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Non-linear ESP Artificial Lift by Multiple Pumps for Oil and Gas Well Development

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Abstract
An "innovative" and "groundbreaking" model is proposed for oil and gas well development, by using the "Non-linear ESP Artificial Lift Method". According to the proposed new sophisticated technology the well known ESP (Electric Submersible Pump) Artificial Lift Method will be extended to non-linear form, by adding multiple pumps. In such way, the well will be able to handle very big flow rates which could be 500,000 bpd, or even up to 1,000,000 bpd. These multiple ESP pumps are used in a definite range of pumping rates. On the other hand, if the pumps are working outside the specified range, then system efficiencies rapidly deteriorate and several mechanical problems may occur. In such case there are two possible solutions: (1) the installation of a wellhead hydraulic choke or (2) by using a variable speed drive (VSD) unit. By using the first solution the wellhead hydraulic choke restricts the pumping rate and forces the ESP pump to operate within its recommended liquid rate range. By the current research NODAL analysis is further presented in order to investigate the negative effects of surface production hydraulic chokes on the energy efficiency of ESP systems, as compared to the application of VSD drives. Consequently, a calculation model is investigated to evaluate the harmful effects of wellhead hydraulic choking and to find the proper parameters of the necessary VSD unit. So, the beneficial effects by using a VSD drive are shown. Hence, the international oil companies must be ready to face the new challenges of drilling of very big flow rates approaching 1,000,000 bpd for a single well.

Key Word and Phrases
Non-linear ESP Artificial Lift Method, Electric Submersible Pump (ESP), Wellhead Hydraulic Choke, Variable Speed Drive (VSD), Nodal Analysis, Oil & Gas Well, Energy Efficiency.

1. Introduction

Artificial lift is a process used on petroleum wells to increase pressure within the reservoir and encourage petroleum to the surface. When the natural drive energy of the reservoir is not strong enough to push the petroleum to the surface, artificial lift is employed to recover more production. While some wells contain enough pressure for oil to rise to the surface without stimulation, most don't, requiring artificial lift. In fact, 95% of the oil wells worldwide require artificial lift from the very beginning. Even those wells that initially posses natural flow to the surface, that pressure depletes over time, and artificial lift is then required. Consequently, artificial lift is generally performed on all wells at some time during their production life.

Although there are several methods to achieve artificial lift, the two main categories of artificial lift include pumping systems and gas lifts. An emerging method of artificial lift, gas lift injects compressed gas into the well to reestablish pressure, making it produce. Even when a well is flowing without artificial lift, it many times is using a natural form of gas lift. The injected gas reduces the pressure on the bottom of the well by decreasing the viscosity of the fluids in the well. This, in turn, encourages the fluids to flow more easily to the surface. Typically, the gas that is injected is recycled gas produced from the well. With very few surface units, gas lift is a good choice for offshore applications. Occurring downhole, the compressed gas is injected down the casing tubing annulus, entering the well at numerous entry points called gas-lift valves. As the gas enters the tubing at these different stages, it forms bubbles, lightens the fluids and lowers the pressure. The gas lift system has some disadvantages. There has to be a source of gas, some flow assurance problems such as hydrates can be triggered by the gas lift.

The most common type of artificial lift pump system applied is beam pumping, which engages equipment on and below the surface to increase pressure and push oil to the surface. Consisting of a sucker rod string and a sucker rod pump, beam pumps are the familiar jack pumps seen on onshore oil wells. Above the surface, the beam pumping system rocks back and forth. This is connected to a string of rods called the sucker rods, which plunge down into the wellbore. The sucker rods are connected to the sucker rod pump, which is installed as a part of the tubing string near the bottom of the well. As the beam pumping system rocks back and forth, this operates the rod string, sucker rod and sucker rod pump, which works similarly to pistons inside a cylinder. The sucker rod pump lifts the oil from the reservoir through the well to the surface. Usually pumping about 20 times a minute, the pumping units are powered electronically or via gas engine, called a prime mover. In order for the beam system to work properly, a speed reducer is employed to ensure the pump unit moves steadily, despite the 600 revolutions per minute the engine achieves.

Another artificial lift pumping system, hydraulic pumping equipment applies a downhole hydraulic pump, rather than sucker rods, which lift oil to the surface. Here, the production is forced against the pistons, causing pressure and the pistons to lift the fluids to the surface. Similar to the physics applied in waterwheels powering old-fashion gristmills, the natural energy within the well is put to work to raise the production to the surface. Hydraulic pumps are generally composed of two pistons, one above the other, which are connected by a rod that moves up and down within the pump. Both the surface hydraulic pumps and subsurface hydraulic pumps are powered by power oil, or clean oil that has been previously lifted from the well. The surface pump sends the power oil through the tubing string to the subsurface hydraulic pump installed at the bottom of the tubing string, the reservoir fluids are then sent up a second parallel tubing string to the surface. Such systems usually produce up to 20,000 bpd.

In addition the electric submersible pump systems employ a centrifugal pump below the level of the reservoir fluids. Connected to a long electric motor, the pump is composed of several impellers, or blades, that move the fluids within the well. The whole system is installed at the bottom of the tubing string. An electric cable runs the length of the well, connecting the pump to a surface source of electricity. The electric submersible pump applies artificial lift by spinning the impellers on the pump shaft, putting pressure on the surrounding fluids and forcing them to the surface. A mass producer, electric submersible pumps can lift up to 90,000 barrels of fluids per day.

On the other hand, the energy demand for oil and gas will increase up to 2030 by 50-60%, as it is increasing worldwide yearly at a pace of 1.5 to 2.0%. Consequently, for the on-shore and off-shore oil and gas reserves exploration was proposed by E.G.Ladopoulos [1]-[15] the new theory of *"Non-linear Real-Time Expert Seismology"*. According to the above modern technology a non-linear 3-D elastic waves real - time expert system was proposed for the exploration of petroleum and gas resources all over the world, including the off-shore petroleum reserves, of the seas and oceans in the whole world in deep waters ranging from 300 to 3000 m, or even much more. Also, the above technology is the best device for searching the on-shore and off-shore hydrocarbon resources in very deep depths, even approaching 20,000 m or 30,000 m.

So, for the new and the existing oilfields there is an absolute need for the improvement of the existing methods of well development. For this reason, by the current investigation the *"Non-linear ESP Artificial Method by Multiple Pumps"* is proposed and introduced. According to the above new technology the ESP Artificial Lift Method will be extended to non-linear forms by adding multiple electric submersible pumps (ESP), in order to increase the production of each well to 500,000 bpd, or even up to 1 million bpd. The above multiple ESP pumps are used in a definite range of pumping rates. The new method has many benefits beyond the existing ESP Artificial Lift Method [16]-[20], as the oil production for each well is increased very much and so there no limits for the oil well production any more.

In addition, if the pumps are working outside the specified range, then system efficiencies rapidly deteriorate and several mechanical problems may occur. Consequently, in such case there are two possible solutions: (1) the installation of a wellhead hydraulic choke or (2) by using a variable speed drive (VSD) unit. By using the first solution, then the wellhead hydraulic choke restricts the pumping rate and forces the ESP pump to operate within its recommended liquid rate range. The current research investigates the detrimental effects of surface chokes on the power efficiency of ESP systems and discusses an alternative solution.

So, nodal analysis is further presented in order to investigate the negative effects of surface production hydraulic chokes on the energy efficiency of ESP systems, as compared to the application of VSD drives. Thus, a calculation model is investigated in order to evaluate the harmful effects of wellhead hydraulic choking and to find the proper parameters of the necessary VSD unit. By this way, the beneficial effects of using a VSD drive are shown. Hence, the oil companies all over the world must be ready to face the new challenges of drilling of very big flow rates approaching 1,000,000 bpd for a single well.

From the above described analysis it is clear the evidence of the applicability of the new method of *"Non-linear ESP Artificial Method by Multiple Pumps"*. Also its novelty, as it is based mostly on a theoretical and very sophisticated model and not to practical tools like the existing methods. So, the new method will be the best technology for drilling of very big flow rates for a single oil well.

2. Non-linear ESP Artificial Lift Method by Multiple Pumps

When oil is first found in the reservoir, it is under pressure from the natural forces that surround and trap it. If a well is drilled into the reservoir, an opening is provided at a much lower pressure through which the reservoir fluids can escape. The driving force which causes these fluids to move out of the reservoir and into the wellbore comes from the compression of the fluids that are stored in the reservoir. The actual energy that causes a well to produce oil results from a reduction in pressure between the reservoir and the producing facilities on the surface. If the pressures in the reservoir and the wellbore are allowed to equalize, either because of a decrease in reservoir pressure or an increase in wellbore and surface pressure, no flow from the reservoir will take place and there will be no production from the well.

In many wells the natural energy associated with oil will not produce a sufficient pressure differential between the reservoir and the wellbore to cause to flow into the production facilities at the surface. In other wells, natural energy will not drive oil to the surface in sufficient volume. The reservoir's natural energy must then be supplemented by some form of artificial lift.

The most common method of artificial lift for big oil production is the ESP Artificial Lift Method [16]-[20]. By this technology an electric submersible pump (ESP) is used, working in a definite range of pumping rates. This method can lift up to 90,000 barrels of fluids per day. Consequently, by international oil companies in order to increase the production of each well, there is an absolute need for the establishment of a new technology of artificial lift so that the produced oil quantity to be very much increased.

Thus, by the current research a new method of artificial lift is proposed, the "Non-linear ESP Artificial Lift Method by Multiple Pumps". By the new method instead of using one ESP pump, multiple pumps are used, by adding the corresponding head of each pump. By this way the production of each well is increased to 500,000 bpd, or even up to 1 million bpd.

The power *P (*in *KW)* of an ESP pump is given by the following formula:

$$P = \frac{Q(\gamma H - p_{\text{int}ake})}{\eta \cdot \eta_{surf}} \tag{2.1}$$

where Q is the pumping rate ($m^3/\sec$), H the head of the pump (m), γ is the specific gravity of the produced liquid (KN/m^3), $p_{\text{int}ake}$ (KN/m^2) is the pump suction pressure, called pump intake pressure, η is pump's efficiency and η_{surf} (usually 0.97) is the power efficiency of the surface equipment.

Since the ESP motor converts the electrical energy input at its terminals into mechanical work output at its shaft, then the energy conversion is characterized by the motor efficiency. Consequently, the power P_e *(KW)* of the electric motor is given by the formula:

$$P_e = \frac{P}{\eta_e} \tag{2.2}$$

where P is the power of the ESP pump and η_e the efficiency of the electric motor.

In (2.1) the head H of the pump is equal to:

$$H = h_{depth} + h_f + h_{wh} + h_{cable} \tag{2.3}$$

where h_{depth} is the pump setting depth, h_f are the frictional pressure losses in the tubing string, h_{wh} are the backpressure losses, as the pump has to work against the well's surface wellhead pressure and the power consumed by overcoming this backpressure is not included in the useful power and h_{cable} are the electrical cable losses.

In (2.3) the frictional pressure losses in the tubing string $h_f\,(m)$ are given by Darcy-Weisbach equation:

$$h_f = f\,\frac{L}{D}\,\frac{v^2}{2g} \tag{2.4}$$

where:

$$L = h_{perf} - h_{depth} \tag{2.5}$$

with h_{perf} the depth of perforations, D diameter of tubing (m), v the velocity of the liquid (m/sec), g gravity acceleration (=9.81 $m/\sec^2$) and friction coefficient which is calculated through the equation of Colebrook-White.

Furthermore, in (2.3) the backpressure losses are equal to :

$$h_{wh} = \frac{p_{wh}}{\gamma} \tag{2.6}$$

with p_{wh} (KN/m^2) the wellhead pressure.

On the other hand, since the ESP motor is connected to the power supply through a long power cable, a considerable voltage drop occurs across this cable. Then, the Voltage drop creates a power loss proportional to the square of the current flowing through the system, as given by the following relation:

$$\Delta P_{cable} = \frac{3I^2 R_T}{1000}\ (KW) \tag{2.7}$$

where I is the required motor current (Amps) and R_T is the resistance of the power cable at well temperature (Ohms).

Then, the electric cable losses h_{cable} are equal to:

$$h_{cable} = \frac{\Delta P_{cable}}{\gamma \cdot Q} \tag{2.8}$$

By the new method of *"Non-linear ESP Artificial Lift with Multiple Pumps"* instead of one pump are used multiple in several positions of the well. Consequently, the total head is the sum of the heads of each ESP pump separately :

$$H = H_1 + H_2 + ... + H_m \tag{2.9}$$

if used m pumps.

So, by using the proposed new technology the production of oil for each single well is increased too much, up to 1 mill. bpd, as by each pump is covered a part of the requested head.

3. Application of Wellhead Chokes

The most ESP artificial lift pumps are designed to operate using electricity at a fixed frequency, usually 60 or 50 Hz. For this reason the ESP pump runs at a constant speed and develops different heads for different pumping rates as predicted by its published performance curve. So, when designing for a constant production rate, a pump type with the desired rate inside of its recommended capacity range is selected.

A basic problem with the usual design of ESP artificial lift is that the ESP installation is investigated for a single design rate only and no information is available for cases when well parameters are in doubt. On the other hand, these problems are solved if NODAL analysis principles are used to describe the operation of the production system consisting of the well, the tubing, the ESP unit, and the surface equipment. Consequently, by NODAL analysis is possible the calculation of the necessary pump heads for different possible pumping rates and the determination of the liquid rate occurring in the total system. It should therefore the required head to produce well fluids to the separator to be equal to the head developed by the ESP pump run in the well.

In addition the number of the required pump stages is found from detailed calculations of the required total dynamic head (TDH), which is the head required to lift well fluids to the surface at the desired pumping rate.

Beyond the above, Figure 1 shows a diagrammatic comparison of the conventional design with the corresponding provided by NODAL analysis. So, conventional design calculates the TDH at the design rate only and then selects the required type of the ESP pump. After selecting the rest of the equipment the ESP unit is run in the well and it is then only hoped that actual conditions were properly simulated resulting in the well output being equal to the design liquid rate. On the contrary, if well inflow performance data were uncertain or missing during the design phase then the ESP stabilized liquid rate is different than that from the design target. By NODAL calculations, however, can be found the required head values for different liquid rates, shown in Fig. 1 by the curve in dashed line. Then the well's actual production rate will be found where the required and the available (provided by the pump) heads are equal, at Point 1 in Figure 1.

Consequently, as the required production of the well is usually due to reservoir engineering considerations, then production of a greater rate is not allowed. If the actual head requirement (actual TDH) is much less than the calculated design TDH, then an hydraulic choke should be placed at the wellhead to restrict the oil rate to the design target. On the other hand, at this rate the ESP pump develops the designed operating head as shown by Point 2.

Since the actual head required for lifting the well liquid to the surface, as found from NODAL calculations, is less than this value, then a sufficient head loss across the choke is needed. This head loss, which is found between Points 2 and 3, must be sufficient to supplement the system's actual TDH to reach the TDH that was used for the original design. By this way, the head requirement of the production system is artificially increased and the ESP pump is forced to produce the desired liquid rate.

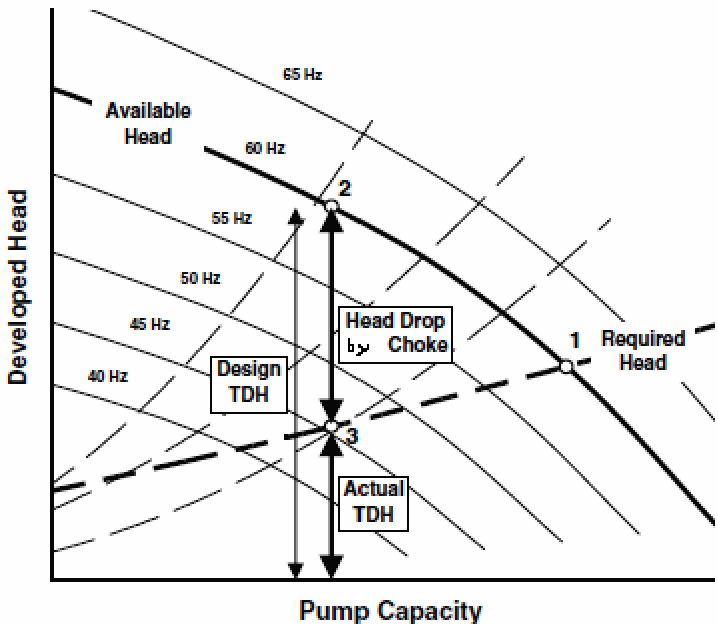

Fig. 1 A wellhead hydraulic choke in ESP pump.

The wasted power P_{wasted} (in *KW)* of the pump because of the hydraulic choke is given by the following relation:

$$P_{wasted} = \gamma\, Q\, \Delta H_{choke} \tag{3.1}$$

where Q is the pumping rate ($m^3/\sec$), ΔH_{choke} the head loss across the hydraulic choke (m) and γ is the specific gravity of the produced liquid (KN/m^3).

As the above power is wasted, then the efficiency of the ESP power system together with the profitability of oil production will decrease. In addition in order to apply NODAL analysis to the ESP installation, then firstly should be calculated the variation of flowing pressures in the well.

The pressure p_d (KN/m^2) available at the ESP pump's discharge is equal to:

$$p_d = p_{wf} - (L_{perf} - L_{pump})grad_l + \Delta p_{pump} \tag{3.2}$$

where p_{wf} denotes the bottomhole pressure (KN/m^2), $grad_l$ the liquid gradient (*KW/m*), L_{pump} (*m*) the pump setting depth, L_{perf} (*m*) the depth of perforations and Δp_{pump} (KN/m^2) the pressure increase developed by the ESP pump.

In addition the required discharge pressure of the ESP pump p_d^* is given by the relation:

$$p_d^* = p_{separ} + \Delta p_{fl} + L_{pump}grad_l + \Delta p_{fr} \tag{3.3}$$

in which p_{separ} is the surface separator pressure (KN/m^2), Δp_{fl} the frictional pressure drop in the flowline (KN/m^2) and Δp_{fr} the frictional pressure drop in the tubing string (KN/m^2).

On the other hand, the available and the required pressures should be equal ($p_d = p_d^*$), then from eqs (3.2) and (3.3) follows the relation:

$$\Delta p_{pump} = p_{separ} + \Delta p_{fl} + L_{perf}\ grad_l + \Delta p_{fr} - p_{wf} \tag{3.4}$$

By dividing (3.4) by the liquid gradient, then reduces to:

$$\Delta H_{pump} = \frac{p_{separ} - p_{wf}}{\gamma} + \Delta H_{fl} + L_{perf} + \Delta H_{fr} \tag{3.5}$$

where ΔH_{fl} is the frictional head drop in the flowline (m) and ΔH_{fr} is the frictional head drop in the tubing string (m).

4. Variable Speed Drive (VSD) Units

If the installation design of the artificial lift is inaccurate and the ESP system produces a higher rate than desired, then the use of wellhead chokes is a common solution to control the production of the well. On the other hand, if a VSD is available, then the elimination of the choke and its associated disadvantages can be accomplished.

So, as could be seen in Fig. 1, by reducing the electrical frequency driving the ESP system to a level where the head developed by the pump is equal to the head required to produce the desired rate (Point 3), then the hydraulic choke is no more needed to adjust the pumping rate. Consequently, by using a VSD unit in order to control the liquid rate of the ESP system, then the several components of the system behave differently as the driving frequency is adjusted.

The use of the variable speed drive (VSD) unit would be therefore the best device to control the ESP pump. The above pump will develop different head values and will need different brake horsepower from the electric motor.

For the VSD unit the following formula is valid:

$$\frac{U_2}{U_1} = \frac{f_2}{f_1} \tag{4.1}$$

where f_1 , f_2 are the AC frequencies (Hz) and U_1, U_2 are the output Voltages at f_1 and f_2 frequencies, correspondingly.

Furthermore, by next formula is shown that the power developed by the ESP pump is proportional with the electrical frequency:

$$\frac{P_2}{P_1} = \frac{f_2}{f_1} \tag{4.2}$$

where f_1 , f_2 are the AC frequencies (Hz) and P_1, P_2 are the motor power available at f_1 and f_2 frequencies, correspondingly.

Consequently, the use of a VSD unit in the ESP artificial lift system, substantially modifies the power conditions of the ESP pump and so there is no need for an hydraulic chock.

The new method of *"Non-linear ESP Artificial Lift by Multiple Pumps"* will be used in combination with the VSD units. Thus, for each ESP pump a VSD unit will be used, in order to control the proper operation of the ESP system.

5. Conclusions

By the current research the new theory of *"Non-linear ESP Artificial Lift by Multiple Pumps"* has been introduced and investigated for the petroleum well development. Thus, by using the proposed new technology then it will be possible the production of very big quantities of oil in each well, which could be 500,000 bpd, or even up to 1 mill. bpd.

Consequently, by the proposed sophisticated technology for energy applications it will be established a strong scientific and technical base for the Science & Technology worldwide in the emerging areas of well development in the energy field. Thus, through the new technology of *" Non-linear ESP Artificial Lift by Multiple Pumps"*, the production of very big quantities of oil and gas for each well will become possible.

The oil and gas markets are multi-billion markets all over the world. Thus, such a contribution requires an international approach, rather than a local approach, as it is referred to a market all over the world with value of many billions. It is therefore expected in order the international oil companies to keep and to improve their leading role in the worldwide Science & Technology in the petroleum field, to get involved in the new and groundbreaking technology in the area of Energy, which is proposed by the present investigation.

Finally, as the proposed new method *"Non-linear ESP Artificial Lift by Multiple Pumps "*, is based on a very sophisticated modern technology, then it is expected to get the best results. So, our proposed high technology method is based on a very sophisticated model by using multiple ESP pumps, instead of using only one pump like the past methods. It is therefore not necessary to open many wells in order to increase the production, like the existing methods.

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