Application of Systematic Approach for Fast Oil Production Enhancement-Case Studies

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Abstract

Full field studies and master development plans are time consuming and expensive tasks for any company to find optimum improved oil recovery method. Fast oil production enhancement is a method applied over existing assets resulting in fast increase in oil production in less expensive way. This approach consists of five steps as identification of source of production decline problem through evaluation of diagnostic tests, prioritizing different solutions for treating the problem, conceptual integrated modeling of reservoir and wells, production network optimization and economic analysis.

In this paper we elaborate and implement these five steps in an Iranian Oil Field with twenty wells. Firstly we found that the production decline is due to poor well cleaning after stimulation and work over operation and also reservoir pressure decline leading to not having sufficient energy to push oil to the surface. Secondly; based on specifications of each well and pre-determined screening criteria; artificial lift methods were prioritized followed thirdly by conceptual modeling of first ranked artificial lift method which was electric submersible pump for first ranked wells. The fourth step was optimization of production network through sequential quadratic programming and lastly probabilistic economic analysis based on different ESP time to failure. The result of this study shows viability of application of ESP in this field in fast way.

Introduction

Application of Improved Oil Recovery (IOR) methods is imperative along with increasing oil demand and decreasing oil production due to oil reservoir depletion. The three general classes of improved oil recovery are enhanced oil recovery (reservoir-based IOR), surface facilities improvement (surface facilities-based IOR) and well production enhancement (well-based IOR).

The reservoir-based IOR consists of miscible/immiscible gas injection, water injection, chemical flooding and smart reservoir. The surface facilities- based IOR is related to upgrading and optimization of surface facilities such as separator and pump. The well-based IOR or well production enhancement methods are categorized as drilling technology, completion technology, artificial lift and chemical injection [1].

Based on the data from more than 80 oil fields and 450 reservoirs developed in Gulf of Mexico, a low-to-high technical IOR recovery factors in range of 2-22% and 2-15% are forecasted for reservoir-based IOR (water injection and gas injection) and well-based IOR (ESP application, hydraulic fracturing and horizontal well) respectively [2].

From time and cost standpoints; studying, designing and implementation of reservoir-based IOR is long term (3-5 years) while surface facilities-based IOR and well-based IOR are medium term (2-3 years) and short term (6 month to 1 year) respectively. Reservoir-based IOR is most expensive amongst other IOR methods while well-based IOR is the cheapest in terms of cost. This study focuses on well-based IOR or well production enhancement method applied over existing assets resulting in fast increase in oil production in less expensive way.

As mentioned, well production enhancement consists of four major methods which are drilling technology such as horizontal well and multi segment well, completion technology such as smart completion and hydraulic fracture, artificial lift such as electrical submersible pump, sucker rod pump, plunger cavity pump, gas lift and finally chemical injection such as gel-polymer.

Commonly, investment for implementing well-based IOR is economic feasible. Based on an economic study using artificial lift method as a well-based IOR for 15 month production on a dead well, contributions of net revenue, capital cost, indirect expense and direct expenses were 87%, 1%, 6% and 6% in net present value (NPV) respectively showing that revenue is considerably more in comparison to cost [3]. In another case, using ESP as a well-based IOR for 10 years production, indicate 200% and 6 month Internal Rate of Return and payout time respectively [4].

Considering systematic approach using well-based IOR in different wells of a field consists of five steps with wide variety tools described in following section. Then the methodology is implemented in an Iranian oil reservoir.

Methodology

Considering the large number of wells and resource constraints, it is needed to apply a methodology to assign the resources in optimum way in order to maximize oil production and consequently Net Present Value (NPV). To meet the goal, five step processes consist of identification of cause of production problem, proposing well-based IOR treatment for each well, prioritization of wells under well-based IOR treatment, conceptual modeling and economic evaluation and finally, portfolio optimization of well-based IOR are applied as shown in figure (1).

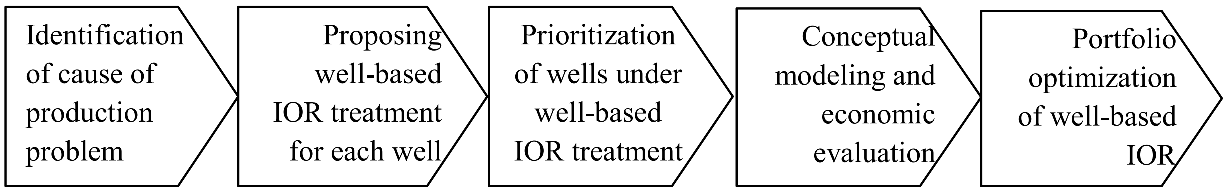

Fig. (1) Five Step Processes for Well-Based IOR Treatment

Production problems such as high water cut, high GOR, sand production, low productivity and asphaltene and scale precipitation are due to different causes.

At first step, diagnostic test such as well test, well log, and production test and etc. should be performed to identify cause of the problem. For instance, to control the excess water production in oil fields, it is necessary to understand water production mechanism. These causes include water coning, fissures or fractures and cement channel problems [5]. The MRI (magnetic resource image) is a powerful logging tool for providing conformance information also known as PLT (production logging tools). It has the capability to identify volumes of free fluids (water and hydrocarbon), the type of formation fluids, and water – free zones. Beside this, diagnostic plots derivative method is used to identify cause of the high water cut [6].

At second step, based on diagnostic test and identification of cause of the problem, solution is proposed. For instance, if there is a problem of lifting due to decrease in reservoir energy, artificial lift methods such as ESP, SRP, PCP and gas lift can be applied. A problem may have different solutions that they are not necessarily optimum to be applied. Consequently it is beneficial to prioritize these solutions based on governing screening criteria on selection. For artificial lift; general screening criteria on macro level are completion systems, well and reservoir production history, pressure history data, current well performance [7, 8].

The multi criteria decision making is one way to select the best solution based on the screening criteria. In this paper TOPSIS method (technique for order preference by similarity to an ideal solution) is presented [9, 10]. TOPSIS is a multiple criteria method to prioritize solutions from a finite set of alternatives. The basic principle is that the chosen alternative should have the shortest distance from the positive ideal solution and the farthest distance from the negative ideal solution. The procedure of TOPSIS can be expressed in a series of steps:

(1) Calculate the normalized decision matrix. The normalized value n_{ij} is calculated as

$$n_{ij} = x_{ij} \Big/ \sqrt{\sum_{j=1}^{m} x_{ij}^2} \qquad j = 1, \dots, m, \quad i = 1, \dots, n.$$

(2) Calculate the weighted normalized decision matrix. The weighted normalized value v_{ij} is calculated as

$$v_{ij} = w_i n_{ij}\,, \quad j = 1, \dots, m, \qquad i = 1, \dots, n,$$

Where w_i is the weight of the ith attribute or criterion, and $\sum_{i=1}^{n} w_i = 1$.

(3) Determine the positive ideal and negative ideal solution.

$$A^+ = \{v_1^+, \dots, v_n^+\} = \left\{\left(\max_j v_{ij} | i \in I\right), \left(\min_j v_{ij} | i \in J\right)\right\},$$

$$A^- = \{v_1^-, \dots, v_n^-\} = \left\{\left(\min_j v_{ij} | i \in I\right), \left(\max_j v_{ij} | i \in J\right)\right\},$$

Where *I* is associated with benefit criteria, and *J* is associated with cost criteria.

(4) Calculate the separation measures, using the n-dimensional Euclidean distance. The separation of each alternative from the ideal solution is given as

$$d_j^+ = \left\{\sum_{i=1}^{n} \left(v_{ij} - v_i^+\right)^2\right\}^{\frac{1}{2}}, \quad j = 1, \dots, m.$$

Similarly, the separation from the negative ideal solution is given as

$$d_j^- = \left\{\sum_{i=1}^{n} \left(v_{ij} - v_i^-\right)^2\right\}^{\frac{1}{2}}, \quad j = 1, \dots, m.$$

(5) Calculate the relative closeness to the ideal solution. The relative closeness of the alternative A_j with respect to A^+ is defined as

$$R_j = d_j^- / \left(d_j^+ + d_j^-\right), \quad j = 1, \dots, m.$$

Since $d_j^- \geq 0$ and $d_j^+ \geq 0$, then, clearly, $R_j \in [0,1]$.

(6) Rank the preference order. For ranking DMUs using this index, we can rank DMUs in decreasing order.

However; in this paper TOPSIS is only applied for ranking wells with same treatment as described in third step. For second step Schlumberger table is used.

In third step, all wells with same treatment are ranked by TOPSIS method. For instance, if well-based IOR treatment of five wells is ESP, by using TOPSIS method these wells are prioritized.

In fourth step, conceptual modeling identifies the quantity of production increase using well-based IOR. To meet this goal; well modeling (PROSPER), conceptual reservoir modeling (MBAL) and production network (GAP) are used.

In last step, Portfolio management is performed in which projects are evaluated, selected and prioritized; existing projects may be accelerated, killed or de-prioritized; and resources are allocated and re-allocated to active projects [11]. In this study each well under specific well-based IOR is a project which should be evaluated in portfolio process to allocate or not allocate money as resource for implementing the well-based IOR. Therefore, the amount of assigned investment has a major impact in preparing well package under well-based IOR method.

The novelty of this study is application of new method along with implementation of the five steps which can guarantee the maximum economic benefit of determined investment to improve oil recovery using well-based methods. Application of Methodology in a case study

Step (1) Identification of cause of Production Problem

Reservoir Pressure Decline leading to lifting problem

The wells under study have lifting problem due to reservoir pressure decline.

Fig. (2) shows static pressure of reservoir which has reduced from more than 5000 psi to approximately 4350 psi in average.

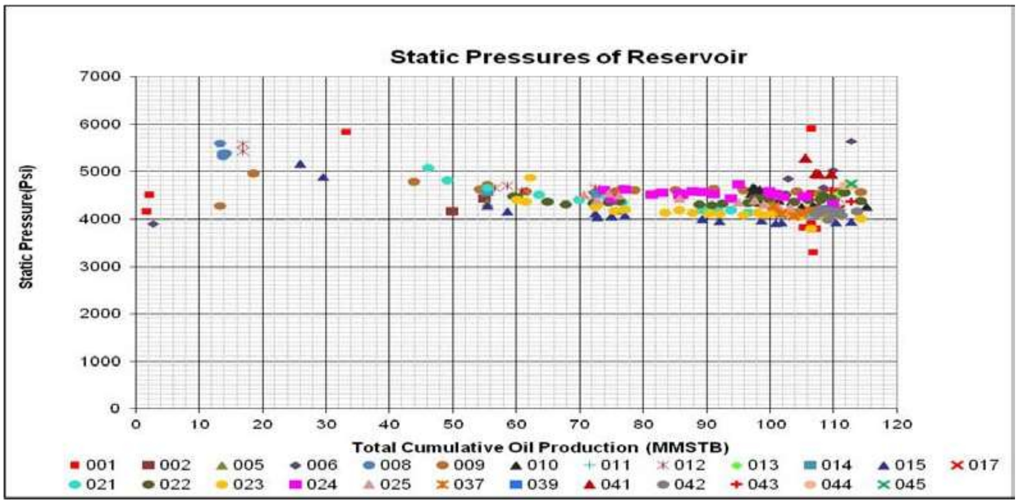

Fig. (2) Static Pressure of Reservoir

Fig. (3) shows the daily production of reservoir with number of wells in it's below. There are some points extracted from this figure:

1- In earlier years despite less number of producing wells the daily production is more than that of in last years
2- Once the daily production has decreased the responsible company has drilled new wells to compensate production reduction
3- The number of active wells has decreased in some periods. It shows that some wells have encountered production problem.
4- After year of 1385 (solar date) although the number of active wells has increased to 20 wells the daily production has not reached 25 MSTB/d. It means that strategy of drilling new wells is not generally helpful. The company should think of new fast production enhancement method along with new full field study and master development plan.

Fig. (3) Total Daily Rate and No. of Producing Wells in Each year of Reservoir

Regarding to point number 3 in above; by investigation of problematic wells' documents it was observed that the company supposed the wells have water production problem due to coning and downhole pressure drop due to reservoir pressure decline. This supposition leaded the company to performed several plugging and acidizing operation to improve Inflow Performance Relationship curve. Fig. (3) tells us these operations have not been successful as expected.

By checking related data as petrophysic log, static and flowing pressure profile in well column, vertical and horizontal distance of production interval from water oil contact (this reservoir has aquifer with edge water mechanism), fracturing distribution within reservoir, water and oil production behavior and performed operation in the wells and other related data; it is concluded that the observed water is due to previous acidizing or drilling operation which has not been cleaned properly leading to be one cause of lifting problems.

To overcome the problem due to reservoir pressure decline there are three choices:

1- Preparing master development plan to apply an EOR method.
2- Applying well- based IOR method such as artificial lift, hydraulic fracturing, acidizing and etc.
3- Performing above two choices in parallel.

The third choice is the best one. Master development plan preparation has its own process and is not in scope of this paper. We want to apply the previously mentioned methodology on second choice.

Step (2) Proposing Well Based IOR Treatment for Each Well

Amongst well- based IOR methods; artificial lift methods are faster with the lowest uncertainty. Operation history in the field shows that acidizing operation does not have favourite results; hydraulic fracturing has uncertainty related to direction of fracturing due to lack of geomechanic study. Application of new drilling technology has its problems and uncertainty.

Artificial lift has five main methods as Rod pump, Progressing cavity pump, Hydraulic pump, Gas lift and Electric submersible pump. The question is which of these methods is suitable for the wells. Schlumberger has published a document to enable production experts to find appropriate artificial method for their wells. Table (1) shows the prioritization of artificial methods based on different criteria.

Table (1) Schlumberger Table-Artificial Lifting Selection Related Parameters (1=Good to Excellent, 2= Fair to Good, 3= Not Recommended or Poor)

Condition	Specific	ESP	Gas Lifting	Hydraulic Pump		PCP	Beam Pump
Production, Reservoir and Well Constraints				Other	Jet		
No. of wells	Single	1	3	2	2	1	1
	More than 1	1	2	1	1	1	1
Production rate	Less than 1000 B/D	2	2	1	1	1	1
	1000 to 10000 B/D	1	1	2	2	2	2
	More than 10000 B/D	1	1	3	3	3	3
Depth of the Well	less than 2500 ft	2	2	2	2	1	1
	2500 to 7500ft	1	1	2	2	2	2
	More than 7500 ft	1	1	1	1	3	2
Casing Diameter	4 1/2 in.	2	2	1	1	1	1
	7 in.	1	1	2	2	2	2
	>9 5/8 in.	1	1	2	2	3	2
well deviation	directional	1	1	2	2	3	2
	horizontal	1	1	2	2	3	2
dogleg severity	per 100 ft 3 to 10°	1	1	1	1	2	2
	More than 10° per 100 ft	2	1	1	1	3	3
temperature	250 to 350°F	1	1	1	1	3	1
	more than 350°F	2	1	1	1	3	1
safety barriers	1	1	1	2	2	1	1
	2	2	1	3	3	3	3
Flowing Pressure	100 to 1000 psi	1	2	1	1	1	1
	Less than 100 psi	1	3	1	2	1	1
Reservoir Availability		2	1	3	3	3	3
Completion	Simple	1	1	1	1	1	1
	Dual or Multiple Zone	2	1	3	3	2	3
Stability	variable	2	1	1	1	1	1
Recovery	secondary(Water injection)	1	3	2	2	1	1
	tertiary	2	2	2	2	2	2
[illegible]							
Water Production	low	1	1	2	2	1	1
	mean	1	2	1	1	1	1
	high	1	3	1	1	1	1
Fluid Viscosity	more than 100 cp	3	2	2	2	1	1
Corrosive Fluid	yes	2	1	2	2	2	2
Sand and abrasive material	10 to 100 ppm	2	1	2	2	1	2
	more than 100 ppm	3	1	3	3	1	3
GOR	less than 500 scf/STB	1	2	1	1	1	1
	500 to 2000 scf/STB	1	1	2	2	2	2
	More than 2000 scf/STB	2	1	2	2	2	3
VLR (Vapor Liquid ration)	Less than 0.1	1	2	1	1	1	1
	0.1 to 1	2	1	2	2	2	2
	more than 1	2	1	2	3	2	2
Polluting material	scale	2	1	2	2	1	2
	Paraffin	2	2	2	2	1	2
	Asphaltene	2	2	2	2	1	2
Treatment	Scale inhibitor	2	1	1	1	2	1
	Corrosion inhibitor	2	1	1	1	2	1
	Solvent	2	1	1	1	3	1
	Acid	2	1	2	2	2	2
[illegible]							
Location	Off shore	1	1	2	2	2	3
	Remote area	1	2	2	2	1	2
	environmentally sensitive area	1	2	2	2	2	2
Electricity Power	Utility	1	1	1	1	1	1
	Generation	2	1	1	1	2	2
Spatial Limitation	Yes	1	2	2	2	2	3
Well service	Coiled tubing unit	2	1	1	1	3	3
	Snubbing unit	2	1	1	1	3	3
	Wireline	3	1	1	1	3	3

The scope of this paper is to prescribe suitable solutions for wells numbers of 2, 3, 4, 5, 6, 9, 10, 14, 15, 18, 19, 21, 23, 25, 37, 39, 41, 43, 44 and 45.

The wells' specifications were compared with schlumberger table (2) and following result was output. It is noted that since all wells belong to one reservoir no comparisons were performed under red color criteria.

Table (2) Prioritization of Artificial Lift Solutions for each well

Well No.	Prioritization of Artificial Lift Solutions
2	ESP, Gas lifting, PCP
3	PCP, ESP, Gas Lifting
4	ESP, Gas lifting
5	PCP, ESP, Gas Lifting
6	ESP, PCP, Gas lifting
9	ESP
10	PCP, ESP
14	ESP, PCP, Gas lifting
15	ESP, Gas lifting
18	ESP, PCP, Gas lifting
19	ESP, PCP, Gas lifting
21	ESP, PCP, Gas lifting
23	ESP
25	ESP
37	PCP, ESP
39	ESP, PCP, Gas lifting
41	PCP, ESP
43	ESP, PCP, Gas lifting
44	ESP, PCP, Gas lifting
45	ESP, Gas lifting

The main solution for most wells is application of Electric Submersible Pump.

Step (3) Prioritization of Wells under well-based IOR treatment-ESP

Due to limitation in budget it is needed to prioritize wells under the best solution. As previously mentioned to do this prioritization it is necessary to apply a method. Here multi criteria decision making method (MCDM) is used to meet the goal. The best method under MCDM fitted this problem is TOPSIS as described in previous section. The main criteria and their effects on prioritization are summarized in Table (3).

Before applying TOPSIS; effectiveness weight of criteria on prioritization should be clear by using MCDM such as Analytical Hierarchy Process (AHP) to use it in TOPSIS calculations. However; here we simply accept 10 % weight for each criterion.

Table (3) Criteria and their influence in Wells' Prioritization for Application of ESP

Criteria	Description	Effect on Prioritization	Weight of Effectiveness (%)
last WHP (psi)	More	Good candidate for ESP	10
Last Production (STB/D)	More	Good candidate for ESP	10
MAX Production (STB/D)	More	Good candidate for ESP	10
Discrepancy between Max Production and Last Production	Less	Good candidate for ESP	10
Cumulative Production (MMSTB)	Less	Good candidate for ESP	10
Production Duration (Year)	Less	Good candidate for ESP	10
Type of Well	More Deviated	Good candidate for ESP	10
Type of Completion	Long Tubing	Good candidate for ESP	10
Relative Horizontal Distance to WOC	More	Good candidate for ESP	10
Relative Vertical Distance to WOC	More	Good candidate for ESP	10

Table (4) Well Specification to use in TOPSIS

Wells	last WHP (psi)	Last Production (STB/D)	MAX Production (STB/D)	Discrepancy between Max Production and Last Production (STB/D)	Cumulative Production (MMSTB)	Production Duration (Year)	Type of Well	Type of Completion	Relative Horizontal Distance to WOC	Relative Vertical Distance to WOC (m)
2	271	1500	5330	3830	19.25	19.17	V	Tubing (long)	2.2	173
3	364	700	2788	2088	8.66	16.75	V	Tubing (long)	1.75	93
4	372	1200	4397	3197	12.54	17.92	V	Tubing (long)	2.4	156.6
5	251	100	4127	4027	12.9	18.00	V	Tubing (long)	1.9	160.8
6	625	1500	1500	0	0.58	1.67	V	Casing	1.4	80
9	351	200	3390	3190	3.07	15.75	D (37.5 deg)	Casing	2.15	103
10	298	600	970	370	0.74	3.92	V	Casing	1	122
14	329	1300	3161	1861	7.42	14.58	V	Tubing (long)	2.6	168
15	376	1300	4520	3220	10.6	14.00	H	Casing	2.75	190
18	297	200	1655	1455	3.27	13.33	V	Tubing (long)	2.5	204
19	501	300	1294	994	1.45	11.83	V	Tubing (long)	2.7	179
21	446	900	2040	1140	4.78	11.67	H	Casing	2	163
23	361	580	1270	690	1.15	9.75	D (64 deg)	Casing	2.2	180.5
25	335	400	1000	600	1.92	9.75	D (60 deg)	Casing	2.2	116
37	408	700	1000	300	0.86	3.17	V	Tubing (Medium)	2.2	155
39	497	1100	1100	0	0.98	2.67	V	Tubing (Medium)	2.5	122
41	768	1000	1000	0	0.73	2.00	V	Tubing (Medium)	2	75
43	496	1200	1200	0	0.45	1.08	V	Tubing (Medium)	2.1	115
44	603	2100	2100	0	0.53	0.67	D (16.26 deg)	Tubing (Medium)	1.8	68
45	681	1450	1450	0	0.1	0.25	H	Tubing (Medium)	2.8	124

After implementing TOPSIS method following prioritization is resulted;

Wells	Weight in Prioritization
45	0.690
44	0.663
43	0.609
39	0.600
23	0.592
6	0.590
37	0.581
21	0.580
41	0.565
25	0.563
10	0.550
19	0.529
14	0.526
15	0.521
18	0.511
9	0.468
3	0.426
4	0.423
2	0.398
5	0.355

Step (4) Conceptual Modeling and Economic Evaluation

In this step it is needed to model both current situation of reservoir and wells as base case and with ESP. Table (5) shows specification of wells with and without ESP. Reservoir pressure is different due to poor quality of reservoir rock.

Table (5) Well Specification with and without ESP

Well	Reservoir Pressure	PI	Completion Before ESP Installation	Tubing Required for ESP	Designed Rate	Tubing Extra
2	4450	2	Casing	2200 (4.5")	3000	-
3	4550	2	Tubing (4.5"*2 7/8")-3398m	2200(4.5"*2 7/8")	3000	1198 (2 7/8")
4	4500	2	Tubing (4.5"*2 7/8")-3314m	2200(4.5"*2 7/8")	3000	1114 (2 7/8")
5	4450	2.2	Tubing (4.5"*2 7/8")-3257m	2200 (4.5"*2 7/8")	3000	418 (2 7/8") and 639 (4.5")
6	5100	1.5	Casing	2200 (4.5")	3000	-
9	4550	1.76	Casing	2450 (4.5")	3000	-
10	4300	0.7	Casing	2500 (4.5")	1100	-
14	4150	2.2	Tubing (5"*4.5")-3165m	2350 (5"*4.5")	3000	815 (4.5")
15	3950	2.2	Casing	2450 (4.5")	3000	-
18	4150	2.2	Tubing (4.5")-3132m	2350(4.5")	3000	782 (4.5")

Well	Reservoir Pressure	PI	Completion Before ESP Installation	Tubing Required for ESP	Designed Rate	Tubing Extra
19	4150	2.2	Tubing (4.5")-3150m	2350(4.5")	3000	800 (4.5")
21	4150	2.6	Casing	2200 (4.5")	3000	-
23	4150	1.27	Casing	2500 (4.5")	2000	-
25	4250	2.08	Casing	2350 (4.5")	3000	-
37	4150	2.2	Tubing (4.5")-1505.3m	2350 (4.5")	3000	844.7(4.5")
39	4150	2.05	Tubing (4.5")-1517.5m	2300 (4.5")	2500	782.5(4.5")
41	5100	1.76	Tubing (4.5")-1502m	1950 (4.5")	3000	448(4.5")
43	4500	2	Tubing (4.5")-1505m	2200 (4.5")	3000	695(4.5")
44	4550	2	Tubing (4.5")-1498m	2200 (4.5")	3000	702(4.5")
45	4750	2	Tubing (4.5")-1506m	2200 (4.5")	3000	694(4.5")

Four scenarios are defined based on budget allocation as:

1) Five first ranked wells with ESP and others are without ESP.
2) Ten first ranked wells with ESP and others are without ESP .

3) 15 first ranked wells with ESP and others are without ESP.
4) All well with ESP.

Fig. (4-6) show production network of these scenarios. Separator pressure is 350 psi and simulation run duration is si years. Minimum abandonment rate of wells is 100 STB/d. Minimum bottom hole pressure for ESP wells is 1800 psi (more than bubble point pressure) and maximum rate of these wells is 3000 STB/d.

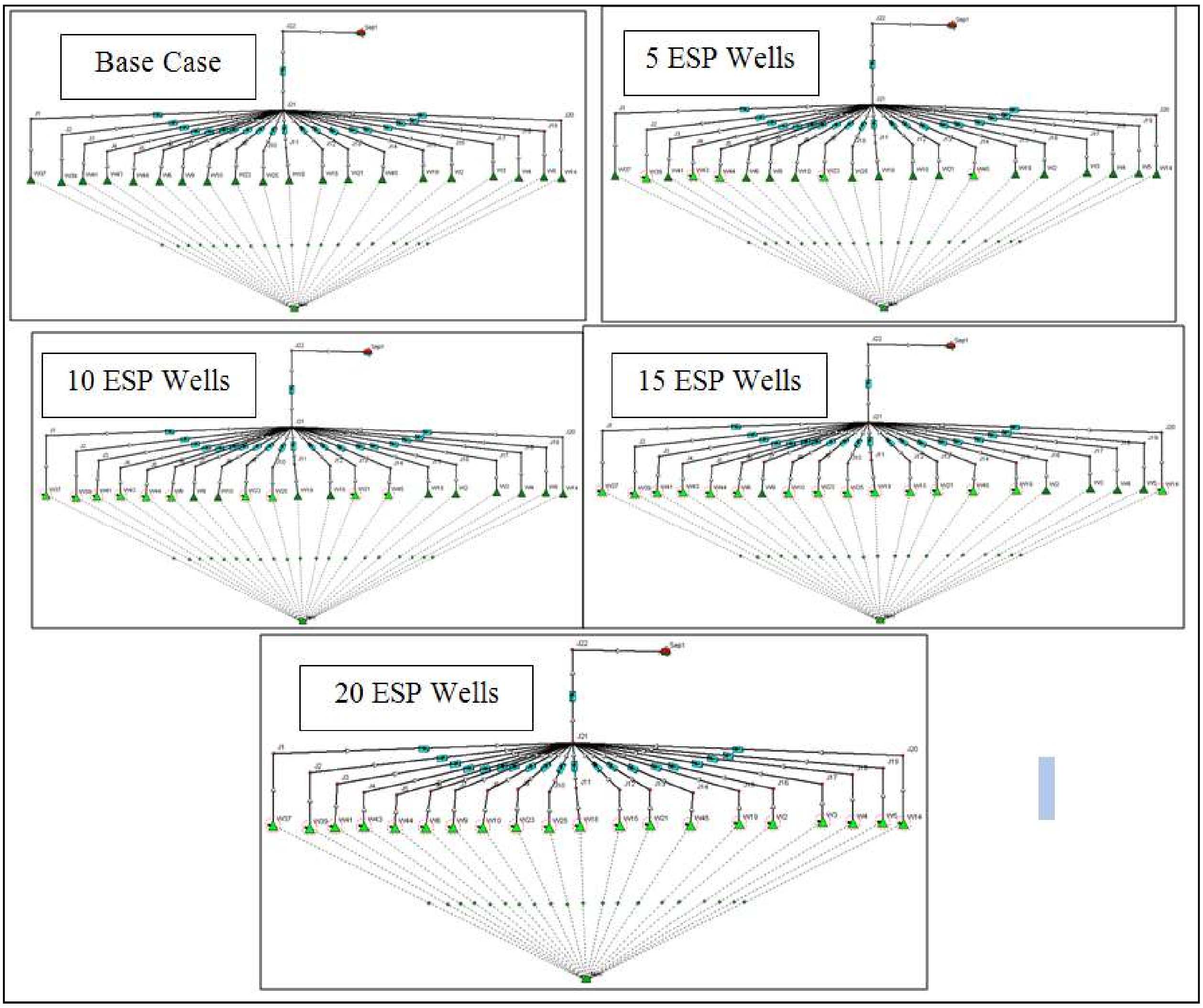

Fig. (4) Four Scenarios for ESP Application based of Prioritization of Wells

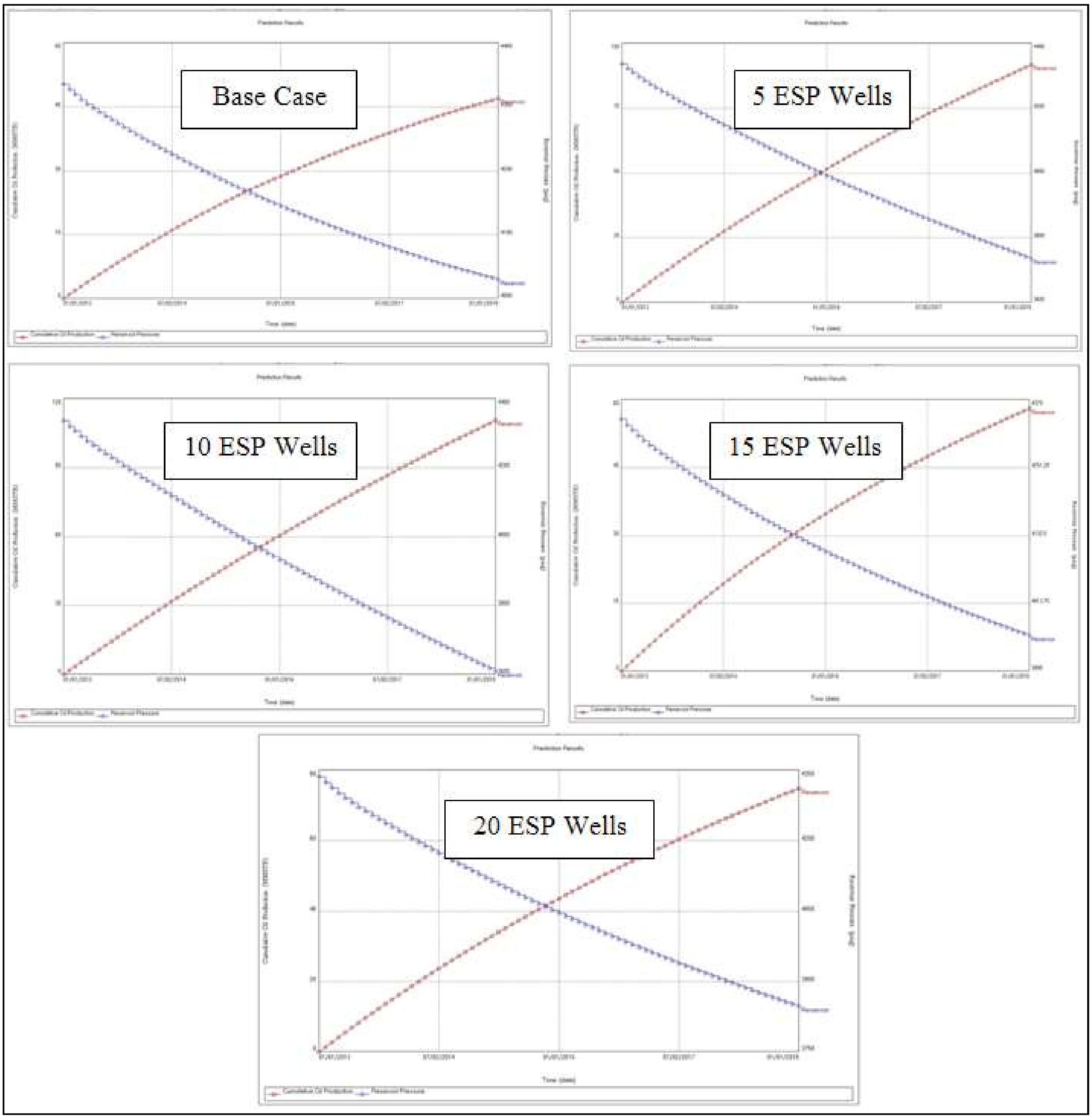

Fig. (5) Result of Four Scenarios of ESP Application

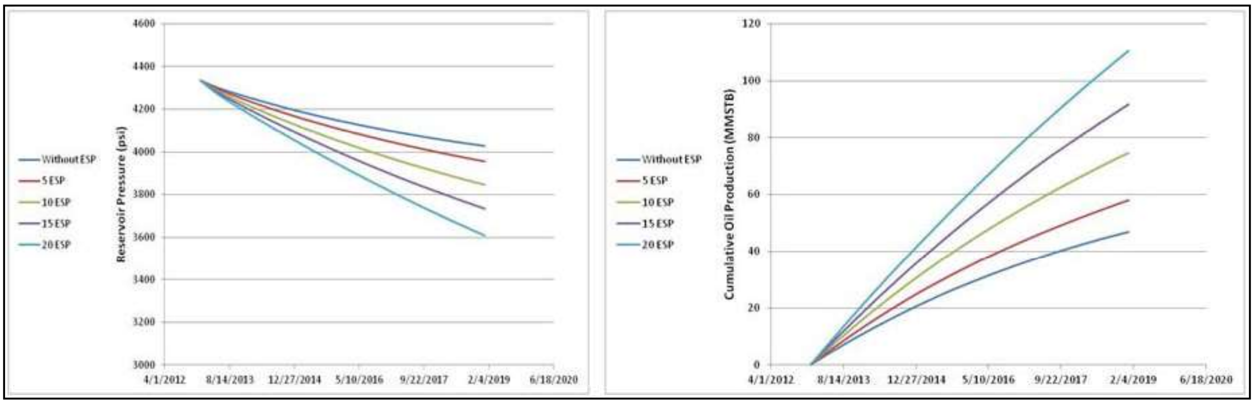

Fig. (6) Reservoir Pressure and Cumulative Production of Four Scenarios

Economic Evaluation

Based on simulation result economic evaluation is performed see table (6).

Table (6) Economic Evaluation of Four Scenarios

No of ESP wells	Cumulative Production (MMSTB)	ESP and equipment per well (MUS$)	Rig time and work-over cost per well (MUS$)	Number of Workover for Changing ESP within 6 years
0	46.902	800	700	3
5	57.941	800	700	3
10	74.687	800	700	3
15	91.648	800	700	3
20	110.438	800	700	3

Number of Workover for ESP Overhaul within 6 years	CAPEX Estimate of Subsurface Development (MMUS$)	Oil Price	Revenue (MMUS$)	NPV (MMUS$)	
				Total	Added (ESP)
9	0	100	4690.2	4690.2	0
9	54	100	5794.1	5740.1	1049.9
9	108	100	7468.7	7360.7	2670.5
9	162	100	9164.8	9002.8	4312.6
9	216	100	11043.8	10827.8	6137.6

Step (5) Portfolio optimization of well-based IOR

Based on prioritization of wells and amount of investment; the number of wells that should be equipped with ESP is realized. For example if 54 MMUS$ is the only budget the first five wells in prioritization should be equipped with ESP.

Conclusion

Following conclusion can be obtained from this study:

- By applying multi criteria decision making methods such as TOPSIS; management process of assets is very fast
- Well-based IOR treatment should be taken into account as long as reservoir studies are being performed
- Optimum investment of limited budget needs a scientific process; in this study there are 20 wells in the same field. One can say that by modeling of these wells it is possible to prioritize them. If there are 100 wells from different fields with limited budget it is time consuming to model all fields and wells. Multi criteria decision making methods are very helpful and fast.

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