Comparison Between ESP and Gas Lift in Buzurgan Oil field/Iraq

Abdul Aali Al Dabaj

University of Technology/Petroleum Technology Department
E-mail: resaldabaj@yahoo.com

Samaher AbdilRassol Lazim
Lecturer

University of Technology/Petroleum Technology Department
E-mail: samaher.rasul@yahoo.com

Omar Ayad Al-Sallami
Master Student
University of Technology/Petroleum Technology Department
E-mail: o_ayad@ymail.com

ABSTRACT

Buzurgan oil Field which is located in south of Iraq has been producing oil for five decades that caused production to drop in many oil wells. This paper provides a technical and economical comparison between the ESP and gas lift in one oil well (Bu-16) to help enhancing production and maximize revenue. Prosper software was used to build, match and design the artificial lift method for the selected well, also to predict the well behavior at different water cut values and its effect on artificial lift method efficiency. The validity of software model was confirmed by matching, where the error difference value between actual and calculated data was (-1.77%).
The ESP results showed the durability of ESP regarding the increment of water cut value, on the other hand Gas lift design was restricted to surface injection pressure and injected gas volume which in return causes a restriction to production rate specially when water cut value increases. Economically the results showed ESP is cheaper and more applicable than gas lift.
Key words: ESP, gas lift, bazurgan oil field, prosper.

مقارنة بين المضخة الغاطسة والرفع بالغاز في حقل بزركان\العراق

د.عبد العالي الدباج
خبير نفطي
الجامعة التكنولوجية\قسم تكنولوجيا النفط

د.سماهر عبد الرسول
مدرس دكتور
الجامعة التكنولوجية\قسم تكنولوجيا النفط

عمر اياد السلامي
طالب ماجستير
الجامعة التكنولوجية\قسم تكنولوجيا النفط

الخلاصة

علىٰ مدىٰ الخمس عقود المنصرمة شهد حقل بزركان الواقع في جنوب العراق انخفاض ملحوض في الانتاج الىٰ الوقت الحالي مما تطلب ايجاد حلول لانعاش الانتاج في الحقل المذكور. ستوفر هذه الورقة البحثية دراسة لمقارنة الانتاج بين طريقة الرفع بالمضخات الكهربائية الغاطسة والرفع باستخدام الغاز وايضا دراسة اقتصادية مصغرة لايضاح امكانية تطبيق الطريقتين.تم استخدام برنامج بروسبير لبناء ومطابقة نموذج البئر المصمم حاسوبيا وايضا لدراسة تاثير ارتفاع القاطع المائي علىٰ انتاج الطريقتين.تم الحصول علىٰ تطابق بين البيانات الحقلية والمحسوبة بفارق (-١,١٧%). اظهرت النتائج تفوق المضخة الكهربائية الغاطسة علىٰ الرفع باستخدام الغاز من الناحيتين العملية والاقتصادية ،حيث استطاعت المضخة الغاطسة زيادة

الانتاج اكثر من ضعف وامكانية استمرار الانتاج بهذا المعدل حتئ مع ارتفاع القاطع المائي ومن الناحية الاقتصادية كانت المضخة الغاطسة اقتصادية اكثر.
الكلمات الرئيسية: المضخة الغاطسة، الرفع الصناعي بالغاز، حقل بزركان النفطي، بروسبير

1. INTRODUCTION

Many oil production improvement methods are involved today in the oil industry but, so far ESP and gas lift are the most common methods that are widely used in many oil fields. A study in 2006 proved that gas lift method occupies 50% of artificial lift method and ESP is sharing 30% of the total artificial lift method in the world, **Ehsan, 2011**.

Maximum potential of any field can be achieved from enhancing the production with less expenditures and this can be done by choosing the most economical artificial lift method. The methods selection is vastly variable from a particular field to another. The history of previously used artificial lift method in the selected field or nearby field can provide a great help in choosing the proper method and never forget to mention that the method selection includes operator experience; the available method of installation in different fields; determining what methods will lift at the desired rates and from the required depths; determine the lists of advantages and disadvantages; evaluation of operating costs, initial costs, production capabilities, etc. Computerized method can simplify the selection process and provide a great deal of accuracy and time saving.

Buzurgan oil field is located in the South–Eastern part of the Republic of, the oil field was discovered in 1970, and in November 1976 its development was started. The field consisting of two domes, southern and northern, the main production layer is Mishrif formation at a depth of (4000 m) where 52 wells have been drilled till 2016 in this field, **al Ansary, 2000**.

2. BUILDING AND MATCHING THE WELL MODEL IN PROSPER

Well BU-16 with current production of 946 STB/day showed the serious need for the artificial lift method due to rapid decline in production comparing with year 2000 where the production was 1680 STB/Day. Building the well model in Prosper consists of modeling the physical part, PVT matching and IPR/VLP quality check.

2.1 Physical part: this part includes analyzing the final well reports starting from the casing setting depths to tubing string compositions and depth for each equipment with internal and external diameter for each section then entering the arranged well completion data and perforation intervals, where the final well depth is 4050.25m, tubing depth 3775.5m and Perforation Intervals are 3806-3814.5 m.

2.2 PVT matching: A black oil model has been used to determine the PVT properties that describe the fluid behavior under different flow conditions. The objective of matching is to eliminate uncertainties based on measured data, operating conditions and create a model that follows field measurement by choosing the best correlation that will be used for the future calculations in PROSPER software. **Table 1** shows the used PVT data for matching.

Sorting, analyzing and entering the differential liberation PVT data for well (Bu-16) is the major step after that the software will run a regression process and propose correlations that can match the actual PVT data from the laboratory. The correlations that match the PVT properties in (Bu-16) were Lasater for Bubble point, Gas Oil Ratio and Oil formation volume factor, and Beal et al correlation for Oil Viscosity, **Fig.1** shows the match point of GOR with the selected correlation. The correlation selection criteria are based on the value of parameters 1&2 that are shown in

Table 2, where Parameter1 is a multiplier whereas Parameter 2 is a shift. Therefore, the best correlation is the one with a parameter 1 close to unity and parameter 2 close to zero.

2.3 Pressure Gradient Matching: This step is essential for choosing the correct correlation that matches the well condition for modeling the multiphase flow that occurs during production. Such match is done when a test point known that includes a (flow rate, well head pressure, reservoir pressure, gauge depth that have been used in test and the gauge reading pressure at the test depth). as the software uses a non-linear regression to best fit a gradient survey. Comparison of the fit parameters will identify which correlation required the least adjustment to match the measured data. This process used to calculate the pressure distribution along the production tubing which is important to determine the multiphase flow type in each section on the production pipe.

Three pressure test points as shown in **Table 3** were used for well (Bu-16) to achieve selecting the best pressure gradient correlation. In This Step pressure gradient plots will be generated with different correlations to be compared with measured gradient survey data. The matched correlation (Beggs and Brill) was selected depending on the test points matching with the correlation graphs **Fig.2** and the matching parameters (Standard deviation:0.000976, Parameter1=1.0296, Parameter 2 = 1) where Parameter 1 is the multiplier for the gravity term in the pressure drop correlation and Parameter 2 is the multiplier for the friction term. If all the data are consistent, these two parameters should be within a ±10% tolerance from the unity.

2.4 VLP/IPR Quality check: This is the final step of the matching process it uses the same test points entered in the pressure gradient step to make sure that the vertical lift performance and inflow performance relation match with the selected correlation in the pressure gradient match step, the software usually draw a graph between VLP and IPR to check that the actual field production test point match the calculated in software depending on the selected correlation as shown in **Table 4.**

3. ARTIFICIAL LIFT DESIGN

PROSPER software is built to let the user design an artificial lift method for a well based on the entered data that the user will provide, normally the artificial lift design in PROSPER is achieved after designing and matching a naturally flow single well model. In case of naturally flow wells, where matching the well parameter in its natural flow condition is the corner stone to build an accurate artificial lift design by eliminating the uncertainty when a correct matching is achieved. After matching is achieved and the required correlation is selected, it is time now to design the artificial lift method which includes designing an ESP (Electric submersible pump) and artificial Gas lift for each well.

3.1 ESP Design

Design of Electrical Submersible Pump in PROSPER allows the User to design an ESP installation. The design is performed in two steps:
1. Determine the required pump head to achieve a specified production rate
2.Select a suitable combination of pump, motor and cable for application.
The ESP design starts with selecting the ESP setting depth in this well the selected depth was set to (3800 m) where it should be above the perforation intervals, **Larry, 2007** (3806-3814.5 m).

3.1.1 Operation Frequency**:** ESP can work at different frequencies after selecting many frequencies it turns out the optimum frequency for the current well condition is 60Hz that gave the best operating efficiency; this is an adjustable option than can be set later for different production rate in the future.

3.1.2 Maximum outside diameter: this option is to set the maximum OD for the ESP pump and motor. The selection criteria were based on API recommendation for ESP selection as in **Fig.3**, **Larry, 2007**, the production casing size for well (Bu-16) at the setting depth above perforation was (6 5/8 in) so the selected ESP O.D. for this option is (5.13 in).

3.1.3 Cable length: The total cable length should be about 100 ft. (30 m) longer than the measured pump setting depth to make surface connections at a safe distance from the wellhead, **Larry, 2007**, so an extra 30m were added to the cable length from surface to setting depth.

3.1.4 Design rate**:** The design rate is specified by the casing size for the well where the min rate should be 750 STB/Day and max 12000 STB/Day for (6 5/8 in) and pump size (5.13 in) as shown in **Fig.3**, the design rate is usually set by the desired rate of production according to pump size any rate from 750 STB/Day to 12000STB/day will make the design valid and efficient, so the selected rate was 3500 STB/Day.
The next step is to calculate the head required to be supplied by the pump to achieve a specified production rate. PROSPER uses the IPR from System Inflow Performance and the specified VLP correlation to calculate the flowing pressure at the sand face finds and the pump intake pressure for the design production rate.
The calculated results showed that the head required to achieve the desired production is 1306.5m with pump intake pressure and discharge pressure of (3211 psig) and (5262 psig) respectively.
According to the calculated head, production casing size and the pump efficiency for the condition of selected well the ESP design results are as follow in **Table 5**. **Fig.4** can show the designed ESP assembly efficiency for the selected production rate at 60 Hz operation frequency.

3.2 Gas Lift Design

Using the same matched well model for designing gas lift method, the design production rate was calculated from the possible maximum production rate, other entered parameters were as follow:
Gas lift gas gravity: assuming the same produced gas to be reinjected with specific gravity is 0.76.
3.2.1 Maximum depth of injection: The maximum depth of injection must be shallower than the production packer, the injection depth to be entered in PROSPER was 3700 m.
3.2.2 Operating injection pressure and kick-off injection pressure: Injected pressure is usually ranging from 100 psi to 300 psi per 1000 t (304.8 m) of depth, **Larry, 2007**, so the design injected pressure was 2450 psia where the calculated injection pressure was 2350 psia. injection pressure is important to keep the injection point as deep as possible to the designed injection depth and also to enable inject the gas volume to selected depth.
Gas lift design performance are summarized in **Table 6** where three valves (type Camco R-20 Valve) at depths (1689.6m, 2355m, 2453m) selected according to **Fig.5** that shows the equilibrium curves for Gas lift design. This design is good enough to support lifting the crude oil to the surface with optimum gas injection volume of 2.6 MMSCF/Day with maximum possible production rate. **Fig.6** shows the Gas lift performance curve for well Bu-16.

4. RESULTS

Running Nodal analysis with sensitivity case of water cut increasing on Bu-16 natural flow condition, shows that the well stop production when water cut value reaches to 30%. **Fig.7** shows the IPR/VLP curve behavior at different water cut values for natural flow condition. This analysis shows the importance of an artificial lift method for supporting the production when water cut value increase in the future.

Results showed that ESP will increase the production to (3615 STB/Day) at water cut 0% and the well would continue producing oil when water cut value reaches to 50% **Table 7** summaries the results for ESP design at different water cut values with reservoir pressure 5050 psi while **Fig.8** shows the VLP/IPR with PIP (pump Intake Pressure) after ESP instillation.

Gas lift design shows that the production would increase to maximum value of 3010 STB/Day at reservoir pressure of 5050 Pisa. **Table 8** shows the summary production results for gas lift design in well (Bu-16). **Fig.9** shows the IPR/VLP for gas lift at pressure 5050 psia with different water cut.

5. ECONOMIC EVALUATION

To make this comparison more realistic an economic evaluation conducted. Most of the special economic data for Buzurgan oil field are not available therefor the ESP economic data were obtained from Ahdeb oil field where there are 192 ESP units, while a modern study in West Qurna field, **SOC, PRDC, UOB, 2012** was used for the gas lift equipment prices. The loss of production during the artificial lift method installation and workover also needed to be considered in economic evaluation where the well is shut during installation. The assumed oil price was 50$ per barrel. Field experience in Ahdeb oil field shows that ESP units working life ranging from 430 days to 1000 days. ESP installation take from 3 to 8 days depending on the operations needed to be done. ESP renting cost ranges 260-300$ per day including the maintenance.

Gas lift equipment life time is usually 10-15 years. The relatively high expenses of full field gas lift project are caused by a new compressor having to be purchased. Gas lift high cost comes from the complex surface facilities required to achieve a gas lift design and work over time by minimum 10 days. It's assumed that the gas lift system needs maintenance every 2 years so it would be 7 times during the 15 years for each well. The data listed in **Table 9** show the gas lift estimations.

Its assumed that the ESP need maintenance every 560 days (1.5 year) so it would be 10 times during the 15 years. The assumed workover time for maintenance is 6 days that would shut a well with average production of (1500 bbl/day). The assumed ESP rent cost is 300$ per day and the workover well cost is 1.5 MM USD$. **Table 10** shows the detailed ESP cost estimation.

6. CONCLUSIONS

1-The ESP lift method can increase the production to 3615 STB/Day while Gas lift increases the production to only 3157 STB/Day

2- The results for ESP Design show that the selected pump efficiency was 72.74%.

3- The Gas Lift Design showed that the optimum Gas Injected Volume is 2.6 MMSCF/Day

4- The ESP Design has increased the production by 14.51% more than Gas lift method.

5- ESP was more durable and efficient than gas lift when water cut increased and reservoir pressure decreased in the future.

6- Economic evaluation showed that the ESP lift method was cheaper than gas lift method.

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ABBREVIATIONS

BHP: bottom hole pressure, psi
ESP: electric submersible pump
GOR: gas oil ratio, scf/stb
IPR: inflow performance relation
PIP: pump intake pressure
VLP: vertical lift performance

Table 1. PVT data for well (Bu-16).

Property	**Value**
GOR SCF/STB	695.542
Specific gravity of Gas	0.76 (air = 1.0)
Water Salinity (PPM)	80000
Reservoir pressure, Psi	5020
Bubble point pressure , psi	2901.44
API	23.5
Temp. ^{o}C	112

Table 2. Match statistics for well (Bu-16).

Property	Standard deviation	Parameter 1	Parameter 2
Bubble point		0.88772	-42.456
Gas Oil Ratio	20.9841	1.44251	3.4416
Oil FVF	0.019343	1.0544	-0.04633
Oil viscosity	0.080142	0.35178	0.42254

Table 3. Data entry for pressure gradient match.

Well name	Well head pressure (psi)	Test rate (STB/Day)	Gage depth (m)	pressure (psi)
Bu-16	327	946	3370	3976
			3540	4234
			3779	4537

Table 4. Calculated and measured production rate, well (Bu-16), well head pressure:330 psi.

Correlation	Test Rate	Calculated Rate	Error %
Beggs and Brill	946	929.2	-1.77

Table 5. ESP design and specifications.

Parameter	Well Bu-16
Pump Name	CENTRILIFT-E127
Motor Name	Boret- EDB125117B5
Motor Name Plate Power (hp)	168.00
Motor Name Plate Volts (volts)	2100.00
Motor Name Plate Amps (amps)	49.00
Number Of Stages	123
Power Required(hp)	156.743
Pump Efficiency(%)	72.743
Current Used (amps)	16.50
Motor Efficiency(%)	83.419
Motor Speed (rpm)	3464.67
Voltage Drop Along Cable(volts)	67.41
Voltage Required @ Surface(Volts)	2587.41
Cable Name	#1 Aluminium 0.33(volts/1000ft) 95 amps max

Table 6. Bu-16 Gas lift design results, Camco R-20 Valve.

Set num.	Valve Type	Measured depth (m)	Tubing pressure (psia)	Casing Pressure (psia)	Temp.@ Valve (°C)	Port Size (64^{th} in)	R Value	Valve opening pressure (psia)	Valve closing pressure (psia)
1	Valve	1689.6	2070.9	2994.5	107.3	12	0.038	2994.5	2959
2	Valve	2355	2693.8	3103.33	109.6	12	0.038	3103.3	3087
3	Valve	2453	2777.89	3027.89	109.86	12	0.038	3027.89	3018

Table 7. Summary results for ESP, well (Bu-16), Res. Pressure 5050 psi,well head pressure 450 psi.

Water cut %	Liquid Rate (STB/Day)	Oil Rate (STB/Day)	BHP (psia)
0	3615	3615	3915
10	3598	3238	3976
20	3577	2861	3982
30	3551	2485	3990
40	3519	2111	4000
50	3481	1740	4011

Table 8. Gas lift results for well Bu-16, reservoir pressure 5050 psia, gas vol. 2.6 MMSCF/Day, well head pressure 450 psia.

Water cut %	Liquid Rate (STB/Day)	Oil Rate (STB/Day)	BHP (psia)
0	3157	3157	4108
10	3026	2724	4147
20	2896	2317	3185
30	2754	1928	4228
40	2592	1555	4276
50	2485	1242	4308

Table 9. Gas lift cost estimation for one well.

Item	Unit cost MMUSD$
Manifold	3.5
Gas compressor	40
*Shut down cost for work over	5.25
Work over cost for 7 times	10.5
1 Km of (4 in) flow line	0.25
1 km of (14 in) flow line	0.5
Gas storage tank 50 MMSCF	15
Sum	75

*shutdown cost for work over = (10 days work over) × (1500 bbl/day) ×(50$ per bbl.) × (7 times needed for work over during 15 years

Table 10. ESP cost estimation.

Item	Cost for 15 years per well MM USD$
Pump rent	1.642
Shut down cost for work over*	4.5
Work over cost	15
Sum	21.142

*shutdown cost= (6 days work over) × (1500 bbl/Day) × (50$ price for 1 bbl) × (10 times needed for work over in 15 years)

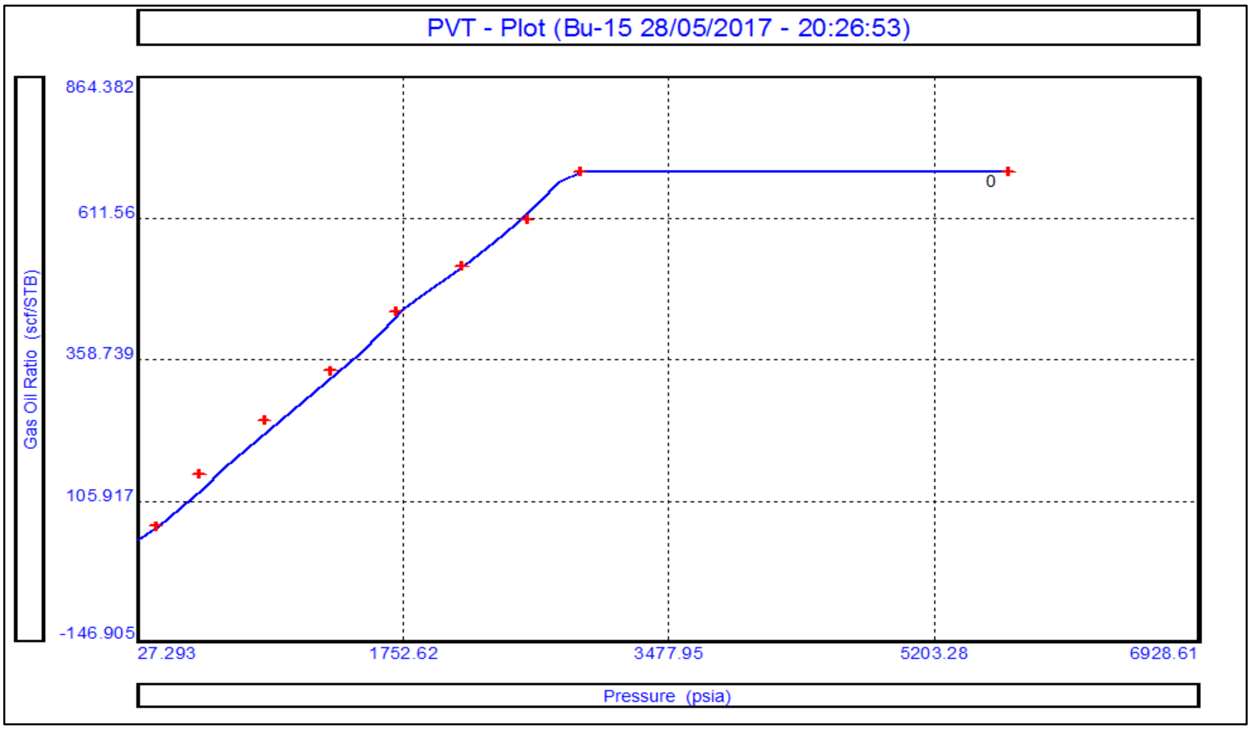

Figure 1. Gas oil ratio matching with Lasater correlation in PVT properties match of avaerage PVT data.

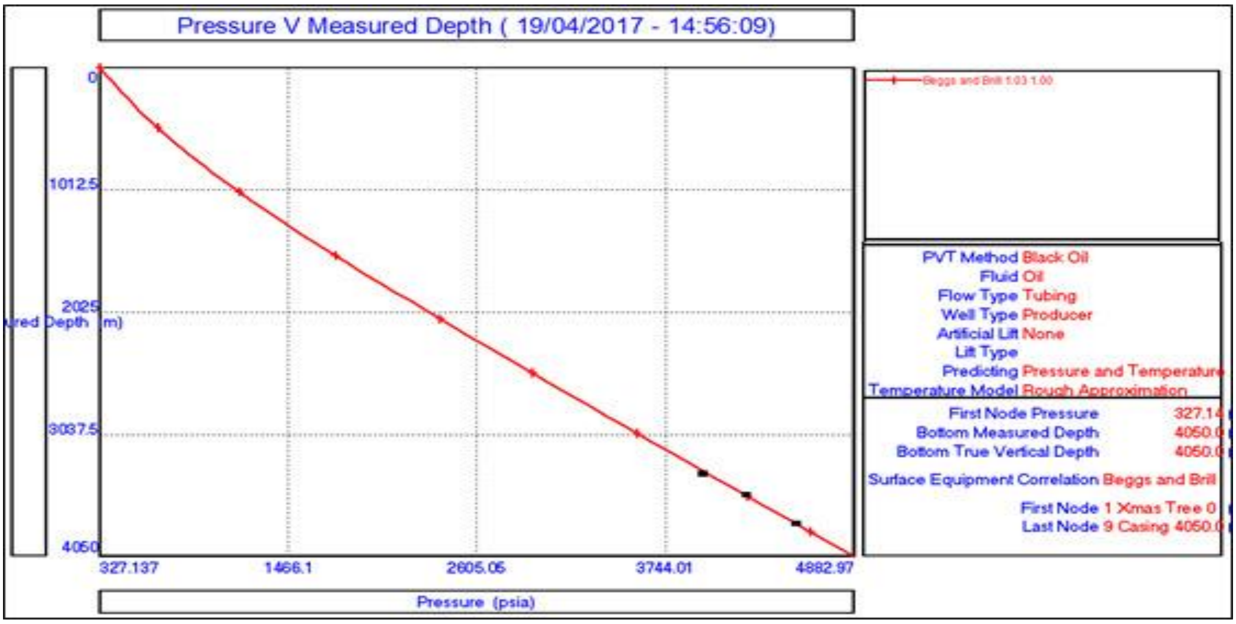

Figure 2. Pressure Gradient match with Beegs and Brill correlation.

Casing Size, in. (mm)	Pump Diameter, in. (cm)*	Flow Rate—Minimum, B/D (m^3/d)**	Flow Rate—Maximum, B/D (m^3/d)**
4 ½ (114.3)	3.38 (8.57)	550	3,100
5 ½ (139.7)	4.00 (10.16)	150	6,800
6 ⅝ (168.3)	5.13 (13.02)	750	12,000
7 (177.8)	5.38 (13.65)	900	18,400
7 ⅝ (193.7)	5.62 (14.29)	9,500	24,000
8 ⅝ (219.1)	6.75 (17.15)	5,000	46,000
10 ¾ (273.0)	8.75 (22.23)	10,300	32,200
13 ⅜ (339.8)	10.25 (26.04)	19,200	58,900

Figure 3. Typical Pump Diameter and Flow Rate for ESP according to API configuration.

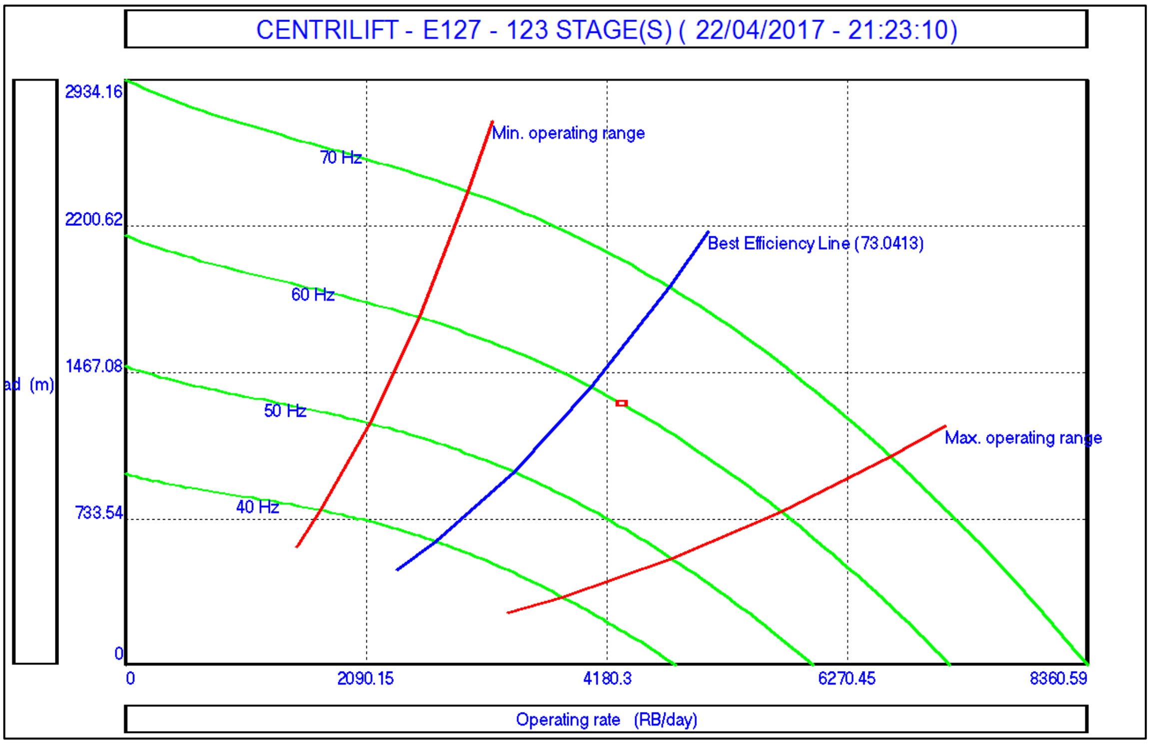

Figure 4. pump efficiency curves at 60 Hz (Bu-16).

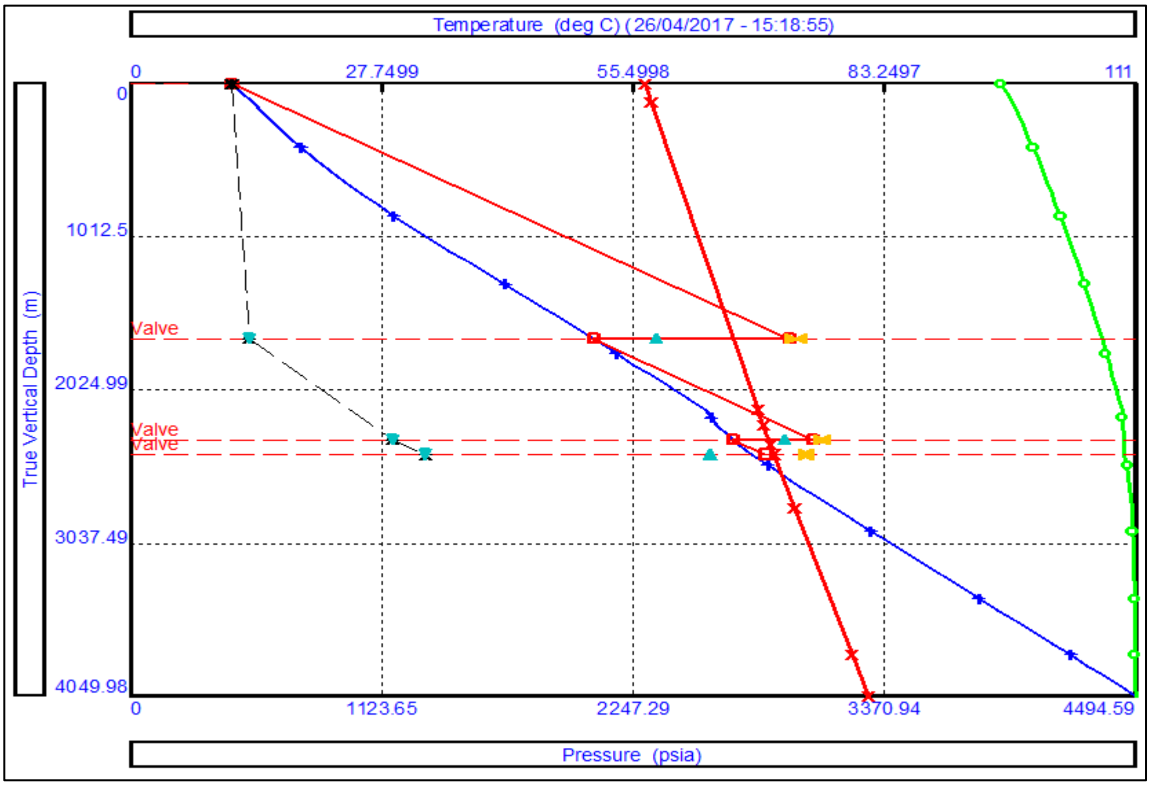

Figure 5. Equilibrium curve for well Bu-16 (Gas Lift).

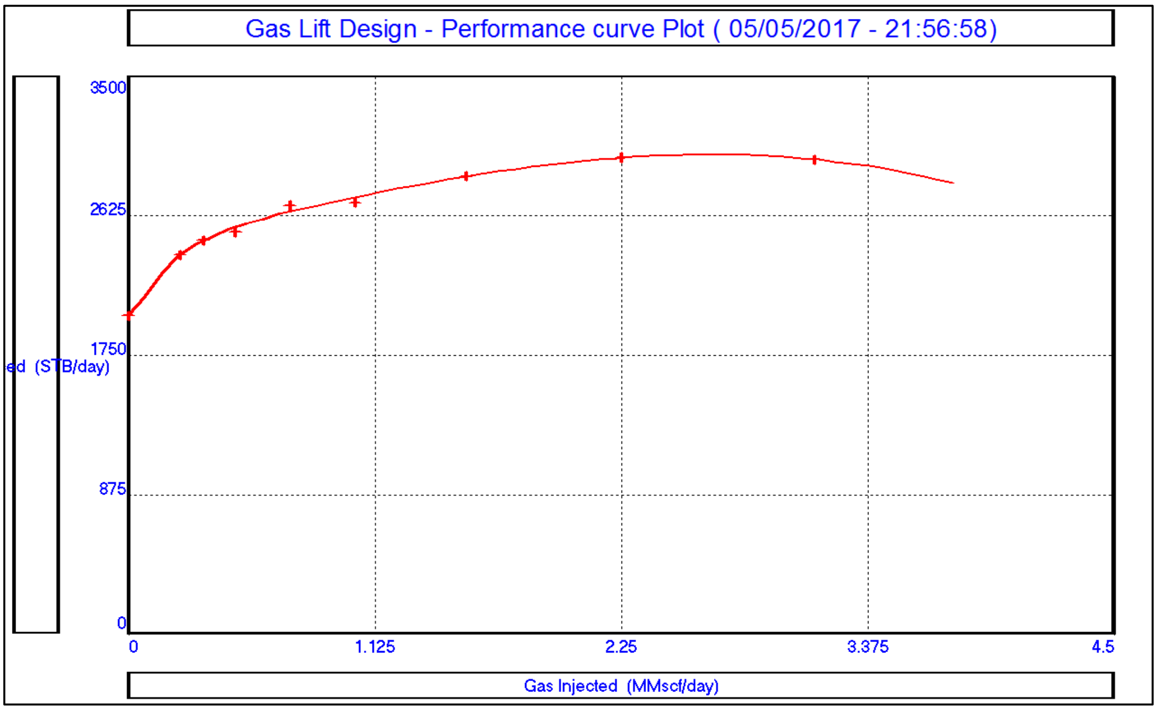

Figure 6. Gas lift performance curve for well Bu-16.

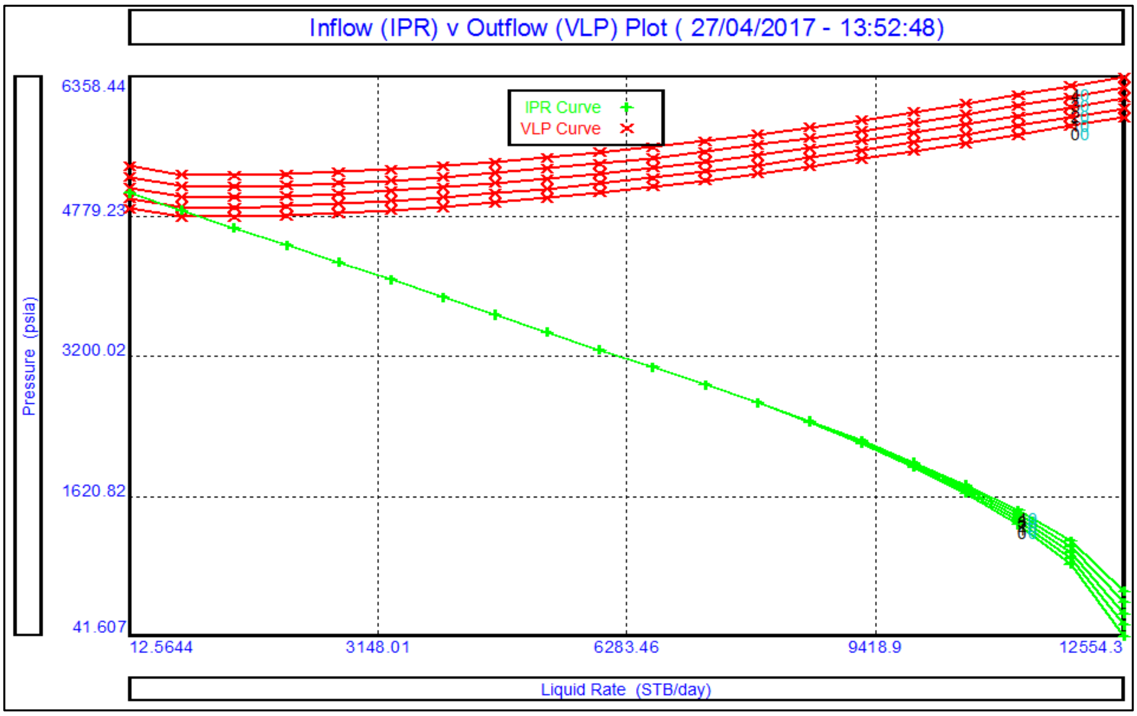

Figure 7. VLP/IPR curve for well (Bu-16), res. Pressure 5050 psia, water cut (0-50 %).

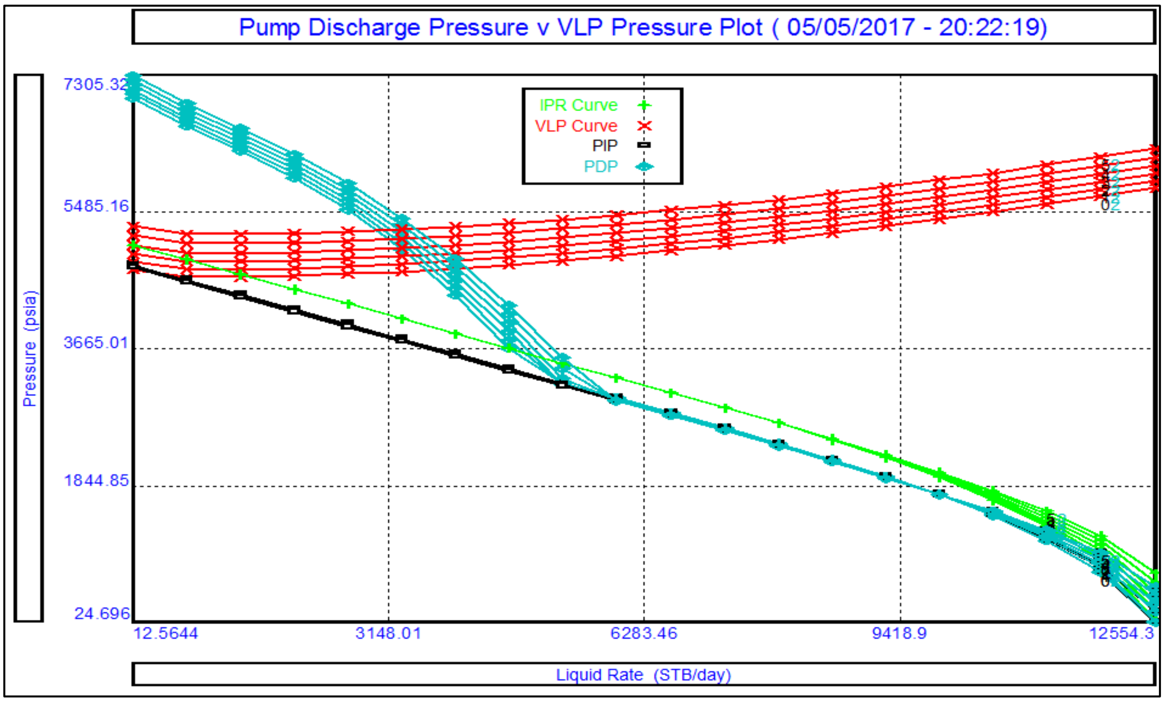

Figure 8. VLP/IPR curve for well (Bu-16) with ESP,

Reservoir. Pressure 5050 psia, water cut (0-50 %).

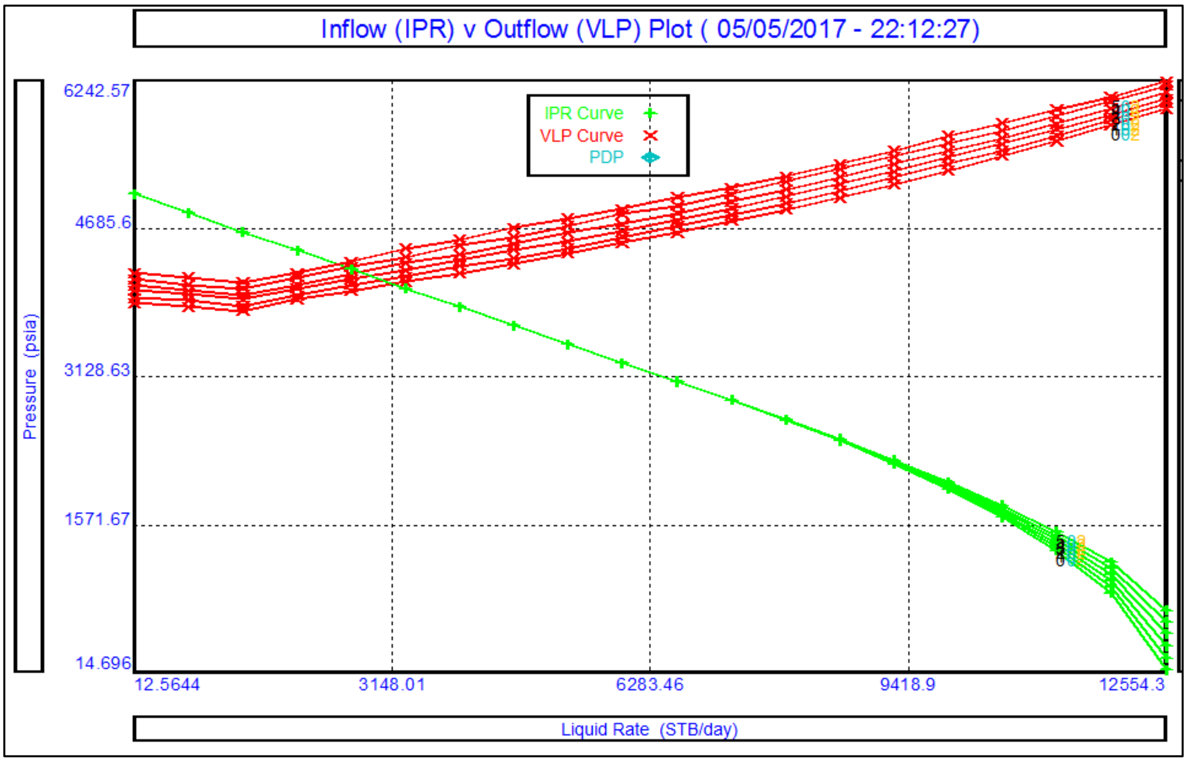

Figure 9. Gas lift VLP/IPR curve for well Bu-16 reservoir pressure 5050 psia, water cut(0-50%).