International Journal of Chemical and Biochemical Sciences
(ISSN 2226-9614)

Journal Home page: www.iscientific.org/Journal.html

Variations of inflow performance relationship in the Western Desert Oil Wells, Egypt

Dr. Shady G. El-Rammah 1, Prof Dr. Mohamed M. Soliman 1,

Eng. Ahmed M. Abdallah2*, Prof. Dr. Adel M. Salem 1

1 Suez University, Faculty of Petroleum and Mining Engineering, Cairo-Suez Road, Suez, Egypt.

2 Khalda Petroleum Company, 290 New Maadi, 3rd sector, Cairo, Egypt

Abstract

The productivity index is an important tool in the petroleum industry, measuring a well's ability in producing fluids. It plays a significant role in various stages, from exploration to production. By evaluating reservoir properties and well performance, the index helps optimizing production strategies, selection of optimum artificial lift system and monitor well behavior. Its importance lies in guiding investment decisions, maximizing oil recovery, and ensuring the sustainable and efficient production of oil reserves. In the western desert of Egypt, Most oil wells are produced using different artificial lift methods in which the reservoir pressure is not sufficient enough to allow the well to flow naturally. Productivity index has been monitored for different wells in several reservoirs, which should be constant over time as long as the reservoir pressure is above the bubble point. However, Tracking many wells performance have showed significant variance in productivity index which has been observed by successive production tests accompanied by measuring the dynamic fluid level. Selection of oil wells completed by electrical submersible pumps (ESP) have given a closer monitor of pressures using the downhole sensor data. R Field has several producing reservoirs which different driving mechanisms. The main selected reservoirs in this study are classified as active water drive with strong pressure support Well R-28 has been completed with ESP and first production data has shown +/- 4,600 BFPD and +/- 2,600 ft. dynamic fluid level. After a short period of production it showed +/- 3,450 BFPD and +/- 750 ft. dynamic fluid level. The analysis of this dramatic changes showed continuous drop in well productivity from +/- 4 bbl./day/psi till reached +/- 2 bbl./day/psi in less than one year. Similar cases are observed in R field.This variance in productivity index cannot be ignored and have a direct impact on the field oil production and shorten the run life of the artificial lift system (ESP). Building databases of the actual production test data of oil wells, measuring the dynamic fluid levels and tracking the running parameters of the ESP are chosen to conduct several case studies that confirm the variation of the productivity index value. These cases will open the gate to re-study the productivity index and proof it is not constant by the time even if the reservoir pressure in constant and above the bubble point.

Keywords: IPR Variation, Productivity Index, Production Data Analysis, Egyptian Western Desert, Artificial Lifting Systems.

Full length article **Corresponding Author*, e-mail: ahmed.mohamed.abdalla7@gmail.com

1. Introduction

Inflow Performance Relationship (IPR) of well is a relation between the flowing bottom-hole pressure and the production rate. For oil wells, it is usually assumed that fluid inflow rate is proportional to the difference between wellbore pressure and reservoir pressure. This assumption leads to a straight-line relationship that can be derived from Darcy's law for steady state flow of an incompressible, single-phase fluid and is called the Productivity Index (PI), which is assumed to have a constant value based on the pre-mentioned conditions [1, 2]. Petroleum engineers are routinely required to predict the pressure-production behavior of individual oil wells. These estimates of well performance assist the engineer in evaluating various operating conditions, determining the optimum production scheme, and designing production equipment and artificial lift systems [3, 4]. Sometimes the concerned wells were exploratory wells or have high uncertainty data as the field was under reservoir development which make it a challenge to create a design for an efficient pumping system that cover the lack of data specially while having low figures of productivity index and deliver a considerable/economic oil rate [3, 5].In Egypt, Artificial lift systems are used by the E&P companies to produce the wells in an economic rates and overcome the depletion phenomena. The most common artificial lift systems are the sucker rod pumps and the electrical submersible pumps, so accurate estimating for the value of productivity index is mandatory for better design and selection for the artificial lift system. A group of artificially lifted wells in the western desert in Egypt were observed having variation trend in productivity value. It was confirmed by periodic surface well test and matching same with the pump intake pressure data of the electric submersible pumps or conducting periodic dynamic fluid level shots. Measuring the reservoir pressure while drilling the offset wells showed the reservoir pressure still above the bubble point pressure. Productivity index variation is a function in of several physical properties, such as absolute and effective permeability, fluid properties, fines migration and mud invasion. There are different well-work options as acid stimulation, de-emulsifier etc. in the industry for remediation and restoration of possible reduction in productivity. [6]

1.1 Productivity Index Calculations

Productivity index of oil wells, including the skin factor, can be written as following as below for radial flow. [1]

$$J = \frac{0.00708 k_0 h}{\mu_0 \beta_0 \ln\left(0.472 \frac{r_e}{r_w}\right) + S} \cdot \int_{p_{wf}}^{p_r} \frac{k_0}{\mu_0 \beta_0} \; dp$$

Where:

J = productivity index (stb/day/psi).

k_0= relative permeability of oil (milli-darcy).

h = length of pay zone (ft.).

μ_0 = oil viscosity (centipoise).

β_0 = oil formation volume factor (bbl. /stb).

re = radius of drainage area of reservoir (ft.).

rw = radius of well (ft.).

S = skin factor (dimensionless)

p_r = reservoir pressure (psi)

p_{wf}= bottom hole flowing pressure (psi)

From this expression, it can be observed that J will be dependent on several factors and it is well known that it will not have a constant value unless the reservoir pressure is above the bubble point. In some particular cases the bottom hole flowing pressure falls below the bubble point while the reservoir pressure still above the bubble point, this is may be attributed to the high drawdown from pay zone while the productivity index value is not high enough which cause high pressure drop across the perforation tunnels . [1] In the design of artificial lift systems, a more simple formula is used in which the productivity index is expressed in terms of total liquid rate divided by the difference between the reservoir pressure and the bottom hole flowing pressure. [2]

$$J = \frac{q_l}{p_r - p_{wf}}$$

Where:

J = productivity index (stb/day/psi).

q_l= total liquid rate (stb)

p_r = reservoir pressure (psi)

p_{wf}= bottom hole flowing pressure (psi)

1.2 Factors Controlling PI

Value of PI can be affected from different field development phases, starting from drilling, completion, production, remediation, etc. There have been many studies in oil and gas industry to identify the factors causing degradation of productivity index such as: 1) Fines migration, 2) fracture connectivity, 3) Drilling and completion fluid invasion, 4) Off-plane perforation, 5) Compaction effect, All these factors are almost not related to pressure depletion phenomena and are not generalized among all fields. Some factors may have greater effect in certain fields while others may not affected at all [2 .Back to the productivity index formula, it is clear that major factors are pressure dependent and can be summarized as below.

1.2.1 Oil viscosity behavior

Viscosity of oil saturated with gas will decline as pressure is decreased from initial pressure to bubble point pressure at constant temperature. Below the bubble point, Viscosity of oil increases as gas migrates out from solution leaving heavy molecules still in liquid phase. Figure-3 shows the effect of changing pressure on the oil viscosity. [1-3]

1.2.2 Oil formation volume factor

When pressure decreases on liquid, the liquid will expand. When it reaches the bubble point pressure, Gas parting out of solution will lead to oil to shrink. The relation between β_0 versus pressure is shown graphically below in Figure-4 [1-3]

1.2.3 Reservoir phase behavior

When reservoir pressure is above the bubble point pressure value, No free gas exist anywhere in the reservoir. However, when pressure drops at any point among the reservoir below the bubble point pressure, free gas will produce and will have negative effect on liquid motion in pores and J will be declined around the wellbore [1-3]

1.2.4. Relative permeability behavior

When free gas forms in the reservoir, the gas saturation starts to increase. The space occupied by the free gas will decrease the effective flow are of liquid. This phenomena decrease the relative permeability of oil and thus decrease the productivity index value .The major drop in productivity index happens when pressure falls below bubble point, so several ways are used to keep the reservoir pressure above the bubble point to maximize the oil production and enhance the well deliverability. However, some fields worldwide have shown variation in productivity index with significant value while pressure is still above the bubble point. Such considerable variation is resulted from different factors not related to decrease in reservoir pressure till below the bubble point pressure. [1-5]

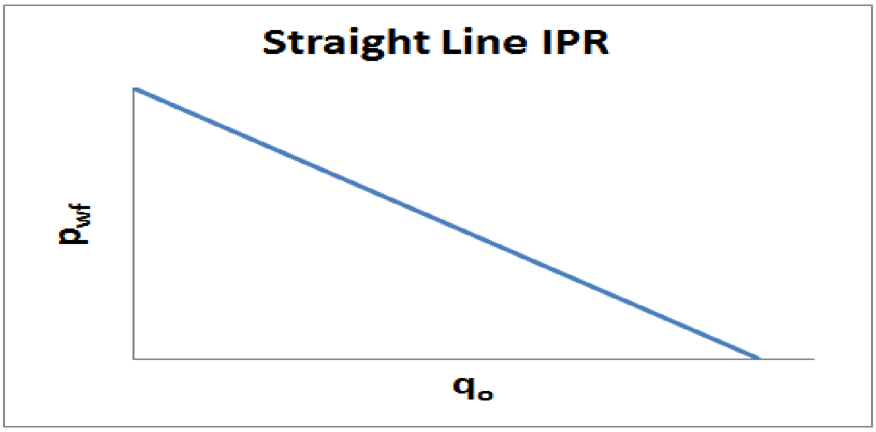

Fig 1: Ideal case of PI

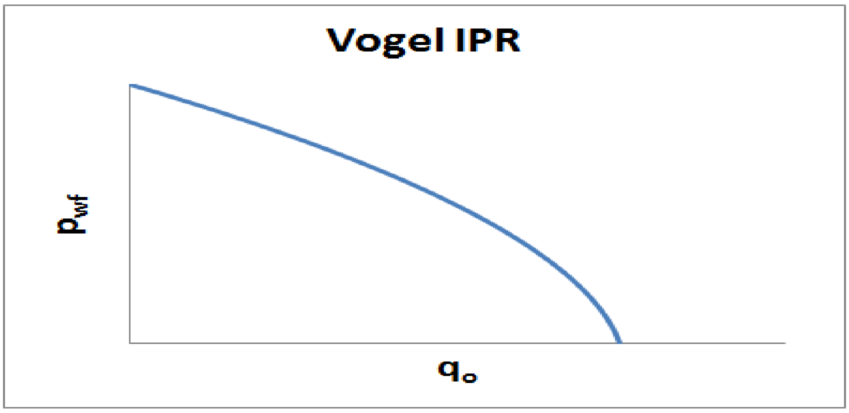

Fig 2: Vogel IPR –Reservoir pressure below bubble point

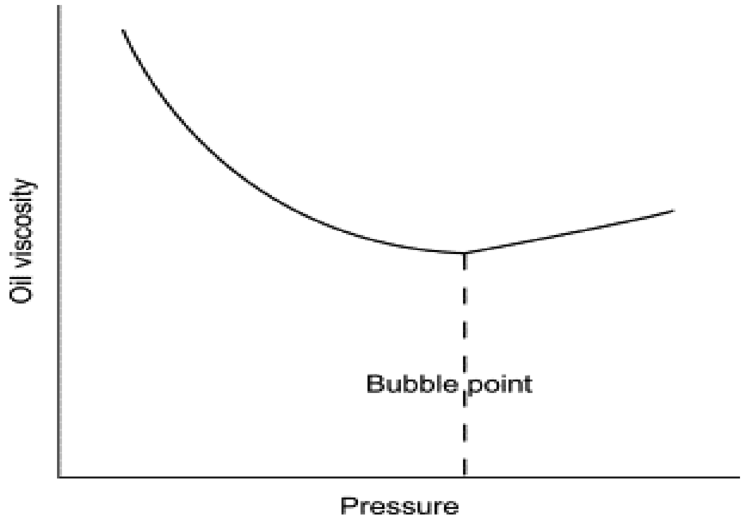

Fig 3: Oil Viscosity versus pressure.

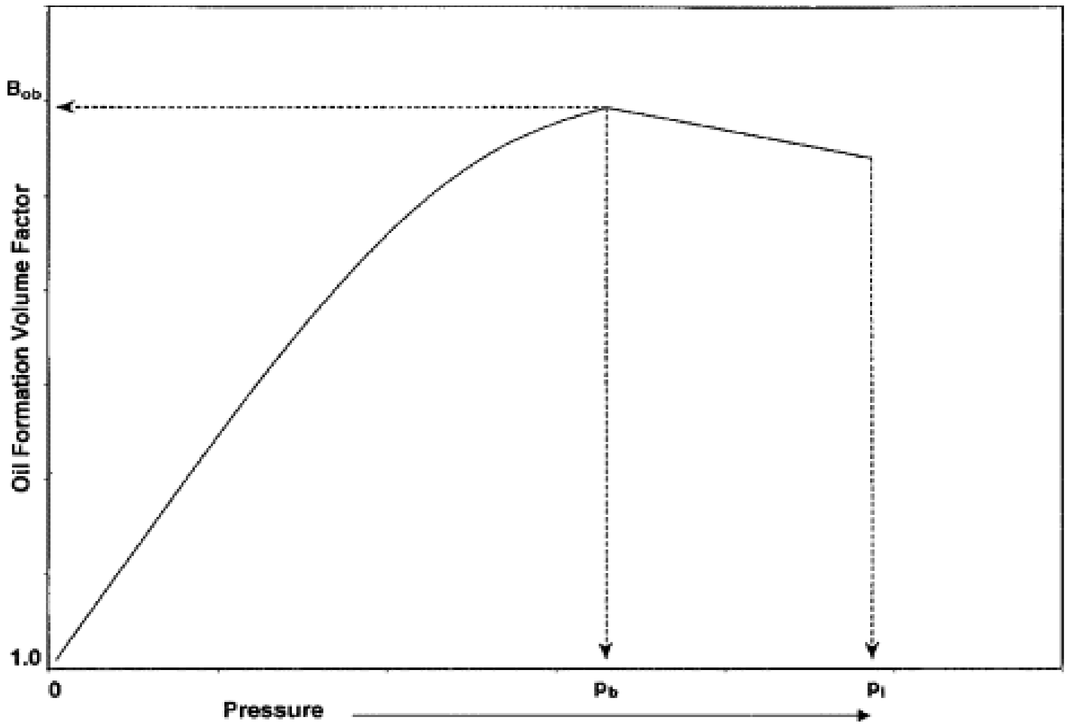

Fig 4: Oil Formation Volume Factor versus Pressure

Table 1: Case History Summary (Saputelli et al., 2010)

Case History	Lithology Environment	Reported PI loss causes	PI loss
Lobster Field [7]	Deepwater turbidity sands	Permeability reduction due to compaction, relative permeability loss, and skin increase due to fines migration.	~ 70 % loss in PI
South Diana (Guenther et al.,2005)	Deepwater unconsolidated turbidite sands separated by thin shales	Permeability reduction due to compaction, and skin increase due to fines migration.	
Genesis Field (Pourciau et al.,2003)	Deepwater unconsolidated thick turbidite sands separated by thin shales	Permeability reduction due to compaction, and skin increase due to fines migration.	80-95 % loss in permeability

Table 2: Actual production test data for well A-1.

Test Date	WHP PSI	SEP PSI	BFPD STB	BS&W %	BOPD STB
2-Feb-2020	260	240	2250	40	1350
15-Feb-2020	380	280	4633	46	2502
17-Feb-2020	340	250	4411	51.7	2131
19-Feb-2020	330	240	4183	65.1	1460
22-Feb-2020	330	240	4117	67.2	1350
28-Feb-2020	310	200	4056	68.8	1265
4-Mar-2020	310	220	4108	68.9	1278
9-Mar-2020	300	210	4023	72.88	1091
21-Mar-2020	280	220	4203	82.57	733
29-Mar-2020	270	200	4007	84.85	607
5-Apr-2020	260	190	3995	86.35	545
13-Apr-2020	260	200	3973	86.29	545
18-Apr-2020	260	200	3899	91.36	337
28-Apr-2020	260	200	3897	90.9	355
21-May-2020	240	200	3892	89.9	393
29-May-2020	240	200	3789.8	90.8	349

16-Jun-2020	240	200	3789	92.27	293
5-Jul-2020	230	200	3757	93.598	241
4-Aug-2020	200	180	3738	94.1	221
18-Sep-2020	200	180	3718	94.44	207
16-Nov-2020	190	170	3662	95.4	168
15-Dec-2020	185	170	3320	94.24	191
4-Jan-2021	180	165	3320	94.92	169
6-Feb-2021	190	170	3460	96.27	129
5-Apr-2021	200	180	3453	96.55	119
29-May-2021	200	180	3452	97	115

Table 3: Actual production test data for well A-2.

Test Date	**WHP PSI**	**SEP PSI**	**BFPD STB**	**BS&W %**	**BOPD STB**
27/Aug/15	160	150	3344	36.3	2130
1/Sep/15	160	150	2931	35.6	1888
5/Sep/15	160	150	2743	35.8	1761
10/Sep/15	150	140	2369	28.5	1694
15/Sep/15	160	150	2300	24.5	1737
23/Sep/15	160	150	2036	37.2	1279
27/Sep/15	160	150	2143	38.7	1314
1/Oct/15	160	150	1985	39.3	1205
9/Oct/15	150	140	1929	43.1	1098
12/Oct/15	150	140	1847	40.9	1092
20/Oct/15	150	140	1829	44	1019
27/Oct/15	150	140	1851	42.06	1072
5/Nov/15	150	140	1755	43	1000
21/Nov/15	130	120	1372	44.7	759
19/Dec/15	130	120	1197	48	622
13/Jan/16	150	140	1029	51.8	496
15/Feb/16	150	130	937	52.6	444
10/Mar/16	140	130	877	54.8	396
12/Mar/16	220	130	925	58.6	383
21/Mar/16	190	140	827	58	347
3/Apr/16	200	140	792	59.7	319

Table 4: Actual production test data for well A-3.

Test Date	**Choke size**	**WHP PSI**	**SEP PSI**	**BFPD STB**	**BS&W %**	**BOPD STB**
25/Dec/18	128	130	120	3707	0.12	3703
28/Dec/18	128	150	130	3602	27.4	2615
31/Dec/18	128	150	140	3690	39.35	2238
4/Jan/19	128	130	110	3904	57.6	1655
7/Jan/19	128	130	110	3938	65.21	1370
11/Jan/19	128	120	100	3965	68.38	1254
16/Jan/19	30	370	110	3814	71.08	1103
16/Jan/19	128	120	110	4000	71.25	1150
16/Jan/19	32	330	110	3882	71	1126
22/Jan/19	128	110	100	3813	72.41	1052
2/Feb/19	128	130	120	4128	77.62	924
8/Feb/19	128	140	120	4049	83	688
16/Feb/19	128	120	100	4301	78.92	907
20/Feb/19	32	560	100	3836	80.49	748
1/Mar/19	32	560	100	3734	82.22	664
9/Mar/19	32	580	100	3732	83.2	627
20/Mar/19	32	540	90	3751	83.5	619
23/Mar/19	32	540	90	3722	83.5	614

9/May/19	32	580	110	3736	84.8	568
31/May/19	32	520	100	3609	84.27	568
15/Jun/19	32	550	90	3528	87.3	448
11/Jul/19	32	440	90	3233	87.15	415
24/Jul/19	32	400	90	3149	88.46	363
15/Aug/19	32	320	90	2777	89.7	286
18/Aug/19	128	100	90	2956	92.08	234
26/Aug/19	128	110	95	2796	86.7	372
18/Sep/19	128	100	90	2548	91.8	209
17/Oct/19	128	100	90	2421	91.46	207
28/Oct/19	128	100	90	2368	90.94	215
1/Nov/19	128	90	80	2559	90.5	243
10/Nov/19	128	100	90	2206	90.9	201
26/Nov/19	128	80	70	1609	90.9	146
11/Dec/19	128	80	70	1540	92.54	115
27/Dec/19	128	90	70	1285	92.1	102
7/Feb/20	128	170	140	6451	89.4	684

Table 5: Actual dynamic fluid shots for well A-4.

DATE	Fluid level	CSG. Ppsig	%Liquid in fluid	NLAP ft
23-Jan-21	3119	0	100	3986
24-Jan-21	2141	0	100	4964
25-Jan-21	3564	0	100	3540
26-Jan-21	3740	0	100	3365
29-Jan-21	3821	3.3	100	3284
1-Feb-21	3907	2	100	3198
5-Feb-21	3681	0	100	3424
5-Mar-21	3532	0	91	3255
3-Apr-21	1810	0	100	5295
17-Apr-21	1752	8.9	100	5353
29-May-21	1487	0	100	5618
10-Jul-21	1435	0	100	5670
10-Sep-21	1264	0	100	5841

Table 6: Comparison between the four wells.

Well	Intial PI	Updated PI	Comment
A-1	+/- 4	+/- 2	ESP work in Down-thrust condition
A-2	+/- 3.4	+/- 0.4	Downgraded the ESP in next work-over operation after premature failure
A-3	+/- 6	+/- 15	Failure in ESP due to up-thrust condition then installed higher capacity ESP
A-4	+/- 0.7	+/- 2	Upgraded the ESP to higher capacity

Figure-1 shows the ideal case of PI in which the relation between the flow rate and drawdown pressure is a straight line, while Figure-2 represent the Vogel relationship in which the pressure fall below the bubble point pressure. The production test data confirmed variance in productivity index of producing wells which are summarized in table-6.

1.3 PI variation during production

It has been thought that the major variation in productivity index value is due to pressure drop below the bubble point pressure, and the relationship between pressure drawdown and rate turned from straight line to a curve. However, some wells recorded variation in PI due to dependent rate process (i.e. sand production and fine migration), or pressure dependent process (i.e. compaction or relative permeability issues) or both processes which makes it more complicated to define the root cause of variation[10]. Effective overburden load as a result of production in stress-sensitive reservoirs often results in a loss in productivity for a wide range of operating conditions and reservoir properties [11]. PI reduction has been observed in the Ewing bank block 873 lobster field, which produces from Gulf of Mexico. Significant PI loss reaches up to 70 % since the start of production. It is suspected the reduction is due to fine migration and compaction from reservoir depletion due to production. [7]

Same phenomena have also been observed in the Genesis field. Some wells has showed drop in productivity due to expected reservoir compaction. It is believed the permeability loss has reached 80 -95 %, which greatly have delayed the reserve recovery and decline in the ultimate recovery from natural separation [12] .On the other hand, Daqing oil field in China is a mature which shows increase in productivity index due to possible increase in water cut. The field was put into production in 1960. Twenty years later, it produced nearly 20 % of the original oil in place (OOIP) and ended its low to medium water-cut stage, the water cut reached 60 %. From 1981, the field entered the high water-cut stage of development. By June 1985, it produced nearly 28% of its OOIP and the water-cut rose to about 73%. The field had already been in its high water-cut production stage for five years [13].The rate of increase of the water-out decreased, but the water-oil ratio increased rapidly. Therefore it is necessary to have a change in production technologies in order to increase the fluid withdrawal rate to keep stable production. In the same time, the well productivity index increased continuously. In order to slow down the rate of decline of the oil production, it was important to increase the production pressure drawdown and fluid production rate. The decision was to switch to artificial lifting systems to achieve the required target production rate. [13]. From 1981 to June 1965, Daqing installed 643 electric submersible pumps which were able to achieve higher fluid production rate. The increase in wells productivity allowed the petroleum engineers to achieve better reservoir management and maximize the recovery by transferring to artificial lift pumping (ESP). [13]

1.4 PI for R-Field – Egypt Western Desert

In Egypt, Variation in productivity index has been observed in R-Field in the western desert. A- field is a mature field producing since 1970s. It is divided into four parts, the concerned wells in this study have been producing from strong active water drive reservoirs with no depletion. The reservoir pressure in all cases is above the bubble point pressure. Wells are completed via artificial lifting systems due to high water cut readings and to maximize the oil recovery. The performance of these wells are tracked using periodic surface well test using third party companies accompanied by tracking the net liquid above ESP or the pump intake pressure if the ESP has a sensor accessory. The variation in productivity index value weather positively or negatively has a major impact on the artificial lifting system both selection and design. For better reservoir managements in exploratory wells, It is decided to complete the wells with ESP with a mandatory downhole senor is installed for better evaluating the producing zone and estimating the proven reserves.First well is A-1, the well is producing from carbonate reservoir with strong active water drive. It has been completed with high capacity ESP to get benefit from the good value of productivity index with stable reservoir pressure above the bubble point. Normal performance of this reservoir is producing while having dramatic increase water cut values since put well on production then stabilize within short time at high water cut value exceeding 90 %.

Unfortunately, Successive surface well tests have showed gradual drop in both production rate and the net liquid above the ESP. Apparently, it seems normal depletion behavior but further review the reservoir performance shows no depletion for nearly twenty years and confirmed no decline in reservoir pressure. The second option is drop in the productivity index of the well. The actual variance of the productivity index value lead to selection of higher capacity ESP than the reservoir can deliver, which definitely will cause operational problems while running the ESP. Conducting several match cases for the well performance has shown drop in PI from +/- 4 bbl./day/psi in Feb. 2020 till reached +/- 2 bbl./day/psi in Nov. 2020. The remedial action during next work over operation from designers' point of view is to select a lower capacity pump to match the current well productivity. Selection of smaller pump capacity from the initial completion has not been accepted due to possibility of loss higher oil production rate. Second well is A-2, the well is producing from the same active carbonate reservoir. The well was been initially completed after testing period over rig and productivity index showed +/- 3.4 bbl./day/psi. The first production test for the well showed +/- 3,344 BFPD, 36% water cut and 2,800 ft. net liquid above pump. The well performance showed gradual increase in water cut ratio with clearly drop in rate and net liquid above pump till produced +/- 790 BFPD, 60% water cut and 740 ft. net liquid above pump.

The initial analysis removed the probability on mechanical problem in the artificial lift system due to data of dynamic fluid shots which confirmed gradual drop in net liquid over pump. Therefore, the problem was related to the reservoir and its productivity index value. Last production test data confirmed the drop in productivity index to +/- 0.4 bbl./day/psi, as a result the ESP pump could not cope with such great drip in PI and run in the severe down thrust conditions. Third well is A-3, the well is producing from strong active sandstone reservoir. The well was been initially completed after testing period over rig and productivity index showed +/- 6 bbl./day/psi. It was considered the killing fluid effect during work over rig operation can cause further decline in productivity and taken into consideration while designing the ESP. After putting the well on production, it showed sharp increase in water cut accompanied by increase in well productivity.

The well performance showed rapid increase in net liquid above pump with increase in actual production rates due to increase in productivity index. Calculations showed PI increased up to +15 bbl./day/psi. The increase in the PI lead to running the ESP out of the recommended range (up-thrust condition) and ended with premature failure of the ESP. the well was enrolled in work over rig schedule after failure and upgraded the existing pump capacity to higher one to cope with the existing well performance. Final production test in table-4 is showing production test data after upgrading the ESP due to pre-mature failure of existing pump and replacing same with higher capacity pump which increased the oil production rate from well. Fourth well is A-4, the well is producing sandstone reservoir with active water drive. The well was completed with low capacity ESP pump due to relative low productivity index (+/- 0.7 bbl./day/psi). The first test data was matched with the target design and normal increase in water cut as expected from active water drive reservoir. However, further production test data showed increase in production rate with remarkable increase in net liquid above the pump. Several dynamic shot levels confirmed increase the well productivity.

Later, the well suffered from sudden drop in production rate with normal running parameters of ESP pump. Further check showed possible mechanical problem in the tubing integrity, the well was enrolled in work over rig schedule and the pulled tubing showed clear hole which resulted in the drop in production rate. The decision was to upgrade the ESP to a higher capacity one to match the variation in productivity index from +/- 0.7 to +/- 2 bbl./day/psi. The selected new pump could produce more than double the previous production rates which maximized the oil production from the well.

2. Conclusions

1. Variance in the value of the productivity index can be significant that affect the design of the artificial lift system even the reservoir pressure is almost stable with no depletion.
2. Variance of productivity index of oil wells while production have been observed in some fields in the western desert of Egypt, such significant value of PI requires changing the artificial lift pumping capacity to cope with the reservoir deliverability.
3. Design/Selection of artificial lifting systems shall consider this phenomena based on the actual performance of the offset producing wells to ensure extended run life and save the down hole equipment from premature failure.
4. It is better for the completion of wells to have accessibility to the formation while the artificial lift system exist in the well for possible stimulation to enhance the well productivity.
5. Installing down-hole pressure gauges along with the completion accessories will have better monitoring & surveillance for the well's performance, avoid the premature failure of the artificial lift system.
6. Consideration of variance of productivity wells based on actual production data will maximize the oil production and minimize the exposure of formation to the killing fluid negative effects during work over operation.

3. Acknowledgment

The authors would like to express appreciation for the faculty of petroleum and mining engineering staff & Khalda Petroleum Company management for their help. All the contributions are well thanked with much gratitude.

References

[1] Brown, E. Kernit & H.D.Beggs. (1977). The Technology of Artificial Lift Methods. Vol. 1, Penn Well, Tulsa, Okla.
[2] H. D. Beggs. (1991). Production Optimization Using Nodal Analysis, OGCI Publications.
[3] T. E. W. Nind. (1964). Principles of Oil Well Production. Publisher McGraw-Hill.
[4] G. Takacs. (2009). Electrical Submersible Pumps Manual: Design, Operations, and Maintenance. Gulf Professional Publishing.
[5] M. Golana & C. H. Whitson. (1991). Well performance- Englewood Cliffs. N.J. Prentice Hall.
[6] R. Huseynov. (2017). Water Breakthrough Effect on Well Productivity and Skin Factor Change https://doi.org/10.2118/189033-MS.
[7] D. Petro, W. Chu, M. Burk & B. Rogers. (1997). "Benefits of pressure transient testing in evaluating compaction effects: Gulf of Mexico deepwater turbidite sands," SPE 38938, Annual Technical Conference, San Antonio.
[8] R. Raghavan, L. Y. Chin. Productivity Changes in Reservoirs with Stress-Dependent Permeability - https://doi.org/10.2118/77535-MS
[9] Petro, D., Chu, W., Burk, M., Rogers, B., "Benefits of pressure transient testing in evaluating compaction effects: Gulf of Mexico deepwater turbidite sands," SPE 38938, Annual Technical Conference, San Antonio, 1997.
[10] L. Yan Li, K. Zaki, Y. Tan, R. Wu & P. Rijken. Productivity Decline: Improved Production Forecasting Through Accurate Representation of Well Damage - https://doi.org/10.2118/196213-MS.
[11] R. Raghavan & L. Y. Chin. Productivity Changes in Reservoirs with Stress-Dependent Permeability - https://doi.org/10.2118/77535-MS.
[12] L. Saputelli, J. Perez, A. Chacon, C. Lopez, J. Patino & M. Eggenschwiler., Well Productivity Index Degradation. Applied Modeling Workflow . https://doi.org/10.2118/133452-MS.
[13] D. Wang & J. Tand. Production Technology of Daqing Oil-Field During Its High Water Cut Stage. https://doi.org/10.2118/14847-MS.