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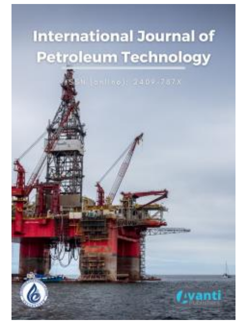

Study on the Influence Law of Temperature Profile of Vertical Wells in Gas Reservoirs

Ma Hansong, Luo Hongwen*, Li Haitao, Xiang Yuxing, Zhang Qin and Li Ying

State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China

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ABSTRACT

Due to the lack of a robust temperature model and poor knowledge about the influence law of temperature profile, it is still highly challenging to interpret the production profile of vertical wells in layered gas reservoirs from distributed temperature sensing (DTS) quantitatively. In this paper, a coupled temperature prediction model for vertical wells in the layered gas reservoir is developed, considering several microthermal effects and non-isothermal seepage. Based on the theoretical simulation, several single factors' influence on the vertical well's temperature profile in a layered gas reservoir has been analyzed. The sensitivity of temperature profiles on different affecting factors has been evaluated through orthogonal test analysis. It has been found that the influence degree of each factor on the temperature profile of the vertical well in the layered gas reservoir is as follows: formation permeability > production rate >water saturation > wellbore inclination angle > relative density of natural gas > formation thermal conductivity > wellbore diameter ($k > Q_g > S_W > \theta > d_g > K_t > D$). The dominant factors affecting the temperature profile of vertical wells in layered gas reservoirs are formation permeability, production rate, and water saturation. The proposed temperature prediction model can serve as the forward model when developing the inversion system to interpret DTS measurement. The findings of this paper provide solid theoretical support for the quantitative interpretation of the flow rate profile for vertical wells in layered gas reservoirs.

*Corresponding Author
Email: rojielhw@163.com
Tel: +(86) 13512368947

1. Introduction

The distributed optical fiber-based downhole temperature measurement technology (DTS) is gradually being applied to the downhole dynamic monitoring of oil and gas wells [1, 2]; DTS technology can identify artificial fractures [3], determine the fluid type [4], assess the effects of fracturing reconstruction [5], and quantitatively interpret the production profile, fracture flow contribution, and fracture parameters of fracturing horizontal wells [6-8], particularly for horizontal wells.

It is challenging to quantitatively evaluate the production profile and fracture characteristics of a vertical well in a layered gas reservoir based on DTS because numerous elements impact the temperature profile of vertical wells in gas reservoirs and the laws are complex. Therefore, the top priorities are determining the primary determinants of the temperature profile of vertical wells in layered gas reservoirs and realizing the prediction of the temperature profile of vertical wells in the layered gas reservoir. Both domestically and overseas, researchers have spent much time studying how to forecast the temperature profile of vertical and horizontal wells.

Ramey *et al*. [9] created the first wellbore temperature model by assuming single-phase flow in the tubing or casing, ignoring the vertical wellbore friction pressure drop, and treating temperature as a function of depth and production time. In their investigation of the heat transfer of hot fluid (gas or liquid) in the wellbore during injection, Satter *et al*. [10] took condensation into account. They examined the effects of injection speed, time, pressure, temperature, and well depth on heat loss. Holst *et al*. [11] assumed steady-state heat transfer in the wellbore and unstable radial conduction in the formation when creating a mathematical model for saturated steam injection along an oil well pipe under constant input conditions. Sagar *et al*. [12] originally developed a two-phase flow steady-state temperature prediction model considering the Joule Thomson effect and kinetic energy based on Ramey's temperature model. However, this model is only applicable to inclined wells. Yoshiok *et al*. [13] developed a temperature prediction model for horizontal wells in conventional gas reservoirs that accounted for a portion of the microthermal impact and located the gas/water input based on DTS test data [14, 15].

Additionally, Zhu Shiyan [16] and Cai Junjun *et al*. [17] developed models for predicting temperature profiles for oil-water two-phase horizontal wells and analyzed how many factors affect the temperature profiles of horizontal wells. In low permeability gas reservoirs, Luo Hongwen *et al*. [18] developed a prediction model for the temperature profile of fractured horizontal wells taking into account various microthermal impacts. They examined the impact of water production distribution on the wellbore temperature profile.

Domestically and internationally, academics have conducted many studies on analyzing and simulating oil and gas well temperature profiles. However, the majority of the current models are for horizontal wells. The properties of a vertical well in layered gas reservoirs need to be sufficiently taken into account in the present models, and there needs to be more study on the influence law of temperature profile of vertical wells in gas reservoirs.

In light of the features of a vertical well in the layered gas reservoir, this work provides a set of prediction models for temperature profiles of a vertical well in a layered gas reservoir based on the conservation of quality and energy. The distribution properties and effect laws of the temperature profile of a vertical well in the layered gas reservoir are simulated and investigated using a coupling solution. The dominant factors affecting the temperature profile of vertical wells in the layered gas reservoir are identified through the use of the orthogonal test analysis method, which establishes the theoretical groundwork for quantitative interpretation of the production profile of vertical wells in a layered gas reservoir and the characteristic reservoir parameters based on DTS monitoring.

2. Temperature Prediction Model of Vertical Well in Layered Gas Reservoir

2.1. Formation Model

(1) Formation Flow Model

The following three-dimensional unsteady flow equation of gas and water phases is established using the pseudo pressure function and the anisotropy of formation permeability by the law of conservation of mass:

Gas phase:

$$\begin{aligned}&\frac{\partial}{\partial x}\left(k_x k_{rgx}\sigma_{gx}\frac{\partial\psi}{\partial x}\right)+\frac{\partial}{\partial y}\left(k_y k_{rgy}\sigma_{gy}\frac{\partial\psi}{\partial y}\right)+\frac{\partial}{\partial z}\left(k_z k_{rgz}\sigma_{gz}\frac{\partial\psi}{\partial z}\right)\\&=\phi S_g C_g \mu_g\frac{\partial\psi}{\partial t}+2\phi\frac{p_g}{Z}\frac{\partial}{\partial t}(S_g)\end{aligned} \tag{1}$$

Water phase:

$$\frac{\partial}{\partial x}\left(\frac{\rho_w k_x k_{rwx}}{\mu_w}\frac{\partial p_w}{\partial x}\right)+\frac{\partial}{\partial y}\left(\frac{\rho_w k_y k_{rwy}}{\mu_w}\frac{\partial p_w}{\partial y}\right)+\frac{\partial}{\partial z}\left(\frac{\rho_w k_z k_{rwz}}{\mu_w}\frac{\partial p_w}{\partial z}\right)=\frac{\partial}{\partial t}(\phi\rho_w S_w) \tag{2}$$

Where ρ_{w} is the density of the water, kg/m^3; ϕ is porosity; S_g 、 S_w are gas and water saturation respectively ; *k* is the permeability of formation, D; k_{ro} k_{rw} represents the relative permeability of oil and water respectively; μ_g 、 μ_{w} represents the viscosity of gas and water respectively, mPa·s; p_{g} 、 p_{w} represents the pressure of gas and water respectively, MPa ; σ_{gx}, σ_{gy}, σ_{gz} represents Non-Darcy gas phase components in the x, y, and z directions respectively; g is the acceleration of gravity, 9.8m/s^2; Z is vertical well depth, positive downward, m.

Boundary conditions include inner and outer boundary conditions, and the inner boundary condition describes the wellbore's condition inside the gas reservoir. The outer boundary conditions show the condition of the gas reservoir's outer boundary.

1) Outer Boundary Condition:

$$\begin{cases}\left.\dfrac{\partial\psi}{\partial x}\right|_{x=0}=0,\left.\dfrac{\partial\psi}{\partial x}\right|_{x=L_x}=0\\\left.\dfrac{\partial\psi}{\partial y}\right|_{y=0}=0,\left.\dfrac{\partial\psi}{\partial y}\right|_{y=L_y}=0\\\left.\dfrac{\partial\psi}{\partial z}\right|_{z=0}=0,\left.\dfrac{\partial\psi}{\partial z}\right|_{z=L_z}=0\end{cases} \tag{3}$$

L_x, L_y, *and* L_z represent the gas reservoir's geometric dimensions in x, y, and z directions, respectively.

2) Internal boundary condition:

$$\psi|_{x=\mathbf{0}}=2\int_{p_o}^{p_{wf}}\frac{p}{\mu_g Z}dp=\psi_{wf} \tag{4}$$

$$p_w|_{x=0}=p_{wb} \tag{5}$$

$$p_g|_{x=0}=p_{wb} \tag{6}$$

Where P_{ub}– Bottom-hole force, MPa;

ψ_{wb} –Bottom-hole pseudo pressure function, MPa^2/(mPa· s).

(2) Formation Temperature Model

The following gas reservoir temperature model is developed based on the energy conservation equation and takes into account a variety of microthermal effects, such as heat conduction, heat convection, the Joule-Thompson effect, thermal expansion, and viscous dissipation.

$$
\begin{aligned}
&\overline{\rho C_p}\frac{\partial T}{\partial t}-\phi\beta T\frac{\partial p}{\partial t}=\frac{\rho k C_p}{\mu_g}\left(\frac{\partial p}{\partial y}\frac{\partial T}{\partial y}+\frac{\partial p}{\partial z}\frac{\partial T}{\partial z}\right)\\
&-\frac{k}{\mu_g}(\beta T-1)\left[\left(\frac{\partial p}{\partial y}\right)^2+\left(\frac{\partial p}{\partial z}\right)^2\right]+K_T\left(\frac{\partial^2 T}{\partial x^2}+\frac{\partial^2 T}{\partial y^2}+\frac{\partial^2 T}{\partial z^2}\right)+\boldsymbol{q}_{wb}
\end{aligned}
\tag{7}
$$

Where C_p is thermal capacity, J/(kg·K); β is thermal expansion coefficient, 1/K; T is the temperature in the reservoir, K; ρ is the fluid density, kg/m^3; k is permeability, mD; K_T is the thermal conductivity of reservoir, J/(m·s·K); $\boldsymbol{q}_{wb}$ represents the heat conduction rate per unit volume between wellbore and reservoir, J/(m^3·s).

(3) Boundary Condition

1) Outer Boundary Condition:

$$
\begin{cases}
\left.\dfrac{\partial T}{\partial x}\right|_{x=0}=0,\left.\dfrac{\partial T}{\partial x}\right|_{x=L_x}=0\\
\left.\dfrac{\partial T}{\partial y}\right|_{y=0}=0,\left.\dfrac{\partial T}{\partial y}\right|_{y=L_y}=0\\
\left.\dfrac{\partial T}{\partial z}\right|_{z=0}=0,\left.\dfrac{\partial T}{\partial z}\right|_{z=L_z}=0
\end{cases}
\tag{8}
$$

2) Internal Boundary Condition:

$$
\begin{cases}
T\big|_{x=0}=T_{wb}\\
-K_T\left.\dfrac{\partial T}{\partial x}\right|_{x=r_w}=U_{Tt}(T_{wb}-T\big|_{x=r_w})
\end{cases}
\tag{9}
$$

Where K_T—Thermal conductivity of reservoir, W/(m·K);

U_{Tt}—integrated heat transfer coefficient [19, 20], W/(m^2·K);

r_w—Wellbore radius, m.

2.2. Wellbore Model

A model for the flow and temperature of a gas-water two-phase wellbore is developed based on the conservation of mass, momentum, and energy. Fig. (**1**) depicts the wellbore's fluid flow direction; in modeling, the impacts of wellbore friction, fluid mixing pressure drop, fluid acceleration pressure drop, and gravity are taken into account, but the effect of gas and water slipping about inside the wellbore is not taken into account.

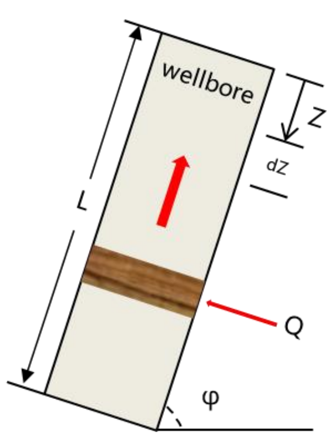


Figure 1: Conservation of wellbore flow energy.

(1) Wellbore Flow Model

There are various portions to the wellbore. According to the laws of conservation of energy and momentum, the wellbore pressure change in any microelement portion of the wellbore can be written as:

$$\frac{dp_{wb}}{dy} = -\frac{\rho_{wb} f v_{wb}^{2}}{R_{inw}} - \frac{d}{dy}\left(\rho_{wb} v_{wb}^{2}\right) - \rho_{wb} g \sin\theta - \frac{\partial(\rho_{wb} v_{wb})}{\partial t} \tag{10}$$

Where R_{inw} is wellbore diameter, m; γ is the opening degree of the wellbore; p_{wb} is pressure in wellbore, MPa; ρ_{wb} is fluid density in the wellbore, kg/m^3; f is shaft lining friction coefficient; v_{wb} is the fluid velocity in the wellbore, m/s; ρ_I is the density of inflow fluid, kg/m^3; v_I is the flow rate of inflow fluid, m/s; θ is the inclination of the horizontal wellbore, °; g is the acceleration of gravity, 9.8m/s^2.

(2) Wellbore Temperature Model

The wellbore temperature model is built as follows, disregarding the influence of heat conduction between fluid phases and based on energy conservation:

$$\begin{aligned}\frac{1}{v}\frac{\partial T}{\partial t} - \frac{\beta T}{\rho v C_p}\frac{\partial p}{\partial t} = {} & \frac{2\gamma \rho_I v_I}{R_{inw}\rho v}\left(T_I - T\right) + \frac{2(1-\gamma)}{R_{inw}\rho v C_p} U_{Tt}\left(T_I - T\right) \\ & - \frac{\partial T}{\partial y} + K_{JT}\frac{\partial p}{\partial y} - \frac{g\sin\theta}{C_p}\end{aligned} \tag{11}$$

Where T_I is fluid inflow temperature, K; T_{wb} is the temperature in the wellbore, K; U_{Tt} is integrated heat transfer coefficient, J/(m^2·s·K); K_{JT} is Joule Thompson coefficient [21, 22], K/MPa.

2.3. Coupling of the Temperature Prediction Model

The gas reservoir and wellbore thermal models are nonlinear and mutually connected. Therefore, it is important to solve the coupled temperature model through iteration. Fig. (**2**) depicts the developed gas reservoir direct well temperature profile prediction model coupling solution flow.

3. Influence Law Analysis and Sensitivity Evaluation of Temperature Profile of Vertical Well in Layered Gas Reservoir

The focus of this paper is an abstract vertical well in the layered gas reservoir; using the temperature profile prediction model of the vertical well developed in this research, the temperature profile of the gas reservoir is simulated and examined, learn how different single components affect the temperature profile of vertical well in a layered gas reservoir and identify the primary controlling parameters that have the most significant impact on that profile, Tables **1** and **2** below display the fundamental parameters needed for the simulation calculation.

3.1. Influence Law Analysis of the Temperature Profile

This paper uses the above abstract vertical well in layered gas reservoir as its research object; the impact of various single factors on the temperature profile of a vertical well in the layered gas reservoir is examined by modeling the well's temperature performance under seven different single factors.

Fig. (**3a**) displays the temperature profile simulation findings for several single well production scenarios; as evidenced by the figure, the wellbore temperature in the pay zone lowers more quickly than that in the cementing portion of the vertical well in the gas reservoir as it gradually rises from the bottom of the well to the wellhead. The wellbore temperature profile overall declines as production rises. The percolation theory states that as production increases, the wellbore pressure profile decreases, and the production pressure difference increases; the wellbore temperature decreases in proportion to how effectively coke soup cools when differential pressure is

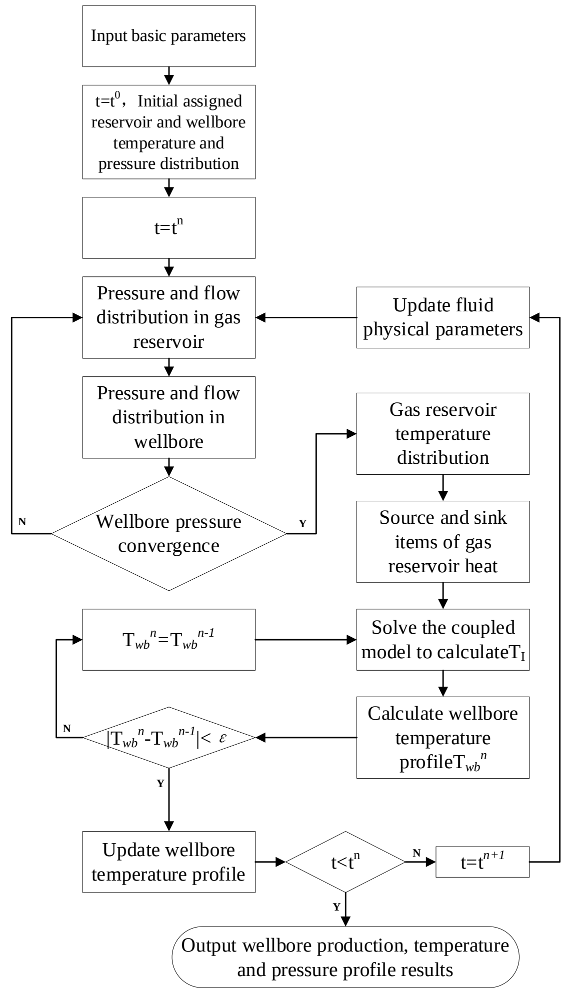


Figure 2: Calculation flow chart of temperature profile prediction model for vertical well in the gas reservoir.

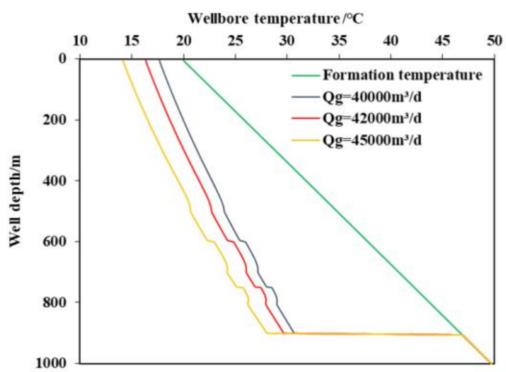
Table 1: Basic parameters for vertical well simulation calculation of gas reservoir.

Reservoir Parameters		Wellbore Parameters		Physical Property of Fluid	
Reservoir depth, m	**1000**	**Well-depth, m**	**1000**	**Gas density, kg/m^3**	**0.9**
Horizontal permeability, mD	0.2	Wellbore diameter, m	0.24	Gas viscosity, mPa·s	0.0221
Vertical permeability, mD	0.02	Casing outer diameter, m	0.1778	Gas heat capacity, J/(kg·℃)	2556
Porosity, %	20	Inner diameter of casing, m	0.1594	Gas expansion coefficient, 10^{-4}/K	0.005
Water Saturation	0.2	Shaft Wall Roughness, m	0.005	Gas volume Coefficient, m^3/m^3	0.005
Supply radius, m	500	Thermal conductivity of casing, J/(m·s·℃)	53	Gas thermal conductivity, 10^{-4} W/(m·℃)	2.63
Ground temperature, ℃	20	Thermal conductivity of cement sheath, J/(m·s·℃)	0.933	Formation water density, kg/m^3	1001
Geothermal gradient, ℃/m	0.03	Thermodynamic parameters of reservoir rocks		Formation water viscosity, mPa·s	0.14
Reservoir temperature, ℃	50	Rock density, kg/m^3	2377	Formation water heat capacity, J/(kg·℃)	4234
Formation pressure, MPa	12	Rock heat capacity, J/(kg·℃)	845	Thermal expansion coefficient of formation water, 10^{-4}/℃	2.02
Number of production layers	3	Total thermal conductivity, J/(m·s·℃)	4.46	Formation water volume coefficient, m^3/m^3	1.02

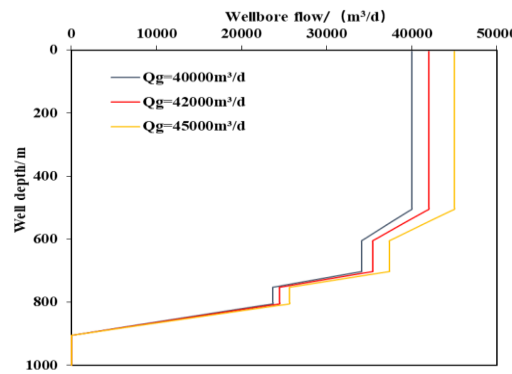
Table 2: Basic parameters of production layer of vertical well in gas reservoir.

Production Layer Number	Top Depth, m	Bottom Depth, m	Permeability, mD	Porosity	Water Saturation	Average Pressure, MPa
1	500	600	0.125	0.12	0.1	11
2	700	750	0.2	0.13	0.15	11.5
3	800	900	0.15	0.11	0.2	12

present. The wellbore flow profile is shown in Fig. (**3b**), and it can be seen that the height of each "step" in the wellbore flow profile corresponds to how much production each pay layer contributes. Each pay layer's production contribution positively correlates with the overall permeability distribution.



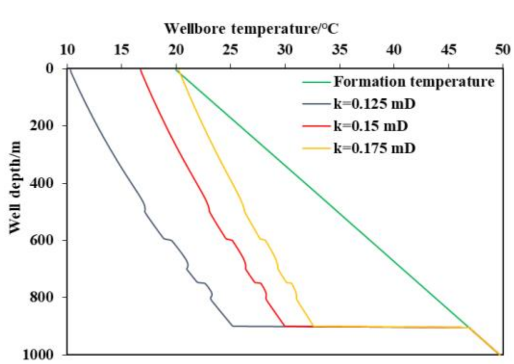
(a) Wellbore temperature profile



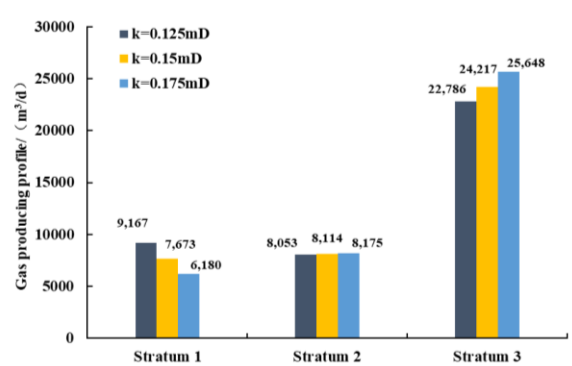
(b) Wellbore flow profile

Figure 3: Effect of production on wellbore temperature and flow profile.

The temperature profile of the vertical well in a gas reservoir under different reservoir permeabilities is depicted in Fig. (**4a**). The figure shows that the wellbore temperature profile increases with increased permeability. However, when permeability rises, the rate at which the wellbore temperature profile rises declines. The higher the formation permeability, the higher the wellbore pressure, and the smaller the production differential pressure, claims the percolation theory. However, when permeability rises, the pace at which the wellbore pressure profile rises declines, weakening the Jiaotang effect brought on by fluid flow and slowing temperature rise. The wellbore gas production profile is shown in Fig. (**4b**). As can be observed, with an increase in average permeability, the production contribution increases with increasing pay interval proximity to the well's bottom while decreasing with increasing pay interval proximity to the wellhead. Permeability significantly influences the wellbore gas production profile, and each production rate's contribution is strongly connected with the permeability distribution.



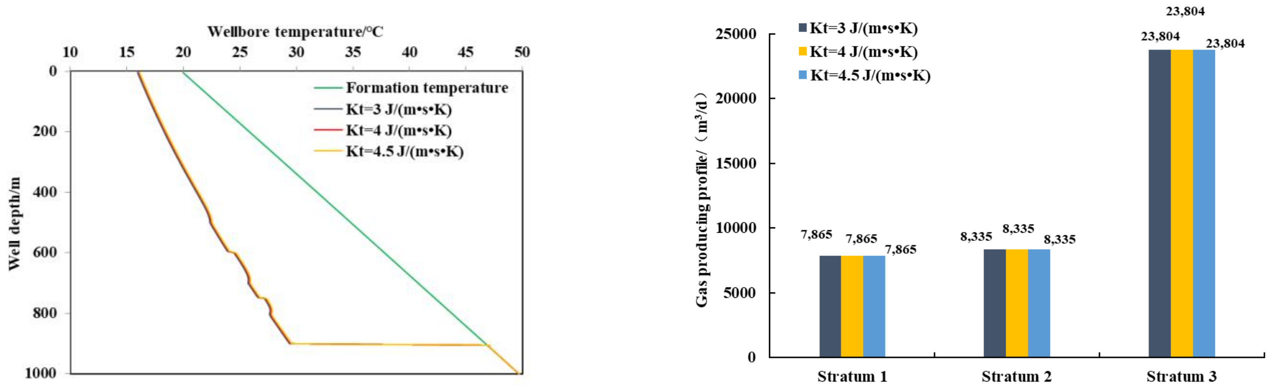
(a) Wellbore temperature profile



(b) Profile of wellbore gas production

Figure 4: Effect of permeability on wellbore temperature and gas production profile.

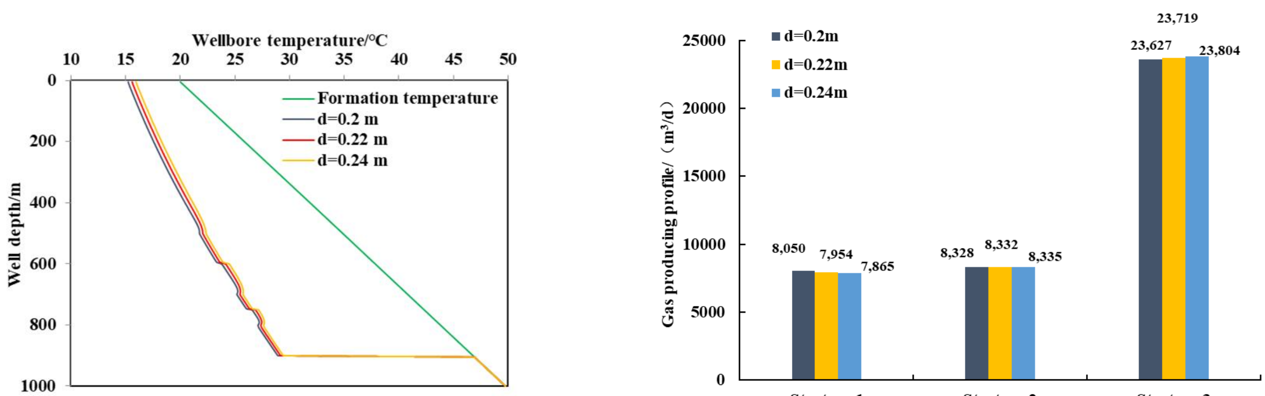
The wellbore temperature profile under various reservoir thermal conductivity is depicted in Fig. (**5a**). The figure shows that the wellbore temperature profile increases with increasing thermal conductivity. This is because as the reservoir's thermal conductivity rises, the rock inside the rock transfers heats more effectively, increasing the amount of heat conducted in a given amount of time. However, the reservoir's rock's thermal conductivity has little impact on the wellbore temperature profile. Nevertheless, it is clear from Fig. (**5b**) that the change in thermal conductivity has little effect on the distribution of wellbore pressure and the production profile.



(a) Wellbore temperature profile (b) Profile of wellbore gas production

Figure 5: Influence of reservoir thermal conductivity on wellbore temperature and gas production profile.

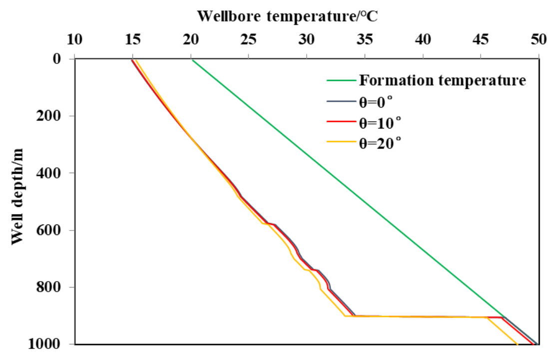
The wellbore temperature curve for various wellbore diameters is depicted in Fig. (**6a**). The figure shows that as the well diameter increases, the wellbore temperature profile rises. This is primarily because when the wellbore diameter increases, friction between the fluid inside and the wellbore itself decreases dramatically, lowering pressure drop loss inside the wellbore. The higher the wellbore pressure profile is, the smaller the production pressure difference is, and the weaker the coke soup cooling effect caused by pressure drop is. As a result, the wellbore temperature profile is improved as the wellbore diameter increases and the inflow temperature rises. The wellbore gas production profile is somewhat impacted by the change in wellbore diameter (Fig. **6b**).



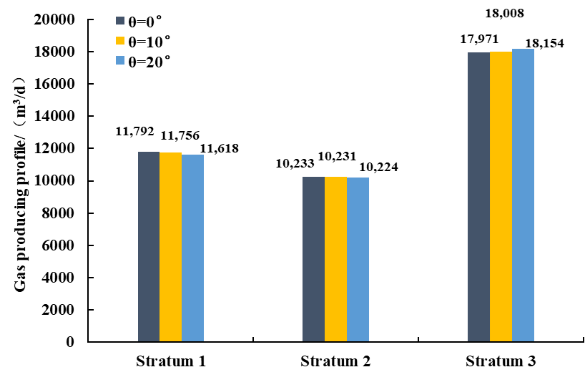
(a) Wellbore temperature profile (b) Profile of wellbore gas production

Figure 6: Influence of wellbore diameter on wellbore temperature and gas production profile.

Fig. (**7a**) depicts the wellbore temperature profile for various wellbore trajectories. The figure shows that the bottom hole temperature and the wellbore temperature of the production section close to the bottom hole decrease with increasing θ. The variation in ground temperature primarily causes this. However, the closer to the wellhead, The wellbore temperature profile decreases with the increase of the θ. Because with the increase of θ, the smaller the wellbore pressure drop is, the higher the wellbore pressure profile is, and the smaller the differential pressure is, leading to the weakening of the cooling effect of coke soup caused by the loss of pressure drop of natural gas. So close to the wellhead, the larger the θ, the higher the temperature. The distribution of formation permeability continues to dominate the distribution of the wellbore production profile (Fig. **7b**).



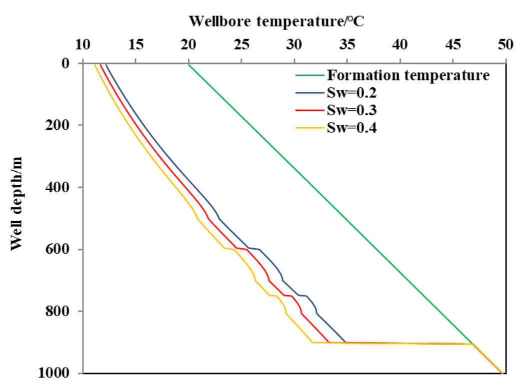
(a) Wellbore temperature profile



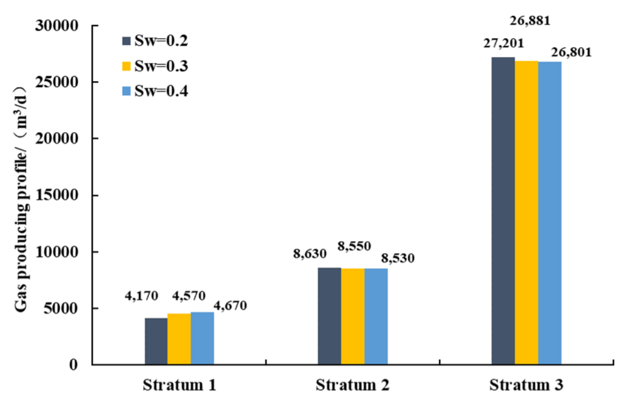
(b) Profile of wellbore gas production

Figure 7: Influence of well trajectory on wellbore temperature and gas production profile.

The wellbore temperature profile under various water saturation conditions is depicted in Fig. (**8a**). The figure shows the negative relationship between wellbore temperature and reservoir water saturation. As water saturation increases, the wellbore temperature profile drops. This is because, under the same gas production rate, the higher the water saturation, the lower the gas phase relative permeability, and the greater the production pressure difference, the stronger the gas phase coke soup cooling effect caused by the pressure drop, resulting in the lower wellbore temperature profile. The permeability distribution of the production layers continues to dominate the production profile, and each production layer's contribution to gas production is positively correlated with permeability (Fig. **8b**).



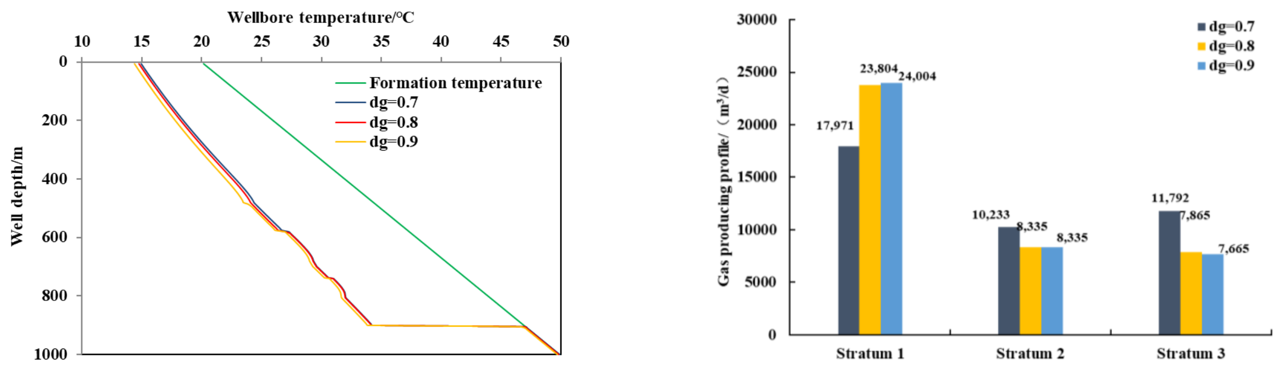
(a) Wellbore temperature profile



(b) Profile of wellbore gas production

Figure 8: Influence of water saturation on wellbore temperature and flow profile.

Fig. (**9a**) depicts how the temperature profile varies as the relative density of the natural gas changes. The figure shows that the wellbore temperature profile generally decreases with an increase in the relative density of natural gas and decreases more quickly as the relative density of natural gas increases. Consequently, the wellbore pressure profile will be lower, and the production differential pressure will be higher as natural gas density increases. The result is a lower wellbore temperature profile because the gas phase of coke soup's cooling effect is amplified by the pressure drop. The permeability distribution of production layers typically controls the production profile, and the contribution of each production layer to gas production is still positively correlated with the permeability of production layers. However, the production contribution of the pay interval closer to the well's bottom slightly declines as the relative density of natural gas rises. In contrast, the production contribution of the pay interval closer to the wellhead slightly rises (Fig. **9b**). This is primarily caused by the alteration of the wellbore pressure profile, which affects the production differential pressure associated with each pay interval.



(a) Wellbore temperature profile (b) Profile of wellbore gas production

Figure 9: Influence of natural gas relative density on wellbore temperature and gas production profile.

3.2. Sensitive Evaluation of the Temperature Profile Through Orthogonal Test Analysis

The temperature profile of the gas reservoir is influenced by various single factors to varying degrees, according to the results of the single-factor analysis presented above, in order to lay the groundwork for later inversion interpretation and to pinpoint the key elements influencing the temperature profile of the vertical well in the gas reservoir. The orthogonal test method is used to examine the sensitivity of various single factors affecting the temperature profile of the vertical well in the reservoir. Tables **1** and **2** display the fundamental parameters for simulation calculation.

The seven factors chosen based on the analysis factors' settings are the single well production, permeability, total thermal conductivity, average water saturation, the relative density of natural gas, wellbore diameter, and vertical well inclination. The orthogonal test analysis of 7 factors and 3 levels was performed, and Table **3** displays the value level design for each influencing factor.

Table 3: Analysis factors and level design of orthogonal test.

Factor	Q_g, m^3/d	K, mD	K_t, J/(m·s·℃)	S_W	d_g	D, m	*θ*, °
Level 1	40000	0.125	3	0.1	0.7	0.2	0
Level 2	42000	0.15	4	0.15	0.8	0.22	5
Level 3	45000	0.175	4.5	0.2	0.9	0.24	10

The standard orthogonal table (Table **4**) of L_{18} (3^7) is chosen for the orthogonal test analysis by the design of the orthogonal test scheme. In order to evaluate the overall change in the wellbore temperature profile due to the interaction of various factors, the average temperature difference between the geothermal profile and the wellbore temperature profile is used. Table **4** displays the results of the orthogonal test. Apply the range analysis method to the results of orthogonal tests to perform sensitivity range analysis. The findings demonstrate that the following factors have the most significant influence on the temperature profile of the vertical well of the gas reservoir, in that order: Permeability>production>water saturation>wellbore inclination angle>relative density of natural gas>reservoir thermal conductivity>wellbore radius($k>Qg>S_W>\theta>dg>K_t>D$). Permeability, single-well production, and water saturation are the main factors influencing the temperature profile of the vertical well in the gas reservoir.

As a result, permeability and water saturation distribution can be used as inversion target parameters for inversion interpretation of DTS monitoring data of vertical wells in gas reservoirs. The forward model is the temperature profile prediction model developed in this paper. The inversion model is developed using the SA algorithm [23], the MCMC algorithm [7], and other artificial intelligence algorithms. The production profile of a vertical well in a gas reservoir with multiple pay zones can be quantitatively interpreted.

Table 4: Analysis results of orthogonal test.

Experiment Number	Q_g	D	k	K_t	S_W	θ	d_g	Average Temperature Difference, ℃
Experiment 1	1	1	1	1	1	1	1	3.4778
Experiment 2	1	2	2	2	2	2	2	2.3926
Experiment 3	1	3	3	3	3	3	3	1.8039
Experiment 4	2	1	1	2	2	3	3	4.4766
Experiment 5	2	2	2	3	3	1	1	2.9035
Experiment 6	2	3	3	1	1	2	2	1.7129
Experiment 7	3	1	2	1	3	2	3	3.548
Experiment 8	3	2	3	2	1	3	1	2.0413
Experiment 9	3	3	1	3	2	1	2	4.6136
Experiment 10	1	1	3	3	2	2	1	1.7583
Experiment 11	1	2	1	1	3	3	2	4.1315
Experiment 12	1	3	2	2	1	1	3	2.1578
Experiment 13	2	1	2	3	1	3	2	2.5333
Experiment 14	2	2	3	1	2	1	3	1.9
Experiment 15	2	3	1	2	3	2	1	4.7525
Experiment 16	3	1	3	2	3	1	2	2.4617
Experiment 17	3	2	1	3	1	2	3	4.9142
Experiment 18	3	3	2	1	2	3	1	3.0512
mean value 1	2.620	3.043	4.394	2.97	2.806	2.919	2.997	-
mean value 2	3.046	3.047	2.764	3.047	3.032	3.180	2.974	-
mean value 3	3.438	3.015	1.946	3.088	3.267	3.006	3.133	-
Range(R)	0.818	0.032	2.448	0.118	0.461	0.261	0.159	-
sort	Second	Seventh	First	Sixth	Third	Fourth	Fifth	-
Order of influence degree	$k > Q_g > S_W > \theta > d_g > K_t > D$							

4. Conclusion

(1) In this paper, a coupled temperature prediction model for vertical wells in the layered gas reservoir is developed considering several microthermal effects and non-isothermal seepage. Based on the theoretical simulation, several single factors' influence on the vertical well's temperature profile in layered gas reservoir has been analyzed. The proposed temperature prediction model can serve as the forward model when developing the inversion system to interpret DTS measurement.

(2) The sensitivity of temperature profiles on different affecting factors has been evaluated through orthogonal test analysis. It has been found that the influence degree of each factor on the temperature profile of vertical well in layered gas reservoir is as follows: formation permeability > production rate >water saturation > wellbore inclination angle > relative density of natural gas > formation thermal conductivity > wellbore diameter ($k > Q_g > S_W > \theta > dg > K_t > D$). The dominant factors affecting the temperature profile of vertical wells in layered gas reservoirs are formation permeability, production rate, and water saturation.

(3) Permeability, production, and water saturation can be used as the inversion target parameters to interpret the monitoring data of the temperature profile of vertical wells in a layered gas reservoir. The findings of this paper provide solid theoretical support for the quantitative interpretation of the flow rate profile for vertical wells in layered gas reservoirs.

List of Abbreviations

L	=	Length of flow string, ft
Z	=	Vertical well depth, positive downward, m.
Q	=	Heat transfer rate per unit length of wellbore, Btu/hr-ft
φ	=	Well inclination from vertical, °
Q_g	=	Single well production, m^3/d
k	=	Reservoir permeabilities, mD
K_t	=	Reservoir thermal conductivity, J/(m·s·K)
D	=	Wellbore diameter, m
θ	=	Wellbore trajectories, °
S_w	=	Water saturation
d_g	=	The relative density of the natural gas

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