# Thermodynamic Model of Steam Injection Pipeline Considering the Effect of Time and Phase Change

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**Abstract**

The thermodynamic parameters along heavy oil thermal recovery wells serve as basis for evaluating the thermal efficiency of steam injection. However, various factors in wellbores affect the variation law of thermodynamic parameters, which thus become difficult to accurately describe. In order to improve the accuracy of thermodynamic parameter analysis, and to identify the main factors and their rules affecting thermal efficiency, a thermodynamic model of wellbores that considers the effects of time and phase change was proposed in this study. With the time factor considered, the transient conduction function of a coupled wellbore-formation was established, and the heat loss during steam injection was analyzed. Meanwhile, a wellbore pressure gradient equation was established using the Beggs-Brill model with consideration of the influence of phase transformation in wellbore. Steam pressure, which varies with flow pattern, was also analyzed. The accuracy of the proposed model was verified by comparing the analysis results with the test data. Therefore, the influence of steam injection parameters on thermal efficiency was studied. Results demonstrate that, the relative error of the pressure analysis result of proposed model is 1.06%, and the relative error of temperature is 0.24%. The water location in the annulus of the wellbore is the main factor affecting thermal efficiency, followed by steam injection rate. The thermal efficiency of the wellbore is about 80% when the water depth in the annulus is 300 m. An increase in the injection rate or the extension of the injection time can improve thermal efficiency, whereas an increase in steam injection pressure reduces thermal efficiency. The proposed method provides a good prospect for optimizing the high efficiency steam injection parameters of heavy oil thermal recovery wells.

*Keywords:* thermal recovery well, thermal efficiency, phase change, parameter sensitivity

## 1. Introduction

Heavy oil resources are abundant in reserves, but it is difficult to exploit because of the high viscosity and poor fluidity. Therefore, thermal recovery technologies have been proposed to improve productivity. These technologies reduce the viscosity of heavy oil and increase their fluidity by injecting high-temperature steam into the formation. Steam injection techniques are widely used in the thermal recovery of heavy oils, and they include steam-assisted gravity drainage [1–3], steam flooding [4], and cyclic steam stimulations [5, 6].

However, steam injection and oil production involve heat loss because of the temperature difference between the fluid and surrounding formation, heat loss, in turn, decreases the efficiency of thermal recovery. Thus, studying the factors affecting heat loss from fluid to formation and proposing a new model are necessary. During thermal recovery, steam flows from the wellhead to the reservoir at a certain injection rate, temperature, pressure, and steam quality according to the heat requirement of the reservoir. This process is made complex by the multi-phase mass transfer and heat conduction involved. The thermodynamic parameters of wells are affected by wellbore structures, the pattern and geometry of the multiphase flow, and the properties of each phase. These factors pose great challenges in the accurate description of vapor parameters and the study of the main controlling factors affecting thermal efficiency.

Thus, scholars have carried out many studies on the calculation methods for vapor parameters at certain depths and the influence law of steam injection parameters [7–9]. However, existing research on flow and heat transfer models, the multi-factor influence law, and the heat loss evaluation of steam injection are still insufficient. Therefore, problems, such as how to improve thermodynamic model by considering the influence of various factors in wellbore, how to reduce calculation errors, and how to identify the dominant factors of thermal efficiency, need to be settled urgently.

Based on the above analysis, this study establishes a new thermodynamic model that considers the effects of time and phase transformation in wellbore and the influences of steam injection parameters on heat loss and pressure gradient. The goal of this study is to obtain the high-accuracy thermodynamic parameters along the depth and provide a reference

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for the optimization of steam injection parameters.

## 2. State of the art

The thermodynamic parameters in the process of steam injection are complex. Therefore, extensive theoretical analyses, experimental research, and finite element simulations have been carried out to investigate the thermodynamic models and heat loss of wellbore formations. Reges et al. [9] proposed a method for calculating temperature profiles in a water injection well, and Alimonti et al. [10] applied the proposed method to calculate wellbore heat loss from fluids. However, this method assumes a constant temperature for an infinitely long heat resource. Such assumption is only appropriate for specific conditions, such as long durations and steady heat transfer. Yang et al. [11] developed a dynamic coupling model of flow and heat transfer and studied the heat transfer characteristics of high temperature and high pressure fluid in thermal recovery wellbore. However, this method assumes that wellbore fluid is always saturated steam, and it ignores the change in wellbore flow patterns. Sun et al. [12] proposed a mathematical model comprising a hydrodynamic equation, which considered the state data of superheated steam and heat loss in seawater. However, the unsteady flow characteristics of hot steam in wellbore were neglected in the study. Guo et al. [13] established a numerical simulation model of heat transfer and fluid flow during steam injection that considers the coupling effect of wells and reservoir. In this model, the unsteady flow and heat transfer of multiple phases in reservoir and wellbore were considered. However, the model focuses solely on the horizontal section and absorption area in a reservoir and neglects the flow characteristics of steam in the vertical section. Considering the coupled effects of stress, pore pressure, and temperature fields on the plastic failure of formations, Wang et al. [14] developed a 3D finite element numerical model to simulate the heat injection process and thereby enhance the recovery of heavy oil reservoirs. However, the finite element model assumes that the temperature of a heat source isconstant, which is not the same as that in practice. Focusing on the problem of uneven heating of the horizontal section of a reservoir, Lin et al. [15] and Chen et al. [16] used the finite difference method to study the distributions of steam pressure, dryness, and heat dissipation along wellbore. However, this method does not consider the coupling effects of the wellbore and formation during steam injection. On the basis of the study of thermodynamic flow models in the process of steam injection, Shu et al. [17] investigated the effects of gravity potential energy on heat loss in the energy equation, but the steam in a wellbore was regareded as a two-phase flow and the effects of phase transformation on gravitational potential energy were neglected. To discuss the influence of time factors, Ramey et al. [18] introduced a time factor to estimate heat loss and initially presented the transient heat conduction function of heat flux in formation. As a result of the disregard for phase change, Ramey's model cannot estimate the heat loss of multiphase flows efficiently.

The aforementioned studies were mainly directed at wellbore-reservoir flow and heat transfer model, which regardeds wellbore fluid as saturated steam without phase change over time. However, only a few studies focused on athermodynamic model that considers the influence of time and phase chnges. Aimed at the influences of time and phase change on high-temperature steam flow in wellbore, the present study proposes a theoretical model that includes governing equations and boundary conditions. In the model, Ramey and Setter's methods are used to calculate the heat loss of a wellbore, and the steam injection process is divided into two periods, namely, the steady heat transfer between the tube center and the outer surface of cement and the heat transfer from the outer surface of cement to the formation. Furhtermore, the Beggs-Brills model is adopted to calculate the wellbore pressure gradient distribution with different annulus media (air, water, and vapor). The accuracy of the model is verified with the measured data. On the basis of the results, the sensitivities of each factor are discussed, and the dominant factors affecting thermal efficiency are clarified. The proposed model provides a good prospect for the optimization of high-efficiency steam injection parameters for heavy oil thermal recovery wells.

The remainder of this study is organized as follows. The thermodynamic model, including the governing equations and boundary conditions is described in Section 3. The accuracy of the model is verified with the experimental data, and the influence laws of the steam injection rate and other factors on heat loss and pressure gradient are presented in Section 4. The present study is summarized, and relevant conclusions are drawn in the final section.

## 3. Methodology

In a steam injection process, the downward flow in the depth direction of a wellbore is a two-phase gas-liquid flow. The vapor parameters change with time along the depth, and the main influencing factors are wellbore structures and formation factors. In the analysis of the thermal performance of a wellbore, a coupled flow and heat transfer mathematical model should be established to directly obtain the pressure gradient, steam quality distribution, and heat loss along the wellbore. To simplify the mathematical model, this study makes the following assumptions.

(1) The injection rate, pressure and steam quality at wellhead remain are constant during the entire injection period.

(2) The section of the wellbore structure is shown in Fig 1.

(3) The physical and thermal properties of the formation are independent of temperature and the well depth.

(4) Heat transfer inside the wellbore is a steady-state process, while heat transfer in the formation is an unsteady-state process.

### *3.1. Heat loss along well depth*

According to the aforementioned assumptions, Ramey and Setter's methods that consider time are used to analyze the heat transfer of high-temperature steam between the

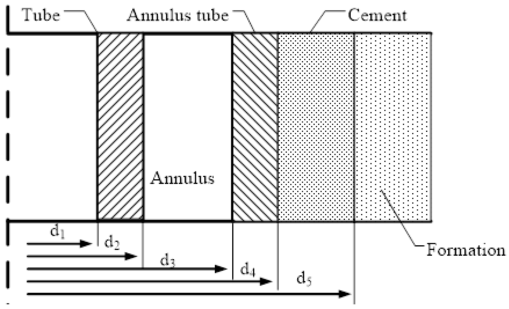



Figure 1: Wellbore structures

wellbore and formation. These methods are also applied to calculate the temperature distribution and heat loss of steam along the wellbore.

The heat transfer process usually consists of unsteady-state heat transfer in the formation and one-dimensional steady-state heat transfer between the injection tube and the outer surface of cement through tubing, annulus, annulus tube, and cement.

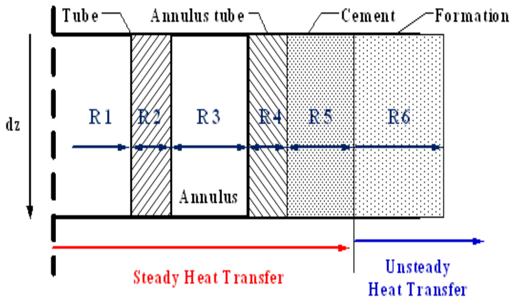



Figure 2: Thermal resistance model

*3.1.1. Steady heat transfer between the tube center and the outer surface of cement*

The temperature difference between the steam and the wellbore causes heat transfer. For steady-state transfer, the heat loss from the steam to the wellbore can be expressed as follwos:

$$\frac{dQ}{dZ} = \frac{T_s - T_i}{R_1 + R_2 + R_3 + R_{4+}R_5} = \frac{T_s - T_h}{R} \tag{1}$$

Where, $dQ/dZ$ is the heat loss of unit depth in unit time, $W/(h{\cdot}m)$;$T_s$ is the steam temperature, $^\circ F$;$T_k$ is the cement outsider surface temperature, $^\circ F$; $R$ is heat transfer resistance, $[W/(h \cdot m \cdot K)]^{-1}$. The thermal resistance $R$ consists of the following five parts as shown in Fig 2.

The total resistance R is based on outside surface diameters of tubing. $R$ is presented by Eq. (2).

$$R = \frac{1}{2\pi d_2}\left[\frac{d_2}{h_1 d_1} + \frac{d_2}{\lambda_{tub}}\ln\frac{d_2}{d_1} + \frac{d_2}{d3\,(h_c + h_r)} + \frac{d_2}{\lambda_{cas}}\ln\frac{d_4}{d_3} + \frac{d_2}{\lambda_{cem}}\ln\frac{d_5}{d_4}\right] \tag{2}$$

$U_2$ is the total heat transfer coefficient that is calculated by Eq. (3).

$$U_2 = \left[\frac{d_2}{h_1 d_1} + \frac{d_2}{\lambda_{tub}}\ln\frac{d_2}{d_1} + \frac{d_2}{d_3\,(h_c + h_r)} + \frac{d_2}{\lambda_{cas}}\ln\frac{d_4}{d_3} + \frac{d_2}{\lambda_{cem}}\ln\frac{d_5}{d_4}\right]^{-1} \tag{3}$$

For the steady-state heat transfer of wellbore, the unit depth heat loss of wellbore can be calculated as follows:

$$dQ = \pi d_2 U_2 (T_s - T_h)\, dZ \tag{4}$$

Therefore, the heat flow $q_L$ can be calculated by Eq. (5).

$$q_L = \pi d_2 U_2 (T_s - T_h) \tag{5}$$

*3.1.2. Heat transfer from the outer surface of cement to the formation*

The transient heat transfer in the formation causes an unsteady heat flux to the surrounding formation. At the beginning, the heat loss for the formation is sharp, but the heat loss and the temperature difference decrease as the formation temperature increases. The heat loss from the wellbore to the formation can be calculated by Eq. (6).

$$dQ = \frac{2\pi\lambda_e (T_h - T_e)}{f(\tau)} dZ \qquad q_L = \frac{2\pi\lambda_e (T_s - T_h)}{f(\tau)} \tag{6}$$

Where, $\lambda_e$ is the thermal conductivity of formation, $W/(m \cdot K)$; $f(\tau)$ is the transient heat conduction function, which can be calculated by Eq. (7) and (8).

$$f(\tau) = 0.985 \ln\left[1 + 1.81\frac{\sqrt{a\tau}}{0.5 d_5}\right] \tag{7}$$

$$T_h = \frac{\lambda_e T_e + 0.5 T_s d_2 U_2 f(\tau)}{0.5 d_2 U_2 f(\tau) + 2\lambda_e} \tag{8}$$

Where, $a$ is the average thermal diffusivity coefficient, $m^2/h$; $\tau$ is the injection time.

According to the constant about injection steam at wellhead, we can see is $T_k$ is constant, but $T_k$ is also different in different depths, so we can solve it by numerical iteration method.

The calculation procedures of the heat transfer coefficient $U_2$ are as follows:

(1) Calculate the transient heat conduction function $f(\tau)$.

(2) Calculate by the hypothetical value $U_2$.

(3) Calculate the heat flow $q_L$ by the hypothetical value $U_2$, so the heat flow $q_L$ is also a hypothetical value.

(4) Calculate the tubing outer wall temperature $T_{c1}$ and casing inner wall temperature $T_{c2}$.

(5) Calculate the heat transfer coefficient $U_2$ by $T_{c1}$ and $T_{c2}$.

(6) Repeat steps b to e until $U_2$ converges and finally get the value of heat flow $q_L$ and the heat transfer coefficient $U_2$.

### 3.2. The calculation of the wellbore pressure distribution

We use the Beggs-Brill's Model to obtain the steam pressure distribution alone wellbore accurately. For the Beggs-Brill's two-phase flow model, the total pressure drop of the wellbore flow is caused potential energy change, kinetic energy change, and friction loss. The momentum balance equation can be defined as follows:

$$\frac{dp}{dz} = \rho_m g \sin\theta - \rho_m v_m \frac{dv_m}{dz} \tag{9}$$

Where, ${dp}/{dz}$is total pressure drop of two-phase flow over the length $dz$ ; $g$ is the gravitational acceleration; $\theta$ is the well angle from horizontal; $f_{tp}$ is the two-phase friction factor; $\rho_m$ and $v_m$ are density and velocity of multiple fluids, it is defined as follows:

$$v_m = v_{sl} + v_{sg} \tag{10}$$

Where, $v_{sl}$ and $v_{sg}$ are superficial velocity of liquid and gas phase, respectively. $v_{sl} = {q_L}/{A_p}$and $v_{sg} = {q_g}/{A_p}$.$q_L$ and $q_g$ are liquid and gas volume flow, and $A_p$ is cross-sectional area of the inner tubing.

According to the Beggs-Brill's model, the flow pattern in vertical tube is divided into distributed flow, intermittent flow and segregated flow. The liquid fractions, friction factor and mixture density can be calculated based on the actual flow model. Then the steam pressure drop in wellbore can be calculated by Eq. (11).

$$\frac{dp}{dz} = \frac{\left[\rho_L H_L + \rho_g (1 - H_L) g \sin\theta - \frac{f_{tp}\rho_m v_m^2}{d}\right]}{1 - {[\rho_L H_L + \rho_g (1 - H_L)] v_m v_{sg}}/{p}} \tag{11}$$

Where, $\rho_L$ and $\rho_g$ are densities of the liquid phase and gas phase in mixture, $H_L$ is the liquid holdup fraction.

## 4. Result Analysis and Discussion

### 4.1. Model validation

The accuracy and reliability of the numerical simulations of the vertical wellbore steam flow were validated through an oil field injection well. The simulation results were compared with the measured field data. The configuration and physical characteristics of the wellbore are listed in Tables 1 and 2, respectively.

Table 1: The structure parameters of the wellbore

| Items | Description | Unit | Value |
|---|---|---|---|
| $zw_{max}$ | depth of the wellbore | m | 600 |
| *dwi* | inner diameter of the tube | inch | 2.44 |
| *dwo* | outer diameter of the tube | inch | 2.875 |
| *dci* | inner diameter of the annular tubes | inch | 8.755 |
| *dco* | outer diameter of the annular tubes | inch | 9.625 |
| *dcem* | outer diameter of the cement sheath | inch | 12.6 |
| *han* | Water location in annulus | m | 300 |

The relative errors between the experimental data and that from the Beggs-Brill's model is shown in Table 3. It is apparent that the relative errors of pressure and temperature are 1.06% and 0.24%, respectively. Therefore, the Beggs-Brill's model is adopted in the following study.

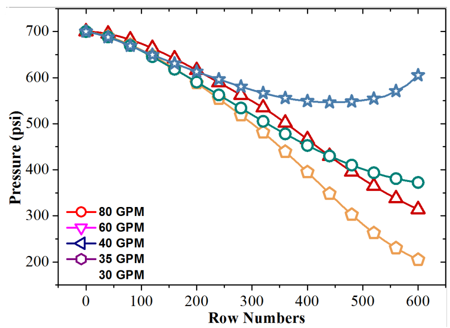
Table 2: physical property parameters used in the wellbore study

| Items | Description | Unit | Value |
|---|---|---|---|
| ae | geothermal gradient | $^\circ F/Km$ | 78 |
| aear | thermal diffusivity of the formation | $m^2/h$ | 0.00094 |
| kear | heat conductivity of the formation | $W/(m \cdot K)$ | 1.08 |
| kcem | heat conductivity of the cement | $W/(m \cdot K)$ | 1.047 |
| kp | heat conductivity of annulus tube | $W/(m \cdot K)$ | 52 |
| kp | heat conductivity of tube | $W/(m \cdot K)$ | 52 |
| egw | Outside surface emissivity of tube | 1 | 0.8 |
| kp | heat conductivity of heat-insulation tube | $W/(m \cdot K)$ | 0.06 |

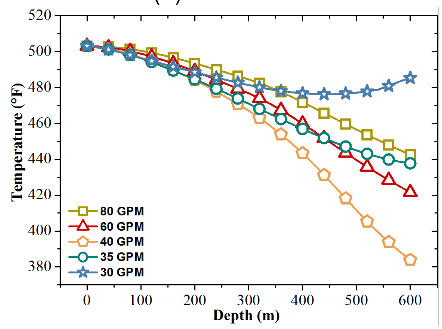
### 4.2. Sensitivity analysis for injection parameters

Previous sections describe, the method was used to analyze the thermal performance of the steam injection system. Most factors used in the numerical study are adjustable and exert great impact on the thermal performance of the system. Therefore, conducting a sensitivity analysis is necessary. Table 4 lists some factors considered in the analysis.

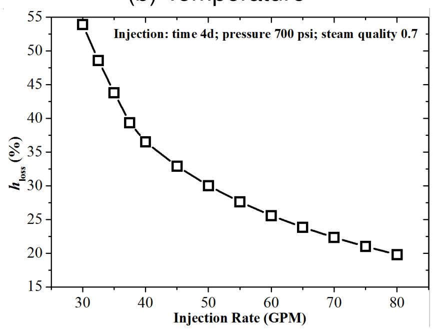
#### 4.2.1. Injection rate




(a) Pressure




(b) Temperature




(c) Percentage of heat loss

Figure 3: Effect of injection rate on wellbore thermal performance

Fig 3(a) presents the profiles of the wellbore pressure dis-

Table 3: Injection steam parameters

| Injection Rate(GPM) | Injection Pressure (psi) | Steam Quality | Injection Time(day) | Annulus media | Water Location(m) |
|---|---|---|---|---|---|
| 70 | 681 | 0.80 | 4 | Air/Water | 300 |

Table 4: Injection parameters for wellbore sensitivity analysis

| Injection Rate | Injection Pressure | Steam Quality | Injection Time | Water Location |
|---|---|---|---|---|
| **GPM** | psi | 1 | inch | m |
| **80** | 1100 | 0.90 | 4 | 450 |
| **70** | 1000 | 0.80 | 6 | 400 |
| **60** | 900 | 0.70 | 8 | 300 |
| **50** | 800 | 0.60 | 10 | 200 |
| **40** | 700 | 0.50 | 12 | 100 |
| **35** | 681 | 0.40 | 15 | 50 |
| **30** | 600 | 0.30 | 18 | 0 |

tributions versus the depth at different injection rates. When the injection rate is higher than 35GPM, the pressure decreases with the depth, and increases with the injection rate. When the injection rate is 35GPM or lower, the pressure along depth first decreases, then increases. This is because the gravity pressure gradient is dominated and trades off the frictional pressure gradient.

Fig 3(b) shows the profiles of wellbore temperature distributions. Similar tendency to pressure is exhibited for temperature.

Fig 3(c) indicates the effect of the injection rate on the percentage of heat loss. The figures demonstrate that the heat loss decreases with the increasing injection rate while the steam quality increases. In addition, the curves in both figures have turning points at 40GPM due to the change of the wellbore flow pattern.

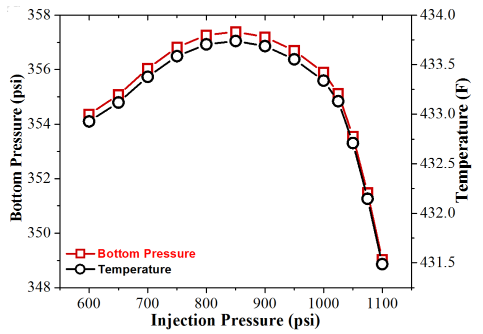
### 4.2.2. Injection pressure

Fig 4 shows the influence of injection pressure on the wellbore's thermal performance. As shown in In Fig 4(a), the steam temperature and pressure at the bottom hole increase until the injection pressure rises to 850 psi, then, they begin to decrease quickly with increasing injection pressure. The wellbore pressure drop is mainly determined by gravity pressure drop and frictional pressure drop. The potential energy change increases the steam pressure, whereas the frictional loss decreases the pressure. When the injection pressure is below 850 psi, the gravity pressure drop plays a major role, by causing a pressure increase. When the injection pressure is higher than 850 psi, the frictional pressure drop dominates, leading to a pressure decrease.

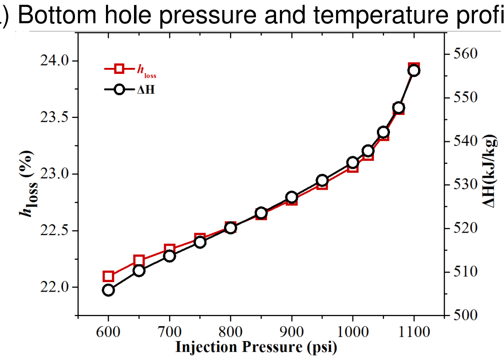
Fig 4(b) present wellbore heat loss versus the injection pressure. Rising the injection pressure increases the steam velocity and lower the liquid film thickness attached on the tube inner surface, which enhances the wellbore heat transfer. Therefore, with the increase of injection pressure, the steam quality at bottom hole decreases, and the wellbore heat loss increases.

### 4.2.3. Injection time

Fig 5(a) shows the impact of injection time on temperature and pressure in the bottom hole. Both pressure and temperature increase with injection time because the temperature




(a) Bottom hole pressure and temperature profiles




(b) Heat loss

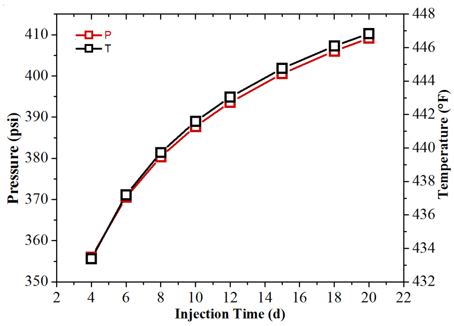
**Figure 4: Effect of injection pressure on wellbore thermal performance**

of the out surface of cement increases due to the decreases of temperature difference between out surface of cement and steam.

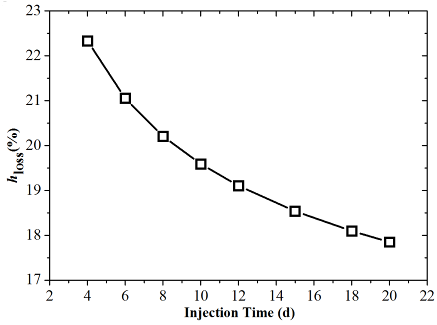
Fig 5(b) demonstrates the wellbore heat loss profile with time. The formation thermal resistance increases with injection time, resulting in the decrease of the heat flux between steam and formation. Therefore, the wellbore heat loss reduces and the steam quality increases.

### 4.2.4. Location of water in annulus

Fig 6 shows the influence of the water location in annulus on the wellbore thermal performance. Annulus media greatly impact the annulus heat transfer. Since the heat transfer coefficient of water is much higher than that of air, the wellbore heat loss increases linearly if water occupy more space in the annulus. When wellbore heat loss increases the steam tem-



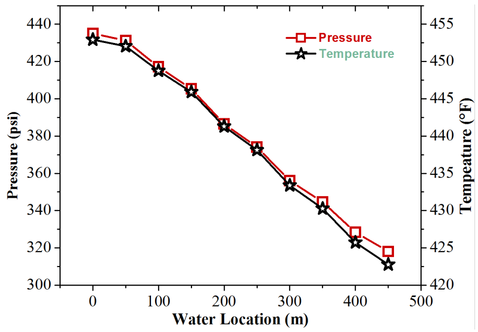

(a) Bottom hole steam quality profile



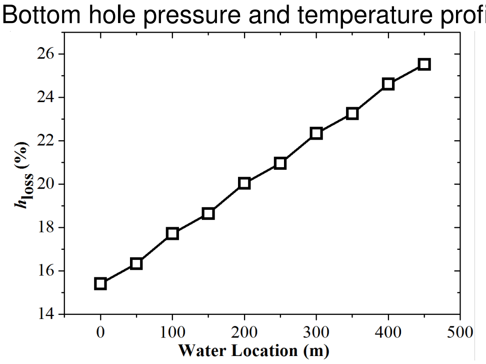

(b) Percentage of heat loss

Figure 5: Effect of injection time on wellbore thermal performance

perature, pressure and quality decrease correspondingly, as shown in Fig 6.




(a) Bottom hole pressure and temperature profiles




(b) Percentage heat loss

Figure 6: Effect of water location in annulus on wellbore thermal performance

## 5. Conclusion

A thermodynamic model was proposed in this study to improve the accuracy of thermodynamic parameter analysis, and to identify the main factors and their rules in affecting thermal efficiency. On the basis of proposed model, the influences of steam injection parameters on thermal efficiency were studied. The following conclusions could be drawn.

(1) On the basis of the proposed thermodynamic model, the data on the wellbore temperature and pressure distribution during the process of steam injection are analyzed. Compared with the test data, the oilfield data show relative errors of 1.06% and 0.24% for the pressure and temperature, respectively. This result confirms the high accuracy of the thermodynamic model.

(2) The location of the annulus water in the wellbore is the dominant factor affecting thermal efficiency, followed by steam injection rate and steam injection pressure. The results show that the dominant factors controlling thermal efficiency are water location and steam injection rate.

(3) An increase in the injection rate or the extension of the injection time can improve the thermal efficiency, whereas an increase in the steam injection pressure reduces the thermal efficiency.

A thermodynamic model that considers the effects of time and phase transformation in wellbore is proposed in this study. The established model improves the accuracy of the calculation of thermodynamic parameters in wellbore and clarifies the main factors affecting thermal efficiency. Moreover, the proposed model offers a certain reference value in optimizing steam injection parameters and improving thermal efficiency. Monitoring the thermodynamic parameters in the process of steam injection is difficult because the temperature of injected steam is usually as high as 5720 ℉ and the pressure is up to 1100Psi. Hence, additional field data can not be obtained. For future research, field feedback data should be continuously collected to perfect and correct the model.

## Acknowledgments

This work was supported by Shangdong Province Natural Science Foundation (ZR2016EEB34) and the Fundamental Research Funds for the Central Universities (16CX02002A).

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