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Experimental Study on Temperature Response and Quantitative Relationship with Injection Profile in Water Injection Wells Based on Distributed Temperature Sensing

Tingting Zhou, Sihang Xie, Hongwen Luo*, Haitao Li, Ying Li, Yixin Zhang and Feifei Ran

Southwest Petroleum University, Chengdu 610500, China

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ABSTRACT

Currently, the understanding of temperature profile responses in water injection wells remains insufficient, making it challenging to interpret water injection profiles using distributed temperature sensing (DTS) data and to perform quantitative diagnosis of downhole injection performance. In this study, a physical simulation experiment was conducted to investigate the effects of injection rate, injection time, injection temperature, and injection position on the temperature profile of horizontal wells. The results indicate that as the injection rate increases, the wellbore temperature profile decreases, and the temperature rise from the heel to the toe becomes less pronounced. The temperature drop corresponding to the water-injection intervals exhibits a linear positive correlation with the injection rate, and a quantitative relationship between temperature change (ΔT) and injection rate was established through regression analysis. Injection temperature significantly enhances the temperature field; higher injection temperatures lead to more substantial overall temperature increases along the profile. The injection position determines the fundamental shape of the temperature profile. Regardless of whether injection is applied at the heel, toe, middle section, or both ends, distinct temperature anomalies are observed around the water-injection locations. Based on this characteristic, water-injection positions can be identified from field DTS data, thereby providing a basis for quantitative evaluation of water injection profiles.

*Corresponding Author
Email: rojielhw@163.com

1. Introduction

Waterflooding development is an important technical means for maintaining stable production and enhancing oil recovery in oil and gas fields. Accurate interpretation of injection profiles in water injection wells is directly related to the evaluation of interlayer water-injection performance, understanding of injection-production relationships, and optimization of subsequent profile control and flooding schemes. Due to the temperature difference that typically exists between injected water and the original formation temperature, continuous heat exchange occurs among the wellbore, reservoir rocks, and formation fluids during the injection process. Consequently, the wellbore temperature profile is simultaneously influenced by multiple factors, including wellbore heat transfer, reservoir heterogeneity, and variations in injection parameters, which increases the difficulty of quantitatively interpreting injection profiles based on temperature data [1,2]. Conventional point-based temperature measurement methods are limited by their precision and dynamic response capability, making it difficult to fully capture the real-time evolution of the temperature field. In contrast, distributed temperature sensing (DTS) technology, with its technical advantages of continuous monitoring along the entire wellbore, strong real-time capability, and high spatial resolution, enables the reconstruction of the actual fluid flow state near the bottom of horizontal wells through interpretation of DTS-measured temperature data. This has opened up new avenues for temperature profile interpretation and injection profile inversion in water injection wells [3-5].

Accurate understanding of temperature distribution patterns in water injection wells serves as the foundation for conducting quantitative interpretation of injection profiles and inversion of DTS data. Since Nowak [6] *et al*. first described the distribution of wellbore flow rates based on temperature measurements and proposed a method for estimating injection profiles from temperature logging curves, and Smith [7] *et al*. pioneered the early theoretical models of temperature fields in injection wells, establishing a foundational framework for subsequent research, extensive studies have been conducted by domestic and international scholars on temperature field modeling, influencing factor analysis, and DTS data inversion for water injection wells.

Hagoort [8] proposed a fundamental formula for estimating flow rates from temperature profile data in flowing wells by solving the heat diffusion equation, providing important theoretical support for research on the correlation between temperature fields and flow rates. Wang Qing's team [9] focused on the phase-change effects of CO_2 in water injection wells, constructed a coupled pressure-temperature calculation model, and systematically revealed that wellhead injection temperature and injection volume are key factors controlling the wellbore temperature and pressure profiles. Ran Feifei *et al*. [10], incorporating the heat transfer characteristics of completion in offshore extended-reach wells, optimized the prior distribution model of the MCMC algorithm to reduce the dependence of inversion results on the initial model. Zhu Haitao *et al*. [11] developed a multi-mechanism coupled transient temperature field model considering the Joule-Thomson effect and viscous dissipation, providing a new theoretical tool for temperature field simulation under complex operating conditions. Zhang Xiliang *et al*. [12], through simulation analysis of seven factors affecting temperature profiles—including injection rate, injection time, and reservoir thermal conductivity—determined that the degree of influence of different factors on the temperature profile of water injection wells, in descending order, is: injected water temperature, injection rate, injection time, reservoir thermal conductivity, wellbore comprehensive heat transfer coefficient, formation porosity, and permeability. Li's team [13,14], targeting the thermal dynamic characteristics of horizontal wells in water-drive reservoirs, developed a dedicated temperature model and, using this as a forward modeling basis, innovatively combined it with the MCMC algorithm to establish a DTS data inversion framework, offering new insights for the quantitative application of temperature data. Zhang *et al*. [15], using the temperature model of Cui's team [16,17] as the forward modeling core, were the first to apply the Levenberg-Marquardt (L-M) algorithm to DTS data inversion in fractured horizontal wells. Subsequently, Zhang [18] proposed differentiated inversion schemes tailored to varying wellbore conditions and production scenarios, an improvement that directly achieved dual enhancements in interpretation efficiency and accuracy. Huang Liang *et al*. [19], after processing field DTS data from actual water injection wells, first conducted qualitative interpretation analysis and then performed inversion using an inversion algorithm. The inversion results for the injection profile were found to be in close agreement with isotope interpretation results, demonstrating the reliability and practicality of the inversion model.

From the perspective of the development of distributed fiber-optic monitoring technology, DTS has gradually expanded from single wellbore temperature monitoring to multiple application scenarios, including injection–production performance evaluation, production profile interpretation, wellbore integrity monitoring, and hydraulic fracturing monitoring [20-23]. For injection and production profile interpretation in horizontal wells, Brown *et al*. [24] applied fiber-optic distributed temperature measurement systems to the monitoring of horizontal water injection wells and production wells at an early stage. Pimenov *et al*. [25] established an injection profile interpretation method for horizontal wells based on distributed temperature monitoring. Ouyang and Belanger [26] discussed the applicability and limitations of DTS-based flow profile interpretation in engineering applications. Yoshioka *et al*. [27] further proposed a method for inverting horizontal well flow profiles using distributed temperature and pressure data. These studies indicate that DTS temperature data can reflect wellbore flow behavior and differences in water intake; however, the interpretation accuracy still depends on a clear understanding of the factors influencing temperature responses.

In terms of experimental and engineering validation, Reges *et al*. [28] calculated zonal injection rates from temperature profiles in multilayer water injection wells, performed uncertainty analysis, and compared the calculated results with measured flow rates. Silva *et al*. [29] developed a scaled horizontal well experimental prototype and verified the feasibility of deriving flow-rate distribution from wellbore temperature profiles. Echaiz Espinoza *et al*. [30] investigated the thermal profile characteristics during the transient injection stage of water injection wells and analyzed the influence of unsteady temperature responses on flow-rate interpretation errors. In recent years, Zhang *et al*. [31], Shi *et al*. [32], and Huang *et al*. [33] have conducted studies on DTS-based temperature field simulation, injection profile interpretation, and inversion methods for water injection wells, promoting the transition of DTS temperature data interpretation from qualitative identification to quantitative evaluation.

Wellbore–reservoir thermal coupling theory provides important support for the interpretation of DTS temperature data. The wellbore heat-transfer model established by Ramey [34] laid the foundation for temperature interpretation during injection and production processes. Sagar *et al*. [35], Hasan and Kabir [36], and Duru and Horne [37] further improved the theoretical framework for temperature data interpretation from the perspectives of flowing wellbore heat transfer, transient temperature responses, and reservoir parameter identification. Hashish and Zeidouni [38] proposed a multilayer reservoir injection profile interpretation method based on warm-back analysis, while Fahim *et al*. [39] used DTS data to visualize the injectivity of water injection wells. Overall, previous studies have provided an important theoretical basis for temperature profile interpretation and DTS data application in water injection wells. However, most existing studies still focus on temperature field theoretical modeling, numerical simulation, and field data inversion. Since the temperature response of field water injection wells is jointly affected by wellbore structure, reservoir heterogeneity, variations in injection parameters, and long-term heat exchange processes, it remains difficult to distinguish the contribution of different factors to the temperature profile, which introduces uncertainty into quantitative injection profile interpretation [40]. In contrast, controlled physical simulation experiments focusing on single factors such as injection rate, injection time, injection temperature, and injection location remain relatively limited, and the quantitative relationship between temperature change and sectional water injection rate still requires further experimental verification. In addition, recent studies on the influencing mechanisms of temperature profiles in water injection wells, wellbore temperature responses in gas reservoirs, and DTS inversion models for horizontal wells further indicate that controlled experimental data and temperature-field response models are critical for improving the reliability of quantitative DTS interpretation [41-46].

Based on this background, this study uses a horizontal-well DTS temperature profile physical simulation apparatus and an approximately homogeneous reservoir model to conduct four types of controlled-variable experiments, including injection rate, injection time, injection temperature, and injection location. The temperature response characteristics of the wellbore under different injection conditions are analyzed, and a quantitative relationship between temperature change and water injection rate is established. The results provide an experimental basis for DTS temperature profile interpretation, sectional water-intake capacity evaluation, and injection profile inversion in water injection wells.

2. Experiment

2.1. Experimental Apparatus

The experiment was conducted using a horizontal-well distributed fiber-optic temperature profile physical simulation apparatus, which mainly consists of a supply module, reservoir module, wellbore module, DTS monitoring module, and recovery module. The supply module was used to provide stable injection flow rate and inlet pressure, thereby simulating downhole flow environments under different injection conditions. The reservoir module consisted of seven groups of core holders and series–parallel pipelines. The cores, with a diameter of 2.5 cm and a length of 5 cm, were fixed by the core holders and used to simulate water-intake units in different injection sections of the horizontal well. The wellbore module was composed of an experimental pipeline with an inner diameter of 6 mm and a total length of 40 m, which was used to simulate the along-wellbore flow and heat-transfer process in a horizontal wellbore. The DTS monitoring module was continuously deployed along the simulated wellbore to acquire real-time temperature profile data along the wellbore. The recovery module was used to collect the produced fluid after the experiment, ensuring continuous and stable operation of the experimental process.

An AP Sensing DTS N62 distributed fiber-optic temperature sensing system was used to acquire the wellbore temperature profiles. The system had a spatial resolution of 0.2 m, a temperature measurement accuracy of 0.01 ℃, and a sampling interval of 1–5 s. Under each experimental condition, the DTS system continuously acquired temperature data, and the continuously collected data within the relatively stable temperature-response period were selected and averaged in this study. The entire experimental apparatus was placed in a thermostatic oven with dimensions of 4 m×2 m×1.5 m and a maximum operating temperature of 150 ℃, which provided a stable simulated formation-temperature environment. Before the formal experiment, the thermostatic oven was heated to the set temperature of 60 ℃ and maintained for more than 30 min. The temperature measured by the high-precision temperature sensor was then compared with the temperature displayed by the oven control system. The experiment was started only after the temperature difference between the two was confirmed to be less than 0.1 ℃. After the supply module, reservoir module, wellbore module, DTS monitoring module, and related testing and metering instruments were connected, a complete horizontal-well DTS temperature profile physical simulation experimental system was formed. The design of the apparatus is shown in Fig. (**1**).

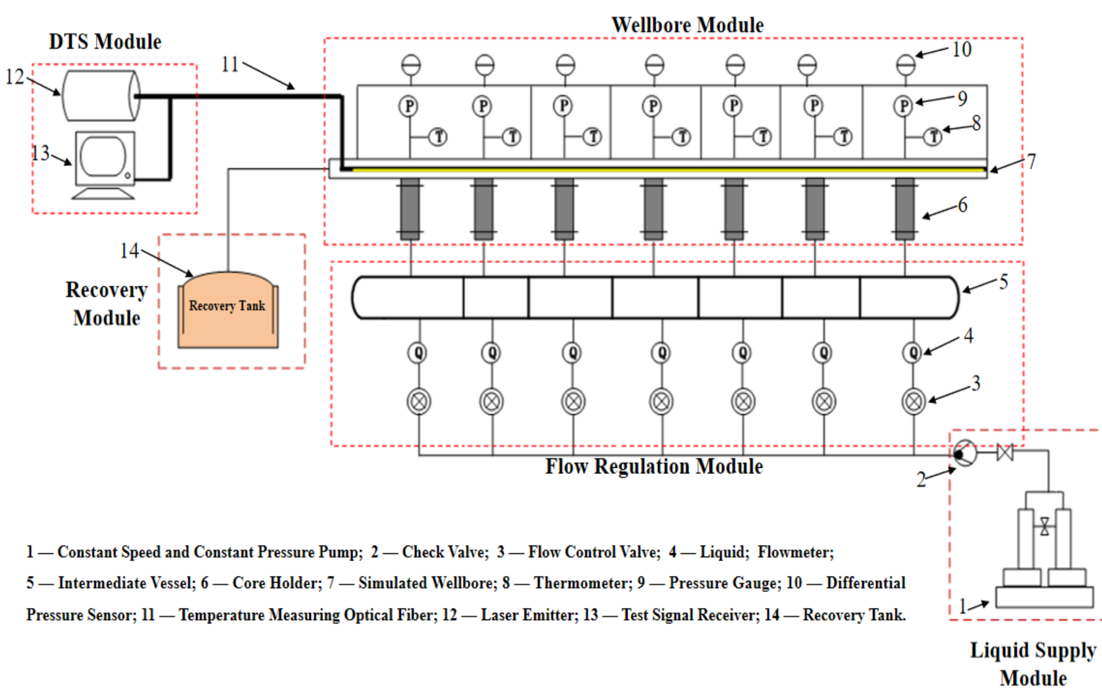


Figure 1: Schematic of the experimental apparatus for horizontal-well injection-profile evaluation.

2.2. Experimental Design

In this study, an approximately homogeneous reservoir was used as the simulation object, and a controlled-variable method was adopted to conduct horizontal-well DTS temperature profile physical simulation experiments, aiming to analyze the response patterns of wellbore temperature profiles under different injection conditions. Seven cores with permeabilities close to 480 mD were selected as reservoir simulation units for different injection sections. The permeabilities of the seven cores were 480, 482, 475, 478, 478, 480, and 484 mD, respectively, so as to reduce the interference of reservoir heterogeneity in identifying temperature response patterns.

According to the similarity criterion between field injection rate and laboratory simulated injection rate, the inner diameter of the laboratory experimental wellbore was 6 mm, and the field-equivalent wellbore diameter was 139.7 mm. The simulated injection rate was set to 20–100 mL/min, corresponding to a field-equivalent injection rate of 129–648 m^3/d, which was used to conduct temperature profile response experiments under different injection rates. The injection times were set to 0.1, 0.5, and 1 h; the injection temperatures were set to 35, 45, 50, and 55 ℃; and the injection location tests included four injection modes, namely heel injection, toe injection, middle injection, and two-end injection. For each injection mode, three simulated injection rates of 20, 40, and 60 mL/min were set. A total of 24 groups of water-injection well temperature profile response experiments were completed in this study (Table **1**).

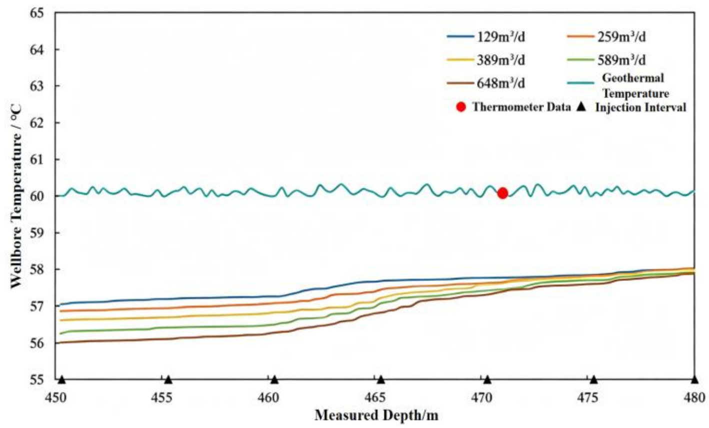
Table 1: Experimental scheme for testing the effects of single factors, including injection rate, injection time, injection temperature, and injection location, on temperature distribution.

No.	Simulated Injection Rate, mL/min (Actual Injection Rate, m^3 /d)	Injection Time, h	Injection Temperature, ℃	Injection Location	Working Fluid	Simulated Reservoir Permeability, mD						
						1#	2#	3#	4#	5#	6#	7#
1	20/40/60/80/100（129/259/389/589/648）	0.5	55	Heel injection	Water	480	482	475	478	478	480	484
2	20（129）	0.1/0.5/1	45			480	482	475	478	478	480	484
3	20（129）	0.5	35/45/50/55			480	482	475	478	478	480	484
4	20/40/60（129/259/389）	0.5	35	Heel injection		480	482	475	478	478	480	484
				Toe injection								
				Middle injection								
				Both-end injection								

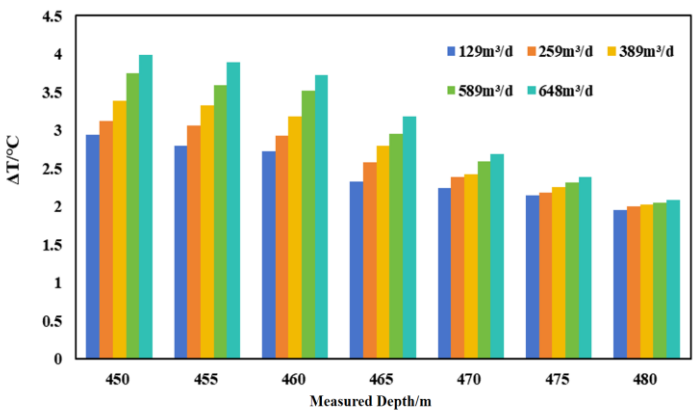
3. Results and Analysis

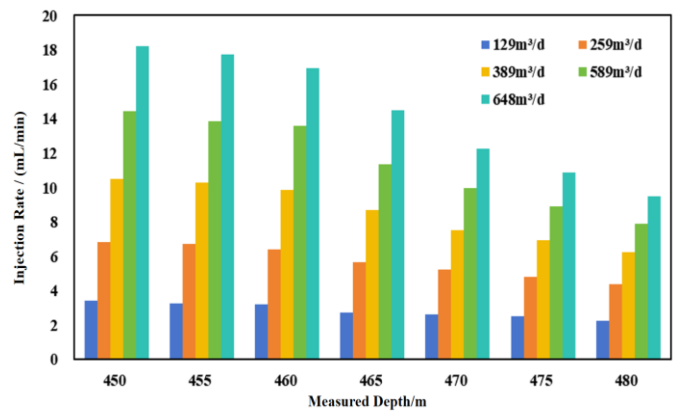
3.1. Effect of Injection Rate on Temperature Distribution

Test results indicate that as the injection rate increases, the wellbore temperature profile decreases overall (Fig. **2a**), demonstrating that the cooling effect of low-temperature injected water on the wellbore is enhanced with increasing injection rate. Under the same injection rate, the wellbore temperature gradually rises from the heel to the toe. As shown in Figs. (**2b**) and (**2c**), under approximately homogeneous reservoir conditions, both the temperature change and the water injection in each injection section generally exhibit a distribution pattern of “higher at the heel and lower at the toe”. With the increase of total injection rate, the temperature change and water injection in each injection section increase simultaneously. This indicates that the temperature change can reflect the water-absorption intensity of different water-absorbing layers and can serve as a key parameter for evaluating the zonal water-injection capacity of water-injection wells based on DTS temperature data.



(**a**) Simulated temperature profile of the horizontal well





(**b**) ΔT of the simulated water-injection profile (**c**) Water injection rate of the simulated water-injection profile

Figure 2: Effect of injection rate on temperature distribution.

To quantitatively analyze the relationship between injection rate and temperature change, regression fitting was performed on the temperature-drop and injection-rate data. The relationship model between temperature change and water injection rate under different injection rates was obtained, which generally satisfies a linear relationship, as shown in Eq. **(1)**:

$$q = A\Delta T + B \tag{1}$$

where q is the water injection rate at the core, ml/min; ΔT is the temperature change at the core location, °C; and A and B are regression coefficients.

Taking the measured ΔT and the corresponding sectional water injection rate of the seven injection sections under the 20 mL/min condition as an example, linear regression analysis was conducted to examine the relationship between temperature variation and water injection rate, as shown in Fig. (**3**). The fitting results indicate a good positive linear correlation between the temperature variation ΔT and the sectional water injection rate, suggesting that, under the same injection condition, temperature variation can reflect the water-intake intensity of different injection sections.

From the trend line in Fig. (**3**), the linear regression relationship between temperature change and water injection rate was obtained, as shown in Eq. (**2**):

$$q=1.1379\Delta T+0.0004 \tag{2}$$

where q is the water injection rate at the core location, ml/min; ΔT is the temperature change at the core location, °C.

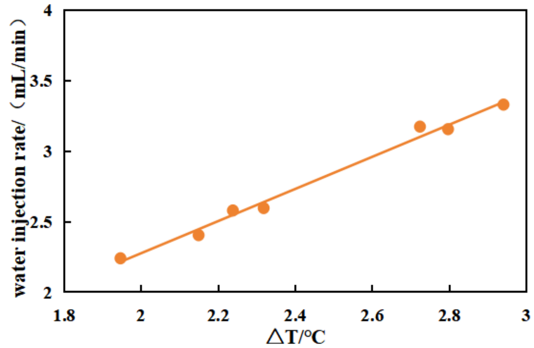
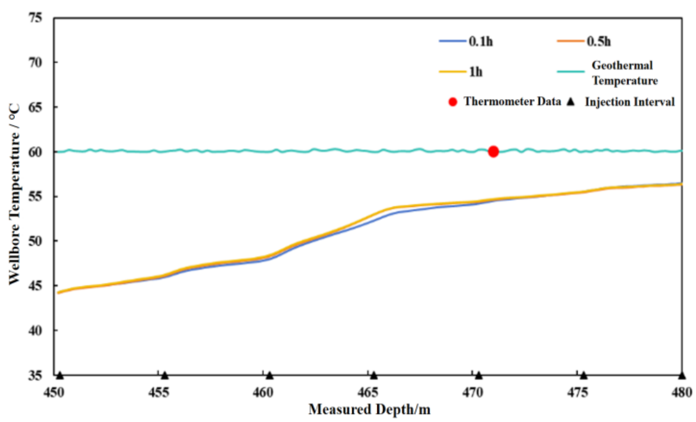


Figure 3: Fitting relationship between temperature change and water injection rate.

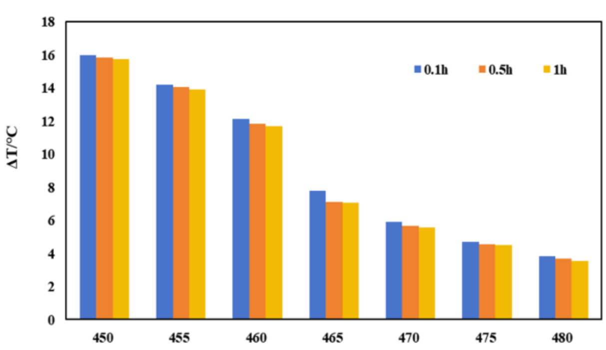
Based on the measured DTS temperature profile, the temperature change data of each horizontal well section are extracted and substituted into the relationship between temperature change and water injection rate given by Eq. **(2)**. Thereby, the water-injection rate distribution in each section can be quantitatively calculated, and the characteristics of the horizontal-well injection profile can be efficiently inverted.

3.2. Effect of Injection Time on Temperature Distribution

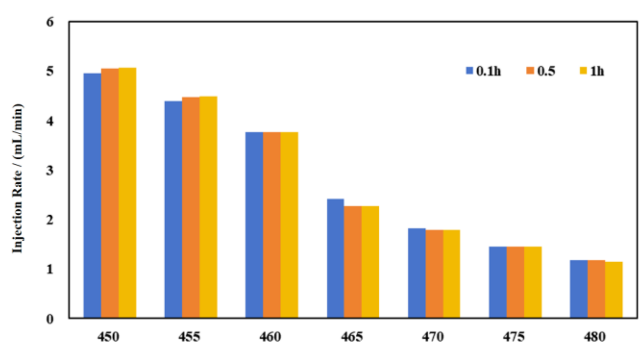
As shown in Fig. **(4a)**, under a constant simulated injection rate, the wellbore temperature profile increases overall as the injection time increases from 0.1 h to 1 h. It can be observed from Fig. (**4b**) that the magnitude of temperature drop decreases with increasing injection time; however, the differences in temperature drop caused by different injection times are extremely small. Meanwhile, the temperature change still exhibits a distribution pattern of higher values at the heel and lower values at the toe, indicating that the heel is more significantly affected by the low-temperature injected water. As shown in Fig. (**4c**), the water-injection distribution in each



(**a**) Simulated temperature profile of the horizontal well



(**b**) ΔT of the simulated water-injection profile



(**c**) Water injection rate of the simulated water-injection profile

Figure 4: Effect of injection time on temperature distribution.

section varies little among different injection times, and the overall pattern remains that of higher injection at the heel and lower injection at the toe. Overall, the injection time mainly affects the recovery process of the wellbore temperature profile, while its influence on the water-injection distribution of each section is relatively minor.

Linear fitting was performed on the temperature change and water injection rate data under different injection times, and the results are shown in Fig. (**5**). As the injection time increased from 0.1 h to 1 h, the slope of the fitting curve exhibited a slight increasing trend, indicating that under the same temperature-drop condition, a longer injection time corresponds to a slightly higher water injection rate. However, the magnitude of this variation is very small, and the differences in water injection rate among different injection times are negligible. It is inferred that the injection time has a minor effect on the quantitative relationship between temperature change and water injection rate. After 0.5 h of injection, the heat exchange between the wellbore and the near-wellbore reservoir has essentially reached a steady state, and further prolonging the injection time contributes little to expanding the low-temperature sweep range. Therefore, a short injection duration of 0.5 h is recommended for field DTS tests to obtain a stable injection profile, which helps reduce the shut-in time and lower operational costs.

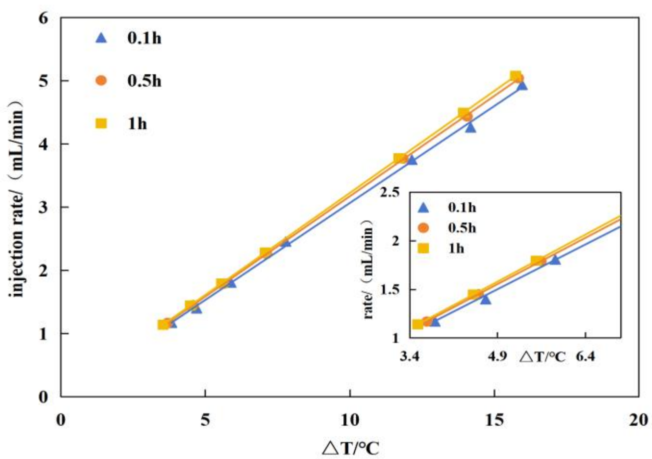


Figure 5: Relationship between temperature change and water injection rate

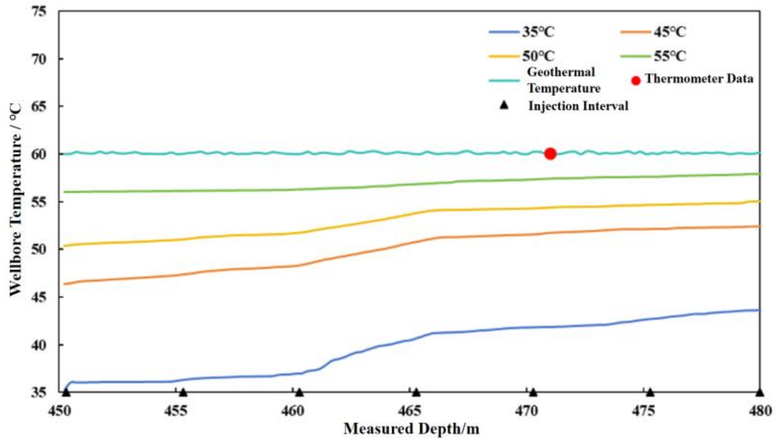
Based on the measured DTS temperature profile, the temperature-change data of each horizontal-well section are extracted. By applying the relationships between temperature change and water injection rate corresponding to different injection times given in Table **2**, the water-injection rate distribution in each section can be quantitatively calculated, thereby enabling rapid inversion of the horizontal-well injection profile.

Table 2: Quantitative relationship between temperature change and water injection rate.

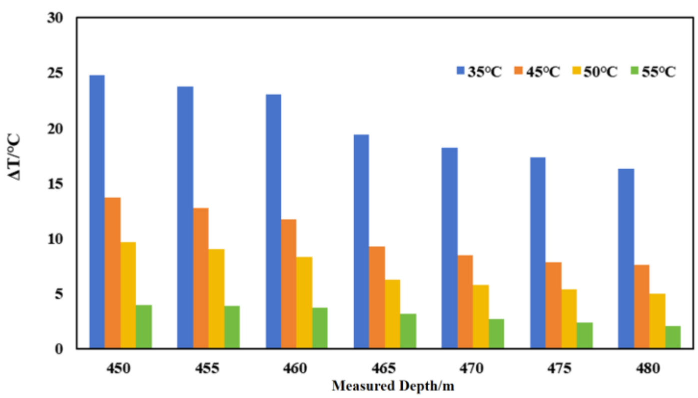
Influencing Factor	Regression Relationship	
injection time (h)	Correlation model	R^2
0.1	y=0.3066x+0.0001	0.98
0.5	y=0.3173x+0.0001	0.99
1	y=0.3225x+0.0002	0.98

3.3. Effect of Injection Temperature on Temperature Distribution

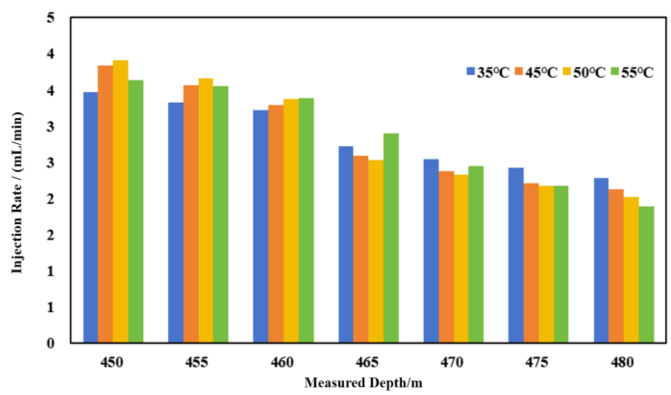
As shown in Fig. (**6a**), under a constant simulated injection rate, the temperature profile of the horizontal well rises overall with increasing injection temperature. In addition, as the low-temperature injected water flows from the heel to the toe along the wellbore, it continuously exchanges heat with the reservoir medium, resulting in a gradual decrease in temperature difference, as illustrated in Fig. (**6b**). It can be seen from Fig. (**6c**) that under different injection temperatures, the water-injection distribution in each section generally remains characterized by higher values at the heel and lower values at the toe. Overall, the injection temperature mainly affects the wellbore temperature response, while its influence on the zonal water-injection distribution is relatively weak.



(a) Simulated temperature profile of the horizontal well



(b) ΔT of the simulated water-injection profile



(c) Water injection rate of the simulated water-injection profile

Figure 6: Effect of injection temperature on temperature distribution.

Linear regression fitting was performed on the temperature-change (ΔT) and water-injection-rate data of each well section under different injection temperatures, with the results shown in Fig. (**7**). The overall trend indicates that as the injection temperature increases, the fitted curve of temperature change versus water injection rate shifts leftward toward the lower-temperature-change region, accompanied by a synchronous increase in the fitting slope, and the incremental water injection rate per unit temperature change increases significantly. Meanwhile, the range of temperature drop (ΔT) decreases with increasing injection temperature.

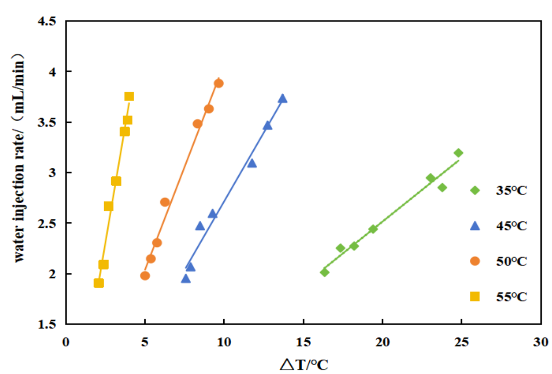


Figure 7: Relationship between temperature change (ΔT) and water injection rate.

Based on the measured DTS temperature profile, the temperature-change data of each horizontal-well section are extracted. By applying the relationships between temperature change and water injection rate corresponding to different injection temperatures given in Table **3**, the water-injection rate distribution in each section can be quantitatively calculated, thereby enabling rapid inversion of the horizontal-well injection profile.

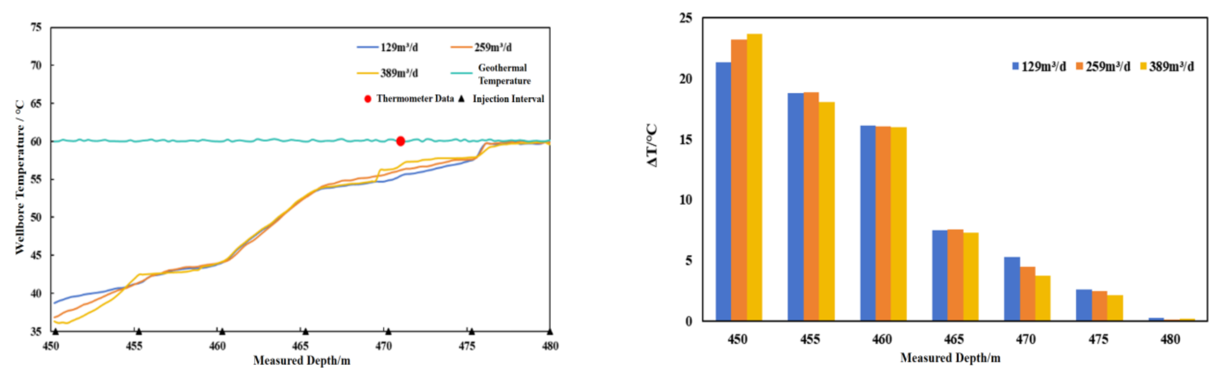
Table 3: Quantitative characterization of the relationship between temperature change and water injection rate.

Influencing Factor	Regression Relationship	
Injection temperature (°C)	Correlation model	R^2
35	y=0.1257x+0.0008	0.96
45	y=0.3117x+0.0002	0.97
50	y=0.4075x+0.0005	0.98
55	y=1.2234x+0.0003	0.98

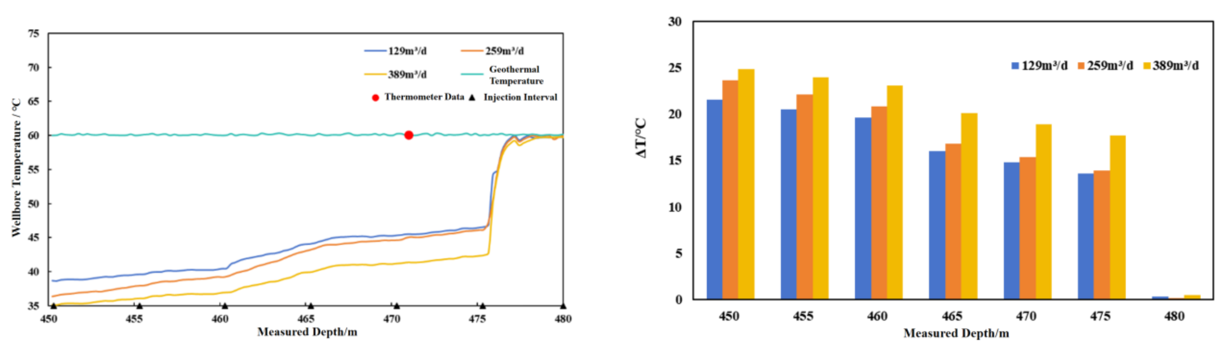
3.4. Effect of Injection Location on Temperature Distribution

Fig. (**8 a-d**) show the wellbore temperature profiles and the temperature changes (ΔT) in each injection section under four injection configurations, namely heel injection, toe injection, middle injection, and dual-end injection, respectively. It can be observed that the injection location exerts a significant influence on the shape of the wellbore temperature profile. In the case of heel injection, the temperature gradient at the heel increases; for toe injection, the temperature gradient at the toe increases. Under middle injection, the temperature profile exhibits a pronounced abrupt change around the middle wellbore section. When injecting from both ends, both the heel and the toe are affected by the injected water, and the temperature drop shows a distinct feature of being more significant at both ends. For all test conditions, there is an obvious temperature discontinuity immediately upstream and downstream of the injection location, and the temperature variation gradually diminishes away from the injection point. Therefore, this response characteristic can serve as an important indicator for identifying the injection location and evaluating zonal water-injection characteristics based on DTS temperature data.

(**a**) Heel injection



(**b**) Toe injection



(**c**) Middle-section injection

(**d**) Heel-Toe injection

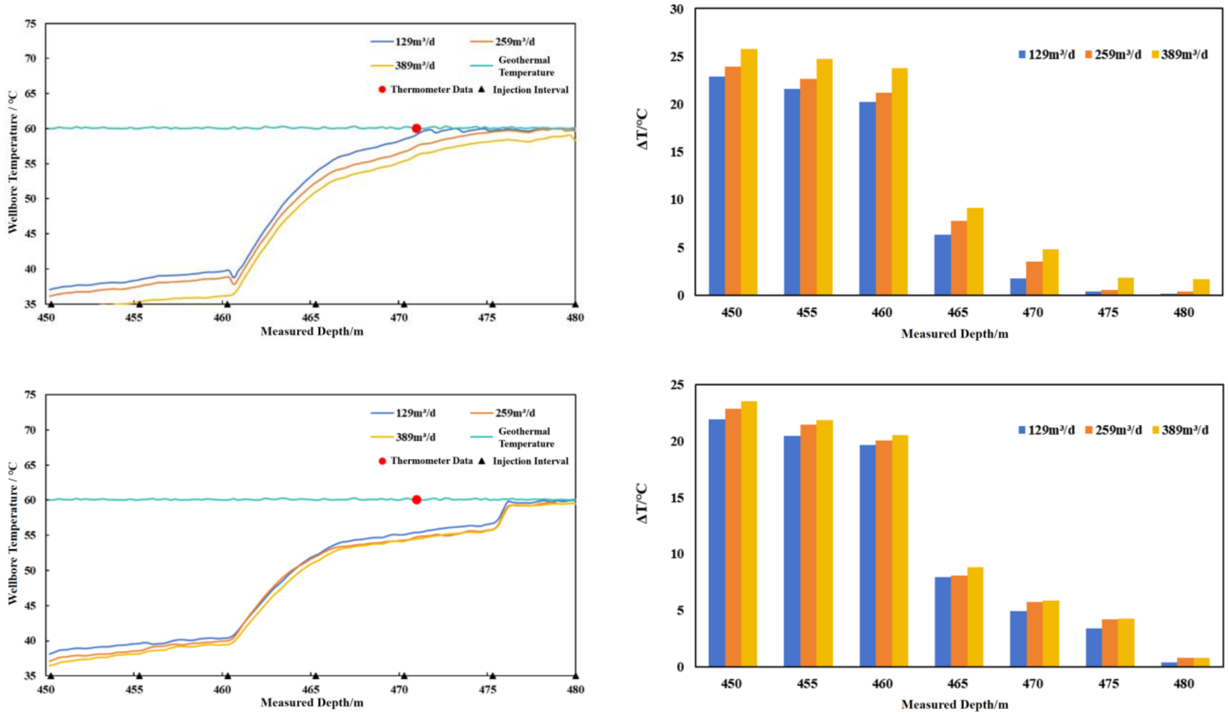


Figure 8: Temperature profiles and ΔT of the water injection profile under different injection positions.

4. Conclusions

4.1. Main Conclusions

In this study, a physical simulation experiment of water-injection wells was conducted in combination with distributed temperature sensing (DTS) technology. The effects of injection rate, injection time, injection temperature, and injection location on the temperature profile of water-injection wells were systematically investigated. Quantitative relationship models between temperature change and water injection rate under different simulated conditions were established, and the underlying mechanisms governing the temperature response characteristics were clarified. The main conclusions are as follows:

1) As the injection rate increases, the wellbore temperature profile of the horizontal well decreases overall. Under a given injection rate, the temperature along the horizontal well exhibits a distribution pattern of "lower at the heel and higher at the toe." The temperature drop in each section is linearly and positively correlated with the corresponding water injection rate, and the model conforms to a linear form.

2) The injection time is positively correlated with the temperature profile. With longer injection time, the heat exchange between the wellbore and the formation becomes more complete, and the temperature profile eventually tends to stabilize. However, the water-injection rate distribution in each section varies little with injection time, becoming essentially stable after 0.5 h. This indicates that injection time mainly affects the degree of temperature recovery, while its influence on water-injection allocation is limited.

3) The injection temperature has a pronounced effect on elevating the temperature field. A higher injection temperature leads to a more significant overall rise in the temperature profile. From the heel to the toe, the temperature difference between the injected water and the reservoir gradually decreases, accompanied by a continuous improvement in heat-exchange efficiency.

4) The injection location determines the fundamental shape of the temperature profile. Regardless of whether injection is performed at the heel, toe, middle, or both ends, there is a clear temperature discontinuity immediately upstream and downstream of the injection point. The rate of temperature variation along the wellbore and the distribution characteristics differs markedly among different injection locations.

4.2. Research Limitations and Prospects

This study analyzed the effects of injection rate, injection time, injection temperature, and injection location on the temperature profile of water injection wells based on laboratory physical simulation experiments, and established a quantitative relationship between temperature variation and water injection rate. It should be noted, however, that the experiments in this study were mainly conducted under approximately homogeneous reservoir conditions and controlled boundary conditions, without fully considering the effects of strong reservoir heterogeneity, multifactor coupling, and complex field wellbore structures. Therefore, the quantitative relationship obtained in this study is mainly applicable to the interpretation of temperature responses in water injection wells within the experimental conditions. Future work will further incorporate heterogeneous reservoir models, multifactor coupled experiments, and field DTS data validation to improve the quantitative interpretation method between temperature response and injection profile.

Conflict of Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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