Science & Technology Development Journal – Engineering and Technology 2024, ():1-10

Open Access Full Text Article

Research Article

Assessment and Analysis of Gas Flow Temperature in Gas Production: A Case Study in VietNam

Ta Quoc Dung[1,2,*], Do Duc Anh[1,2]

ABSTRACT

In this study, a comprehensive model is introduced for predicting fluid flow temperature in gas wells, integrating the mechanical energy balance equation with convection, conduction, and radiation modes of heat transfer. The pressure calculation process is enhanced by the incorporation of the Gray correlation. The key findings reveal a remarkable consistency between the proposed model and measured data, demonstrating deviations of only 0.34% and 0.63% for pressure loss prediction and temperature distribution along the borehole, respectively. Nodal analysis emerges as a valuable technique, enabling precise calculations of pressure and temperature in the wellbore and reservoir flow. Through sensitivity analysis, the study evaluates the impact of various factors, such as tubing size and production rate, on temperature and pressure in the wellbore, considering both wellhead and bottom hole locations. Conclusions drawn from the sensitivity analysis underscore the significant influence of changes in flow rate on temperature along the production tubing, with an increase from 20 to 100 mmscf/d resulting in a temperature rise from 150 to 300 ^oF. Tubing size is identified as a crucial determinant in pressure loss calculations, showing a slight decrease in wellhead temperature from 281 to 252 ^oF when increasing tubing size from 3 to 5.5 inches at a fixed production rate. However, variations in tubing diameter exhibit substantial effects on temperature and pressure under different operating production rates.

Key words: Temperature, Pressure, Nodal Analysis, Temperature Model, Gas Well Deliverability

[1]*Faculty of Geology and Petroleum, Ho Chi Minh City University of Technology (HCMUT), Ho Chi Minh City, Vietnam*

[2]*Vietnam National University Ho Chi Minh City, Vietnam*

Correspondence

Ta Quoc Dung, Faculty of Geology and Petroleum, Ho Chi Minh City University of Technology (HCMUT), Ho Chi Minh City, Vietnam

Vietnam National University Ho Chi Minh City, Vietnam

Email: tqdung@hcmut.edu.vn

History

- Received: 18-10-2023
- Accepted: 05-3-2024
- Published Online:

DOI :

INTRODUCTION

The control of production pressure within the production tubing is integral to facilitating upward flow during the production process. Concurrently, temperature regulation is crucial for managing the production volume. Elevated pressure and reduced temperature conditions can induce two-phase flow, resulting in substantial damage to the system. While temperature variations during gas flow may not directly influence pressure data, they do impact parameters like the Z factor and gas viscosity, thereby introducing errors in pressure calculations. Consequently, there has been a notable focus on studying temperature changes within the production tubing of gas wells.

Alves et al. (1992) [1] underscored those prior correlations developed by researchers aimed at simplifying calculations often yielded unrealistic estimations for more general scenarios. To address this limitation, they proposed a method that incorporates fewer restrictive assumptions. Their approach is applicable to pipelines, production, and injection wells, accommodating single- or two-phase flow, and encompassing a broad range of inclination angles from horizontal to vertical, utilizing both compositional and black-oil fluid models.

This research centers on examining the temperature model of well WELL 1X in the BlackCat gas field, situated in the Cuu Long basin, Vietnam. To achieve a more comprehensive computation of fluid temperature distribution within the production pipe for deep water production, an analysis model introduced by Alves et al. is employed. Additionally, Gray correlation is utilized to estimate pressure losses throughout the wellbore. Subsequently, a production evaluation and well performance analysis, employing Nodal Analysis, are conducted, considering various changes in tubing size and flow rate [2,3].

By employing these methodologies and techniques, a more precise understanding of the temperature profile and its impact on overall well performance can be achieved, particularly in the context of deep-water production scenarios in the BlackCat gas field [4].

METHODOLOGY

Heat transfer mechanism

Figure 1 shows the thermal exchange between hydrocarbon fluid and the inner wall of the tubing predominantly transpires through forced convection. Furthermore, heat is conducted through the tubing wall, casing wall, and the cement sheath [4]. Within the annular

Cite this article : Dung T Q, Anh D D. **Assessment and Analysis of Gas Flow Temperature in Gas Production: A Case Study in VietNam**. *Sci. Tech. Dev. J. – Engineering and Technology* 2024; ():1-10.

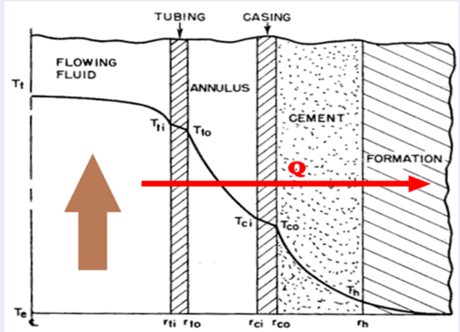

Figure 1: Wellbore heat transfer and temperature distribution[5]

space, conventionally occupied by completion fluids between the casing and tubing, heat transfer involves contributions from both radiation and natural convection. This section will intricately explore the particulars of each mechanism of heat loss from the fluid to the surrounding formation, drawing upon insights elucidated in the work of Willhite (1967)[6].

Heat conductive transfer

The heat transfer arising from conduction can be characterized using Fourier's equation in radial coordinates. A visual representation of the conduction-based heat transfer is depicted in Figure 2, as outlined in the work of reference[5].

$$Q = 2\pi r \triangle L k \frac{\partial T}{\partial r} \quad (1)$$

By taking the integration of (1), heat transfer is expressed:

$$Q = \frac{2\pi k (T_i - T_0) \triangle L}{\ln\left(\frac{r_0}{r_i}\right)} \quad (2)$$

Due to the elevated thermal conductivity and the relatively diminutive radial separation between flowing fluids and the borehole wall, heat transfer in the adjacent walls is typically regarded as being in a steady state[7].

$$Q = \frac{(2\pi k_t (T_{ti} - T_{to}) \triangle L)}{\ln\left(\frac{r_{to}}{r_{ti}}\right)} \quad (3)$$

Casing wall:

$$Q = \frac{(2\pi k_{ca} (T_{ci} - T_{co}) \triangle L)}{\ln\left(\frac{\tau_{co}}{\tau_{ci}}\right)} \quad (4)$$

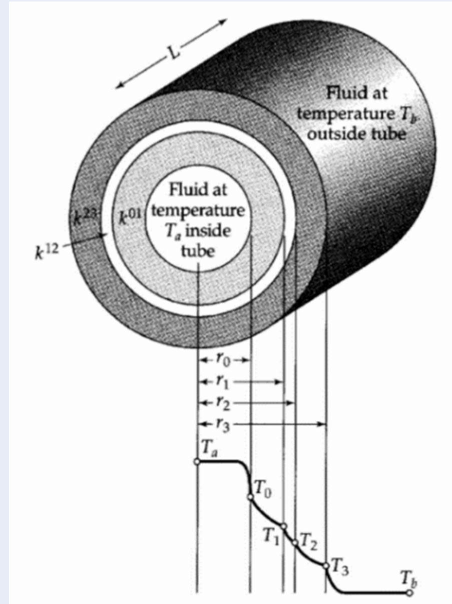

Figure 2: Heat conduction through cylindrical tubing[5]

Cement sheath:

$$Q = \frac{2\pi k_{cement} (T_{co} - T_h) \triangle L}{\ln\left(\frac{r_b}{r_{co}}\right)} \quad (5)$$

The conveyance of heat into the adjacent rock transpires via heat conduction, constituting a transient process. Given the typically substantial volume of rock, approaching infinity, the attainment of steady-state conditions in this context may extend over periods of several months or even years. The transient radial heat conduction equation is employed to articulate this process and is formulated as follows:

$$Q = \frac{2\pi k_e (T_h - T_e) \triangle L}{f(t)} \quad (6)$$

The determination of the dimensionless time function can be ascertained through the work of Hasan and Kabir[5].

$$f(t) = 1.1281\sqrt{t_D}\left[1 - 0.3\sqrt{t_D}\right] \ (t_D \leq 1.5) \quad (7)$$

$$f(t) = [0.4063 + 0.5 \ln(t_D)] \left[1 + \frac{0.6}{t_D}\right] (t_D > 1.5) \quad (8)$$

Convective and Radiative heat transfer

Annulus fluid

The expression for radial heat due to natural convection and radiation of the fluid within the annulus is articulated as follows:

$$Q = 2\pi r_{ci}\left(h_{c,an} + h_{r,an}\right)\left(T_{to} - T_{ci}\right)\triangle L \tag{9}$$

The suggested correlation for the estimation of the convective heat coefficient within the annulus is presented by Dropkin and Sommerscales. The formula they propose is as follows:

$$h_{c,an} = \frac{0.049\left(GrPr\right)^{\frac{1}{3}} Pr^{0.074} k_{an}}{r_{to}\ln\left(\frac{r_{ci}}{r_{to}}\right)} \tag{10}$$

The flow regime in natural convection is determined by the dimensionless Grashof number, expressed as follows:

$$Gr = \frac{g\rho_{an}^{2}\beta\left(T_{to} - T_{ci}\right)\left(r_{ci} - r_{to}\right)^{3}}{\mu_{an}^{2}} \tag{11}$$

The Prandtl number in equation (10) can be defined as follows::

$$Pr = \frac{\mu_{an} c_{p_{an}}}{k_{an}} \tag{12}$$

The calculation of the heat transfer coefficient for radiation within the annulus can be derived using the Stefan-Boltzmann law applied to a concentric annulus:

$$h_{r,an} = \frac{\sigma\left(T_{to}^{2} + T_{ci}^{2}\right)\left(T_{to} + T_{ci}\right)}{\frac{1}{r_{to}} + \frac{r_{to}}{r_{ci}}\left(\frac{1}{r_{to}} - 1\right)} \tag{13}$$

Tubing fluid

The expression for radial heat due to forced convection within the tubing is as follows:

$$Q = 2\pi r_{ti}\ h_{c,f}\left(T_f - T_{ti}\right)\triangle L \tag{14}$$

$h_{c,f}$ These mathematical expressions can be utilized for the calculation:

$$h_{c,f} = \frac{k_f}{2r_{ti}} Nu \tag{15}$$

$$Nu = 0.023\left(Re\right)^{0.8}\left(Pr\right)^{\frac{1}{3}} \tag{16}$$

The Prandtl number, denoted as Pr, can be determined by substituting the relevant properties of the tubing fluid into equation (12).

Overall Heat Transfer Coefficient

The radial heat transfer transpires between the wellbore fluid and the formation, surmounting various resistances as illustrated in Figure 1. This process can be expressed as follows:

$$Q = 2\pi r_{to} U_{to}\left(T_f - T_h\right)\triangle L \tag{17}$$

As previously mentioned, the limited radial separation between the flowing fluids and the borehole wall typically renders the heat transfer process as steady state. Consequently, the heat flowing through each element illustrated in Figure 1 is equalized. Through this analysis, the combination of equations (3), (4), (5), (9), and (14) yields the comprehensive heat transfer equation.

$$U_{to} = r_{to}^{-1}\Bigg[\frac{1}{r_{ti}h_{c,f}} + \frac{\ln\left(\frac{r_{to}}{r_{ti}}\right)}{k_t} + \frac{1}{r_{ci}\left(h_{c,an} + h_{r,am}\right)} + \frac{\ln\left(\frac{r_{co}}{r_{ci}}\right)}{k_c} + \frac{\ln\left(\frac{r_h}{r_{co}}\right)}{k_{cement}}\Bigg]^{-1} \tag{18}$$

Several acceptable assumptions can be made to simplify equation (18). The high heat transfer coefficient of the fluid results in Tf being approximately equal to Tti. Additionally, the substantial thermal conductivity of metals, along with the relatively thin tubing and casing walls, permits the neglect of resistances associated with these elements. Consequently, equation (18) can be simplified to:

$$U_{to} = r_{to}^{-1}\left[\frac{1}{r_{ci}\left(h_{c,an} + h_{r,an}\right)} + \frac{\ln\left(\frac{T_h}{T_{co}}\right)}{k_{cement}}\right]^{-1} \tag{19}$$

Temperature Model

The derived equation for the temperature profile is founded on the principles of mass conservation, momentum, and energy balance within a differential control volume of a pipe. The temperature formulation proposed by Alves et al.[1] can be represented as follows:

$$\frac{dT_f}{dL} = -\frac{\left(T_f - T_c\right)}{A} - \frac{g\cos\left(\theta\right)}{c_p g_c j} - \phi \tag{20}$$

$$A = \frac{c_p w}{U_{to}\pi r_{to}} \tag{21}$$

$$\phi = \frac{v}{c_p g_c j}\frac{dv}{dL} - \eta\frac{dP}{dL} \tag{22}$$

Pressure-gradient calculating for gas well performance.

The equation describing the pressure gradient for gas flow within a pipe is conventionally articulated to represent the total pressure loss [5,6].

$$\frac{dp}{dz} = \frac{f\rho_n v_m^2}{2d} + \frac{g_c}{g}\rho_s \sin(\theta) \qquad (24)$$

f: friction number.

d: tubing inside diameter, ft.

ρn: mixture average density of liquid and gas phase, lbm/ft3

ρs: slip mixture density of liquid and gas phase lbm/ft3.

vm: mixture average velocity, ft/sec.

Nodal analysis

Nodal analysis constitutes a systematic methodology employed in the optimization of oil and gas wells. This approach entails a thorough examination of the entire producing system, allowing for a meticulous evaluation of each component. Whether applied to individual components within a producing well or multiple wells within a production system, nodal analysis seeks to optimize these elements to attain the desired flow rate. Through the consideration of the characteristics and interactions of various components in the system, nodal analysis facilitates the identification of opportunities for improvement and the implementation of effective optimization strategies [8].

In the analysis of the production system, a comprehensive consideration of all pertinent components is undertaken, commencing from the static reservoir pressure, and extending to the separator. Figure 3 delineates a production system, emphasizing distinct nodes within the red circle, and provides estimations of pressure losses for each component. The central focus of this investigation revolves primarily around wellbore nodal analysis, an approach that amalgamates reservoir inflow and wellbore lift capabilities. This integration is achieved by intersecting the Inflow Performance Relationship (IPR) and Tubing Performance Relationship (TPR) curves on a pressure and production rate plot, facilitating the prognostication of operating flow rates [9].

Moreover, sensitivity evaluations are conducted to optimize production or identify potential issues by scrutinizing the effects of varying parameters.

Inflow Performance:

The Inflow Performance Relationship (IPR) elucidates the correlation between the producing bottomhole pressures of a well and the corresponding production rates, under a specified reservoir condition. It offers insights into how the well's productivity varies with changing bottomhole pressures [3].

Tubing Performance:

The Tubing Performance Relationship (TPR) delineates the fluid's performance as it traverses through the tubing in the borehole [8]. This relationship generates a plot of the bottomhole pressure against the corresponding flow rate. In constructing this performance model, it is imperative to account for variations in pressure and temperature to maintain a stable flow rate. Given the consequential alterations in the flow's independent properties, the black oil model emerges as a valuable tool in addressing this issue and faithfully representing the fluid's behavior in the wellbore [8].

RESULTS AND DISCUSSION

In this section, the veracity of the proposed methodology is substantiated through a comparative analysis between the predicted model and actual field data acquired from gas well WELL 1X in the BlackCat gas field. The assessment of vertical lift performance is conducted by employing the Gray correlation with the Prosper software, which facilitates the derivation of a comparable result for the operating point in contrast to the curve derived using a temperature model. This comparative analysis serves to evaluate the precision and efficacy of the proposed approach. Furthermore, sensitivity studies will be undertaken to scrutinize the ramifications of variations in parameters on the assessment of gas well performance. Through the exploration of diverse parameter scenarios, a comprehensive comprehension of the factors influencing gas well performance can be attained.

Well data acquisition and analysis

Well deviation survey

Prior to simulating field cases and conducting sensitivity analyses, data acquisition and analysis represent pivotal preparatory steps. Figure 4 furnishes a comprehensive overview of the well's depth profile, denoting its extension to a total measured depth (MD) of 13,418 ft and a total vertical depth (TVD) of 12,731 ft. The production tubing encompasses the entire length of 13,418 ft MD, while the bottom hole registers a vertical depth of 12,731 ft. Positioned at a depth of 659 ft TVD is a 4 1/2" downhole safety valve located at the well's summit. The well comprises 13 3/8" and 9 5/8" casing sections, with shoe locations at 6,662 ft MD and 10,329 ft MD, respectively.

Drilled in a vertical orientation from the surface to a depth of 5,900 ft, the well subsequently transitions

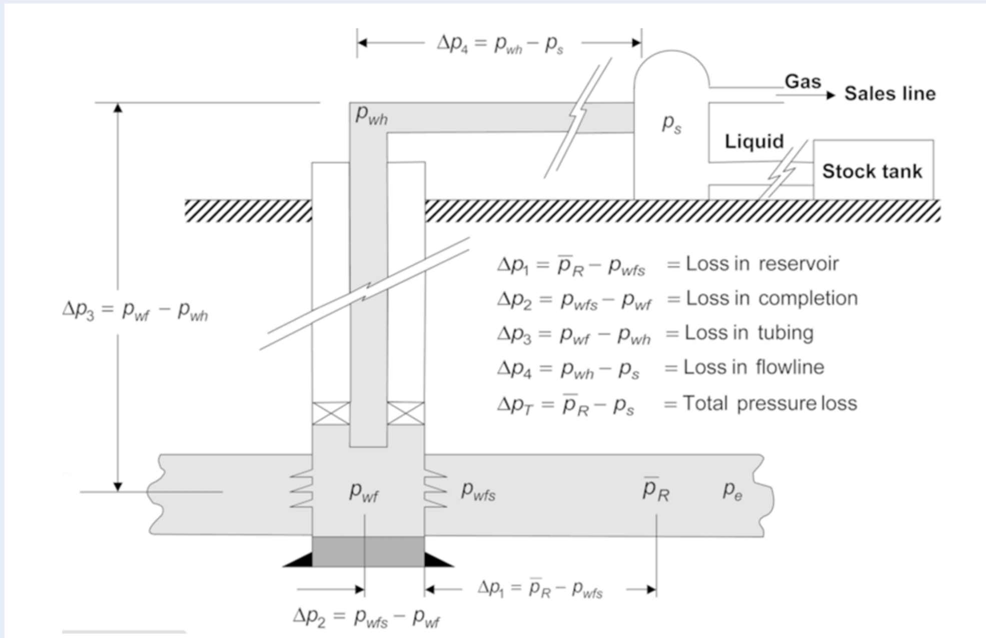

Figure 3: Common node at different locations in the system [8]

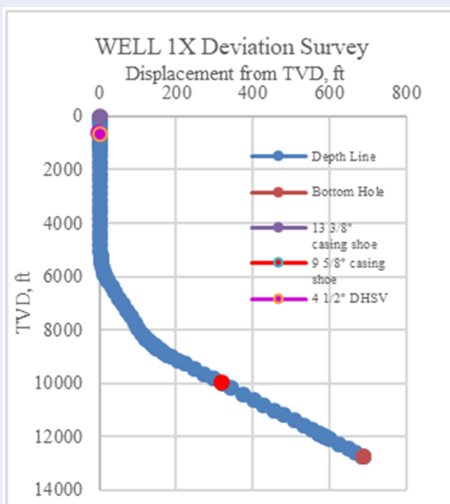

Figure 4: Gas well WELL 1X schematic

into horizontal drilling towards the bottom hole. The inclination angle fluctuates between 2° and 20° concerning the vertical axis, indicative of the alteration in drilling direction.

These delineated details furnish the requisite contextual information for the subsequent simulation endeavors, field case analyses, and sensitivity assessments pertaining to the well's performance.

Well data input

This study examines data extracted from WELL 1X within the BlackCat gas field, located in Vietnam. The data comprises various parameters pertaining to the well's information [Table 1], Fluid data [Table 2] and Reservoir data [Table 3], as outlined below.

Methodology

Coupling algorithm: In the coupling algorithm, two levels of sophistication can be employed when amalgamating the heat balance and mechanical energy balance equations to concurrently compute pressure and temperature changes [2]. Achieving convergence on both pressure and temperature within a specified pipe length increment necessitates the implementation of a double-iterative procedure, as illustrated in Figure 5.

Temperature profile of gas well WELL 1X

In general, a favorable correspondence is observed between the calculated and measured temperature profiles from the wellhead to a depth of 8,000 ft, as illustrated in Figure 6. However, discernible discrepancies emerge in the lower section of the well, specifically spanning from 8,100 ft to the bottom hole, as depicted in Figure 7. This incongruity can be ascribed to the presence of downhole equipment influenced by heat conductive mechanisms, which, if not duly considered, may introduce errors in the calculations.

Table 1: Well data input data

Well Information		
Well head pressure	1890	psig
Well head temperature	268	oF
CGR	0.0003	bbls/mmscf
Gas flow rate	55.5	MMscf/day

Table 2: Fluid data of gas well WELL 1X

Gas composition (%)			
N2	0.08	iC4	1.32
Co2	0.07	nC4	2.14
H2S	0	iC5	0.91
C1	70.5	nC5	1.01
C2	9.11	nC6	1.3
C3	1.32	C6+	8.23

Table 3: Reservoir data for gas well WELL 1X

Pr (psi)	7500
Tr (^oR)	810
Thickness (ft)	300
Permeability (mD)	2
Rw, ft	0.25
Re, ft	2979
Skin factor	2
D, non – Darcy flow factor	0.00006

The noted disparities in temperature data underscore the significance of accounting for the impact of heat conductive mechanisms on downhole equipment. This underscores the imperative for more precise models that incorporate these effects, ensuring enhanced temperature predictions and more dependable evaluations of well performance.

The fluid temperature is initially determined by the bottom hole temperature, which is equivalent to the formation heat as shown in Figure 8. Subsequently, heat is transferred outward through the annulus and casing in a horizontal direction, leading to a decrease in temperature. The annulus fluid is disregarded, and as air occupies the annulus, which possesses a relatively low thermal conductivity, the heat transfer from the inside and outside of the casing becomes approximately equal.

Pressure profile of gas well WELL 1X

The application of Gray correlation to determine pressure gradients yields highly accurate pressure values when compared to measured data as shown in Figure 9. The analysis employed identical temperature profile values. Conversely, the model lacking a temperature component exhibits a significant deviation from the measured data, indicating a lack of confidence in its accuracy. In contrast, the temperature model, which incorporates the pressure model, closely aligns with the measured data, demonstrating its reliability. Consequently, this integrated model can be effectively utilized.

The significance of using temperature data to predict pressure at bottom hole is further emphasized by the findings in Figure 10 and Table 4. The temperature profile derived from Prosper, which calculates gas temperature based on surrounding temperature and utilizes a simple linear interpolation method

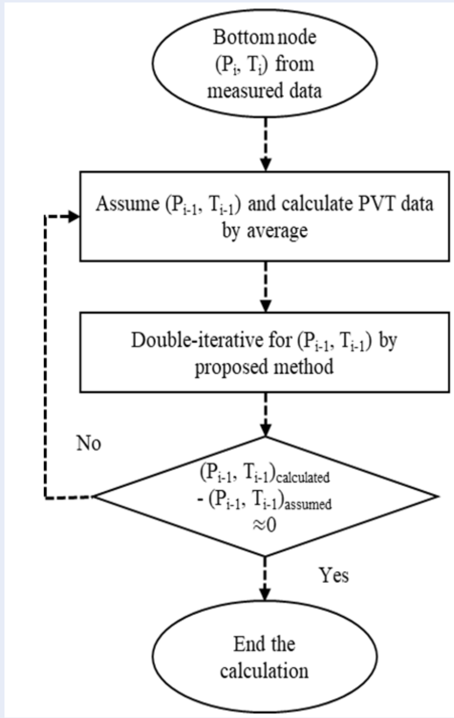

Figure 5: General workflow illustration

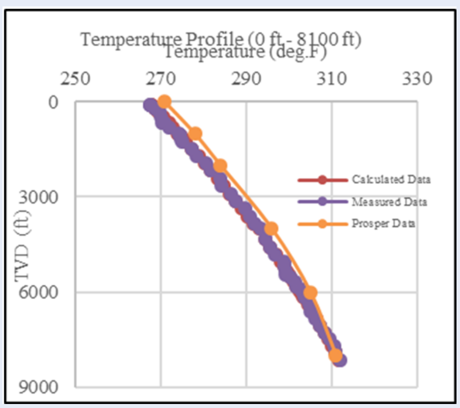

Figure 6: Predicted with Measured temperature (0-8100 ft)

to compute bottom hole pressure, demonstrates low accuracy when compared to measured data. Consequently, it is recommended to replace the linear interpolation approach with a more comprehensive heat transfer analysis that incorporates relevant heat mechanisms. This enhancement will lead to improved accuracy in temperature predictions and subsequent pressure calculations.

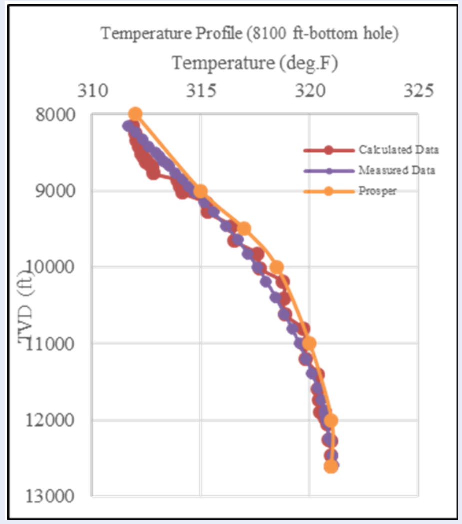

Figure 7: Predicted and Measured temperature (8100 ft-Bottom hole)

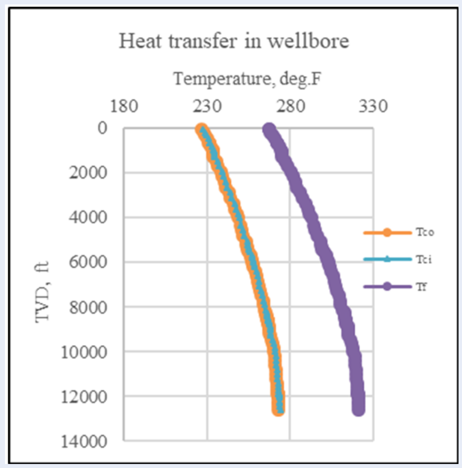

Figure 8: Heat transfer from tubing to casing

Sensitivity analysis

Effect of gas flow rate on the wellhead temperature.

In any production scenario, it is imperative for the wellhead temperature to be lower than that at the bottom hole. Referring to Figure 11, if the bottom hole temperature is maintained at a constant value of 321°F, with a gas production rate of 55 mmscf/day, the wellhead temperature is calculated to be 268°F. This observation suggests that when gas flows rapidly to the wellhead, temperature loss is minimized due to the limited convection within the production tubing. Conversely, at low production rates, significant heat

Table 4: Bottom hole pressure of gas well WELL 1X with different Temperature profiles.

Model	Pressure, psi
General temperature model	5083
Measured Data	5066
Linear Interpolation Temperature Data	4956
Software (Prosper)	4910

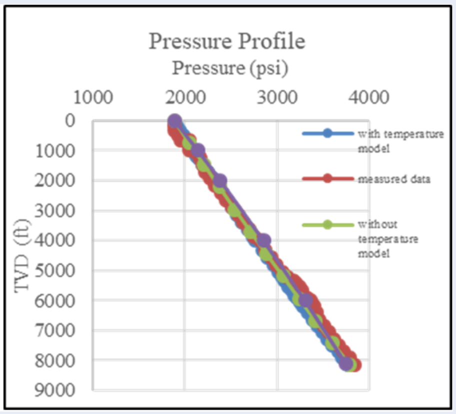

Figure 9: Pressure profile from 0 ft – 8100 ft

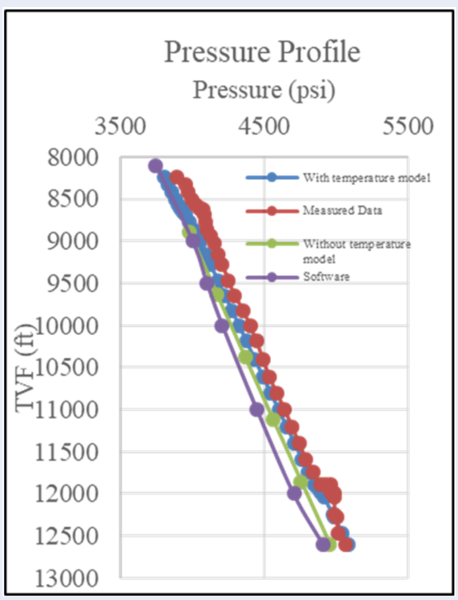

Figure 10: Pressure profile from 8100 ft – bottom hole

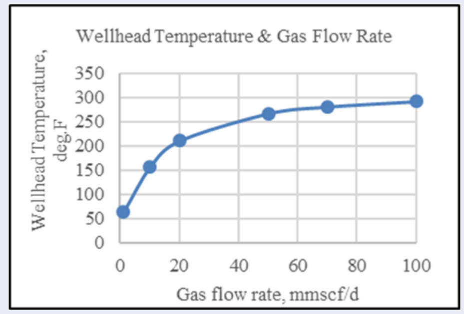

Figure 11: Effect of flowrate on well head temperature of WELL 1X

transfer to the surrounding environment results in a lower wellhead temperature.

Effect of tubing size on the temperature

It is imperative to acknowledge that alterations in tubing size can induce variations in the operating production. Consequently, for a comprehensive analysis, the study is conducted considering changes in tubing size while maintaining fixed operating production, as well as exploring diverse scenarios with varying operating production rates..

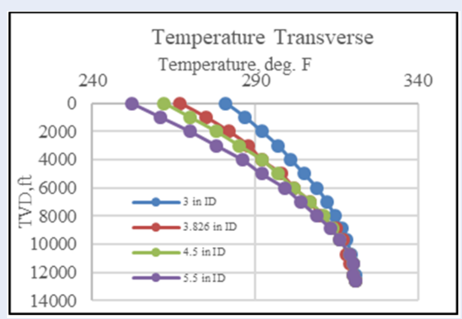

Figure 12: Effect of tubing size on well head temperature of WELL 1X

The impact of distinct tubing sizes is illustrated in Figure 12. The adjustment of tubing size leads to variations in both pressure and temperature at the wellhead. In general, as the tubing size increases, there is a substantial rise in wellhead pressure, coupled with a marginal decrease in wellhead temperature. Consequently, the inference drawn from this illustration is that tubing size exerts a considerable influence on wellhead pressure, with a comparatively minor effect on wellhead temperature.

Various Operating Production

Augmenting the tubing size facilitates an enhancement in the flow rate at the operating point, thereby resulting in increased production at the surface. In these instances, the node is situated at the wellhead location to scrutinize the ramifications of diverse operating conditions.

Figure 13 shows difference results from nodal analysis using with and without temperature models for determining the flow rate at bottom. In comparison to alternative models, the omission of a temperature model in the pressure calculation culminates in lower gas flow rates, particularly at 38 mmscf/d and 49.51 mmscf/d, as delineated in Table 5. This underscores the significance of integrating temperature considerations into the pressure model. The oversight of temperature effects along the tubing leads to a reduction in the produced gas flow rate.

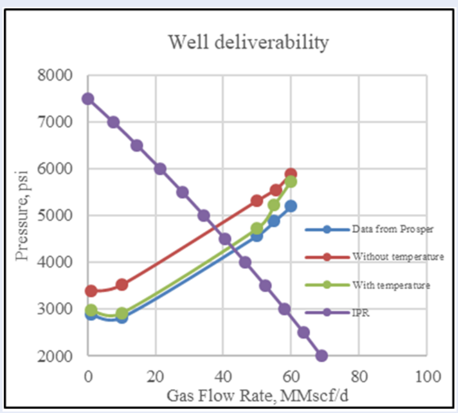

Figure 13: Well deliverability of gas well WELL 1X

CONCLUSION

This study introduces a model for predicting fluid flow temperature in oil wells, integrating the mechanical energy balance equation with three modes of heat transfer: convection, conduction, and radiation. The pressure calculation process incorporates the Gray correlation.

Key Findings:

The proposed model exhibits a negligible difference from the measured data, with a deviation of only 0.34% and 0.63% for pressure loss prediction and temperature distribution along the borehole, respectively. Nodal analysis emerges as a valuable technique for calculating pressure and temperature in the wellbore and reservoir flow, offering the capability for sensitivity analysis to assess the impact of various factors.

Sensitivity analysis is conducted to evaluate the effects of tubing size and production rate on temperature and pressure in the wellbore, considering both the wellhead and bottom hole locations.

Conclusions from Sensitivity Analysis:

Changes in the flow rate exert a significant influence on the temperature along the production tubing. An increase in gas flow rate from 20 to 100 mmscf/d results in a temperature rise from 150 to 300 ^{o}F.

Tubing size plays a pivotal role in pressure loss calculation. For a fixed production rate, increasing the tubing size from 3 to 5.5 inches leads to a slight decrease in wellhead temperature from 281 to 252 ^{o}F. However, considering various operating production rates, changes in tubing diameter induce significant variations in temperature and pressure.

NOMENCLATURE

length of each segment, ft

g_c: conversion factor, 32.17 lbm·ft/(lbf·sec^2)

h_c: convective heat coefficient, Btu/(hr·ft^2·^{o}F)

H_L: holdup liquid

h_f: radiative heat coefficient, Btu/(hr·ft^2·^{o}F)

t_D: dimensionless time

U_{to}: Overall heat transfer coefficient, Btu/(hr·ft^2·^{o}F)

$\bar{\rho}$: average mixture density, lb/ft^3

A: relaxation distance, ft

Cp: Specific-heat capacity, Btu/lb·^{o}F

d: Inner tubing diameter, ft

F: Friction factor

f(t): Transient heat conduction function

g: gravitational acceleration, ft/sec^2

Gr: Grashof number

J: conversion factor for the mechanical equivalent of heat, ft·lbf/Btu

k: thermal conductivity

Nu: Nusselt number

P: pressure, psi

Pr: prandtl number

r: radial distance or radius, ft

Re: Reynold number

T: temperature, ^{o}F

v: velocity, ft/sec

w: mass rate, lb/ft^3

Table 5: Operation point with different prediction method

	BHP, psi	Q_g, mmscf/d
Without temperature model	4789	38
With temperature model	4289	49
Prosper	4223	51

β: fluid thermal expansion coefficient, $1/^{o}F$

ε: emissivity

η: Joule-Thomson coefficient, $^{o}F \cdot ft^2/lbf$

θ: inclination angle

σ: Stefan-Boltzmann constant, 1.731×10^{-9} $Btu/(hr \cdot ft^2 \cdot {}^{o}R^{-4})$

ϕ: lumped parameter, $^{o}F/ft$

q: flow rate, stb/day

SUBSCRIPTS

an: annulus

f: fluid

to: outer tubing

ti: inner tubing

ci: inner casing

co: outer casing

ca: casing

t: tubing

wh: wellhead

wf: bottom hole

L: liquid

fri: friction

acc: acceleration

ele: elevation

CONFLICT OF INTEREST

The authors pledge the content is the results of research of the authors. The figures and results in the paper are true and of no competing interest.

AUTHORS' CONTRIBUTION

Ta Quoc Dung: Led the development of a novel model for predicting fluid flow temperature in oil wells.

Do Duc Anh: Integrated the mechanical energy balance equation with convection, conduction, and radiation for heat transfer, and incorporated the Gray correlation for pressure calculation.

REFERENCES

1. Alves IN, Alhanati FJS, Shoham O. A Unified Model for Predicting Flowing Temperature Distribution in Wellbores and Pipe-lines. SPE Pron Eng. 1992;7:363-7;Available from: https://doi.org/10.2118/20632-PA.
2. Petroleum E. PROSPER Single Well Systems Analysis. 8th ed. Scotland: Petroleum Experts; 2003;.
3. Mach JPE, BK. A Nodal Approach for Applying Systems Analysis to the Flowing and Artificial Lift Oil or Gas Well. 1979;.
4. Phu NT, Hoanh NV, Dung TQ, Ha LT. Assessing the effect of gas temperature on gas well performance. PetroVietNam J. 2022;6;Available from: https://doi.org/10.47800/PVJ.2022.06-06.
5. Hasan AR, Kabir CS. Heat Transfer During Two-Phase Flow in Wellbores; Part I–Formation Temperature. SPE Annual Technical Conference; 1991;Available from: https://doi.org/10.2523/22866-MS.
6. Willhite G. Over-all heat transfer coefficients in steam and hot water injection wells. J Pet Technol. 1967;607-15;Available from: https://doi.org/10.2118/1449-PA.
7. Sagar. Predicting Temperature Profiles in a Flowing Well. 1991;Available from: https://doi.org/10.2118/19702-PA.
8. Beggs H. Production Optimization Using Nodal Analysis. OGCI; 2003;.
9. Tek MR. Temperature and Pressure Gradients In Gas Wells. 1978;Available from: https://doi.org/10.2118/7495-MS.

Tạp chí Phát triển Khoa học và Công nghệ – Engineering and Technology 2024, ():1-1

Open Access Full Text Article

Bài nghiên cứu

Đánh giá và phân tích ảnh hưởng của nhiệt độ trong khai thác khí tại Việt Nam

Tạ Quốc Dũng[1,2,*], Đỗ Đức Anh[1]

TÓM TẮT

Nghiên cứu đưa ra một mô hình toàn diện để dự đoán nhiệt độ của chất lỏng trong giếng khí, bằng cách tích hợp phương trình cân bằng năng lượng cơ học với các cơ chế truyền nhiệt thông qua khuếch tán, truyền dẫn và bức xạ.Tính toán áp suất được chính xác hóa bằng việc tích hợp hệ số tương quan Gray. Kết quả chính của nghiên cứu cho thấy độ chính xác hơn giữa mô hình đề xuất và dữ liệu đo lường, với sai số là 0.34% và 0.63% cho dự đoán tổn thất áp suất và phân bố nhiệt độ dọc theo giếng. Nghiên cứu đã sử dụng phân tích điểm nút là một công cụ hiệu quả để tính toán chính xác áp suất và nhiệt độ trong giếng và dòng chảy trong ống khai thác. Ngoài ra, thông qua phân tích độ nhạy, nghiên cứu đánh giá tác động của các yếu tố khác nhau, như kích thước ống và lưu lượng khai thác lên nhiệt độ và áp suất trong giếng từ vị trí đầu giếng đến đáy giếng. Kết quả từ phân tích độ nhạy nhấn mạnh ảnh hưởng đáng kể của sự thay đổi lưu lượng đối với nhiệt độ dọc theo ống khai thác khi tăng lưu lượng từ 20 đến 100 mmscf/d dẫn đến sự tăng nhiệt độ từ 150 đến 300 độ F. Kích thước ống được xác định là một yếu tố quyết định trong việc tính toán tổn thất áp suất, cho thấy nhiệt độ đầu giếng giảm nhẹ từ 281 đến 252 độ F khi tăng kích thước ống từ 3 đến 5.5 inch. Như vậy, đường kính ống khai thác khác nhau tạo ra các thay đổi đáng kể đối với nhiệt độ và áp suất với lưu lượng khai thác khác nhau.

Từ khoá: Nhiệt độ chất lưu, áp suất chất lưu, phân tích điểm nút, mô hình nhiệt độ, hiệu suất khai thác

[1]*Khoa Địa chất và Dầu khí, Trường Đại học Bách Khoa, Việt Nam*

[2]*Đại học Quốc gia Thành phố Hồ Chí Minh, Việt Nam*

Liên hệ

Tạ Quốc Dũng, Khoa Địa chất và Dầu khí, Trường Đại học Bách Khoa, Việt Nam

Đại học Quốc gia Thành phố Hồ Chí Minh, Việt Nam

Email: tqdung@hcmut.edu.vn

Lịch sử

- Ngày nhận: 18-10-2023
- Ngày chấp nhận: 05-3-2024
- Ngày đăng:

DOI :

Trích dẫn bài báo này: Dũng T Q, Anh D D. **Đánh giá và phân tích ảnh hưởng của nhiệt độ trong khai thác khí tại Việt Nam**. *Sci. Tech. Dev. J. - Eng. Tech.* 2024; ():1-1.