Open Access Journal

Journal of Power Technologies 99 (2) (2019) 123–130

journal homepage:papers.itc.pw.edu.pl

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

Xuan Zhao[a,b], Chengcheng Niu[c], Jun Wang[c], Xiuxing Zhu[a,]

[a]*College of Pipeline and Civil Engineering, China University of Petroleum, Qingdao 266580, China*
[b]*SINOPEC International Petroleum Company Colombia Branch, Bogotá, Colombia*
[c]*SINOPEC Research Institute of Petroleum Engineering, Beijing 100101, China*

Abstract

Thermodynamic parameters in heavy oil thermal recovery wells form the basis for evaluating the thermal efficiency of steam injection. However, various factors in wellbores affect the variation law of thermodynamic parameters, hindering attempts to make an accurate description of them. A thermodynamic model of wellbores is proposed in this study which factors in the effects of time and phase change with a view to: (i) improving the accuracy of thermodynamic parameter analysis, and (ii) identifying the main factors and rules that govern thermal efficiency. 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 results of the analysis with the test data. Taking this approach, the influence of steam injection parameters on thermal efficiency was studied. The 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 main factor affecting thermal efficiency is water in the annulus of the wellbore, followed by the 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 extension of the injection time can improve thermal efficiency, whereas an increase in steam injection pressure reduces thermal efficiency. The proposed method provides good prospects for optimizing high efficiency steam injection parameters of heavy oil thermal recovery wells.

Keywords: thermal recovery well; thermal efficiency; phase change; parameter sensitivity

1. Introduction

There are abundant reserves of heavy oil, but extraction is hampered by 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 fluidity by injecting high-temperature steam into the formation. Steam injection is widely used in the thermal recovery of heavy oils, applying techniques such as steam-assisted gravity drainage [1–3], steam flooding [4] and cyclic steam stimulations [5, 6].

Steam injection and oil production involve heat loss because of the temperature difference between the fluid and the surrounding formation. Heat loss, in turn, decreases the efficiency of thermal recovery. Thus, there is a self-evident need to study the factors affecting heat loss from fluid to formation and to propose a new model. 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.

Researchers have carried out many studies on calculation methods for vapor parameters at certain depths and regarding the influence of the 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. Outstanding issues requiring urgent resolution are: how to improve the thermodynamic model by considering the influence of vari-

*Corresponding author
Email address: zhuxx99@126.com (Xiuxing Zhu)

ous factors in the wellbore, how to reduce calculation errors and how to identify the dominant factors of thermal efficiency.

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

2. State of the art

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 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. This method assumes constant temperature for a heat resource of infinite duration, which 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 a thermal recovery wellbore. This method assumes that the wellbore fluid is always saturated steam and 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 are 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 the heat source is constant, which is not found 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 the 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 the wellbore was regarded 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. Since it disregards phase change, Ramey's model cannot efficiently estimate the heat loss of multiphase flows.

The aforementioned studies were mainly directed at wellbore-reservoir flow and heat transfer models, which regard wellbore fluid as saturated steam without phase change over time. Few studies focused on a thermodynamic model that considers the influence of time and phase changes. The present study factors in the influences of time and phase change on high-temperature steam flow in the wellbore and proposes a theoretical model that includes governing equations and boundary conditions. In this model, Ramey and Setter's methods are used to calculate the heat loss of the wellbore, while the steam injection process is divided into two periods: (i) the steady heat transfer between the tube center and the outer surface of cement, and (ii) the heat transfer from the outer surface of the cement to the formation. Furthermore, 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 measured data. The results are then used to discuss the sensitivities of each factor and to clarify the dominant factors affecting thermal efficiency. The proposed model provides good prospects for optimizing 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 final section sets out the summary and conclusions.

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. When analyzing 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) Injection rate, pressure and steam quality at wellhead remain constant during the entire injection period.

(2) A 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.

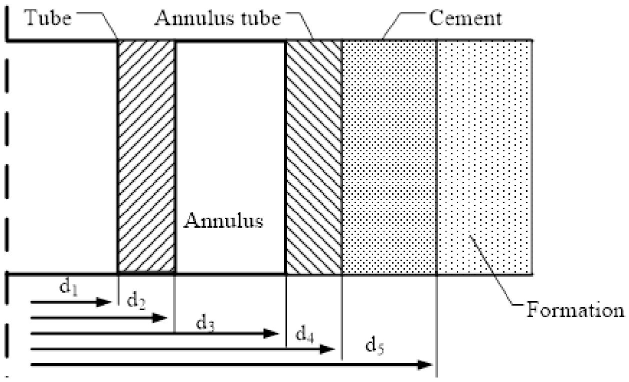


Figure 1: Wellbore structures

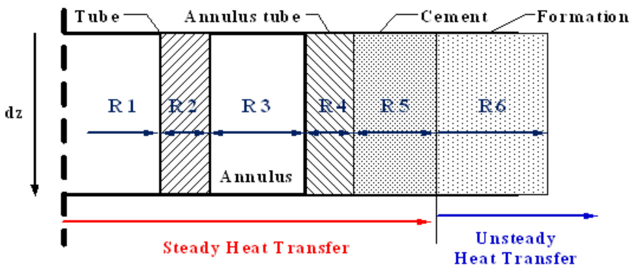


Figure 2: Thermal resistance model

(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 the well depth

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

3.1.1. Steady heat transfer between tube center and the outer surface of the 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 follows:

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

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 outside surface temperature, $^{\circ}F$; R is heat transfer resistance, $[W/(h \cdot m \cdot K)]^{-1}$. Thermal resistance R consists of the following five parts as shown in Fig. 2.

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 the wellbore, the unit depth heat loss of the wellbore can be calculated as follows:

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

Therefore, 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 the cement to the formation

The transient heat transfer in the formation causes an unsteady heat flux to the surrounding formation. The initial heat loss to the formation is sharp, but the heat loss and the temperature difference both decrease as the temperature of the formation 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, λ_e is the thermal conductivity of formation and $W/(m \cdot K)$; $f\,(\tau)$ is the transient heat conduction function, which can be calculated by Eq. 7 and 8.

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

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

Where a is the average thermal diffusivity coefficient and m^2/h; τ is the injection time.

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

The calculation procedures for heat transfer coefficient U_2 are as follows:

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

(2) Calculate hypothetical value U_2.

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

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

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

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

3.2. Calculation of wellbore pressure distribution

We use the Beggs-Brill Model to obtain accurate steam pressure distribution along the wellbore. For the Beggs-Brill two-phase flow model, the total pressure drop of the wellbore flow is caused by 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 gravitational acceleration; θ is the well angle from the horizontal; f_{tp} is the two-phase friction factor; ρ_m and v_m are density and velocity of multiple fluids, 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 a cross-sectional area of the inner tubing.

In the Beggs-Brill model, the flow pattern in the 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 ρ_L and ρ_g are densities of the liquid phase and gas phase in mixture and H_L is the liquid holdup fraction.

4. Results 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.

The relative errors between the experimental data and the data from the Beggs-Brill model are 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 model is adopted in the following study.

Table 1: 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

Table 2: Physical property parameters used in the wellbore study

Items	Description	Unit	Value
ae	geothermal gradient	$^\circ\mathrm{F}/Km$	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

The method set out above was used to analyze the thermal performance of the steam injection system. Most factors used in the numerical study are adjustable and exert a great impact on the thermal performance of the system. Therefore, a sensitivity analysis must be conducted. Table 4 lists some factors to be considered in the analysis.

4.2.1. Injection rate

Fig. 3(a) presents the profiles of the wellbore pressure distributions versus depth at various injection rates. When the injection rate is higher than 35 GPM, the pressure decreases with depth and increases with the injection rate. When the injection rate is 35 GPM or lower, the pressure along the 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. A similar tendency re. 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 40 GPM due to the change in 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 Fig. 4(a), the steam temperature and pressure at the bottom hole increase until the injection pressure rises to 850 psi, then, they both begin to decrease quickly with increasing injection pressure. The wellbore pressure drop is mainly determined by gravity pressure drop and frictional pressure drop. The change in potential energy increases the steam pressure, whereas the frictional loss decreases the pressure. When the injection

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, GPM	Injection Pressure, psi	Steam Quality	Injection Time, inch	Water Location, 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

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) presents wellbore heat loss versus injection pressure. Rising injection pressure increases the steam velocity and lowers the liquid film thickness attached to the tube inner surface, which enhances the wellbore heat transfer. Therefore, with the increase of injection pressure, the steam quality at the 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 of the outer surface of the cement increases due to the decrease in temperature difference between the outer surface of the cement and the steam.

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

4.2.4. Water in the annulus

Fig. 6 shows the influence of water in the annulus on the thermal performance of the wellbore . 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 occupies more space in the annulus. When wellbore heat loss increases the steam temperature, pressure and quality decrease correspondingly, as shown in Fig. 6.

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 the proposed model, the influences of steam injection parameters on thermal efficiency were studied. The following conclusions could be drawn.

(1) Using the proposed thermodynamic model, the data on the wellbore temperature and pressure distribution during the process of steam injection were 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) Annulus water in the wellbore is the dominant factor affecting thermal efficiency, followed by the steam injection rate and steam injection pressure. The results show that the dominant factors controlling thermal efficiency are water and the steam injection rate.

(3) An increase in the injection rate or extension of the injection time can improve thermal efficiency, whereas an increase in steam injection pressure reduces 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 the injected steam is usually as high as 5720℉ and the pressure is up to 1100 Psi. Hence, additional field data cannot 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).

References

[1] Z. Khansari, P. Kapadia, N. Mahinpey, I. D. Gates, A new reaction model for low temperature oxidation of heavy oil: experiments and numerical modeling, Energy 64 (2014) 419 – 428.

[2] K. Miura, J. Wang, An analytical model to predict cumulative steam/oil ratio (csor) in thermal-recovery sagd, Journal of Canadian Petroleum Technology 51 (4) (2012) 268–275.

[3] Y. Yang, S. Huang, Y. Liu, Q. Song, S. Wei, H. Xiong, A multistage theoretical model tocharacterize the liquid level during steam-assisted-gravity-drainage process, SPE Journal 22 (1) (2017) 327–338.

[4] M. H. B., C. A. N., S. A. O., T. R. B., Heat transfer measurement in a three-phase direct-contact condenser under flooding conditions, Applied Thermal Engineering 95 (2016) 106–114.

[5] F. Sun, C. Li, L. Cheng, S. Huang, M. Zou, Q. Sun, X. Wu, Production performance analysis of heavy oil recovery by cyclic superheated steam stimulation, Energy 121 (2017) 356–371.

[6] J. Sandler, G. Fowler, K. Cheng, A. R. Kovscek, Solar-generated steam for oil recovery: Reservoir simulation, economic analysis, and life cycle assessment, Energy Conversion and Management 77 (2014) 721–732.

[7] B. Han, W. Cheng, Y. Nian, C. Wang, L. Yang, Analysis for flow and heat transfer of thermal recovery well with steam and multiple thermal fluids injection., Journal of Engineering Thermophysics 37 (2016) 1867–1874.

[8] B. Zhang, Research and application of wellbore heat insulation technology for heavy oil thermal recovery, Chemical Engineering & Equipment 32 (9) (2012) 98–100.

[9] R. J. E. O, S. A. O, M. C. W. S. P, C. L. G, B. U. J. B, Flow rates measurement and uncertainty analysis in multiple-zone water-injection wells from fluid temperature profiles, Sensors 16 (7) (2016) 1077–1083.

[10] C. Alimonti, E. Soldo, D. Bocchetti, D. Berardi, The wellbore heat exchangers: A technical review, Renewable Energy 123 (2018) 353–381.

[11] X. Yang, X. Zhang, Research on unsteady state heat transfer process of steam injection wellbore in thermal production well, Technology & Development of Chemical Industry 46 (6) (2017) 48–51.

[12] F. Sun, Y. Yao, X. Li, An equivalent evaluation model for heat loss of superheated steam flow in offshore parallel dual-tubing wells, Journal of Beijing Institute of Petrochemical Technology 25 (6) (2017) 15–24.

[13] C. Guo, M. Xu, S. Xue, F. Qu, Process analysis of unsteady heat transfer and fluid flow during steam injection via horizontal wells, Journal of China University of Petroleum (Edition of Natural Science) 40 (4) (2016) 116–120.

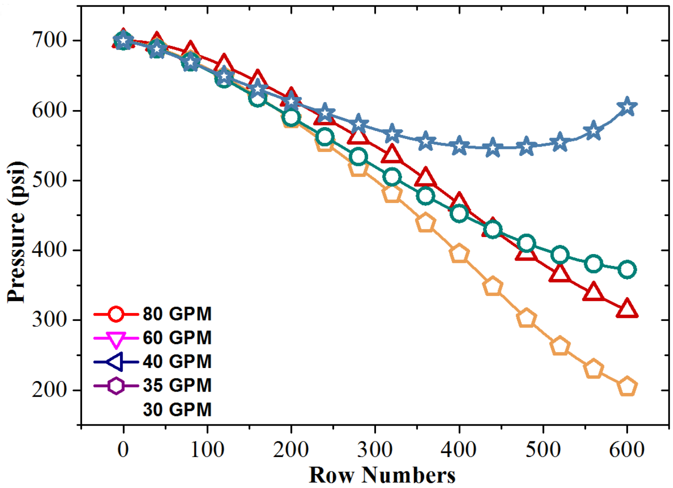
[14] H. Wang, W. Yan, J. Sun, J. Deng, Y. Cao, L. Zhang, X. Yan, J. Gao, H. Pan, H. Liu, Numerical simulation and parameter optimization for heat injection progress of heavy oil thermal recovery wells, China Offshore Oil and Gas 28 (5) (2016) 104–109.

[15] R. Lin, S. Qi, W. Shen, J. Yang, X. Wang, H. Wang, S. Wang, Z. Shu, Study on parameters of steam injection in SAGD circulating preheating section, Journal of China University of Petroleum (Edition of Natural Science) 42 (1) (2018) 134–141.

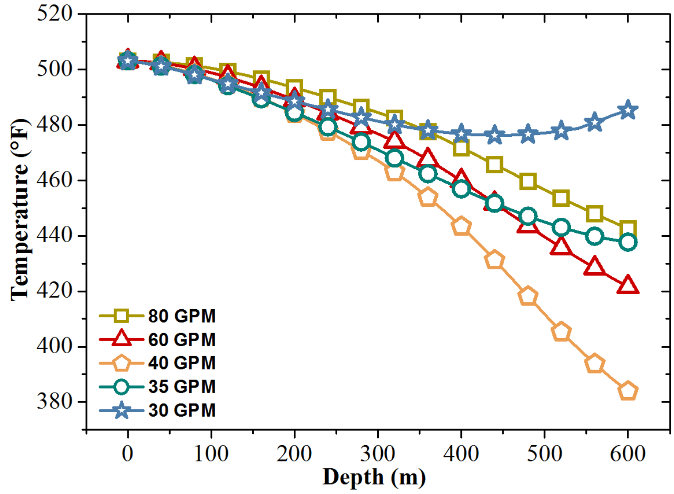
[16] H. Chen, M. Li, Q. Di, C. Liu, Numerical simulation of the outflow performance for horizontal wells with multiple steam injection valves, ACTA Petrolei Sinica 38 (6) (2017) 696–704.

[17] H. Shu, X. Sun, Influence of gravitational potential energy on thermodynamic calculation of steam injection well, Journal of Chongqing University of Technology 29 (5) (2015) 22–26.

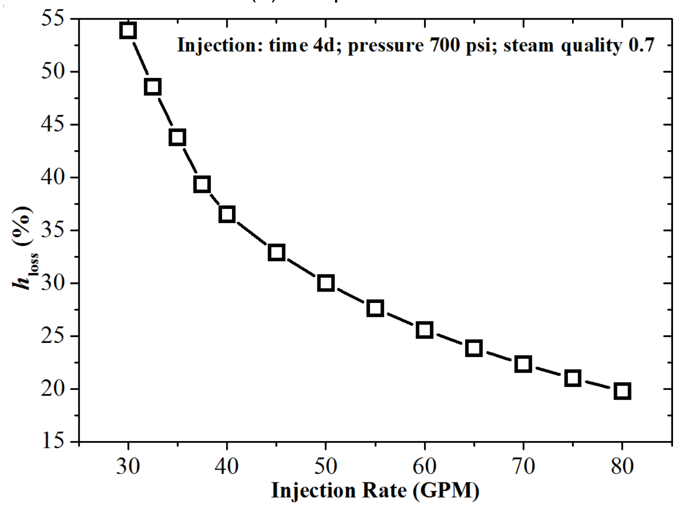
[18] H. J. Jr. Ramey, Wellbore heat transmission, Journal of Petroleum Technology 14 (2013) 427–435.



(a) Pressure

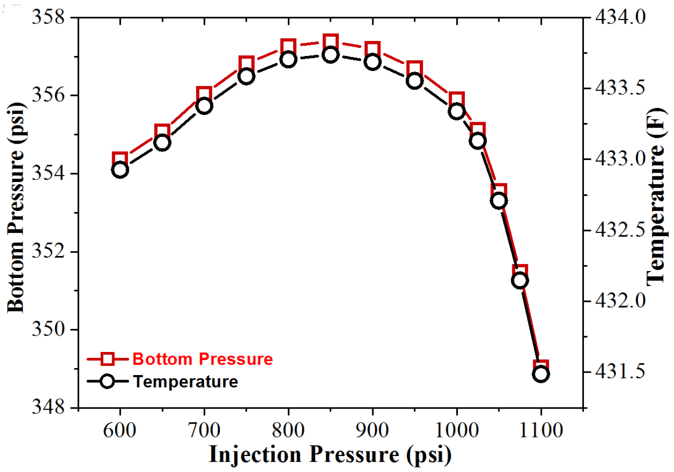


(b) Temperature

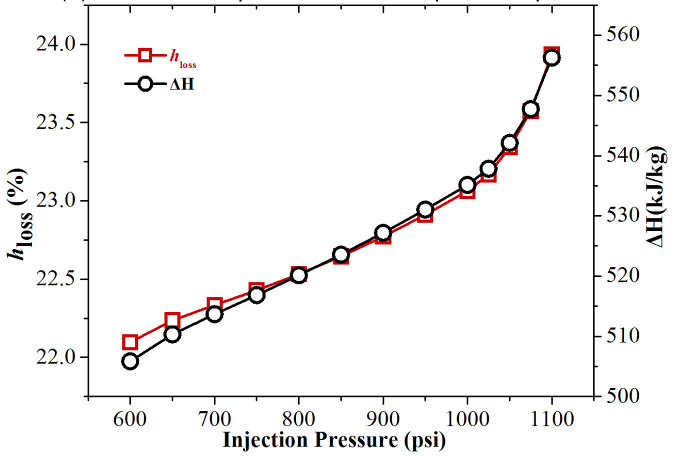


(c) Percentage of heat loss

Figure 3: Effect of injection rate on wellbore thermal performance

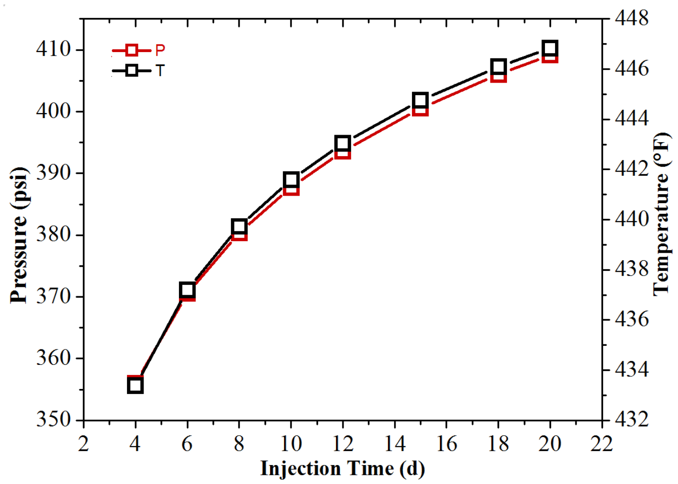


(a) Bottom hole pressure and temperature profiles

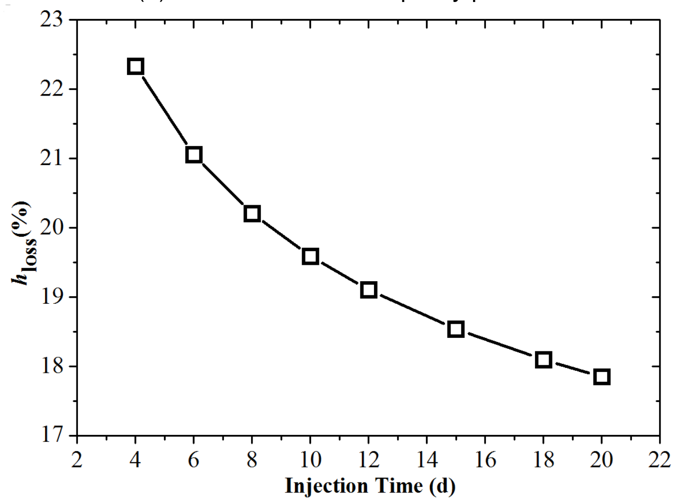


(b) Heat loss

Figure 4: Effect of injection pressure on wellbore thermal performance

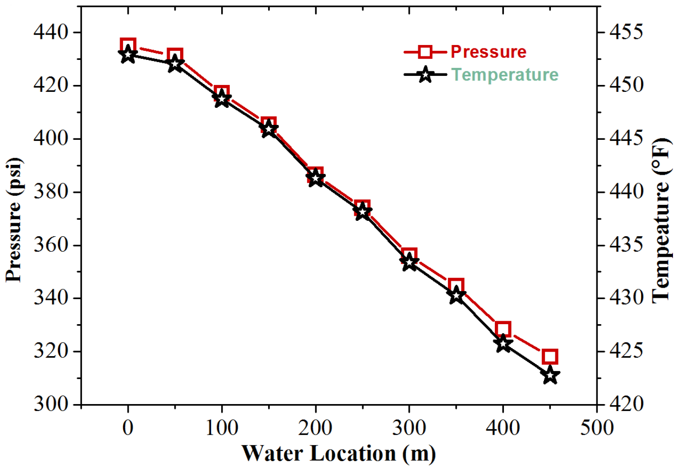


(a) Bottom hole steam quality profile

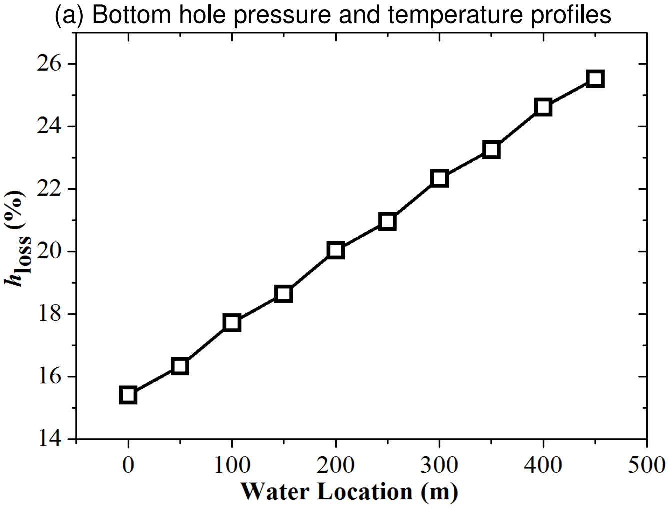


(b) Percentage of heat loss

Figure 5: Effect of injection time on wellbore thermal performance



(a) Bottom hole pressure and temperature profiles



(b) Percentage heat loss

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