Performance Prediction of a Well Under Multiphase Flow Conditions
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Abstract
This paper presents an analytical method to predict production performance of a well producing from a solution gas-drive reservoir. Many available analytical techniques published for a solution gas-drive reservoir have been intended mainly for data analysis techniques and they were proved to be valid only for one particular flow regime (i.e., transient flow).

Many have used Inflow Performance Relationship (IPR) method to predict the well performance in these reservoirs. The shortcoming of this method is that it is based on regression to either field data or numerical simulation results. The data are sampled on one particular flow regime (i.e., boundary-dominated or pseudo-steady state flow). Hence, the outcomes are highly dependent on the condition at which the data are sampled.

The analytical method in this paper addresses all flow regimes (transient, transition, and boundary dominated flow). The solution also considers that all phases (oil, gas, and water) can flow. This solution is also validated with results from numerical simulation for various fluids and reservoir properties.

Introduction
The objective of this work is to develop a model to forecast performance of a well in a solution-gas drive reservoir where oil, gas and water are simultaneously flowing.

Many authors1-7 studied the well performance under solution-gas drive assuming water is immobile. The main purpose of their studies is to analyze pressure transient and production data obtained from this system. They came up with different approaches, such as pressure, pressure squared, and pseudopressure methods, to make use the single-phase solution. One thing in common is they generate their results using numerical simulator which are then compared with the single-phase solution using their methods.

In this study, we will also formulate the multiphase flow (oil, gas and water) problem into the single-phase flow analog. However, we attempt different approach that we use our method to generate the well performance which is then compared with the results from a numerical reservoir simulator.

Mathematical Model
The mathematical model developed in this paper assumes a laminar, horizontal and radial flow with three phases of oil, gas and water with a well at the center of the circular reservoir. Capillary pressure is ignored. The reservoir is considered homogeneous and isotropic. The governing equation for this system, in Darcy unit, is:

\[ \frac{1}{r} \frac{\partial}{\partial r} \left[ r \frac{\partial p_p}{\partial r} \right] = \frac{\phi}{k} \frac{\partial^2 p_p}{\partial \tau_t^2} \] ...........................................(1)

Eq. 1 is completely linear and is analogous to the single-phase flow problem. The pseudopressure, \( p_p \), and pseudotime, \( \tau_t \), are defined as:

\[ p_p = \frac{1}{L_p} \int_{p_{phase}} \rho \left( \int_{p_{phase}} \right) dp \] ...........................................(2)

\[ \tau_t = \left( \frac{c_i}{L_p} \right) \int_{0}^{1} \frac{1}{c_i} dt \] ...........................................(3)

Where:

\[ L_p = \frac{k_{rw} + k_{rw} + k_{rg}}{\mu_o + \mu_w + \mu_g} \] ...........................................(4)

\[ c_i = S_o c_o + S_w c_w + S_g c_g + c_f \] ...........................................(5)

Note that the upper limit of the pseudopressure integral is the pressure at the specific location instead of the average reservoir pressure. The relationship between saturations (oil, gas and water) and pressure at any time is computed using Eqs. 6 and 7. Hence, relative permeability needed to compute the pseudopressure and pseudotime integrals can be obtained, and the saturation used for this purpose is the average saturation of the system. In this study, we use two-phase relative permeability of oil-gas (with connate water) and oil-water systems. Stone I method8-10 is used to obtain the three phase expression for relative permeability to oil (\( k_{ro} \)).
We use a numerical simulator to validate the analytical model. The well is produced at a constant total reservoir rate. The fluid and reservoir/well properties are shown in Tables 1 and 2 and Figs 1 and 2. The results using these data are shown in Figs. 3 to 5.

In Fig. 3, we compare the oil, gas, and water production from both models (numerical and analytical models). The solid lines data come from the numerical simulator and the solid symbol data are from the proposed analytical model. It is shown that both results are in good agreement. This observation is also true for average saturations (Fig. 4) and for bottom hole flowing pressure (Fig. 5).

The oil rate, in general, decreases with time as the relative permeability to oil decreases because the oil saturation becomes smaller as the time advances.

The gas production decreases at first because the gas production comes only from solution gas (at this time the gas in the reservoir is immobile). As the gas saturation is greater than the critical gas saturation, the free-gas (gas released from oil in the reservoir) is started to be produced. This causes the gas production increases. At late time, the depletion takes control the production and the gas production decreases.

On the other hand, the water production increases at the beginning. This may be due to the decreasing rate of oil relative permeability is greater than the decreasing rate of water relative permeability. At later time the water production decreases as the reservoir pressure depleted.

**Model Validation**

We also experimented by using different reservoir permeability (5, 10, and 100 mD). Since the production mode is constant total reservoir production, the reservoir permeability does not seem to affect the oil, gas, and water production (Fig. 8) and the average oil saturation (Fig. 9). As expected, the pressure drop is higher as the permeability is smaller indicated by lower bottom hole flowing pressure for smaller permeability (Fig. 10).

From these results we also see good agreements between results from numerical simulator and those from analytical solution.

**Sensitivity on Skin Factor**

The results are plotted in Figs. 11 to 13. From this exercise, the effect of skin for constant total reservoir production is only observed on the bottom hole flowing pressure. For most cases the agreements between the numerical model and the analytical model are quite good. The discrepancy between the two is observed for high skin of +20. At early time, the numerical solution seems to be unstable. At the transition region, again, the numerical model is smaller that the analytical solution before it recovers back to the values predicted by the analytical solution at the boundary dominated region. This behavior may be due to the fact that the analytical solution uses average saturation. However, to reach a conclusive statement, further investigation is warranted.

**Conclusions**

To summarize the results from this work, we conclude that:

1. We have developed the analytical model for predicting well performance under multiphase flow condition in a solution gas drive reservoir.
2. This model has been successfully validated against a numerical reservoir simulator. For most cases, the agreements with the numerical reservoir simulator are very good. For cases where the pressure drop is very high (such as in a very high production, a well with high skin factor, and in a very low permeability reservoir), there are discrepancies in the transition region. This should be subject for further research.
3. The pseudopressure and pseudotime integrals developed in this study should also be applicable for data analysis of well performance in a solution gas drive reservoir where water is also flowing.
Nomenclature

- \( A \) = Drainage area, Acre
- \( B_o \) = oil formation volume factor, rb/stb
- \( B_g \) = gas formation volume factor, rb/scf
- \( B_w \) = water formation volume factor, rb/scf
- \( c_o \) = oil compressibility, 1/psi
- \( c_g \) = gas compressibility, 1/psi
- \( c_w \) = water compressibility, 1/psi
- \( c_t \) = total compressibility, 1/psi
- \( c_r \) = rock compressibility, 1/psi
- \( GOR \) = producing gas-oil ratio, scf/stb
- \( h \) = reservoir thickness, ft
- \( k \) = reservoir permeability, mD
- \( k_{ro} \) = oil relative permeability
- \( k_{rg} \) = gas relative permeability
- \( k_{rw} \) = water relative permeability
- \( p \) = pressure, psi
- \( p_b \) = bubble point pressure, psia
- \( p_i \) = initial pressure, psia
- \( p_o \) = normalized pseudopressure, psi
- \( q_o \) = oil rate, stb/D
- \( q_g \) = gas rate,MSCF/D
- \( q_w \) = water rate, stb/D
- \( q_T \) = Total reservoir (sandface) rate, rb/D
- \( t \) = time, Day
- \( t_a \) = normalized pseudotime, Day
- \( r \) = radius distance from well, ft
- \( r_w \) = well radius, ft
- \( R_{so} \) = solution gas-oil ratio, scf/stb
- \( R_{sw} \) = solution gas-water ratio, scf/stb
- \( s \) = skin factor
- \( S_o \) = oil saturation
- \( S_g \) = gas saturation
- \( S_w \) = water saturation
- \( WOR \) = producing water-oil ratio, stb/stb
- \( \mu_o \) = oil viscosity, cp
- \( \mu_g \) = gas viscosity, cp
- \( \mu_w \) = water viscosity, cp
- \( \phi \) = porosity


Appendix A—Governing Equation

The radial flow equations for oil, gas, and water in the reservoir are as follows:

**Oil phase:**

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ r \frac{k k_{ro}}{\mu_o B_o} \frac{\partial p}{\partial r} \right] = \frac{\partial}{\partial t} \left[ \frac{\phi}{B_o} \right] S_o \quad \text{.................. (A-1)}
\]

**Water phase:**

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ r \frac{k k_{rw}}{\mu_w B_w} \frac{\partial p}{\partial r} \right] = \frac{\partial}{\partial t} \left[ \frac{\phi}{B_w} \right] S_w \quad \text{.................. (A-2)}
\]

**Gas phase:**

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ r \left( \frac{k k_{rg}}{\mu_g B_g} + R_{so} \frac{k k_{ro}}{\mu_o B_o} + R_{sw} \frac{k k_{rw}}{\mu_w B_w} \right) \frac{\partial p}{\partial r} \right] = \frac{\partial}{\partial t} \left[ \frac{\phi}{B_g} \right] S_g + \frac{\partial}{\partial t} \left[ \frac{\phi}{B_o} \right] S_o + \frac{\partial}{\partial t} \left[ \frac{\phi}{B_w} \right] S_w \quad \text{.................. (A-3)}
\]

Expanding Eq. A-1 for oil phase, we obtain:

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ r \frac{k k_{ro}}{\mu_o B_o} \frac{\partial p}{\partial r} \right] = \frac{\partial}{\partial t} \left[ \frac{\phi}{B_o} \right] S_o + \frac{\partial}{\partial t} \left[ \frac{\phi}{B_o} \right] S_o \phi \quad \text{.................. (A-4)}
\]

The reservoir permeability is assumed not to change significantly as the pressure changes, and this is a valid assumption in most cases. We also assume that the fluid properties can be evaluated at the average reservoir pressure. Expanding Eq. A-4 further, and rearranging, we have:

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ r \frac{k k_{ro}}{\mu_o B_o} \frac{\partial p}{\partial r} \right] = \frac{\partial}{\partial t} \left[ \frac{\phi}{B_o} \right] \left( S_o B_o - S_w B_w \right) + \frac{S_o}{B_o} c_f \quad \text{.................. (A-5)}
\]
Similar as Eq. A-5, we obtain for water phase:

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ \frac{k_{rw} \hat{c}_p}{\mu_w \hat{c}_p} \right] = \phi \frac{\hat{c}_p}{\partial t} \left[ \frac{S_w B_w - S_w B_w'}{B_w'} \right] + \frac{S_w}{B_w} c_f \]

For free-gas phase, we have that

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ \frac{k_{rg} B_g}{\mu_g B_g} \right] = \phi \frac{\hat{c}_p}{\partial t} \left[ \frac{S_g B_g}{B_g} + R_{so} \frac{S_o B_o}{B_o} + R_{sw} \frac{S_w B_w}{B_w} \right] + \left( \frac{S_g}{B_g} + R_{so} \frac{S_o B_o}{B_o} + R_{sw} \frac{S_w B_w}{B_w} \right) c_f \]

Expanding Eq. A-11 and rearranging, we obtain

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ \frac{k_{rg} B_g}{\mu_g B_g} \right] = \phi \frac{\hat{c}_p}{\partial t} \left[ S_g - S_g B_g' B_g + R_{so} \frac{S_o B_o}{B_o} \right. \\
+ R_{so} \frac{S_o B_o}{B_o} B_g - R_{so} \frac{S_o B_o}{B_o} B_g' \left. + R_{sw} \frac{S_w B_w}{B_w} B_g + R_{sw} \frac{S_w B_w}{B_w} B_g' \right] \\
- R_{sw} \frac{S_w B_w}{B_w} c_f + \left( \frac{S_g}{B_g} + R_{so} \frac{S_o B_o}{B_o} + R_{sw} \frac{S_w B_w}{B_w} \right) c_f \\
- R_{sw} \frac{S_w B_w}{B_w} c_f \]

Expanding Eq. A-3,

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ \frac{k_{rg} B_g}{\mu_g B_g} \right] \]

Expanding Eq. A-9 further, we obtain

\[
\frac{1}{r} \frac{\partial}{\partial r} \left[ \frac{k_{rg} B_g}{\mu_g B_g} \right] \]

Substituting Eqs. A-4 and A-10 into Eq. A-8, we obtain
Where
\[ c_i = S_o c_o + S_w c_w + S_g c_g + c_f \]  \hspace{1cm} (A-16)

The relative permeability-viscosity in the left-hand-side and the compressibility in the right-hand-side are dependent upon pressure, hence the partial differential equation in Eq. A-15 is non-linear. Our goal is to linearize Eq. A-15.

Introducing pseudopressure
\[ p_p = \frac{1}{\left( \frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \right)} \int_{0}^{p} \left( \frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \right) dp \]  \hspace{1cm} (A-17)

Defining
\[ l_p = \frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \]  \hspace{1cm} (A-18)

Substituting Eq. A-18 into Eq. A-17
\[ p_p = \frac{1}{l_p} \int l_p dp \]  \hspace{1cm} (A-19)

Taking derivative of Eq. A-19 with respect to pressure, we obtain
\[ \frac{dp_p}{dp} = \frac{l_p}{l_p} \]  \hspace{1cm} (A-20)

Writing in term of pseudopressure Eq. A-17 becomes
\[ \frac{1}{r} \frac{\partial}{\partial r} \left[ \frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \right] \frac{\partial p_p}{\partial r} = \frac{\phi c_i}{k} \frac{\partial p_p}{\partial r} \]  \hspace{1cm} (A-21)

Substituting Eq. A-20 into Eq. A-21
\[ \frac{1}{r} \frac{\partial}{\partial r} \left[ \frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \right] \frac{\partial p_p}{\partial r} = \frac{\phi c_i}{l_p} \frac{\partial p_p}{\partial r} \]  \hspace{1cm} (A-22)

Introducing pseudotime as
\[ t_o = \int_{0}^{t} l_p dt \]  \hspace{1cm} (A-23)

Inserting pseudotime (Eq. A-23) in Eq. A-22, we obtain
\[ \frac{1}{r} \frac{\partial}{\partial r} \left[ \frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \right] \frac{\partial p_p}{\partial r} = \frac{\phi c_i}{l_p} \frac{\partial p_p}{\partial t_o} \]  \hspace{1cm} (A-24)

We now have Eq. A-24, which is completely linear and it is analogous to the liquid solution. Next is to derive the expression of the inner boundary condition for constant total reservoir rate production.

The total velocity is
\[ v = k \left[ \frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \right] \frac{\partial p}{\partial r} \]  \hspace{1cm} (A-25)

Rewriting Eq. A-25 in term of total rate and rearranging we have
\[ \left[ \frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \right] \frac{\partial p}{\partial r} = \frac{q}{2 \pi k h} \]  \hspace{1cm} (A-26)

Use pseudopressure in Eq. A-26, we obtain
\[ \frac{\partial p_p}{\partial r} = \frac{q}{2 \pi k h} \]  \hspace{1cm} (A-27)

As shown in Eq. A-27, the inner boundary condition for our multiphase system is also linear provided that pseudopressure (Eq. A-19) is used.

**Appendix B—Saturation and Pressure Relationship**

To compute the pseudopressure and pseudotime, knowledge of the relationship between saturation and pressure need to be known. This appendix is to provide a procedure for determining the average saturation profiles as functions of reservoir pressure.

The remaining gas-in-place (solution and free gas) at any time can be computed by Eq. B-1.
\[ G_g = \frac{r w w S_v w S_v + S_g V_p}{B_w - B_g} \]  \hspace{1cm} (B-1)

Taking derivative of Eq. B-1 with respect to pressure, we obtain
\[ \frac{dG_g}{dp} = \frac{V_p \left[ B_w \left( S_v w S_v + S_g V_p \right) - (1 - S_g - S_v) B_g \right]}{B_w^2} \]  \hspace{1cm} (B-2)

The remaining oil-in-place at any time is
\[ N_o = \frac{S_o V_p}{B_o} \]  \hspace{1cm} (B-3)

Taking derivative of Eq. B-3 with respect to pressure, we obtain
\[ \frac{dN_o}{dp} = \frac{V_p \left[ S_o + \phi c_f \left( \frac{S_g}{B_o} - \frac{B_g}{B_o} \right) \right]}{B_o} \]  \hspace{1cm} (B-4)

The water-in-place (negligible water influx) at any time is
\[ W_r = \frac{S_w V_p}{B_w} \]  \hspace{1cm} (B-5)

Taking derivative of Eq. B-5 with respect to pressure, we obtain
\[ \frac{dW_r}{dp} = \frac{V_p \left[ S_w + \phi c_f \left( S_o - \frac{S_w}{B_w} \right) \right]}{B_w} \]  \hspace{1cm} (B-6)

Production gas-oil ratio is defined as
\[ GOR = \frac{q_g}{q_o} + \frac{r w w k_{ro} \mu_o B_o + k_{rg} \mu_o B_o}{k_{ro} \mu_g B_g} \]  \hspace{1cm} (B-7)

Production gas-oil ratio can also be computed by
\[ GOR = \frac{dG_g}{dN_o} \frac{dN_o}{dp} \]  \hspace{1cm} (B-8)
Next is to substitute Eq. B-2 and Eq. B-4 into Eq. B-8. The resulting equation is then equated with Eq. B-7. After rearrangement, we obtain expression for oil saturation (Eq. B-9).

\[
S'_o = \frac{1}{k_{go} \mu_o + R_{sw} k_{ro} \mu_w B_w} \left[ \frac{R_{sw} S_o B_g}{B_o} + \frac{R'_{sw} S_w B_g}{B_w} \right] + \frac{R_{sw} S_w B_g}{B_w} - S'_o - \frac{(1 - S_o - S_w)}{B_g} B_g \\
+ c_f \left( \frac{R_{sw} S_w B_g}{B_w} + (1 - S_o - S_w) - \frac{S_o k_{rg} \mu_o}{k_{ro} \mu_g} - S_o R_{sw} \frac{k_{ro} \mu_w B_w}{B_g} \right) \\
+ \frac{S_o B_o}{B_w} \left( \frac{k_{rg} \mu_o}{k_{ro} \mu_g} + R_{sw} \frac{k_{ro} \mu_w B_w}{B_g} \right)
\]

.............................. (B-9)

Production water-oil ratio is defined as

\[
WOR = \frac{q_w}{q_o} = \frac{k_{ro} \mu_o B_o}{k_{ro} \mu_w B_w}
\]

................................. (B-10)

Production water-oil ratio can also be computed by

\[
WOR = \frac{q_w}{q_o} = \frac{dW_r / dt}{dN_r / dp} = \frac{dW_r / dp}{dN_r / dp}
\]

................................. (B-11)

We then equate Eq. B-10 and Eq. B-11, and after substituting Eqs. B-4 and B-5 and rearrangement, we obtain expression for water saturation in Eq. B-12.

\[
S'_w = \frac{k_{ro} \mu_o}{k_{ro} \mu_w} \left[ S'_o - S_o \frac{B_o}{B_o} \right] - c_f \left[ \frac{S_w - S_o}{k_{ro} \mu_w} \right] + S_w \frac{B'_w}{B_w}
\]

................................. (B-12)

We, now, have two equations and two unknowns (oil and water saturations). Therefore, we can solve Eqs. B-9 and B-12 simultaneously to obtain oil and water saturations as functions of pressure.
Table 1—Fluid Properties

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<th>Oil Viscosity (cp)</th>
<th>Gas Viscosity (cp)</th>
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Table 2—Reservoir/Well Properties

- Initial pressure, $p_i$ = 4000 psia
- Bubble point pressure, $p_b$ = 4000 psia
- Reservoir thickness, $h$ = 15 ft
- Permeability, $k$ = 100 mD
- Porosity, $\phi$ = 0.1
- Rock compressibility, $c_f$ = 3x10^-6 psi-1
- Drainage area, $A$ = 160 Acre
- Well radius, $r_w$ = 0.33 ft
- Skin factor, $s$ = 0
- Total sandface production, $q_T$ = 200 bbl/D
Figure 1—Relative permeability oil-water system.

Figure 2—Relative permeability gas-oil system.

Figure 3—Production rate of oil, gas and water.

Figure 4—Average saturation.

Figure 5—Bottom hole flowing pressure.

Figure 6—Effect of total production rate on the oil production.
Figure 7—Effect of total production rate on the average oil saturation.

Figure 8—Effect of total production rate on the bottom hole flowing pressure.

Figure 9—Effect of reservoir permeability on the oil production rate.

Figure 10—Effect of reservoir permeability on the bottom hole flowing pressure.

Figure 11—Effect of skin on the oil production.
Figure 12—Effect of skin on the average oil saturation.

Figure 8—Effect of skin on the bottom hole flowing pressure.