

## FULL FIELD PRODUCTION OPTIMIZATION STUDY USING NODAL ANALYSIS TECHNIQUE

*Reda Abdel Azim*

*Future University in Egypt Petroleum Engineering Department, Egypt*

Received February 7, 2019; Revised April 4, 2019, Accepted April 24, 2019

---

### **Abstract**

To better understand the well performance and forecast its future response, a PIPESIM model was built for each tested intervals of the currents wells excluding the intervals which are tested by swabbing due to the high uncertainty of getting conclusive results from these types of test. These PIPESIM models simulate the actual inflow and outflow performance of the tested intervals with the same completion used during the DST results and depends on the initial condition of each well (initial reservoir pressure, well head pressure, and water cut value). Sensitivity Analysis is done for the different parameters (water cut, wellhead pressure, reservoir pressure, tubing diameter) produced from each reservoir. The field contains 10 wells, two of them exist in north area (J-1, and J-2), one in the central area (JC-1) and the others located at the south area (JS-1, JS-2, JS-3, JS-4, JS-5, JS-6, and JS-7).

**Keywords:** *Production Optimization; Nodal Analysis; Artificial Lift.*

---

## **1. Introduction**

The studied field planned to produce from Bentiu and Abu Gabra formation. DST data are available from most of the existing wells testing each interval separately using natural flow completion. For the tight interval, the interval is tested by swabbing.

The objectives from the production technology study of the existing wells are summarized in the following points:

- Simulate the well performance using PIPESIM and forecast its performance by making sensitivity analysis on parameters affecting the well performance (i.e. well head pressure, reservoir pressure, water cut, tubing size).
- Choose the optimum completion for the producing wells.
- Screen the different Artificial lift (AL) methods to select the best candidate to produce all the wells.

## **2. Production technology workflow**

Fig.1 shows the production technology workflow used to achieve the above-mentioned objectives. The next section details all the steps used in the nodal analysis sensitivity and the Artificial lift screening.

## **3. Vertical flow correlation selection**

After building PIPESIM models for each perforation interval, a correlation match module is used to choose vertical flow model that simulates the well flow performance. Fig. 2 shows the behavior of the different vertical flow correlations for well JS- 1 with the tested interval (2452–2457 m) that is used to select the best vertical flow correlation based on the surface production rate. Table 1 summarizes the matched correlations for well JS-1 for both Bentiu and Abu Gabra reservoirs for each tested interval. From this analysis, it was found that HAGEDORN & BROWN

(HBR) [2] correlation is the best model to simulate the liquid vertical flow for the wells producing from Bentiu & Abu Gabra, while ANSRI correlation [3] is the best model to simulate the gas flow for the wells tested in the gas zone of Abu Gabra.

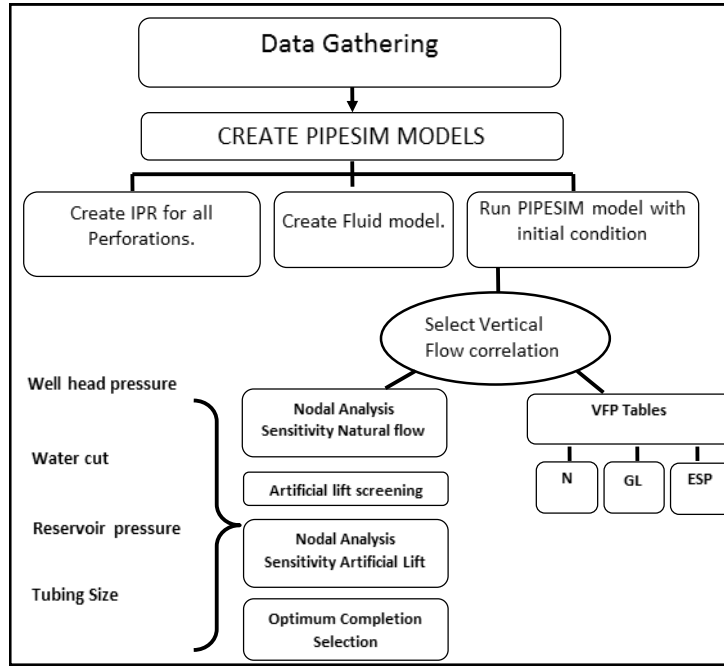


Fig. 1. Production technology workflow for the studied field

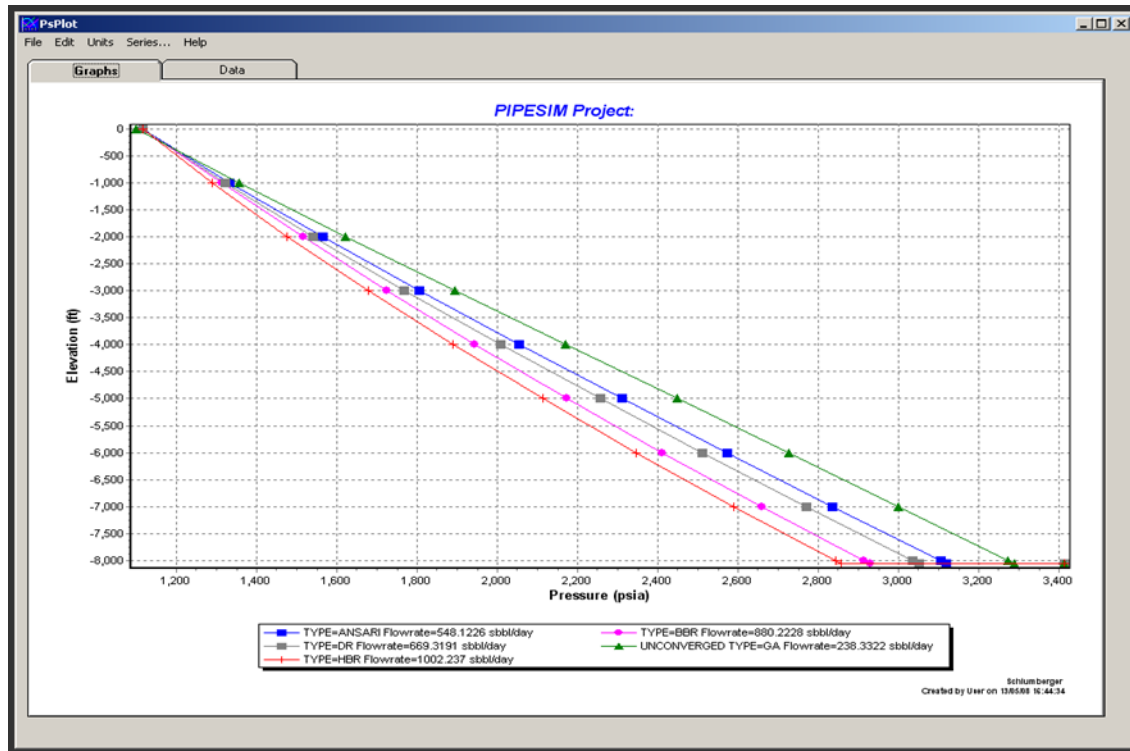


Fig. 2. Different vertical flow correlations for well JS-1 (interval 2452-2457m)

Table 1. Vertical flow correlation selection based on JS-1 test

Depth (m)	Formation	Correlation matched	Rate actual	Rate PIPESIM model	Status	Flowing pressure psi	PI DST, Bbl/d/psi	Reservoir Pressure psi
3038-3043	AG	-----	Traces	No model	swabbed		--	
2771-2775	AG	-----	Traces	No model	swabbed		--	
2566-2573	AG	ANSRI	8.9 MMscf/d	8.8 MMcf/d	Flowing naturally	3219	--	3550
2452-2457	AG	HBR	1011 bbl/d	990 bbl/d	Flowing naturally	3017	1.9	3400
1476-1483	Bentiu	HBR	603 bbl/d	612 bbl/d	Flowing naturally	1790	3.02	2033
1381-1384	Bentiu	HBR	491.2 bbl/d	512 bbl/d	Flowing naturally	1812	3.9	1916

#### 4. Sensitivity scenarios for Bentiu Formation

This section gives detailed overview of the different sensitivity runs performed on one selected zone in Bentiu from well JS-1 as a sample.

##### 4.1. Sensitivity scenarios for Bentiu Reservoir

The selected zone for Bentiu is from well JS-1 in the tested interval (1381 – 1384 m). The well parameters used to construct the PIPESIM model for this zone are as follows:

- Tubing size = 2.441 inch (ID);
- Flowing pressure = 1686 Psi (from DST data);
- GOR= 100 SCf/Stb (from DST data);
- WHP = 220 psi (from DST data)
- Water cut = 0 % (from DST data);
- Reservoir pressure= 1916 Psi (from RFT/DST data);
- Gross rate = 512 BLPD (from DST data);

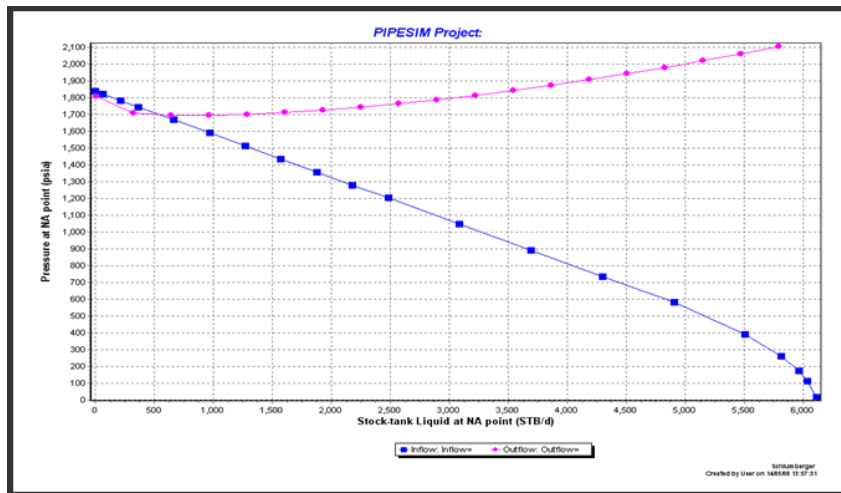


Fig.3. Nodal analysis model for the selected zone in Bentiu formation

Figure 3 gives the nodal analysis performance (inflow and outflow performance) with a schematic diagram showing the tested zone in well JS-1. The nodal analysis model parameters that match the current situation of the selected perforation interval in Bentiu are summarized in the following points:

- The Qmax (AOF) for this well = 6200 BBL /day, with current PI = 3.9 bbl/day /psi.

- Well producing 500 bbl/day during the test which considers 10 % from maximum potential for this well.
- The intersect between inflow and outflow performance is showing unstable flowing condition (may lead to well stop flowing at early stage of production).

Different sensitivity analysis runs are performed on the current base case of the selected zone. These runs are summarized in the following sections.

#### 4.2. Sensitivity on Well head pressure

The well head sensitivity runs are performed from the current well head condition of 220 to drop to 50 psi. Figure 4 shows the inflow and outflow performance for these sensitivity runs. As shown in Fig. 4, the well showed improve in its performance as results to a drop in the well head pressure. However, this improvement is very limited due to the limited reduction in well head pressure (minimum of 50 psi). Table 2 gives the expected gross rate per each drop in well head pressure.

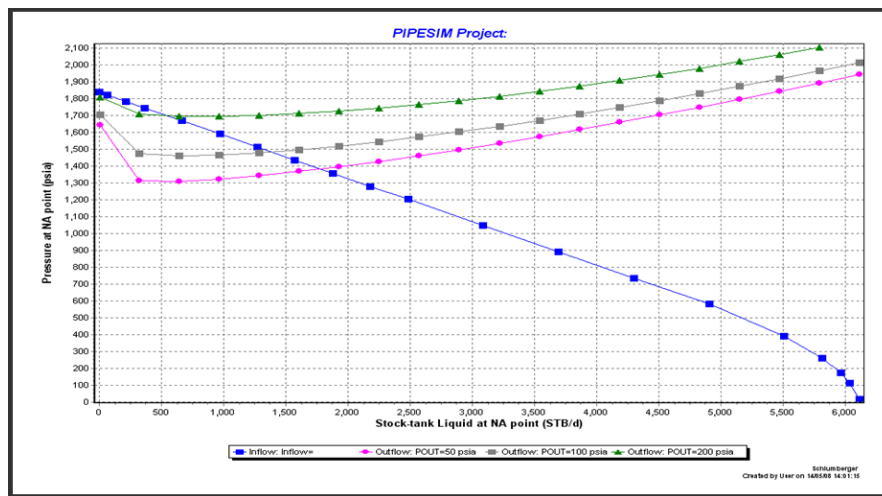


Fig. 4. Nodal analysis models for the well head sensitivity

Table 2. Well head sensitivity analysis results

WHP, psi	Gross rate BLPD
220	500
100	1400
50	1800

#### 4.3. Sensitivity on reservoir pressure

The reservoir pressure sensitivity runs are performed on changing the reservoir pressure from current condition to 1840, 1700 & 1500 psi. Figure 5 shows the inflow and outflow performance for these sensitivity runs. As shown from Fig. 5, the well stops flowing as a result to a drop-in reservoir pressure from the initial test condition. Table 3 gives the expected gross rate for each reservoir pressure.

Table 3. Reservoir pressure sensitivity analysis results

Reservoir pressure, psi	Gross rate, BLPD
1840	500
1700	No flow
1500	No flow

#### 4.4. Sensitivity on reservoir pressure vs. well head pressure

The sensitivity analysis is performed on change reservoir pressure from 1840, 1700, 1500 psi vs. change in WHP of 220, 100 and 50 psi. As shown from results even at very low well

head pressure, the well stops flowing at 1300 psi. Thus, the current operating condition for the well is very risky.

#### 4.5. Sensitivity on water cut

The sensitivity runs are performed on different values of water cut of 0, 10 and 20 % at the current condition of the well head pressure of 220 psi. As shown from the results in Table 4, the well performance is highly affected with increasing in the water cut. The well will stop flowing at water cut of 20 %.

Table 4. Water cut sensitivity analysis results

W.C., %	Gross rate, BLPD
0	500
10	280 (unstable condition)
20	No flow

#### 4.6. Sensitivity on different tubing diameter

The sensitivity runs are performed at well head pressure of 50 psi with different tubing diameter of 2", 3 1/2" & 4 1/2". From Table. 5, it can be easily noticed a significant change in well performance when using 3 1/2" tubing diameter compared to the 2 7/8", and there is no much different between 3 1/2" & 4 1/2". Thus, the 3 1/2" is recommended over the 4 1/2".

Table 5. Tubing size sensitivity analysis results

Tubing diameters, inch	Gross rate, BLPD
2 7/8"	1600
3 1/2 "	2100
4 1/2"	2350

### 5. Artificial Lift Screening for Bentiu formation

As from the natural flowing analysis for both Bentiu and Abu Gabra, it was realized the importance of using artificial lift method especially for Bentiu wells from the starting of production. The next sections summarize the artificial lift screening performed for Bentiu reservoir based on the reservoir rock and fluid characteristic of each reservoir separately.

#### 5.1. Artificial Lift Screening for Bentiu

Artificial lift (AL) screening software [4] is used to select the best artificial lift candidate for Bentiu reservoir based on its rock and fluid characteristics. Table 6 gives the main Bentiu reservoir characteristics that are used in selecting the best AL method. Based on the parameters shown in Table 6 gives the weight percent of the selected AL method compared to the others. As shown from the results, the best AL candidates for Bentiu are ESP, PCP and Gas lift.

Table 6. Artificial lift screening parameters for Bentiu

Parameters	Value	Parameters	Value
API gravity	30 API	Dogleg	0 deg/100ft
Production rate	500-2000 bbl/D	Water cut (%)	0 – 100 %
Flowing bottom hole pressure	1600 psi	Electricity available	Yes
Deviation	0 deg	Height restriction	No
Gas available	Yes	Casing size	7"
Depth	5000 ft	H <sub>2</sub> S content	0
Gas liquid ratio	100 scf/bbl	Subsurface safety valve	Yes
Solid content (%)	0	Stuffing box	No
Bottom hole temperature	150 F	CO <sub>2</sub> content	0
Gas well dewatering	No		

### 5.2. Artificial lift analysis (ESP vs Gas Lift)

In this section, two artificial lift methods were studied to describe their performance over the FDP time period and how each artificial lift type acts during the well life. All the artificial lift analysis had been conducted for well SP-21 as a pilot well reflect the field higher cumulative liquid production during the primary depletion scenario obtained from the simulation model.

The objective is to perform a nodal analysis for the above mentioned well at different time spots over the well life for three different FDP scenarios which are the primary depletion, the water injection, and the gas injection. The input data used to build the nodal analysis model for the selected well is taken from the dynamic modeling. These data are: reservoir pressure, flowing bottom hole pressure, water cut, gas oil ratio at each time spot. The results from this analysis are to choose the ESP pump and the proper Gas lift design which can achieve the dynamic model liquid rate at surface and to check if this pump or the gas lift design can work properly along the well life time.

Accordingly, the next sections give the ESP and Gas Lift analysis for each FDP scenario separately.

### 5.3. Artificial lift analysis for primary depletion scenario

Fig. 5 gives the selected well performance based on the dynamic modeling with the different points selected along the life of the well to perform the nodal analysis to select the optimum ESP and Gas lift design for the selected well. PIPSIM model had been built for the three selected points along the life of the well based on the reservoir pressure, bottom hole flowing pressure, water cut, and gas oil ratio available from the dynamic modeling.

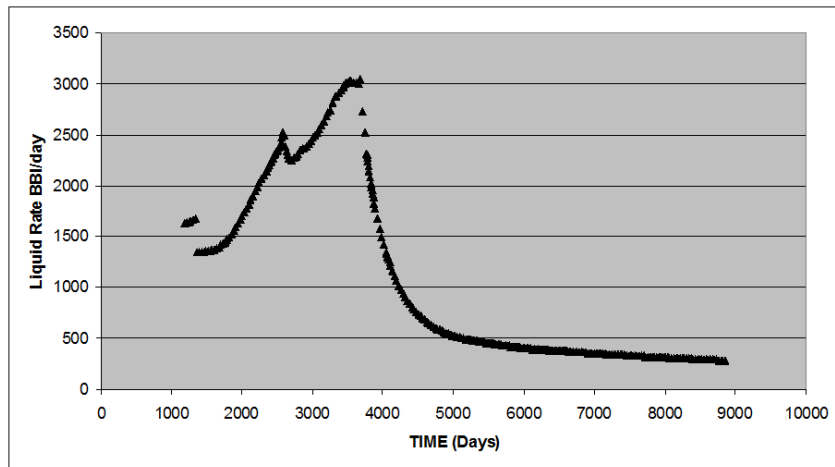


Fig.5. Liquid rate performance of the selected well from the dynamic modeling

Table 7 gives the selected ESP pump along with the well head pressure for this pump for the three selected points.

Table 7. Summary of the ESP design for the primary depletion scenario

Time	PR, psi	W.C. %	GOR scf/stb	QL stb/d	No. of stages	WHP, psi	H.P.	Pump type
2127	1008	16	61	1855	102	850	97	GN2500
3284	398	26	109	2818	250	600	178	GN3200
6584	160	90	430	374	350	400	36	DN1000

General charts (Fig. 6a, b, c) have been generated to show the behavior of well head pressure versus No. of stages per each ESP pump based on the change in reservoir pressure, water cut, GOR and liquid rates. The importance of these charts is that it can be used to select the proper ESP pump based on the well conditions and the required well head pressure (WHP)

based on the surface facilities design. From the ESP analysis for the pilot well (Table 7 and Fig. 6), it can be easily concluded that the ESP design to obtain the predicted performance of the wells requires changing the ESP during the life time of the well. This is a very important factor that should be taken into consideration in designing the proper artificial lift for the new proposed wells. Similarly for the gas lift design, Table 8 gives the gas lift design parameter which is the point of injection, the gas injection rate, and the surface injection pressure along with the well head pressure at each selected time during the life of the well.

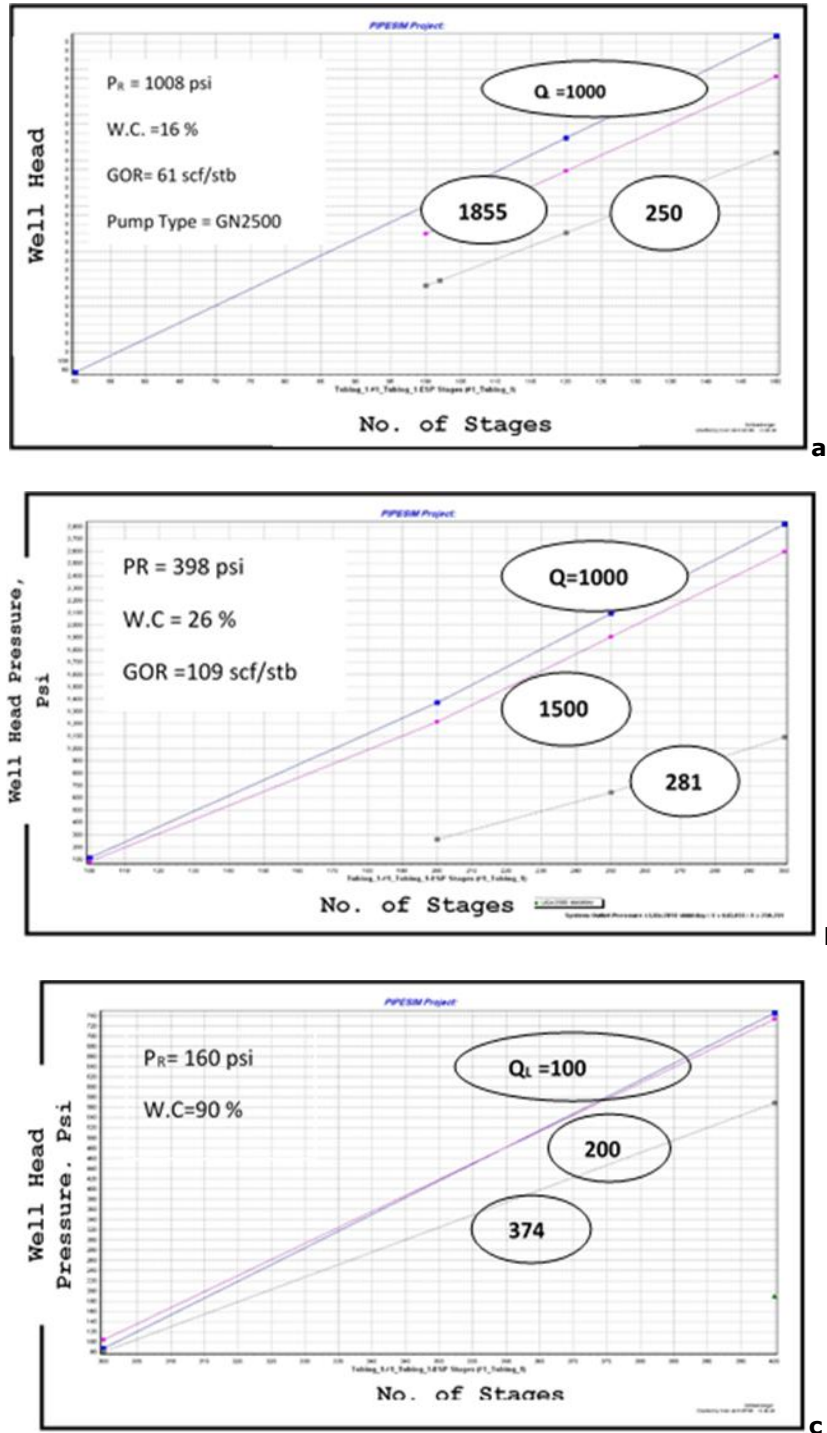


Fig. 6. General charts for ESP design for primary depletion scenario



Table 8. Gas lift design summary for the primary depletion case

Time	PR psi	W.C. %	GOR scf/stb	QL <sub>r</sub> stb/d	P <sub>inj</sub> , psi	Q <sub>inj</sub> opti- mum MMscf/d	Point of injection	WHP, psi
2127	1008	16	61	1855	1000	4	5100 ft	350
3284	398	26	109	2818	-	-	-	-
6584	160	90	430	374	-	-	-	-

From Table 8, it can be easily concluded that the gas lift was able to operate at the initial time with surface injection pressure of 1000 psi and injection rate of 4 MMSCF/D with well head pressure of 350 psi. However, for the rest of the points, gas lift cannot get the rate obtained from the dynamic model at these conditions.

#### 5.4. Artificial lift analysis for water injection scenario

Similarly, as discussed before for the primary depletion case, the same selected pilot well is used to analyze the performance of both ESP and Gas lift during the life time of the well. Figure 7 gives the liquid rate performance for the water injection case obtained from the dynamic modeling along with the selected time spots for the nodal analysis work.

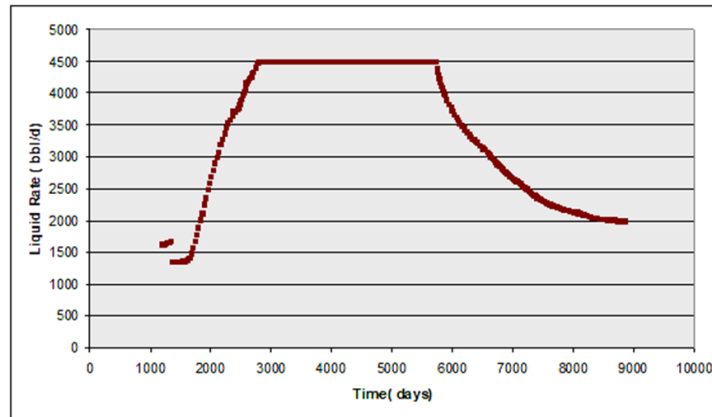


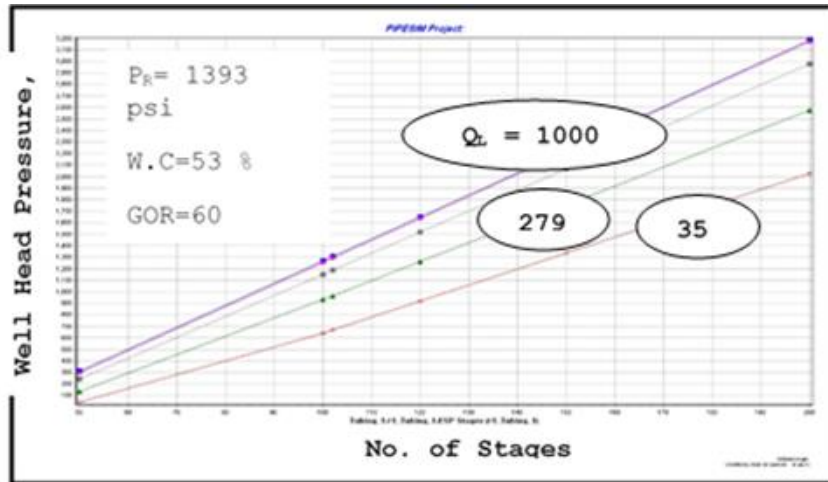
Fig. 7. Liquid performance for the water injection scenario of the selected well

A PIPSIM model had been built for the three selected points along the life of the well based on the reservoir pressure, bottom hole flowing pressure, water cut, and gas oil ratio available from the dynamic modeling for the water injection scenario. Table 9 gives the selected ESP pump along with the well head pressure for this pump for the three selected points. General charts (Fig. 8 a, b, c) have been generated for each pump to describe the change in well head pressure due to the change in the number of stages for the used pump under different conditions. For the ESP analysis in case of water injection, it is easily noticed that the ESP pump needs to be changed along the life of the well similar to the case of primary depletion. Similarly, for the gas lift analysis, Table 10 gives the gas lift design parameters for the pilot well selected for the water injection scenario. Similarly, as the primary depletion case, the gas lift cannot operate at high rate (4500 STB/D) and low reservoir pressure as shown from the last two points in Table 9. This indicates that the gas lift cannot be selected as a good candidate to achieve the production rates predicted from the dynamic modeling phase for field wells.

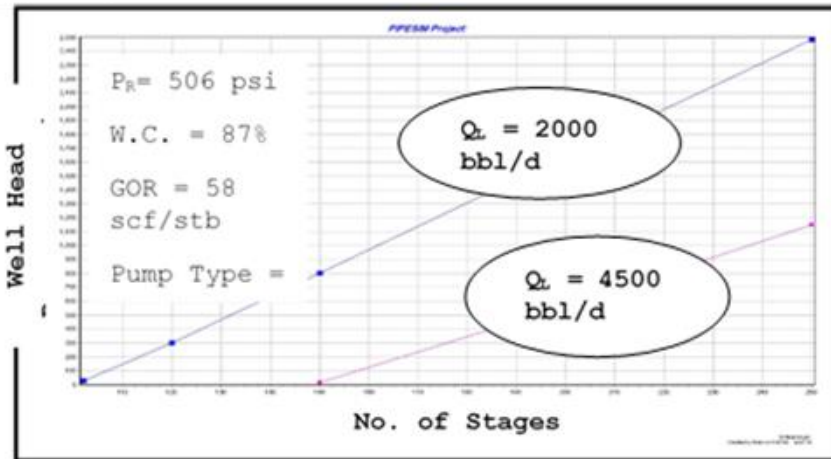
Table 9. Summary of the ESP design for the water injection scenario

Time	PR psi	W.C. %	GOR scf/stb	QL <sub>r</sub> stb/d	No. of stages	WHP, psi	H.P.	Pump type
2036	1393	53	60	2791	80	600	102	GN3200
4196	506	87	58	4500	201	600	285	GN4000
8306	172	97	360	2053	174	600	174	GN3200

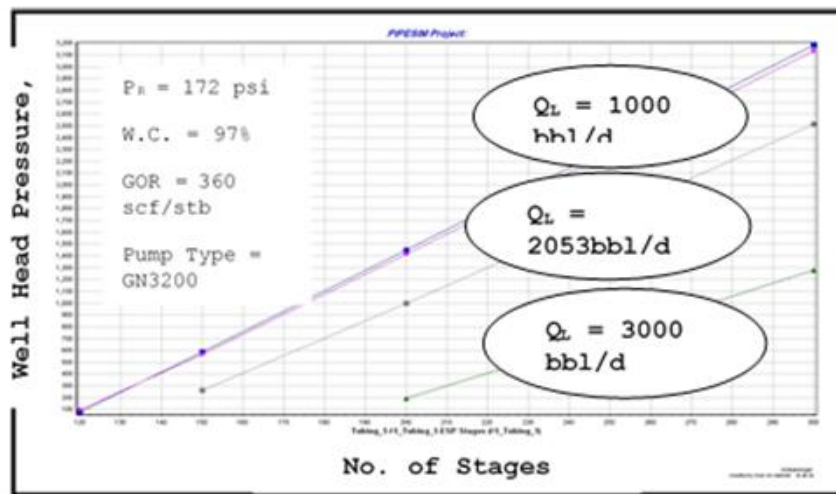




(a)



(b)



(c)

Fig. 8. General ESP design charts for water injection scenario

Table 10. Gas lift design summary for the water injection scenario

Time	PR psi	W.C. %	GOR scf/stb	Q <sub>L</sub> stb/d	P <sub>inj</sub> , psi	Q <sub>inj</sub> opti- mum MMSCF/d	Point of injection	WHP psi
2036	1393	53	60	2791	2000	4	5100 ft	450
4196	506	87	58	4500	-	-	-	-
8306	172	97	360	2053	-	-	-	-

## 6. Conclusion

For Bentiu Reservoir all the sensitivity runs showed that the wells stop flowing (Natural flowing) when water cut reached 20 %. Sensitivity on well head pressure showed that the decreasing in WHP can improve well performance. The average WHP for the current wells are around 200-300 psi so there is no room to change WHP.

The sensitivity on reservoir pressure showed that the well performance is very sensitive to the reservoir pressure. Based on these analyses, it is recommended to run the completion equipped with artificial lift from the starting of production to avoid any future work over to change the completion. The Artificial Lift screening showed that ESP, Gas Lift (GL), and PCP are candidates to produce Bentiu wells.

The drawback of the gas lift is that the well production is highly sensitive to the change in reservoir pressure. Both ESP & GL wells showed stable performance at increasing of WC.

The tubing diameter of 3.5" is recommended to produce Bentiu wells. A detailed analysis for both ESP and Gas Lift was performed to examine the efficiency of the both methods in producing the recommended production rates for a pilot well obtained from the dynamic modeling for three different recommended scenarios which are the primary depletion, water injection and gas injection. The results show that ESP can produce the predicted well performance, but it needs to be changed during the life time of the well by changing its number of stages to handle the changes in the liquid rates and reservoir pressures anticipated from the three tested scenarios.

## References

- [1] PIPESIM User Guide-Version 2007.2, Schlumberger, 2005
- [2] Khasanov MM, Krasnov V, Khabibullin R, Pashali A, and Guk V. A Simple Mechanistic Model for Void-Fraction and Pressure-Gradient Prediction in Vertical and Inclined Gas/Liquid Flow. SPE Production & Operations 24(1):165-170.
- [3] Su H-J and Oliver DS. Smart Well Production Optimization Using An Ensemble-Based Method. SPE Reserv. Eval. Eng., 2010, 13: 884-892.
- [4] Abdul Majeed GH, Al-Soof NBA, and Alassal JR. An improved revision to the Hagedorn and Brown liquid holdup correlation. J. Can. Pet. Technol., 1989; 28(6).

*To whom correspondence should be addressed: Dr. Reda Abdel Azim, Future University in Egypt Petroleum Engineering Department, Egypt*