Optimization of Petroleum Production System using Nodal Analysis Program

Ibraheem Salaudeen[1*], Daniyar Bopbekov[2], Abdulsalam Abdulkarim[3]

[1]Department of Petroleum Engineering, Abubakar Tafawa Balewa University Bauchi, Nigeria.
[2]Department of Petroleum Engineering, Nazarbayev University, Nur-Sultan, Kazakhstan.
[3] Department of Petroleum and Gas Processing Engineering Technology, Bonny Island, Nigeria.

ABSTRACT: This research attempted to optimize petroleum production system of well X in Field Y in Niger Delta region of Nigeria located in Gulf of Guinea by adopting Nodal analysis technique. A non-commercial software known as Nodal Analysis Program was used for the analysis. The dataset available from offset well were used as the input parameters to the software for the selection of the most economical production string for the new well. The production system has two adjustable components: vertical tubing and nearly horizontal flowline. The flowline inclination is -3.0 degree to the horizontal. The productivity index of the well was obtained in order to know the deliverability of the well. Several combinations of the tubing and flowline have been used in the analysis of the production system. The optimal configuration of the production system components is selected by the maximum operating flow rate of 1118 stb/day. The stable operational region is determined with the assumption that the system will be stable above the flow rate corresponding to the minimum on the outflow performance relation (OPR) curve. The introduction of the gas lift into the optimal system configuration increased the operating oil rate from 1118 stb/day to production rate of approximately 1287 stb/day, but the operating oil rate decreased with higher gas injection rate to 1115 stb/day. The optimal gas injection rate is selected by highest operating oil rate. The fluctuations in the oil price did not change the selection of the optimal configuration and gas injection rate. The investigation of the flow regime in the system before and after gas lift has revealed that the effect of gas injection on the flow regime is minor, probably due to low injection rate. Disperse flow was the flow regimes investigated and established for vertical flow (tubing) before and after gas injection. While on the other hand, elongated bubble was established to be the flow regime in flowline before gas injection and slug flow after gas injection in the flowline.

KEYWORDS: Nodal Analysis Program, IPR-OPR Curve, Optimization, Operating points, Flow regimes

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I. INTRODUCTION

Proper design and selection of production string to give optimal operational conditions is a must before embarking on any oil gas production operation. Nodal analysis entails a process, which uses nodes to converge the oil and gas production rate and optimize the total production system (Guo, et al, 2007). Figure 1 shows a schematic diagram of a simple production system. Hand calculations, though, tedious and cumbersome can be performed to compute the flow rates and pressures at the different nodes. However, with advances in technology, several computer programs such as PIPE SIM, PROSPER, can be applied to simplify and accelerate the process. In this research, production system of well X in field Y in Niger Delta region of Nigeria is optimized using the NODAL ANALYSIS PROGRAM. The nodal analysis software, developed at the University of Tulsa, served as an alternative package to commercial software. The tool computes the necessary data needed to plot the inflow performance relation curve (IPR) and outflow performance relation curve (OPR) for critical analysis. In an attempt to carry out the optimization plan, optimal flow was determined and production component such as tubing and flowlines was selected in the most economically feasible manner. A gas lift injection was modeled at different injection rates, flow regimes both in the tubings as well as the flowlines were determined, and finally stable and unstable regions were identified.

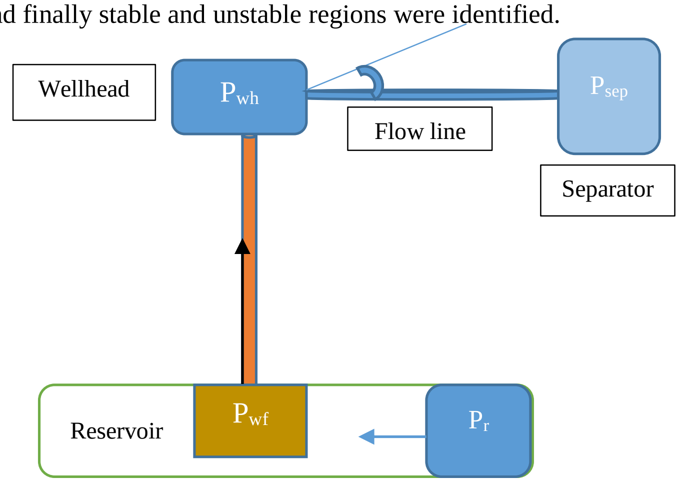

Figure 1: Schematic of production system.

*Corresponding author: isalaudeen@atbu.edu.ng

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Lea and Rowlan (2019) explained the application of nodal analysis for gas or oil well modelling which simulates and model well's performance through flow components that ensure flow assurance such as chokes, tubings, flow lines etc., completion effects such as perforations and well deliverability in terms of inflow performance. Many researchers have applied nodal analysis to diverse problems in oil and gas industry (Odjugo et al., 2020, Al-Qasim et al. 2019, Fan and Sarica 2019, Wilson 2015, Lea 1988, Dala et al. 2015, James and Rowlan 2019a, Abdullahi et al., 2019, Noor et al., 2017, Duncan et al., 2015, Soomro et al., 2015, Widyasari *et al.*, 2019**,** Al-Ruheili *et al.*, 2012)

The determination of well deliverability entails combination of inflow performance that describes reservoir deliverability and wellbore outflow performance that defines the production string resistance to flow. Oil and gas properties are strong function of pressure and temperature which vary with location within the oil and gas production system. To model and simulate the fluid flow in the production system, the system is usually divided into discrete nodes that separate system into different components to easily evaluate the fluid properties at each element. The system analysis for determination of fluid production rate and pressure at a specified node is called Nodal analysis in petroleum engineering (Guo, et al, 2007, Dala et al. 2015, Jansen, 2017).

Guo et al (2007) explained that pressure continuity is the basis for performing Nodal analysis where a unique pressure value exist at a given node regardless of whether the pressure is evaluated from the performance of upstream equipment or downstream equipment. The performance curve (pressure–rate relation) of upstream equipment is called "inflow performance curve"; the performance curve of downstream equipment is known as outflow performance curve. The operating points are selected based on the intersection of the IPR and OPR curve (Figure 2). For convenience, nodal analysis is usually conducted using the bottom-hole or wellhead as the solution node, as the pressure is normally measured at either the bottom-hole or the wellhead.

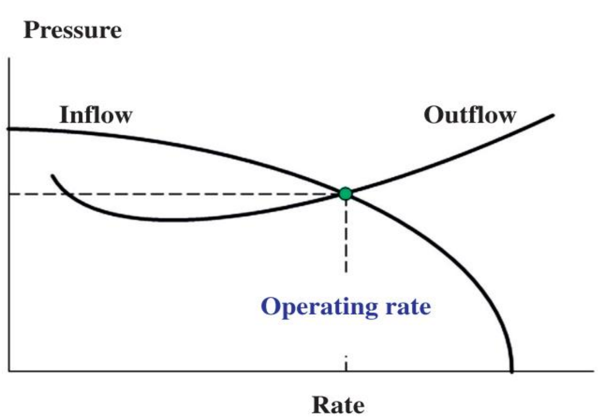

Figure 2: Illustration of Nodal Analysis graph(Lea and Rowlan, 2019b).

Al-Anazi *et al.*, 2017 adopted nodal analysis to optimize smart wells, improved recovery, reduced Operating Expenditure (OPEX) and they concluded that nodal analysis is a powerful tool capable of simulating downhole conditions for inflow-outflow performance optimization of fluid from the reservoir.

In this paper, nodal analysis program is applied to optimize the production system of well X in filed Y in Niger Delta region of Nigeria by selecting the optimum tubing and flowline sizes among different options available - 2, 3, and 3.5 inches considering the cost of steel as well as the average crude oil price as at March 2021 with possible fluctuations of plus or minus $20 based on predictions made by the research team. Stable regions and flow regimes were identified. The gas lift injection was also modelled to determine the best injection rate based on the optimized production string-tubing and flowlines. The software is a non-commercial software and has not been used for nodal analysis for the new well considered in our study.

II. THEORY AND MATHEMATICAL BACKGROUND

A) Single phase productivity index

The IPR curve is linear for the values of the flowing bottomhole pressure above bubble point, because the flow is single phase. The maximum single-phase flow rate is calculated by:

$$q_b = J(\bar{P} - P_b) \tag{1}$$

where q_b is the oil flowrate (stb/d) at bubble point pressure, J is the productivity index (stb/d/psi) and $\bar{P}, P_b$ (Psia) are average reservoir and bubble point pressure respectively (Ahmed and Mckinney, 2005, Guo et al., 2007).

When the pressure in the bottomhole drops below bubble point pressure, the IPR is not linear because the flow is multiphase as gas starts to come out of the solution. At that point, the bottom hole pressure is described to be below saturation or bubble point pressure. The flow rate is related to the pressure difference by:

$$q_o = q_b + \frac{P_b J_{P_b}}{1+V}\left[1 - (1-V)\left(\frac{P_{wf}}{P_b}\right) - V\left(\frac{P_{wf}}{P_b}\right)^2\right] \tag{2}$$

where q_o is oil flowrate (stb/d) at any pressure below bubble point pressure, J_{P_b} is Productivity index (stb/d/psi) at bubble point pressure, V is Vogel coefficient with a constant value of 0.8, P_{wf} is bottomhole flowing pressure (Psia).

Combining Eqs. (1) and (2) gives Eq. (3).

$$q_0 = J(P - P_b) + \frac{P_b J_{pb}}{1+V}\left[1 - (1-V)\left(\frac{P_{wf}}{P_b}\right) - V\left(\frac{P_{wf}}{P_b}\right)^2\right] \tag{3}$$

By letting $J = J_{pb}$, the oil flow rate becomes:

$$q_0 = J_{pb}\left(P - P_b + \frac{P_b}{1+V}\left[1 - (1-V)\left(\frac{P_{wf}}{P_b}\right) - V\left(\frac{P_{wf}}{P_b}\right)^2\right]\right) \tag{4}$$

Applying Vogel coefficient into the equation and rearranging Eqn. (4), we have:

$$J_{pb} = \frac{q_o}{P - P_b + \frac{P_b}{1+0.8}\left[1 - (1-0.8)\left(\frac{P_{wf}}{P_b}\right) - 0.8\left(\frac{P_{wf}}{P_b}\right)^2\right]} \tag{5}$$

Eq. (5) is used to calculate single phase productivity index of the well (Guo et al., 2007). In order to investigate the flow regimes in the tubing as well as the flowline, superficial velocity of the phases flow is required. Superficial phase velocities can be calculated knowing the flow rate and conduit diameter as given by Eqs. (6) and (7).

$$v_{sO} = \frac{q_O}{A_p} \quad (6)$$

$$v_{sG} = \frac{q_G}{A_p} \quad (7)$$

where, A_p *is* area to flow, q_O *is* oil rate (bbl/day), q_g *is* gas rate (cuft/day).

The gas rate at the surface before the gas lift is determined as the amount of gas that left the solution at a particular pressure and temperate, which can be obtained using:

$$Q_g = Q_o\left(R_{si} - R_s(p,T)\right) \quad (8)$$

After the gas lift, Eqn. (9) can be applied for analysis.

$$Q_g = Q_o\left(G_{inj} + R_{si} - R_s(p,T)\right) \quad (9)$$

where, $R_s(p,T)$ *is* solution gas-oil ratio at specific pressure and temperature (SCF/STB), G_{inj} *is* injected gas-oil ratio (SCF/STB).

Since the phase volumes change with pressure and temperature, it is necessary to calculate the flow rate at the point of interest adopting Eqns. (9) and (10).

$$q_g = Q_g B_g(p,T) \quad (10)$$

$$q_o = Q_o B_o(p,T) \quad (11)$$

where, $q_g -$ gas flow rate in (cuft/day), $B_g -$ gas formation volume factor (cuft/SCF), $q_o -$ oil flow rate in (bbl/day), $B_o -$ oil formation volume factor (bbl/STB). Details of Eqs. (6) through (11) can be found in (Brill and Beggs, 1991).

III. METHODS

Nodal analysis program software which is an excel based program that constructs IPR and OPR curves for the node at the bottom hole and determines the operating pressure(s) and flow rate(s) for the production system was used. The software requires production system parameters and selection of an appropriate correlations to successfully run. Parameters of the production system required for the software to successfully run range from fluid properties to production string geometries. Correlations used in the software include Kartoatmodjo's correlation for the oil properties, Standing's for the z factor and Beggs and Brill model for the pressure drop along the tubing and flowline.

Once appropriate input parameters are keyed in or imported into the software, the calculation of the OPR and IPR curves can be initiated and comparisons can be made between OPR and different IPRs. The program will output the IPR, OPR and operating conditions on the separate sheet. Error message will pop up if the system does not have any operating point.

Field *Y* is located in Niger Delta Nigeria-West Africa. The full reservoir description can be found in our previous paper (Abdullahi et al. 2019) and some research papers published by other investigators such as (Chukwu, 1991, Burke, 2000).

IV. RESULTS AND DISCUSSION

From the available data gathered, the single-phase productivity of the well was determined to be 1.12 stb/day/psi which shows the potential of the well in terms of the volume of oil that can be delivered economically to the surface. In order to appropriately optimize the production string, the flowline was firstly optimized using the available dimensions to construct IPR – OPR to obtain the operating points such as flow rates, bottom hole pressure, well head pressure and separator pressure. The general input parameters are shown in Table 1.

Table 1: Input parameters required by the software.

Fluid Specific Gravities		**Flowrate Data**	
Oil Specific Gravity	45 (API)	Test Oil Flowrate	1,500 (STB/day)
Water Specific Gravity	1.01	Formation Gas-Oil Ratio	400 (SCF/STB)
Gas Specific Gravity	0.65	Water Cut	0 (%)
Reservoir Data		**Gas Lift Data**	
Reservoir Pressure	2,250 (psig)	Gas Lift Included	NO
Bubble Point Pressure	1,250 (psig)	Gas Injection Depth	4,500 (ft)
Test Bottom Hole Flowing Pressure	853 (psig)	Injection Gas Specific Gravity	0.68
Reservoir Pressure at Test Conditions	2,250 (psig)	Injection Gas-Oil Ratio	285 (SCF/STB)
Operating Conditions		**Correlations to Use**	
Separator Pressure	450 (psig)	Solution Gas & Bubble Point Correlation	Kartoatmodjo
Separator Temperature	80 (deg F)	Oil Formation Volume Factor Correlation	Kartoatmodjo
Well Head Pressure	0 (psig)	Oil Viscosity Correlation	Kartoatmodjo
Well Head Temperature	160 (deg F)	Z Factor Correlation	Standing
Bottom hole Temperature	220 (deg F)	Tubing Pressure Drop Correlation	Beggs - Brill Model
Choke Included	YES	Flowline Pressure Drop Correlation	Beggs - Brill Model
Bean Choke Size	64 (1/64 in)		
Tubing Data		**Flowline Data**	
Tubing Depth	4,500 (ft)	Flowline Length	15,000 (ft)
Tubing Inner Diameter	3 (in)	Flowline Angle	--3(deg)
		Flowline Inner Diameter	3.5 (in)
Economics Data			
Price of steel*	$6per ft per in.		
Price of oil (exclude gas production)	$70 per STB		

***Example:* 20-foot section of 3-inch diameter pipe = | 20 ft | | $5/ ft-in | | 3 in | = $ 300**

Appropriate values of flowlines diameters and other necessary data were imported into the software, and the software was run. The operating points displayed and output from the software are shown in Table 2.

Figure 3 shows the optimized production rate for each flowline internal diameter (ID) considered. The IPR of each flow line were overlain in the plot while the OPR was clearly and separately plotted. It can be observed that flow line with 3.5 inches internal diameter had the highest production rate of 1118 stb/day and flow line with 2.5 inches internal ID has the least flow rate per day. The operating points of each flowline are displayed in Table 2.

Table 3 shows oil revenue and pipe cost for different flowline diameters considered. From the table, the flowline with 3.5 inches has the highest production rate and as such it has the highest revenue of $28, 570,770. Therefore, internal diameter of 3 inches and 3.5 inches are selected as the optimized tubing and flowline of the production string respectively. Furthermore, the optimized value of the internal diameter of 3.5 inches for flowline is used to optimize for tubing diameter. Figure 4 shows the IPR-OPR curve for each scenario and the operating points are summarized in Table 4.

From Figure 4, the OPR curves for tubing with 3.0 and 3.5 inches' seem to overlap but, tubing with 3.0 inches internal diameter has slightly higher production rate (1118.23 stb/day) than the tubing with 3.5 inches (1106.91). The economic analysis was carried out to finally select the best tubing, considering cost and oil price (Table 5).
From the table, the tubing with 3 inches internal diameter has the highest revenues per annum as well as the highest net income compared with 2-inches and 3.5-inches tubing. Therefore, the recommended production string for well X should consist of 3 inches and 3.5 inches internal diameter for tubing and flowline respectively.

Table 4 Operating points.

Flowlines ID	Q_o (STB/day)	P_{wf} (psia)	P_{wh} (psia)	P_{sep} (psia)
2.5	973.37	1461.66	460.69	464.70
3.0	1069.92	1367.77	407.99	464.70
3.5	1118.23	1321.4	382.07	464.70

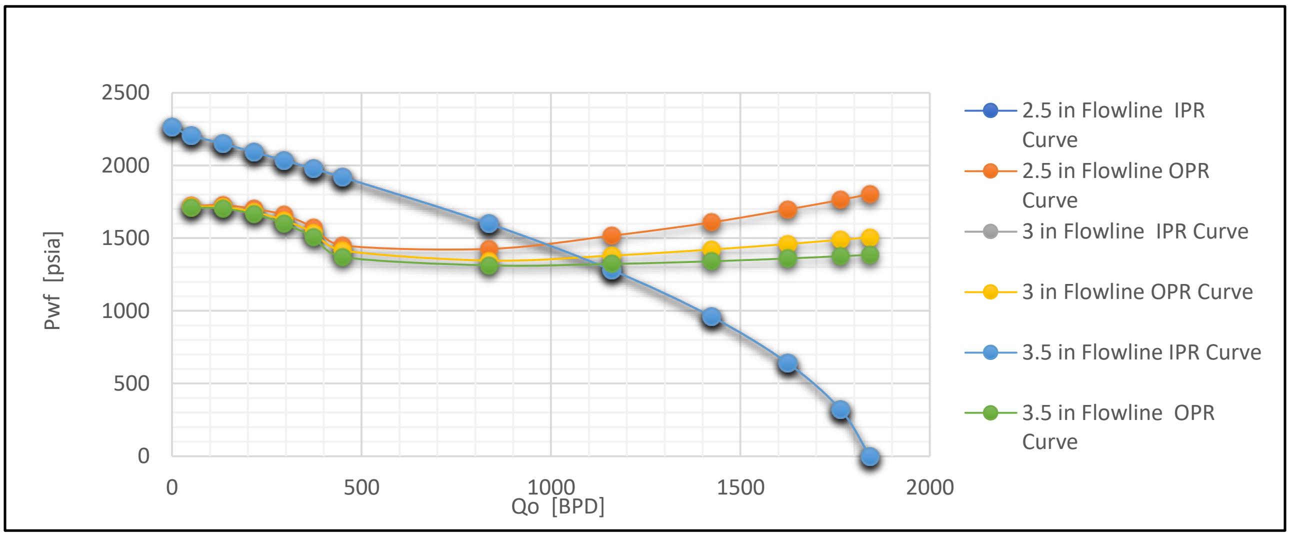

Figure 3: IPR- OPR curve for 2.5'', 3.0'' and 3.5'' flowline internal diameter.

Table 2: Oil revenue and pipe cost for different flowline diameters.

Flowline ID (inches)	Tubing ID	Steel Price ($/ft-in)	Pipe cost ($)	Qo (stb/d)	Oil Price ($/stb)	Revenue ($)	
						7 days	365 days
2.5	3.0	6	306,000	973	70	476770	24860150
3.0	3.0	6	351,000	1069.92	70	524260.8	27336456
3.5	3.0	6	396,000	1118.23	70	547932.7	28570777

Table 3: Operating points for different tubing internal diameters.

Tubing ID	Q_o (STB/day)	P_{wf} (psia)	P_{wh} (psia)	P_{sep} (psia)
2.0	1052.68	1384	379.21	464.70
3.0	1118.23	1321.4	382.07	464.7
3.5	1106.91	1332.29	381.56	464.7

Table 5: Oil revenue and pipe cost for different tubing diameters.

Tubing ID (inches)	Flowline ID (inches)	Steel Price ($/ft-in)	Pipe cost ($)	Qo (stb/d)	Oil Price ($/stb)	Revenue ($)	
						7 days	365 days
2.0	3.5	6	369,000	1052.68	70	515813.2	26895974
3.0	3.5	6	396,000	1118.23	70	547932.7	28570777
3.5	3.5	6	409,500	1106.91	70	542385.9	28281551

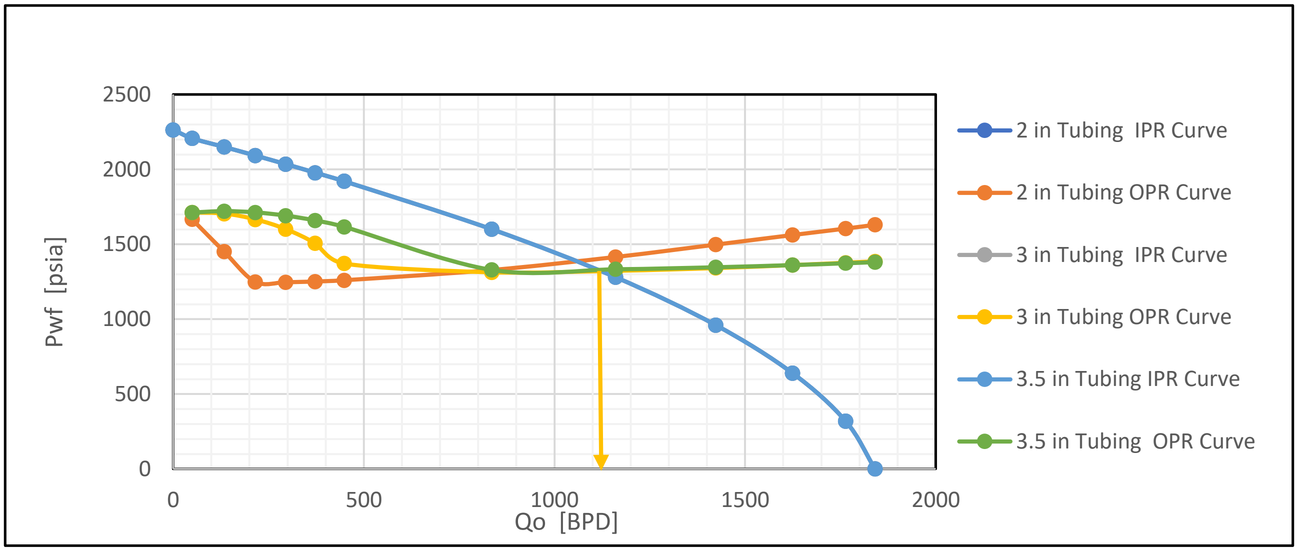

Figure 4: IPR-OPR curve for tubing geometry.

A) *Modeling of Gas Injection*

The optimum flowline and tubing diameters selected from the previous section were used to model gas injection into the tubing at a depth of 4,500 ft, with injection volume factors of 1,000, 2,000, 3,000, 4,000, and 5,000 SCF/STB respectively. The injected gas gravity is 0.68. The IPR and OPR curves with the varying gas injection rates are presented in Figure 5.

The optimum production rate for each injection gas-oil ratio in scf/stb obtained from Figure 5 are used to generate the oil revenue possible per annum as displayed in Table 6. From the table, it is observed that 1000 scf/stb injection rate has the highest production rate, highest oil revenue and highest net income. As the gas-oil injection ratio increases the flow rate decreases. It can also be observed from Figure 6 that, the optimum gas injection rate increased oil production as

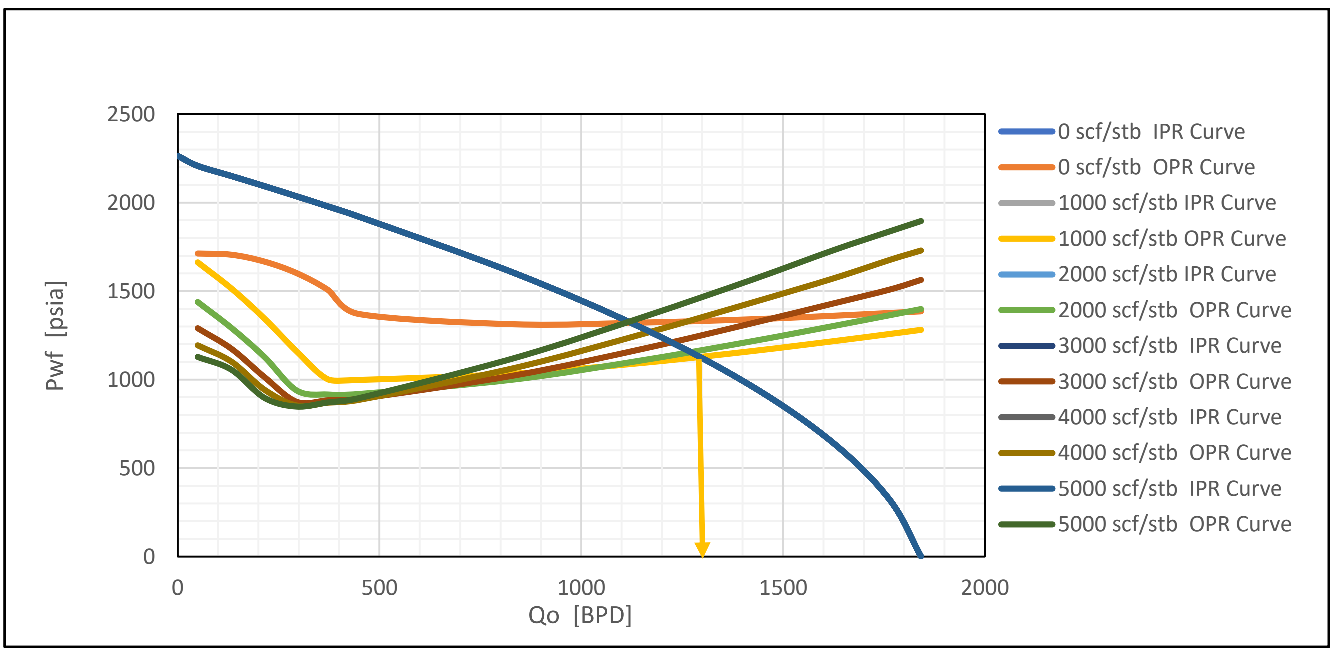

Figure 5: IPR-OPR curve with varying gas -oil injection ratio.

compared to a scenario when there was no gas injection. Sensitivity analysis was also run to checkmate the optimized system. This was done by factoring fluctuation of plus or minus $20 into the selection plan. Tables 7, 8 and 9 give the details of the oil revenue as well as the net income for tubing and flowline at different oil prices as well as at different gas injection scenario. From Tables 7, 8 and 9, it can be concluded that 3.0 inches internal diameter tubing, 3.5 inches internal diameter flowlines and gas injection rate of 1000 scf/stb can be selected for the optimal running of the well.

B) *Flow Regime of the Optimized Production String before and after Gas Injection*

The flow in the production system is mostly multiphase- two-phase, because the bottom hole pressure is below the saturation pressure which implies that gas comes out of the solution as the pressure decreases. When the gas lift is applied, additional amount of free gas is introduced into the system, which affects the flow pattern. The flow regime in the system is not uniform and changes with superficial velocities of the phases and the orientation of the conduit (vertical for tubing and nearly horizontal for flowline). There

Table 6: Oil revenue, net income and pipe cost for different gas injection rates.

Injection Gas-Oil Ratio (SCF/STB)	Tubing ID (in)	Flowline ID (in)	Pipe cost ($)	Q_o (STB/day)	Oil price $/STB	Revenue ($)		Net Income ($)	
						7 days	365 days	7 days	365 days
0	3.0	3.5	396,000	1118.23	70	547,933	28,570,777	151,933	19,599,365
1000	3.0	3.5	396,000	1286.53	70	630,400	32,870,842	234,400	22,989,303
2000	3.0	3.5	396,000	1264.71	70	619,708	32,313,341	223,708	22,647,115
3000	3.0	3.5	396,000	1219.43	70	597,521	31,156,437	201,521	21,845,758
4000	3.0	3.5	396,000	1169.61	70	573,109	29,883,536	177,109	20,951,690
5000	3.0	3.5	396,000	1114.61	70	546,159	28,478,286	150,159	19,949,583

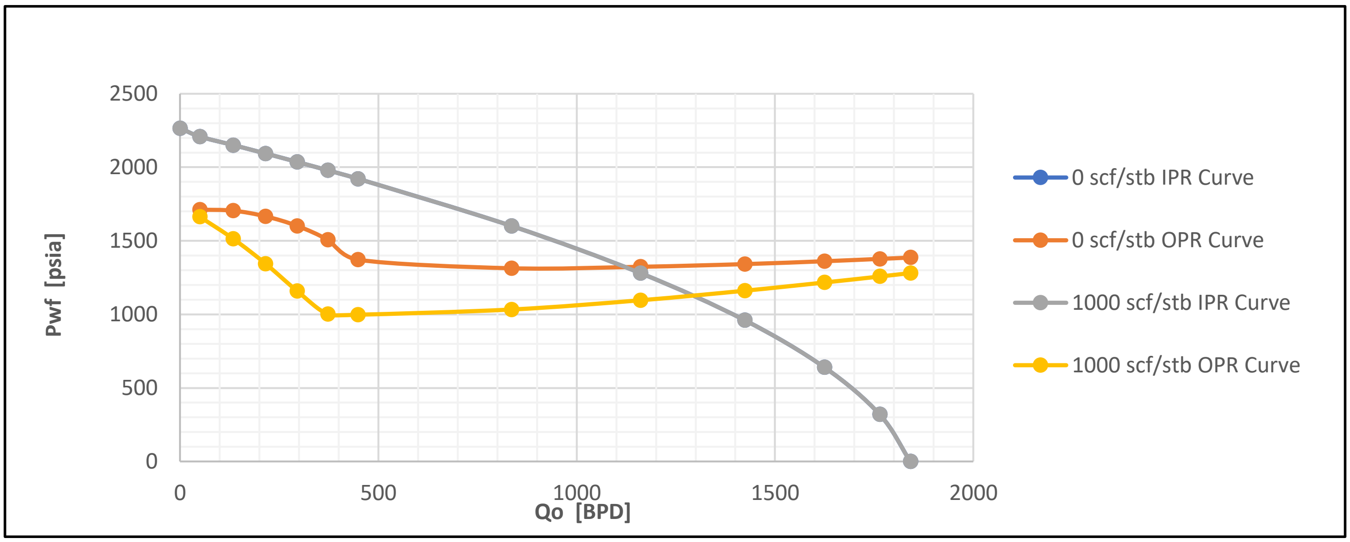

Figure 6: IPR-OPR for gas injection and no gas injection scenario.

Table 6: Net income for different tubing diameters at different oil prices.

Flowline ID	Net income for 1 year ($)		
	50 $/STBs	70 $/STBs	90 $/STBs
2.5 inch	18,842,410	26,526,974	34,211,538
3.0 inch	20,011,698	28,174,777	36,337,856
3.5 inch	19,791,608	27,827,051	35,952.494

Table 7: Net income for different flowline diameters at different oil prices.

Flowline ID	Net income for 1 year ($)		
	50 $/STBs	70 $/STBs	70 $/STBs
2.5 inch	17,451,250	24,554,150	31,657,050
3.0 inch	19,175,040	26,985,456	34,795,872
3.5 inch	20,011,698	28,174,777	36,337,856

Table 8: Operating points before and after gas lift.

Operating points	Before gas Lift	After Gas Lift
Q_o (STB/day)	1118.23	1286.53
P_{wf} (psia)	1321.4	1126.15
P_{wh} (psia)	382.07	506.51
P_{sep} (psia)	464.70	464.70

Table 9: Net income for different gas injection rates at different oil prices.

Injection Gas-Oil Ratio (SCF/STB)	Net income for 1 year ($)		
	50$/STBs	70$/STBs	90 $/STBs
0	20,011,698	28,174,777	36,337,856
1000	23,083,173	32,474,842	41,866,511
2000	22,684,958	31,917,341	41,149,724
3000	21,858,598	30,760,437	39,622,276
4000	20,949,383	29,487,536	38,025,689
5000	19,945,633	28,082,286	36,218,939

are various flow regime maps for the two-phase flow in the literature (Brill and Beggs, 1991, Lea and Rowlan 2019a). Most of them attempted to map flow regimes on the plot of superficial liquid velocity versus superficial gas velocity. Two widely used maps have been selected to evaluate the flow regimes in this paper: one for vertical pipe proposed by Lea and Rowlan 2019a (Figure 7) and the second one for horizontal pipe proposed by Mundhane et al., 1974 (Figure 8).

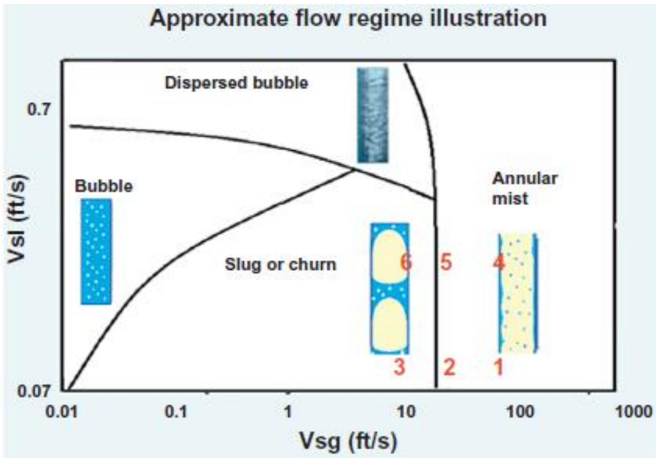

Figure 7: Flow regime maps for vertical pipes James F. Lea and Rowlan 2019a.

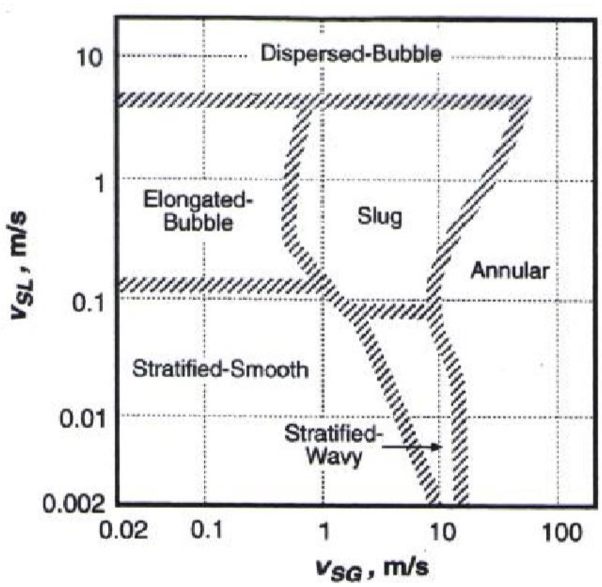

Figure 8: Flow regime map for horizontal pipes (Mandhane et al., 1974).

The operating points before and after gas injection with the optimized system is presented in Table 10. Since the diameters of the flowline and the tubing in the bottomhole are known, only flow rates are to be determined. The oil rate is determined by the software, as well as other operating parameters like pressure throughout the system, which are shown in Table 10.

Table 10: Operating Points before and after gas lift.

Operating points	Before gas Lift	After Gas Lift
Qo (STB/day)	1118.23	1286.53
Pwf (psia)	1321.4	1126.15
Pwh (psia)	382.07	506.51
Psep (psia)	464.70	464.70

Investigation of flow regimes was carried out with available data using Eqs. (7 - 10). In addition, Al-Marhoun's correlations (Al-marhoun, et al, 2015) are applied for the oil formation volume factor and solution gas-oil ratio, while gas formation volume factor is calculated for the 1:1 mixture of methane and ethane, using z-factors graph**.** The points of interest are the bottom of the tubing and the flowline. Thus, fluid properties are determined for the pressure and temperature in the bottomhole and the flowline. The flowline pressure and temperature are assumed to be an average between the wellhead and the separator.

V. CONCLUSION

The Nodal Analysis Program software has been successfully applied to the production system and an optimum configuration is selected based on the economic feasibility and other relevant factors. Introduction of the gas lift and its effect on the system performance has been evaluated as well. Finally, the flow regime nature in the two sections of the system were investigated before and after the gas lift application. The selection of the piping diameter is justified by the oil revenue for the operating period and the cost associated with the piping installation. The pipe cost depends on the size of the pipe. The optimized geometry for the production string where best operating conditions of pressure and flow are achieved consist of 3.5-inch flowline and 3.0-inch tubing.

The system has different operating point with changing flowline ID. The decrease in the flowline ID hinders the flow, as the frictional pressure drop becomes more dominant at the higher oil rates that results in the intersection of the OPR and IPR curves at the lower oil rates. The gas-oil ratio injection rate of 1000 scf/stb was optimized for the gas lift operation because higher injection rate was found to be associated with decreasing oil rate and increasing frictional pressure drop. A stable flow is observed based on the flow regime identified before and after gas injection. Hence, non-commercial software is proved to be effective in optimizing production system and solving some other production related problems.

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