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Performance Analysis of Compositional and Modified Black-Oil Models For a Gas Lift Process

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Résumé — Analyse des performances de modèles *black-oil* pour le procédé d'extraction par injection de gaz — Les procédés artificiels d'extraction par injection de gaz sont utilisés pour améliorer le taux de récupération des champs pétroliers matures. Un modèle mathématique intégré a été développé pour détecter de faibles changements temporels et spatiaux dans plusieurs composants des procédés continus d'extraction par injection de gaz. La solution numérique utilisée pour résoudre le modèle du procédé d'extraction dépend fortement du comportement thermodynamique des hydrocarbures impliqués. Un traitement complet de la composition utilisant une équation d'état offre les résultats les plus précis, mais à un coût de calcul très élevé. Les résultats de nos travaux de recherche montrent que l'implication des paramètres de stabilité et des procédures de calcul flash, peut diviser par deux le coût du calcul tout en gardant la précision attendue. Ces travaux montrent que la précision admissible peut être également atteinte, avec un coût minimum du calcul, par l'utilisation de modèles modifiés de type *black-oil* des fluides. Le modèle modifié de *black-oil* est un outil performant dans le cas où un nombre élevé d'itérations du modèle est nécessaire pour trouver les combinaisons optimales des paramètres du procédé d'extraction par injection de gaz.

Abstract — Performance Analysis of Compositional and Modified Black-Oil Models For a Gas Lift Process — *Artificial gas lift is frequently used to boost production rate of mature oil fields. An integrated mathematical model was developed in order to track the spatial and temporal changes in various components of the continuous gas lift process. The computational demand for solving the comprehensive gas lift model highly depends on the thermodynamic treatment of the hydrocarbon fluids involved. A full compositional treatment using an equation of state provides the most accurate results but at a high computational cost. The results of this article showed that the computational cost can be halved without sacrificing accuracy by using reduced parameter stability and flash calculation procedures. It was also demonstrated that a Modified Black-Oil treatment of the fluids can provide reasonable accuracy at a much-reduced computational cost. The Modified Black-Oil treatment provides a valuable tool when the model has to be solved many hundreds of times to find the optimal combination of the gas lift parameters.*

NOMENCLATURE

a	Energy parameter of PR-EOS
K	K-value
m	Number of significant eigenvalues
M_w	Molecular weight (g/mole)
Nc	Number of components
p	Pressure (bar)
$\bar{p}$	Average reservoir pressure (bar)
q	Eigenvector elements
Q	Molar flow rate (mole/day)
R	Gas constant
R_g	Dimensionless volumetric vaporized oil-gas ratio
r_g	Dimensionless molar vaporized oil-gas ratio
R_o	Dimensionless volumetric gas-oil ratio
r_o	Dimensionless molar gas-oil ratio
S	Diagonal matrix
scm	Standard cubic meter
t	Time (day)
T	Temperature (K)
x	Oil phase composition
y	Gas phase composition
z	Overall fluid composition
α	Energy parameter of PR-EOS for each component
ε	Tolerance
ρ	Density (kg/m^3)
$\bar{\rho}$	Molar density (kmole/m^3)
δ	Binary interaction parameters
λ	Eigenvalues
ω	Acentric factor

Subscripts

c	Critical conditions
g	Gas phase
i	Component index
inj	Injection
j	Component index
o	Oil phase
res	Reservoir
sep	Separator
st	Standard conditions
wf	Sand face flowing
wh	Wellhead

INTRODUCTION

Gas lift is a process that reduces the hydrostatic pressure in the tubing, facilitating production from wells with low reservoir pressure. Gas is injected into the tubing, as deep as possible, and mixes with the fluid from the reservoir *(Fig. 1)*. The injected gas lifts the produced fluid to the surface by one or more of the following processes [1]:

- the injected gas reduces the average fluid density above the injection point so that the pressure differential between reservoir and wellbore will be increased;
- some of the injected gas dissolves into the produced fluids. The reminder, in the form of bubbles, will expand due to reductions in the hydrostatic pressure as the fluids rise up the tubing;
- the coalescence of these gas bubbles into large bubbles occupies the full width of the tubing and displaces liquid slugs to surface.

In the gas lift process, output streams of multiple well are collected in a manifold pipe. Stable flow of each well fluid is ensured by placing a choke of suitable diameter at the end of the tubing. The two-phase fluid issuing from the choke enters the common manifold pipe and then is flashed in a series of flash drums (often three) to separate the oil and gas. The oil stream is sent to stock tanks while a part of the flashed gas is re-compressed and injected into the wellbore.

The availability of accurate, reliable and computationally efficient mathematical model of the gas lift process is highly desirable for design and operation of a gas lift system. The solution of the integrated gas lift model demands an accurate gas-lift performance curve for each well. In practice, the gas-lift performance curve for each well changes with time and must reflect the temporal changes in the reservoir pressure and composition. Without a comprehensive mathematical model, however, this performance curve must be obtained from an empirical (piecewise linear or quadratic) fit to a few isolated experimental points [2]. Although empirical performance curves can be evaluated very rapidly, which aids the solution of the combinatorial problem, they cannot reflect the temporal changes in the reservoir conditions, which makes the optimization result less reliable.

Two basic factors must be clearly noted in developing a mathematical model for the continuous gas lift process. First, the gas lift process is inherently transient and the model must account for the temporal changes in the reservoir. Second, the performance of the gas lift process is highly composition dependent, which must be catered for in the model. This is particularly important for description of the multiphase flow in the wellbore and in a lesser extent in the common manifold. The early models of the continuous gas lift process employed a black-oil treatment of the hydrocarbon fluids except in the flash separators that were treated on a compositional basis [3, 4]. Such models are unreliable since the multiphase flow regime of the oil/gas mixture and consequently, the pressure drop in the wellbore is highly composition-dependent. As the mixture flows up the wellbore, the flow regime can undergo several fundamental

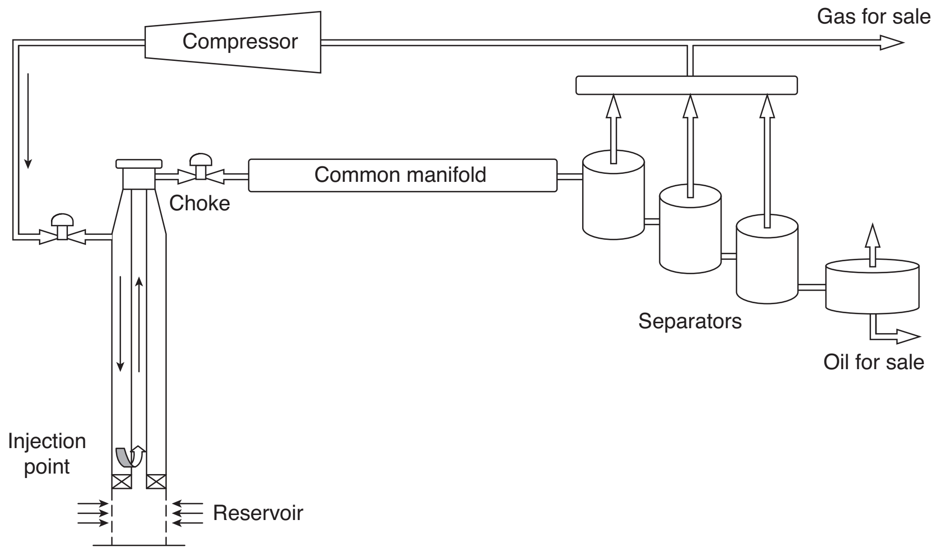

Figure 1

Schematic of the continuous gas lift process.

changes that have different pressure drop characteristics. An accurate description of two-phase flow and changes in the flow regime is essential for a reliable continuous gas lift model. Palke [5] and Ayatollahi *et al*. [6] have reported a model of the continuous gas lift process where all components have received a compositional treatment. The price paid for the more accurate compositional treatment is a huge increase in computation time, in particular, in the calculation of the wellbore pressure drop. Our aim is to present a continuous gas lift model based on a Modified Black-Oil (MBO) treatment that can deliver accuracy similar to a full compositional model but at a much reduced computational cost.

1 AN INTEGRATED CONTINUOUS GAS LIFT MODEL

In this section, we give a brief description of the various parts of the continuous gas-lift process model. The overall mathematical model integrates the individual models for a reservoir, a wellbore, a choke, a common manifold as well as the oil/gas separators. The integrated model can be used to predict the field performance over an extended production period. The various components in the integrated continuous gas lift model are closely coupled and their conditions change with time due to the feedback loop, caused by re-compression and re-injection of the lifting gas. In order to track such variations, the period of operation was divided into a number of shorter time steps. The length of the time step was selected such that the flow and composition from the reservoir could be assumed unchanged. In this way, at each time step all process components were solved simultaneously. At the end of each time step, the reservoir pressure and composition as well as the injection gas composition were updated, and the model was solved for the next time step. The iterative procedure used to advance the model is shown in Figure 2.

1.1 Reservoir Model

The objective of the reservoir model is to provide the bottom-hole pressure, composition and flow rate. In principle, we are free to use any appropriate model but to keep the computational cost down. Here, a simple homogeneous radial flow reservoir model that admits an analytical solution is employed [7]. The reservoir model is limited by the following assumptions:
- the reservoir boundaries are no-flow;
- both hydrocarbon phases are produced as if in a pseudo-steady state;
- the reservoir is produced from a single well only;
- the effects of gravity and capillary pressure are neglected.

1.2 Choke Model

The choke is a short narrow tube flow restriction placed between the top of the tubing and the separator. In practice, the choke diameter should be small enough to cause a critical flow that is essential for stable production. In critical flow, the fluid flow rate across the choke is dependent only on the upstream pressure, so that the separator pressure (downstream pressure) can be changed without altering the wellhead or

sand face pressures. Critical flow occurs when the ratio of downstream to upstream pressures falls below a critical value, usually near 0.5. The rapid flow through the narrow choke is essentially governed by acceleration of the fluid and frictional pressure drop has a minor role. Many models have been developed to describe the choke flow. We have adopted the model proposed by Sachdeva *et al*. [8]. This model is sophisticated enough to cope with both multiphase flow and sub-critical flow. It is based on the following assumptions:
- flow is one dimensional;
- phase velocities are equal at the throat;
- the predominant pressure drop is the acceleration term;
- the gas quality is constant for high speed processes;
- the liquid phase is incompressible.

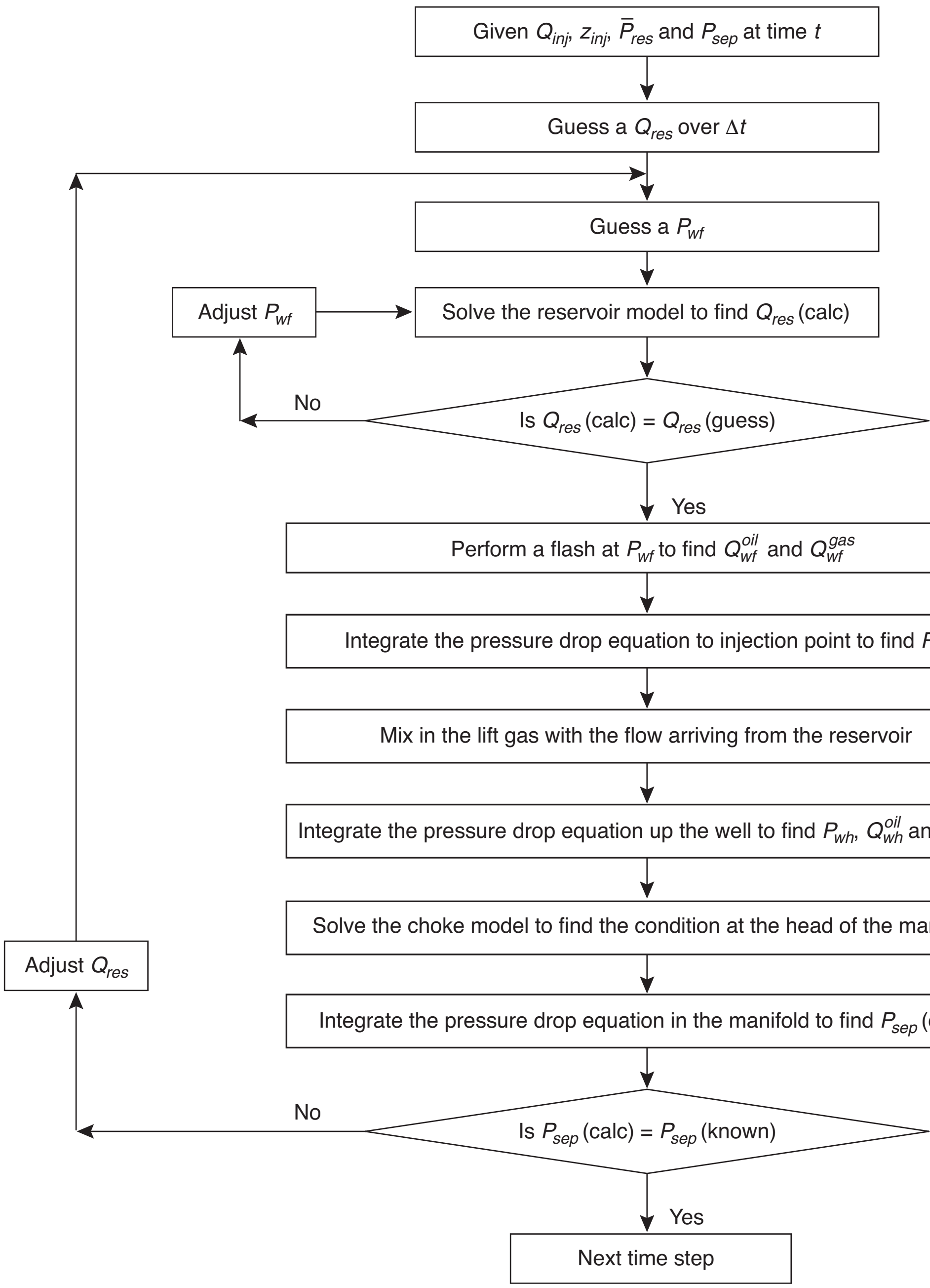

Figure 2

Flowchart for advancing the gas lift model on a single time step Δt.

1.3 Separator Model

A separator is a vessel which takes a multiphase fluid stream and separates it into two streams, each predominated by one phase. The amount of each output stream depends upon the separator pressure. In order to reach the best separation process, several separators are connected in series. Each separator has progressively lower pressure. In this study, a series of three separators is used. Separator models are applied to determine the separated oil and gas compositions and flow rates. Moreover, the thermodynamic phenomenon of the gas flashing out of the liquid phase is modeled using multi-component phase stability and flash calculations.

1.4 Two-Phase Wellbore and Manifold Models

The two-phase flow effects in wellbores and pipes can have a strong impact on the performance of the gas lift process. Pressure drop in the gas lifted well, can lead to a loss of oil production at the toe or overproduction at the heel. The most complex and time-consuming part of the integrated gas lift model is the two-phase flow calculations in the wellbore. Gas injection leads to a variable flow pattern through the well. The interface between the two phases can be distributed in many configurations. The two-phase pressure drop calculation is strongly dependent on the flow regimes. Several multiphase flow regime maps and correlations have been developed based on numerous two-phase flow experiments conducted in pipes of varying diameter, inclination and flow rates [9, 10]. The early versions of the multiphase flow correlations were developed on the empirical basis. The correlations are based on curve fitting of the experimental data. Hence, their applicability is generally limited to the range of variables explored in the experiments. Furthermore, such correlations exhibit large discontinuities at the flow pattern transitions that can cause convergence problems in the pressure gradient integration through the well. Subsequently, a more mechanistic approach based on the solution of the momentum equation in the pipe, coupled with appropriate correlations was employed to develop a more accurate flow regime map with smoother transitions between various regimes [11-13]. In mechanistic models, however, the effects of system parameters are incorporated in a way that can be applied over a wide range of geometry and fluid conditions. In this study, identification of the flow regimes and computation of pressure drop in the gas lifted well as well as the common manifold are based on the mechanistic model developed by Petalas and Aziz [13]. In order to establish the local flow regime, it is necessary to perform a multiphase flash calculation to find the extent, physical property and superficial velocity of the phases. Once the superficial gas and liquid velocities are determined, an appropriate multiphase map can be employed to identify the local flow regime and associated local pressure gradients.

2 THE THERMODYNAMIC TREATMENT OF THE FLUIDS

The gas and oil phases consist of different components such as methane, ethane, propane and other hydrocarbons. Accuracy and speed of the computation for a continuous gas lift model highly depend on the thermodynamic treatment of the fluids involved. Most studies assume the hydrocarbon fluids as two pseudo-components namely oil and gas with constant composition. Hence, calculations are performed based on the simplified black-oil equations. The oil and gas phases are recognized by oil and gas specific gravities that are assumed to remain constant through the process. In a standard black-oil model, the gas can be dissolved into the oil phase. A standard black-oil model usually treats the PVT properties of hydrocarbon phases as a single function of pressure and temperature. Hence, oil and gas properties such as density, viscosity and specific volume are computed by experimental correlations at every pressure and temperature. Empirical correlations are applied to calculate the dissolved gas into the oil phase. Moreover, the effect of compositions on pressure and temperature is neglected in the standard black-oil approach. In fact, the effect of compositions on pressure profile and fluid flow properties should be taken into account when the flowing liquid and gas are composed of more than one component.

Standard black-oil description is employed in almost all previous studies of gas lift modeling. Application of the standard black-oil model in the calculation of the two-phase pressure drop in gas lifted well, leads to substantial error due to the changes in composition and bubble point pressure along the well. The wise approach to predict the phase behavior is a fully compositional description method in which all components are allowed to distribute between the phases. Moreover, an equation of state is used to describe the equilibrium between the phases. Having the compositions, fluid properties are obtained from the phase behavior calculations. Since the oil and gas compositions in a gas lifted well are varied, the bubble point pressure is also variable. Figure 3 shows the dependency of the bubble-point pressure on the volumetric gas-oil ratio at 360 Kelvin. The effect of composition is considered in compositional description; however, it is ignored in the standard black-oil description.

The main drawback for compositional description is its high computational cost for stability and flash calculation depending on the number of hydrocarbon fluid components. For a fluid having Nc components (or pseudo-components), $2Nc+1$ nonlinear algebraic equations are required to be solved. Usually, individual components are lumped into some pseudo components to reduce the dimension of the problem. It is possible to achieve an important saving in computing time and storage for the phase equilibrium calculations by employing the so-called reduction method. The method is based on reducing the dependent variables (that is, the compositions at constant temperature and pressure) of

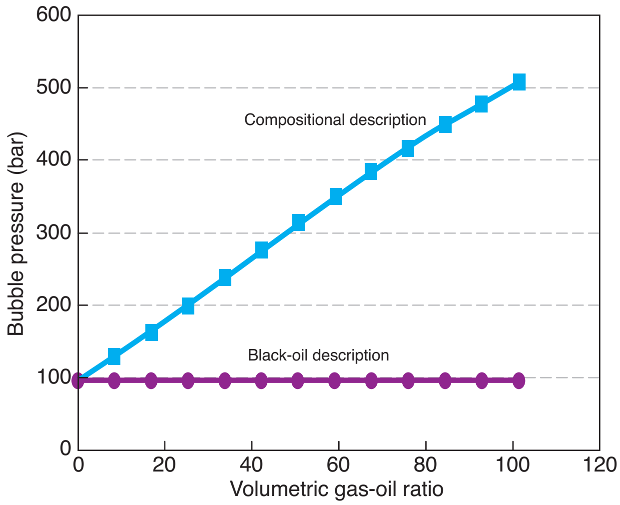

Figure 3

Bubble point pressure versus gas-oil ratio at 360 K.

the Gibbs-free energy through a specific transformation. In 1986, Michelsen [14] introduced this method to perform flash calculations assuming all Binary Interaction Parameters (BIP) to be zero. As a result of this assumption, the nonlinear algebraic equations were reduced to three regardless of the number of components. This leads to a drastic reduction of computational time. For hydrocarbon mixtures containing some amounts of non-hydrocarbon components, the BIP are not equal to zero. Jensen and Fredenslud [15] extended the Michelsen's approach by using two more reduced parameters when only one column of the BIP matrix is non-zero. Hendricks [16] used an eigenvalue analysis method to identify the dominant BIPs in the phase-split calculations. The BIP matrix is recalculated by setting all small eigenvalues to be zero, using some predetermined criterion. Firoozabadi and Pan [17, 18] have extended stability analysis and flash calculations in reduced space form by dominant eigenvalue decomposition of the BIP matrix using Lagrange multipliers. They have used the Tangent Plane Distance (TPD) in the reduced space format to perform stability analysis testing and observed that the TPD surface is "smoother" in the reduced space than the compositional ones. The reduced parameters approach is defined in the following while detailed discussion is available in the literature (Firoozabadi and Pan, 2001; Pan and Firoozabadi, 2001).

Given the temperature, the pressure P, and the overall composition z_i, the expression for the energy parameter "α" in Peng-Robinson equation of state (PR-EOS) is given by:

$$\alpha = \sum_{i=1}^{Nc}\sum_{j=1}^{Nc} z_i z_j \alpha_i^{0.5}\alpha_j^{0.5}(1-\delta_{ij}) \quad (1)$$

where:

$$\alpha_i = 0.427\frac{RT_{ci}^2}{\rho_{ci}}\left\{1+\left(0.480+1.57\omega_i-0.176\omega_i^2\right)\left(1-\left(\frac{T}{T_{ci}}\right)^{0.5}\right)\right\}^2 \quad (2)$$

Let: $\beta_{ij} = (1-\delta_{ij})$; β, is a symmetric matrix with elements β_{ij} that can be expressed as:

$$\beta = SDS^T \quad (3)$$

The diagonal matrix is given by:

$$D = \begin{pmatrix} \lambda_1 & \cdots & 0 \\ \vdots & \ddots & \vdots \\ 0 & \cdots & \lambda_{Nc} \end{pmatrix} \quad (4)$$

where the orthogonal matrix S is given by:

$$S = \left(q'^{(1)} q'^{(2)} \ldots q'^{(Nc)}\right) \quad (5)$$

$\lambda_1, \ldots, \lambda_{Nc}$ are the eigenvalues of β and $q'^{(1)}, q'^{(2)}, \ldots, q'^{(Nc)}$ are the corresponding eigenvectors. Each eigenvector is given by:

$$q'^{(i)} = \left(q'_{i1} q'_{i2} \ldots q'_{iNc}\right) \quad (6)$$

Then:

$$\beta_{ij} = (1-\delta_{ij}) = \sum_{k=1}^{Nc}\lambda_k q'_{ki} q'_{kj} \quad (7)$$

and the PR-EOS parameter "a" becomes:

$$\alpha = \sum_{k=1}^{Nc}\lambda_k \sum_{k=1}^{Nc}\alpha_i^{0.5} z_i q'_{ki} \sum_{k=1}^{Nc}\alpha_j^{0.5} z_j q'_{kj} \quad (8)$$

Let:

$$q_{ki} = \alpha_i^{0.5} q'_{ki} \quad (9)$$

Then:

$$\alpha = \sum_{k=1}^{Nc}\lambda_k \sum_{k=1}^{Nc} z_i q_{ki} \sum_{k=1}^{Nc} z_j q_{kj} \quad (10)$$

Defining the reduced parameters Q_k as:

$$Q_k = \sum_{k=1}^{Nc} z_i q_{ki} \quad (11)$$

Then:

$$\alpha = \sum_{k=1}^{Nc}\lambda_k Q_k^2 \quad (12)$$

In this way, the parameters of an equation of state and fugacity coefficients as well as the equilibrium ratio and compressibility factor become a function of the reduced parameters (Q_k). In general, only a few eigenvalues from $\lambda_1, \ldots, \lambda_{Nc}$ are significant; most of the eigenvalues in a multi-component mixture are very close to zero *(see Tab. 4 in Sect. 3)*. Assume for $k > m$, λ_k's become negligible and m would be much less than Nc. The system of nonlinear equations can be reduced from a system of Nc to a system of

$m+1$ equations, with $m+1$ unknowns (m reduced parameters plus the vapor mole fraction).

Even though the multi-component fluids are lumped using the reduced methods, flash calculations are still iterative and thus compositional modeling is still slow. A number of modifications to the standard black-oil model have been proposed [19-22] to extend its range of applications to variable bubble point situations sometimes under the name of "modified black oil model". The main difference between the standard black-oil model and the MBO model lies in the treatment of the oil in the gas phase. The MBO approach assumes that the stock-tank oil component can exist in both oil and gas phases under reservoir conditions. It also assumes that the oil content of the gas phase can be defined as a sole function of pressure called vaporized oil-gas ratio, R_g. This function is similar to the solution gas-oil ratio, R_o, used to describe the amount of gas-in-solution in the oil phase [21].

In this article, a MBO procedure proposed by Shank and Vestal [20] and Wang [22] is used with some modifications. In MBO description, the fluid is composed of two pseudo-components, separator gas (suffix g) and stock-tank oil (suffix o) and either component may be present in the hydrocarbon gas and oil phases. The mole fraction of the pseudo-components in the gas, y_g and y_o, and oil phases, x_g and x_o, are constrained by:

$$y_o + y_g = 1 \tag{13}$$

$$x_o + x_g = 1 \tag{14}$$

These may be evaluated from the molar gas-oil ratio and molar oil-gas ratio as:

$$y_o = \frac{1}{1+r_o} \text{ and } y_g = \frac{r_o}{1+r_o} \tag{15}$$

$$x_o = \frac{1}{1+r_g} \text{ and } x_g = \frac{r_g}{1+r_g} \tag{16}$$

The dimensionless molar gas-oil ratio, r_o and molar (vaporized) oil-gas ratio, r_g, can be determined from the standard black-oil parameters, R_g and R_o, through:

$$r_o = R_o \frac{\bar{\rho}_{gst}}{\bar{\rho}_{ost}} \text{ and } r_g = R_g \frac{\bar{\rho}_{ost}}{\bar{\rho}_{gst}} \tag{17}$$

where $\bar{\rho}_{ost}$ and $\bar{\rho}_{gst}$ are the oil and gas molar densities at standard conditions.

In standard black-oil model, solubility data (R_o and R_g) are measured in *PVT* laboratory for a fluid with certain composition and tabulated as a function of pressure. In the gas lifted well, the fluid composition above the injection point is varied since the composition of the injection gas is varied with time. Due to the changes in oil-gas ratio (R_g) of the recycling gas, it is impossible to represent the varying *PVT* properties of the recycled gas with a single *PVT* table in the MBO model. Every time the produced gas passes through the separators and injected back into the wellbore, its oil-gas and accordingly vaporization characteristics change. Thus, we need to develop the MBO PVT properties when the experimental PVT table is not available for the fluid having different compositions. In this study, we first tuned the critical properties and acentric factor of C_7^+ that matched as best as possible to the experimental data of the available PVT laboratory experiments. Next, we used the multi-component flash calculations for different values of the stock-tank oil composition (z_o) to produce the required MBO PVT property tables at different pressures (from well-bottom pressure to the wellhead pressure). Each PVT property table includes two functions for oil-gas ratio R_g and gas-oil ratio R_o as required for the MBO calculations. At each point in the wellbore the given pressure and composition R_o and R_g can be directly determined using the table lookup. A simple MBO flash calculation can then be applied to find the distribution of the phases as depicted in Figure 4. In multi-component flash calculations, the equilibrium phase compositions are calculated iteratively via solving the equal-fugacity equations. In MBO models however, the flash calculations are faster and non-iterative due to the simple relationships employed.

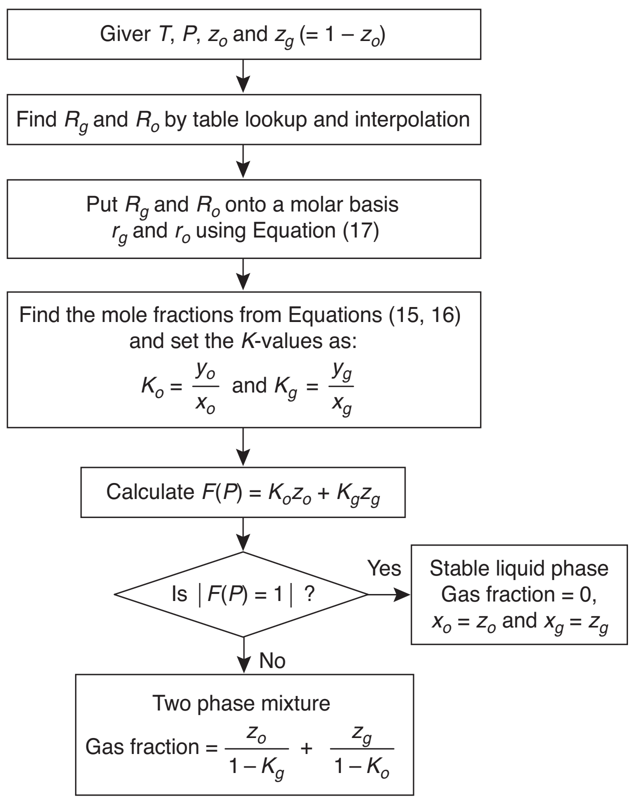

Figure 4

The non-iterative MBO flash calculation procedure.

In this study, accuracy and speed of a typical continuous gas lift model are first calculated using the full and reduced compositional description. The results are then compared with the MBO description.

3 RESULTS AND DISCUSSION

An illustrative example based loosely on a mature Iranian oil field is considered to demonstrate the effect of different thermodynamic approaches on the long-term production of a single gas lifted well. Calculated cumulative oil production of the well over a 10 year period based on different thermodynamic approaches, including the full compositional, reduced parameter and the MBO methods are compared. The field started operation in 1968 and could produce naturally until 2000. By the year 2000, the reservoir pressure had dropped to a level that did not allow a natural production thus several wells were put on to the gas lift technique. The reservoir characteristics and initial conditions are shown in Table 1. A particular well considered in this study have a depth of 1 980 m and is equipped with a gas lift valve at 80 m above the sand face. The temperature in the wellbore was assumed to fall linearly from the reservoir temperature to its value at the surface. The fluid from the well entered a common manifold through a 0.0255 m diameter choke and was directed to a train of three separators placed in series.

The composition of fluid entering the well is shown in Table 2. The compositional and MBO treatments are based on the Peng-Robinson equation of state. Standard Peng-Robinson parameters were used for all components except the heavy C_7^+ pseudo-component. The critical properties for the C_7^+ component were adjusted to match the measured oil formation volume factor, oil density, oil viscosity, gas-oil ratio and the bubble point pressure. The binary interaction parameters are shown in Table 3.

The integrated gas lift model requires calculation of numerous two-phase pressure gradients of the wellbore over the 10 year production period. As a result, the CPU time may become prohibitive and it is desirable to reduce the solution time as possible. Multi-component phase stability and flash calculations are by far the most time-consuming parts of the computation and can be improved by applying the reduced

TABLE 1

The gas lift process characteristics

Areal extent of reservoir (km^2)	12.4
Thickness (m)	80
Initial res. pressure (bar)	241
Reservoir temperature (K)	367
Porosity	0.20
Permeability (md)	200
Well depth (m)	1 980
Gas injection depth (m)	1 900
Well diameter (m)	0.0762
Common manifold diameter (m)	0.5
Common manifold length (m)	500
Surface choke diameter (m)	0.0255
First separator pressure (bar)	7
Second separator pressure (bar)	6.65
Third separator pressure (bar)	6.3

TABLE 2

Composition and component properties of the reservoir fluid

No.	Component	Composition (moles)	M_w (g/mole)	T_c (K)	P_c (bar)	ω
1	CO_2	1.63	44.01	304.21	73.77	0.2250
2	H_2S	0.17	34.08	373.60	90.08	0.0810
3	N_2	0.25	28.01	126.20	33.94	0.0400
4	C_1	14.39	16.04	190.60	46.00	0.0115
5	C_2	7.13	30.07	305.40	48.84	0.0908
6	C_3	8.08	44.10	369.80	42.46	0.1454
7	i-C_4	1.67	58.12	408.10	36.48	0.1760
8	n-C_4	4.67	58.12	425.20	38.00	0.1928
9	i-C_5	1.61	71.94	464.74	34.77	0.2235
10	n-C_5	2.95	72.15	469.60	33.74	0.2273
11	C_6	5.42	84.99	515.28	32.57	0.2637
12	C_7^+	52.03	243.0	744.47	17.17	0.8561

TABLE 3

The binary interaction parameters of the reservoir fluid (δ_{ij})

Component	CO_2	H_2S	N_2	C_1	C_2	C_3	i-C_4	n-C_4	i-C_5	n-C_5	C_6	C_7^+
CO_2	0	0.1150	– 0.0171	0.0956	0.1401	0.1368	0.1368	0.1412	0.1297	0.1347	0.1420	0.1089
H_2S	0.1150	0	0.1588	0.0888	0.0862	0.0925	0.0560	0.0626	0.0650	0.0709	0.0570	0.0450
N_2	-0.0171	0.1588	0	0.0312	0.0319	0.0886	0.1315	0.0597	0.0930	0.0936	0.1650	0.1000
C_1	0.0956	0.0888	0.0312	0	0.0030	0.0075	0.0137	0.0129	0.0182	0.0185	0.0240	0.0597
C_2	0.1401	0.0862	0.0319	0.0030	0	0.0019	0.0051	0.0046	0.0079	0.0081	0.0119	0.0400
C_3	0.1368	0.0925	0.0886	0.0075	0.0019	0	0.0015	0.0013	0.0031	0.0032	0.0056	0.0275
i-C_4	0.1368	0.0560	0.1315	0.0137	0.0051	0.0015	0	0.0005	0.0008	0.0008	0.0020	0.0181
n-C_4	0.1412	0.0626	0.0597	0.0129	0.0046	0.0013	0.0005	0	0.0009	0.0010	0.0023	0.0191
i-C_5	0.1297	0.0650	0.0930	0.0182	0.0079	0.0031	0.0008	0.0009	0	0.0004	0.0008	0.0136
n-C_5	0.1347	0.0709	0.0936	0.0185	0.0081	0.0032	0.0008	0.0010	0.0004	0	0.0008	0.0133
C_6	0.1420	0.0570	0.1650	0.0240	0.0119	0.0056	0.0020	0.0023	0.0008	0.0008	0	0.0092
C_7^+	0.1089	0.0450	0.1000	0.0597	0.0400	0.0275	0.0181	0.0191	0.0136	0.0133	0.0092	0

parameter techniques without sacrificing accuracy. In order to demonstrate the extent of the saving, the two-phase flow regime and the calculated pressure gradient in the wellbore are compared. The well is 1 980 m deep with the diameter of 0.076 m. The pressure and temperature at the bottom-hole were taken as 180 bar and 360 K respectively. Pure methane was injected as a lift gas 80 m above the sand face at a rate of 85 000 m^3/day. The reduced parameter phase stability and flash calculations were performed using 12, 6 and 1 reduced parameters (m = 12, 6 and 1) and the results are shown in Figure 5. Eigenvalues of the β matrix for the fluid are listed in the order of their absolute magnitude in Table 4.

TABLE 4

Eigenvalues of the reservoir fluid

No.	Absolute Values of Eigenvalues (λ)
1	11.4635
2	0.3819
3	0.1832
4	0.0984
5	0.0526
6	0.0348
7	0.0138
8	0.0058
9	0.0007
10	0.0005
11	0.0004
12	0.0004

All runs have been performed on a computer with a Pentium IV, 3 GHz dual processor and 2 GB RAM. The applied programming language is FORTRAN and the program has been compiled with Compaq Visual FORTRAN version 6. The CPU time for the one-reduced parameter case which corresponds to ignoring all binary interaction coefficients was as little as 0.03 s. CPU time for the 12 component case, which is equivalent to a rigorous multi-component computation, was 0.19 s. The results for the one-reduced parameter case are, however, significantly different from those for the 6 and 12 reduced parameter cases. This is due to the fact that the well fluid contains carbon dioxide, hydrogen sulphide and nitrogen that interact considerably with the hydrocarbon components. In contrast, the results for the intermediate 6 reduced parameter case were essentially the same as those for the full compositional treatment while only 0.09 s of CPU is required. Employing the reduced parameter method with six reduced parameters can deliver the same accuracy as the full compositional treatment at half of the CPU time.

The CPU time for the MBO case was as little as 0.02 s. The MBO treatment shows a moderate deviation from the full compositional treatment while reduces the computational costs by a factor of 10. In particular, the correct two-phase flow regimes are identified with a small difference in the location of transition points in the wellbore. This is particularly advantageous when the gas lift model has to be solved over the life time of the reservoir and need to repeat the pressure drop calculations many hundreds of times. Figure 5 also shows that the wellhead pressure gradient calculated by the full compositional approach deviates about 11% from the standard black-oil approach. The results show that standard black-oil approximation may cause

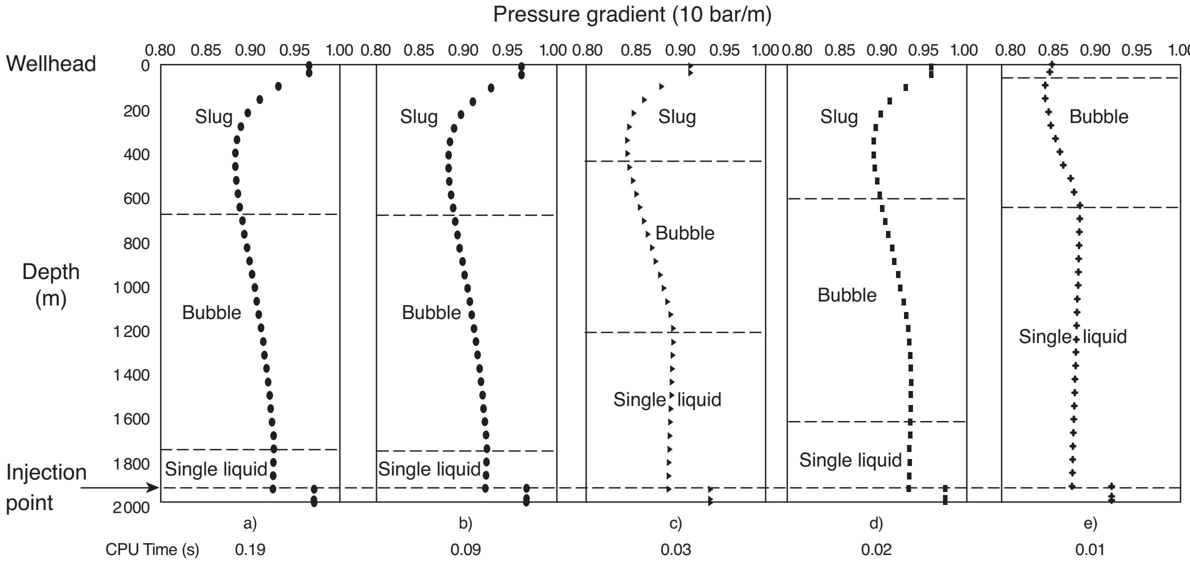

Figure 5

Flow patterns and pressure gradients calculated using a) 12, b) 6 and c) 1 reduced parameters, d) MBO model and e) standard black-oil.

error in the pressure profile prediction since the effect of composition change is ignored in the method.

The cumulative oil production over a 10 year period predicted by solving the integrated gas lift model is shown in Figure 6. Results for different treatments of the fluids are compared in a range of gas injection rates. The outcome for the 6 reduced parameter case was practically the same as those for the full compositional treatment. The MBO treatment, on the other hand, produces acceptable results using around one-tenth of the CPU cost as compared to the full compositional treatment *(see Fig. 7)*. The average difference between the compositional and MBO curves is less than 4%. It is clear that the difference between MBO treatment and compositional description increases at higher gas injection rates. For example, in the gas injection rate of 220 000 m^3/day, the estimated cumulative oil production by

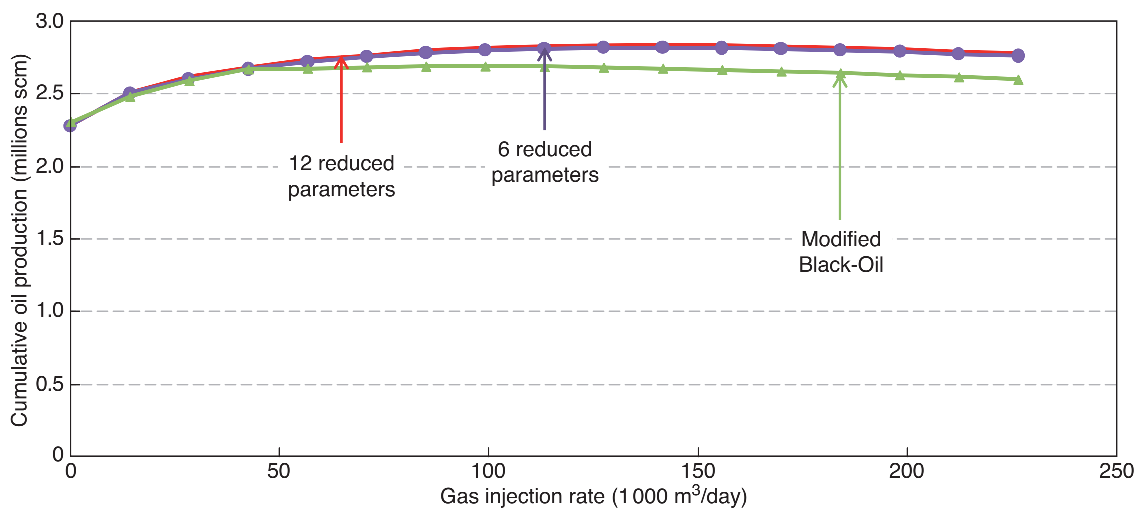

Figure 6

Cumulative oil production in 10 years predicted by compositional method compared to the MBO approach at different gas injection rate.

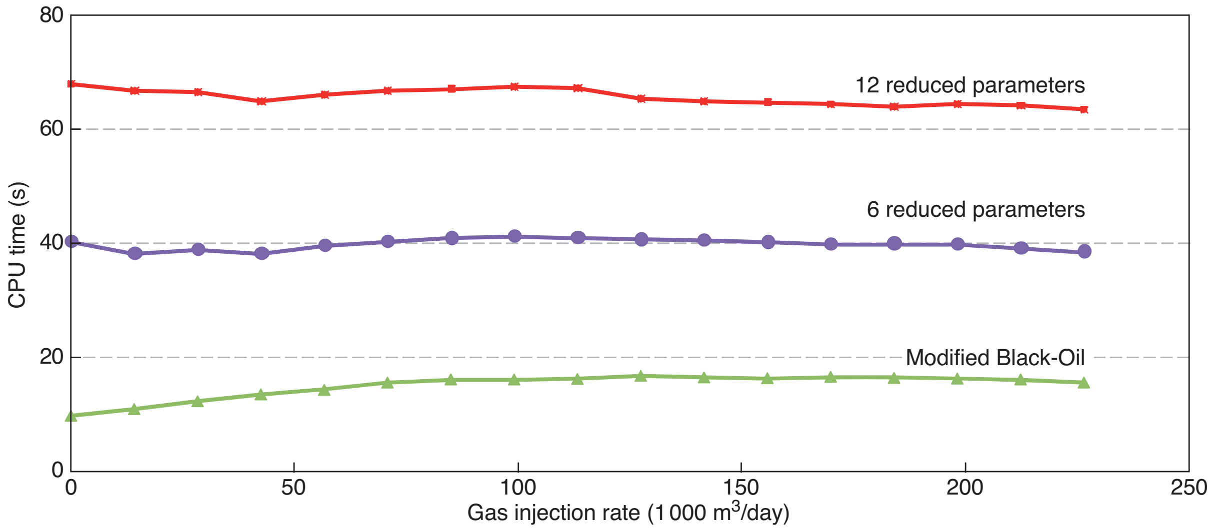

Figure 7

CPU time to calculate cumulative oil production in 10 years obtained from compositional and MBO approach at different gas injection rate.

the compositional approach is 0.167 million m^3 greater than the simulated value using the MBO approach. This is due to the higher gas injection rate leading to higher oil/gas composition variations within the wellbore that is fully handled by the compositional treatment. It seems that in the case of higher gas injection rate using a compositional approach improves the estimation.

CONCLUSIONS

An integrated continuous gas lift model was developed to evaluate the Modified Black-Oil (MBO) approach against the fully compositional and reduced parameter methods. Performance of the models was compared in different gas injection rates. Computational cost to solve the integrated model is dependent on the thermodynamic treatment of the hydrocarbon fluids involved. The standard black-oil model that assumes a constant bubble pressure is not reliable for gas lift studies due to large bubble pressure variations in the wellbore. The results of an illustrative example having a single well demonstrate that even lumping the multi-component fluids via reduced methods does not cure the computational time due to the iterative flash calculations required. Thus, an accurate non-iterative phase behavior model is quite desirable. Simulation results show that acceptable outcome can be obtained from a MBO treatment when the fluid is assumed to be composed of two pseudo-components. Either the components may be present in the hydrocarbon gas and oil phases. Computational cost using the MBO treatment is about an order of magnitude smaller than the full compositional approach. This is particularly advantageous when the model has to be solved many hundreds of times in finding the optimal combination of gas lift parameters.

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