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An Analysis of the Use of Hydraulic Jet Pumps, Progressive Cavity Pumps and Gas Lift as Suitable Artificial Lift Methods for Heavy Oil Production in East Soldado Reservoirs, Offshore the Southwest Coast of Trinidad

Raffie Hosein [a, Ψ], and Amrit S. Balgobin [b]

Department of Chemical Engineering, Faculty of Engineering, The University of the West Indies, St Augustine, Trinidad and Tobago, West Indies;
[a]E-mail: Raffie.Hosein@sta.uwi.edu; Chemical.Engineering@sta.uwi.edu
[b]E-mail: amrit.balgobin@bakerhughes.com

[Ψ] *Corresponding Author*

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Abstract: *Artificial lift refers to the use of artificial means to increase the flow of oil from a production well when there is insufficient pressure in the reservoir to lift the oil to surface, or in flowing wells to obtain a desired production rate. Generally, this is achieved by the use of a mechanical pump inside the well or by decreasing the weight of the oil column by injecting gas some distance down the well. On platform X in the Soldado field offshore the Southwest coast of Trinidad, gas-lift and to a lesser extent, progressive cavity pumps (PCP), are installed in wells to sustain the desired oil production targets. More recently, hydraulic jet pumps have been installed. However, a performance analysis of these lift systems has never been conducted to determine which one is most suitable for this reservoir. In this study the software PipeSim was used to develop models for the currently installed gas lift and PCP configurations and then optimised to determine the best oil lifting capabilities for these two systems. Similar models were developed for the hydraulic jet pumping system using the SNAPTM software. Data from a pilot well indicate that the optimised installations for gas lift, PCP, and hydraulic jet pumps when sequentially applied are capable of lifting 90, 325, and 450 barrels of fluid per day (bfpd) respectively. These results indicate that hydraulic jet pumps are capable of lifting 40 % more fluids than PCP and 400 % more than gas lift. A lift score analysis between PCP pumps and hydraulic jet pumps was then conducted by comparing lifting potential, installation cost and time, rig vs. non-rig intervention for the installation; and ease of operation and optimisation. The results from this analysis indicate- that the average lift score for hydraulic jet pumps was 4.5 and 2.5 for PCP pumps. These results indicate that in addition to having the highest lifting capability, hydraulic jet pumps are cheaper and easier to install, operate and maintain. It is also a more cost-effective oil lift system compared to PCP pumps. This lift score can also be used as a guide to effectively optimise artificial lift systems for other oil wells from this field.*

Keywords: *Artificial lift; jet pumps; performance evaluation; increase flow; oil well; Trinidad*

1. Introduction

Artificial lift may be defined as the addition of energy to the column of fluid within the wellbore to obtain a higher production rate from the well (Clegg, 1985). This addition of energy is usually applied when the reservoir pressure is declining and the desired production rates cannot be sustained (Hesham and Addou, 2006). The energy addition is by two primary mechanisms:

1. Reduction in column hydrostatic pressure by gas injection
2. The addition of a displacement type device by down-hole pump installation

Both mechanisms increase oil production by reducing the back pressure on the formation allowing for longer economic production periods.

Artificial lift systems can be classified into three primary categories; gas lift; rod pumps/progressive cavity pumps (PCP); hydraulic jet pumps

1.1 Gas Lift

This operation involves the injection of a high pressure gas stream into the production tubing to reduce the fluid column density (see Figure 1). This causes an upward movement of the wellbore fluid to surface as well as greater inflow from the reservoir. This type of lift can be either continuous or intermittent (Vincent et al., 1953). Gas lift is used extensively around the world. A central gas-lift system can easily be used to service many wells or an entire field and lower total capital cost. It is the best artificial lift method for sand or solid materials. The produced sand causes few mechanical problem in the gas-lift system; whereas, only a little sand plays havoc with other pumping methods, except the progressive cavity pumps (PCP). Deviated or crooked holes can be lifted easily with gas lift. This is especially important for offshore platform wells that are usually drilled directionally. Gas lift permits the concurrent use of wireline equipment, and such downhole equipment is easily and economically serviced. This flexibility allows for routine repairs through the tubing.

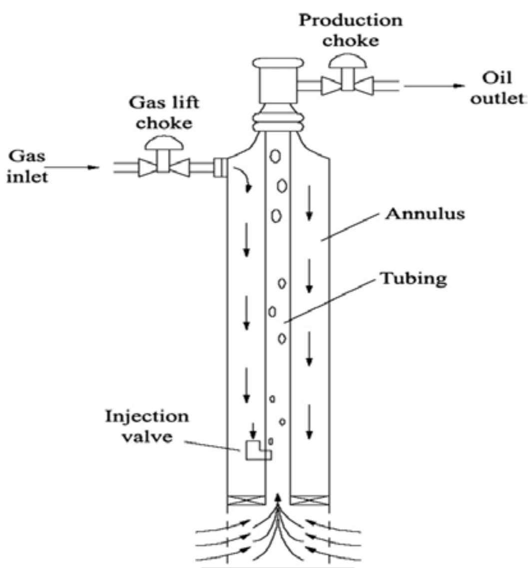


Figure 1. Gas Lift

1.2 Rod Pumps/Progressive Cavity Pumps (PCP)

Rod pumps (see Figure 2) or progressive cavity pumps (PCP) (see Figure 3) assist the flow of fluid from the well bore to surface. Reservoir deliverability is increased as the back pressure on the formation is reduced during the operation (Wang et al., 2010). Rod pumping bottomhole assemblies (BHA) comprise of a plunger, fullbore barrel, flow valve and inflow valve. The up and down reciprocating motion of the plunger produces fluid from the wellbore to surface (Wang et al. 2010).

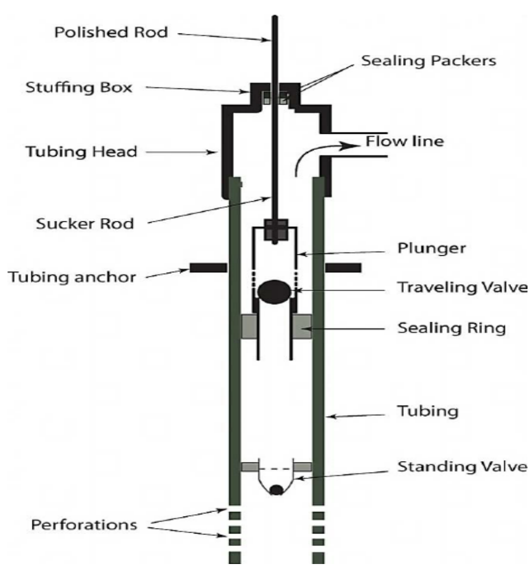


Figure 2. Rod Pump

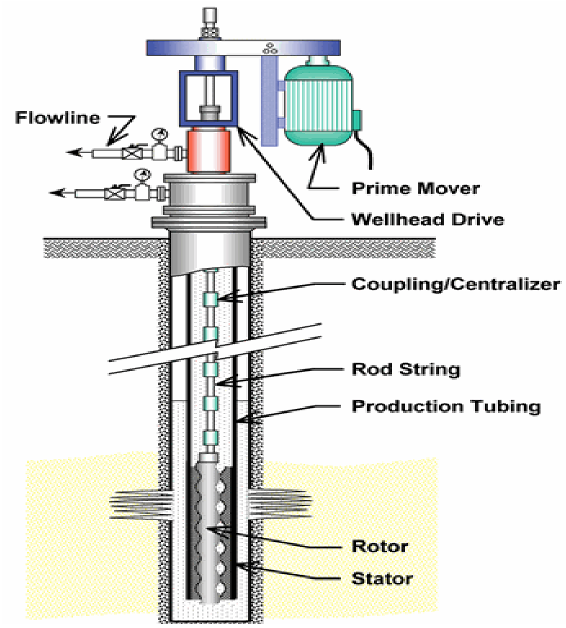


Figure 3. Progressive Cavity Pump (PCP)

Introduced in 1936, the PCP has a simple design and rugged construction. Its low operating speeds (300 to 600 rev/min) enable the pump to maintain long periods of downhole operation, if not subjected to chemical attack or excessive wear or it is not installed at depths greater than 4,000 to 6,000 ft. The pump has only one moving part downhole with no valves to stick, clog, or wear out. The pump will not gas lock and can easily handle viscous heavy oil, sand production. It is not normally plugged by paraffin or scales. PCP BHAs comprise of a rotor and stator. The rotation of the spiral-shaped rotor within the stationary elastomeric stator diplaces fluid out of the stator into the production tubing.

1.3 Hydraulic Pump Systems

Jet pumps (see Figure 4) and reciprocating positive-displacement pumps are the two primary hydraulic pumps. The hydraulic jet pump was designed based on the Venturi lift principle (Petrie, 1987). The Venturi effect is created when high pressure/low velocity power fluid (refined oil or produced fluid) is pumped through a nozzle in the pump. Power fluid exiting the nozzle is at high velocity/low pressure. The pressure drop draws in reservoir fluid which mixes with the power fluid in the expansion tube or throat. The mixture fluid changes in the diffuser back to high pressure/low velocity which exit the jet pump housing and travel up the annulus to surface.

Hydraulic pumping is a proven artificial-lift method that has been used since the early 1930s. Successful applications have included setting depths ranging from 500 to 19,000 ft and production rates varying from less than 100 to 20,000 B/D. Hydraulic pumping systems are suitable for wells with deviated or crooked holes that can cause problems for other types of artificial lift. The surface facilities can have a low profile and may be clustered into a central battery to service numerous wells. The significant feature of jet pumps is being able to easily run the pump in and out of the well. It is especially attractive on offshore platforms and remote locations. Jet pumps can even be used through flowline installations. By changing the power-fluid rate to the pumps, production can be varied from 10 to 100% of pump capacity. It can easily handle viscous heavy oil and sand production.

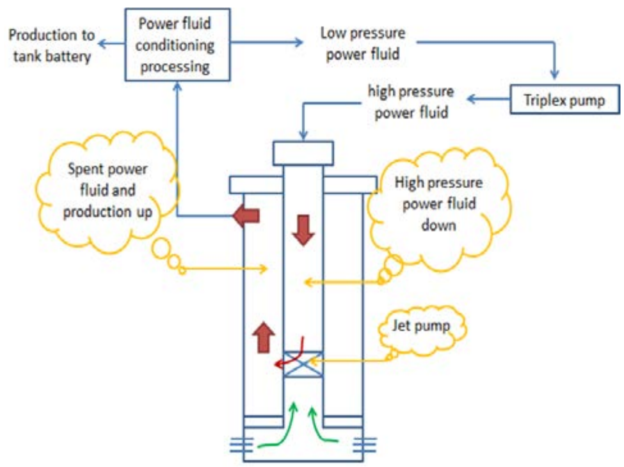


Figure 4. Jet Pump

2. Artificial Lift Monitoring and the Soldado Artificial Lift Experience

Artificial lift systems require continuous monitoring and updating of operating conditions, so as to obtain optimal well productivity. Well and reservoir data are used to model the well potential or inflow performance relationships (IPR) for continuous monitoring of the lift system. IPR curves can be constructed using the relationship between pressure and flow rate described by Vogel (1968) as:

$$Q_o = (Q_o)_{max}[1 - 0.2(P_{wf} / \bar{p}) - 0.8(P_{wf} / \bar{p})^2]$$

where,

Q_o = oil rate at P_{wf} (STB/day)

$(Q_o)_{max}$ = maximum oil flow rate at zero wellbore pressure, i.e., AOF (STB/day)

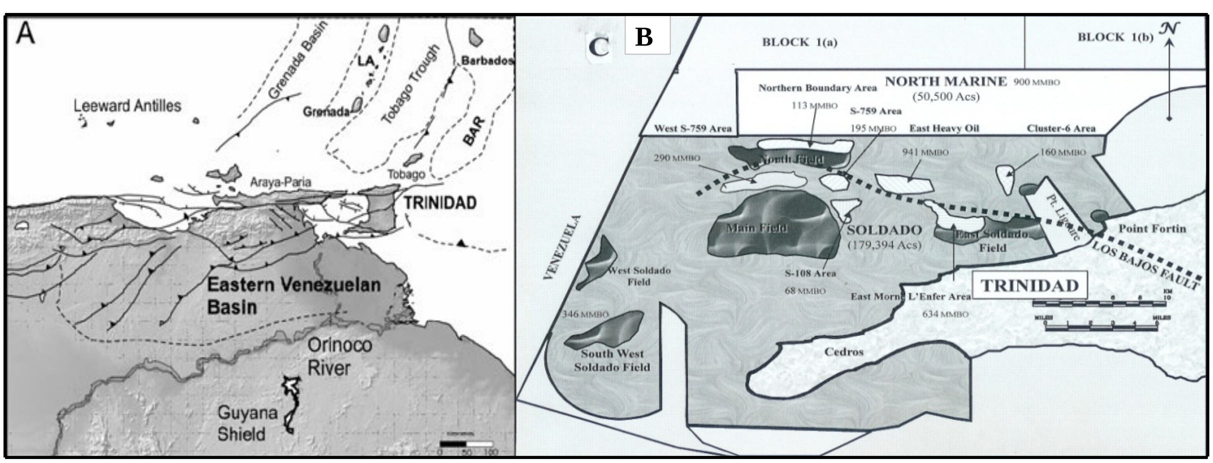
$\bar{p}$ = current average reservoir pressure, psig

P_{wf} = bottom-hole flowing pressure, psig

To use this relationship, the oil production rate; flowing bottom-hole pressure from a production test; and an estimate of the average reservoir pressure at the time of the test must be obtained. With this information, the maximum oil production rate can be estimated and used to estimate the production rates for other flowing bottom-hole pressures, P_{wf}, at the current average reservoir pressure, $\bar{p}$, (Larry and Clegg, 2007). An IPR curve is then generated by plotting surface production rate (STB/d) versus flowing bottom-hole pressure (P_{wf} in psi) on cartesian coordinates. This plot is very useful in estimating well capacity, designing tubing string, and scheduling an artificial lift method.

Trinidad is located East of the Eastern Venezuelan basin; and the Soldado acreage, which had its first oil discovery in 1953, is located offshore the Southwest Coast of Trinidad (see Figure 5). Oil production began in 1957 from the North, Main and East Soldado Fields. Gas lifting operations were implemented in many wells within the North and Main Soldado areas which have low viscosity oil with relatively low GOR's. As deeper reservoirs became pressure depleted, wells were recompleted in shallower horizons with significantly higher oil viscosities. Higher crude viscosities and increased solids production made gas lift a less effective means of sustaining production. Hydraulic pumping was implemented on some wells in the East Field due to high oil viscosities, low reservoir pressures and flow assurance requirements due to wax content. Hydraulic pumping had many challenges which were maintenance related.

Figure 5. Location of Soldado Acreage Offshore the Southwest Coast of Trinidad



Progressive cavity pumping (PCP) was initiated in the Main Soldado Field. The effectiveness of this technology for producing high viscosity oil and formation fines would lead to field wide implementation to boost production in areas that were not amenable to gas lifting operations. This technology requires a rod string to transfer rotational energy down-hole to the rotor – posing a restriction in wells where the inclination exceeds 40° (Wang et al., 2010). Due to platform integrity issues PCP's are installed on wells across the East Field that is accessible by work-over rigs. This is a major limitation of the existing East Field platform infrastructure limiting the installation of PCP's to free standing wells.

3. Study Objective and Methodology

The objective of this study was to analyse three artificial lift methods currently applied in the Soldado acerage and to demonstrate which artificial method is most suitable for the Soldado East field heavy oil reservoirs using data from a pilot test well. Installation and operational cost and parameters were then applied to develop a matrix for future selection of suitable artificial lift method for heavy oil application.

Figure 6 shows a workflow of the methodology used The workflow was divided into three tiers to model the optimum production that can be attained for a pilot well designed to produce oil either under gas lift, PCP or jet pump from platform X for the East Soldado Field.

3.1 Tier-1 Modelling

1. Completion IPR Model (Vogel, 1968)
2. Fluid Viscosity Model (Hossain et al., 2005)

The commercial software PipeSim was used to develop the tier-1 models mentioned above, for determining the deliverability for the pilot well under natural flow and at the deepest artificial lift installation point. The data required for the models are shown in Table 1. These models were then used as the base for tier-2 models.

Table 1. Reservoir and Wellbore Parameters for Tier-1 Modelling

Reservoir/Wellbore Parameter	Pilot Well
Estimated Reservoir Pressure (psi)	1025
Reservoir Temperature (°F)	125
Reservoir Permeability (mD)	1460
API Oil Gravity (°API)	19
Formation Watercut (%)	72
Gas Oil Ratio (scf/stb)	83
Production Tubing ID (inches)	1.969
Power Tubing ID (inches)	2.441
Last Well Test Rate (blpd)	300
Power Fluid Liquid	Water
Power Fluid Specific Gravity	1.01
Jet Pump Nozzle Diameter (inches)	0.125

Due to the low gas to liquid ratio (GLR) the Pseudo Steady State (PSS) completion model was used. The PSS/Darcy equation (shown below) assumes that the fluid is single phase, laminar flow exists and the fluid is essentially incompressible. A Vogel (1968) correction was applied for liquid flow below the bubble point.

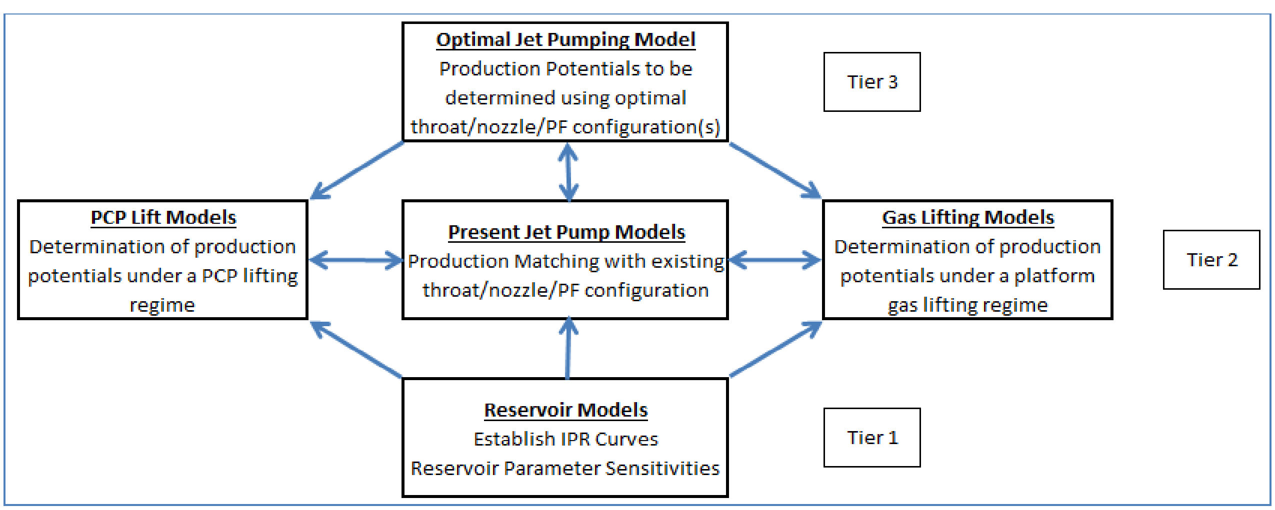
3.1.1 Pseudo-Steady State Flow

$$\bar{p} - P_{wf} = \frac{141.2\, q\, \mu\, B_o}{kh} \left[\ln(r_e / r_w) - 0.75\right]$$

where,

$\bar{p}$ = current average reservoir pressure, psig
P_{wf} = bottom-hole flowing pressure, psig
q = flow rate STB/d
μ = viscosity, cp
B_o = oil formation volume factor, rb/STB
r_e = external (drainage) radius, ft
r_w = well-bore radius, ft
k = permeability, md
h = reservoir thickness, ft

Figure 6. Workflow to Determine a Suitable Artificial Lift Method for the East Soldado Field



3.1.2 Viscosity Model

The Hossain et al. (2005) correlation provide the best prediction for oil viscosity for the East Soldado field. This correlation is valid for heavy oils (10 < API < 22.3) and was used in this study:

$$\mu_{od} = 10^{A}(T^{B})$$

where,

$A = -0.71523g_{API} + 22.13766$ and

$B = 0.269024g_{API} - 8.268047$

g_{API} is the API gravity of stock tank oil

3.2 Tier-2 Modelling

The tier-1 models developed for the pilot well were applied in tier-2 modelling for the development of lifting models under gas lift and PCP type regimes, as well as the development of a model for the existing jet pumping configurations. The models were validated using the surface parameters and from production matching (see *Appendix 1*, Tables A1 and A2). Tier-2 modelling involved:

1. Design and modelling a gas lift type lifting regime to establish a production potential under gas lift conditions using the PipeSim software.
2. Design and modelling a PCP type lifting regime to establish a production potential under PCP conditions using the PipeSm software.
3. Design and modelling a jet pump lifting regime which is representative of the present production conditions and productivity of the pilot well using the SNAP software.

3.3 Tier-3 Modelling

Tier-3 modelling was conducted using the SNAP jet model to determine the production configuration for optimal productivity using the available surface equipment. The production rates from each artificial lift regime were compared to determine the most appropriate lifting regime.

4. Data Analysis and Results

4.1 Tier-1 Model and Results

Static pressure surveys were not available for the pilot well. To confirm the bottom-hole pressure, the following calculation was done using the known fluid column characteristics and wellbore geometry.

Oil Gravity – 18°API

Oil Specific Gravity = 141.5 / Oil API Gravity + 131.5
= 141.5 / (18 + 131.5)
= 0.946

Pilot well water cut – 72%

East Field Water Pressure Gradient – 0.442 psi/ft

Wellbore fluid gradient:
= (0.72*0.442)+(0.28*0.946*0.442")"=0.435 psi/ft"

Mid Perforation Depth – 3,663' MD; 3,264' TVD

Well Static Fluid Level from Surface – 884' MD; 848' TVD (Perforation Submergence 2416' TVD)

The wellbore static fluid level correlates directly to the reservoir pressure at the sand-face.

Estimated Reservoir Pressure:

Reservoir Pressure = Pressure Gradient x Perforation TVD
= 0.435 psi/ft x 2416ft = 1,050 psi

Table 2 shows the reservoir pressures obtained from the calculations.

Table 2. Calculated Reservoir Pressure

Well	Pilot Well
Formation Water Cut (%)	72.0
Well Fluid Gradient (psi/ft)	0.435
Reservoir Pressure (psi)	1,050

The pilot well can produce under natural flow (see Figure 7). This is determined by the intersection of the blue (IPR) curve by the pink (vertical lift performance) curve. Once these two curves intersect at a satisfactory value then artificial lift is not required. If the curves do not intersect or intersect at an undesirable low values, then artificial lift should be considered to improve production rates. Evidence shows the basis for determining feasible production rates for the reservoir/ well system (see Figures 7 and 8). Table 3 shows the results of tier-1 model.

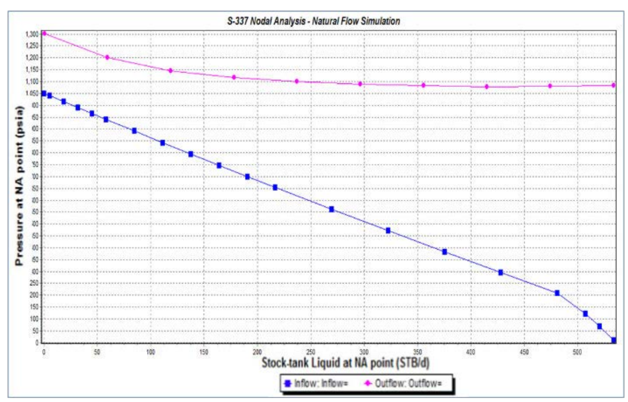


Figure 7. IPR and VLP Curves for Pilot Well

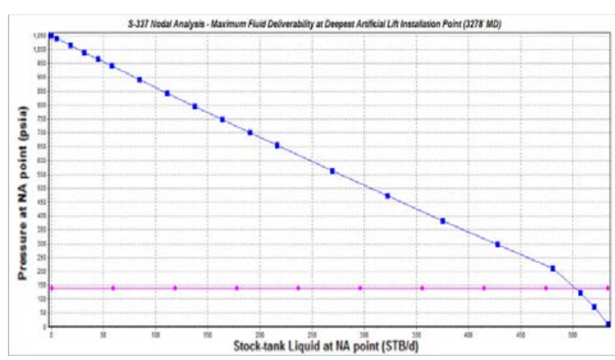


Figure 8. Artificial Lift Confirmation Plot for Pilot Well

Table 3. Tier-1 Model Results

Well	Pilot Well
Artificial Lift Needed	Yes
IPR-VLP Intersection	No
Maximum Potential	510 STB/d

4.2 Tier-2 Model and Results

Tier-2 modelling involved further development of the tier-1 model for the pilot well. Each artificial lift method utilised on platform X (gas lift, PCP and jet pump) was simulated to determine production potential for each lift model for comparison.

4.2.1 Artificial Lift Method 1 – Gas Lift

Considerations:

1. Production tubing size: 2-7/8" 6.5 lb/ft (ID – 2.441")
2. Gas Lift System details:
   a. 1200 psi system
   b. SLB Camco BK-1 Series Valves

Available Injection Gas per well: 0.1 – 0.2 MMscf/d.

Gas lift models were designed using the existing equipment and conditions on platform X. The designs were then applied to the tier-1 model to simulate the production rates under gas lift. The efficiency of this lift regime was analysed using a lift performance plot to determine the maximum production which can be obtained using gas lift and the quantity of gas required for injection for this production.

4.2.2 Pilot Well Gas Lift Potential

Figure 9 shows the results from nodal analyses conducted using platform X gas lift operating conditions and the production potentials (shown in column 3 of Table 4). Figure 10 shows the sensitivities investigated to determine the optimal injection/ production configuration. The maximum potential of the gas lifting regime is shown in columns 5 and 6 of Table 4.

Figure 9. Pilot Well Gas Lift Potential

Table 4. Results from Tier-2 Gas Lift Models

Well	Pilot Well
Design Feasibility at Present Conditions	No
Lift Potential (blpd)	80
Required Injection Gas (MMscf/d)	0.28
Maximum Lift Potential (blpd)	94
Required Injection Gas (MMscf/d)	0.75

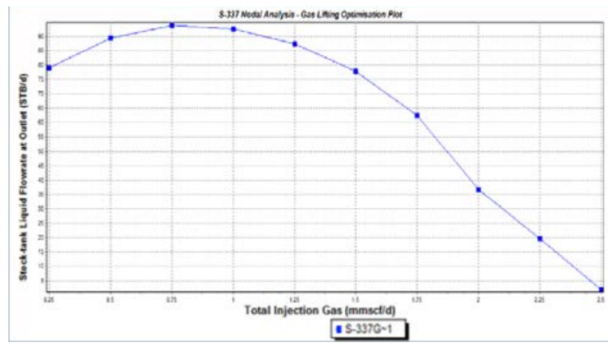


Figure 10. Pilot Well Gas Lift Optimisation Plot

Based on gas lifting operations, the total expected gain is 224 blpd with a required gas injection pressure of 1,200 psi and gas rate of 2.23 MMscf/d.

4.2.3 Artificial Lift Method 2 – Progressive Cavity Pumping

Four assumptions were made to develop the PCP lift model in PipeSim. These are:

1. Pump setting depths (PSD) were estimated to be placed approximately fifty (50') above the liner top. This would allow for ease in pumping spacing as well as promote higher gas expulsion rates.
2. Standard PCP submergence operating practices were 500' to 900' of fluid submergence. This allows for maximum drawdown whilst ensuring the PCP maintains constant fluid contact (for cooling and lubrication).
3. Zero frictional pressure drop within production tubulars.
4. Pump volumetric efficiency of 100% though not possible due to entrained gas in the production stream.

Design Basis for PCP Modelling (S-337):

PSD = 3,303' (TOL) - 50' = 3,253'

Equation 1: PSD Calculation

Determination of FBHP for Scenario 1 – PSD 3,253' with 900' submergence:
Mid perforation depth – 3,264' (TVD)
Pump depth – 3,253' MD (2,824' TVD)

BHP at Pump Depth
= 1,050 psi – [(3,264-2,824) x 0.435] = 859.6 psi

Resultant BHP with a 900' fluid column:

BHP of system
= 859.6 psi – (900ft x 0.435 psi/ft) = 533.1 psi

The calculations were repeated for 500', 700' and 900' submergence configurations. Table 5 shows the derived flowing bottom-hole pressures for the aforementioned conditions.

Table 5. PCP FBHP for Submergence at 500, 700 and 900 Feet

Submergence	Flowing Bottom Hole Pressures (psi)
	S-337
500'	380
700'	466
900'	533

The values in Table 5 were applied to the PCP model to replicate the maximum production potentials under a PCP-type regime. This was achieved by determining the inflow into the wellbore by using a drawdown pressure, defined as follows:

Drawdown =
Reservoir Pressure (P_r) – Flowing Bottom Hole Pressure (FBHP)

4.2.4 Pilot Well PCP Potential

Figure 11 and Table 6 show the results from modelling and installing the resultant PCP design at FBH pressures of 380, 466 and 533 psi, respectively, into the respective tier-1 model.

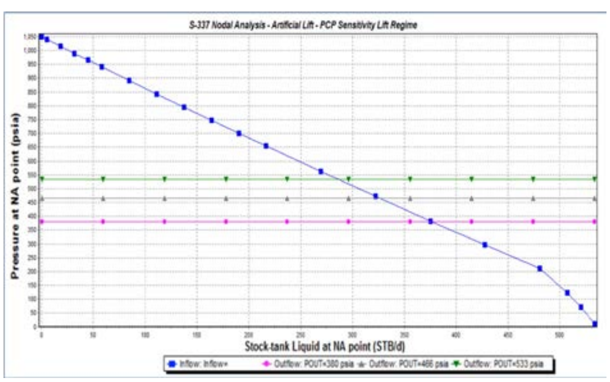


Figure 11. Pilot Well PCP Production Potentials

Table 6. PCP Performance Data for Submergence at 500, 700 and 900 Feet

Well		Pilot
Design Feasibility at Present Conditions		Yes
Production Potential for Submergence Specified (BLPD)	500 ft	375
	700ft	325
	900ft	278

Based on empirical data from PCP operations within the East Soldado acreage, a minimum of 700' of fluid submergence is the optimum trade-off between pump submergence and fluid drawdown. The expected production from PCP lifting operations (assuming absolute pump volumetric efficiency and ignoring frictional pressure drops) is 325 BLPD. This production is an overestimate of the potential and simulations should be done with PCP modelling software to determine a more accurate production potential.

4.2.5 Artificial Lift Method 3 – Jet Pumping Operations

The objective of tier-2 jet pumping modelling was to develop an accurate model of the existing conditions with the presently installed nozzle-throat configurations in the pilot well. This would be the basis for the first level of jet lift performance comparison and the base model for tier-3 modelling. Figure 12 represents the present potential for the pilot well under the current throat/nozzle/injection pressure regime. A summary of the production potential derived from the jet pump design installed into the tier-1 model is shown in Table 7.

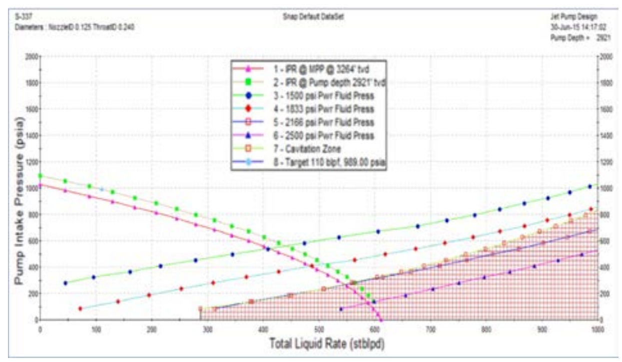


Figure 12. Pilot Well Present Jet Pumping Model

Table 7. Summary of Existing Jet Pump Models

Well	Pilot Well
Production Target, bfpd	410
Injection Pressure, psi	1,560
Power Fluid Required, bfpd	1,300
Throat/Nozzle Size	0.125/0.240

Note: Injection rates were at 900 – 1,100 psi during initial test – October, 2013.

Based on the present designs, the expected production is 410 bfpd. It should be noted that based on simulation sensitivities, the present model have not been optimised. Thus, the jet pumping model developed in tier-2 was then used as the base for tier-3 modelling. Tier-3 was designed to develop optimal jet pumping models to determine the true production capability of the jet pumping system.

4.3 Tier-3 Model and Results

Tier 3 involved the manipulation of tier-2 jet pumping model to obtain an optimal model whilst remaining within the confines of the surface equipment (maximum pumping pressure of 2,700 psi). It should be noted that three power fluid pumps are available for the delivery of power fluid down-hole. Thus, the operating restriction would be the injection pressure whilst allowing for large volumes of injection fluid to be transmitted. Figure 13 shows the optimised Tier-2 Jet Pumping Model.

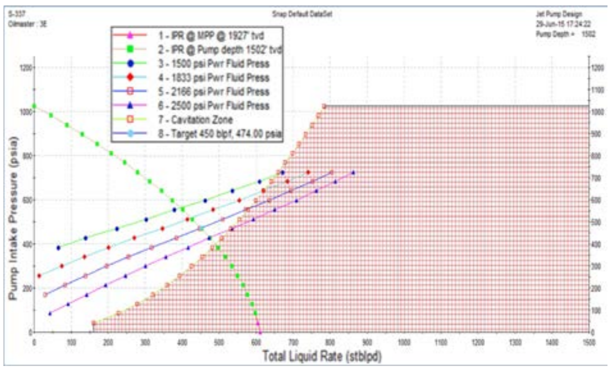


Figure 13. Pilot Well Optimised Jet Pumping Model

Table 8 shows the optimum condition and production potential for the jet pump model determined from this study for the pilot well. The incremental increase in production based on the revised models is 500 bfpd requiring an additional 176 blpd of injection fluid, amounting to a total production of 1,500 bfpd.

Table 8. Optimised Jet Pump Model Parameters

Well	Pilot Well
Production Target, bfpd	450
Injection Pressure, psi	2,166
Power Fluid Required, bfpd	1,150
Throat/Nozzle Size	3E

5. Discussion

The objective of this performance analysis was to determine which artificial lift method is most suitable for heavy oil using the East Soldado field as an example. Based on current well conditions of low GOR's and high water cut, the gas available for injection for gas lift is 0.28 MMscf/d which allows a production rate of 80 bfpd as shown in Figure 10 and Tables 4 and 9.

Figure 11 shows the results from modelling the PCP design at three submergence depths and the corresponding FBH pressures. Under a PCP type regime, a minimum of 700 feet of fluid submergence is the optimum trade-off between pump submergence and fluid drawdown. The expected production from PCP lifting operations (assuming absolute pump volumetric efficiency and ignoring frictional pressure drops) is 325 blpd. Figure 13 and Table 8 show the required injection pressure and fluid for an optimised jet pump model to produce 450 bfpd using the current well configuration.

Table 9 shows that from these three artificial lift models, hydraulic jet pumps are capable of lifting 40 % more fluids than PCP and 400 % more than gas lift for this heavy oil field. Other reasons contributing to the attractiveness of hydraulic jet pumps are the low installation cost and little set-up time; the existing infrastructure requires minimal surface work; and there is no need for rig intervention.

Table 9. Production Potential Comparison for Artificial Lift Studied

Well		Pilot
Deepest Lifting Point		3,278 ft
Maximum Potential (bfpd)		505
Production via Artificial Lift Method (bfpd)	PCP	325
	Jet Pump	450
	Gas Lift	80

The tier-2 jet pump models were modified for increased production and for the prevention of pump cavitation. A matrix was developed to compare and rank each lifting method: 1 – Poor/Undesirable, 2 – Tolerable, 3 – Fair, 4 – Excellent, and 5 – Ideal. Cost evaluations were done relative to the method with the lowest criteria cost.Based on Table 10, using hydraulic jet pumps is the most efficient and cost-effective artificial lift method for the Soldado East Field with a total score of 4.5.

The limitations to this study were identified as:

1. Pressure surveys for the reservoirs under study were not available. Thus, reservoir pressure had to be calculated using static fluid stream existing in the wellbore.
2. Individual well tests data were unavailable due to test trap system on the platform. Platform X testing system utilises a test separator (operating at 50 psi) with all fluids from the separator proceeding to a 3 bbl metering vessel. Testing jet pumping well resulted in flooding the separator due to the high GLR of the system and volume of liquid being tested.

6. Conclusions

Based on the analysis, it can be concluded that jet pumps are capable of lifting 40% more fluids than PCP and 400% more than gas lift for the East Soldado Field. A lift score analysis was developed in this study between PCP pumps, hydraulic jet pumps and gas lift.

The results indicate that hydraulic jet pumps are cheaper and easier to install, operate and maintain. Moreover, this lift score analysis can be applied to determine the most suitable artificial lift method for other fields in the Soldado acerage.

Table 10. Artificial Lift Comparison Matrix

Criterion	Progressive Cavity Pumping	Hydraulic Jet Pumping	Gas Lifting
Production Potential	**325 bfpd** requiring electric power Production Potential – Optimisic PCP simulations done ignoring frictional pressure from and assuming 100% pump efficiency. **Score: 3**	**450 bfpd** requiring 1,150 bfpd PF Production Potential – Realistic Low resource cost as water is utilised as power fluid and the PF is fully recycled through continuous operations. **Score: 5** (1,150 bfpd – stream recycled)	**80 bfpd** requiring 0.28 MMscf/d Production Potential – Realistic High resource demands as produced low GOR's and watercut impose gas demands on field. **Score: 1** (1.25 Mscf/bfpd - poor)
Installation Cost	High Investment Cost required for PCP installation as Winch work (Rig) is required for pump installation. High costs for PCP pumps. High surface equipment cost for PCP Drivehead, Power generation equipment and transmission system. **Score: 1**	Low Investment Cost required for Jet Pump Installation. No rig intervention required – wireline operations only. Minimal Jet Pump Cost Moderate Surface equipment (PF pump and PF Tank) cost. **Score: 4**	High Investment Cost required for Gas Lift installation. Rig intervention required for placement of gas lifting string. Costly GL Mandrels and Valves required. Moderate surface equipment (Nat. Gas Compressor) costs. **Score: 2**
Installation Time	Lengthy Installation time as complete installation requires two tubular trips (Tubing String with stator + Rod String with rotor), wellhead and drivehead placement and electrical connection required. **Score: 1**	Low installation time as components can be transferred and installed using wireline. Trips required 2 – tubing stop profile and jet pump assembly. Moderate time required for PF transmission lines (if not in place). **Score: 4**	Lengthy installation time required for the makeup and placement of a gas lifting string with gas lift mandrels and valves. Moderate time required for Gas transmission lines (if not in place). **Score: 3**
Start-up Time (First Oil)	Moderate start-up time. Process requires power system hook-up and completion fluid offloading. **Score: 4**	Minimal start-up time. No offloading required as well control is not required. PF pump start-up = first oil **Score: 5**	Moderate start-up time. Process requires Gas system hook-up and completion fluid offloading. **Score: 3**
Ease Of Optimisation/ System Change-out	Optimisation resources minimal but range is limited (if VFD is present). Drastic optimisation efforts require rig intervention for pump change out. **Score: 2**	Initial Optimisation resources required – minimal (PF pump pressure/rate adjustment). Drastic optimisation efforts requires wireline operations for pump replacement **Score: 4**	Initial Optimisation resources required – requires wireline operations for valve replacement. Drastic optimisation efforts require rig intervention. **Score: 1**
Chemical Injection Complexity/Cost	Injection requires chemical injection mandrel, valve and transmission line for downhole placement. **Score: 3**	Chemical can be injected and placement downhole by mixing with injection fluid within fluid reservoir/PF transmission line. **Score: 5**	Injection requires chemical injection mandrel, valve and transmission line for downhole placement. **Score: 3**
Average Lift Score	**2.3**	**4.5**	**2.2**

Source: Abstracted from Balgobin (2015)

Appendix 1: Well Test Data

Table A1 shows the production test data used to production match modelling parameters in Tier 1. Table A2 shows the tank test data used for production matching Tier-2 Jet Pumping Models.

Table A1. Jet Pumping Test Data for Pilot Well

Date	Test Oil (bpd)	Test Water (bpd)	Gross Fluid (bpd)	Watercut (%)
23/05/13	51.62	105.38	157	71.7
24/05/13	45.58	115.42	161	71.7
25/05/13	37.37	94.63	132	71.7

Table A2. Well Test Data after Jet Pumps were Installed

Date	Rate (bbl/hr)	Rate (bbl/day)
Oct, 2013	24.6	590.4
Nov, 2013	23.2	556.8
Dec, 2013	20.0	480.0
Jan, 2014	15.0	360.0
Feb, 2014	10.0	240.0
Mar, 2014	8.0	192.0
April, 2014	5.5	132.0
June, 2014 – Jan, 2015	0.0 – 1.4	0 – 33.6
Feb, 2015	23.3	599.2
April, 2105	25.1	602.4

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Authors' Biographical Notes:

Raffie Hosein *is Senior Lecturer and the Head of the Department of Chemical Engineering and Coordinator of the MSc Reservoir Engineering Programme at The University of the West Indies (UWI), Trinidad and Tobago. Previously, he worked as a Petroleum Engineer with the Ministry of Energy and Energy Industries in Trinidad and later, as Senior Associate Professor in the Department of Petroleum Engineering at Texas A&M University at Qatar. Dr. Hosein received his B.Sc., M.Phil., and Ph.D. degrees in Petroleum Engineering from The UWI. He holds a CEng status, a MEI Chartered Petroleum Engineer with the Energy Institute of London and a Fellow with the Institute of Materials, Minerals and Mining (FIMMM) also of London. In 2018, Dr. Hosein received from the Society of Petroleum Engineers (SPE) the Regional Distinguished Achievement Award for Petroleum Engineering Faculty - Latin America and Caribbean Region.*

Amrit S. Balgobin *is a Technical Support Engineer with Baker Hughes, Gulf of Mexico region, Trinidad Operations. He received his B.Sc. in Chemical and Process Engineering and then his MSc in Petroleum Engineering from The University of the West Indies, Trinidad and Tobago.*

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