Available online at www.elixirpublishers.com (Elixir International Journal)

Petroleum Engineering

Elixir Petrol. Engg. 80 (2015) 30895-30900

Elixir ISSN: 2229-712X

The Effect of Wellbore Fluids Interaction on oil Inflow Rate

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ARTICLE INFO

Article history:

Received: 4 December 2014;
Received in revised form: 25 February 2015;
Accepted: 4 March 2015;

Keywords

Inflow rate,
Absolute open flow,
Productivity index,
Reservoir fluids,
Production performance.

ABSTRACT

The rate at which oil is moved from the reservoir to the wellbore is directly proportional to the pressure draw down with other parameters kept constant, hence inflow performance relationship provides a direct relationship between the flowing bottom hole pressure and flow rate. Since the reservoir fluids are usually not single phase but are often accompanied by bottom water aquifers, oil well drilled in such reservoir may produce some water depending on the production practice, hence determining the flow rate of the individual fluids is often difficult, and in this work we have determined the real flow rate of oil in the presence of other fluids for real case in Niger Delta and also determining its IPR using IHS WellTest Simulator 2014 V2 which made use of multirate test data from a Niger Delta well. From this research it can be clearly said that if other constraints in the production tubing are kept constant, the higher the difference between the static reservoir pressure and the flowing bottom hole pressure, the higher the production rate. The idea of this pressure rate behavior will enable the Production Engineers to evaluate various operating scenarios to ascertain the optimum production. Understanding and measuring the variables that control the relationship that exist between oil and other fluids and their effect on inflow rate is the focus of this work. These issues is looked into by modeling the present conditions with the use of a simulator called FAST WELL TEST using production data from a Niger Delta well in Nigeria.

Introduction

The rate of movement of reservoir fluids (Oil, Gas & Water) from the reservoir rock matrix to the well-bore at the expense of pressure drop is inflow rate. It is a tool used in measuring the performance of an oil well by the Petroleum Engineers. Basically, two types of flow are pronounced when well performance evaluation is called for; the inflow, which is flow from the reservoir to the well-bore, and outflow, which is from the well-bore to the surface wellhead. Pressure-rate behavior of oil wells is often analyzed to evaluate various operating conditions, determine the optimum production scheme, and design production equipment and artificial lift methods (Jones et al, 1976). Oil well performance is modeled with the inflow performance relationship (IPR), which describes the capacity of a particular well to produce fluids. Nodal analysis (a widely-used technique in the oil industry) optimizes well production using inflow performance with tubing performance (TPR) relationships that relate the surface pressure to well bottomhole pressure.

Inflow performance relationship (IPR) relates the well production rate as a function of the draw-down pressure and gives a comprehensive understanding of what the reservoir can deliver into the well at a specific time (Perkins, 1993). The inflow performance of horizontal and vertical wells is characterized by different IPRs. To account for the performance of oil and gas wells, Production Engineers are often called upon to predict the pressure-production behavior of wells to determine their productive capacity. Having an idea of the pressure-rate behavior enables engineers to evaluate various operating scenarios to ascertain the optimum production scheme and to design and install surface and subsurface production equipment when necessary. Knowledge of the pressure rate behavior can be bore at the reservoir depth. If the well-bore pressure is equal to the reservoir pressure there can be no inflow. If the well-bore pressure is zero, the inflow would be a maximum possible that is the Absolute Open Flow, AOF (Landman, 1994).

Accumulations of Hydrocarbons

(Klins and Majher, 1989) noted that the accumulations of hydrocarbons are invariably associated with aqueous fluids (formation waters), which may occur as extensive aquifers underlying or with hydrocarbon-bearing layers, but always occur within the hydrocarbon bearing layers as connate water. These fluids are commonly saline, with a wide range of compositions and concentrations. The presence of this fluid in the production stream usually poses some challenges during oil production resulting in interferences with inflow rate. Water production kills oil and gas wells, leaving a significant amount of hydrocarbon in the reservoir. Their study showed that, large sample gas wells revealed that the original reserves figures had to be reduced by 20% for water problems alone and using an IPR developed for a vertical well gave unsatisfactory results for horizontal well flow which should have its own specifically derived IPR.

Flow geometry of horizontal and vertical wells

Furui et al (2003) also noted that the drainage pattern and flow geometry of horizontal and vertical wells were different. A horizontal well was more likely to have radial flow near the well-bore and linear flow away from the well-bore while a vertical well was most likely to have radial flow only, highlighting the need for separate IPRs. For intermediate well-bore pressures, the inflow will vary. For each reservoir, there is a unique relationship between the inflow rate and well-bore pressure. For a heterogeneous reservoir, the inflow performance

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might differ from one well to another. The performance is commonly defined in terms of a plot of surface production rate (stb/d) versus flowing bottom hole pressure (Psi). Several models are available for determining the different types of inflow performance relation. They are; straight line flow, Vogel's method, future IPR flows, the Standing's method and many more. The production engineers use the inflow curves also known as IPR curves (Inflow Performance Relationships) to evaluate well performance. The inflow curve of a well is equivalent to the output curve but it is measured at bottom hole conditions. Both curves are individual for each well and vary with the productive life of the well. The output curves are obtained from the measurements at surface conditions of the flow and pressure. The first application of inflow curves was done in the petroleum industry by (Fetkovich, 1975).

Steady-State and Pseudo Steady Sate Models

(Butler, 1994) presented steady-state models for box-shaped reservoirs. Their models yielded very similar results, although they were derived by different approaches. Butler's model was based on the image well superposition technique. On the other hand, (Elsevier, 2005) presented a pseudo-steady-state model that is widely used for horizontal well productivity. The model assumes a box-shaped reservoir and a well parallel to the x-direction. All the above models are for incompressible or slightly compressible single-phase liquid; however, they can be extended to other fluid types.

Pressure rate relationship

(Galice and Vogel, 1992) were one of the earliest researchers analyzing pressure-rate relationships. He pointed out that a straight-line relationship should not be anticipated for multiphase (e.g., oil and gas) flow conditions. He reported that when combining with gas oil ratio observations, the productivity index (PI) might be of value interpreting abnormal well behavior in gas-drive reservoirs. Following their work, different methods to predict the pressure production performance of oil wells producing from solution-gas drive reservoirs were also proposed by some researchers which are widely used because they only require parameters available from a production test.

Effect of water cut on ipr curves

(Sachdeva, 1986) examined the effect of water cut on IPR curves and its relationship to other factors such as interflow rates. For solution gas drive reservoirs, he showed that the gross inflow rate decreases as the water cut increases whereas the gross (total of flow rates for all phases) inflow rate for active water drive wells will increase as the water cut increases. The method requires well test data including oil (q_o) and water (q_w) production rates, flowing bottom hole pressure (p_{wf}) and average reservoir pressure (p_r).

Materials and methodology

Material and data requirement

The following data were gotten from two wells in the Niger Delta:

- The field measured multi rate well test data.
- The pressure measurement of the wells during the period.
- The flow rate measurement of oil and gas during the period.
- The reservoir pressure of the wells at the start of the production.

Procedure

After a thorough study on the data gotten from the field, the data were treated and used in the plotting of the Inflow Performance Relationship curve for the establishment of the result using "Well Simulator 2014 V2".

Results and discussions

Absolute open flow:

From the plots analysis below, absolute open flow is the flow rate at which the flowing bottom hole pressure is zero, hence from Well 1 IPR, the absolute open flow rate of oil is 3771.4 bbl/d with water rate of 1804 bbl/d at the reservoir pressure 18000 psia which set the gross production at absolute open flow at 5576.2 bbl/d during the period of 52560 hours (figure1below).

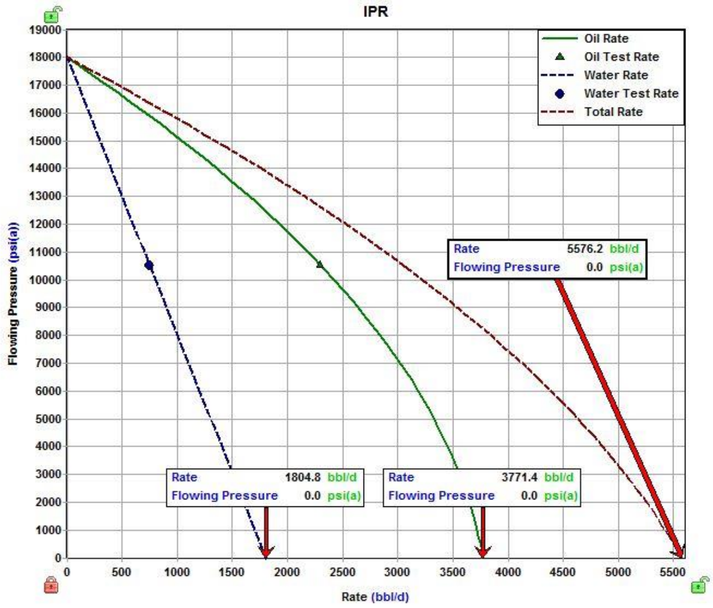

Figure 1. Total flow rate IPR for Well 1 at AOF.

Similarly, based on the IPR curves gotten from the simulation of Well 2 data at AOF, oil flow rate is set at 7612.4 bbl/d, that of water at AOF is 2123.7 bbl/d and the maximum total gross rate was 9736.1 bbl/d during the period of 87600 hours (figure 2 below).

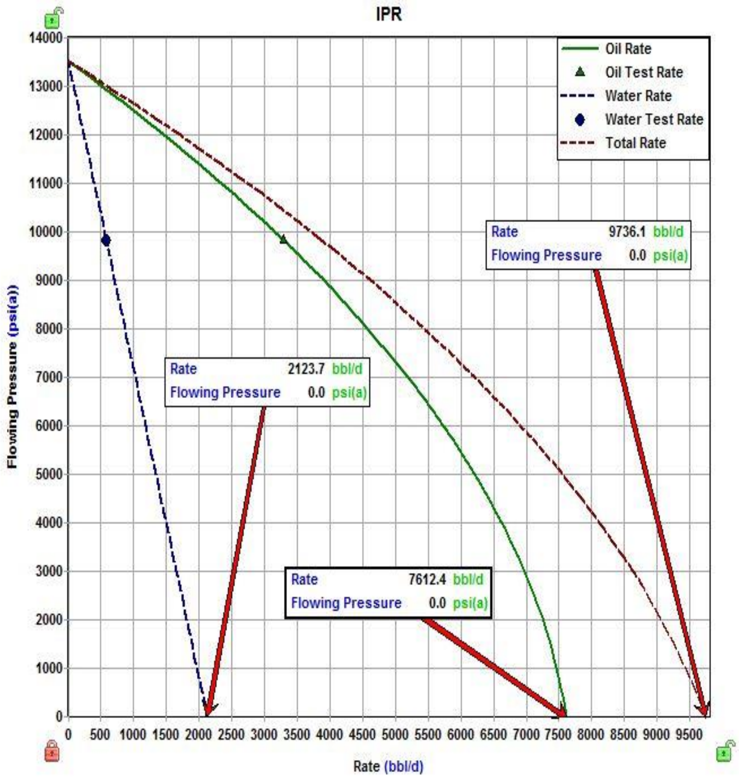

Figure 2. Total flow rate IPR for Well 2 at AOF

Table 1. Well 1 production data

Oil Rate	Water Rate	P_{wf}
bbl/d	bbl/d	psi(a)
0	0	18000
149.366613	40.10695187	17600
295.7533435	80.21390374	17200
439.1601914	120.3208556	16800
579.5871567	160.4278075	16400
717.0342395	200.5347594	16000
851.5014397	240.6417112	15600
982.9887574	280.7486631	15200
1111.496193	320.855615	14800
1237.023745	360.9625668	14400
1359.571415	401.0695187	14000
1479.139203	441.1764706	13600
1595.727108	481.2834225	13200
1709.33513	521.3903743	12800
1819.96327	561.4973262	12400
1927.611527	601.6042781	12000
2032.279902	641.7112299	11600
2133.968394	681.8181818	11200
2232.677003	721.9251337	10800
2300	750	10520
2328.40573	762.0320856	10400
2421.154575	802.1390374	10000
2510.923537	842.2459893	9600
2597.712616	882.3529412	9200
2681.521813	922.459893	8800
2762.351127	962.5668449	8400
2840.200559	1002.673797	8000
2915.070108	1042.780749	7600
2986.959775	1082.887701	7200
3055.869559	1122.994652	6800
3121.79946	1163.101604	6400
3184.749479	1203.208556	6000
3244.719616	1243.315508	5600
3301.70987	1283.42246	5200
3355.720241	1323.529412	4800
3406.75073	1363.636364	4400
3454.801336	1403.743316	4000
3499.872059	1443.850267	3600
3541.9629	1483.957219	3200
3581.073859	1524.064171	2800
3617.204935	1564.171123	2400
3650.356128	1604.278075	2000
3680.527439	1644.385027	1600
3707.718868	1684.491979	1200
3731.930413	1724.59893	800
3753.162076	1764.705882	400
3771.413857	1804.812834	0

Table 2. Well 2 production data

Oil Rate X Axis	Water Rate	P_{wf}
bbl/d	bbl/d	psi(a)
0	0	13500
301.4876545	47.19283971	13200
596.9605926	94.38567941	12900
886.4188145	141.5785191	12600
1169.86232	188.7713588	12300
1447.291109	235.9641985	12000
1718.705182	283.1570382	11700
1984.104539	330.3498779	11400
2243.489179	377.5427177	11100
2496.859103	424.7355574	10800
2744.214311	471.9283971	10500
2985.554803	519.1212368	10200
3220.880578	566.3140765	9900
3288	580	9813
3450.191637	613.5069162	9600
3673.487979	660.6997559	9300
3890.769606	707.8925956	9000
4102.036516	755.0854353	8700
4307.288709	802.278275	8400
4506.526187	849.4711147	8100
4699.748948	896.6639544	7800
4886.956993	943.8567941	7500
5068.150321	991.0496338	7200
5243.328933	1038.242474	6900
5412.492829	1085.435313	6600
5575.642009	1132.628153	6300
5732.776472	1179.820993	6000
5883.896219	1227.013832	5700
6029.00125	1274.206672	5400
6168.091564	1321.399512	5100
6301.167162	1368.592352	4800
6428.228044	1415.785191	4500
6549.27421	1462.978031	4200
6664.305659	1510.170871	3900
6773.322392	1557.36371	3600
6876.324408	1604.55655	3300
6973.311709	1651.74939	3000
7064.284293	1698.942229	2700
7149.24216	1746.135069	2400
7228.185312	1793.327909	2100
7301.113747	1840.520749	1800
7368.027466	1887.713588	1500
7428.926468	1934.906428	1200
7483.810754	1982.099268	900
7532.680324	2029.292107	600
7575.535178	2076.484947	300
7612.375315	2123.677787	0

Wells production at test point

At test point P_R=18000psia, P_{wf} =10520 psia, Q_o=2300bbl/d, Q_w=750bbl/d and the maximum total rate at that point was 3050 bbl/d as shown in figure 1. Assuming only oil was produced using the same reservoir energy and condition; the AOF would have been 5001.2bbl/d as shown in Figure3.

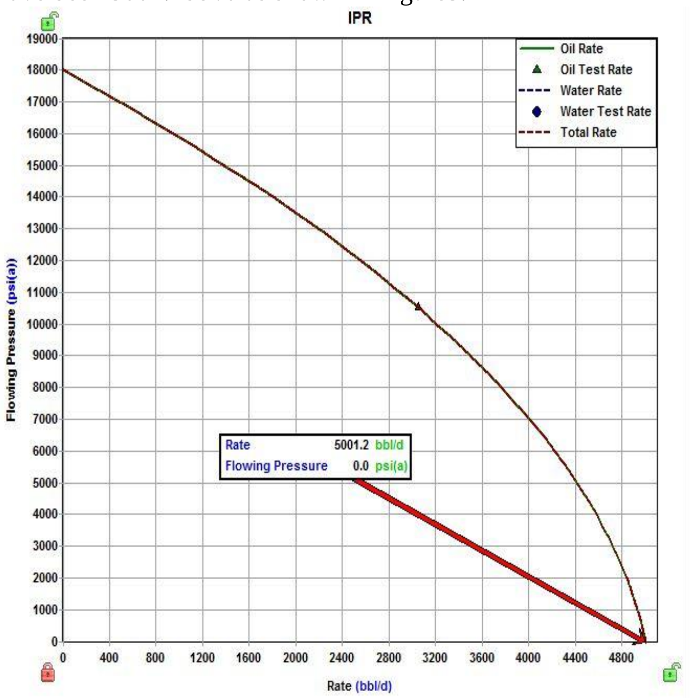

Figure 3. IPR for Well 1 at test point

At test point, Well 1 gives P_R=13500 psia, P_{wf}=9813 psia, Q_o=3288 bbl/d, Q_w=580 bbl/d as shown in figure 4.2.Assuming the total flow rate was only for oil at test point i.e. Q_o=3868 bbl/d, hence the AOF of the well will be 8955.2 bbl/d as shown in figure 4.

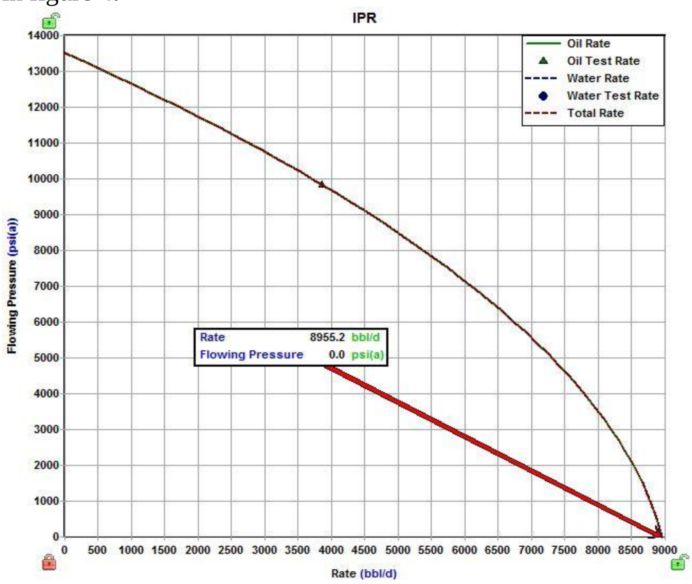

Figure 4. IPR for Well 2 at test point

Oil production productivity index

From the plots, PI is mathematically given as;

$$PI = \frac{Q}{P_R - P_{wf}} = \frac{Q}{\Delta P} \quad (1)$$

Where Q =flow rate at deviation from linear (bbl/d)

P_{wf} =corresponding pressure at deviation from linear (psia)

P_R =reservoir pressure (psia)

Hence for Well 1,

Q =1400 bbl/d

P_R =18000 psia

P_{wf} =14000 psia $\therefore$

$$PI = \frac{1400}{18000 - 14000} = \frac{1400}{4000} = 0.35 \text{ psia/bbl/d} \quad (2)$$

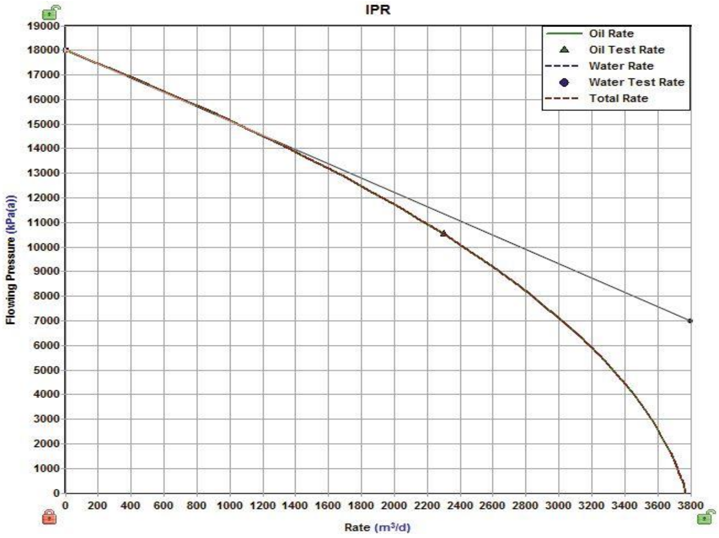

Figure 5. IPR for Well 1 indicating PI

For Well 2,

Q =2800 bbl/d

P_R =13500 psia

P_{wf} =10500 psia $\therefore$

$$PI = \frac{2800}{13500 - 10500} = \frac{2800}{3000} = 0.93 \text{ psia/bbl/d} \quad (3)$$

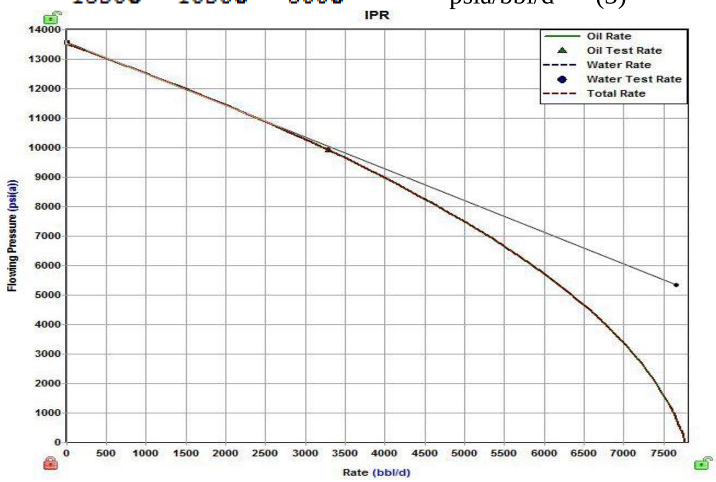

Figure 6. IPR for Well 2 indicating PI

The calculated result of the deduced data from the plots shows that Well 1 is producing at PI of 0.35 (figure 5), while Well 2 PI is 0.93 (figure 6). Hence, Well 2 productivity is better compared to that of Well 1. The effect of water in the flow stream is more prevalent in Well 1 than Well 2. The productivity index value of zero shows no flow and that of the value of one shows maximum flow, hence Well 1 is flowing at the PI of 0.65 less below maximum and Well 2 is flowing at PI of 0.07 less to reach maximum.

Conclusion

Based on the available well data statistical evaluation and simulations of the two wells, the following conclusions have been drawn;

Figure.1 shows that Well 1 is producing at oil flow rate = 3771.4 bbl/d and water flow rate=1804 bbl/d at absolute open flow of bottom flowing pressure = 0 with gross production rate=

5576.2 bbl/d. From figure 5, the productivity index of the well is PI = 0.35 bbl/d/psia. Assuming Well 1 was producing only oil without water stream in the flow, using the same reservoir energy condition the oil flow rate would have been q_o = 5001.2 bbl/d at AOF (figure.3), leaving the productivity index at PI = 0.43 bbl/d/psia. Hence it is very clear that Well 1 is producing below average and the cause may be attributed to the presence of water in the flowing stream and skin in the well. From figure. 2, Well 2 is producing at oil flow rate = 7612.4 bbl/d, water flow rate = 2123.7 bbl/d at AOF with gross production rate = 9736.1 bbl/d and from figure 4.6 the productivity index of Well 2 was PI = 0.93 bbl/d/psia. From figure 4.4 assuming that Well 2 is producing only oil without water stream , the flow rate of oil would have been q_o = 8955.2 bbl/d at the same reservoir condition leaving the productivity index PI = 0.97 bbl/d/psia. Thus from the PI of Well 2, it has clearly shown that Well 2 is producing at a near maximum.

From the results, it has been clearly seen that the gross production when the flowing stream was oil and water at AOF (figures 1 &.2) is greater than the gross production when it was only oil in the flowing stream (figures.3 &.4). This is as a result of the slightly compressible nature of oil at high temperature and pressure which brings about the curved shape in the oil IPR train due to expansion of oil as pressure is reduced. From the results also, it has been clearly seen that if reservoir pressure is maintained, the lower the flowing bottom hole pressure, the higher the production rate and the more economical the well is i.e. the higher the difference between the reservoir pressure and the flowing bottom hole pressure, the better the production yield, hence the maximum difference between the P_R and P_{wf} makes the production at maximum (AOF).

Recommendation

The idea of the pressure-rate behavior enables engineers to evaluate various operating scenarios to ascertain the optimum production scheme and to design and install surface and subsurface production equipment when necessary. Knowledge of the pressure-rate behavior can be quite helpful in designing and evaluating stimulation treatments or any operation that improves flow efficiency, like the estimation of future performance which is required for forecasting and planning purposes. The investigation of well-bore fluids interaction effect on oil flow rate method used in this work proves efficient in the separation of oil flow rate, water flow rate and the total flow rate. This research is recommended for use in the study of oil well performance with emphasis on oil inflow rate challenges. The information provided here could also be used for further research of problems of this kind.

Nomenclature

AOF = Absolute Open Flow
bbl/d = barrel per day
IPR = Inflow Performance Relationship
PI = Productivity Index
PR = Reservoir pressure
Pwf = Bottom hole flowing pressure
ΔP = change in pressure
Q = flow rate
Qo = oil flow rate
Qw = water flow rate
Stb/d = Stock tank barrel
TPR = Tubing Performance relationship

Acknowledgment

The Authors wish to acknowledge Dr. Uduak Mme of Norwegian University of Science and Technology (NTNU) Norway, for his guidance and support during this research work. Appreciation goes to the Staff and Technologist of Department of Chemical & Petroleum Engineering, University of Uyo, Uyo, Nigeria for their assistance.

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