Production Data Analysis in a Gas-Condensate Field: Methodology, Challenges, and Uncertainties

Heidari Sureshjani, Mohmmad Hossein
IOR Research Institute, Tehran, I.R. IRAN

Azin, Reza*+
Department of Petroleum Engineering, Faculty of Petroleum, Gas and Petrochemical Engineering, Persian Gulf University, Bushehr, I.R. IRAN

Lak, Ahmad; Osfouri, Shahriar
Department of Chemical Engineering, Faculty of Petroleum, Gas and Petrochemical Engineering, Persian Gulf University, Bushehr, I.R. IRAN

Chahshoori, Robab; Sadeghi, Foroozan
Department of Petroleum Engineering, Faculty of Petroleum, Gas and Petrochemical Engineering, Persian Gulf University, Bushehr, I.R. IRAN

Lali, Marziyeh; Gerami, Shahab
IOR Research Institute, Tehran, I.R. IRAN

ABSTRACT: *Production data analysis techniques have been widely used for estimating reservoir properties such as gas in place and average pressure. Knowledge of this information is crucial for proper reservoir management. The present study discusses the roadmap, challenges and uncertainties for analyzing production data in an Iranian gas-condensate offshore field. This work is an integrated study involving the quality check of production data, platform process simulation, orifice simulation, modeling choke performance, well modeling, and Rate Transient Analysis (RTA). The study is an inverse analysis which starts from production platform and continues down to the reservoir. To perform data analysis, we propose five general steps which are: Data gathering/extraction/quality check, well rate determination, well bottom hole pressure estimation, layer rate allocation, and reservoir property estimation. In this study, these steps are discussed elaborately. Furthermore, challenges of each step are presented and discussed. In addition, the required input and also missing data for each step is mentioned. Also, to cope with lack and/or uncertainties of data, feasible solutions are proposed for the current field situation as well as future developments. This paper can help petroleum engineers to know where to start and how to proceed to get to the final step of the analysis, i.e. estimating field gas in place. It also provides insights to challenges and uncertainties of the production analysis in gas-condensate fields.*

KEYWORDS: *Gas condensate reservoir; Production data analysis; Data uncertainty; Integrated reservoir study.*

* *To whom correspondence should be addressed.*
+ *E-mail: reza.azin@pgu.ac.ir*
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INTRODUCTION

Techniques of production data analysis are regarded as one of the important engineering tools to give information such as gas in place, average reservoir pressure, permeability, and skin factor. The first practical and comprehensive method for analysis of production data was presented by *Arps* [1]. *Arps* empirical equations, which are exponential, harmonic and hyperbolic, are still very useful for determining ultimate expected recovery and production prediction. *Fetkovich* [2] presented *Arps* equations in dimensionless form and incorporated them into transient stems to generate analytical-empirical type curves. Introducing the concept of material balance time and material balance pseudo time (*Blasingame & Lee* (1986); *Blasingame & Lee* 1988) was a great advancement in the area of production data analysis [3,4]. These time functions are used to account for variable well rate/pressure conditions. Considering the literature of production analysis, many studies have been performed for dry gas reservoirs. Important examples are works of *Palacio & Blasingame* (1993) [5], *Agarwal et al.* (1999) [6], *Ansah et al.* (2000) [7], and *Mattar & Anderson* (2005) [8]. However, little attention has been devoted to gas-condensate systems.

Obtaining representative composition of reservoir fluid has an important effect on prediction of reservoir behavior. Some phenomenon such as gas coning and liquid drop-outs can reduce the accuracy of fluid composition.

Parhamvand et al. (2013) obtained an equilibrium contact mixing method to estimate the original reservoir fluid compositions when gas coning is happened [4]. They mixed collected samples from only oil zone with the producing gas oil ratio and separated prepared well stream at initial gas oil contact conditions. Then detailed equation of state characterization were used to simulate experimental separator tests.

Due to small amounts of liquid drop-outs in lean gas condensates reservoirs, full experimental tracking of phase diagram is almost impossible. *Gharesheikhloo & Moayyedi* (2014) proposed a new procedure based on experimental-simulation method in order to constructing phase diagrams for a lean gas condensate reservoir fluid [10]. They showed that critical points of lean gas condensate reservoir fluid could not be detected experimentally due to exclusive phase behavior of the fluid and it only can be estimated by allegorical extrapolating of accessed quality lines.

The present study aims to discuss production data analysis in an Iranian multilayer, gas condensate field located offshore in Persian Gulf which is still under development. To the best of our knowledge, a well-organized methodology for analyzing a multi-layer multi-well gas-condensate reservoir is not available in literature. Most methods are developed for single well dry gas reservoirs. The only available analytical method for gas condensate reservoirs is proposed by *Heidari Sureshjani & Gerami* [11]. This method is suited for single-well single-layer gas-condensate systems. In its current form, it cannot be applied for the reservoir under study. The lack of a suitable RTA model is not the only problem. Preparation of input data (well rates and bottom hole pressure history) for RTA models in this field is also a real challenge. In this paper, these challenges and uncertainties and solutions to meet them are addressed. In the next sections, statement of problem is presented first. Then, production platforms are briefly described. Next, the integrated methodology is proposed for analysis of the whole process. After that, challenges and uncertainties are discussed in detail. Finally, concluding remarks are presented.

STATEMENT OF THE PROBLEM

Determination of well rate history in this field has been of great attention from the start of production. In the daily recorded data, total gas and condensate rates of production platform is recorded. However, production rate of individual wells is not known. An important application of knowing well rates is to analyze them to evaluate well production performance, analyze well flow behavior and estimate reservoir parameters of well drainage volume. In another words, production analysis cannot be performed unless well rate history is available. The reason is that production data analysis methods are per well basis. Also, in full field simulations, knowing the individual well rates can be very helpful for history matching task. In this paper, we propose a step by step roadmap for analysis of production data in this field. To perform these steps, we faced a lot of challenges due to lack and/or uncertainties of data and also absence of models for some parts of our specific problem. This paper

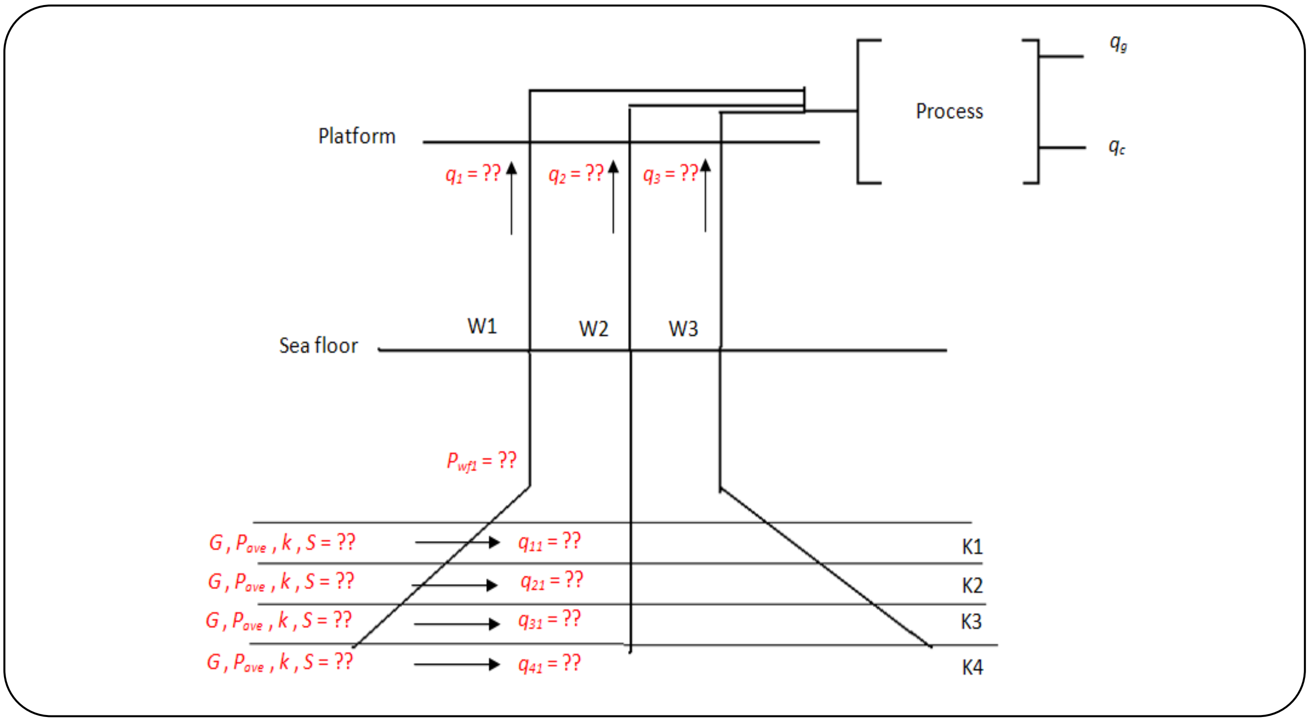

Fig. 1: Overall schematic of physical model with three arbitrary wells.

focuses only on one phase of this field, though the provided guidelines are somehow applicable for all production phases. Fig. 1 briefly presents schematic of the problem in which three arbitrary wells are joined at the inlet of process platform. The parameters to be calculated are as follow:

- Gas and condensate rate of each well
- Flowing bottom hole pressure
- Production rate of each layer
- Reservoir parameters such as gas in place, average pressure, permeability and skin
- Well production forecast

The available daily production data include total gas and condensate flow rates, well head pressures, percent of choke opening, choke downstream pressure and temperature. The last two data were missing for some operating periods.

DESCRIPTION OF PRODUCTION PLATFORMS

There are two drilling platforms A and B operating in this phase of field. Each platform consists of 6 deviated wells numbered as A-1 through A-6 and B-1 through B-6. The flow of each well in each platform is controlled by adjustable chokes. The streams of these wells are forwarded to a production platform, which consists of two parallel process trains. These trains are designed for primary processes such as dehydration of well streams. The fluids from wells of platforms A and B are transmitted to train 1 and train 2, respectively. Also, a side stream from platform A is designed to balance flow rates in two trains. The purpose of this process unit is to remove water from produced hydrocarbons so that corrosion and hydrate formation in the sea line is inhibited. The gas, condensate and water streams are separated in each train. Separated water flows to water treatment unit while separated gas and condensate streams are first metered using orifice meters and then mixed and transmitted to onshore refinery through sea line.

OVERALL MEHODOLOGY

As stated, the input data for production analysis techniques are history of well rate and bottom hole pressure. However, these data are missing for this field. Instead, total production rate of platform is available. In addition to total platform daily production rate, production history of each train is also recorded. Therefore, total flow rate must be split to obtain flow rate of each well. This means dividing total gas and

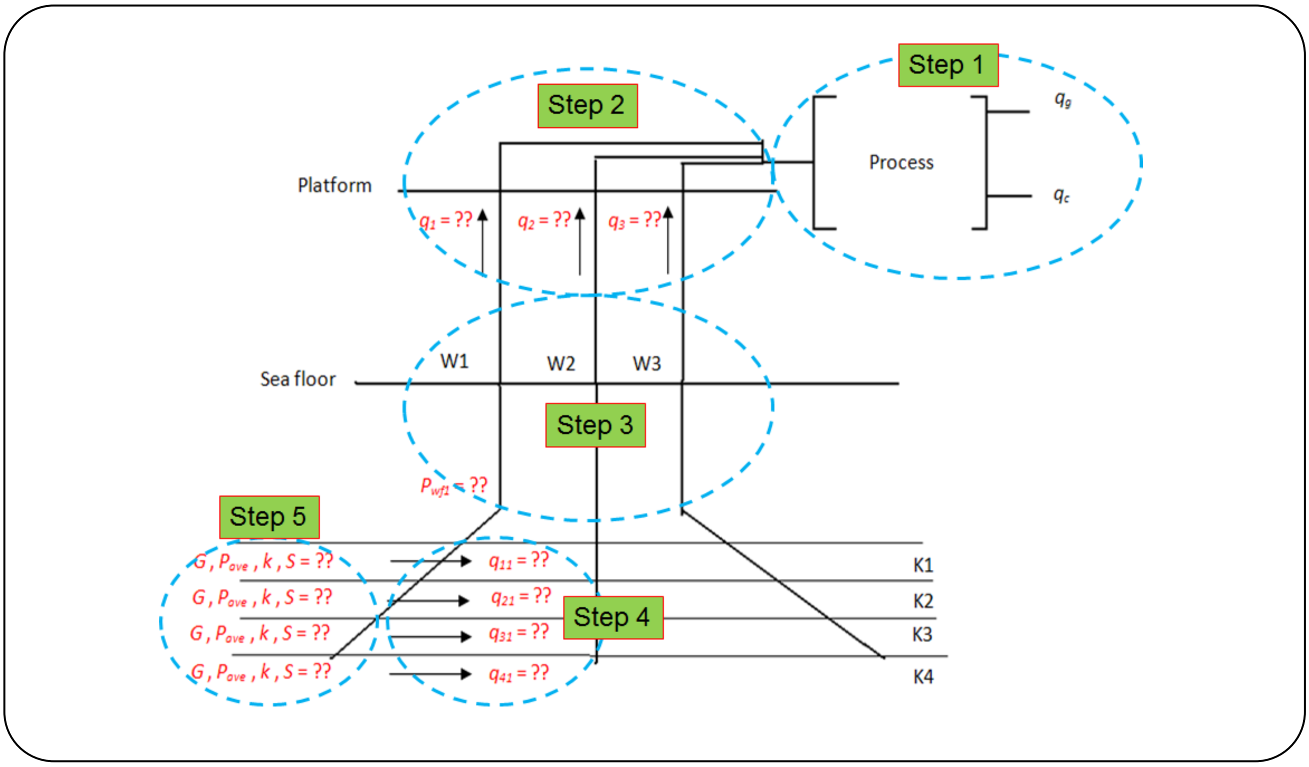

Fig. 2: General steps for performing production data analysis in the reservoir under study.

condensate rates into those of each well. Here the question may arise is to what extent the daily recorded data are reliable. It is worth mentioning that there may be two important sources of error, errors associated with measuring devices and human error. The second source seems to be less important and here, it is less pronounced. Undoubtedly, the first step is to perform quality check of production data. To do so, preliminary consistency checks should be performed. Also, accuracy of orifice meters must be evaluated. In the next step, the daily recorded well head flowing pressures must be converted to flowing bottom hole pressures. Knowing the well pressure/rate data, one can apply data analysis techniques to determine reservoir parameters. However, these techniques are basically developed for single layer reservoirs. In case of multi-layer systems (as is the case of this reservoir), averaging techniques may be used. The averaging techniques are applicable when layers have good communication within the reservoir. On the other hand, if there is no cross flow between layers, it is more convenient to analyze production data of each layer separately. Consequently, the calculated well rate for each well must be divided to production rate of each layer. Thereafter, suitable methods may be used to analyze data and estimate properties for each layer individually. In summary, the general steps are as follows.

- Step 1: Gather platform production data, organize and summarize them. Then check the consistency of recorded data and evaluate the quality and accuracy of data.
- Step 2: Split total gas and condensate rate from each train to rate of wells feeding that train.
- Step 3: Convert wellhead flowing pressure to flowing bottom hole pressure.
- Step 4: Determine contribution of each layer to production.
- Step 5: Analyze well (layer) rate and pressure data to estimate reservoir properties.

Fig. 2 presents the sequence of five steps in overall methodology. The above steps should be performed in consecutive order as the output of each step is the input of the next. Each step has its own challenges and uncertainties which will be discussed elaborately in the next section.

CHALLENGES AND UNCERTAINTIES

In this section, the missing data, challenges and uncertainties of each step are presented. In addition,

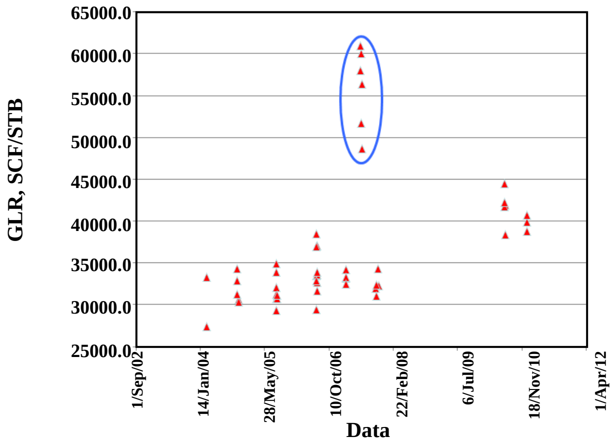

Fig. 3: GLR vs. date for separator test data of wells in platform A.

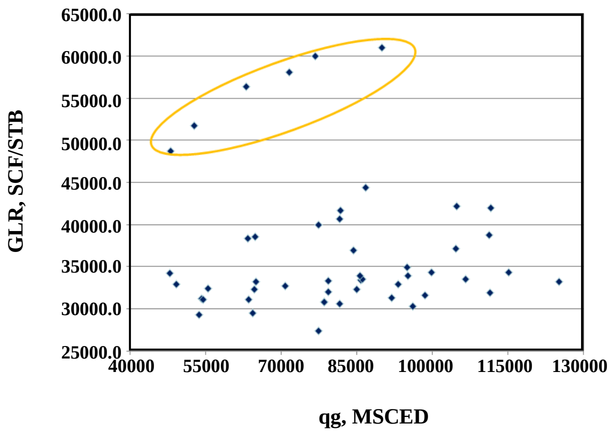

Fig. 4: GLR vs. gas rate for separator test data of wells in platform A.

we explain how to cope with some of the challenges of each step.

Step 1: Data Gathering and Quality Check

The first task in this stage is to gather, extract, and organize the required data. These data are both static and dynamic data. There are immense amount of raw data which are not really all necessary. We must first recognize which part of data is required for our calculations. Next, these data are extracted, organized and classified in an appropriate format. In summary, these data are classified as dynamic data, separator test (multi-rate test) data, and static data. Dynamic data include well head pressure, choke opening (%), choke upstream pressure, choke downstream pressure, choke downstream temperature, and total gas and condensate production flow rate for each train and platform. Separator test data are collected in certain days when flow of only one well is directed to a test separator for single-well flow analysis. Collected data during test separator are mainly dynamic and contain well head pressure, choke opening (%), separator pressure, choke downstream temperature, and well gas and condensate flow rate. In addition to dynamic data, there are some static data which are necessary for analysis. These include Process Flow Diagram (PFD), design data of process unit and orifice meters, well deviation survey data, tubing size and tubing properties. After collection of data, an overall review of data should be conducted to determine the off data. As an example of this step, Gas Liquid Ratio (GLR) data of separator test were examined for wells of platform A, as shown in Figs. 3 and 4 As seen, there are 6 data points that fall in the oval and show sever deviation from the bulk of data, no matter if the data are plotted against time or gas rate.

In the daily recorded data, flow rates of both trains are available, as well as total platform flow rate. It is obvious that a simple summation of flow rates of trains must equal total flow rate of platform. According to our examination, some of data seemed to be erroneous. This can be seen in Figs. 5 and 6 for gas and condensate flow rates, respectively. The erroneous data points are those which exhibit difference between summation of trains rates and total platform rate. We can identify them as non-zero green data points. For condensate flow rates, we should not expect exact zero points because liquid measurements are always subject to error and uncertainty. Accordingly, we should not ignore all non-zero data point for condensate flow rates and only eliminate points which exhibit significant difference. We should note that the condensate flow rates have little effect on the total wet gas rates because the reservoir is very lean and oil-gas ratio is very small. For gas data points, however, the measurements are expected to be more precise and we should eliminate all non-zero green data points. These two examples are a simple quality check of data. Another main concern is whether measuring devices are functioning properly or not. These devices include pressure meters, temperature meters and orifice meters. Among these, orifice devices seem to be more susceptible to errors. To examine these devices, standard orifice equations (*Bradley & Gipson* 1987; *Cholet* 2001;

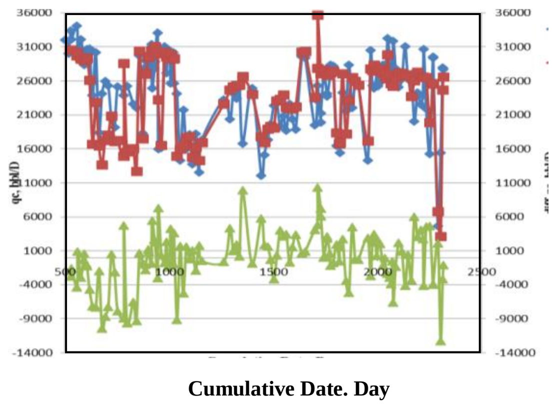

Fig. 5: Comparison of total reported condensate rate and summation of condensate rates of trains.

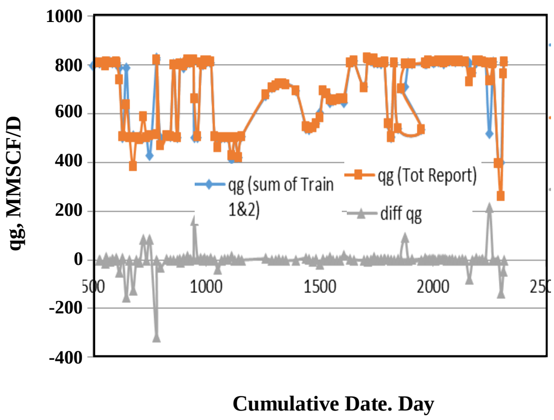

Fig. 6: Comparison of total reported gas rate and summation of gas rates of trains.

Silla 2003; *Perry & Green 2008*) should be programmed, validated against available design data and then used to test validity of operation data [12-15]. Calculated volumetric flow rates are expected to be in agreement with recorded production data. However, in the absence of a well-organized set of operation data such as inlet pressure and temperature, pressure drop across the orifice, and fluid composition, predictions may not be compared with operating data properly. Although we have programmed the orifice equations and validated them against design data, the valid operation data were not available to examine the validity of design constants for operation conditions. Therefore, accuracy of gas-phase and liquid-phase orifices is still under question. By the way, we used our programs to conduct sensitivity studies to study the effect of different parameters on calculated flow rate. Effects of composition, fluid molecular weight and liquid density, flowing pressure, flowing temperature, and pressure difference across the orifice were studied, and part of the results are shown in Figs. 7-9. Considering a 4-component composition (C_1, C_2, CO_2, H_2S), the effect of mole fraction change of each component on gas rate has been shown in Fig. 7. As can be seen, the gas composition has very small effect on the calculated gas rate. It is seen that 7% increase in methane mole fraction results in 2.4% increase in gas rate. For ethane, 250% increase in mole fraction causes 0.8% decrease in gas rate. For carbon dioxide, an increase of 400% in its mole fraction results in 2.4% decrease in gas rate. Finally, 700% increase of hydrogen sulfide mole fraction results in 0.3% decrease in gas rate. Also, Fig. 8 indicates that gas molecular weight and liquid density have little impact on the orifice results. It is observed that 3% increase in gas molecular weight causes 1% decrease in gas rate. Also, 1% increase in liquid density results in 0.5% decrease in liquid rate. Effects of flow pressure and temperature and also pressure difference are presented by Fig. 9. As observed from this figure, 1% increase in pressure causes 0.5% increase in gas rate, 1% increase in temperature results in 0.15% decrease in gas rate and 1% increase in pressure difference leads to 0.5% increase in gas rate. In summary, important issues of the first step may be outlined as follow:

- Required data must be recognized, extracted and sorted.
- Preliminary data quality control and consistency checks must be performed and outliers should be removed.
- Make sure that measuring devices, e.g. orifice meters, are working properly. The calculated rates must be in agreement with daily reported gas and condensate rates.
- According to sensitivity studies, effect of change in gas composition and fluid properties on calculated gas rate is ignorable. Therefore, the effect of compositional change during production life of reservoir may be ignorable on orifice calculations.

Step 2: Well Rate Determination

As stated, the individual daily well rates are not recorded in this field. For calculation of well rate history, we use choke models. The installed chokes in this field

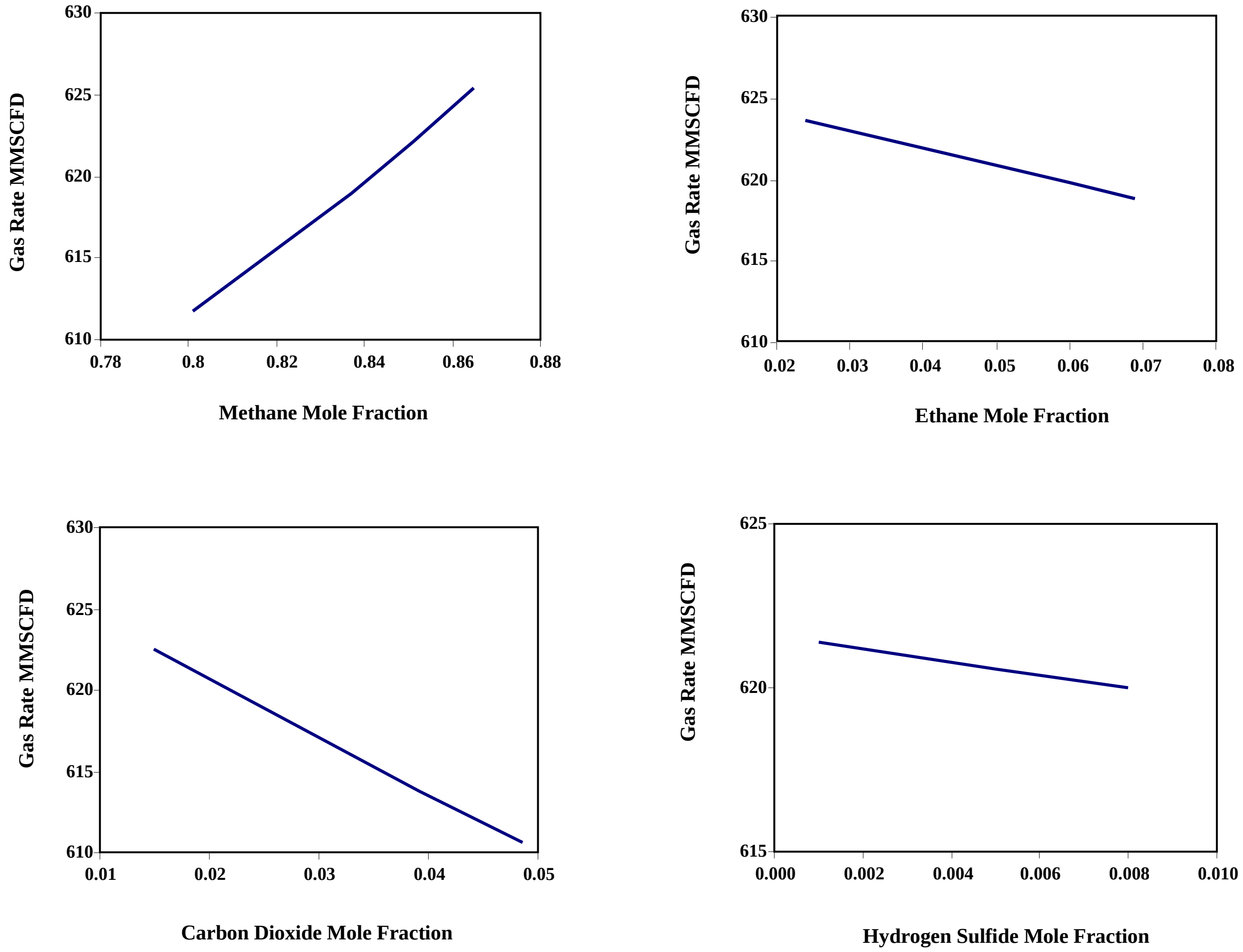

Fig. 7: Effect of composition on calculated gas rate by orifice.

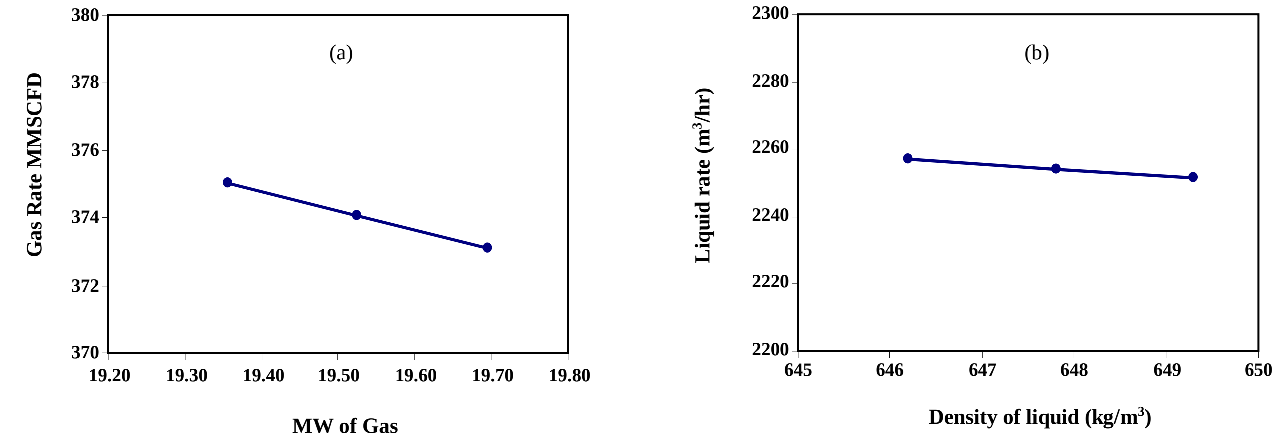

Fig. 8: Effect of (a) gas molecular weight and (b) liquid density on the calculated rate.

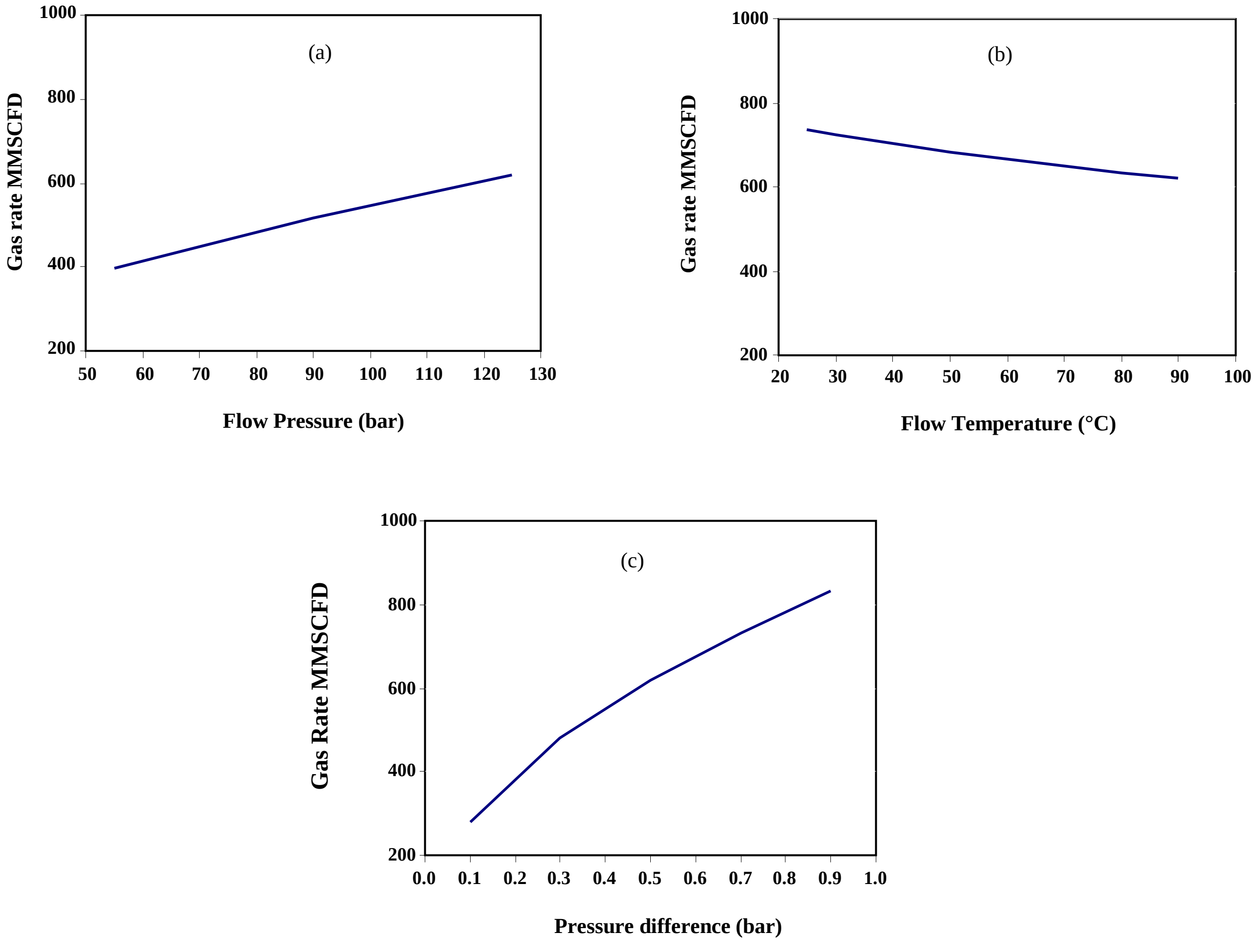

Fig. 9: Effect of (a) flow pressure (b) temperature and (c) pressure difference on the calculated rate.

are adjustable, i.e. their opening changes automatically with time. One main problem that we encountered was that the actual opening size of chokes was not recorded; instead, percent of opening was recorded on daily average basis. It is obvious that models developed for choke performance, e.g. *Gilbert* model (*Gilbert* 1954), require actual choke size [16]. Another main problem is selection of proper model to be used, as there are many models available in literature. The third challenge is that overall fluid composition or GOR must be known to perform choke calculations. A comprehensive survey of available documents revealed that no relationship between actual choke size versus choke opening was present for wells of this reservoir. Therefore, we tried to establish a reliable correlation between choke opening percent and nominal bean size within the operating ranges using separator test data. In these tests, both gas and condensate flow rates are measured for specific well head pressures, and the choke opening percent and separator pressure are recorded for each test. Knowing these parameters, a linear relationship between percent of opening and choke size was found, as shown in Fig. 10 for wells of platform A. We point out that such a relation is not necessarily a straight line as we obtained S-shaped curves for wells located in another part of field. Fig. 11 shows a nonlinear correlation for a specific well. Note that this relation could be either per well basis or per platform basis (i.e. for a cluster of wells). Our investigation reveals that per well basis relations would eventually result in better rate estimations. Note that the relation shown in Figures 10 is applicable for wells of this platform only and may not be applied to other wells, as it is obtained from test separator data of the wells of this phase of field. Another point is that these relations are only applicable for the exhibited

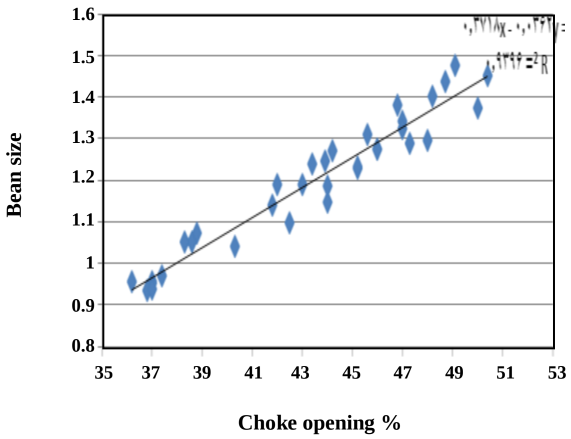

Fig. 10: Relationship between choke opening (percent) vs. bean size for wells of platform A.

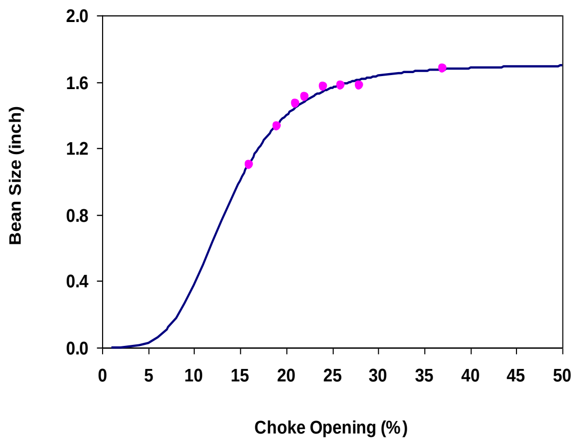

Fig. 11: Relationship between choke opening (percent) vs. bean size for well 4 of platform C.

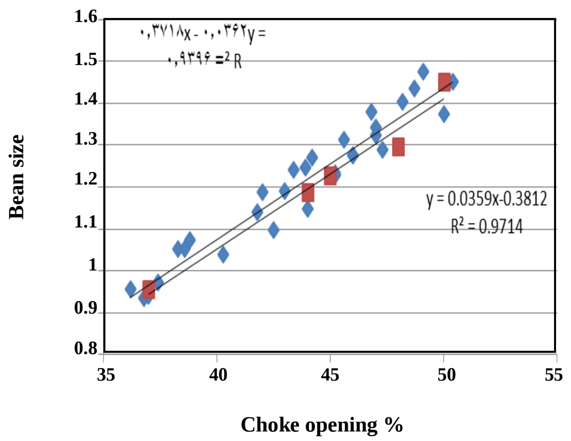

Fig. 12: Slight shifting of the fitted line to tune it for wells of platform A.

range of opening percent and extrapolation out of this range is not guaranteed. To assure that the calculated rates are acceptable, two criteria must be met:

1. For the same wellhead pressure and opening percent in separator test data, the choke model must give the same flow rates as those measured in the tests.

2. Once the individual well flow rates are calculated, the summation of these rates must equal to those of total platform flow rates available in daily reports.

The relationship in Figure 10 represents not only the relation between opening percent and bean size, but also the tuning of the used choke model with separator test data. Therefore, we are somehow sure that the first criterion could be fairly met. To meet the second criterion, the calculated rates must be added and we must see if they are in agreement with total rates of each train. We can also tune the line for the second criterion. This is typically shown in Fig. 12. Normalization can be achieved by slight shifting or rotating of the corresponding line. It should be emphasized that the choke model for calculating rate must be the same as that used for determining relation between choke actual size and percent opening. Table 1 presents the obtained relations between choke opening percent and bean size for wells in platform B. It also shows the introduced errors of calculated rates when compared to measured rates from separator tests**.** This table shows that first criterion is fairly met for wells of platform B. Table 2 compares calculated and measured total gas and condensate flow rates for platforms A and B for specific dates in year 2010, using best relationship between opening percent and actual size. This table illustrates that the second criterion is met with acceptable accuracy. For calculating well flow rates using choke models, we must know history of Gas-Oil Ratio (GOR). Considering that GOR data of individual well are unknown but those of each train are known, we assumed that GOR of all wells are equal to GOR of the corresponding train. Because gas and condensate orifices do not operate at standard pressure and temperature, measured streams need to be recombined and flashed at standard conditions to give total gas and total condensate flow rate at standard conditions. Then, we can simply divide standard gas and condensate flow rates to obtain producing GOR. Here the problem is that for recombining streams we need to know operational compositions entering the gas and condensate orifice.

Table 1: Relations for wells in platform B and the introduced errors of calculated rates compared to measured rates from separator tests.

Well Number	Correlation of Choke Opening percent (x) and Bean Size (y)	R^2	Absolute Average Percent Error
1	$y = 0.0137x + 0.4838$	0.8006	10.24
2	$y = 0.0219x + 0.1678$	0.9857	2.76
3	$y = 0.4172e^{0.0215x}$	0.9342	6.11
4	$y = 0.0153x + 0.4243$	0.9462	7.04
5	$y = 0.0113x + 0.5447$	0.9052	7.93
6	$y = 0.0194x + 0.1989$	0.9978	1.68

Table 2: Measured and calculated total flow rates of platform A and B (sum of rates of all wells) for specific dates in year 2010.

Date	Calculated Rate			Reported Rate			Absolute Percent Error		
(MMDDYYYY)	Calculated condensate rate (STB/D)	Calculated gas rate (MMSCFD)	Calculated rich gas rate (MMSCFD)	Measured condensate rate (STB/D)	Measured gas rate (MMSCFD)	Measured rich gas rate (MMSCFD)	Condensate	Gas	Rich gas
1/7/2010	19043.24	802.89	817.243	26033.2	749.9	777.5	26.85	7.07	5.11
1/19/2010	19673.95	790.43	805.2584	27003	814.97	843.6	27.14	3.01	4.54
1/31/2010	21666.9	783.02	799.3505	26237.7	806.61	834.4	17.42	2.92	4.20
2/8/2010	19898	794.37	809.3673	29890	807	835	33.43	1.57	3.07
2/9/2010	22047.1	794.4	811.0171	27091	814	843	18.62	2.41	3.79
2/13/2010	17775.18	771.08	784.4773	27228	814	843	34.72	5.27	6.94
2/17/2010	21286.77	768.48	784.524	26836.17	812.06	840.5	20.68	5.37	6.66
2/25/2010	19688.78	756.67	771.5096	25458.21	814.25	841.2	22.66	7.07	8.28
3/2/2010	17949.6	762.88	776.4088	25521	816.2	843.3	29.67	6.53	7.93
3/5/2010	18752.47	767.65	781.7839	25509.2	817.3	844.4	26.49	6.07	7.42

However, producing fluid composition was not known, and design composition was used for this part of calculations.

The summary of this section may be outlined as follow.

- To calculate individual well rates, we have performed choke calculations.
- One main problem is that the actual choke size is not available; instead opening percent of chokes were recorded.
- To use choke models, we need to know actual choke size. Therefore, separator test data were used to obtain a relationship between bean size and opening percent for the wells of each train. The correlation inherently includes tuning of the used choke model for wells of this phase of field.
- To make sure of calculations, two criteria must be met. First, for the same wellhead pressure and opening percent in separator test data, the choke model must calculate the same rates as those measured in the tests.

Second, the summation of calculated well rates must be equal to those of total platform (train) rates available in daily reports.

● The first criterion is somehow met because we used the separator test data for obtaining relation between choke size and percent opening. To meet the second criterion, the obtained relation could be normalized with respect to total rate so that total calculated and measured rates can be in good agreements.

● The GOR obtained from total streams was used for each well. Design composition was used to convert the GOR at platform pressure and temperature to standard condition.

Step 3: Calculation of Bottom hole Pressure

As mentioned, to apply production analysis techniques, we must know well flow rates as well as flowing bottom hole pressure. Therefore, daily wellhead pressures must be converted to flowing bottom hole pressures. The input data for this task are well flow rate and either flowing composition or GOR. When the GOR is used, oil density and gas specific gravity must also be known. If we have the tuned compositional fluid model, we can use fully compositional flow model which may be more accurate than black oil correlations. However, the problem is that the fluid samples in data bank of this field represent initial fluid composition, which may be different from what is flowing to the well as liquid phase forms and accumulates in the reservoir. After formation of condensate bank around the well, the overall composition flowing to wellbore becomes leaner than that of initial reservoir fluid. In another word, the producing GOR increases as the production time increases. Therefore, changes in GOR may be regarded as an indication of changes in fluid composition and its effect on well flow modeling can be studied. In this case, black oil correlations can be used for which GOR, oil density and gas gravity must be known. As a result, effect of compositional change can be indirectly incorporated in the calculations. Alternatively, we can use fully compositional models but we have to use initial fluid composition.

One main challenge of this step is selection of best correlation (correlations) for obtaining holdup and pressure profile in the well. To do so, we can use Pressure Logging Tool (PLT) tests in which real bottom hole

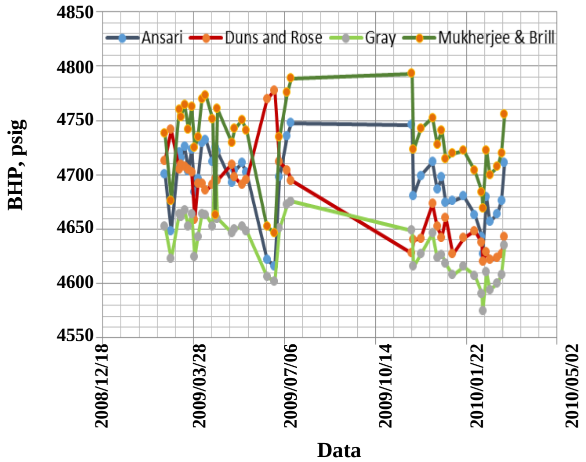

Fig. 13: Different correlations for determination of bottom hole pressure in Well 1 of platform A.

pressures are reported for certain rates and wellhead pressures. This information can be used to select appropriate correlation. The problem is that PLT tests are limited to specific wells and specific times. Selected correlations may be applied to the rest of wells for which no PLT test are reported. Fig. 13 is an illustrative example of different correlations for determination of bottom hole pressure for well 1 in platform A. This figure compares bottom hole pressure calculated by four correlations in different operating dates.

Step 4: Contribution of Each Layer to Production

Production data analysis techniques are generally developed for single-well, single-layer systems. In this reservoir, there are 4 producing layers which have potential of gas production, although all layers are not perforated in all wells. For multi-layer systems, there may be two solutions:

● The flow rate of each layer is determined and production analysis is performed per-layer basis. In this case, production history of each layer must be first determined so that average pressure and gas-in-place of that layer can be estimated. This approach is suitable when the layers do not have communication within the reservoir.

● Total flow rates of all layers are used as the input data which would yield an average value for gas in place and average pressure of all layers. This approach is most suited for systems where layers have strong communication within the reservoir.

Considering that layers of this reservoir may not have strong communication within the reservoir, we prefer the first approach. To do so, calculated well flow rates must be split to each layer. For this purpose, we can use PLT tests. In these tests, contribution of each layer to production is determined for different flow rates. To determine layer rates history, these tests must be performed at different points of time. If so, interpolation techniques can be used with respect to flow rate and time to determine flow rate of each layer versus time in each well. The main problem is that the number of PLT tests is limited to only four wells in a 12-well cluster, each run at one day among 8 years of production. In this case, it is not possible to determine history of rate from each layer. Clearly, contribution of each layer to production changes as the time goes by, and one PLT test would not be sufficient to determine flow rates of each layer for the entire production period in a long period of production.

Step 5: Analysis of Well/Layer Production Data

The last step deals with analyzing well rate/pressure history to estimate parameters such as gas in place and average pressure history. Analysis of production data for a multi-layer, multi-well gas-condensate reservoir is very complicated. There is no reported comprehensive analysis methodology for such a complex system. To the best of our knowledge, even commercial softwares do not have any suitable inverse model for a reservoir with high complexity. The analyst may simply use different methods in the commercial software and estimate some values for reservoir properties. However, the question would arise on the reliability of those methods. For example, the dry gas analytical methods are developed based on the assumption of single phase flow in the reservoir. This assumption is violated in a gas condensate reservoir. Accordingly, applicability of all methods should be examined for gas-condensate reservoirs. To do so, we use synthetic simulation models to produce arbitrary production data. The generated data are then analyzed using available models and values of gas in place and average pressure are determined. The methods are suitable if the estimated values are in agreement with those of input in the simulation model. To perform this part of the project, we propose a step-wise procedure as follows.

- Evaluate empirical methods for analysis of production data in single-layer gas condensate reservoirs.
- Evaluate empirical methods for analysis of production data in multi-layer gas condensate reservoirs.
- Evaluate dry gas analytical methods for analysis of production data in single-layer gas condensate reservoirs.
- Evaluate dry gas analytical methods for analysis of production data in multi-layer gas condensate reservoirs.
- Evaluate dry gas analytical methods for analysis of production data in multi-well gas condensate reservoirs.
- Evaluate gas condensate analytical methods.
- Extend gas condensate analytical methods to be applicable for multi-layer and also multi-well systems.
- Summarize and organize the core findings of previous steps and prepare an analysis protocol for gas condensate reservoirs.
- Implement data quality control and consistency check to prepare the input data for analysis.
- Apply the analysis techniques and estimate reservoir properties.
- Compare the findings with other sources of information.

There may be some challenges which arise when dealing with the above tasks. The first question is to find the best method(s). In general, production analysis methods can be divided into two categories, known as empirical (traditional) and analytical (modern) methods. Traditional methods are basically developed for conditions where well flow rate declines. The wells in the reservoir under study do not still show decline behavior. This may limit application of these methods for analysis of production data in this field. The methodology for analysis of data depends on the condition of cross-flow within the layers in the reservoir. There is uncertainty about communication of layers within the reservoir which may cause trouble for selection of appropriate model for analysis. For the situation where production rate of each layer cannot be determined, total rate must be used and an average value for gas in place of all layers would be obtained. If layers do not have communication with each other, averaging techniques would not work well. This becomes even more severe for gas-condensate systems. We have conducted some basic studies for arbitrary gas reservoirs. Results show that in general both empirical and analytical methods show poor estimations and predictions when multi-layers are replaced by an equivalent single layer. Also, accuracy of all methods increases as the degree of communication between layers increases.

Table 3: Comparison of predicted and simulated production using Arps empirical relations.

Parameters	Decline Exponent		Error percent of predicted rate		Error percent of predicted cumulative production	
	Shirman method	Type Curve method	Shirman method	Type Curve method	Shirman method	Type Curve method
Single layer	0.36	0.3	11.8	3.6	1.4	0.5
Layered-No Cross-flow	0.79	0.8	24.0	22.7	3.2	3.4
Layered-Medium Cross-flow	0.34	0.4	48.9	67.3	3.0	4.5
Layered – 100 % Cross-flow	0.17	0.2	61.0	79.1	2.0	2.4

Table 4: Comparison of estimated and true values using Blasingame analytical techniques.

Parameters	Error percent of estimated gas in place		Error percent of predicted rate		Error percent of predicted cumulative production	
	Type Curve method	DMB method	Type Curve method	DMB method	Type Curve method	DMB method
Single layer	0.4	1.6	0.4	1.0	0.2	0.4
Layered-No Cross-flow	27.5	18.7	50.4	26.7	5.7	2.5
Layered-Medium Cross-flow	10.8	1.7	22.3	2.7	2.2	0.2
Layered – 100 % Cross-flow	4.8	0.2	10.4	2.1	1.4	0.1

However, when there is no cross-flow, all methods show poor estimations and predictions. Therefore, if we recognize that the reservoir has poor or no flow communication between layers, averaging all layers as a single average layer may results in wrong interpretations. In this case, we must determine the individual layer rate and analyze production of each layer separately. Tables 3 and 4 present summary of the results for single-layer and multi-layer synthetic examples using empirical and analytical methods, respectively. In Table 3, the first raw is a single layer example and next ones are multi-layer examples. The empirical Arps method was applied to predict rate and cumulative production for these examples. The results of the empirical method were compared against a commercial numerical simulator so that errors can be obtained. As can be observed, increasing the degree of cross flow increases the accuracy of the results. The least errors are observed for the single layer case. It should be noted that our interpretation is based on the results of cumulative production, because the errors for rates are calculated for a specific point of time which is not an average error, and that is why we see an increasing trend downward which is in contrary to the error trend of cumulative production. In Table 4, analytical methods were used to predict gas in place, rate, and cumulative production. As can be seen, except for the first raw which is single layer example, the error decreases downward with increase of degree of cross flow. The single layer case, however, provides the best results. From this table, we can also find out that DBM method provides more accurate results than those of type curve method.

Normally, analytical models are developed for a well with fixed drainage boundaries. However, assumption is not necessarily true in multi-well systems. Recently, studies (*Marhaendrajana & Blasingame* 2001) have been performed to account for changes in well drainage boundaries in oil and dry gas reservoirs. This issue may add another complexity to analysis of data in multi-well gas condensate systems [17]. To the best of our knowledge, only one analytical model is available for production analysis of a single-well in single-layer gas-condensate systems(*Heidari Sureshjani & Gerami* 2011) [17]. On one hand, this model considers the flow of both oil and gas phases in the reservoir. On the other hand, it requires a lot of input data which may inherently have uncertainties. Effect of these uncertainties can be reflected in the estimated reservoir parameters and may introduce substantial error. As long as the sandface pressure is above dew point pressure, dry gas models can be used. However, our studies reveal that analytical dry gas methods underestimate gas in place when two-phase flow exists in the reservoir. The problem becomes more uncertain and complicated when dealing with a multi-layer multi-well gas-condensate reservoir (as is the case of the reservoir under study). The existing analytical model for gas-condensate reservoirs is too ideal to be applied for the reservoir under study. Still we are not sure whether an ideal model can be extended to apply for multi-well, multi-layer gas-condensate reservoirs. Considering the above mentioned procedure and challenges, massive amount of researches and investigations must be performed to accomplish this step of the project.

CONCLUSIONS

A general roadmap was proposed for analysis of production data in gas-condensate fields. This road map consists of five main steps, i.e. data gathering/extraction/quality check, well rate determination, well bottom hole pressure calculation, layer rate determination, and reservoir property estimation. Based on field observations, it was found that:

- To check the quality of data, the first task is to perform simple consistency checks. Thereafter, the proper functioning of orifice meters must be evaluated. Investigation shows the fluid composition and also fluid properties do not have considerable effect on the determined rate by orifice. In contrast, the wrong pressure, temperature and pressure drop across the orifice may cause error in the reported rates determined by orifice.
- Flow rate of individual well rates may be determined through choke modeling. To assure the accuracy of calculated rates, two criteria must be met; first, for the same wellhead pressure and opening percent in separator test data, the choke model must calculate the same rates as those measured in the tests. Second, the summation of calculated well rates must be equal to those of total platform (train) rates available in daily reports.
- A procedure for the analysis of well/layer pressure/rate data was presented and possible challenges of this step were outlined.

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