Prediction of temperature drop accompanying a given pressure drop for natural gas wellstreams

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PROFESSIONAL PAPER

Accurate prediction of the temperature drop accompanying a given pressure drop for the natural gas production systems is necessary in the effective design of natural gas production facilities. Current rigorous compositional models depend on many variables and require information about fluid composition. In this paper, a simple-to-use method which is easier than current available models, is presented to predict accurately the appropriate temperature drop accompanying a given pressure drop in natural gas production systems based on the black-oil model to get a quick approximate solution for the temperature drop of a natural gas streams in gas production systems. Considering the results, the new developed correlation is recommended for rapid estimation of temperature drops in gas production systems for pressures up to 45 MPa and pressure drops up to 25 MPa. The obtained results illustrate that good agreement is observed between the reported data and the values calculated using the new developed method. The average absolute deviation between reported data and the proposed correlation is around 4.6%. The proposed method appears to be superior owing to its accuracy and clear numerical background, wherein the relevant coefficients can be retuned quickly for various data.

Key words: natural gas, liquid content, temperature drop, Black-Oil model, simulation

1. Introduction

Predicting accurate temperature profiles in gas-production systems can improve the design of production facilities. As an example, temperature profiles in systems have application in accurate two-phase flow pressure drop prediction, gas-lift designs, and etc. If composition of gas is available, engineers predict the temperature drop by using a computer simulation program based on a fully compositional equation of state (EOS) *pVT* formulation and flash calculation. The program will perform a flash calculation, internally balancing enthalpy. It will calculate the temperature downstream of the choke, which assures that the enthalpy of the mixture of gas and liquid upstream of the choke equals the enthalpy of the new mixture of more gas and less liquid downstream of the choke. Otherwise, the gas production system can be modeled with the use of a black–oil model, which is also a tool for modeling the gas reservoir exploitation and for calculating the resources.[12] Black-oil simulators represent a high percentage of all simulation applications and they can model immiscible flow under conditions such that fluid properties can be treated as functions of pressure.[1] Coats[6] presented radial well simulations of a gas condensate that showed a modified black-oil *pVT* formulation giving the same results as a fully compositional equation of state (EOS) *pVT* formulation for natural depletion above and below dew point. Under certain conditions, he found that the modified black-oil model could reproduce the results of compositional simulation for cycling above the dew point.[12,10]

Fevang et al.[10,11] obtained results which mostly support the conclusions by Coats.[6] However, they found differences in oil recoveries predicted by compositional and modified black oil (MBO) models when the reservoir is a very rich gas condensate and has increasing permeability downwards.[12] According to their final conclusions, a black oil simulator may be adequate where the effect of gravity is negligible, and for gas injection studies black oil model can only be used for lean to medium-rich gas condensate reservoirs undergoing cycling above dew point.[12] El-banbi and McCain[7,8] suggested that modified black oil (MBO) approach could be used regardless of the complexity of the fluid. Their paper presented the results of a full field simulation study for a rich gas condensate reservoir. The modified black oil (MBO) model performance was compared with the performance of a compositional model in the presence of water influx and also a field wide history match study was conducted for above and below the dew point.[7,8] Their paper presents an accurate match of average reservoir pressure and water production rates. They also mentioned contrary to the common belief, the modified black oil (MBO) approach proves to be sufficient for modelling gas condensate behaviour below the dew point and using the modified black oil (MBO) approach, instead of a fully compositional approach, may result in significant time saving especially in full-field simulation studies.[7]

El-Banbi et al.[9] presented the set of correlations to generate modified black-oil *pVT* properties without the need for fluid samples or elaborate procedure for equation of states (EOS) calculations.

Choking, or expansion of gas from a high pressure to a lower pressure, is generally required for control of gas well flow rates. Choking is achieved by the use of a choke or a control valve.[1] The pressure drop causes a decrease in the gas temperature, thus hydrates can form at the choke or control valve. For a single component fluid, such as methane, a Mollier diagram can be used to calculate temperature drop directly. However, natural gas is not a single component and a Mollier diagram will probably not be available.[1]

For black oil models and when composition of natural gas is not available, It is an essential to develop a simple correlation to predict accurately the appropriate temperature drop in natural gas production systems based on the black-oil model to get a quick approximate solution for the temperature drop of a natural gas streams. According to our knowledge, there is no correlation in the petroleum literature for the black-oil model to estimate temperature drop accompanying a given pressure drop for natural gas production streams. This paper describes a simple-to-use method for accurate prediction of temperature drop in the natural gas production systems for black-oil models.

2. Developing Simple Correlation

The required data to develop this correlation includes the reported from reference 8 (which are based on Gas Processors and Suppliers Association, Engineering Data Book, 9th edition, Tulsa, OK, 1972) for the temperature drop accompanying a given pressure drop at various initial (up stream) pressures and for wide range of gas well streams liquid content.[1] In this work a simple correlation is developed to estimate the appropriate temperature drop in natural gas production wells based on the black-oil model as a function of gas initial pressure, gas pressure drop and gas liquid contents. The following methodology has been applied to develop this correlation:

Firstly, the appropriate temperature drop in natural gas production systems are correlated as a function of initial (upstream) pressure of gas stream for different pressure drops. Then, the calculated coefficients for these polynomials are correlated as a function of pressure drop. The derived polynomials are applied to calculate new coefficients for equation (1) to predict the appropriate temperature drop in natural gas production systems. Table 1 shows the tuned coefficients for equations (2) to (5).

Table 1. Tuned coefficients used in Equations (2) to (5)

Coefficient	Pressure drop less than 13800 kPa	Pressure drop more than 13 800 kPa
A_1	1.040 719 991 7	9.362 950 815 33
B_1	5.863 426 642 58 x 10^{-1}	-6.939 607 862 509 x 10^{-1}
C_1	-6.342 086 209 79 x 10^{-2}	-2.382 350 807 x 10^{-3}
D_1	2.814 825 604 12 x 10^{-3}	1.707 747 521 64 x 10^{-3}
A_2	2.430 764 529 804 x 10^{-3}	-1.0182 981 741 4
B_2	3.069 694 101 171 x 10^{-2}	1.677 279 709 66 x 10^{-1}
C_2	-2.701 623 402 13 x 10^{-3}	-6.403 523 610 97 x 10^{-3}
D_2	2.322 543 561 003 x 10^{-5}	-1.349 784 156 13 x 10^{-5}
A_3	-4.474 832 714 94 x 10^{-3}	3.407 062 549 01 x 10^{-2}
B_3	-1.218 162 552 3 x 10^{-3}	-6.307 680 717 04 x 10^{-3}
C_3	1.731 754 226 62 x 10^{-4}	2.974 089 458 302 x 10^{-4}
D_3	-4.277 312 720 08 x 10^{-6}	-2.195 720 171 01 x 10^{-6}
A_4	1.155 971 384 07 x 10^{-4}	-3.50 210 682 437 8 x 10^{-4}
B_4	-8.871 530 681 92 x 10^{-6}	5.983 899 386 423 x 10^{-5}
C_4	-1.032 600 663 99 x 10^{-7}	-2.950 536 870 498 x 10^{-6}
D_4	-7.938 290 866 22 x 10^{-9}	2.757 769 149 12 x 10^{-8}

Table 2. Tuned coefficients for equation (6)

Coefficient	Value
α	-5.555 968 253 968
β	4.943 879 595 915 x 10^{-2}
γ	8.171 231 318 052 x 10^{-8}
θ	-2.610 407 344 111 x 10^{-10}

In brief, the following steps are repeated to tune the correlation's coefficients.

1. Correlate the appropriate temperature drop in natural gas production systems as a function of initial pressure (p_i) for a given pressure drop (Δp).
2. Repeat step 1 for other pressure drops (Δp).
3. Correlate corresponding polynomial coefficients, which are obtained in previous steps versus pressure drop, a = f(Δp), b = f(Δp), c = f(Δp), d = f(Δp) [see equations (2)-(5)].

Equations (1) to (5) represent the new developed correlation in which four coefficients are used to correlate the temperature drop as a function of initial (upstream) pressure in MPa and the given pressure drop in MPa, where the relevant tuned coefficients have been reported in table 1, these tuned coefficients help to predict the temperature drop accompanying a given pressure drop for the natural gas well-stream for pressures up to 45 MPa and pressure drops up to 25 MPa. Those tuned coefficients can be retuned quickly if more data are available in the future according to the above-mentioned procedure.

$$\ln(\Delta T_i) = a+b_p+c_p^2+d_p^3 \quad (1)$$

where:

$$a=A_1+B_1(\Delta p)+C_1(\Delta p)+D_1(\Delta p)^3 \quad (2)$$

$$b=A_2+B_2(\Delta p)+C_2(\Delta p)+D_2(\Delta p)^3 \quad (3)$$

$$c=A_3+B_3(\Delta p)+C_3(\Delta p)+D_3(\Delta p)^3 \quad (4)$$

$$d=A_4+B_4(\Delta p)+C_4(\Delta p)+D_4(\Delta p)^3 \quad (5)$$

This method is based on a liquid content of 112.3 m^3 /million m^3. For each increment of 56 m^3 /million m^3, there is a correction of 2.77 °C in temperature drop. For example, if there is no liquid, the final temperature is 5.54 °C cooler (the temperature drop is 5.54 °C more) than indicated by equation (1). Equation (6) is applied to correct temperature drop based on the liquid content of the gas (L, m^3/ million m^3), where the final gas tempera-

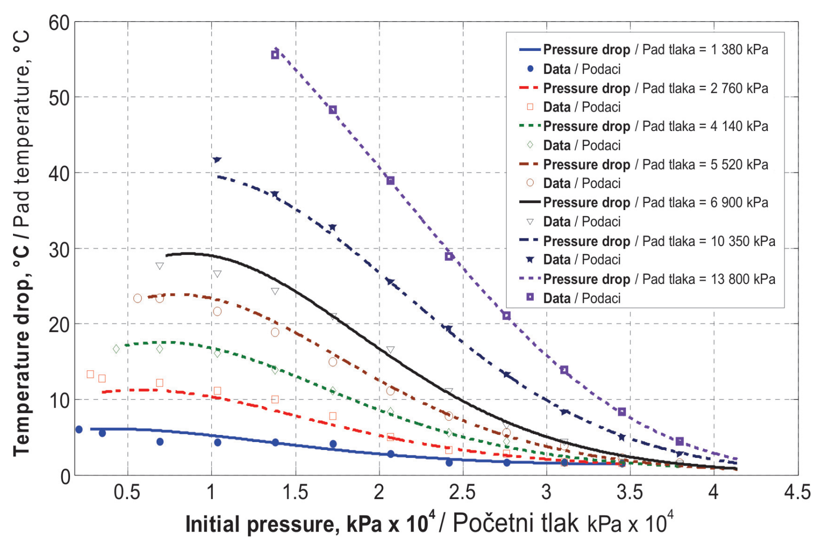

Fig. 1. Predicting temperature drop accompanying a given pressure drop for natural gas well-stream using the proposed method and comparison with reported data at liquid content of 112.3 cubic meters per million standard cubic meters.[1]

Sl. 1. Predviđeni pad temperature koji prati odgovarajući pad tlaka za plinske bušotine, korištenjem predložene metode i usporedba s podacima iz izvještaja kod sadržaja kapljevine od 112,3 m³/milijun m³ .[1]

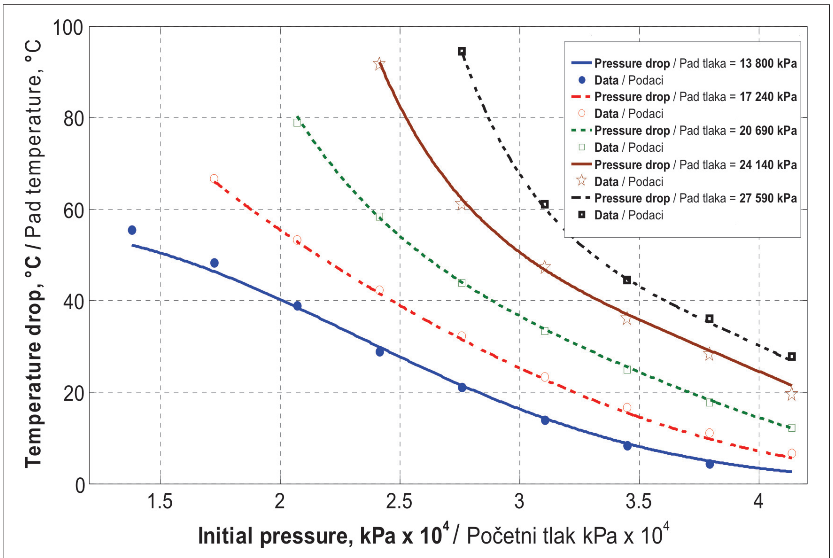

Fig. 2. Predicting temperature drop accompanying a given pressure drop for natural gas well-stream using the proposed method and comparison with reported data at liquid content of 112.3 cubic meters per million standard cubic meters.[1]

Sl. 2. Predviđeni pad temperature koji prati odgovarajući pad tlaka za plinske bušotine, korištenjem predložene metode i usporedba s podacima iz izvještaja kod sadržaja kapljevine od 112,3 m³/milijun m³.[1]

ture drop (ΔT) can be determined using Equation (7). Table 2 gives the tuned coefficients used in Equation (6).

$$\Delta T_{correction} = \alpha + \beta L + \gamma L^2 + \theta L^3 \quad (6)$$

$$\Delta T = \Delta T_i + \Delta T_{correction} \quad (7)$$

The obtained results illustrate that good agreement is observed between the reported data and the values calculated using the new developed method. In addition, we have selected exponential function to develop the correlation, because these functions are smooth and well-behaved (i.e. smooth and non-oscillatory) equations which should allow for more accurate predictions.[2-5]

3. Results

Figures 1 and 2 show the results of the proposed method comparing with the reported data[1] at various initial pressures and pressure drops and at liquid content of 112.3 cubic meters per million standard cubic meters where these figures show excellent agreement between proposed method and reported data.[1] Figure 3 illustrates the correction factor for natural gas temperature drop as a function of gas liquid content. Figures 4 and 5 show the performance of proposed correlation to predict temperature drop as a function of pressure and pressure drop at low and high pressure drops range respectively for liquid contents of 112.3 cubic meters per million standard cubic meter of natural gas. These figures show the excellent performance of proposed correlation. However, the greater the amount of liquid in the gas the lower the temperature drops, thus leading to higher the calculated final temperature. Table 3 shows the accuracy of proposed correlation in terms of average absolute deviation percent with some typical reported data. It shows the proposed correlation has an average absolute deviation percent about 4.6 percent, which is very small deviation from reported data. Sample calculations shown here clearly demonstrate the simplicity of the proposed method and the benefits associated with such estimations.

Example:

A natural gas stream flows at 10 MPa and it will have a pressure drop around 4.14 MPa. Calculate the temperature drop for this gas if liquid content is 240 cubic meters per million standard cubic meters.

Solution:

Because pressure deop is less than 13.8 MPa, we use the coefficients in the first column of table 1 and we will have:

a=2.580 9 [from equation (2)]

b=0.061 0 [from equation (3)]

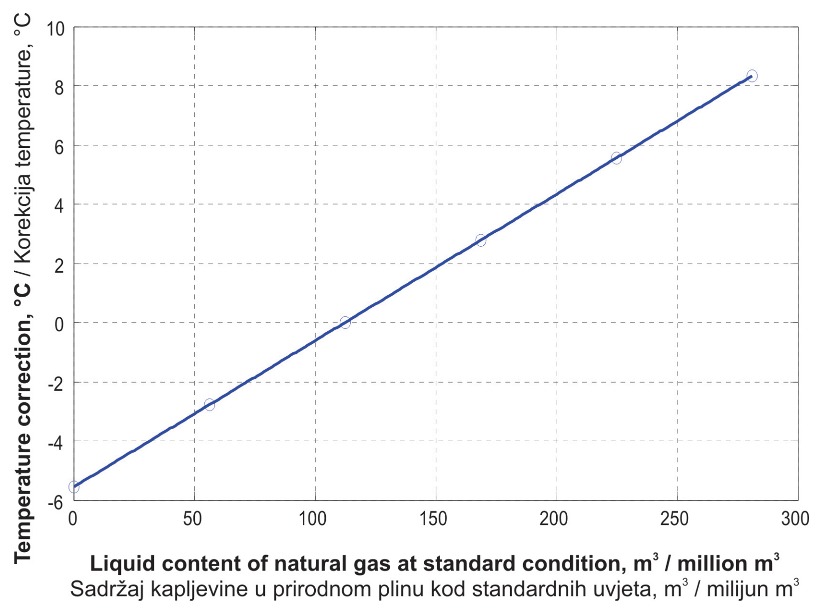

Fig. 3. Temperature drop correction factor as a function of liquid content of natural gases

Sl. 3. Faktor korekcije pada temperature kao funkcija sadržaja kapljevine prirodnog plina

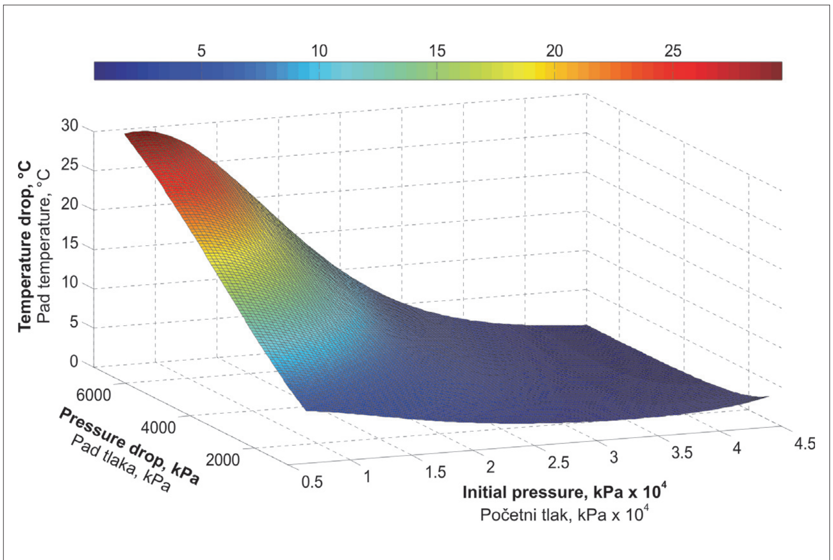

Fig. 4. Correlation performance for prediction of temperature drop as a function of initial pressure and pressure drop at liquid content of 112.3 cubic meters per million standard cubic meters (low pressure drop range). Color bar shows the temperature drop.

Sl. 4. Rezultat korelacije u predviđanju pada temperature kao funkcije početnog tlaka i pada tlaka kod sadržaja kapljevine od 112,3 m³ na milijun m³ prirodnog plina (opseg pada niskog tlaka). Crta u boji pokazuje pad temperature.

c=-0.006 9 [from equation (4)]

d=0.0000 765 36 [from equation (5)]

ΔT_i=13.22 °C [from equation (1)]

Now, we correct temperature drop by equations (6) and (7) for liquid content of 240 cubic meters per million standard cubic meters:

From equation (6):

$\Delta T_{correction}$=6.31 °C

From equation (7):

$\Delta T = \Delta T_i + \Delta T_{correction}$ =13.22+6.31=19.53 °C

This is classic example showing how the information evolving out of this correlation can be used to predict the temperature drop accompanying a given pressure drop for the natural gas production systems.

4. Conclusions

In the present work, a simple-to-use correlation is developed to predict natural gas temperature drops at a given pressure drop in gas production systems. The new proposed correlation is based on the black-oil model, which is simpler than current available models that involve a large number of parameters and require more complicated and longer computations. Considering the results, the new developed correlation is recommended for rapid estimation of wellbore temperature drops in gas production systems for pressures up to 45 MPa and pressure drops up to 25 MPa. This Simple-to-use approach can be of immense practical value for the gas reservoir and production engineers to have a quick check on wellbore temperature drops in gas production systems at various conditions. In particular, personnel dealing with regulatory bodies of natural gas production would find the proposed approach to be user friendly involving no complex expressions with transparent calculations. The correlation proposed in the present work is simple and unique expression which is non-existent in the literature. This is expected to benefit and making design decisions which could lead to informed decisions on the temperature drop in black-oil model.

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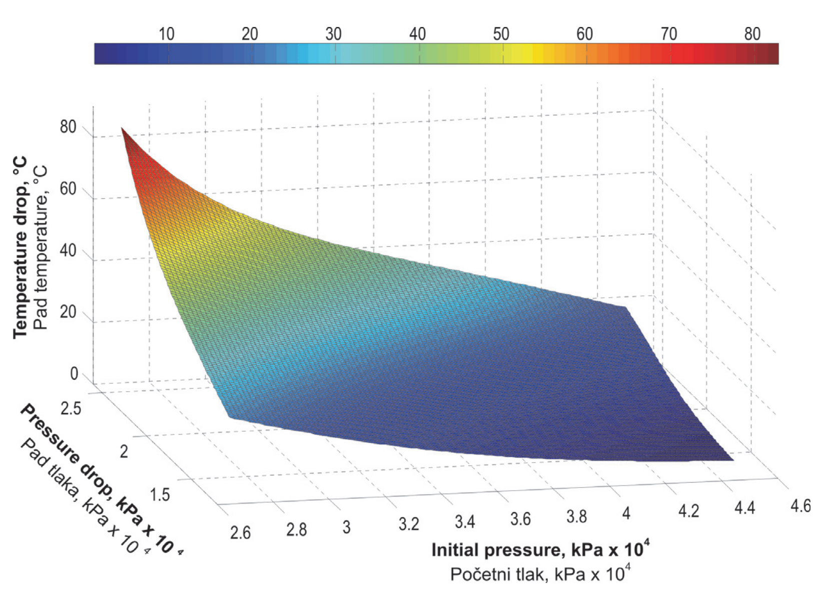

Fig. 5. Correlation performance for prediction of temperature drop as a function of initial pressure and pressure drop at liquid content of 112.3 cubic meters per million standard cubic meters (high pressure drop range). Color bar shows the temperature drop

Sl. 5. Rezultat korelacije u predviđanju pada temperature kao funkcije početnog tlaka i pada tlaka kod sadržaja kapljevine od 112,3 m³ na milijun m³ prirodnog plina (opseg pada visokog tlaka). Crta u boji pokazuje pad temperature

Table 3. Accuracy of proposed method

Upstream pressure, MPa	Pressure drop, MPa	Reported temperature drop, °C1	Calculated temperature drop, °C	Ansolute deviation percent
3.448 3	1.379 3	5.555 6	6.097	**8.87**
27.586	2.758 6	2.777 8	2.583	**7.54**
20.69	4.137 9	8.333 3	8.005	**3.94**
10.345	5.517 2	21.666 7	23.165 5	**6.91**
24.138	13.793	28.888 8	29.586	**2.41**
27.586 2	17.241 38	32.222 2	31.508	**2.21**
41.379	20.689	12.222 2	12.082 4	**1.14**
41.379	27.586	27.777 7	26.817 2	**3.45**
Average absolute deviation percent				**4.6**

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Nomenclature:

Δp_i initial pressure in MPa

Δp pressure drop in MPa

ΔT temperature drop, °C at various liquid contents

ΔT temperature drop for liquid content of 112.3 m³ / million m³, °C

$\Delta T_{correction}$ Correction for temperature drop in other liquid contents of gas, °C

L Liquid content of gas, m³/million m³

i Index for initial pressure (upstream pressure)

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