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Estimating Solution Gas-Drive Future Well Performance As A Function Of Oil Mobility Profile

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Abstract. Wiggins et al. pointed out the key to know a solution gas-drive performance lies in its mobility function. In predicting future inflow performance relationship of a solution gas-drive reservoir, the underlying assumption of almost all available correlations is the oil mobility profile stays the same throughout a reservoir life. However, in order to know the complete mobility profile of a reservoir, one of the parameters that has to be know is the reservoir's saturation distribution – which it is not. This study aims to generalize oil mobility profile of solution gas-drive reservoirs to solve the issue. All cases for this study are generated using commercial reservoir simulator. By incorporating the generalized oil mobility profile into Standing's definition of future well performance, the new method requires only a single flow data test to be able to estimate future performance and gives a more accurate estimation compared to other method that also requires a single flow data test.

Keyword(s): parameter characteristic, solution gas-drive reservoir, mobility function profile, average reservoir pressure

1 Basic Theory and Development

Several correlations have been developed before in order to estimate future inflow performance curves for solution gas-drive reservoirs. There are several well-known methods for future IPR predictions such as Standing (1971), Fetkovich (1973), Uhri and Blount (1982), Eickmeier (1968), and Kelkar and Cox (1985). Fetkovich (1973) suggested that for a solution gas-drive reservoir, oil mobility can be assumed linear to reservoir pressure. This linear assumption was then proven incorrect by Camacho and Raghavan (1989) using numerical simulator. Uhri-Blount (1982) developed a method using the same assumption as Fetkovich (1973), this method needs two flow data test and the result will depend on at which point the flow data were taken. Eickmeier (1968) developed a method to predict maximum flow rate at future time by combining Fetkovich and Vogel equations. By assuming n=1, Eickmeier's method only requires a single flow test data:

$$\frac{q_{o,max,f}}{q_{o,max,p}} = \left(\frac{p_{r,f}}{p_{r,p}}\right)^3 \tag{1}$$

Kelkar-Cox (1985) applied the concept from Fetkovich (1973) that the n value is constant throughout a reservoir's life. Their method also requires two flow data tests.

Standing (1971) stated that the productivity index of present-day value and productivity index of any future value can be estimated by its mobility function:

$$J_f{}^* = J_p{}^* \left(\frac{k_{ro}}{\mu_o B_o}\right)_f \Big/ \left(\frac{k_{ro}}{\mu_o B_o}\right)_p \tag{2}$$

This means Standing's method needs the mobility function data at the future reservoir pressure which in practice, is not available. This study is intended to modify Standing's method for future IPR that requires the computation of mobility functions to calculate future productivity index, J_f*, to only needing to compute future reservoir pressure by generalizing solution gas-drive reservoirs' mobility profile by using Ilk's characteristic parameter concept.

Based on the work of Camacho-Raghavan (1989), Ilk et al. (2007) developed a function to correlate normalized pressure and 1-normalized mobility function:

$$\left[1 - \frac{f(\bar{p}) - f(p_{abn})}{f(p_i) - f(p_{abn})}\right] = 1 - \zeta \left[\frac{\bar{p} - p_{abn}}{p_i - p_{abn}}\right] + (1-\zeta)\left[\frac{\bar{p} - p_{abn}}{p_i - p_{abn}}\right]^2 - 2(1-\zeta)\left[\frac{\bar{p} - p_{abn}}{p_i - p_{abn}}\right]^3 \tag{3}$$

Note that in this study, p_{abn} refers to average reservoir pressure when the simulator is stopped. The new general correlation for mobility profile will be based on equation 2 that normalized mobility function and normalized pressure has a third-degree polynomial (cubic) relationship.

2 Methodology

The commercial software used for this study is Computer Modeling Group (CMG) IMEX. All simulation cases were modeled with the following assumptions:

- The reservoir is cylindrical
- The reservoir is bounded and homogenous with single vertical well located in the center, completed through whole formation thickness, no limited entry effects
- Initially at bubble point pressure (single-phase oil initially)
- No produced water, water present in the reservoir is connate water
- Water-wet rock
- Interfacial tension and non-Darcy flow effects are not considered
- Isothermal condition exists

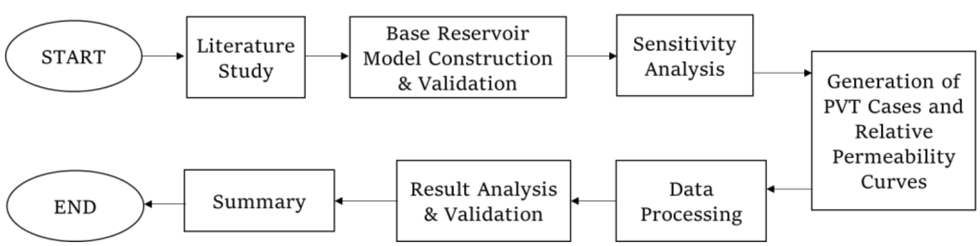

Figure 1. General workflow

A base reservoir model is constructed from modifying the SPE second comparative solution project. The data used can be seen in Appendix A and the validation steps can be seen in Appendix B.

For the purpose of developing a general mobility-pressure profile correlation, a total of 8 PVT sets were prepared as seen in table 1. Note that the PVT sets used in this study are not real black oil PVT. It is approximated that PVT choices will not affect the final general correlation of the profile significantly.

Table 1. Black oil properties.

PVT Set	Initial GOR [SCF/STB]	Oil Density [°API]	Gas Gravity [dimensionless]	Reservoir Temperature [°F]
1	132	20	0.6	150
2	132	20	0.6	240
3	132	20	0.8	150
4	132	20	0.8	240
5	900	45	0.6	150
6	900	45	0.6	240
7	900	45	0.8	150
8	900	45	0.8	240

Based on table 1, Standing's correlations were used to calculate bubble point pressure, oil formation volume factor, and solution gas ratio. Beal-Chew correlation was used to calculate live oil viscosity. The data ranges used for generating relative permeability curves are taken from Fattah (2014) which was summarized from 47 field cases. However, note that the relative permeability curves are also not real field cases curves.

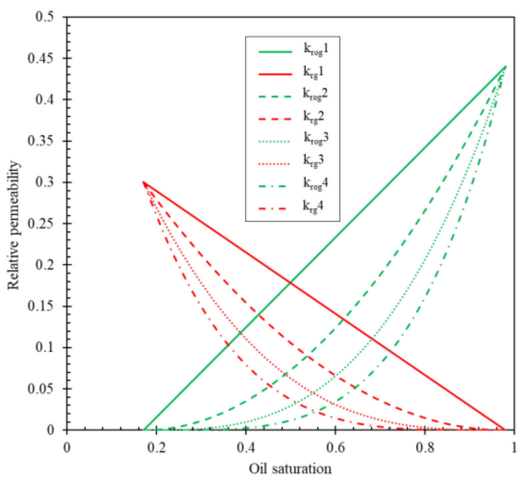

Figure 2. Relative permeability curves for k_r1, k_r2, k_r3, k_r4 sets

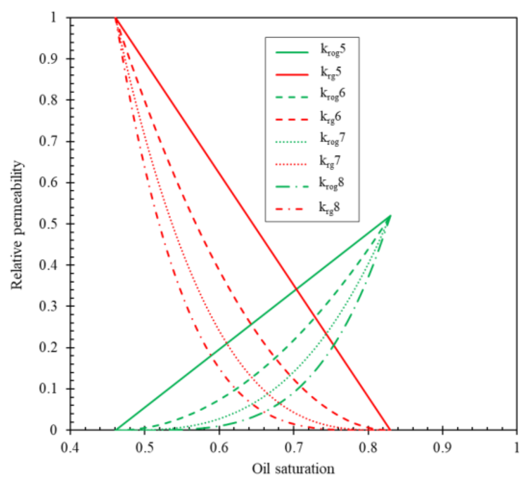

Figure 3. Relative permeability curves for k_r5, k_r6, k_r7, k_r8 sets

3 Result and Validation

From the previous 8 PVT cases and 8 relative permeability cases combined, a total of 64 numerical simulation cases were run. All models were run under BHP constraints of 14.7 psia. Since the models are not based on field cases, another mean of validation is needed to make sure the mobility function results from these numerical cases are valid. For this purpose, mobility – pressure behavior graphs from Fattah et al. (2014) were used as references. After going through this process, a total of 39 out of 64 cases were justified to represent solution-gas drive mobility function profile. Figure 4 shows normalized reservoir pressure vs normalized mobility function of the 39 numerical simulation cases. The bold black line on the figure is the average of these cases.

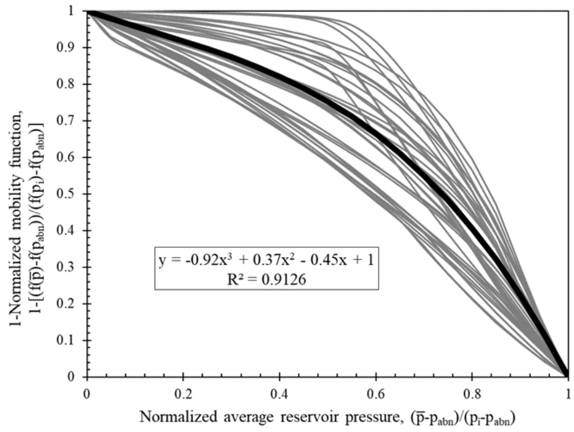

Figure 4. Generalized profile of normalized pressure vs normalized mobility function

By taking into account that p_{abn} equals to atmospheric pressure, the equation on figure 5 can be re-written mathematically as:

$$\frac{f(\bar{p})-f(p_{abn})}{f(p_i)-f(p_{abn})}=0,92\left(\frac{\bar{p}}{p_i}\right)^3-0.37\left(\frac{\bar{p}}{p_i}\right)^2+0.45\left(\frac{\bar{p}}{p_i}\right) \tag{4}$$

Integrating equation 6 into equation 1 and assuming $f(p_{abn})=0$:

$$J_f{}^*=J_p{}^*\left[0,92\left(\frac{\bar{p}}{p_i}\right)^3-0.37\left(\frac{\bar{p}}{p_i}\right)^2+0.45\left(\frac{\bar{p}}{p_i}\right)\right] \tag{5}$$

If the future productivity index is known, then future well performance can be calculated by:

$$q_{o,max}=\frac{J_f{}^* p_{rf}}{1.8} \tag{6}$$

For validation purpose, 6 data set examples from Kelkar-Cox (1985) were used. One data set example is shown in table 2. The flow data test for table 2 is as follows: p_r = 2340.1 psi, $q_{o,max}$ = 538.3 bbl/ day.

Table 2. Validation of example cases for future flow rate prediction (Kelkar-Cox, 1985)

p_r [psia]	$q_{o,max}$ [bbl/day]	Calculated $q_{o,max}$	
		Eickmeier	Modified Standing
2180.5	372.7	435.5	422.52
2173.3	365.9	431.2	417.82
2166.3	359.2	427.05	413.29
2159.5	352.8	423.04	408.92
2152.9	346.5	419.17	404.72
2146.5	340.7	415.45	400.69
Average percent error		20.4%	16.33%

Appendix C shows all these data set examples. Eickmeier's method is used for comparison as it also only requires a single data flow test for estimating the future well performance. The new method of estimating future well performance as a function of mobility profile is referred as "Modified Standing" in Table 2.

For all six data set examples, the average percent error of all sets for the modified Standing method and Eickmeier's method are 11% and 14% respectively.

4 Summary

From the result of this study and under mentioned assumptions, it can be concluded that the modified Standing method that uses generalized mobility profile yields a slighty more accurate result than another method that only requires a single flow data test. It is estimated to an even better result could be achieved if mobility at $p = 0$, $f(p_{abn})$, is not assumed as 0.

Appendix A

Table A.1. Base reservoir model data.

Property	Value
Radial grid	30 x 8 x 10
Outer radius, r_e	820 ft
Well radius, r_w	0.3 ft
Grid thickness	1.5 ft
Porosity	0.1

Appendix B

To see whether the constructed model is a solution gas-drive reservoir, the model was run under a certain bottomhole pressure constraint. Then, the flow rate at the start of boundary-dominated flow (pseudo-steady state) is computed. This process is then redone several times under different BHP constraints. Type curve from Fetkovich (1980) was used to determine the starting time of boundary-dominated flow as seen on figure A1. All the data were then plotted and turned dimensionless with flow rate on the y-axis and pressure on the x-axis. Figure A2 shows that the dimensionless pressure vs rate points are close to Vogel's equation in graph form.

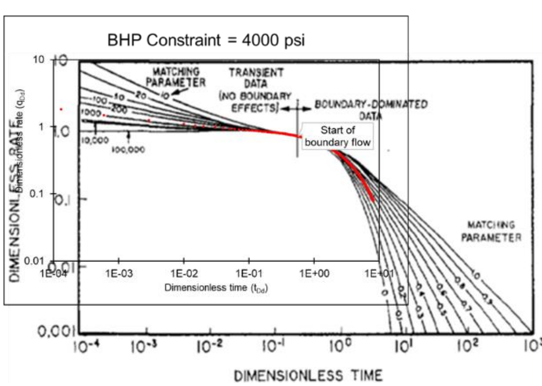

Figure B.1. Determination of the start of boundary-dominated flow using type curve from Fetkovich (1980)

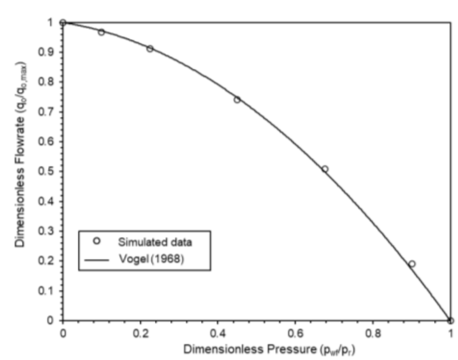

Figure B.2. All plotted data taken at pseudo-steady state in comparison to Vogel's equation

Appendix C

Table C.1. Data set examples from Kelkar- Cox (1985)

Set	1		2		3		4		5		6	
Present data	p_r	$q_{o,max}$	p_r	$q_{o,max}$	p_r	$q_{o,max}$	p_r	$q_{o,max}$	p_r	$q_{o,max}$	p_r	$q_{o,max}$
	2090	184	1945	150	2340.1	538.3	2289.5	481.8	2346.4	319.3	2292.9	289.5
Future data	p_r	$q_{o,max}$	p_r	$q_{o,max}$	p_r	$q_{o,max}$	p_r	$q_{o,max}$	p_r	$q_{o,max}$	p_r	$q_{o,max}$
	1805	118	1805	118	2180.5	372.7	2180.5	372.7	2240.1	261.8	2240.1	261.8
	1650	91	1650	91	2173.3	365.9	2173.3	365.9	2237.3	260.5	2237.3	260.5
	1480	67	1480	67	2166.3	359.2	2166.3	359.2	2231.9	257.3	2231.9	257.3
	1250	43	1250	43	2159.5	352.8	2159.5	352.8	2226.5	254.2	2226.5	254.2
	915	20	915	20	2152.9	346.5	2152.9	346.5	2221.2	251.1	2221.2	251.1
	340	3	340	3	2146.5	340.7	2146.5	340.7	2213.6	246.4	2213.6	246.4

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