# A Comparative Study of Gas Lift and Electrical Submersible Pump (ESP) for Production Optimization.

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**Abstract**

*One of the key aspect of exploration and production (E&P) industry is the production Of hydrocarbon from underground reservoirs to the surface production and storage facilities via the wellbore. When a well is drilled, the reservoir fluid flows naturally with the primary energy of the reservoir but when it becomes necessary that oil fails to flow naturally, then an artificial lift system is installed to aid the flow by lowering the hydrostatic pressure inside the production tubing. This study presents a comparative study of gas lift and electrical submersible pump (ESP) for production optimization of UFET_3 well to select the best option for the field. PROSPER software was used to build a natural flowing case, gas lift and ESP to simulate different scenarios. The result obtained showed that the ESP system has a production rate of 4645.9 STB/day higher than the natural flowing case, gas lift has 785.7 STB/day higher than natural flowing case. In addition, ESP has a production rate of 3860.2 STB/day higher than gas lift. Considering economy, ESP generated the highest gross profit ($4.882B) a difference of $1.42M & $1.8M from gas lift and natural flowing case respectively. But considering other factors like water cut and replacement of failed pumps, gas lift system was preferred for proper production optimization of the field. However, gas lift was chosen for UFET_3 well based on the availability of readily compressed gas, higher life time expectance and lower operational cost as compared with the ESP which had the highest production potential.*

Keywords**:** *Gas lift, ESP, artificial lift, natural flow, production optimization, PROSPER, economic and sensitivity analysis*

## 1. INTRODUCTION

One of the key aspect of the exploration and production (E&P) companies is the production of the hydrocarbon from the underground reservoir to the surface production and storage facilities via the wellbore. Though the operation of the hydrocarbon is usually interdisciplinary or an integrated study comprising the geophysical, geology, petrophysical, drilling, completion, reservoir, production, economics, just to mention a few. There is a school of taught which states that all other aspects of petroleum engineering are dreamers, except the production team who are the real people because they get the contents of the reservoir for sale.
Hydrocarbon production spans three stages: primary, secondary and tertiary stages. The primary stage makes use of the natural energy inherent in the reservoir and if it becomes necessary that it cannot or it’s no longer sufficient enough to lift the oil to the surface due to the hydrostatic head which denotes that an artificial lift system or assisted flow is required. According to Carlos et al (2013), artificial lift technology (gas lift or pumping system) is employed in oil field when the reservoirs have lost their natural means of producing its content to the surface production facilities. Ayatollahi et al., (2001) stated that selection of proper artificial lift method is critical to the long-term profitability of the oil well; a poor choice will lead to low production and high operating costs. Djikpesse et al (2010) presented a study on the optimization of gas lift system under facilities constraints and Pengjuand Michael (2004) developed an optimization algorithm for gas

lift to simulate oil reservoir in a long term basis.While Shauna et al (2000) have it that gas-liquid ratio is very important or critical in a stable oil production with just minimal fluctuation in the gas-liquid ratio for offshore applications in the gas lifted well design. Figure 1 represents a schematic of a gas lift system.

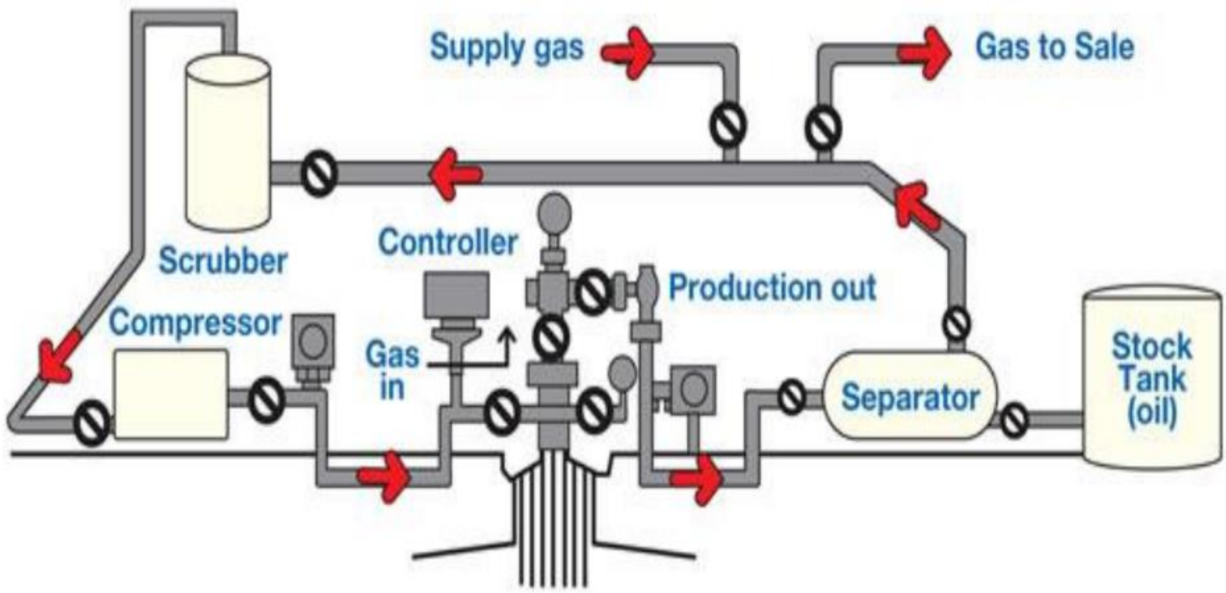


**Figure 1: Schematic of Gas Lift System.**

Naturally, it is difficult for oil and gas operators to remain in their peak production stage for a long period of time. Thus, they are faced with unnecessary decline in pressure, increase in water cut and reduction in well deliverability etc which directly affects the rate of production and this is a challenge to the oil and gas industry today. The decline may be as a result of loss or mismanagement of wells, excessive pressure drops along the production system, oversized or undersized tubing, and improper perforation method etc. A change in a single component of the production system may lead to a change in the pressure drop behavior of the other components since the various components are interactive.

Furthermore, when it becomes visible that the natural means of production is no longer sufficient, artificial lift is installed to increases production but face some notable problems such as the number of wells drilled in the field, handling of solid/sand, handling of corrosion/scale, high GOR, water cut, flowing pressure and temperature limitation, well depth, space, production rate, flexibility, electrical power, economics etc. which are factors to consider in the selection prior to the installation. In this study, sensitivity analysis will be conducted on some of these factors to optimize production. Therefore, this paper is aimed at selecting the best artificial lift techniques for UFET_3 well maximum production/profit from the field to;

i. To reduce the weight of the column of fluid in the tubing, thereby enabling the bottomhole pressure of the well to adequately lift the column and also to overcome the resistance in the tubing, pipes and connections.

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ii. Find the maximum production rate achievable using gas lift and ESP

iii. Determine the optimum lift gas injection rate and depth

iv. Design the operating and unloading valves

v. To carry out an economic analysis on gas lift and EPS and also, a cost benefit analysis of changing various components of the system resulting from the production system optimization.

Electric Submersible Pump systems as shown in Figure 2, incorporate or make use of an electric motor and centrifugal pump unit installed at reservoir through the production string and are connected with the aid of an electric power cable to the mechanism of control at the surface and a transformer. The downhole components of the pump are suspended above the perforations of wells. Often times, the motor with a pump and seal immediately above it is located on the bottom of the work string. The power cable is clamped to the tubing and plugs into the top of the motor. As the fluid passes through the well, it must go through the motor and the pump and in this process, the motor is cooled by the fluid. The fluid then enters the intake and is taken into the pump. Each stage (impeller/diffuser combination) adds pressure or head to the fluid at a given rate. The fluid will build up enough pressure, as it reaches the top of the pump, to be lifted to surface and into the separator or flow line**.**

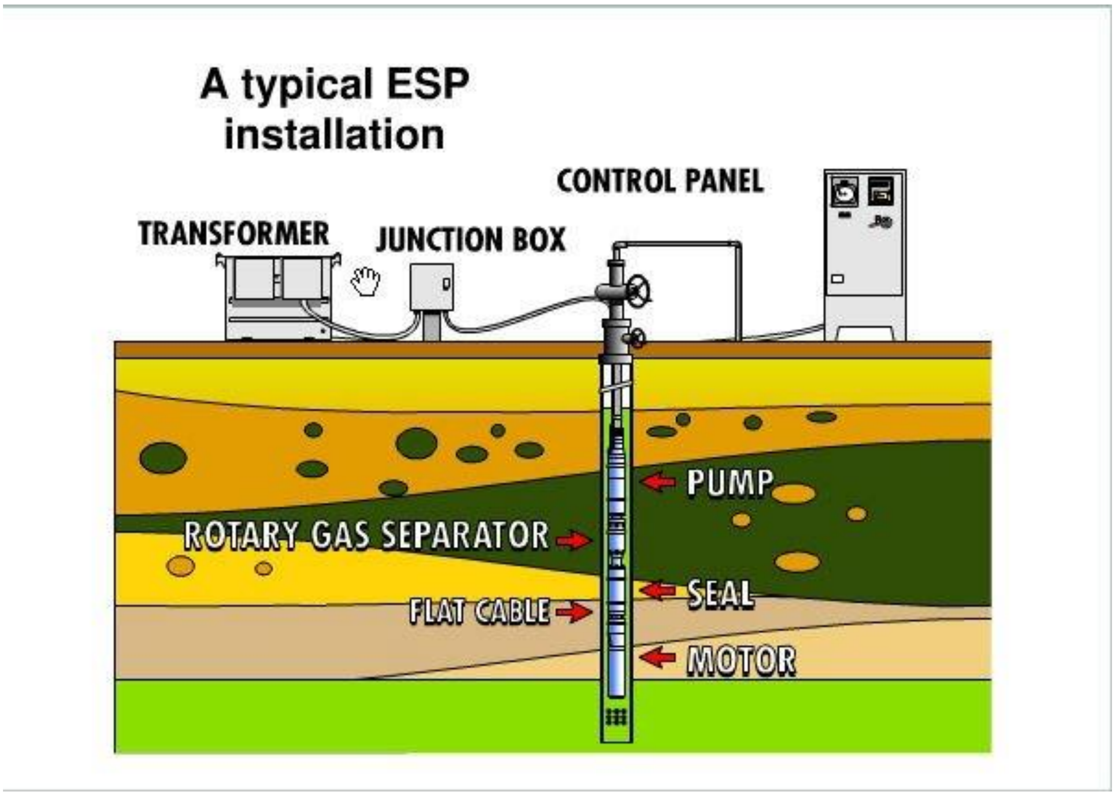


**Figure 2: Schematic of an ESP system** (Source: www.alibaba.com)

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Wang et al. (2002) worked on the application of production optimization technique for oil field operations and in that process, a procedure was developed for allocation of optimal rate of production, the rate of the lift gas, and the simultaneous connection of the wells with surface pipeline systems. Blanksby et al (2005) worked on the deployment of electrical submersible pump with high horsepower to extend the Brent field in the North Sea. They considered downhole and topsides facilities for their ESP selection consideration.The work of Vachon (2005) presents some of the latest aspects of ESP operations. The paper discusses optimization of ESP operations using downhole chokes and variable speed drives. Intelligent well technology, i.e. they emphasized on the remotely control system and monitoring of the downhole parameters.

The general guidelines (Weatherford 2005) in Table 1 summarizes typical characteristics and applications for each form of artificial lift. These are general guidelines, which vary among manufacturers and researchers. Each application needs to be evaluated on a well-by-well basis.

**Table 1: Operating Parameters of a Gas Lift and ESP**
(Weatherford International Ltd., 2005)

| OPERATING PARAMETER | GAS LIFT SYSTEM | ESP |
|---|---|---|
| Typical Operating Depth (TVD) | 5000 to 10000ft | - |
| Maximum operating depth (TVD) | 15000ft | 15000ft |
| Typical operating volume | 100 to 10000 BFPD | 100 to 30000 BFPD |
| Maximum | 30000 | 40000 |
| Operating volume | BFPD | BFPD |
| Typical Operating Temp. | 100-250 $^{O}$F [40-120$^{O}$C] | - |
| Maximum Operating Temp. | 400 $^{O}$F [205 $^{O}$C] | 400 $^{O}$F [205 $^{o}$C] |
| Typical Wellbore Deviation | 0 to 50 deg | - |
| Maximum Wellbore Deviation | 70$^{O}$ Short to Medium Radius | 0 to 90 deg |
| Corrosion Handling | Good to Excellent | Good |
| Gas Handling | Excellent | Fair |
| Solids Handling | Good | Fair |
| Fluid Gravity | >15 $^{o}$API | >10 $^{o}$API |
| Servicing | Wireline or Workover Rig | Workover or Pulling Rig |
| Prime Mover | Compressor | Electrical Motor |
| Offshore Application | Excellent | Excellent |
| System Efficiency | 10 to 30% | 35 to 60% |

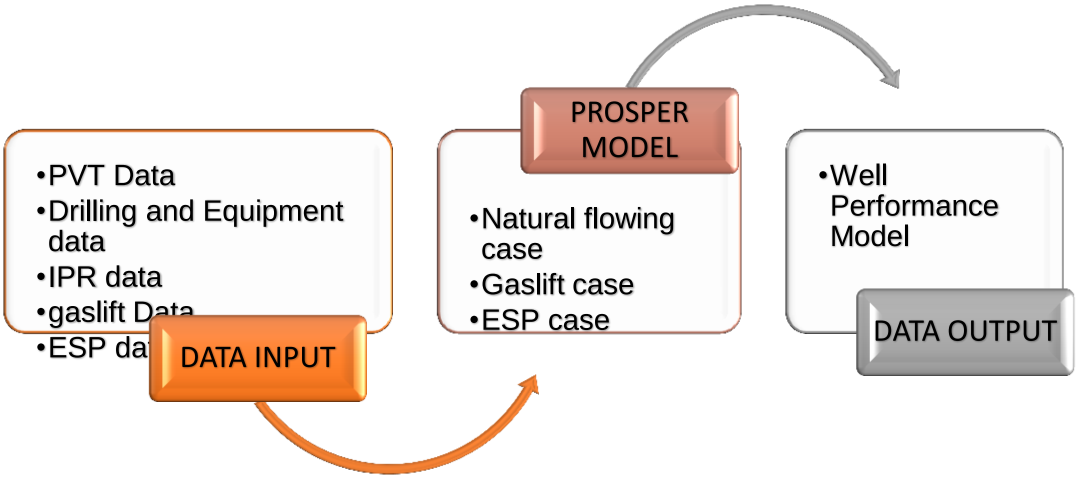
## 2. MATERIALS AND METHOD

The methodological design approach of this paper is presented in Figure 3 (Prosper workflow) to compare the natural flowing well and artificial lift well. Therefore, three basic scenarios will be developed in the prosper model and these are:

I. Design a natural flowing oil well to serve as a base case

II. Design a gaslift system for same well to evaluate its performance
III. Design an ESP system for the same well to evaluate its performance

PROSPER is designed to allow building of reliable and consistent well models, with the ability to address each aspect of wellbore modelling viz; PVT (fluid characterization), VLP correlations (for calculation of flowline and tubing pressure loss) and IPR (reservoir inflow). By modelling each component of the producing well system, the User can verify each model subsystem by performance matching. Once a well system model has been tuned to real field data, PROSPER can be confidently used to model the well in different scenarios as presented in Figure 3 and to make forward predictions of reservoir pressure based on surface production data.




Additional factors that will be considered during the selection/design process include:

i.

**Figure 3: Prosper Model case scenarios**

ii. Operating cost
iii. Availability of the lift gas
iv. Servicing frequency (maintenance cost)

**Design Factors**

i. Gas injection depth, pressure and GLR for desired production
ii. Principles of unloading operations
iii. Well gradients
iv. Gas lift valve spacing principles
v. Types of gas lift valves
vi. Mechanics of gas lift valve operation
vii. Factors that affect efficiency

**Workflow in PROSPER**

i. Collection of well and production data from a wells
ii. Building a single well model with the available data
iii. Design a base case without an artificial lift using prosper
iv. Development of the inflow and outflow performance
v. Using prosper to design the gas lift and ESP option
vi. Compare the production rate of the well using gas lift and ESP as the artificial lift method.
vii. Evaluate the effect of the tubing and/or water cut, subsurface safety valve sizing , reservoir pressure, skin, productivity index(PI) and gas-oil ratio (GOR) etc.

viii. Predicting the best option among these two models.

**FET_3 Input Data**

The PVT data, laboratory, flow test data and inflow performance are given in Tables 2 – 5.

**Table 2: PVT data for UFET_3**

| Property | Value |
|---|---|
| Gas-oil ratio (GOR) | 400 scf/stb |
| Oil gravity | $30^0$API |
| Gas gravity | 0.75 |
| Water salinity | 80000 ppm |
| Reservoir pressure | 4000 psi |
| Bubble point pressure | 2500 psi |
| Temperature | $200^0$F |

**Table 3: Laboratory PVT Properties**

| Pressure (psi) | Gas oil ratio (scf/stb) | Oil FVF (rb/stb) | Oil viscosity (cp) |
|---|---|---|---|
| 4000 | 400 | 1.198 | 1.11 |
| 3000 | 400 | 1.207 | 1.05 |
| 2500 | 400 | 1.214 | 1.01 |
| 2000 | 237 | 1.178 | 1.15 |
| 1500 | 324 | 1.138 | 1.34 |

**Table 4: Flow test data**

| Parameter | Value |
|---|---|
| Test data | 01/01/2010 |
| Test comment | Min Flow test |
| Well head flowing pressure | 1000 psig |
| Flowing tubing head temperature | $153^0$F |
| Water gas ratio | 5 stb/MMscf |
| Condensate gas ratio | 5 stb/MMscf |
| Gas flow rate | 15 MMscf/d |
| Measured guage depth | 4500 ft |
| Measured guage pressure | 1920 psig |
| Static reservoir pressure@ top perforation | 2300 psig |

**Table 5: Inflow performance data**

| Parameter | Value |
|---|---|
| res temp | $200^0$F |
| water cut | 0 |
| total GOR | 400 scf/stb |
| h | 100 ft |
| res k | 150 mD |
| dietz shape | 31.6 |
| rw | 0.354 ft |
| s | 2 |
| area | 340 acre |

## 3. RESULT

**Inflow (IPR) and Outflow (VLP) Performance Match**

The prosper model was calibrated to reproduce the well test results and the calibrated model was used to study the impact of tubing size and reservoir pressure on the well performance. From Figure 4, one can see that the test point lies outside of the solution envelope. This can happen for various reasons and it is the engineer's task to find out exactly what are the possible reasons behind this behavior.

In matching the vertical lift performance as shown in Figure 5, the multiphase flow correlation was tuned in order to match a downhole pressure while GOR was tuned so that the intersection VLP/IPR will match the production rate as per well test. The available parameters for matching depend on the IPR model in use. For Darcy-IPR model selected for this study, permeability, skin or pressure could be used. Thus, pressure was adjusted to match the IPR and the GOR was check to make sure test data is same with PVT data since the reservoir is still undersaturated.In this case of UFET_3, the bubble point pressure of the fluid at reservoir temperature is 2500 psig, while the reservoir pressure is currently 3800 psig. This implies that the oil is still undersaturated at 3800 psig. Therefore, the produce GOR must be equal to initial solution GOR of 400 scf/stb. Table 6 shows the measured and the calculated rate and pressure of UFET_3.

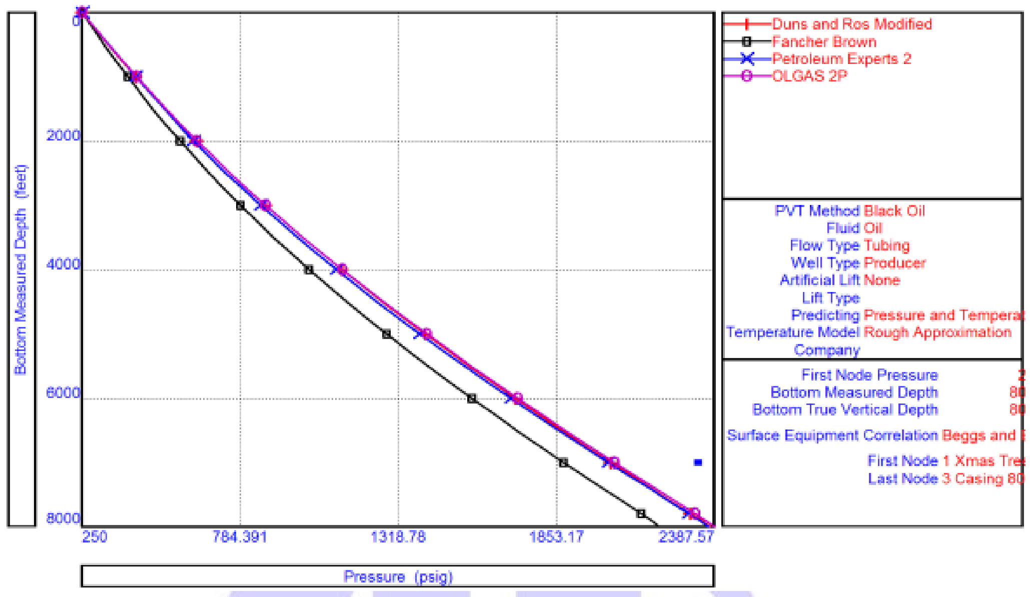



**Figure 4: VLP correlation comparison**

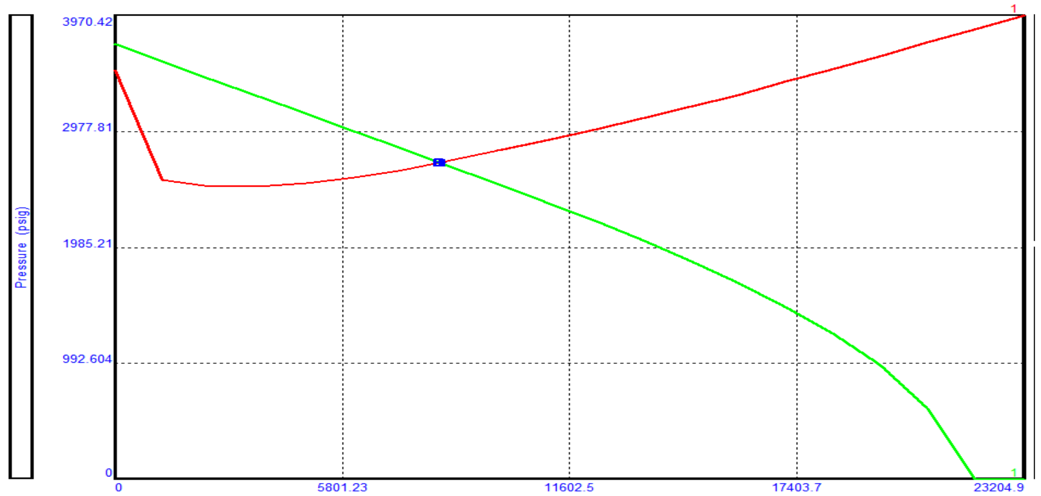



**Figure 5: Inflow performance and outflow performance match with test data**

**Table 6: VLP/IPR plot analysis**

| Liquid Rate (STB/day) | | | Bottom Hole Pressure (Psig) | | |
|---|---|---|---|---|---|
| Measured | Calculated | % difference | Measured | Calculated | % difference |
| 8290.0 | 8299.9 | 0.11885 | 2706.01 | 2706.69 | 0.025172 |

**Result of Gaslift Performance**

The available injection gas for UFET_3 was 10 MMscf/day but the optimum gas lift rate for this well is estimated as 8.323 MMscf/day as shown in Table 7. Therefore, since the available gas is higher than the optimum gas required, the program will only inject the optimum gas into the well, which is 8.323 MMscf /day in this case. In case the available gas is less than optimum gas, the actual available gas value will be used. The gaslift design rate is presented in Table 8.

**Table 7: Result of gaslift calculated rate**

| GLR Injected | Liquid Rate | Oil Rate | VLP Pressure | IPR Pressure | Standard Deviation | Design Rate | Oil Rate |
|---|---|---|---|---|---|---|---|
| scf/STB | STB/d | STB/d | psig | psig | | MMscf/d | STB/d |
| 1398.95 | 9075.7 | 1815.1 | 2279.87 | 1904.52 | 34.361 | 8.323 | 1599.1 |

**Table 8: Result of gaslift design rate**

| Liquid Rate | Oil Rate | Injection Gas Rate | Injection Pressure |
|---|---|---|---|
| STB/d | STB/d | MMscf/day | psig |
| 7154.94 | 1430.99 | 5.9420 | 1287.49 |

**UFET_3 Well Gas lift Design**

Figure 6 represents UFET_3 well gaslift design valve setting depths. The values of the various valves are shown in Table 9. From Figure 6, the first unloading valve is set at 2975.25 ft, while the second and third unloading valves are set at 4835.08 ft and 5884.3 ft respectively. The orifice set at 6161.3 ft is serving as the operating valve.

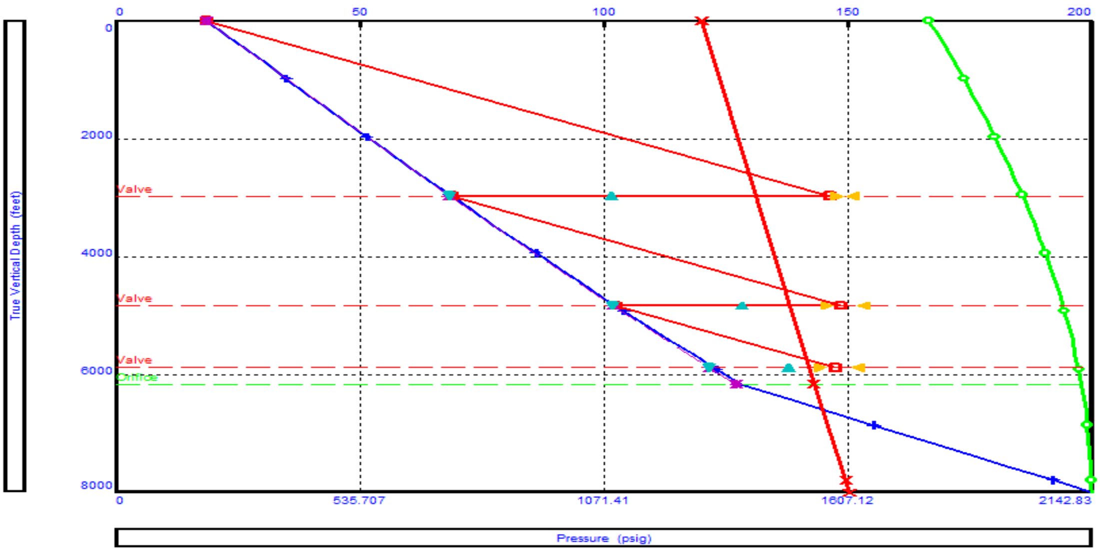



**Figure 6: UFET_3 gas lift valve design**

**Table 9: Result of gaslift valve depth design**

| Valve Type | Measured Depth | True Vertical Depth | Tubing Pressure | Valve Opening Pressure | Valve Closing Pressure | Opening CHP | Closing CHP |
|---|---|---|---|---|---|---|---|

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| | feet | feet | Psig | psig | psig | psig | psig |
|---|---|---|---|---|---|---|---|
| Valve | 2975.25 | 2975.25 | 737.241 | 1618.61 | 1585.12 | 1500 | 1466.51 |
| Valve | 4835.08 | 4835.08 | 1097.15 | 1642.76 | 1562.56 | 1450 | 1369.8 |
| Valve | 5884.3 | 5884.3 | 1313.25 | 1629.79 | 1547.49 | 1369.8 | 1287.49 |
| Orifice | 6161.3 | 6161.3 | 1414.36 | | | 1287.49 | |

**Result of ESP Performance**

The prosper software has several pumps, motors and cable from different Vendors. In the first design, Centurion G110 5.38 inches (6000-14000 rb/day) was selected from the list of suitable pumps. The pump needs 71 stages and requires 426.22 HP power rating at the design rate. From the list of suitable motors, Centrilift 562 450HP 2460V 10A and Figure 7shows the design operating point superimposed on the pump performance curve. It can be inferred from Figure 7 that the selected pump will fail shortly when installed because the pump is operating very close to the maximum operating efficiency.

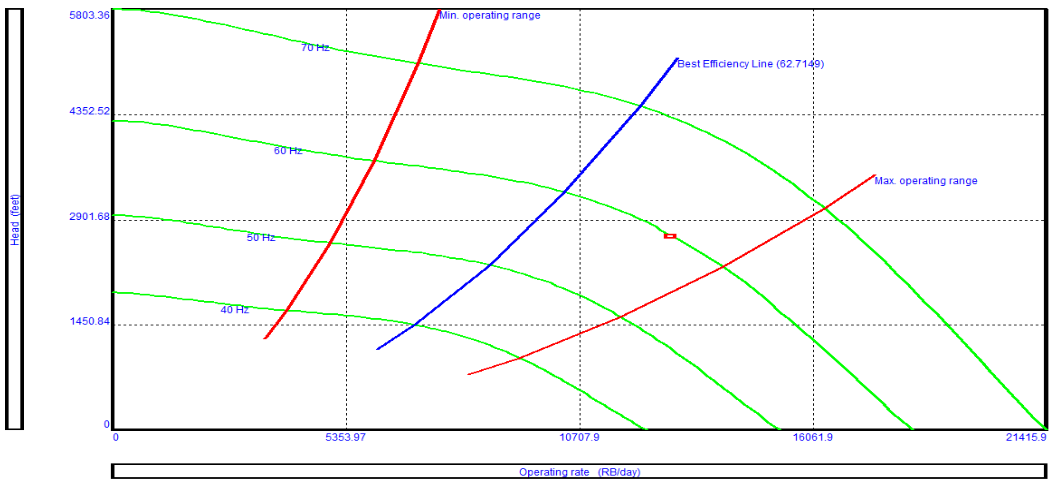


**Figure 7: Centurion G110 5.38 inches (6000-14000 rb/day) operating point**

Furthermore, since Centurion G110 5.38 inches pump is running a little close to its maximum output; perhaps the next biggest pump would be a better choice, especially if the pump is expected to handle a greater lift duty due to increasing water cut during the pump's run life. Hence, REDA HN15000 5.63 inches (12000-18000 rb/day) with 61 stages was selected with the motor Reda 540_90.0_Int 400HP 2116V 113A and the same cable as shown Figure 8. This pump is operation close to its minimum efficiency and has some excess head. Hence should be considered for UFET_3 well.

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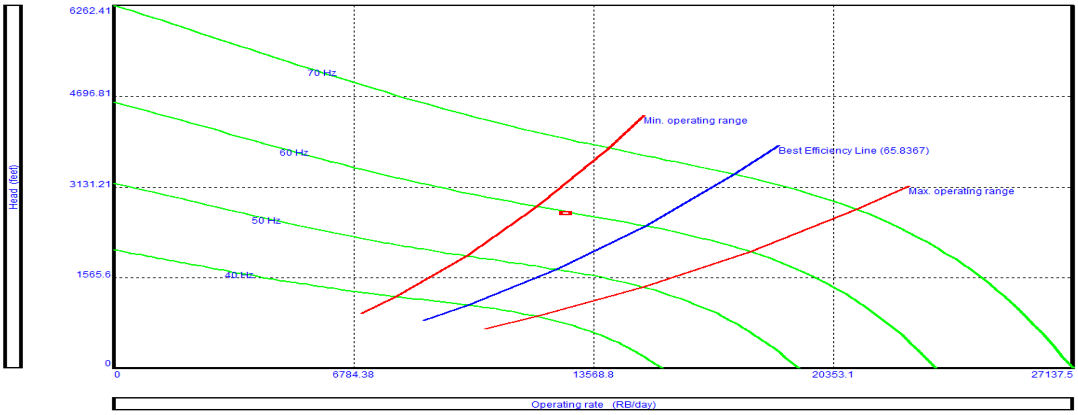


**Figure 8: REDA HN15000 5.63 inches (12000-18000 rb/day) operating point**

**Comparison of Production Performance**

The result of the production forecast shown in Table 10 indicates that the ESP solution gives a superior production rate compared to gas lift and the natural flowing case “base case”. It could be observed also that the gas lift production rate is higher than the natural flowing well. Hence, based on production capacity, ESP is by far a better option to gaslift and flowing the well by natural energy of the reservoir, but one cannot not jump into conclusion without considering several other factors that might lead to the overall failure or success of the installation. Though ESP gives a better production capacity but might fail to meet its design rate due to changes in the reservoir properties and such needs another pump to handle the current conditions of the reservoir. ESP fails in higher water cut and when it fails, the entire system is pulled out and a new pump is designed to meet the current reservoir conditions.

**Table 10: Comparison of production performance**

| Liquid Rate (STB/day) | | | Pressure (psig) | | |
|---|---|---|---|---|---|
| Natural Flowing | Gaslift | ESP | Natural Flowing | Gaslift (VLP Pressure) | ESP (Pump Discharge Pressure) |
| 8290.0 | 9075.7 | 12935.9 | 2706.01 | 2279 | 3206.38 |

## 4. CONCLUSIONS

Through consideration of the production profile, desired rate and advantages /disadvantages of gas lift and ESP for production optimization to compare the most suitable artificial lift methods for UFET_3 field, the following conclusions were drawn:

i. Both gas lift and ESP give a large increase in production compared to the natural flowing case, but ESP is higher on production capacity as compared to gaslift for UFET_3 well. This is a reason to believe that the same difference would be seen in a full field artificial lift campaign. In this study, from a production point of view and gross profit, the ESPs inplementation is by far higher than gaslift implementation which is a short coming in choosing ESP.

ii. For UFET_3, there is a nearby gas compression station. This makes gaslift installation a better option for this field.

iii. Implementation of ESPs carry greater risk because of the complexity of the equipment and limited lifetime. When ESPs fail this require a full workover, which is more expensive mainly because of the required rig operation compared to a wireline operation.

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