

Integrated Analysis of Choke Performance and Flow Behaviour in High-Rate, Deviated Gas-Condensate Wells

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Abstract: Understanding the flow behaviour in a gas well is crucial for future production strategies, obtaining bottomhole conditions from wellhead production data, analyzing production data and estimating reservoir properties. In this work, the pressure profile and flow regime are studied on four wells of a multi-well, multi-layer gas-condensate reservoir, producing at high rate. The wells are deviated and cased-holes, with the gas flowing through tubing to the wellhead. Here, a comprehensive quality assessment of data is presented. An algorithm is proposed to model wellhead chokes and determine production rates of individual wells from overall, commingled daily flow rates. The pressure profile and flow regime were determined in each well through back-calculation and nodal analysis. The bottomhole pressure is predicted. The best correlations are selected by comparing the model results with reported production logging tool (PLT) data. The rates of produced condensate and water (equivalent to gas) and their PVT properties, e.g. API of condensate, had little impact on choke calculations, which is due to high flow rate gas. The flow is shown to be gas-like at the bottom, which turns to mist flow near the wellhead. Liquid holdup is subject to the wellhead pressure and well flow rate. It decreases with an increase in wellhead pressure and gas flow rate. The findings here can be extended to other wells in the same reservoir, which can introduce guidelines for gas-condensate well modeling.

Keywords: Gas Condensate, Gas Well, Choke Modeling, Well Flow Modeling, Flow Regime

1. Introduction

Gas condensate systems induce a number of physical phenomena: unstable flow regime, turbulence, and phase change due to pressure and temperature changes. Any pressure drop throughout the flow path, i.e. from reservoir down to the sand face of well and from bottom hole to wellhead, may cause phase segregation and liquid holdup. The degree of liquid holdup

depends on richness of gas condensate system. Deviation in the flow path and high flow rate introduces extra pressure drop and slip velocity.

Wellhead chokes are mechanical equipments installed to control flow rate in high capacity wells. These devices are used to maintain sufficient back pressure which protect the well formation from damage caused by excessive pressure drop and stabilize flow

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rate (Nasriani & Kalantari, 2011). The chokes restrain the reservoir from water coning in gas wells and provide stabilized flow to surface equipment. These devices can be either fixed or adjustable.

Modeling the flow of the compressible fluids, e.g. gas condensate, through chokes is studied by a number of investigators. The flow of fluid through chokes can be either critical or sub-critical. The critical flow occurs when velocity is equal to or above that of sound. In this case, mass flow rate is at its maximum, a function of upstream conditions only, and independent of pressure drop through the choke, while the sub-critical flow occurs when the maximum flow rate is less than sound velocity. Determination of flow regime is important in compressible fluid flow (Osman & Dokla, 1990). Tangren, Dodge, and Seifert (1949) are the first who studied the flow of fluids through the chokes and showed that the flow across the restriction is independent of pressure drop across the chokes at critical conditions. Fortunati (1972) proposed the empirical correlations for subcritical and critical conditions and transition between them using experimental data for a homogeneous mixture. The Gilbert empirical correlation was originally developed for modeling critical flow through chokes as a function of gas-liquid ratio (GLR), the choke size and gas flow rate (Gilbert, 1954). The Gilbert correlation was later extended to take into account the other combinations of operating data to fit different types of fluids and flow conditions.

Studies of well flow modeling are extensively addressed in the related literature: as well as single and two-phase flow regimes in gas wells. It is well-known that different flow regimes may form during two-phase flow in wells. Types of flow regimes depend on the operating parameters like gas and liquid flow rate, physical properties of fluids (density, viscosity, and surface tension), and well parameters like dip angle and diameter (Shoham, 2006). Different two-phase flow patterns in pipelines are identified as stratified, intermittent, slug, annular, churn, dispersed bubble, Taylor bubble, and bubble patterns (Gomez, Shoham, Schmidt, Chokshi, & Northug, 2000; Xiao, Shonham, & Brill, 1990; Yahaya & Al Gahtani, 2010). The two-phase flow pattern in pipelines can be predicted by either empirical or analytical models. Shoham (2006) conducted experimental studies by focusing on the operating parameters in order to propose empirical flow models in vertical, inclined, and horizontal pipes. Some experiments are based on the gas/water system, and their results are then extended to

gas/condensate systems. This is one of the uncertainties associated with well flow modeling and calculation of pressure profile, as these correlations show error when applied to gas/condensate wells. A suggested solution is to optimize the parameters of correlations by matching with field measurements of the pressure drop. The models originally obtained through experiments may be optimized to fit the real gas condensate conditions, provided there are sufficient down hole pressure versus depth records. The obtained correlations may be subject to change with time if flow regime changes throughout the life of a well. Consequently, the analytical models consider physical mechanisms as well as operating and geometrical parameters and physical properties to determine transition between different flow regimes. The works of Yemada Taitel and Dukler (1976), Yehuda Taitel and Barnea (1990), Ansari, Sylvester, Sarica, Shoham, and Brill (1994), Gomez et al. (2000) and Xiao et al. (1990) are examples of the analytical models proposed for modeling two-phase flow in vertical, inclined, and horizontal pipes. When two-phase flow models are applied to gas wells, reservoir properties must be taken into account. Peaceman (1978) studied the performance of vertical and inclined wells through reservoir simulation. Where the bottom-hole pressure, reservoir pressure at the well grid block, absolute and relative permeabilities, fluid densities and viscosities, and pressure gradient in well block were considered. Another important parameter for modeling gas wells is liquid holdup, especially at the bottom hole. This phenomenon may occur in gas-condensate reservoirs when the flow velocity becomes less than the critical value, which has negative impacts on gas flow and reservoir performance. Critical gas velocity can be predicted by Turner, Hubbard, and Dukler (1969) method. Sutton, Cox, Lea, and Rowlan (2010) provide guidelines for calculation of critical gas velocity according to properties of gas and liquids flowing in the well and its effect on velocity profile and location of critical velocity in the well. The works of Flanigan (1958), Beggs and Brill (1973), Mukherjee and Brill (1985), Ansari et al. (1994), Kabir and Hasan (2006), Zhou and Yuan (2010) and Zhang, Wang, Sarica, and Brill (2003a, 2003b) are examples of the studies which consider liquid hold-up and critical velocity in flow modeling of gas wells. Hagedorn and Brown (1965) do not support the flow pattern, although it is applied for predicting pressure profile and holdup in vertical wells. There are a number of studies, by Govier and Fogarasi (1975), Kabir and

Hasan (2006) and Williams (2009) which focus on the flow of gas and condensate in wells, where the complex PVT behavior require inclusion of accurate thermodynamic concepts in conjunction with well flow modeling. Peffer, Miller, and Hill (1988) proposed a modified method to calculate bottom hole pressure in gas wells in the presence of liquid. However, this method is applicable to low volumes of liquid (Kabir & Hasan, 2006).

The objective of this work is to introduce a comprehensive and integrated choke modeling associated with well flow modeling in a multi-well, multi-layer gas-condensate reservoir producing at high rate. In the next sections, the available information is presented and quality of data will be assessed first. Then, the production rates of individual wells are determined according to the commingled, overall daily flow rates using a detailed choke modeling. The pressure profile and flow regime are determined at each section through back-calculation and nodal analysis, in addition to bottom hole pressure prediction. The concluding remarks appear in the last part.

2. Assessment of Available Information

The subject under study is an offshore reservoir located in Persian Gulf with 12 producing wells in one of its platforms. Gas flow from each well passes through a choke valve before entering the platform header. The chokes installed on wellhead are of adjustable type, and their size can be changed to regulate the flow rate according to prevailing operating conditions. The fluid properties are given in table 1. The initial dew point pressure of reservoir fluid is 4630 psia. The, initial CGR and maximum liquid drop-out are 33.4 bbl/scf and 1.64%,

respectively. The pressure and temperature is used to calculate heat capacity ratio, which is used to calculate critical pressure ratio. The heat capacity ratio, defined as the specific heat at constant pressure divided by specific heat at constant volume is between 1.23-1.28. The, critical pressure ratio is between 0.548-0.557, which is higher than the downstream to upstream pressure. The, preliminary analysis of flow regime for the time span under study reveals that flow through all chokes is critical and flow velocity is equal to or higher than sound velocity. At these conditions, the flow rate through chokes is at its maximum, only a function of upstream conditions and independent of downstream parameters. The available information for each well consists of static data, dynamic data, test separator data, and pressure, volume, temperature (PVT) data. The static data include well, formation and drilling information. Dynamic data refer to that information which was collected during production. Typically, dynamic data for this reservoir include wellhead pressure (upstream and downstream of choke), choke opening percent, and wellhead temperature. Production flow rate, are not available for individual wells; rather, total production rate for platforms were recorded on the daily basis for about seven years. The test separator data refer to the information collected from a well when its flow is redirected to test separator. These are the only available production data for individual wells, including choke opening percent, wellhead pressure, separator pressure, gas and liquid (condensate) flow rate. These data are used to determine individual well flow rate, according to the operating (dynamic) data. The data range covered by the valid separator test is presented in table 2.

Table 1. Compositional PVT properties for the fluid

Component	Composition (mole fraction)	Pc (atm)	TC (°F)	Volume Shift	MW (gr mol)	Acentric Factor
N2-C1	0.861	4.49E+01	1.87E+02	-0.154	1.66E+01	0.0095473
H2S	0.0024	8.82E+01	3.73E+02	0.2	3.41E+01	0.1
CO2	0.0193	7.28E+01	3.04E+02	0.2	4.40E+01	0.225
C2-C3	0.072	4.65E+01	3.24E+02	-0.154	3.39E+01	0.112607
IC4toC6	0.0228	3.51E+01	4.50E+02	0.09888	6.73E+01	0.217958
C7toC12	0.0199	3.04E+01	5.89E+02	-0.104548	1.27E+02	0.6046
C13+	0.0026	1.46E+01	7.04E+02	0.260615	2.75E+02	0.98027

Table 2. Range in separator test data for modelling chokes

Property	A-02	A-05	A-07	B-02	Units
WHP	210-250	211-243	208-231	208-239	Barg
DST	59-67	61-67	59-68	60-69	°C
DSP	110-115	110-115	110-115	115-119	Barg
Gas flow rate	53-111	45-118	35-113	40-94	MMSCFD
Gas-liquid ratio	30000-44000	32000-48000	32000-46000	50000-66000	SCF/STB

The correct condensate to gas ratio (CGR) is calculated by flash calculation on the test separators. The available PVT data include compositional analysis, as well as basic sediment and water, and condensate to gas ratio (CGR) for separator tests. In addition to the aforementioned information, the production data reports are available from downstream gas refineries. Careful review of all reports revealed that there were discrepancies between daily production of platforms, test separator reports and downstream facilities at some certain operating days. An example of inconsistent data is presented in figure 1. In this figure, gas to liquid ratio (GLR) is plotted against gas flow rate for the test separator. The recorded points which fall into the oval zone have higher GLR than the expected trend. Further investigations indicated that the mechanical and/or instrumental problems in liquid flow rate measurement facilities, as well as human error could be a source of the observed discrepancies. Based on a comprehensive and integrated investigation of all available information, production data are filtered and the inconsistent data are removed, and robust data are extracted for the rest of studies.

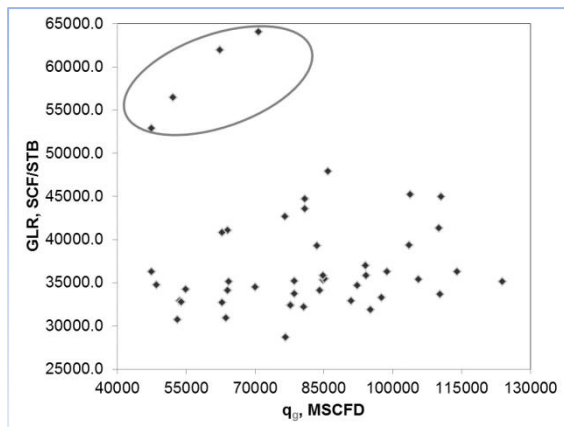


Figure 1. GLR versus gas flow rate for test separator data

3. Choke Modeling

One of the input data in well flow modeling is gas flow rate of individual wells. In the reservoir under study, the production rate is reported for the entire platform rather than per individual well. The total flow rate of the platform is the sum of gas and condensate flow rates per well (Craft & Hawkins, 1991):

$$q_{g,tot} = \sum_i [q_g + q_c (GE)]_i \quad (1)$$

Where, i refer to an individual well, q_g and q_c are the gas and condensate flow rates,

respectively, and GE is the gas equivalent of condensate.

$$(GE)_c = 133000 \frac{\gamma_c}{MW_c} \quad (2)$$

$$MW_c = \frac{5954}{API - 8.811} \quad (3)$$

In equations (2-3), γ_c , MW_c and API are the specific gravity, molecular weight and API gravity of condensate, respectively.

For the wells under study, no correlation was available between choke bean size and choke opening, nor between flow rate and choke opening; therefore, the first step was to determine a correlation between choke sizes and well flow rate. To do this, test separator data are carefully analyzed to obtain the best correlation for each well. An optimization procedure with consecutive trial and error calculations is performed to extract optimum correlation for each choke. The calculation algorithm for modeling chokes and correlating choke percent opening and gas flow rate is presented in figure 2.

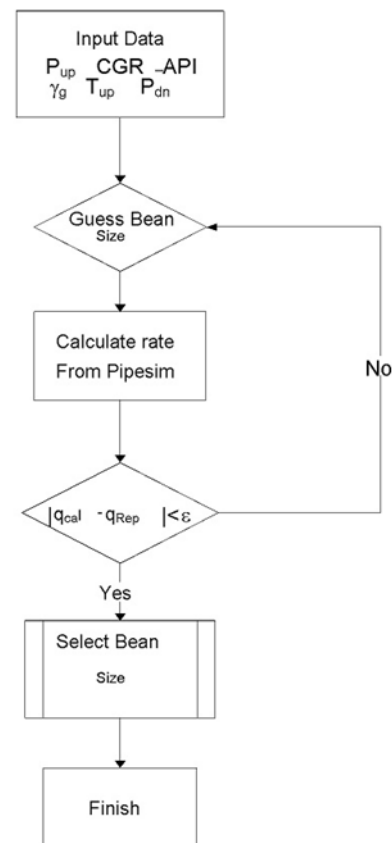


Figure 2. Algorithm for modeling chokes and determining the proper correlation between choke size and percent opening

The input data consist of upstream pressure (P_{up}), downstream pressure (P_{dn}), CGR, condensate API, gas gravity (γ_g) and

upstream temperature (T_{up}). Based on this proposed algorithm, a bean size is assumed first; then, the flow rate is calculated through the Pipesim software (Schlumberger, 2008) and is compared with the reported flow from test separator data. This procedure is repeated for each well until the calculated flow rate converges to the reported value. Analysis of the average absolute deviation for each well, defined by equation (4), determines the best correlation between bean size and choke opening for each well.

$$AAPD = \frac{\sum_{i=1}^n \left| \frac{q_{g, Rep} - q_{g, Cal}}{q_{g, Rep}} \right|}{n} \times 100 \quad (4)$$

A typical plot of correlation for bean size versus percent choke opening for one of the platforms, (A) is presented in figure 3. The linear correlation is shown on the same figure, which is applicable in the range of 35-54% choke opening. Similar plots are obtained for chokes for individual wells. Further investigations indicated that, the flow rates of produced condensate and water (equivalent to

gas) and their PVT properties, e.g. API of condensate, have little impact on choke calculations. For example, changing API from 48 to 52 resulted in about 0.002 inches difference in choke bean size, which is practically insignificant. Similar results are obtained for water flow rate. The sensitivity analysis results for the effects of condensate API and producing water flow rate on the calculated bean size and gas flow rate, are summarized in tables 3-4, respectively. According to these tables, it can be suggested that water and condensate flow rates have little impact on calculations, as well as the API of condensate. Therefore, liquid flow rates may be safely neglected in obtaining the correlation between choke bean size and percent opening, and the correlation can be based on the dry gas flow rate only. This is due to the relatively low flow rates of condensate and water compared to high flow rate of gas in a lean gas reservoir like the one in this study. By ignoring liquid flow rates, the uncertainties in liquid flow meters will be diminished.

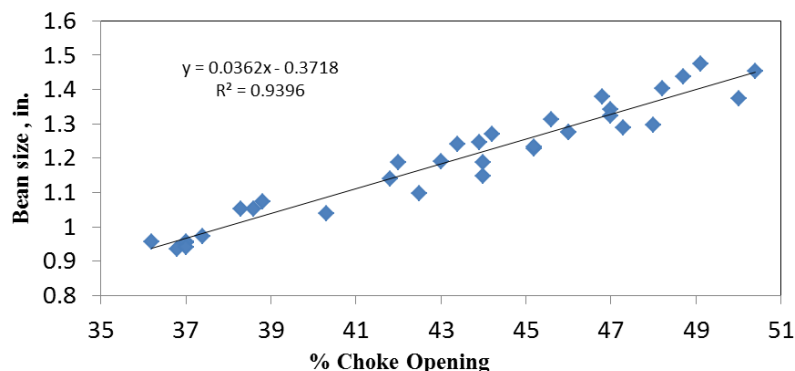


Figure 3. Correlation for bean size versus percent choke opening for platform A

Table 3. The effect of API on the flow rate

API=48		API=52.74		API=54	
q_g MMSCFD	q_c STBD	q_g MMSCFD	q_c STBD	q_g MMSCFD	q_c STBD
43.65	1248.5	43.77	1251.7	43.79	1252.5

Table 4. The effect of elimination of water on the relation of bean size and choke percent

Choke Opening Percent	Bean Size Obtained From Pipesim Without Water Rate	Bean Size Obtained From Pipesim With Water Rate
36	0.869	0.8665
43	1.037	1.0348
50	1.167	1.1647
48	1.1834	1.1806
42	1.063	1.061
36	0.869	0.8665

4. Pressure Profile and Flow Regime

When the flow rate per well is established (figure 4), the next step is to determine the bottom hole pressure, as well as temperature and pressure profile and flow regime throughout the well. The gas rate for selected operating days in wells A-02, A-05, A-07, B-04 are presented in figure 4. In this step, the bottom hole pressure (BHP) is related to well head pressure (WHP) and pressure losses due to friction ($\Delta P_{\text{friction}}$), gravity ($\Delta P_{\text{gravity}}$) and acceleration ($\Delta P_{\text{acceleration}}$), respectively:

$$\text{BHP} = \text{WHP} + \Delta P_{\text{friction}} + \Delta P_{\text{gravity}} + \Delta P_{\text{acceleration}} \quad (5)$$

For the reservoir under study, the production logging tools (PLT) are available in four wells at specific dates. The reports contained pressure, flow rate, and temperature profile at the producing zone of reservoir. These data are applied to select the best correlations that would show the best match with PLT data.

The pressure profile versus depth for all four wells are presented in figure 5. The PLT data are shown for comparison. The average absolute deviation for pressure prediction in all wells is shown in figure 6. According to figure 5, the Zhang et al. (2003a, 2003b) model is found to match with PLT data for wells A-02, A-05, and A-07, while the last well (B-04) showed a good match with Hagedorn and Brown (1965) correlation. It should be mentioned that the Zhang et al. (2003a, 2003b) model is a mechanistic model applied for prediction of flow pattern transitions, pressure gradient, liquid holdup and slug characteristics in gas-liquid pipe flow, and is valid for all inclination angles. The results indicate that this model works well for gas condensate systems flowing through deviated wells. The Hagedorn and Brown (1965) correlation is applied for pressure loss and holdup in vertical well (B-04), but it does not predict flow pattern. For this case, the Orkiszewski (1967) model is adopted to model the flow regime.

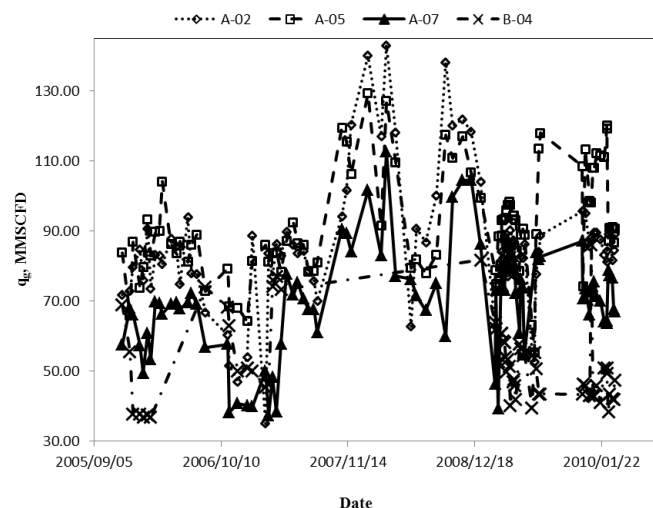


Figure 4. Gas rate for selected operating days in wells A-02;05;07 and B-04

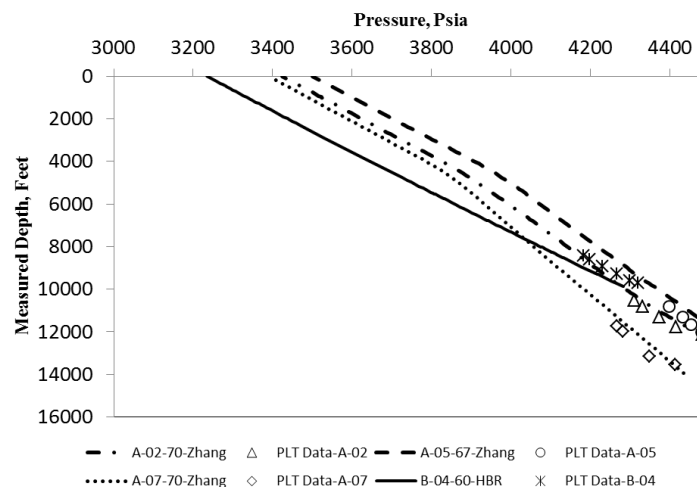


Figure 5. pressure profile for wells

The bottom hole pressures (BHP) for selected operating days in wells A-02; 05; 07 and B-04 are presented in figure 7. The dew point line is plotted in this figure. According to figure 6, the well fluid is below or near to dew point at the sand face for the duration of this study. The jumps in pressure may be due to changes in gas flow rate. Alternatively, work over operations, e.g. stimulation by well acidizing, or new perforations in adjacent layers may lead to higher flow rates and subsequent fluctuations in bottom hole pressure. Another possibility may be a sudden change in flow rate which may result in revaporization or movement of the collected liquids. The profiles of pressure, temperature and liquid holdup for well A-02 is presented in figure 8. Similar results are presented in figures 9-11 for wells A-05, A-07, and B-04, respectively. According to the results, the flowing fluid is mostly gas in the well, with a small fraction of holdup close to the wellhead. The depth of liquid holdup formation is different from one well to another, yet its value

is very small in the deviated wells A-02, A-05, and A-07, compared to the vertical well B-04. It can be observed that the hold-up behavior of the vertical well B-04, which adopt the Hagedorn and Brown (1965) model to predict holdup, is different from other wells which are deviated in pattern. Holdup of liquid, mostly condensate than water is an indication of losing part of produced condensate in the well at prevailing conditions. The density difference between gas and liquid causes the liquid phase to slip in the reverse direction. Thus, low holdup implies that most of the liquid is carried out of the well. Nevertheless, flow regime and onset of transition may be subject to change with time whereby flowing pressure, CGR, PVT and fluid composition change during production life of reservoir. Further investigation of the results indicated that liquid holdup is subject to the wellhead pressure and well flow rate, which decreases as the wellhead pressure increases. The lower gas flow rates resulted in higher liquid holdup and faster change in flow regime within the well.

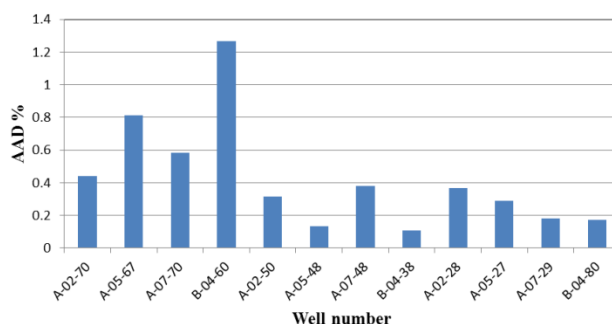


Figure 6. Average Absolute Deviation for pressure prediction in all wells

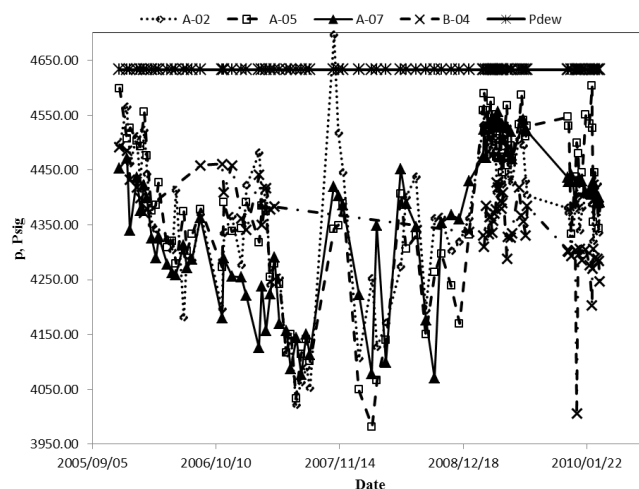


Figure 7. Bottom hole pressure (BHP) for selected operating days in wells A-02;05;07 and B-04

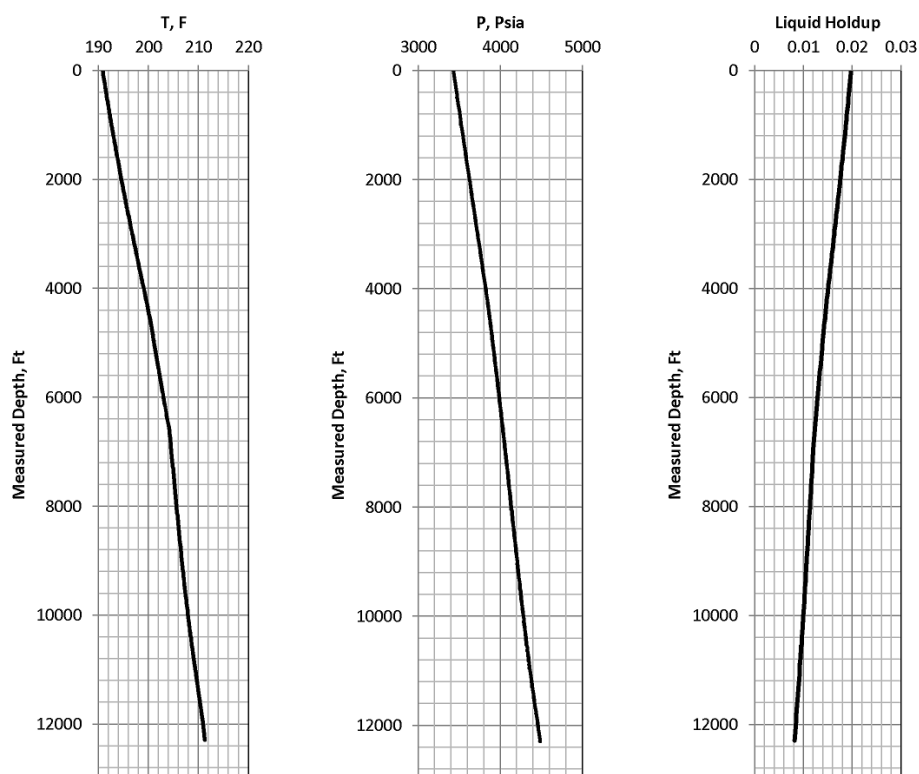


Figure 8. Liquid holdup, pressure and temperature profiles for the well A-02

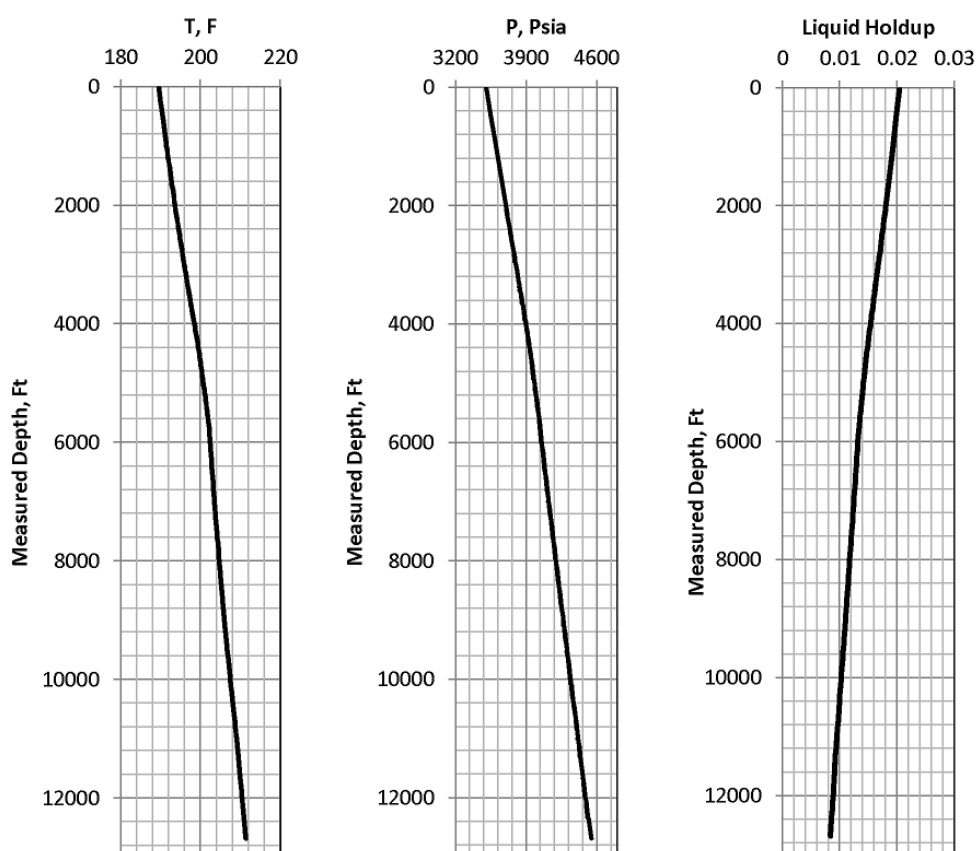


Figure 9. Liquid holdup, pressure and temperature profiles for the well A-05

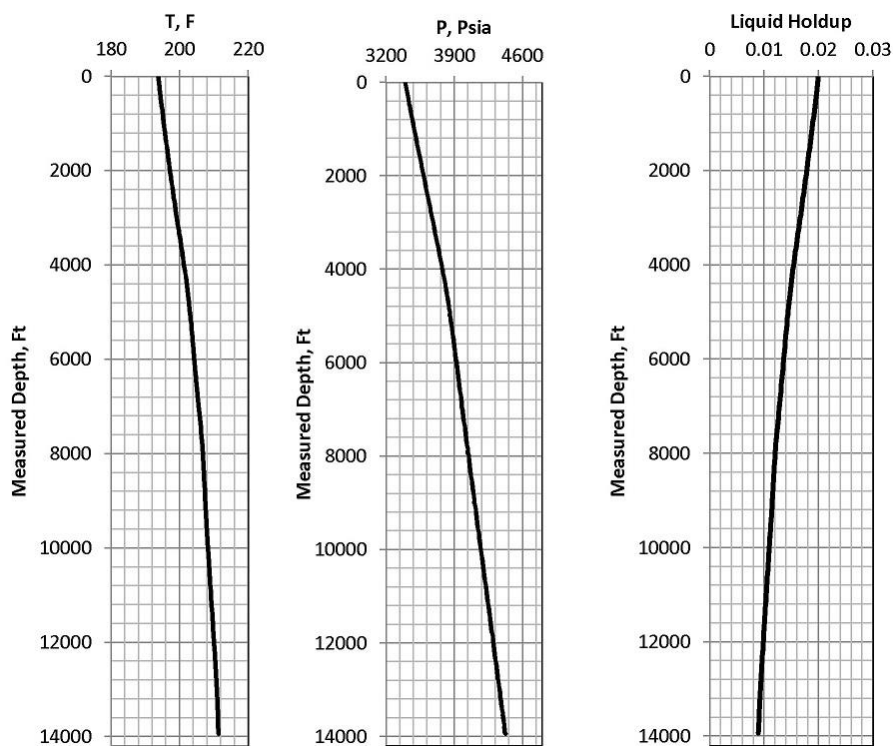


Figure 10. Liquid holdup, pressure and temperature profiles for the well A-07

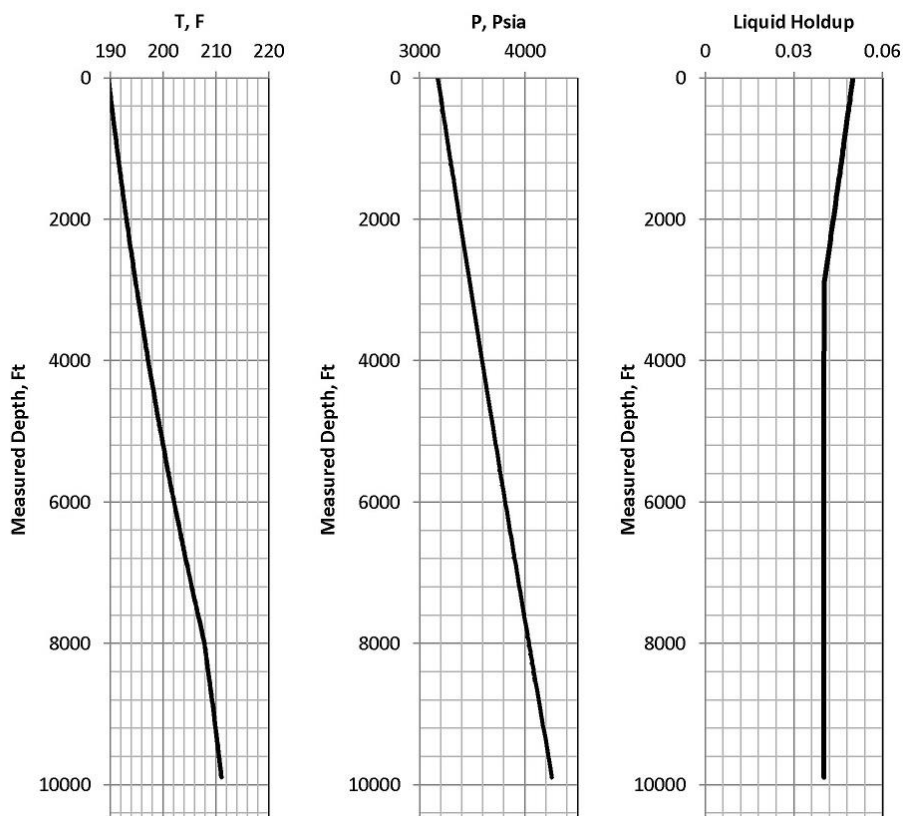


Figure 11. . Liquid holdup, pressure and temperature profiles for the well B-04

5. Conclusion

In this work, an integrated algorithm is proposed for well flow modeling in gas condensate wells. This approach begins with modeling wellhead chokes to determine choke coefficients and individual well flow rates from overall platform rate, followed by examining different models to obtain the most suitable model which matches the PLT recorded data. Based on the results of this study, it is found that:

1. Flow rates of produced condensate and water (equivalent to gas) and their PVT properties, e.g. API of condensate, have little impact on choke calculations.
2. Best correlations for pressure profile and flow regime are selected by comparing this model results with reported production logging tool (PLT) data. The Zhang et al. (2003a, 2003b) and Hagedorn and Brown (1965) correlations are found to match with PLT data of four gas condensate wells.
3. The flow is gas-like at the bottom and shifts to mist flow, followed by transition near the wellhead.

Acknowledgement

The financial support of this project is provided by National Iranian Oil Company (NIOC). This support is gratefully acknowledged.

Nomenclature

MW	Molecular weight
n	Number of data points
P	Pressure
q	Flow rate
ΔP	Pressure drop

Greek symbols

γ	Specific gravity, Dimensionless
ε	Error

Subscripts

c	Condensate
cal	Calculated
dn	Downstream
g	Gas
tot	Total
Rep	Reported
up	Upstream

Abbreviations

AAPD	Average absolute percent deviation
BHP	Bottomhole pressure Bottom Hole Pressure

CGR	Condensate gas ratio
DSP	Downstream pressure
DST	Downstream temperature
GE	Gas Equivalent
GLR	Gas liquid ratio
PLT	Production Logging Tools
PVT	Pressure volume temperature
SCF	Standard Cubic Feet
STB	Stock Tank Barrel
WHP	Wellhead Pressure

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