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RESEARCH ARTICLE

Inflow Performance Relationship Correlation for Solution Gas-Drive Reservoirs Using Non-Parametric Regression Technique

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Abstract:

Background:

The Inflow Performance Relationship (IPR) describes the behavior of flow rate with flowing pressure, which is an important tool in understanding the well productivity. Different correlations to model this behavior can be classified into empirically-derived and analytically-derived correlations. The empirically-derived are those derived from field or simulation data. The analytically-derived are those derived from basic principle of mass balance that describes multiphase flow within the reservoir. The empirical correlations suffer from the limited ranges of data used in its generation and they are not function of reservoir rock and fluid data that vary per each reservoir. The analytical correlations suffer from the difficulty of obtaining their input data for its application.

Objectives:

In this work, the effects of wide range of rock and fluid properties on IPR for solution gas-drive reservoirs were studied using 3D radial single well simulation models to generate a general IPR correlation that functions of the highly sensitive rock and fluid data.

Methodology:

More than 500 combinations of rock and fluid properties were used to generate different IPRs. Non-linear regression was used to get one distinct parameter representing each IPR. Then a non-parametric regression was used to generate the general IPR correlation. The generated IPR correlation was tested on nine synthetic and three field cases.

Results & Conclusion:

The results showed the high application range of the proposed correlation compared to others that failed to predict the IPR. Moreover, the proposed correlation has an advantage that it is explicitly function of rock and fluid properties that vary per each reservoir.

Keywords: Inflow Performance Relationship (IPR), Analytical and empirical correlations, Solution gas-drive reservoirs, 3D radial single well simulation models, Non-linear regression, Non-parametric regression.

1. INTRODUCTION

Predicting the relationship between the flow rate and the pressure drop performance in the reservoir is very important for continuous production optimization. IPR curve can be combined with tubing performance curve to monitor well productivity, designing production and artificial lift equipment and to choose the proper remedial treatment options (acidizing, fracturing, work over, *etc.*) for optimum well performance.

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In calculating oil production, it was assumed that an oil production rate is directly proportional to draw down. Using this assumption, well's behavior can be described by productivity index; PI. This PI relationship was developed from Darcy's law for steady state radial flow of a single incompressible fluid.

$$q = J(Pe - Pwf) \quad \textbf{(1)}$$

Evinger and Muskat [1] pointed that the above relationship is not valid for two phase flow.

The first presentation of an inflow performance relationship (IPR) was made by Rawlins and Schellhardt [2]. They used their plot to show the effect of liquid loading on the production performance of gas wells. Gilbert [3] introduced the concept of an "Inflow Performance Relationship" (IPR).

Based on our literature survey, the different IPR correlations can be divided into empirically-derived and analytically-derived correlations.

1.1. The empirically derived correlations are:

- Vogel [4]
- Fetkovich [5]
- Jones *et al.* [6]
- Richardson and Shaw [7]
- Wiggins [8, 9]
- Klins and Majcher [10]
- Sukarno and Wisnogroho [11]

1.2. The Analytical correlations are:

- Wiggins *et al.* [8, 12]
- Del Castillo *et al.* [13, 14]

Detailed description of all the above IPR models is given on Abdel Salam [15].

Different attempts afterwards were used to either give theoretical explanations of the above IPR correlations or to introduce modifications to the above IPR correlations. Examples of these attempts are as follows:

In 2007, Haiquan *et al.* [16] deduced a dimensionless IPR for a single phase (oil or gas), based on the nonlinear flow mathematical model developed by Forcheimer. This IPR for solution gas-drive reservoirs ($P_r \leq P_b$) as well as partial solution gas- drive reservoirs ($P_r \geq P_b$ and $P_{wf} \leq P_b$), developed by recognizing the similarity of deliverability equations between laminar flow and nonlinear (turbulent) flow of a single phase, and a general dimensionless IPR formula is gained by summing up and normalizing the IPRs in different cases as shown below where the characteristic parameters (a) and (n) have explicit physical significance.

$$\left(\frac{p_{wf}}{p_r}\right)^n = 1 - a\left[\frac{q_o}{q_{o\max}}\right] - (1-a)\left[\frac{q_o}{q_{o\max}}\right]^2 \quad \textbf{(2)}$$

The parameter (n) describes the average extent of solution gas-drive. If n = 1, **Eq. 2** is the dimensionless IPR for single phase oil flow (without solution gas-drive); n=2, dimensionless IPR for single phase gas flow or oil flow by solution gas-drive; and 1<n<2, dimensionless IPR for partial solution gas-drive. The parameter (a) describes the type of flow where for a=1, the flow is considered of laminar flow.

Ilk *et al.* [17] provided the analytical development of "Vogel"-type Inflow Performance Relationship correlations for solution gas-drive reservoir systems by proposing a characteristic mobility function that extended Del Castillo and Archer *et al.* [13, 14] work for assuming a polynomial mobility profile rather than the linear profile.

In 2009, Jahanbani and Shadizadeh [18] presented analytical solution for determination of IPR curves of oil wells below the bubble point pressure. This approach uses the results of well test analysis along with relative permeability and PVT data using the analytically derived flow equation in both transient and pseudo steady state.

Elias *et al.* [19] extended the Del Castillo and Archer *et al.* [13, 14] mobility equation as function of pressure and generated an empirical mobility ratio equation based on 47 field cases.

In 2012, Khasanov *et al.* [20] studied the effect of change in relative permeability and hence the mobility on the shape of the IPR using single well reservoir simulation models. They showed that Fetkovich Equation can be a good representation of the deliverability equation especially in the transition zone where the P_{wf} is slightly lower than the P_b and the shape of K_{rg} is not increasing sharply with increase in gas saturation. Khasanov *et al.* [20] proposed a generic IPR correlation close to Fetkovich equation as follows:

$$\frac{q_o}{q_{o\max}} = \left[1 - \left[\frac{P_{wf}}{P_r}\right]^{m_k}\right]^{n_k} \tag{3}$$

Where m_k ranges from 1.4 to 2 with value of 2 being noticed when the P_{wf} is close to P_b and K_{rg} is not increasing sharply with increase in gas saturation with $K_{rg\ max}$ value being less than 0.05. The n_k values range from 0.75 to 1 with low values occurring in the transition zone during the depletion process where the P_{wf} is slightly lower than the P_b with low gas saturation and n_k value tends to be1 when the reservoir pressure and the P_{wf} are far below the P_b.

Through time IPR curves have used in different applications, Brown [21] in 1982 used IPR combined with tubing intake curves to provide an optimum artificial lift method to produce the well. In 1988, Avery and Evans [22] utilize IPR curves in examining the well performance under different artificial lift designs. IPR curves were also used during enhanced oil recovery process where Yeu *et al.* [23] in 1997 used IPR to predict the performance of an oil well under the implementation of polymer flooding. After emerging of the multi-lateral technology, Guo *et al.* [24] in 2006 derived composite IPR for multi-lateral wells. These are few of the many applications of IPR in oil industry.

Most of the IPR correlations suffer from common limitations that they are not explicitly function of the different reservoir rock and fluid properties that vary from one reservoir to another or its difficulty to be applied. This will affect the accuracy of the correlations especially if the reservoir properties of the well under study are completely different from the properties used in generating these correlations. In this work, a single well 3D radial reservoir model with solution gas-drive as the main driving mechanism was built and reservoir simulation was used to generate different IPRs by changing the reservoir rock and fluid properties. The most sensitive reservoir rock and fluid properties were selected to generate the new IPR correlation. This new correlation is based on generating 550 combination of the selected reservoir rock and fluid properties and run the simulation models to generate different 550 IPR curves. Then, the non-parametric regression technique was used to generate the new IPR correlation that is explicitly function of the reservoir rock and fluid properties that highly affect the IPR curve.

The outline of the paper is as follows. **Firstly**, we presented the assumptions we used in generating the single well reservoir simulation model. **Secondly**, we studied the sensitivity of the IPR towards different rock and fluid parameters to choose the highly sensitive parameters to be used in the IPR correlation. **Thirdly**, we presented the nonlinear and non-parametric regression techniques we used to develop the IPR correlation that is explicitly function of reservoir rock and fluid properties. **Finally**, we presented the validation of the new correlation based on different synthetic and field cases.

2. MODEL CONSTRUCTION

MORE [25] that stands for Modular Oil Reservoir Evaluation was used to simulate the multi-rate test for constructing the IPR curve. The reservoir simulator was used to construct 550 reservoir models that cover a wide range of rock and fluid properties. These different reservoir models were used to examine the sensitivity of IPR curve towards the change in the reservoir rock and fluid properties, to select the highly sensitive properties for developing the IPR correlation. It is important to mention here that in constructing the single well reservoir simulation model, all the points on the IPR curve were in the pseudo-steady flow period with constant rate at the inner boundary and no flow at the outer boundary with two phases flowing which were oil and gas. The general assumptions used in building the reservoir models can be summarized as follows:

- 3D radial flow into the well bore as shown in Fig. (**1**).
- The reservoir initially at the bubble point pressure
- Vertical well at the center of the formation.
- The well is completed through the whole formation thickness.

- Homogeneous, bounded reservoir (Pseudo steady state flow period).
- Isothermal conditions exist
- Two Phase Flow (Oil & Gas).
- Capillary pressure is neglected

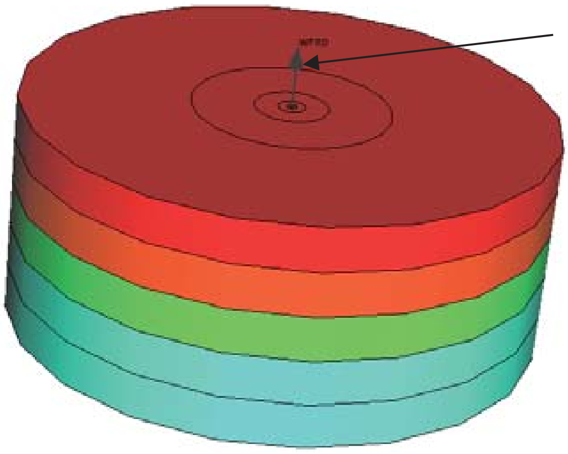


Fig. (1). 3D radial Model.

3. SENSITIVITY ANALYSIS

The sensitivity analysis is performed to examine the effect of different reservoir rock and fluid properties on the IPR behavior and hence selecting the highly sensitive parameters to be used in generating the IPR correlation.

Table (**1**) gives the range of reservoir rock and fluid properties used in this study. In the sensitivity analysis, one parameter was changed at a time while the rest was kept at its base value to be able to identify the sensitive parameters to the shape of the IPR curve.

Different rock and fluid properties are included in this study and the following list gives the properties that were found to have major effect on the IPR behavior using both IPR and dimensionless IPR plots:

Bubble Point Pressure, P_b
Reservoir Depletion Ratio (P_r/P_b)
Critical Gas Saturation, S_{gcr}
Residual Oil Saturation in Gas, S_{org}
Relative Permeability to Oil at S_{wcr}, K_{row} at (S_{wcr})
Relative Permeability to Gas at (1-S_{wcr}-S_{org}), K_{rg} at (1-S_{wcr}-S_{org})
Oil-Gas Relative Permeability Exponent, OGEXP
Gas Relative Permeability Exponent, GEXP
Skin, S

Figs. (**2** to **19**) show the IPR and dimensionless IPR behavior under the effect of the above mentioned rock and fluid properties that affect the IPR.

Table 1. Range of data used in the construction of the Proposed IPR Correlation.

Rock/Fluid Property	Range	Units
Initial Reservoir Pressure (Bubble point pressure)	1451 - 5413	psi
Reservoir Depletion Ratio (P_r/P_b)	0.33 - 0.95	dimensionless
Reservoir Temperature	100 - 400	° F
Oil Gravity	0.7 - 0.85	dimensionless

(Table 1) contd.....

Rock/Fluid Property	Range	Units
Gas Gravity	0.5 - 1.2	dimensionless
Water Gravity	1.0 – 1.25	dimensionless
Water Viscosity	0.1 - 1.0	cp
R_s	0.47 - 2.16	Mscf/stb
B_o	1.12 - 2.52	bbl/stb
μ_o	0.09 - 0.44	cp
Z(Gas Deviation Factor)	0.7 - 1.042	dimensionless
S_{wcr}	0 - 0.3	fraction
S_{gcr}	0 - 0.3	fraction
S_{orw}	0 - 0.6	fraction
S_{org}	0 - 0.4	fraction
OGEXP (K_{rog} Exponent)	1 - 5	dimensionless
OWEXP (K_{row} Exponent)	1 - 7	dimensionless
WEXP (K_{rw} Exponent)	2 - 8	dimensionless
GEXP (K_{rg} Exponent)	1 - 7	dimensionless
$K_{rw\ at}$ (S_{orw})	0.2 – 1.0	fraction
$K_{row\ at}$ (S_{wcr})	0.2 – 1.0	fraction
$K_{rg\ at}$ ($1-S_{wcr}-S_{org}$)	0.4 – 1.0	fraction
Drainage Radius	100 - 10000	ft
Thickness, h	10 - 1000	ft
K_v	0.5 – 500	md
K_h	1 - 1000	md
Skin	(-6) to (6)	dimensionless
Porosity	0.03 - 0.35	fraction

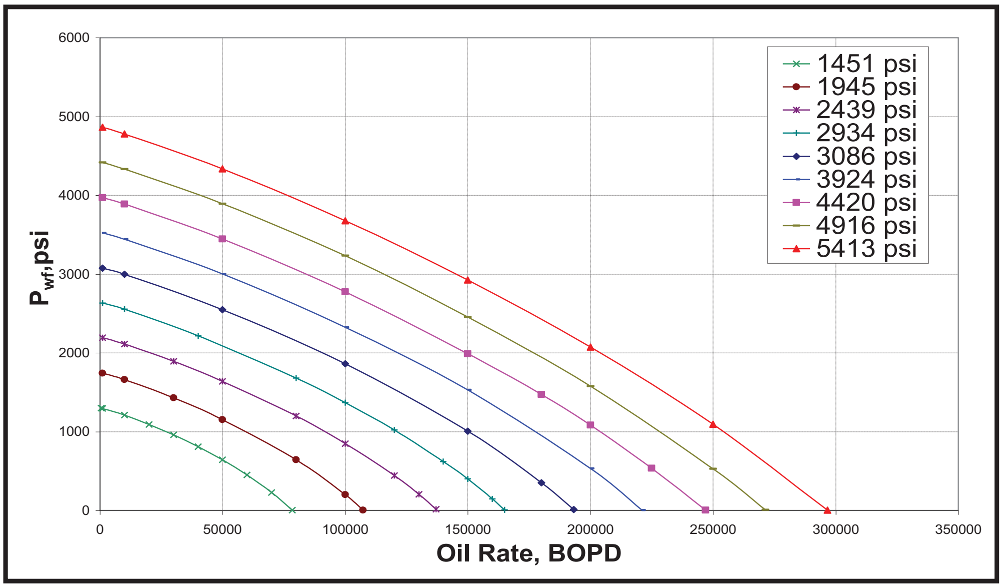


Fig. (2). Effect of Bubble Point Pressure on the IPR curve.

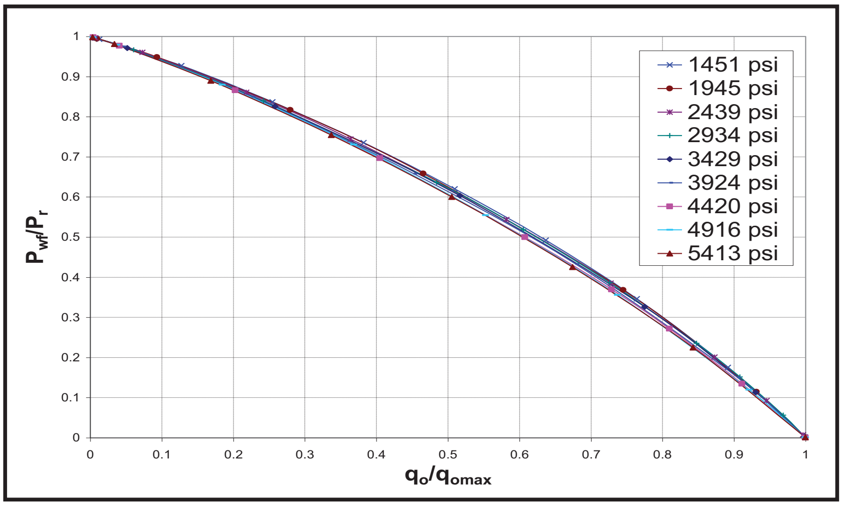


Fig. (3). Effect of Bubble Point Pressure on the dimensionless IPR curve.

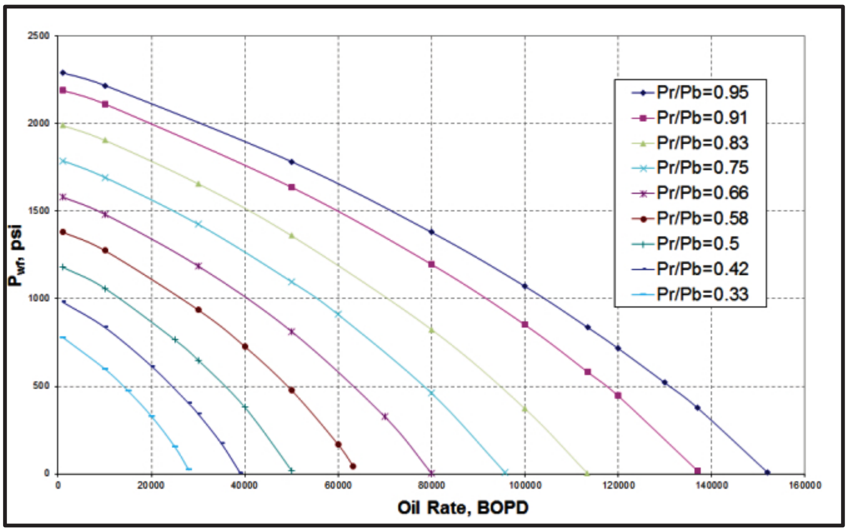


Fig. (4). Effect of Reservoir Pressure Depletion on the IPR curve.

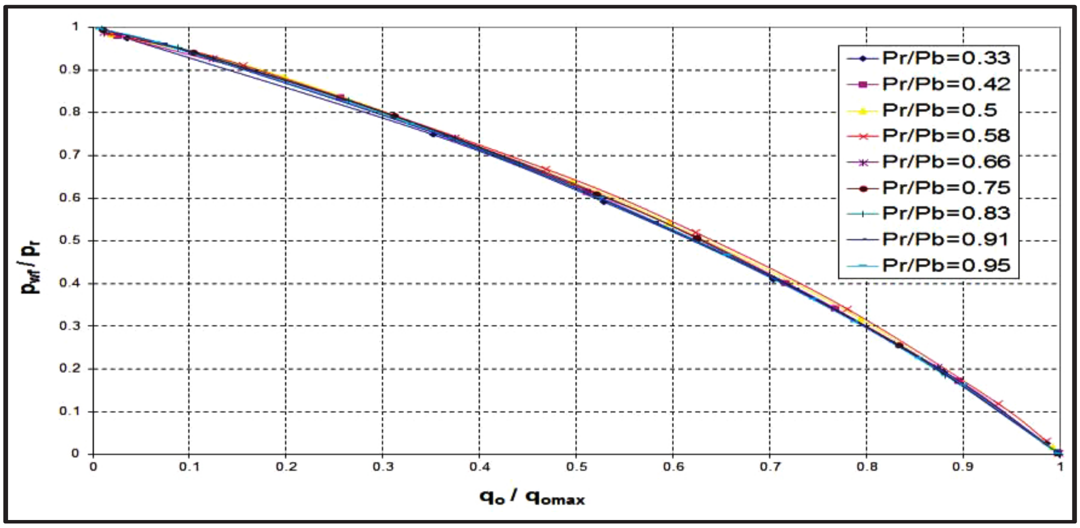


Fig. (5). Effect of Reservoir Pressure Depletion on the dimensionless IPR curve.

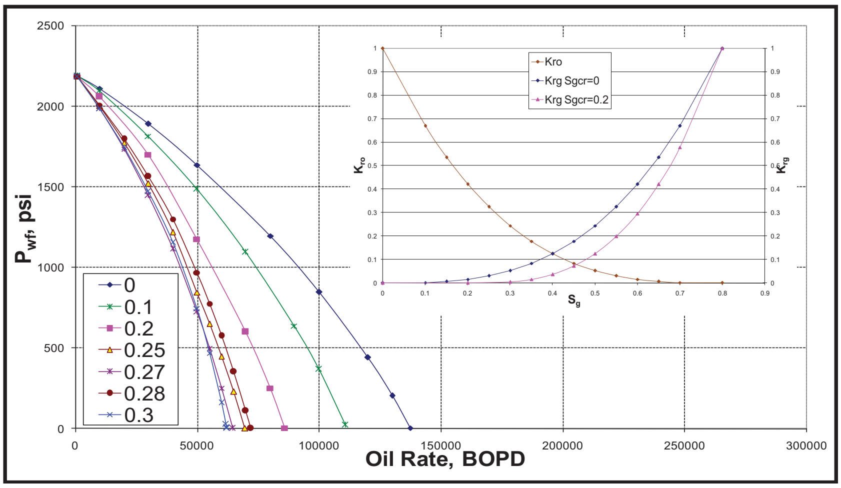


Fig. (6). Effect of S_{gcr} on the IPR curve.

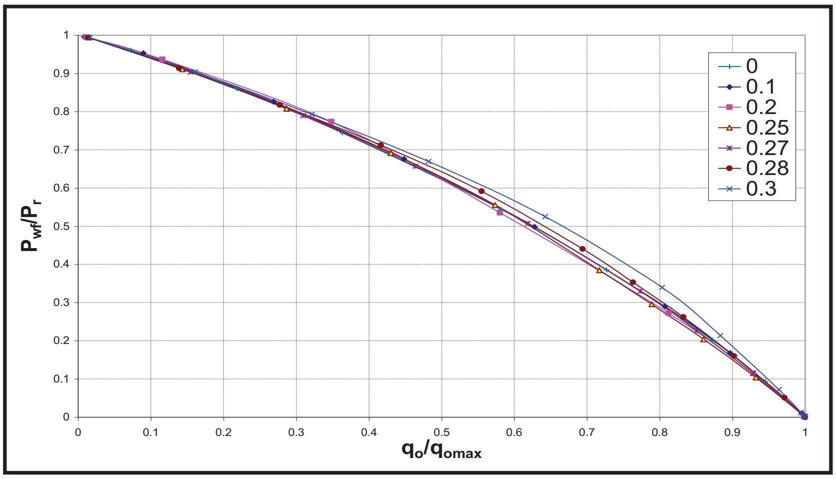


Fig. (7). Effect of S_{gcr} on the dimensionless IPR curve.

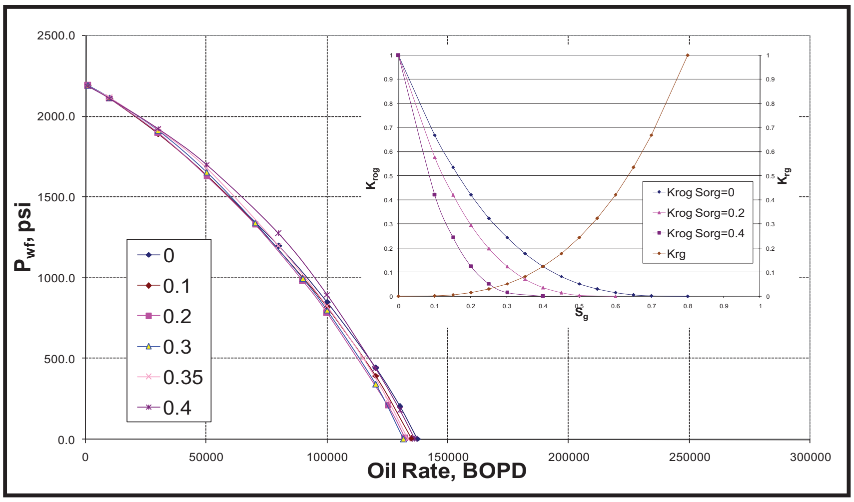


Fig. (8). Effect of S_{org} on the IPR curve.

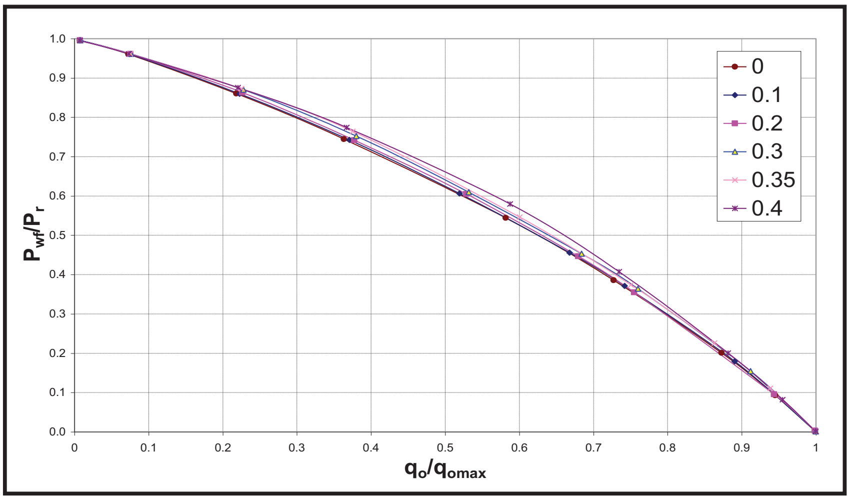


Fig. (9). Effect of S_{org} on the dimensionless IPR curve.

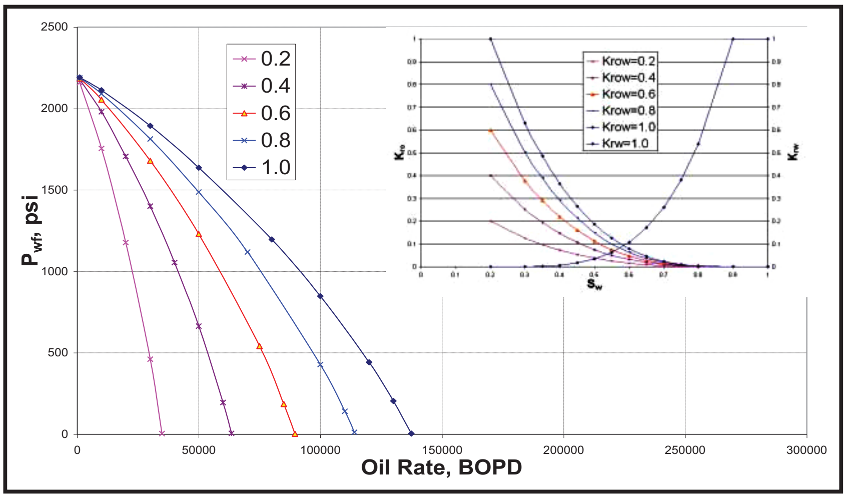


Fig. (10). Effect of K_{row} at (S_{wcr}) on the IPR curve.

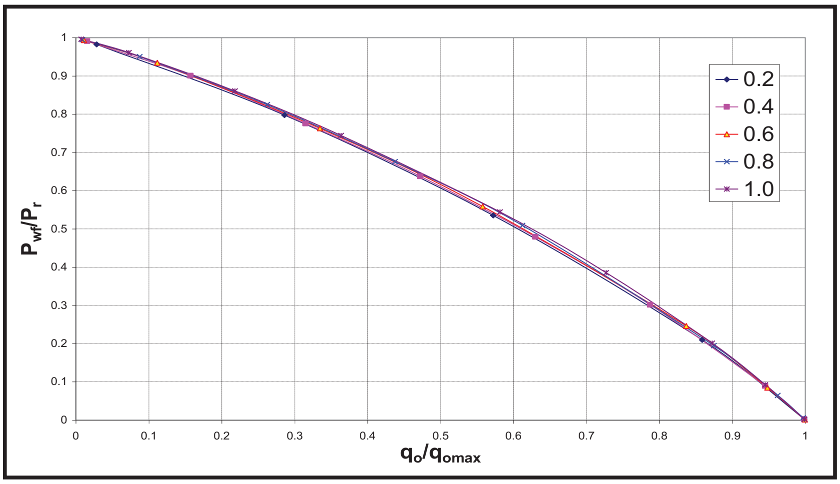


Fig. (11). Effect of K_{row} at (S_{wcr}) on the dimensionless IPR curve.

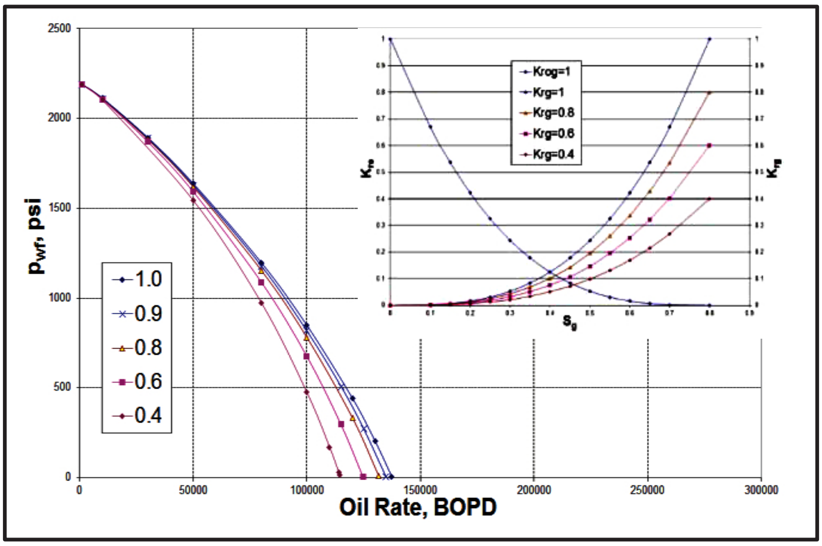


Fig. (12). Effect of K_{rg} at (1-S_{wcr}-S_{org}) on the IPR curve.

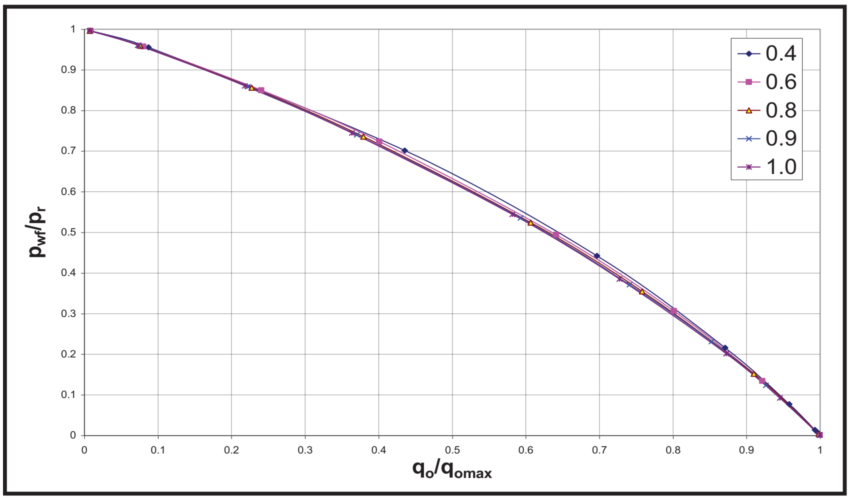


Fig. (13). Effect of K_{rg} at (1-S_{wcr}-S_{org}) on the dimensionless IPR curve.

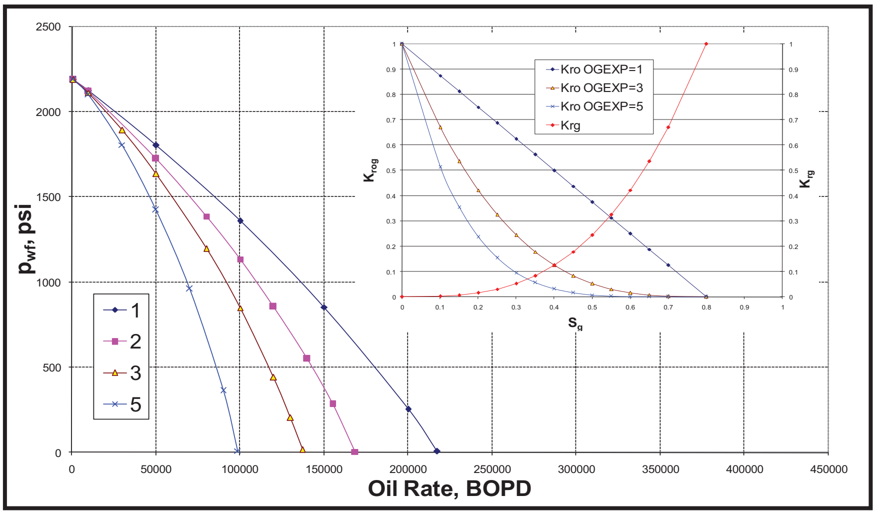


Fig. (14). Effect of OG Exponent on the IPR curve.

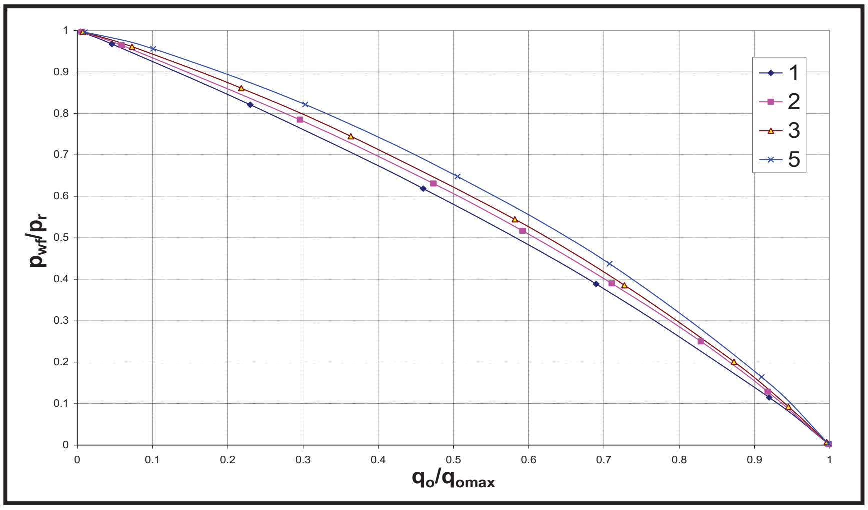


Fig. (15). Effect of OG Exponent on the dimensionless IPR curve.

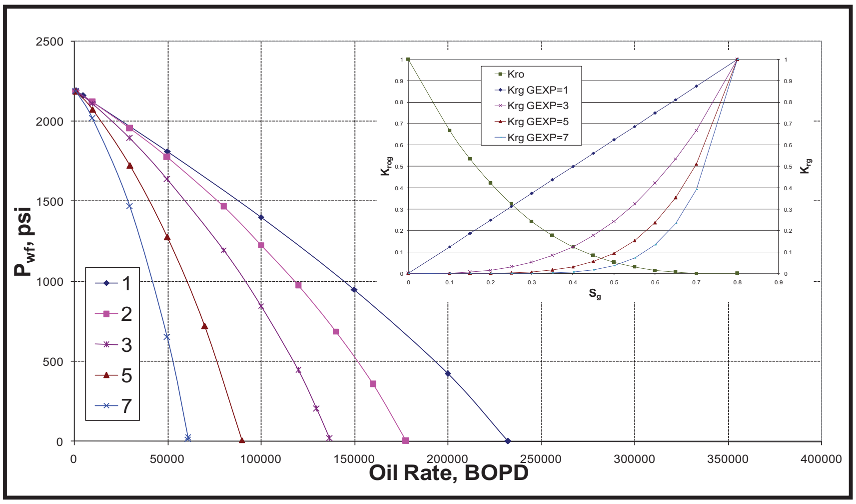


Fig. (16). Effect of Gas Exponent on the IPR curve.

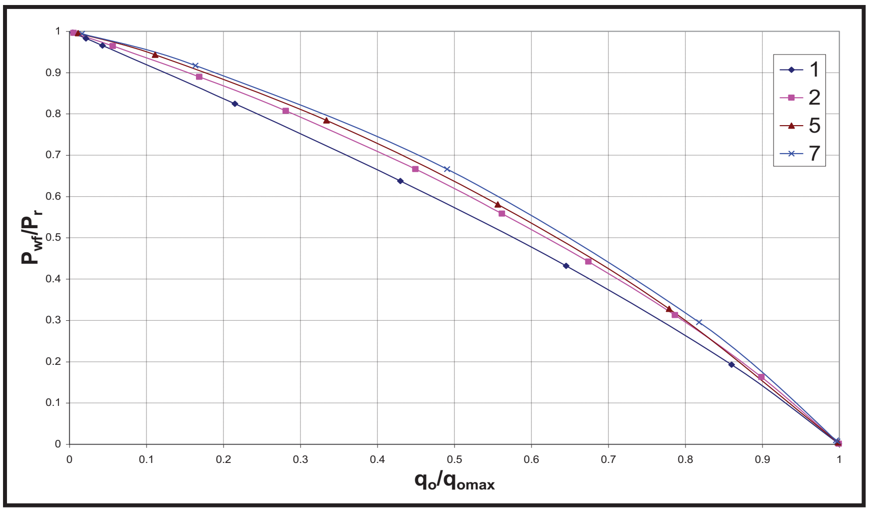


Fig. (17). Effect of Gas Exponent on the dimensionless IPR curve.

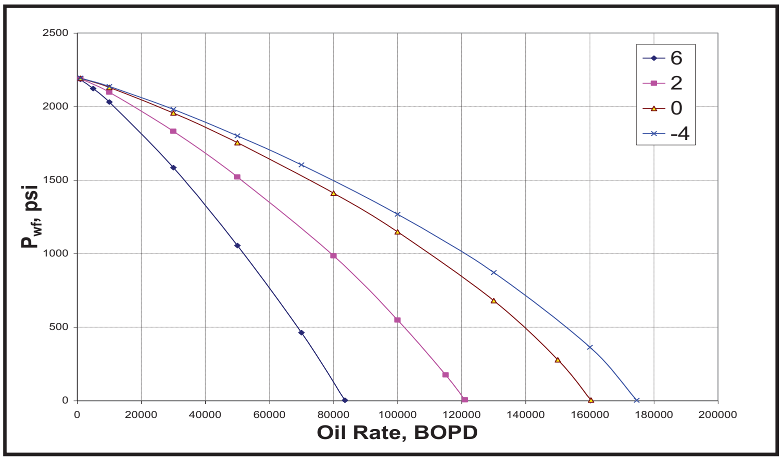


Fig. (18). Effect of Skin on the IPR curve.

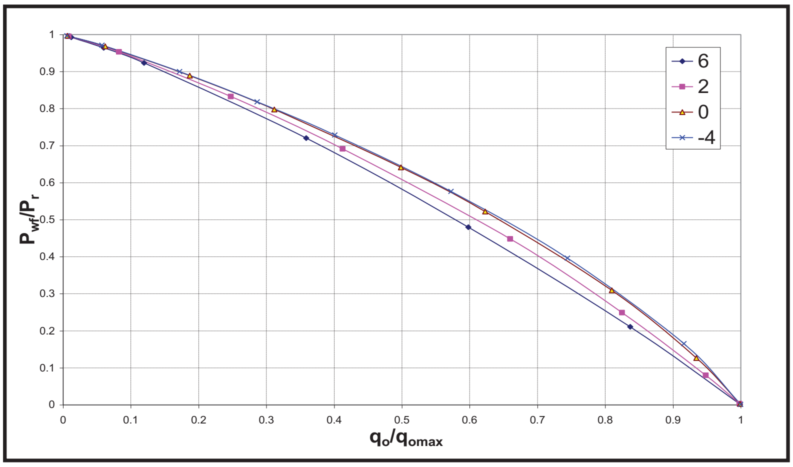


Fig. (19). Effect of Skin on the dimensionless IPR curve.

The IPR and the dimensionless IPR performance was found insensitive to all the parameters that are mainly affecting the water flow in the reservoir, as the assumption used in this study is solution gas- drive reservoir with minimum water flow. This is in addition to the other parameters that has less effect on the oil and gas flow.

3.1. The following list gives the properties that found did not affect the IPR behavior:

1. Water Gravity, γ_W
2. Water Viscosity, μ_W
3. Critical water saturation, S_{wcr}
4. Residual oil saturation in Water, S_{orw}
5. Relative permeability to water at S_{orw}, K_{rw} at (S_{orw})
6. Oil-Water relative permeability exponent, OWEXP
7. Water relative permeability exponent, WEXP
8. Porosity

3.2. The following list gives the properties that found did not affect the dimensionless IPR behavior:

1. Temperature
2. Oil gravity
3. Gas gravity
4. Vertical permeability
5. Horizontal permeability

6. Drainage radius
7. Formation thickness

3.3. Non-Parametric Regression Analysis

550 IPRs were generated from the combination of the 9 sensitive parameters identified from the sensitivity analysis using simulation models. This was followed by implementing the non-linear regression technique to get the distinct parameter (C_1) that represents each IPR based on Vogel [4] and Richardson and Shaw [7] correlations as shown below in **Eq. 4**:

$$\frac{q_o}{q_{o\max}} = 1 - C_1\left[\frac{P_{wf}}{P_r}\right] - (1 - C_1)\left[\frac{P_{wf}}{P_r}\right]^2 \tag{4}$$

The generated values for C_1 corresponding to the 550 combinations of different rock and fluid properties represent the database used in generating the new IPR correlation.

In order to generate IPR correlation that is explicitly function of the different reservoir rock and fluid properties, we need to build a correlation between the C_1 (dependent variables) given in **Eq. 4** and the 9 sensitive rock and fluid properties (independent variables) presented before. Since the formula that relates the dependent and independent variables is not known so parametric regression analysis cannot be implemented here which leads to the implementation of non-parametric regression analysis in our work. Neural Network modeling can be considered as one of the non-parametric modeling approaches and has wide range of applications in oil industry. However, the method that was used here is based on the Alternating Conditional Expectation (ACE) algorithm [26, 27]. A comparison between Neural Network and ACE algorithm was used to build bubble point pressure correlation for oil reservoirs [28] and it was found that the predictive strength of ACE is much higher compared to Neural Network for the studied samples. The ACE algorithm is based on the concept of developing non-parametric transformations of the dependent and independent variables. Moreover, the transformations are constructed point wise based only on the data without the need to know a prior function between the dependent and independent variables. The final correlation is given by plotting the transformed dependent variable against the sum of the transformed independent variables. The final result is a maximum correlation between the dependent and multiple independent variables with a minimum error. Fig. (**20**) shows the relationship between the transformed dependent variable C_1 versus the sum of the transformed independent variables that gives the highest correlation coefficient. The optimal regression correlation here is **0.91775** as shown in Fig. (**20**).

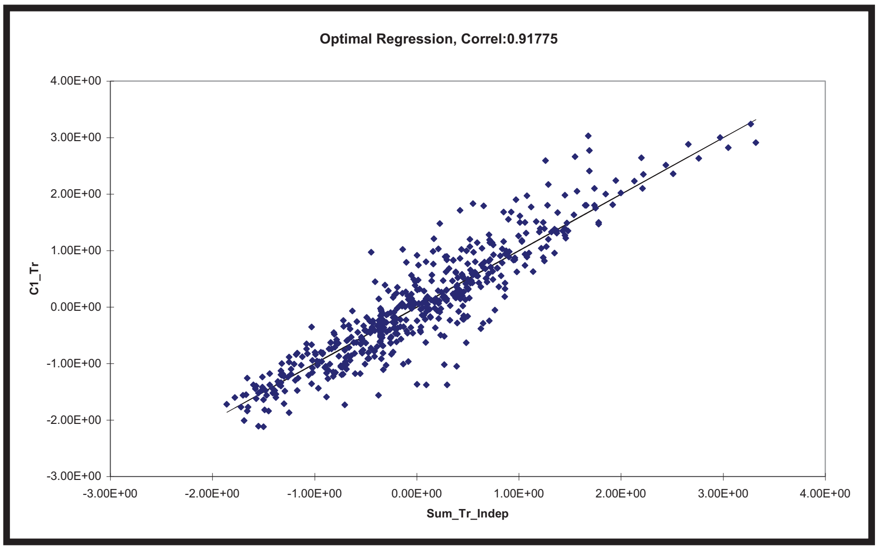


Fig. (20). Transformed dependent variable vs. sum of the transformed independent variables.

The 550 several combinations of the 9 sensitive parameters which represent the independent variables with one dependent variable that is C_1 were used in the ACE Algorithm [27] to find the best correlation between the dependent and the independent variables. The resulted IPR correlation is given in **Eq. 4** with C_1 as explicit polynomial function of different reservoir rock and fluid properties which is given as follows:

$$C_1 = -0.012(A)^2 + 0.161(A) + 0.517 \quad \mathbf{(5)}$$

Where, the independent variable (A) is given as:

$$A = B + C + D + E + F + G + H + I + J \text{ Where,} \quad \mathbf{(6)}$$

$$B = 1.34\left(P_r/P_b\right)^2 - 1.326\left(P_r/P_b\right) + 0.1$$

$$C = 0.072(GEXP)^2 - 0.766(GEXP) + 1.431$$

$$D = 0.054\left(K_{rg}\big|_{(1-Swi-Sorg)}\right)^2 + 0.634\left(K_{rg}\big|_{(1-Swi-Sorg)}\right) - 0.457$$

$$E = 0.424\left(K_{row}\big|_{S_{wcr}}\right)^2 - 1.471\left(K_{row}\big|_{S_{wcr}}\right) + 0.793$$

$$F = 0.083(OGEXP)^2 - 0.816(OGEXP) + 1.487$$

$$G = 4.812\text{E}-08(P_b)^2 - 2.28\text{E}-04(P_b) + 0.225$$

$$H = -1.192\left(S_{gcr}\right)^2 + 2.421\left(S_{gcr}\right) - 0.171$$

$$I = 0.02(s)^2 + 0.202(s) - 0.165$$

$$J = 0.963\left(S_{org}\right)^2 - 1.351\left(S_{org}\right) + 0.161$$

Fig. (**21**) shows the comparison between the calculated and measured C_1 distinct IPR parameter from our reservoir parameters data base used in building the IPR correlation. This reflects the good accuracy of the correlation to accurately predict the IPR performance within our data base. At the same time, the variation of C_1 from 0 to 1 reflects that the selected reservoir parameters used in building the IPR correlation cover wide range of reservoir rock and fluid properties which increase the range of application of the proposed IPR correlation compared to C_1 of 0.2 used by Vogel [4] correlation.

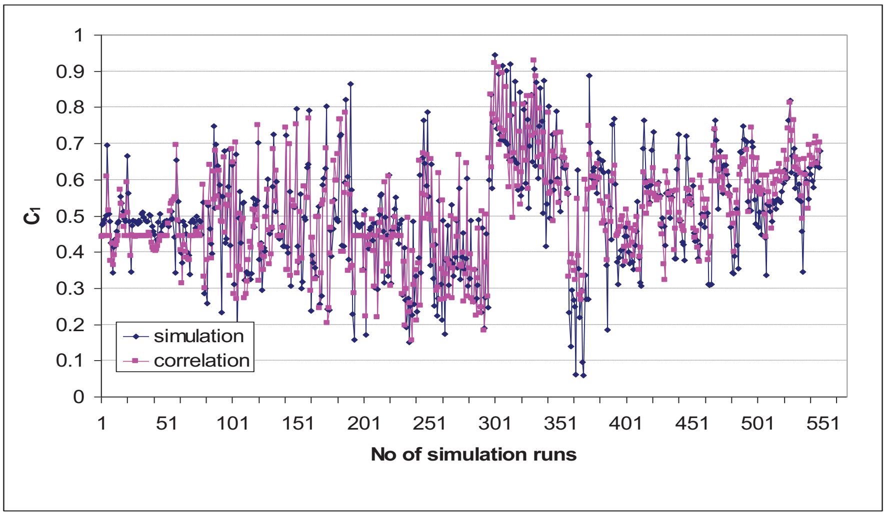


Fig. (21). C_1 comparison; simulation versus proposed correlation for the data base cases.

4. VALIDATION

4.1. Synthetic Cases

In order to test the performance of our proposed IPR correlation in accurately predicting the IPR performance, we generated nine different combinations of reservoir rock and fluid properties which are different from those used in our data base used in building the correlation, and then we used reservoir simulation model to generate the IPRs for these 9 different combinations. We used our proposed correlation with the nine different reservoir rock and fluid properties to estimate the distinct IPR parameter C_1 which is then used to get the IPR performance per each reservoir and compare it with the actual IPR generated from the reservoir simulation. The proposed IPR correlation was able to successfully predict the true IPR with the least error compared to the other IPR models within errors range from 2.0 to 2.4%. Fig. (**22**) shows the comparison between the actual C_1 generated from the reservoir simulation models with that calculated from the proposed IPR correlation from the data base cases and the nine validation cases (points in pink color). In addition, Figs. (**23a** and **b**) and Tables (**2a** and **b**) give the IPR comparison from 2 out of the 9 validation cases which show 2.4 and 2.3% error respectively. As observed from Figs. (**23a**, and **b**) and Table (**2a** and **b**) our proposed correlation was able to accurately predict the IPR performance within an acceptable accuracy compared to the other correlations. In all these synthetic cases, the multi rate test data was taken at high draw down that can reach to more than 90% of the reservoir pressure which is practically difficult to be done in the field cases as will be shown later.

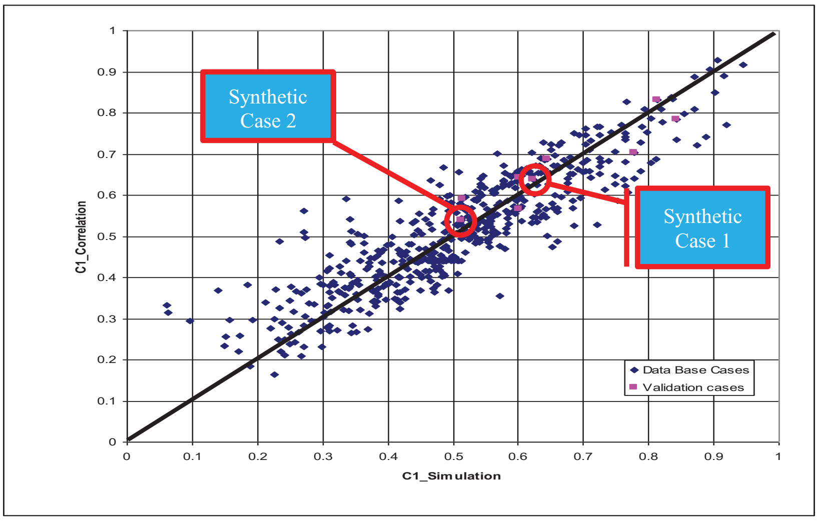


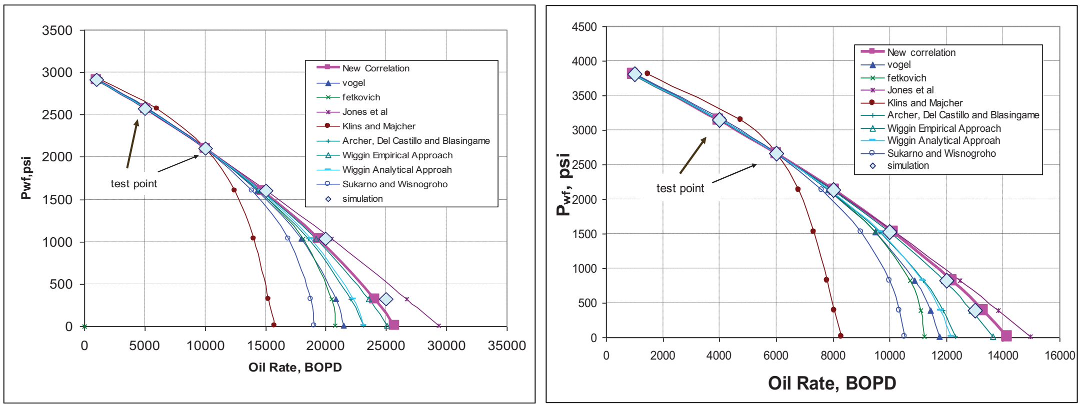
Fig. (22). Comparison of C_1 from the simulation models and the proposed correlation for the 550 data base cases and 9 synthetic cases.

Table 2a. Multi-rate test data and estimated flow rates for synthetic case 1.

Multi rate Data		Proposed Correlation	Vogel	Fetkovich	Jones *et al.*	Klins and Majcher	Archer, Del Castillo and Blasingame	Wiggins Empirical Solution	Wiggins Analytical Solution	Sukarno and Wisnogroho
P_{wf} (psi)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)
2917	1000	1012	1058	906	994	1373	1040	1013	1014	1103
2569	5000	5066	5200	5000	5000	6010	5148	5083	5082	5323
2105	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000
1602	15000	14753	14282	14463	15070	12472	14465	14685	14598	13895
1031	20000	19378	17963	18130	20444	14009	18512	19171	18760	16904
321	25000	24016	20815	20506	26699	15227	22056	23543	22238	18788
7	26550	25662	21459	20761	29321	15712	23089	25039	23133	19056
0		25699	21470	20762	29383	15724	23110	25072	23149	19059
Average absolute errors		2.4%	10.1%	12.4%	4.1%	30.7%	7.1%	3.5%	6.0%	15.5%

Table 2b. Multi-rate test data and estimated flow rates for synthetic case 2.

Multi rate Data		Proposed Correlation	Vogel	Fetkovich	Jones *et al.*.	Klins and Majcher	Archer, Del Castillo and Blasingame	Wiggins Empirical Solution	Wiggins Analytical Solution	Sukarno and Wisnogroho
P_{wf} (psi)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)	q_o (bbl/day)
3810	1000	937	985	898	967	1466	974	944	951	1040
3152	4000	3969	4060	4000	4000	4743	4039	3987	4010	4156
2669	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000
2137	8000	8037	7812	7851	8027	6787	7866	7991	7895	7615
1524	10000	10131	9491	9498	10192	7329	9642	9998	9671	8984
824	12000	12187	10866	10714	12482	7788	11177	11911	11148	9984
390	13000	13284	11431	11106	13824	8055	11867	12896	11776	10351
9	13660	14136	11745	11220	14959	8288	12307	13634	12153	10542
0		14155	11750	11220	14985	8294	12315	13650	12160	10545
Average absolute errors		2.3%	6.6%	10.0%	4.2%	31.4%	4.9%	1.1%	5.3%	11.8%



(a) **(b)**

IPR comparison for synthetic case 1 **IPR comparison for synthetic case 2**

Fig. (23). IPR comparison of two validation cases from the proposed correlation compared to actual generated from simulation and other commonly used IPR correlations.

4.2. Field Cases

Three different field cases from different solution gas-drive fields worldwide were used to test the practical application of the proposed correlation compared to the other widely used correlations in accurately predicting the multi-rate test data. The major difficulties noticed in these field cases are that, most of the multi rate tests taken from wells especially in solution gas-drive reservoirs were obtained with minimum range of draw down as it is practically difficult to design multi rate tests for wells with high drawdown. On the contrary, for the synthetic cases shown above, we have tendency to reach very high drawdown where the bottom hole flowing pressure can reach to extremely low values as shown in Figs. (**23a** and **b**) where one is able to test the performance of different correlations at low and high drawdown conditions for better judgement. This problem in most of the multi-rate test data of all the field cases leads to the difficulty in assessing the effectiveness of our proposed correlation compared to the other correlations as all of the correlations give acceptable results at low range of drawdowns which will be observed in the next section of the field cases discussion.

4.2.1. Field Case 1: Well 6, Field A [5, 29]

Field A is solution gas-drive carbonate reservoir; the average gas saturation at the time of the tests was between 10 and 12%. The reservoir was above the critical gas saturation at the time of the tests. The rock and fluid properties and the C_1 IPR distinct parameters calculated from the proposed correlation are given in Table (**3**).

The test consists of seven individual flows, the first four flow rates were run in a normal increasing sequence followed by reducing rate and then increasing rate. Table (**4**) shows the multi-rate test data taken from this well.

Fig. (**24**) gives Jones *et al.* plot for this field case. It seems that two out of the seven test points (P_{wf}=1178 psi & P_{wf}=1142 psi) lied out of the straight line trend and it showed that there is an error for these measured points and it must be excluded from using them as test points for the IPR construction. Fig. (**25**) gives Fetkovich plot for same field case.

Table (**5**) shows the flow rates estimated for this case for the proposed and commonly used IPR correlations using test point at a flowing bottom hole pressure of 921 psi, representing 32% drawdown for all the correlations with additional one test point for Fetkovich and Jones *et al.* correlation. As can be seen, the absolute open flow potential (AOF) varies from 420 to 552 BOPD from the different correlations. The largest flow was calculated with Jones *et al.* correlation, while the smallest one was obtained using Sukarno *et al.* correlation.

Fig. (**26**) gives the proposed correlation compared to the other correlations. The average absolute errors between the recorded flow rate data and the estimated rates as shown in Table (**5**) was 5% for the proposed correlation, Vogel, Jones *et al.*, Sukarno *et al.* and Klins and Majcher correlations while it was 6% for Wiggins Empirical correlation [8, 9] and Fetkovich. The proposed correlation was able to accurately predict the multi-rate test data within a reasonable accuracy compared to the other correlations with all the correlations showing almost same average absolute errors due the small drawdowns of all the test points.

Table 3. Reservoir properties and C_1 estimate for field case 1.

P	P_b	(P_r/P_b)	S_{gcr}	S_{org}	OG EXP	G EXP	K_{row} at (S_{wcr})	K_{rg} at $(1-S_{wcr}-S_{org})$	Skin	C_1
1345	2020	0.67	0.05	0.4	4.1	3.1	1	0.67	0	0.22

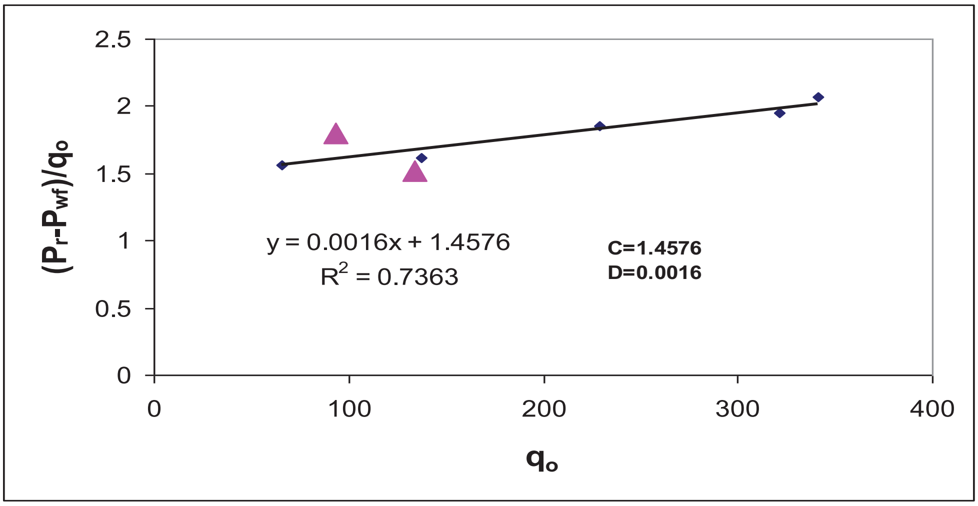


Fig. (24). Jones *et al.* plot for field case 1.

Table 4. Multi-rate test data for field case 1.

Oil Rate (bbl/day)	P_{wf} (psi)
0	1345
66	1242
93	1178
134	1142
137	1123
229	921
321	719
341	638

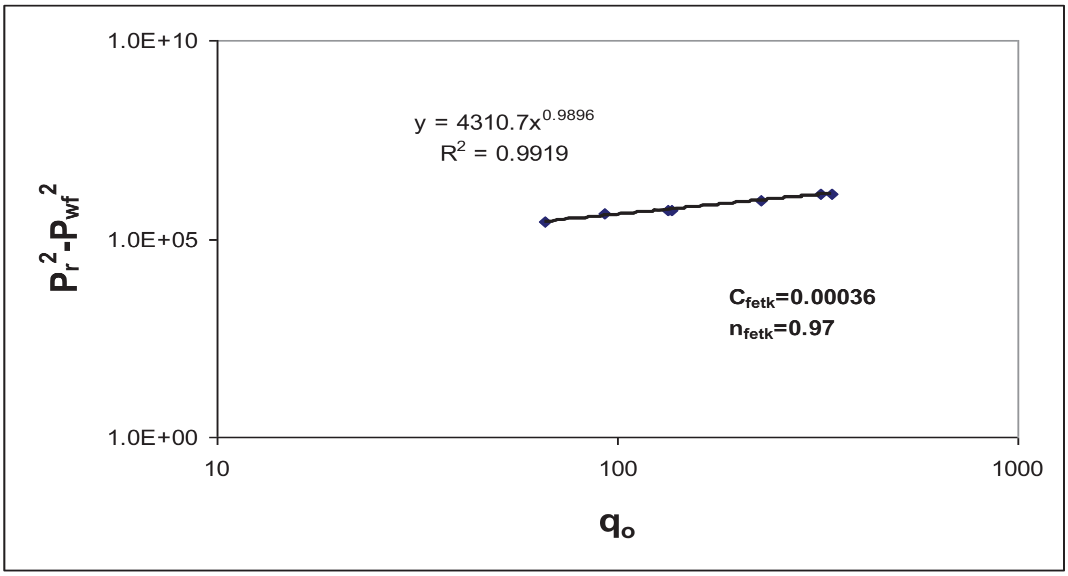


Fig. (25). Fetkovich plot for field case 1.

Table 5. Multi-rate test data and estimated flow rates for field case 1.

Field data		New Correlation	Vogel	Fetkovich	Jones *et al.*	Klins and Majcher	Wiggins	Sukarno *et al.*
Pwf (psi)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)
1345	0	0	0	0	0	0	0	0
1242	66*	62	63	66*	66*	65	60	65
1178	93	99	99	103	103	103	96	103
1142	134	119	119	123	122	123	116	123
1123	137	129	129	133	132	133	126	133
921	229*	229*	229*	229*	229*	229*	229*	229*
719	321	312	312	305	312	305	320	303
638	341	341	341	330	343	329	353	327
400		410	409	387	427	386	439	379
200		450	448	414	492	418	499	406
0		474	470	423	552	440	547	420
Average absolute errors		5%	5%	6%	5%	5%	6%	5%

* Test Points

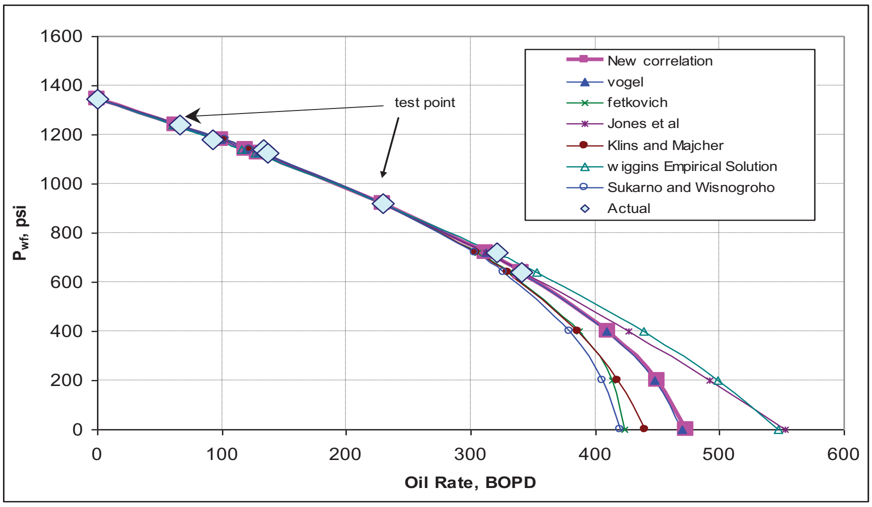


Fig. (26). IPR comparison for field case 1.

4.2.2. Field case 2: Well B, Keokuk Pool, Seminole County, Oklahoma, December 1934 [29]

Table (**6**) gives the reservoir properties and the C_1 estimate for this field case. Table (**7**) shows the multi-rate test data taken from this case. Table (**8**) shows the flow rates estimated for this case for the proposed and commonly used IPR correlations using test point at a flowing bottom hole pressure of 1196 psi, representing 30% drawdown and another test point at a flowing bottom hole pressure of 1443 psi, representing 16% drawdown for Fetkovich and Jones *et al.* correlation. The absolute open flow potential (AOF) varies from 2034 to 2870 BOPD. The largest AOF was calculated from Fetkovich while the smallest one was obtained from Klins and Majcher correlation.

Table 6. Reservoir properties and C_1 estimate for field case 2.

P	P_b	(P_r/P_b)	S_{gcr}	S_{org}	OG EXP	G EXP	K_{row} at (S_{wcr})	K_{rg} at $(1-S_{wcr}-S_{org})$	Skin	C_1
1714	3420	0.50	0.1	0.05	2.32	3.11	0.8	0.54	0.1	0.41

Table 7. Multi-rate test data for field case 2.

Oil Rate (bbl/day)	P_{wf} (psi)
0	1714
280	1583
508	1443
780	1272
1125	1196
1335	982

Table 8. Multi-rate test data and estimated flow rates for field case 2.

Field data		New Correlation	Vogel	Fetkovich	Jones *et al.*	Klins and Majcher	Wiggins	Sukarno *et al.*
Pwf (psi)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)
1714	0	0	0	0	0	0	0	0
1583	280	311	317	195	231	349	307	331
1443	508*	624	632	508*	508*	671	619	650
1272	780	978	982	934	910	1000	975	990
1196	1125*	1125*	1125*	1125*	1125*	1125*	1125*	1125*

(Table 8) contd.....

Field data		New Correlation	Vogel	Fetkovich	Jones *et al.*	Klins and Majcher	Wiggins	Sukarno *et al.*
Pwf (psi)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)
982	1335	1507	1488	1642	2188	1418	1519	1452
800		1794	1750	2033		1606	1820	1673
600		2068	1987	2389		1761	2117	1859
400		2300	2173	2653		1875	2377	1993
200		2490	2307	2815		1961	2601	2081
0		2638	2389	2870		2034	2788	2131
Average absolute errors		18%	19%	24%	33%	23%	18%	20%

* Test Point

Fig. (**27**) gives the proposed correlation compared to the other correlations. The average absolute errors between the recorded flow rate data and the estimated rates was 18% for the proposed correlation and Wiggins Empirical correlation [8, 9], 19% for Vogel, 20% for Sukarno *et al.*, 23% for Klins and Majcher, 24% for Fetkovich, 33% for Jones *et al.* correlation. The proposed correlation gives the reasonable error compared to the other correlations used in this case with highest error obtained from the two-point tests which are Fetkovich and Jones *et al.* correlations. All the single-point test correlations including the proposed correlations show almost the same average absolute error due to the low drawdowns of the test points as mentioned in the previous field case.

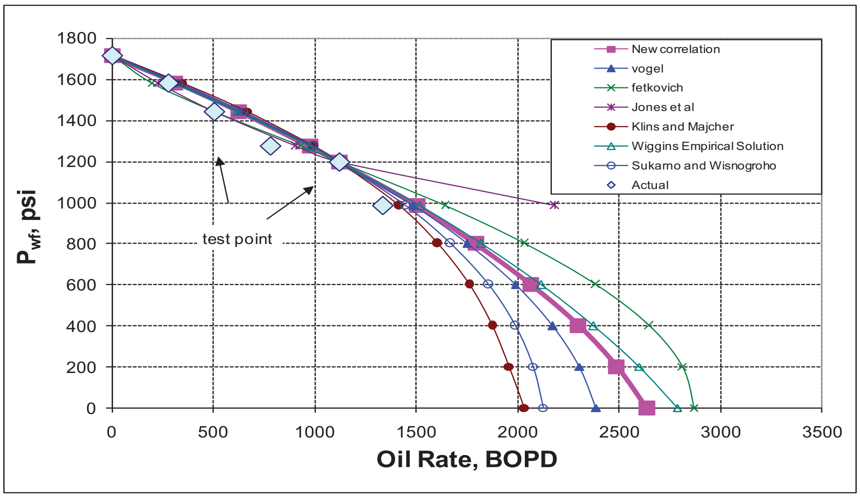


Fig. (27). IPR comparison for field case 2.

4.2.3. Field case 3: Well B, Keokuk Pool, Seminole County, Oklahoma, August 1935 [29]

The multi rate test has been repeated for this well from Field Case 2 after 8 months of production with a drop in reservoir pressure from 1714 psi to 1605 psi. Table (**9**) gives the reservoir properties and the C_1 estimate for this field. Table (**10**) shows the multi-rate test data taken from this well. Table (**11**) gives the flow rates estimated for this case for the proposed and commonly used IPR correlations using test point at a flowing bottom hole pressure of 1231 psi, representing 23% drawdown and another test point at a flowing bottom hole pressure of 1381 psi, representing 14% drawdown for Fetkovich and Jones *et al.* correlation. As can be seen, the Absolute Open Flow potential (AOF) varies from 1618 to 4907 BOPD. The largest AOF was calculated from Jones *et al.* correlation, while the smallest one was obtained from Klins and Majcher correlation.

Fig. (**28**) gives the proposed correlation compared to the other correlations. The average absolute errors between the recorded flow rate data and the estimated rates was 7% for the proposed correlation, Vogel, Wiggins Empirical correlation, Sukarno *et al.*, and Klins and Majcher while it was 10% for Fetkovich, 12% for Jones *et al.* correlation.

Table 9. Reservoir properties and C_1 estimate for field case 3.

P	P_b	(P_r/P_b)	S_{gcr}	S_{org}	OG EXP	G EXP	K_{row} at (S_{wcr})	K_{rg} at $(1\text{-}S_{wcr}\text{-}S_{org})$	Skin	C_1
1605	3420	0.47	0.1	0.05	2.32	3.11	0.8	0.54	2.0	0.49

Table 10. Multi-rate test data for field case 3.

Oil Rate (bbl/day)	P_{wf} (psi)
0	1605
420	1381
720	1231
850	1120

Table 11. Multi-rate test data and estimated flow rates for field case 3.

Field data		New Correlation	Vogel	Fetkovich	Jones *et al.*	Klins and Majcher	Wiggins	Sukarno *et al.*
Pwf (psi)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)
1605	0	0	0	0	0	0	0	0
1381	420*	446	451	420*	420*	467	445	459
1231	720*	720*	720*	720*	720*	720*	720*	720*
1120	850	910	902	931	953	880	911	889
982		1131	1107	1174	1259	1048	1134	1073
800		1397	1343	1454	1695	1226	1404	1273
600		1656	1558	1703	2233	1372	1668	1442
400		1880	1724	1883	2861	1478	1899	1561
200		2069	1843	1993	3651	1555	2095	1639
0		2222	1915	2030	4907	1618	2258	1683
Average absolute errors		7%	7%	10%	12%	7%	7%	7%

* *Test Point*

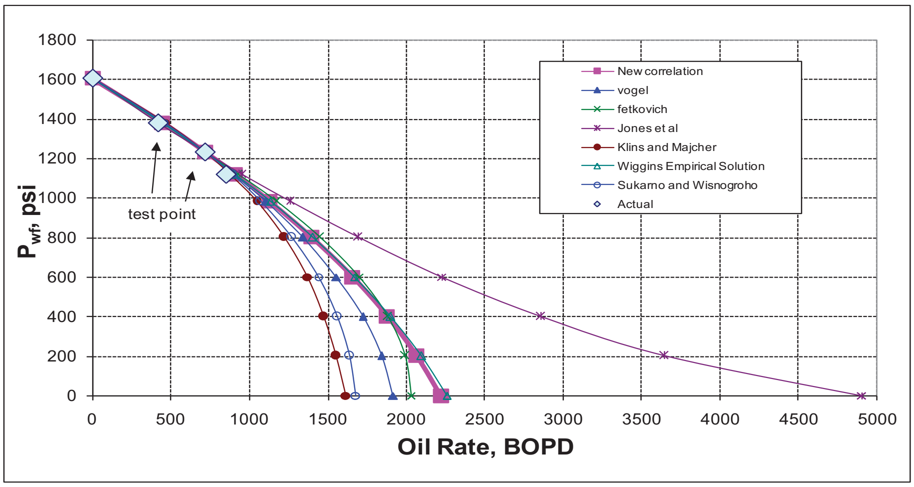


Fig. (28). IPR comparison for field case 3.

This case represents a good opportunity to examine the behavior of the proposed correlation in predicting the future IPR using Eickmeier [30] Equation compared to the other correlations. Eickmeier equation as shown below is used to predict maximum oil rate by knowing the predicted reservoir pressure:

$$q_{omax2} = q_{omax1}\left(\frac{P_{r2}}{P_{r1}}\right)^3 \quad (7)$$

The IPR prediction using Fetkovich is based on assuming constant values for n_{fetk}, C_{fetk}. Case 2 and 3 show minor differences in these values so the assumption of using these values as constant during prediction is valid in this case only.

Table (**12**) shows the predicted flow rates for field case 3 using data from case 2 for the proposed and the other commonly used correlations. As can be seen, the absolute open flow potential (AOF) varies from 1670 to 2357 BOPD.

The largest AOF was calculated from Fetkovich while the smallest one was obtained from Klins and Majcher. Fig. (**29**) gives the proposed correlation compared to the other correlations. The average absolute errors between the recorded flow rate data and the estimated rates was 3% for the proposed correlation, 6% for Wiggins Empirical correlation, 7% for Vogel, 8% for Klins and Majcher, 9% for Sukarno *et al.*, and Jones *et al.* and 10% for Fetkovich. The proposed correlation gives the least error compared to the other correlations during the prediction which indicates the reasonable accuracy of the proposed correlation in predicting the future IPR.

Field cases 2 & 3 present good real field examples to examine the prediction of future IPR using Eickmeier [30] Equation. The results showed that using constant values for Fetkovich and Jones *et al.* during predicting the future IPR might not be a good assumption in some cases. The proposed correlation that depends on only single-point test shows its good accuracy in predicting the future IPR compared to all the other correlations as seen from Table (**12**).

Table 12. Multi-rate test data and estimated future flow rates for field case 3.

Field data		New Correlation	Vogel	Fetkovich	Jones *et al.*	Klins and Majcher	Wiggins	Sukarno *et al.*
Pwf (psi)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)
1605	0	0	0	0	0	0	0	0
1381	420	435	462	355	411	482	451	478
1231	720	702	738	678	739	743	730	749
1120	850	887	924	924	1028	908	924	925
982		1103	1134	1220	1496	1082	1150	1116
800		1362	1376	1578		1265	1423	1324
600		1614	1596	1908		1416	1691	1499
400		1832	1766	2154		1525	1925	1623
200		2016	1888	2305		1606	2124	1704
0		2166	1962	2357		1670	2289	1750
Average absolute errors		3%	7%	10%	9%	8%	6%	9%

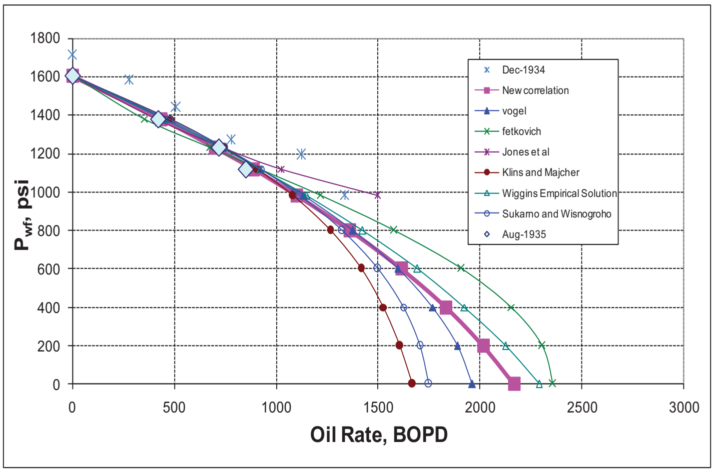


Fig. (29). Future IPR comparison for field case 3.

As shown from the above field cases, variety of field cases with different reservoir rock and fluid properties were presented. Jones at al. Correlation failed to predict the IPR to the AOF for field case 2 due to having a negative turbulent flow coefficient (D), which resulted in calculating unreal value for the flow rates at low bottom hole flowing pressure. This limits the practical application of Jones *et al.* correlation.

SUMMARY AND CONCLUSION

Following conclusions can be drawn:

1. All the IPR correlations which are widely used to predict the deliverability of wells produced from solution gas-drive reservoirs suffer from one common limitation that they are not explicitly function of the different reservoir rock and fluid properties that vary from one reservoir to another. Thus, none of the correlations could be considered as the best method over a wide range of reservoir conditions. One may provide the best estimation for a particular case, while providing the worst for some other cases.
2. The proposed correlation and Vogel correlation used the same base equation with the main difference that Vogel uses a constant distinct C_1 value of 0.2 while for the proposed correlation, the distinct C_1 value varies depending on reservoir rock and fluid properties which could vary from one reservoir to another. It was shown in the 550 generated reservoir cases that C_1 distinct values can range from 0.1 to 0.9. This expands the range of application of the proposed correlation compared to the others.
3. The proposed correlation showed good accuracy compared to the other widely used correlations in predicting the true multi-rate test data as shown in the different synthetic and field cases presented in this work. The synthetic cases which reached to drawdown of almost 99% showed that the proposed correlation gives less error compared to the other correlations especially compared to Vogel correlation as both use the same equation with only difference in the distinct C_1 value used in both. For the field cases due to the practical difficulty of the field cases to have test points at higher draw down (the maximum drawdown used was 30% of the reservoir pressure), so the effectiveness of the proposed model compared to the rest of the models cannot be assessed properly at very low pressure (high draw down). However, the proposed correlation did not show any severe discrepancy compared to the other correlations in predicting the wells deliverability.
4. The proposed correlation was also examined for predicting the future IPR as shown in the Field cases 2 and 3 and the results show its good accuracy compared to all the other correlations. This is in addition to the failure of Fetkovich and Jones *et al.* to predict accurately the IPR in some of the cases due to the assumption of using constant values of Fetkovich and Jones *et al.* parameters during prediction.
5. The most important feature of the proposed correlation is its dependency on many reservoir rock and fluid properties that proved to highly affect the IPR modeling in solution gas-drive reservoirs based on the sensitivity study done in this work. This will allow the user to use all the available data to accurately predict the IPR performance rather than using any of the current empirical correlation that depends on specific reservoir rock and fluid properties or the analytical correlation that is rather difficult to be applied or does not cover a wide range of reservoir data.

NOMENCLATURE

γ_o	=	Oil gravity
γ_w	=	Water gravity
γ_g	=	Gas gravity
μ_o	=	Oil viscosity, cp
μ_W	=	Water viscosity, cp
Bo	=	Oil formation volume factor, bbl/stb
C	=	Jones *et al.* laminar-flow coefficient, psi/stb/day
$\mathbf{C_{fetk}}$	=	Fetkovich productivity index of the reservoir (PI), stb/day/psi2n
D	=	Jones *et al.* turbulence coefficient, psi/ (stb/day)2
GEXP	=	Gas relative permeability exponent that affects the curvature of Krg
h	=	Formation thickness, ft
J	=	Productivity index of the reservoir, bbl/day/psi
$\mathbf{K_h}$	=	Horizontal permeability, md
$\mathbf{K_{rg}}$ **at (1-$\mathbf{S_{wcr}}$-$\mathbf{S_{org}}$)**	=	Relative permeability to gas at (1-Swcr-Sorg), fraction
$\mathbf{K_{ro}}$	=	Oil relative permeability, fraction
$\mathbf{K_{row}}$ **at ($\mathbf{S_{wcr}}$)**	=	Relative permeability to oil at Swcr, fraction
$\mathbf{K_{rw}}$ **at ($\mathbf{S_{orw}}$)**	=	Relative permeability to water at Sorw, fraction
$\mathbf{K_v}$	=	Vertical permeability, md
$\mathbf{m_k}$	=	Khasanov *et al.* exponent

$\mathbf{n_{fetk}}$	=	Fetkovich flow exponent
$\mathbf{n_k}$	=	Khasanov *et al.* exponent
OGEXP	=	Oil-Gas relative permeability exponent that affects the curvature of Krog
OWEXP	=	Oil-Water relative permeability exponent that affects the curvature of Krow
$\mathbf{P_b}$	=	Bubble Point Pressure, psi
$\mathbf{P_e}$	=	Pressure at the outer boundary, psi
$\mathbf{P_r}$	=	Average reservoir pressure, psi
$\mathbf{P_{r1}}$, $\mathbf{P_{r2}}$	=	Average reservoir pressure at the current and predicted IPR correlation, respectively, psi
$\mathbf{P_{wf}}$	=	Bottom hole flowing pressure, psi
$\mathbf{q_o}$	=	Oil flow rate, bbl/day
$\mathbf{q_{omax}}$	=	Maximum oil flow rate, bbl/day
$\mathbf{q_{omax1}}$, $\mathbf{q_{omax2}}$	=	Maximum oil flow rate at the current and predicted IPR correlation, respectively, bbl/day
$\mathbf{r_e}$	=	Drainage Radius, ft
$\mathbf{R_s}$	=	Solution Gas Oil Ratio, Mscf/STB
$\mathbf{r_w}$	=	Well radius, ft
S	=	Skin
$\mathbf{S_{gcr}}$	=	Critical gas saturation, fraction
$\mathbf{S_{org}}$	=	Residual oil saturation in gas, fraction
$\mathbf{S_{orw}}$	=	Residual oil saturation in water, fraction
$\mathbf{S_{wcr}}$	=	Critical water saturation, fraction
$\mathbf{T_r}$	=	Reservoir temperature, F
WEXP	=	Water relative permeability exponent that affects the curvature of K_{rw}
Z	=	Gas deviation factor

ETHICS APPROVAL AND CONSENT TO PARTICIPATE

Not applicable.

CONSENT FOR PUBLICATION

Not applicable.

CONFLICT OF INTEREST

The authors declare no conflict of interest, financial or otherwise.

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Declared None.

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