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Application of Artificial Lift Method to Solve Liquid Loading Problems; Case Study in Gas Wells of N Field

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ABSTRACT: Liquid unloading is a common problem in gas wells. If not addressed immediately, the presence of liquid will impede the gas flow to the surface. This research analyzed the application of both artificial lift methods, namely Gas lift and Electrical Submersible Pump (ESP), to solve liquid loading problems in 2 gas wells MSDC-04 and MSDC-07. The analysis begins by evaluating the current condition of the gas lift design. The results of the evaluation are used to optimize gas lift design, including optimization of gas injection flow rate and injection point depth. Pump design planning with ESP is carried out as a comparison. Furthermore, economic calculations are carried out with the lifting cost parameter as a limitation. Redesigning gas lift for MSDC-04 and MSDC-07 wells provides the most economical results. MSDC-04 well-increased gas production flow rate to 554.67 MScfd, and gas lifting cost was 0.4938 US$/MScf. Meanwhile, for MSDC-07 well, the gas lift redesign increased the gas production flow rate to 315.73 MScfd, and the gas lifting cost was 0.9107 US $/MScf.

KEYWORDS: *Gas lift, Electrical Submersible Pump, Liquid loading, Lifting Cost*

I. INTRODUCTION

In the primary stage of production, fluid or gas will naturally flow to the surface. However, as the production time increases, the reservoir pressure decreases, which affects the well's ability to flow liquid or gas to the surface naturally. Artificial lift methods are needed to maintain oil or gas production. Some of the commonly used artificial lifting methods include Gas lift, Electrical Submersible Pump (ESP), Hydraulic Jet Pump, Progressive Cavity Pump (PCP), Plunger Lift, and Sucker Rod Pump.In a water-drive gas reservoir, pressure drop often causes water to accumulate at the bottom of the well as a result of gravity. This condition causes gas cannot flow to the surface, which is known as a liquid loading problem. The liquid loading problem can be identified by calculating the critical gas production rate, as shown by Turner[1]. If the gas rate is above the critical rate, the droplet can be lifted to the surface. Conversely, if the gas rate is below the critical rate, gas will fall and accumulate at the bottom of the well. There have been many studies related to liquid loading. Duggan introduced the concept of critical minimum wellhead gas velocity for early indication of liquid loading problems [2]. Coleman states that the critical rate turner's is accurate for predicting liquid loading problems [3], and Guo presented a further improvement on the Turner criteria. Lea and Nickens [4] discuss how to solve the fluid loading problem [5]. N. Dousi [6]demonstrated that in some situations, the metastable flow rate can exceed the Turner rate, thereby effectively eliminating the detrimental effects of liquid loading [6]. Good design ESP system has proven to be reliable in various water dewatering applications in gas fields, especially those aimed at water gas wells with low formation pressure and high volume [7]. The research results of Chidirim Ejim and Jinjiang Xiao show that the gas lift method (continuous, plunger-assisted, gas-assisted) is the most effective method for solving liquid loading problems [8]. The ESP method provides the lowest effectiveness.

This research will compare the use of 2 artificial lift methods on the MSDC-04 well and the MSDC-07 well to solve the liquid unloading problem. Both of these wells are gas wells with strong water drives. A very large rate of water production causes a water slug in the tubing which inhibits the gas flow rate. An artificial lift method is needed to solve this problem. The artificial lift currently installed in the two wells is a gas lift. There is a problem with the operating valve that has been closed by the presence of water so that the unloading valve located above it switches its function to become an operating valve. From an evaluation of the current situation, the use of gas lifts is considered to be ineffective because the flow rate of gas production has decreased but requires more gas supply for gas lift injection purposes, while the total gas production flow rate for consumer needs must also be met. Therefore, gas lift optimization is carried out under current conditions for both wells by increasing the gas injection flow rate and increasing the injection point depth by planning a gas lift redesign. Another artificial lift method for comparison is Electrical Submersible Pump (ESP). ESP is expected to increase the flow rate of gas production by producing large amounts of water. The application of ESP to the two gas wells with liquid loading problems requires careful determination of the depth of the pump and additional equipment components. The artificial lift method to be used is selected based on the low lifting cost value[9]. The lower lifting cost value is considered more economical because the resulting production rate can cover expenditure costs for pump realization needs.

II. MATERIALS AND METHODS

Liquid loading is an accumulation of liquid at the bottom of the wellbore as reservoir pressure decreases. It generally occurs in wet gas reservoirs but can also occur in dry gas reservoirs due to water directly entering the wellbore from an adjacent aquifer [10]. The accumulation of liquid at the bottom of the well causes the productivity of gas wells to decrease. Turner proposed and investigated two models to determine the main controlling factors in liquid accumulation in gas wells, i.e., liquid droplets entering into the high-velocity main gas stream and continuous liquid film flow moving along the production tubing [11]. To predict the critical gas velocity and gas critical flow rate, the Turner equation is used as follows;

$$Vgc = 1.92x\frac{\sigma^{1/4}x(\rho 1-\rho g)^{1/4}}{\rho g^{1/2}} \quad (1)$$

$$Qgc=\frac{PrxTscxAxVgc}{1000xPscxZxT}x3600x24 \quad (2)$$

Where:

Vgc	= Critical velocity of the gas, ft/s
σ	= surface tension, dyne/cm
ρg	= Density of gas, lb/cuft
ρl	= Density of liquid, lb/cuft
Qgc	= Critical gas flow rate, Mscfd
Pr	= Reservoir pressure, psia
Psc	= Standard state pressure (14.7 psia)
A	= Tubing surface area, ft²
T	= Reservoir temperature, °R
Tsc	= Standard state temperature (60 °F), °R
Z	= gas compressibility factor

The productivity index (PI) is one of the parameters used to determine the ability of a well to produce fluid per day at each difference in reservoir pressure (Pr) and well bottom flow pressure (Pwf). The productivity index can be calculated by the following equation [10]:

$$PI = \frac{Q}{Pr-Pwf} \quad (3)$$

PI	=	Productivity Index, bfpd/psia
Q	=	Production flow rate, bfpd
Pr	=	Reservoir pressure, psia
Pwf	=	bottom well pressure, psia

As for planning the redesign of the gas lift, Otis's method is used with the following steps (Figure 2):

a. Calculating Liquid Level Column (LLC).

$$\Delta P = Pr - Pwf \quad (4)$$

$$\Delta D = \frac{\Delta P}{SGw} \quad (5)$$

$$LLC = Dmid\ Perforation - \Delta h \quad (6)$$

b. Correction of kick-off pressure and injection pressure using correction graphs of gas injection pressure at the surface Vs gas injection pressure at the mid-perforation depth (Figure 1).

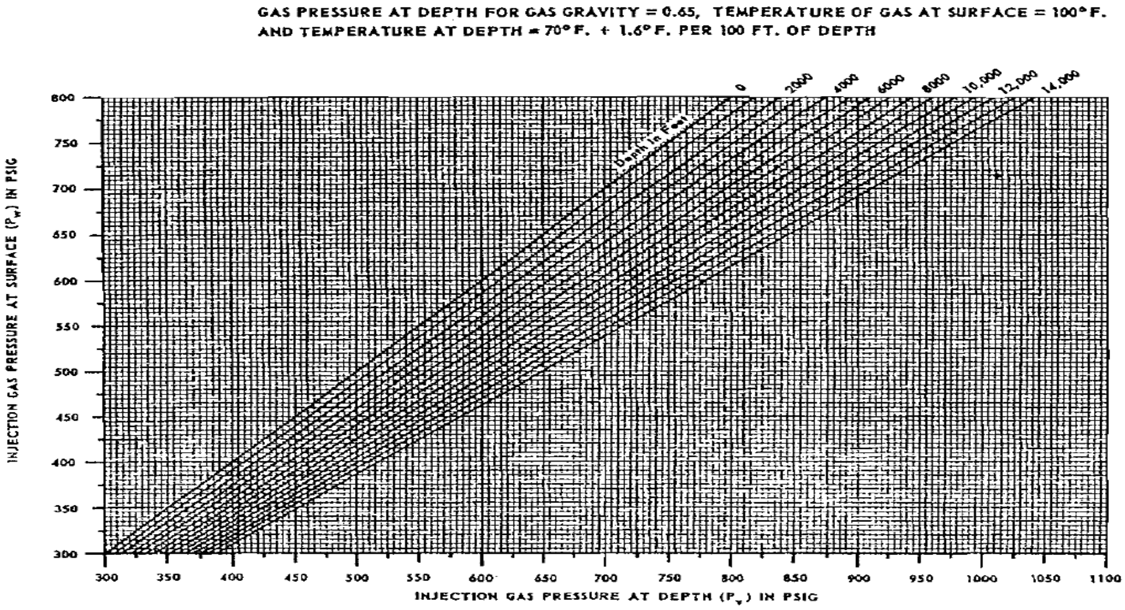

Figure 1. Graph of Surface Temperature Correction and Mid Perforation Temperature [12]

c. Calculate Pwh with the Otis Method.
   Pwh Otis = Pwh + 0.2 (Pso – Pwh) (7)
d. Draw the LLC depth line with Pwf on the gas lift redesign chart.
e. Draw Pso and Pko lines with corrected Pso and corrected Pko.
f. Take the point of intersection between the results of the plot points d and point e, then take the difference of 100 ft from the point of intersection for the factor of safety.
g. Pwh and Pwh Otis plots with intersection results.
h. Calculate the killing fluid pressure taken at each depth interval by multiplying the fluid gradient by the killing fluid depth.
i. Draw the Pwh line through the killing fluid depth interval point to the Pko line and then to the Otis Pwh line. This point on the Pko line represents the depth of the first gas lift unloading valve.
j. Draw a line from Pwh Otis to Pso line in line with a triangular ruler, do it until or before the point of intersection (point F).
k. Count the number of points contained in Pso, and this line represents the number of gas lift valves that will be used next.

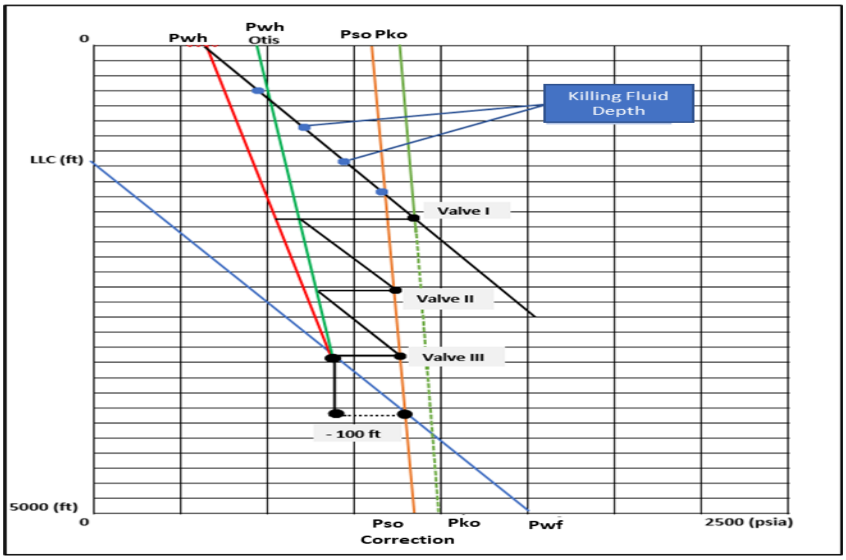

Figure 2. Gas lift design used Otis Method

The Electrical Submersible Pump (ESP) Redesign planning is carried out in the following steps:

Step 1
1. Create an IPR curve.
2. The IPR curve used is a single-phase IPR curve.
3. Determine the target production rate.
4. The target production rate is determined based on the type of pump used. The selection of pump type is made by looking at the minimum casing size. The maximum production rate is obtained from the IPR curve according to the selected pump capacity.

Step 2
Determine the average specific gravity and fluid gradient.

SGavg = (SGw x Wc) + (SGo x (1-Wc) Gfavg = SGavg x 0.433 (8)

Step 3
Determine Pump Setting Depth (PSD).
PSD is determined according to company policy which is under three joints (90 ft). PSD is placed below the depth of mid-perforation so that the gas produced does not enter the pump to prevent a gas lock from occurring.

PSD = D Mid perforations + 90 ft (10)

Step 4
Determine Pump Intake Pressure (PIP).

ΔD = PSD – D Mid Perforations (11)

ΔP = ΔD x Gf avg (12)

PIP = Target Pwf + ΔP (13)

Step 5
Calculating the Presence of Gas.

Vig = Qg x Bg (14)

Vw = total Qw (15)

Vt = Vig + Vw (16)

% free gas at pump intake = $\frac{\boldsymbol{Vig}}{\boldsymbol{Vt}}$x 100% (17)

The result of % free gas entering pump intake must be less than 10%. If it is more than 10%, it must be recalculated to determine the selection of a gas separator or gas handler to prevent gas from entering the pump.

$Vig\ new = (1-\text{SE}) \times (1-\text{NS}) \times Vig$ (18)

Where:

Gas Separator Efficiency (SE) = 80%

Natural Separation Factor (NS) = 20%

Step 6
Determine the Total Dynamic Head (TDH) and the optimum number of stages.
Total Dynamic Head (TDH)

$$\text{Fluid Over Pump (FOP)} = \frac{PIP}{Gfavg} \quad (19)$$

$$\text{Vertical Lift (HD)} = \text{PSD} - \text{FOP} \quad (20)$$

$$\text{Friction Loss (F)} = \frac{2.083\left(\frac{100}{C}\right)^{1.85}\left(\frac{Qt}{34.3}\right)^{1.85}}{ID^{4.8655}} \quad (21)$$

$$\text{Tubing Friction Loss (HF)} = \frac{F\ x\ PSD}{100} \quad (22)$$

$$\text{Tubing Head (HT)} = \frac{Pwh}{Gf\ avg} \quad (23)$$

$$TDH = HD + HF + HT \quad (24)$$

Number of Optimum stages

$$\text{n Stage} = \frac{TDH}{Head} \quad (25)$$

The optimum number of stages is obtained from the ESP pump performance curve, namely from the plot of the target production flow rate with the head curve (Figure 3).

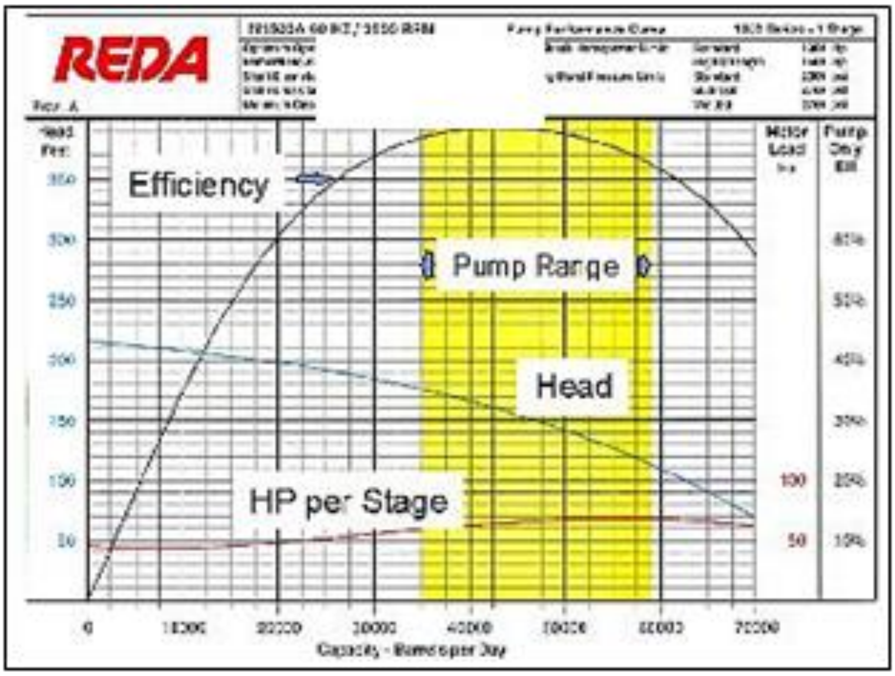

Figure 3. ESP Pump Performance Curve

Step 7

Determine Q possible from the stages available in the field and Q assumptions.

If an optimum number of stages is not available in the field, the number of stages close to optimum stages can be used. The total dynamic head (TDH) must be recalculated according to the assumed production rate (Q assumed) and the number of stages available in the field.

1. TDH for the number of stages available in the field
   - Determine Q assumptions.
   - Determine the number of heads/stages for each Q assumption on the ESP pump performance curve.
   - Determine the price of the head (ft) for each stage available in the field.

$$\text{TDH} = \frac{headxn\ stages}{stage} \tag{26}$$

2. TDH for each Q assumption
   - Determine Pwf for each Q assumption with equation 3.
   - Determine the vertical lift (HD).

$$\text{HD} = \frac{PSD - Pwf}{stage} \tag{27}$$

   - Determine friction loss (F) and tubing friction loss (HF) with Equation 21 and Equation 22.
   - Determine the tubing head (HT) with equation 23.
   - Determine TDH with equation 24.

From the results of the above calculations, plot TDH for the number of stages used with TDH for each Q assumption. The intersection of the two lines shows the possible Q of each stage to be used.

Step 8

a. Motor Selection

   HP = stages x (HP/stage) x SGavg (28)

   The choice of motor is determined by the type of motor that has a higher HP than the calculated HP. Motors can be installed in single, upper tandem (UT), lower tandem (LT), and center tandem (CT) according to HP needs.

b. Protector Selection

$$\text{TOB} = \frac{Head@@{=}0xstagexSGavgxshaft\ area}{2.31} \tag{29}$$

   The type of protector chosen has a greater Thrust on Bearing (TOB), well conditions, and reservoir temperature.

c. Defining Shrouds

   The selected shroud outside diameter must be less than the ID casing and length from the pump to the bottom of the motor with a safety factor of 5 ft.

Length of Shroud = L pump + L protector + L gas separator + L motor + 5 ft (30)

d. Cable Selection

The cable selection procedure is as follows:

- Check the clearance between the ID of the casing and the maximum OD of the pump unit (i.e., the largest OD between the motor and the pump)
- Choose a cable according to the bottom temperature of the well and according to the motor voltage

e. Motor Lead Extension (MLE) Selection

MLE is used if the clearance between the casing ID and the maximum OD of pump components (motor OD, protector OD, and pump OD) is too small so that no ESP cable size fits. The choice of MLE is also influenced by the temperature of the well and the type of motor used.

MLE clearance = ID casing – OD protector

f. Determining Transformer Selection

Before selecting a transformer, it is necessary to determine the voltage drop per 1000 ft for the cable type using the ESP cable voltage drop chart and a temperature correction factor according to the reservoir temperature. After obtaining the temperature and voltage drop correction values, the selection of transformers for each stage can be determined as follows:

L Flat cable = L protector + L pump + 5 ft Length of Cable = PSD + L flat cable

$$\text{Cable Volt Drop} = \frac{\text{Voltage drop x (L cable) x Tcorr}}{1000} \quad (31)$$

Surface Voltage = Motor Volts + Cable Volt Drop

$$\text{Surface KVA} = \frac{\text{Surface voltage x Motor Ampere x 1.73}}{1000} \quad (32)$$

The voltage loss in the cable increases with the length of the cable, and voltage loss originating from the motor affects the voltage required above the surface so that power to the transformer must exceed the voltage required above the surface.

g. Determining Switchboard Selection

The choice of switchboard exceeds the HP capacity, voltage, and current of the electric motor used.

h. Calculating Cable Clamps

A cable Clamp is used to attach the pump cable to the outside of the tubing. Each 15 ft requires one cable band and an additional five cable bands for each pump component.

$$\text{Cable clamps} = \frac{\text{PSD}}{5} + 5 \quad (33)$$

Lifting Cost

The basic economic calculation used is the amount of lifting Cost for each type of artificial lift.

$$\text{Lifting costs} = \frac{\frac{\text{Capital costs}}{\text{amortization time}} + \text{non}-\text{capital costs}}{\text{flow rate x 365}} \quad (34)$$

Capital costs are funds used to finance asset procurement and operations. While, Non-capital costs are costs incurred to operate a system.

III. RESULTS AND DISCUSSION

Both of MSDC-04 and MSDC-07 are gas wells in the NY field in the Malacca Strait. Both of these wells have a liquid loading problem where the flow rate of water production is very high. This condition causes the flow rate of gas production to be hampered. Both of these wells also have a strong water drive. The flow rate of water production continues to increase, and the reservoir pressure does not decrease rapidly. In this case, the decrease in reservoir pressure cannot be used as an indicator of a liquid loading problem. But it can be seen at critical gas velocity and gas critical flow rate; namely, the velocity of the fluid phase is the same as the velocity of the gas phase. The critical velocity of gas and critical flow rate of gas in these two wells are 4.98 ft/s and 2624.05 Mscfd, while the flow rate of gas production in MSDC-04 well is currently 281 Mscfd and the flow rate of gas production in MSDC-07 well is 105 Mscfd so that it is already below the critical gas flow rate and ability of gas to flow to the surface is no longer feasible. An increase in the flow rate of water production followed by a decrease in the flow rate of gas production also proves the occurrence of liquid loading. MSDC-04 well has experienced an increase in water production since 2014 from 740 bwpd to 2613 bwpd while a decrease in gas production from 2376 Mscfd to 281 Mscfd and for MSDC-07 increased water production from 103.3 bwpd to 1313 bwpd and decreased gas production from 2173.5 Mscfd to 105 Mscfd.

Currently, both wells use continuous gas lifts with three gas lift valves to overcome liquid loading problems. However, the current use of gas lifts is considered ineffective due to the increased volume of water in the tubing. The increase in water volume causes the operating valve on the gas lifts to move to the unloading valve. For MSDC-04 well, the operating valve switches to the second unloading valve, while for MSDC-07 well, it switches to the first unloading valve. This resulted in a decrease in the flow rate of gas production in both wells. From the evaluation of the installed gas lift, it is necessary to optimize the gas lift to increase gas production. Unfortunately, optimization by increasing the gas injection flow rate cannot be carried out due to limited gas availability. Optimization is done by redesigning the depth of the gas lift operating valve. MSDC-04 well has three gas lift valves installed at depths of 1658.94 ft, 2328.64 ft, and 3101.43 ft. The redesign of the gas lift valve resulted in three valves with a depth of 2265.68 ft, 3100.32 ft, and 3695.82 ft. Optimizing the depth of the gas lift valve increases the total flow rate of water production by 4900 bwpd and the flow rate of gas production by 526.94 Mscfd. Additional compressors are required for a valve operating depth of 3695.82 ft to obtain a pressure of 1145.7 psia. As for MSDC-07 well, three gas lift valves have been installed at depths of 2006.76 ft, 3495.42 ft, and 4384.34 ft. The redesign obtained the depth of the gas lift valve at 2272.5 ft, 3108.78 ft, and 3587.6 ft. This optimization increases the total flow rate of water production by 3600 bwpd and the flow rate of gas production by 288 Mscfd. Adding a compressor to the operating valve depth of 3587.6 ft to obtain the required pressure of 1004.53 psia.

To obtain the optimum production rate, the gas injection rate for MSDC-04 well was increased from 0.33 MMscfd to 0.48 MMscfd. This optimization increases the flow rate of water production to 5157.8 bwpd and the flow rate of gas production to 554.67 Mscfd. For the MSDC-07 well, the gas injection flow rate was increased from 0.395 MMscfd to 0.52 MMscfd. This optimization increases the flow rate of water production to 3948.16 bwpd and the flow rate of gas production to 315.73 Mscfd.By using ESP, the production flow rate is much greater than that of gas lift. This is because the depth of the pump is below the depth of mid-perforation, causing the natural (gravity) separation of water and gas. Water will descend through the shroud before entering pump components, and gas will rise through the annulus to be produced. Whereas in the gas lift, gas and water in the tubing are in the form of slugs so that the fluid flow gradient is heavier. Especially if the flow rate of water production is dominant and the amount of gas injection flow rate is very limited.The results of the economic calculation of the gas lift redesign of the MSDC-04 well obtained a water lifting cost of 0.0531 US$/bbl and a gas lifting cost of 0.4938 US$/Mscf. In comparison, the ESP with 118, 122, and 126 stages obtained a water lifting cost of 0.0953 and 0.0920 US $/bbl, respectively, and a gas lifting cost of 0.8862 and 0.8556 US $/Mscf, respectively. From the results of the two methods, gas lift redesign is more economical than ESP.For the MSDC-07 well, the gas lift redesign resulted in a water lifting Cost of 0.0728 US$/bbl and a gas lifting cost of 0.9107 US$/Mscf. While ESP with 166, 170, and 174 stages obtained water lifting costs of 0.1141, 0.1123, and 0.1118 US$/bbl, respectively, and gas lifting costs of 1.4273, 1.4042, and 1.3989 US$/Mscf respectively. For MSDC-07 well, gas lift also provides a lower lifting cost than ESP.

IV. CONCLUSION

Liquid loading problems in MSDC-04 and MSDC-07 wells can be identified from the critical gas flow rate. The liquid loading problem causes a decrease in gas production due to water blocking. This problem can be overcome by redesigning the depth of the gas injection valves of these two wells. Likewise, ESP can be a solution to overcome the problem of liquid loading in both MSDC-04 and MSDC-07 wells. ESP method is more effective in overcoming liquid loading problems in two wells compared to gas lift. This is indicated by a higher gas production rate. The depth of the pump, which is located below the depth of mid-perforation, helps the separation of water and gas by gravity compared to gas lift. In a gas lift, water and gas are produced together to form a slug in the tubing. However, economically, the gas lift method provides a lower lifting cost than ESP.

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