewhat contradict to FSI data, the overall match proves the applicability of Fiber Optic technology combined with advanced numerical simulations for well diagnostics in complex geothermal wells.

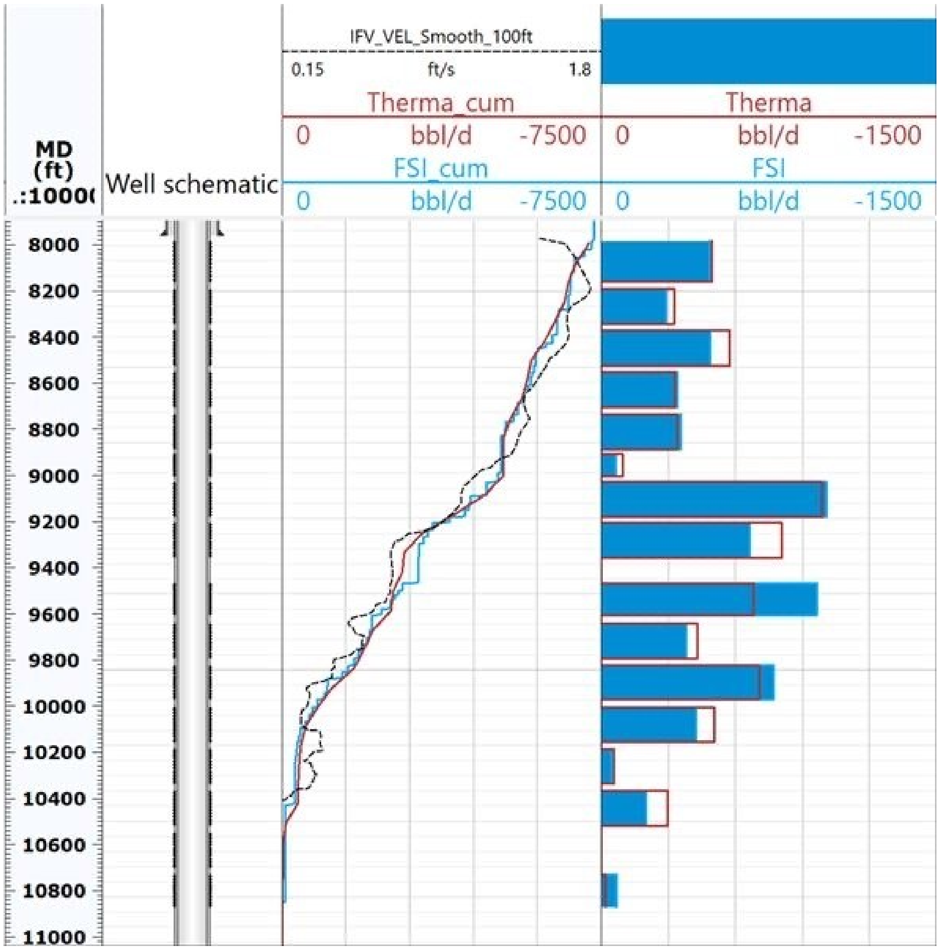

Figure 7. Comparison of injectivity profiles: cumulative (left), FSI (blue), numerical model (brown) and front-tracking velocity (dashed); differential (right), from DTS data using fully transient numerical model (brown) and reference FSI data (blue).

6. CONCLUSIONS

In this paper, we presented a comprehensive discussion on the interpretation of Distributed Temperature Sensing data for a geothermal horizontal injection well. The focus was on analyzing transient regimes generated during shut-in and reinjection stages and leveraging these for both qualitative and quantitative assessments. Using advanced simulation tools, we demonstrated how transient temperature profiles can be interpreted to extract meaningful insights about well performance and system behavior. Specifically, model-based interpretation was shown to provide a detailed characterization of the injectivity profile, capturing key thermal and flow dynamics within the injection interval.

To ensure the reliability of the findings, the interpretation results were compared with Flow Scanner measurements. This validation process, one of the first conducted specifically for geothermal wells, confirmed the accuracy and robustness of the DTS model-based interpretation. It also highlighted the efficiency and quality of fiber-optic technology for geothermal applications, solidifying its potential as a reliable tool for advanced well diagnostics. By demonstrating the repeatability and consistency of the data, this work promotes the broader adoption of fiber optic technology in geothermal reservoir monitoring.

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