SELECTION OF ARTIFICIAL LIFT SYSTEMS BASED ON ECONOMIC CRITERIA

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Abstract

Selecting the most optimum artificial lift system for a well is currently a major challenge. Considering the location, depth, estimated rate, the reservoir properties and other factors, one of the most important criteria in selecting the artificial lift method is the economic criterion. This study will take a look at the Net Present Value method considered when selecting an artificial lift method for a certain well. This method consists in determining all foreseeable proceeds and payments related to every period of time and the updating thereof throughout the duration of investment operation, in order to ensure comparability with the investment performed in the present.

Key words: Artificial lift, ESP, Rod pumping, Net Present Value method.

1. Introduction

The process of selecting and applying an artificial lift system is very complex. This requires attention and an in-depth knowledge, on the part of the production engineer or the operator, of the well's potential as well as of the geographical and environmental conditions that might cause major issues. Also, factors such as the location and installation surface, depth, estimated rate, reservoir and fluids properties, flexibility, efficiency and other factors should be taken into account. Besides the aforementioned factors, it is necessary that the choice over the specific artificial lift system satisfy also certain economic criteria.

Wells producing heavy crude oils and having high flow rate shall be completed with hydraulic pumping because the power fluid lowers viscosity and friction losses when mixed with heavy crude oil. On the other hand, the ESP (*Electrical Submersible Pumping*) system has a low efficiency when lifting heavy crude oils, because the lifting of this kind of oils requires a high power, which may result in motor overheating. The economic factors included in operational costs and capital investments are very important in selecting the artificial lift methods.

Capital investments include the cost of initial installation and the specific completion of the artificial lift systems (for example the compressors in the case of gas-lift system). Operational costs include energy costs required for system operation, the costs related to repair and the replacement of system components.

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The "Net Present Value" (NPV) used by Lea and Nicksen [3] is a good method in selecting artificial lift methods based on economic criteria.

In economic terms, this method depends on costs related to the artificial lift methods throughout the operational period. These costs depend on the price of the crude oil barrel, maintenance costs, inflation rates and anticipated profit obtained from oil and gas production, etc. In this study, the (NPV) method has been used in order to select the artificial lift method, and the obtained results have confirmed the opinions of authors Lea and Nicksen.

2. Selecting the artificial lift system

In order to take advantage of the maximum potential of a crude oil/gas reservoir, it is necessary to select the optimum artificial lift method for each well from the reservoir complying with all technical and economic criteria. Throughout time, the methods for selecting the artificial lift systems for the wells exploiting an oil reservoir have varied greatly, each company suggesting the most appropriate method by considering criteria such as:

- Well depth, flexibility of the artificial lift system, the surface installation, type of crude oil, water cut, and other operational issues;
- Determining the methods considering their advantages and disadvantages;
- The use of new software enabling the selecting of the most adequate method;
- The use of the economic criterion for selecting the artificial lift systems (CAPEX, OPEX, etc.).

Table 1 contains a classification of certain criteria that may be deemed important for selecting the artificial lift systems.

3. The Net Present Value (NPV) method

The Net Present Value method depends on the operational costs of the artificial lift methods throughout the length of operation.

Table 1 *Artificial lift systems comparisons [1,2,4,6]*

Criterion \ System		Rod Pumping	Gas lift		ESP	PCP	Hydraulic Pumping	
			Contin.	Interm.			Piston	Jet
Depth		Low & Average	No limits		No limits	Low & Average	No limits	
Operational duration		High	High		Medium	High	Low	Medium
Flexibility		Very Good	Very Good	Limited	Poor	Poor	Good	Average
Surface installation		Medium	Large		Medium	Small	Large	
Heavy crude oils		Good - Poor	Poor - Excellent		Poor	Average - Poor	Good - Excellent	
Water cut		Very Good	Poor - Average		Very Good	Very Good	Very Good	
Operating problems	**Sand problems**	Not recommended	Very Good		Poor	Very Good	Average - Poor	
	Paraffin	Average	Poor		Poor	Poor	Average - Good	
	Corrosion	Good - Very Good	Very Good		Average - Poor	Average - Poor	Good - Very Good	
	Reservoir Temp.	Good	High		Limited	Average - Good	Very Good	
	Free gas effect	Medium	Very Good		Poor	Average	Average - Good	
	Treatments applied	Many	Little		Very much	Many	Medium	
	Electrical power	Could be used	Not needed		Required	Required	Could be used	
	Gas source	Could be used	Required		Not needed	Not needed	Not needed	

These costs are conditional upon the price of the crude oil barrel, maintenance costs, inflation rates, anticipated profit, etc.

So as to apply the NPV method, the operator must know the advantages and disadvantages of the artificial lift systems and must estimate very well the associated costs of each system, inclusively of the additional equipment (*i.e.* additional costs) that might be required.

To illustrate the application of NPV method let us consider two wells with the following data:

- Well 1 with low rate q_l = 375 (bbl/d), Water cut WC = 60 (%), Depth H = 2070 (m), Viscosity μ = 7,78 (cP) and it's located in Desert-like unpopulated area (Onshore).
- Well 2 with high rate q_l = 1900 (bbl/d), Water cut WC = 7 (%), Depth H = 2300 (m), Viscosity μ = 7,78 (cP) and it's located in Desert-like unpopulated area (Onshore).

There are common costs and economic variables that must be considered too (they are all the same for all different systems):

- Fixed Costs 300 $/Month;
- Fluid Disposal 0,35 $/bbl water;
- Electricity* 1 kw/h = 0,3$;
- Oil revenue 50 $/Barrel;
- Natural Gas revenue 3 $/Mscf;
- Inflation Rate* 2,4 %/year;
- Discount percentage* 9,52 %/year;
- Oil production decline rate 20 %/year;
- Oil revenue increase 1 %/year;
- Royalty* 16,67%.

* - Data of Libya.

The authors have put together a calculation algorithm to determine the updated net present value based on which the data concerning both wells have been processed. In order to get accurate and extremely precise results, the fluid rate must be introduced in barrels and the price in US dollars.

The initial investment differs from one method to another, but for the NPV method application the same value is taken into account for all artificial lift methods. The artificial lift methods require various installations and different installation costs; Table 10 shows the costs related to the used methods.

The operational duration of the components of the artificial lift systems is very important to estimate. For example, if a pump in the ESP system has operation duration of 5 years, and the well may still be productive for up to 15 years, then the price of the new pump must be added after installing it in the system. The NPV method compares the artificial lift systems by calculating the cumulated NPV profit depending on the period in which the production flow rate decreases until abandonment value. This offers a direct comparison among artificial lift systems as concerns the expected net profit obtained from the production of a well.

The economic calculation equations for selecting the artificial lift methods in terms of economic analysis are the following:

- Initial Oil Rate, (bbl/y):

$$q_{oi} = 365{,}25 \cdot q_o \cdot \mathbf{WC} \qquad (1)$$

where: q_o is oil rate.

- Abandonment Oil Rate, (bbl/y) [5,7]:

$$q_{o\,aband} = 365{,}25 \cdot q_{aband} \cdot WC_{aband} \qquad (2)$$

where:

q_{aband} is abandonment rate;

WC_{aband} - abandonment water cut at q_{aband}.

- Decline Rate:

$$R_{decl} = \frac{\textbf{Oil prod. Decline rate}}{\mathbf{100}} \qquad (3)$$

- Years to Abandonment [5]:

$$Y_{aband} = -\frac{\left(\ln[(q_{oi})] - \ln[(q_{o\,aband})]\right)}{\ln(1 - R_{decl})} \qquad (4)$$

Initialize at Year 0

- $q_{o(0)} = \dfrac{q_{oi}}{365{,}25}$, (bbl/d),
- $WC_{(0)} = WC$,
- $GOR_{(0)} = GOR$,
- $Cumulative\ NPV_{(0)} = \mathbf{0}$,
- $Cumulative\ Oil_{(0)} = \mathbf{0}$.

where:

GOR stands for Gas/oil Ratio.

- Calculate production decline factor:

$$R = \ln(1 - R_{decl}) \qquad (5)$$

The algorithm for the calculus of costs and present value up to the abandonment year is illustrated below:

For the first year, I = 1,

- Calculate daily production rate at end of year I, (bbl/d):

$$q_{o(I)} = q_{o(0)} \cdot Exp(R \cdot I) \qquad (6)$$

- Calculate maximum production for year I for full production I, (bbl/d):

$$q_{max(I)} = \frac{365{,}25 \cdot (q_{o(I)} - q_{o(I-1)})}{R} \qquad (7)$$

- Adjust for lost production, (bbl/d):

$$q_{o(I)} = q_{max(I)} - \left(\frac{q_{max(I)}}{365{,}25}\right) \cdot wo_d \cdot w_y \qquad (8)$$

where:

wo_D stands for workover operations per day;

w_y - number of intervention per year.

- Calculate cumulative oil produced to end of year I:

$$Cum_{o(I)} = Cum_{o(I-1)} + q_{o(I)} \qquad (9)$$

- Calculate water cuts and gas/oil ratio:

$$WC_{(I)} = WC_{(0)} + I \cdot \frac{[(WC]_{aband} - WC)}{Y_{aband}} \qquad (10)$$

$$GOR_{(I)} = GOR_{(0)} + I \cdot \frac{[(GOR]_{aband} - GOR)}{Y_{aband}} \qquad (11)$$

where:

GOR_{aband} stands for gas/oil ratio at q_{aband}.

- Calculate water and gas rates for Year I:

$$q_{w(I)} = q_{o(I)} \cdot \frac{WC_{(I)}}{(1 - WC_{(I)})} \qquad (12)$$

$$q_{g(I)} = \mathbf{10^{-3}} \cdot q_{o(I)} \cdot GOR_{(I)} \qquad (13)$$

- Calculate required cost and revenue factors as follows:

- $$R_{inflation} = \left(\frac{1 + R_{inf}}{100}\right)^{I-0{,}5} \qquad (14)$$

where:

R_{inf} stands for inflation rate.

- $$R_{discount} = \left(\frac{1 + P_{disc}}{100}\right)^{I-0{,}5} \qquad (15)$$

where:

P_{disc} stands for discount percentage.

- $$R_{barrel} = \left(\frac{1 + P_{bp}}{100}\right)^{I-0{,}5} \qquad (16)$$

where:

P_{bp} stands for oil revenue increase percentage.

- $$R_{equipment} = \left(\frac{1 + P_e}{100}\right)^{I-0{,}5} \qquad (17)$$

where:

P_e stands for equipments cost.

- $$R_{elec} = 24 \cdot \frac{kw}{q_l} \cdot P_{kw} \qquad (18)$$

where:

P_{kw} - electricity price per kilowatt.

- Calculate fluid disposal costs:

$$F_{c\,(I)} = R_{inflation} \cdot F_{dc} \cdot (q_{o(I)} + q_{w(I)}) \qquad (19)$$

where:

F_{dc} stands for fluid disposal cost.

- Calculated fixed operating cost:

$$c_1(f(I)) = R_1 inflation \cdot \mathbf{12} \cdot (cc + c_1 lift \qquad (20)$$

where:

cc represents common fixed cost;

c_{lift} – artificial lift system specific fixed cost.

- Calculate workover cost:

$$c_{wo\,(I)} = R_{inflation} \cdot wo_D \cdot w_y \qquad (21)$$

- Calculate completion cost:

$$c_{e\,(I)} = c_{e\,(I-1)} \qquad (22)$$

Completion costs are calculated by adding up all components of the used system. Tables 6, 7, 8 and 9 mention the equipment and their prices and, most importantly, the operation duration.

If one or several components of the system reach their operational limit, then they shall be replaced by other components (J) and the costs of the equipment is recalculated in the respective year as follows:

$$c_{e\,(I)} = c_{e\,(I)} + R_{equipment} \cdot c_{e}\,(J) \tag{23}$$

- Calculate electricity cost:

$$c_I(elec(I)) = R_I inflation \cdot R_I elec \cdot (q_I o(I) + q_I w(I)) \tag{24}$$

- Calculate total costs for Year I:

$$c_{T(I)} = F_{c\,(I)} + c_{f\,(I)} + c_{wo\,(I)} + c_{e\,(I)} + c_{elec(I)} \tag{25}$$

- Calculate total income for Year I:

$$T_{i(I)} = R_{barrel} \cdot \left(\frac{1 - Royalty}{100}\right) \cdot q_{o(I)} \cdot P_b + q_{g(I)} \cdot P_g \tag{26}$$

where:

P_b stands for price of oil;

P_g - price of natural gas.

- Calculate NPV from Year I:

$$\mathbf{NPV}_{(I)} = \frac{T_{i(I)} - c_{T(I)}}{R_{discount}} \tag{27}$$

- Calculate cumulative NPV from Year I-1 to Year I:

$$Cumulative\,\mathbf{NPV}_{(I)} = Cumulative\,\mathbf{NPV}_{(I-1)} + \mathbf{NPV}_{(I)} \tag{28}$$

4. Results and Discussions

Calculations results are included in Tables 2 and 3. Lea and Nicksen [3] have concluded, in their work, that wells with low rates have high operational costs (14-26%). This has been noticed also in the case low rates of the well analysed in this study. Table 2 shows that, in this case, operational costs are higher and vary between 30-62%). Therefore, the reduction of operational costs may be a significant factor in selecting the optimum artificial lift method in the situation of wells with low rates. In the case of the well with high or average rates, operational costs are low as compared with the profit realised from well production. Lea and Nicksen gave an example of a well with high rate (17,000 bbl/d) and have applied the NPV method in the case of three artificial lift systems ESP, hydraulic jet pumping and gas lift (rod pumping was excluded).

Their results and the results presented in Table 3 have confirmed that these operational costs for wells with high or average rates do not represent an important factor in selecting the optimum artificial lift method.

Costs varied between (1.6-2%) according to Lea and Nicksen, and between (4-6%) according to the results shown in Table 3.

In order to select the most optimum artificial lift method, the criteria mentioned in Table 1 must also be taken into account.

Hence, further to the analysis carried out at the two wells, it has resulted that:

- For Well 1 (low rate) the “rod pumping” system was used, which is the most optimum method in economic terms (Table 2) and according to the other criteria in Table 4.
- For Well 2 (high rate), the "ESP" system was chosen, having an optimum method economically speaking (Table 3) as well as in accordance with all other criteria set forth in Table 5.

Table 2 *Results of the calculations using the NPV method for Well 1 (low rate)*

Method	P_b, $	$, mil.	Cost $, mil.	Cost/NPV
ESP	50	2,24	0,78	35%
Gas lift	50	1,8	0,8	44%
Rod pumping	50	2,24	0,67	30%
Hydraulic pumping	50	2,11	1,3	62%

Table 3 *Results of the calculations obtained by the NPV method for Well 2 (high rate)*

Method	P_b, $	$, mil.	Cost $, mil.	Cost/NPV
ESP	50	58,30	2,4	4%
Gas lift	50	55,60	3,43	6%
Hydraulic pumping	50	53,30	2,9	5%

Table 4 *Selecting the artificial lift method for Well 1*

Criterion	Well data	Rod pumping
Depth	2070 m	Recommended for average or low depths
Viscosity	7,78 cP	A good method for low viscosities
Water cut	33% - 97%	Good operation regardless of the water cut
Surface installation	Desert-like unpopulated area	Favourable

Table 5 *Selecting the artificial lift method for Well 2*

Criterion	Well data	ESP
Depth	2300 m	No limits
Viscosity	7,78 cP	Good results for low viscosity
Water cut	7% - 90%	Good operation regardless of the water cut
Surface installation	Desert-like unpopulated area	Favourable

Table 6 *Price of rod pumping equipment [3]*

Equipment	Price, $	Operation duration, (years)
Tubing	80.000	15
Rods	20.000	4
Pump	6.000	Depending on manufacturer

Table 7 *Price of equipment on the ESP system [3]*

Equipment	Price, $	Operation duration, (years)
Tubing	80.000	15
Pump	25.000	Depending on manufacturer
Protector	4.000	Depending on manufacturer
Gas separator	5.000	Depending on manufacturer
Motor	15.000	Depending on manufacturer
Electric cable	50.000	6

Table 8 *Price of equipment on the hydraulic pumping system [3]*

Equipment	Price, $	Operation duration, (year)
Tubing	80.000	15
Pump	20.000	Depending on manufacturer

Table 9 *Price of equipment on gas lift system [3]*

Equipment	Price, $	Operation duration, (years)
Tubing	80.000	15
Valve	2.000	3
Mandrel	5.000	10

Table 10 *Expenses related to every artificial lift method considered separately [3]*

	Rod pumping	Hydraulic pumping	Gas lift	ESP
Installation, $	141.000	173.000	239.000	105.000
Workover, $/day	1.000	1.000	1.000	1.000
Wireline Cost, $/day	-	-	1.000	-
Gas injection, $/m^3	-	-	0,24	-
Maintenance cost, $/month	200	2.900	3.000 – 6.000	225

5. Conclusions

The examples used as part of the (NPV) method in this study and by Lea and Nicksen have demonstrated how to select the most adequate artificial lift method in economic terms.

These examples have also shown the necessary data allowing the production engineer to make the best choice among the various artificial lift methods and maximize the profit from well production for certain period of time or even throughout the entire operation duration of the respective well.

The reduction of operation costs for low rate wells may be a significant factor in selecting the most appropriate artificial lift method for a certain oil well.

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