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# ASSESSING THE EFFECT OF GAS TEMPERATURE ON GAS WELL PERFORMANCE

**Nguyen Thanh Phu[1,2], Nguyen Van Hoanh[3], Ta Quoc Dung[1,2], Le The Ha[4]**
[1]Faculty of Geology and Petroleum, Ho Chi Minh City University of Technology (HCMUT)
[2]Vietnam National University
[3]Cuu Long JOC
[4]Petrovietnam
Email: tqdung@hcmut.edu.vn
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## Summary

Gas temperature is an essential parameter in estimating production rate and pressure model inside the production tubing. Three heat transfer mechanisms named as conduction, convection and radiation have been applied to identify the gas temperature declination. Gas wells with bottom hole temperature greater than 160°C and gas rates reaching 55 million standard ft$^3$ per day (MMscf/d) indicate a higher heat loss due to convection than the other two mechanisms. Conduction is the main factor in explaining heat diffusion to the surrounding at the top of the well. The study presents a strong similarity in value compared to the field data by combining Gray correlation and heat transfer model to predict the bottom hole pressure with an error of approximately 3%. Additionally, the gas temperature affects gas rate prediction through gas viscosity and Z factor. With the gas composition mostly containing C1 (70.5%), gas viscosity and Z coefficient at the wellhead are not as high as 0.017 cp and 0.92 respectively. It is possible to have a two-phase flow, then a temperature model along the production tubing is necessary to ensure the gas production rate.

**Key words:** Heat transfer mechanism, Gray correlation, gas production rate.

## 1. Introduction

Measurement of wellhead fluid temperature in the surface is often unreliable as they can be influenced by errors in the measurement procedure and by daily and seasonal temperature variations [1]. In particular, tubing steel is a very good conductor of heat, and variations in temperature of the surface equipment can greatly impact the wellhead temperature [2]. That is why the wellhead temperature must be developed by temperature profile along the tubing.

Gas production inevitably involves significant heat exchange between the wellbore and its surroundings. The presence of seawater and air adds complexity to the heat transfer process in an offshore environment. During production, hot gas continues to lose heat due to cold ambient temperature when it flows inside the borehole [3]. Following the idea of calculating the temperature profile, this paper presents the simple stepwise calculation procedure for gas temperature profile in wellbore. The temperature loss affects the flow rate prediction and pressure profile in the production tubing. The value of gas physical qualities that determine the result of tubing pressure is evident in temperature data. If the understanding of heat transfer is better, the accuracy in predicting the pressure or gas flow rate will be higher.

## 2. Methodology

### 2.1. Heat transfer in wellbore

Heat transfer occurs between the fluid in wellbore and the formation, however, there are some heat resistances of the tubing wall, tubing insulation, tubing-casing annulus, casing wall, and cement. From that view, the temperature distribution in wellbore is dependent on the well structure and geological conditions of the surrounding formation. Heat transfer in a wellbore is governed by three main mechanisms: conduction, convection, and radiation. Conduction and convection are the most reliable technique of exchanging heat from
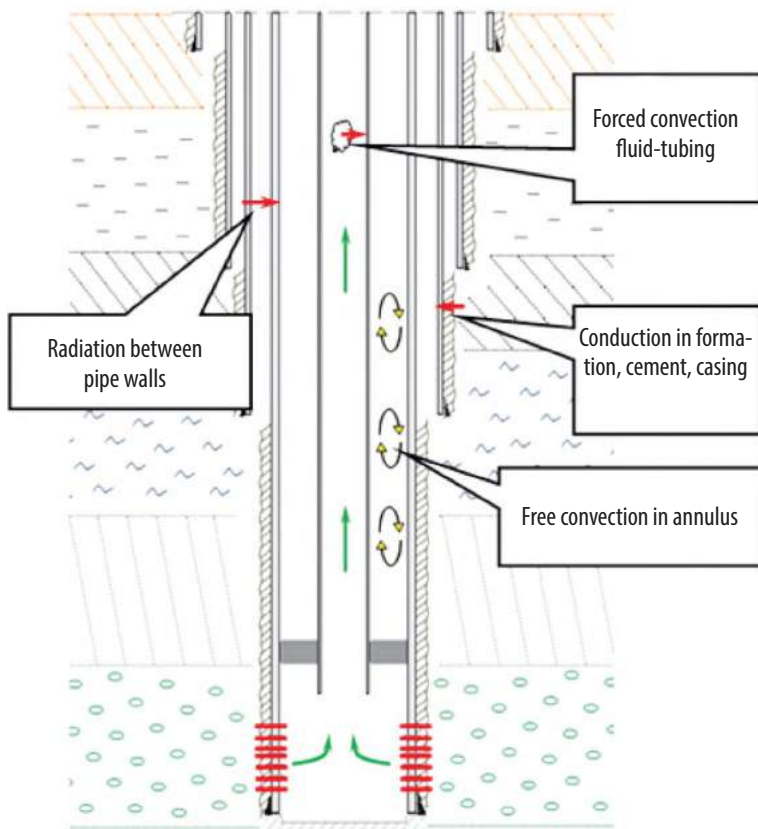
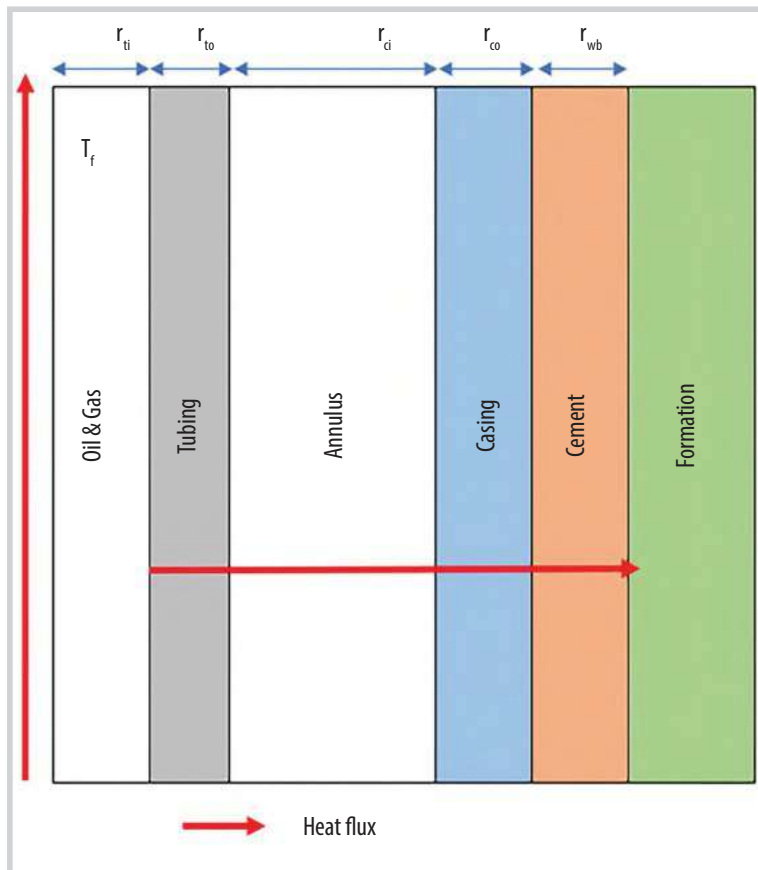*Figure 1. Three heat mechanisms occur along the production tubing [4].*



*Figure 2. Structure of heat transfer model for wellbore without insulation [5].*

a gas flow in a production tubing. Although radiation has little effect on heat loss, it must be included to ensure the model's validity.

In this research, a basic well model is assumed firstly to calculate the overall heat transfer in the absence of insulation. Six zones were considered from the centre of wellbore to formation as shown in Figure 2. The production fluid zone is located inside the tubing and the surrounding is the wellbore region.

$T_f$: Fluid temperature (°C or °F)

$r_{ti}$: Inner tubing radius (inch)

$r_{to}$: Outer tubing radius (inch)

$r_{ci}$: Inner casing radius (inch)

$r_{co}$: Outer casing radius (inch)

$r_{wb}$: Wellbore radius (inch)

### 2.2. Conduction

It illustrates the transfer of heat between neighbouring regions of production tubing by solid material. In principle, the hotter material will transfer the heat to the less ones. In this understanding, the heat is transferred in horizontal direction through tubing, casing to formation.

The rate at which conduction occurs, $\Delta Q_1$, is dependent on the geometry of the grain (formation), thermal conductivity of the material, and the temperature thermal gradient.

$$\Delta Q_1 = 2\pi . k . \Delta L \frac{T_{casing} - T_{formation}}{ln\left(\frac{r_{wb}}{r_{co}}\right)} \quad (1)$$

$$k = k_{gas} . (1 - H_L) + k . H_L \quad (2)$$

where:

$\Delta Q_1$: Heat transfer by conduction (British thermal unit/hr - BTU/hr) 1 BTU/hr ~ 1 KJ/hr

k: Average conductivity

$H_L$: Holdup liquid (if there is no liquid phase let $H_L = 0$)

$r_{wb}$: Wellbore radius (inch)

$r_{co}$: Outer casing diameter (inch)

$T_{casing}$: Casing temperature (°F)

**Table 1.** *Conductivity (k) and specific heat of fluid [4]*

| Fluid type | Specific heat of fluid (BTU/lb/°F) | Conductivity (BTU/hr/ft/°F) |
|---|---|---|
| Water (low salinity) | 1 | 0.35 |
| Water (high salinity) | 1.02 | 0.345 |
| Heavy oil | 1.04 | 0.34 |
| Medium oil | 0.49 | 0.089 |
| Light oil | 0.5 | 0.0815 |
| Gas | 0.26 | 0.0215 |

$T_{formation}$: Tubing temperature (°F)

Table 1 summarises the typical values of conductivity and specific heat of fluid for different fluid types.

### 2.3. Convection

The transfer of heat of gas flow is named convection. Convection occurs through the combination of conduction and fluid motion. There are two typical convections: forced convection in tubing and free convection in annulus.

Natural or free convection exists when there is a change in temperature from the bottom to the wellhead. Forced convection appears by artificially forcing gas to flow over the surface subjected to any external operation units.

The rate of convection, $\Delta Q_2$, increases at an increasing rate in case the fluid-motion exists.

The rate of heat flux by free convection is:

$$\Delta Q_{2forced} = 2\pi . r_2 . h_f . \Delta L . (T_2 - T_1) \tag{3}$$

$$h_f = \frac{0.023 . k . R_{en}^{0.8} . P_r^{1/3}}{r_{ti}} \tag{4}$$

where:

$\Delta Q_2$: Heat transfer by convection (BTU/hr)

$T_1$: Temperature at upper segment in production tubing (°F)

$T_2$: Temperature at lower segment in production tubing (°F)

$\mu$: Gas viscosity (cp)

$r_{ti}$: Inner tubing radius (inch)

$\Delta L$: Different in tubing length (ft)

$R_{en}$: Reynolds number

$P_r$: Prandtl number

$$P_r = \frac{C_p \mu}{k} \tag{5}$$

$$C_{pavg} = C_{pgas}(1 - H_L) + C_{pfluid}(H_L) \tag{6}$$

where:

$C_{pavg}$: Average specific heat of mixture (BTU/lb/°F)

$C_{pg}$: Average specific heat of gas (BTU/lb/°F)

$C_{pfluid}$: Average specific heat of liquid (BTU/lb/°F)

$H_L$: Holdup liquid

The specific heat of fluid value can be looked up from Table 1.

The rate of heat flux by free convection is:

$$\Delta Q_{2free} = 2\pi r_{ti} h_c \Delta L (T_2 - T_1) \tag{7}$$

$$h_c = \frac{0.049(G_y P_r)^{1/3} P_r^{0.0074} k}{r_{to} ln(\frac{r_{ci}}{r_{to}})} \tag{8}$$

where:

$r_{to}$: Outer tubing radius (inch)

$r_{ci}$: Inner casing radius (inch)

$G_y$: Grashof number is:

$$G_y = \frac{\beta . g . (T_2 - T_1) . r_2^3}{\mu^2} \tag{9}$$

where:

$\beta$: The coefficient of thermal expansion

The total heat by convection is:

$$\Delta Q_2 = \Delta Q_{2forced} + \Delta Q_{2free} \tag{10}$$

### 2.4. Radiation

The gas flow which has a high temperature emits heat to the production tubing and gas component significantly evaporates under high temperature. Each gas component has its own boiling temperature, if the temperature is higher than that boiling temperature, the component will evaporate leading to reduction in the heat of fluid. That mechanism is called radiation and it co-occurs with either conduction or convection. In most cases, radiation appears in pipe wall areas:

$$h_r = \frac{\sigma . (T_2^2 - T_1^2) . (T_2 + T_1)}{\frac{1}{\varepsilon + \frac{r_1}{r_2} . (\frac{1}{\varepsilon} - 1)}} \tag{11}$$

where:

$\varepsilon$: Tubing emissivity

$\sigma$: Stefan-Boltzmann constant, approximately 5.67 x $10^{-8}$(W.m$^{-2}$.K$^{-4}$)

Table 2. General tubing emissivity [4]

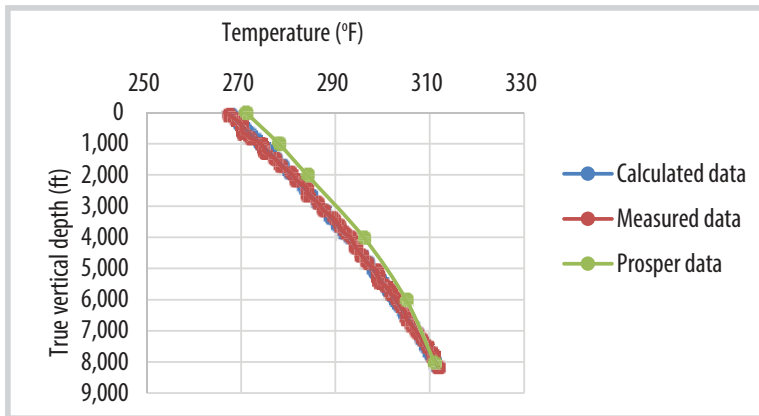| Mild steel tubing | ε |
|---|---|
| Plastic coated tubing | 0.65 |
| Stainless steel (13%) | 0.65 |
| Stainless steel (15%) | 0.4 |
| Line pipe | 0.3 |



Figure 3. Temperature loss from 0 - 8,100 ft. Calculated data has been matched with measured data.
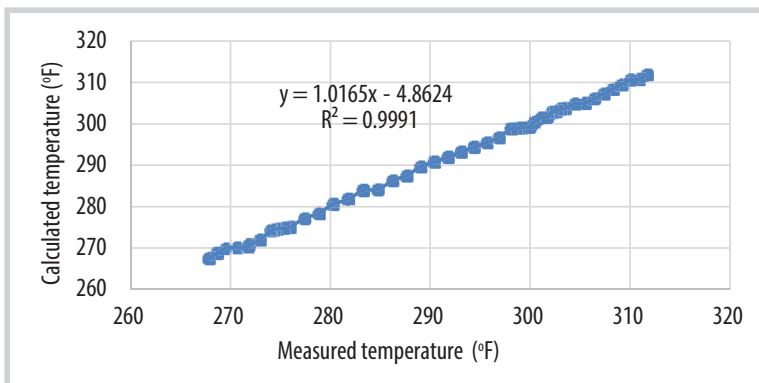


Figure 4. Temperature data comparison inside tubing with depth: 0 - 8,100 ft.

Table 2 provides values of the conduction heat transfer coefficient and the emissivity for different types of tubing material.

Total heat loss by depth:

$$\Delta T = \frac{\sum \Delta Q}{U. \Delta D^2} = \frac{\Delta Q_1 + \Delta Q_3}{U. \Delta D^2} \qquad (12)$$

where:

ΔD: Difference in depth (ft)

ΔT: Temperature decrease when flowing up (°F)

U: Overall heat transfer coefficient

$$U = \frac{1}{h_f} + \frac{1}{h_c} + \frac{1}{h_r} \qquad (13)$$

To check the value of U, by the experience U value should be in:

- Dry Gas: 1 - 3 BTU/(hr.ft².°F)

- Retrograde condensate fluid: 5 - 7 BTU/(hr.ft².°F)

- Oil: 8 - 9 BTU/(hr.ft².°F)

### 2.5. Gray correlation in calculating gas well performance

The investigation of the relation between gas production rate and bottom hole pressure is described as gas well performance. Gray correlation is applied to build the pressure profile along the production tubing. In Gray correlation, it can be applied for high-rate condensate gas ratio (more than 50 barrels per million standard ft³) and large tubing inside diameter (3.5 or 4.5 inches) [6].

The total pressure loss is demonstrated in Equation (14). There are three factors affecting the pressure change: friction force, potential and kinetic energy [7]. If the tubing is divided into small segments, then the pressure loss by kinetic energy is not considerable.

$$\frac{dP}{dZ} = \frac{f. p_n. v_m^2}{2. (r_1 + r_1)} + \frac{g_c}{g} \rho_s. \sin \theta \qquad (14)$$

where:

f: Friction factor number

$v_m$: Mixture velocity (ft/s)

$\rho_n$: Mixture average density of liquid and gas phase (lbm/ft³)

$\rho_s$: Slip mixture density of liquid and gas phase (lbm/ft³)

θ: Well deviation angle (degree)

### 3. Implementation

### 3.1. Well information

The gas well X1 is located in a reservoir with a high pressure of 7,500 psi and a massive temperature of 322°F (around 168°C).

The stainless steel was designed to evaluate the heat transfer in the production tubing for the gas well. The well produces single gas phase at sand layer where the geothermal gradient is 0.015°F. The surrounding temperature is measured which shows a slow effect on the fluid temperature due to the strong thermal insulation.
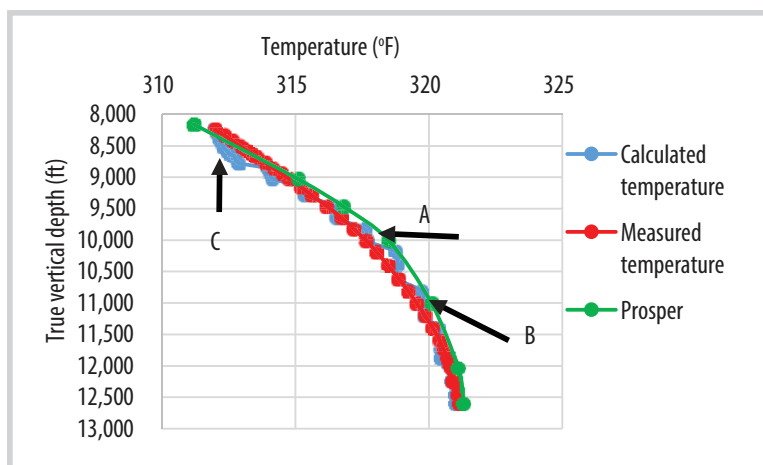
**Figure 5.** *Temperature loss from 8,100 ft - bottom hole. Calculated data has been matched with measured data.*

**Table 3.** *The difference of three values*

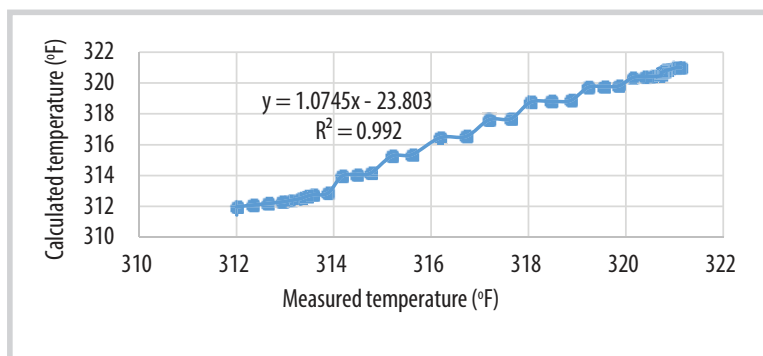| Temperature data | Measured data (°F) | Calculated data (°F) |
|---|---|---|
| Point A at 10,190 ft | 318.038 | 318.751 |
| Point B at 11,994 ft | 320.81 | 320.82 |
| Point C at 8,942 ft | 314.474 | 314.058 |



**Figure 6.** *Temperature data comparison inside tubing with depth: 8,100 ft - bottom hole.*

### 3.2. Heat transfer in well bore and surrounding temperature

The well depth is 13,419 ft long (measured depth - MD), and 12,731 ft long (true vertical depth - TVD). The well has been split into two parts: from surface, 0 - 8,100 ft. The other is from 8,100 ft to bottom hole.

It can be seen from Figure 3, along the tubing, the calculated temperature from three heat transfer mechanisms has been matched with the measured data. The Prosper data has given a slight equal to the calculated data. The $R^2 = 0.9991$ from Figure 4 shows the similarity of measured and calculated temperature data.

At the near surface region, different layers of wellbore component have been installed such as surface casing, cement and annulus. There is a lack of tubing equipment in the surface region, so that the heat loss is mainly by conduction. Tubing equipment plays as a heat insulation that prevents the production heat flux transfer to

the surrounding area. It can be seen that the conduction mechanism response for the high heat loss as a shortage of heat insulation in top section of the well. Heat transfers from inside tubing to casing and formation.

At the lower section, the calculated temperature data fluctuates with the measured data. At bottom hole, it records a high flow rate and a high temperature. High temperatures tend to transfer heat faster, the convection appears regularly. From the well structure, at bottom hole there are various equipment such as safety valve or gauge. It absorbs the heat release. There are reasons explaining why the heat transfer 's value cannot be incorrect. There are three points which are used to give some view about the value (Table 3).

The difference between data of three points is not considerable. With $R^2 = 0.992$, which is shown in Figure 6, it can be concluded that the model is correct when compared with the measured data.

To summarise, the temperature change near the surface has shown a perfect match with the measured data, and there is some variation in value when moving down to the bottom hole. A few remarks have been made about the temperature profile in production tubing:

- In production tubing, the heat from bottom hole condition is dispersed in two directions: moving up to low temperature area at the wellhead and transferring to the surrounding environment. Convection is the main mechanism which causes the high drop in flow 's temperature at bottom hole.

- The flow is not in steady state. The flow rate increases in value and becomes stable when reaching the surface. That can explain why at the near bottom hole region, the calculated temperature data has some differences.

- There is an equipment installed along the below tubing which is to control flow rate and pressure. By adding with elevation,

a decrease in temperature is a contributing factor to ensure the prediction accuracy.

- Temperature profile at surrounding environment.

The heat transfer in wellbore has been simplified in three types of temperature:

$T_g$: temperature of produced gas.

$T_{ci}$: Temperature inside casing: measured by heat transfer from the production tubing through the annulus to the inner casing region.

$T_{co}$: Temperature outside casing: the heat transfer from inside to outside casing by the conduction heat mechanism.

The test used 9 5/8" casing for analysing. This casing has been installed from the top to 10,000 ft of true vertical depth. It is the nearest region casing from the production tubing. Inside the casing is a free space – annulus, and the outside is cementing layer. The casing material is steel, which is a good heat conductor. This is a reason why the temperature difference between inside and outside casing is not considerable (Figure 7).

As a result, the temperature of fluid is the highest as it is calculated by the bottom hole temperature which is equal to the formation temperature. Next the heat transfers outside through the annulus and casing in horizontal direction and lowers the value.

### 3.3. Temperature effect on gas viscosity and Z factor

The equation for viscosity analysis is from Gray correlation, which takes account of the temperature change along the production tubing. In this section, the gas viscosity curve named general temperature model illustrates the value of gas viscosity when gas temperature reduces by three heat transfer mechanisms. Another method in calculating gas viscosity is the linear decrease of temperature profile in tubing.

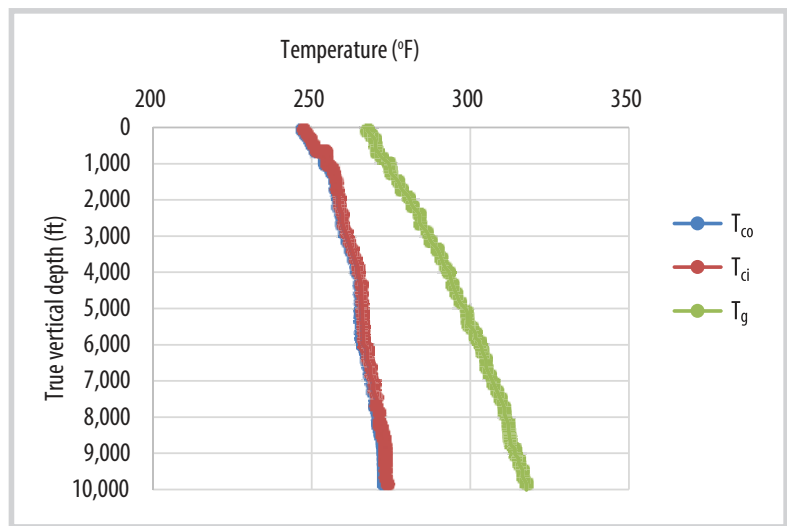At low temperature, the gas becomes cooler and reduces its viscosity. The viscosity



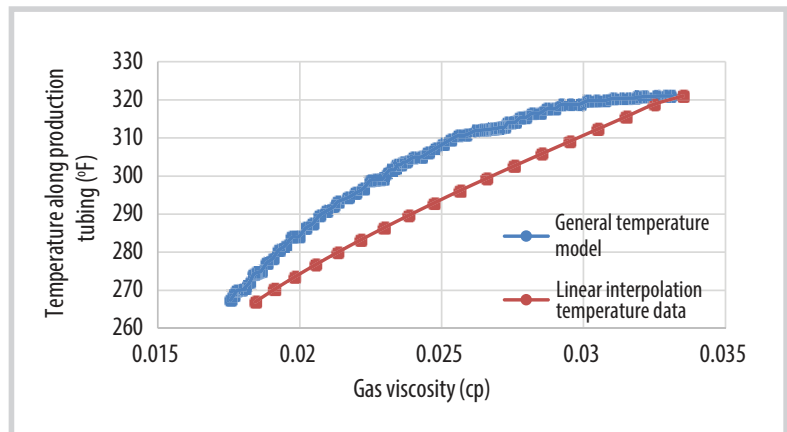**Figure 7.** *Heat transfer from tubing to casing.*



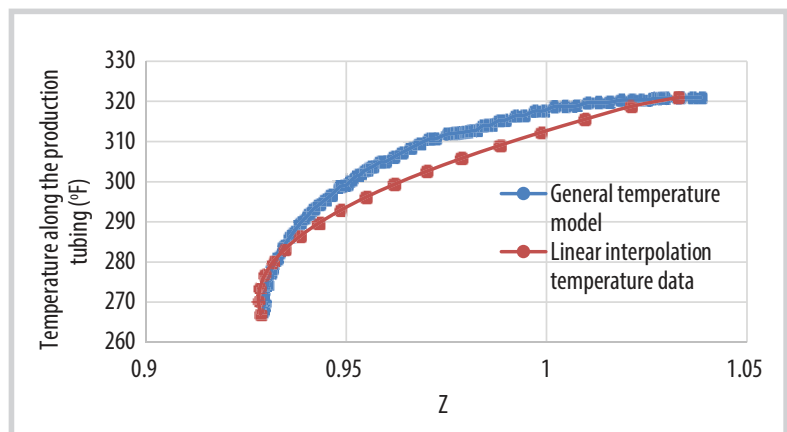**Figure 8.** *Gas viscosity analysis.*



**Figure 9.** *Z factor analysis.*

at bottom hole shows the same value, 0.047 cp. It has a small different value in the well head between two temperature models, 0.017 and 0.018 cp, respectively. The gap between two curves in Figure 8 represents the actual change in gas viscosity inside the production tubing. When using linear interpolation temperature data, it highlights the mistake in generating the phase diagram or predicting the actual flow rate.

It is claimed that the temperature of the gas influences the change of the Z factor, and that the Z factor influences the pressure calculation and gas flow rate capability.

The method uses a pseudo temperature to find the value of Z by using the Beggs and Brill correlation in measuring the Z factor. The Z factor curve relating to the linear interpolation of temperature in bottom hole pressure prediction is virtually identical to the curve that is considered the temperature model.

The Z factor calculated in the well head gives the closest in value to the two curves at the bottom hole, 0.929 and 0.928. However, along the production tubing, there is a difference in value of Z factor as it considers the temperature drop in constant value. This will reveal the pressure profile calculation mistake.

### 3.4. Temperature effect on the pressure profile in production tubing

In a flowing fluid, one of the most critical values is pressure. If there is a pressure differential between the bottom hole and the well head (BHP > WHP), the fluid can flow. The pressure change in the production tubing is slightly affected by temperature. However, the temperature model alters the Z, viscosity, and other properties, all of which have an impact on the pressure value.

The Gray correlation is used to apply the pressure gradient. As a result, the pressure determined using the applied general temperature model has a high degree of accuracy when compared to the measured data.

The analysis used the same temperature profile value. As the difference in temperature at the top section is not considerable, the pressure profile applying the temperature drop in linear value is identical.

Between estimated and measured results, linear regression has been investigated. The $R^2$ value is 0.998. It is similar to the value of one. As a response, the pressure model has been
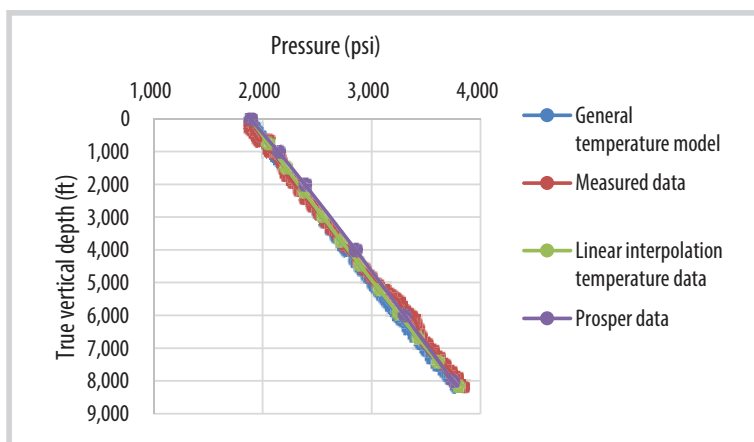


**Figure 10.** *Pressure changes from surface - 8,100 ft of true vertical depth along production tubing.*
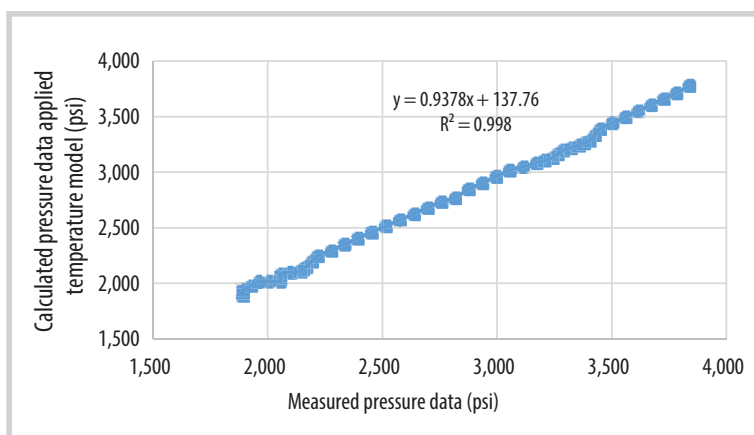


**Figure 11.** *Data comparison of pressure in tubing from surface - 8,100 ft of true vertical depth.*
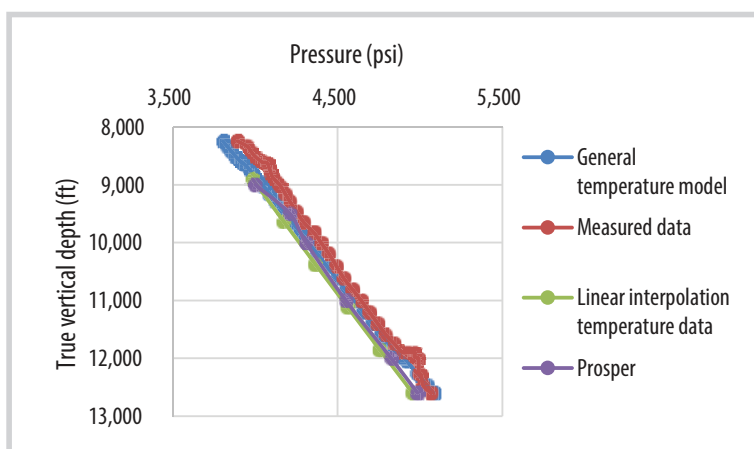


**Figure 12.** *Pressure changes from 8,100 ft - bottom hole along production tubing. Pressure changes from 8,100 ft - bottom hole along production tubing.*

**Table 4.** *The value of bottom hole pressure*

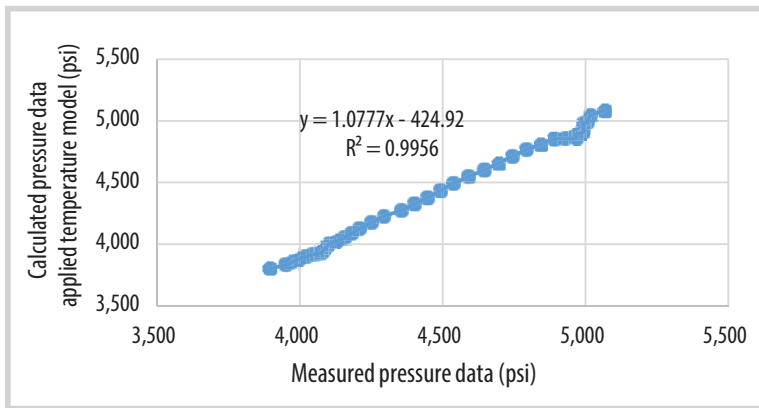| Model | Pressure (psi) |
|---|---|
| General temperature model | 5,083 |
| Measured data | 5,066 |
| Linear interpolation temperature data | 4,956 |
| Prosper | 4,984 |

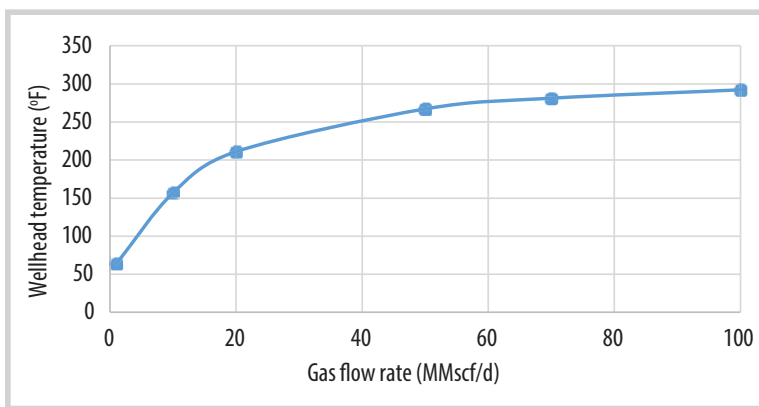*Figure 13. Data comparison of pressure in tubing from 8,100 ft - bottom hole.*



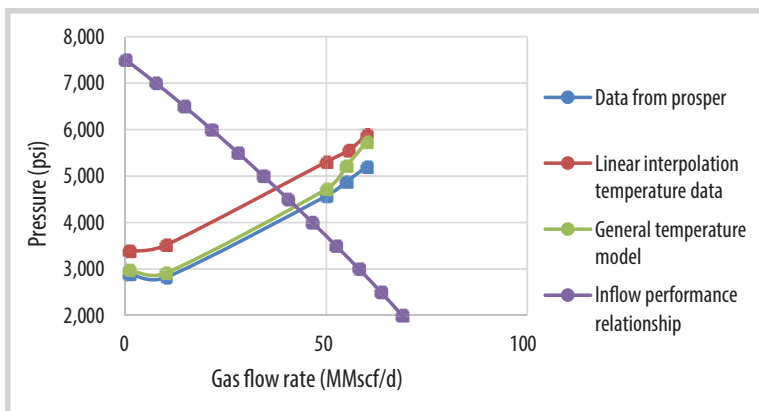*Figure 14. The relation between wellhead temperature and gas flow rate*



*Figure 15. Gas well performance and compare the effect of temperature model.*

**Table 5.** *Well deliverability*

| Model | Bottom hole pressure (psi) | Qg (MMscf/d) |
|---|---|---|
| Linear interpolation temperature | 4,789 | 38 |
| General temperature | 4,289 | 49 |
| Prosper | 4,223 | 51 |

corrected. It points out that if the surrounding region of tubing is only annulus and casing, there is no need to apply the heat transfer mechanism to generate tubing pressure profile.

At the section from 8,100 ft of true vertical depth to the bottom hole, the pressure traverse has been analysed:

With pressure line drawn by applying the general temperature model, the pressure figures have a high acceptance, compared to the measured data. On the other hand, with the line generated by Prosper software, the value obtained is quite close to the measured data. Meanwhile, there is certain difference in calculating pressure traverse without recognising the temperature change affected by the heat mechanisms. The comparison of bottom hole pressure data is shown in Table 4.

To equalise the calculated and measured pressure data, a linear regression has been drawn. The $R^2$ value is 0.9956. It has the same value as number one. Accordingly, the pressure model was approved.

### 3.5. Effect of gas produced on gas temperature

In any case of production, the wellhead temperature must be lower than that at the bottom hole. From Figure 10, if the bottom hole temperature is kept constant in 321°F, when the gas produced rate is 55 million standard ft³ per day, the wellhead temperature is 268°F, it can be concluded that when gas flows up to the wellhead, the higher rate of gas is produced, the lower the temperature loss will be due to the low effect of convection inside the production tubing. A low production rate gives low wellhead temperature as the heat mostly transfers to the ambient environment.

### 3.6. Temperature effect on gas production flow rate

The relation between gas temperature, pressure and flow rate within the production tubing can be seen in the vertical lift performance (VLP). In applying nodal analysis, various rates are calculated to find out the well operating point. From that, temperature change in the production tubing impacts on the gas production rate prediction. The reliability of vertical lift performance should be checked again.

Table 6. *Gas composition*

| 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 7. *Reservoir input data*

| | |
|---|---|
| Pr (psi) | 7,500 |
| Tr (°R) | 810 |
| h (ft) | 300 |
| k (mD) | 2 |
| $r_w$ (ft) | 0.25 |
| $r_e$ (ft) | 2,979 |
| s | 2 |
| D, non - Darcy flow factor | 0.00006 |

Table 8. *Well depth*

| Measured depth (ft) | True vertical depth (ft) |
|---|---|
| 0 | 0 |
| 6,662 | 6,620 |
| 13,419 | 12,731 |

Table 9. *Well input data*

| | |
|---|---|
| Gas flow rate (MMscf/d) | 55.5 |
| Gas oil Ratio - GOR | 7,690 |
| Production tubing ID (inch) | 3.826 |
| Production tubing OD (inch) | 5.042 |

The vertical lift performance is tested by applying the Gray correlation. The Prosper software gives a similar number in operating point compared with the curve used temperature model. The vertical lift performance which does not contain the temperature model has a lower value of well deliverability than the others. The gap between this vertical lift performance curve and the others can be explained by the impact of temperature on the pressure profile while increasing the flow. To generate vertical lift performance curve, it uses the value of Q: flow rate and temperature profile to predict the bottom hole pressure (BHP) and draw the relation between Q and the bottom hole pressure. If the temperature drop is in the linear gradient and the flow is too fast, there will be more errors in the pressure value. It should acquire the heat transfer model in wellbore to ensure the accuracy of well deliverability.

In comparison to the other models, the value of gas flow rate in the pressure without temperature model is lower, at 38 and 49,51 million standard ft³ per day, respectively. According to Table 5, if the pressure model does not account for temperature along the tubing, the produced gas flow rate will be reduced.

## 4. Conclusion

In order to produce single-phase gas in a gas well, the pressure gradient in the tubing must be reasonable. An incorrect value of gas flow rate will result from an error in pressure measurement. One of the variables suspected of causing errors in the pressure gradient measurement is the temperature model in the wellbore. There are some remarkable points in this study:

To predict bottom hole pressure, the temperature profile in the production tubing should be computed considering the specified heat transfer mechanism since it gives a small error. The gas temperature model is checked with the measured data and shows nearly accurate value. With the bottom hole temperature being 321°F, the gas test rate 55.5 million standard ft³ per day, the wellhead temperature calculated by heat transfer mechanism 268°F, the predicted bottom hole pressure is virtually accurate compared to pressure values that do not involve a heat transfer mechanism.

The heat transfer process in the wellbore happens in two main directions: horizontal: heat transfer from the production tubing to the annulus, casing or cement known as conduction, and vertical: heat changes based on the convection process in the production tubing. Conduction occurs at the top section of the well. Convection is the most critical part in decreasing the gas temperature due to fast flow rate at the well head. Radiation has a minor impact on the pipe wall. Hence, it should be taken into account in order to ensure the model's accuracy.

Fluid temperature has a significant impact on gas viscosity since it is directly related to the cooling of the gas flow. Once implementing the temperature model, the result shows that the viscosity at the wellhead is 0.017 cp. The Z factor equals 0.92 for the wellhead and 1.92 for the bottom hole, respectively. In addition to affecting the bottom well pressure value, these two parameters also influence gas flow

rate. Low gas viscosity and Z factor value due to incorrect temperature profile can result in low production rate and damage to the operation procedure because two-phase flow happens.

Gray correlation gives a high level of accuracy in the value of pressure profile compared between calculated and measured data. As higher flow rates the wellhead temperature is also high corresponding the flow rate prediction of well deliverability. The vertical lift performance model containing the temperature model gives a similar value of gas production rate as compared with the Prosper commercial software: 49 million standard ft³ per day and the bottom hole pressure is 4,289 psia. The correct vertical lift performance model delivers a great level of accuracy in determining the gas flow rate.

### Acknowledgment

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