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Evaluate Field Development Option, Production Optimization Scenarios and Analysis of Surface Network Upgrading Phases of Abu-Attifel

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Abstract

Most of the mature field surface networks suffer from the back pressure applied on the wellheads. An extra pressure in front of the influent fluids should be overcome to handle the fluids to the final destination gathering point. This paper presents de-bottlenecking of Abu Attifel surface network and the solution proposed during production optimization phases. To capture the performance of Abu Attifel field wells, sixty wells single branch model were built using nodal analysis technique. All these wells were connected together to present the total field network. The network model consists of two different pressure systems. Low pressure system, which are 7 wells connected directly to the second stage separator, the remaining 53 wells are connected to the first stage separator operating at higher pressure. The network model was calibrated and matched globally through tuning of pipeline roughness and compared with the pressure measuring points at the gathering manifolds. As a result, reasonable match was obtained with 2% difference between actual and model calculated flow rates. All gathering points and well headers were matched with the available pressure and flow rate measurements. This validated network provided a valuable tool to evaluate, optimize and enable enhancement of the oil production. It defined several solutions to increase oil production such as converting some wells to the lower pressure separator, and the visibility to install two multiphase booster pumps in the flow line.

Introduction

In many mature fields the issue of overcoming network backpressure exists. It is where an extra pressure in front of the fluid should be overcome to flow the fluids at desired rate through pipelines or to the final gathering point.
The purpose of this paper is to evaluate the possible backpressure applied on Abu Attifel field network system. It has been observed that total field production is less than the summation of production taken from individual well test.
Abu Attifel field is located in the East-Central part of the Libyan Desert; the field was started-up in 1972. Abu Attifel field consists of two areas, main area of 44 wells and west area of 12 wells. The total production is 98,000 STB/day, and 185 MM SCF/day of gas with water cut of 54 %. Most of the production comes from Upper-Nubian Sandstones layer, and the drive mechanism is water Aquifer, supported by water Injection scheme.

Well test interpretation was performed for nine wells. The output of well test interpretation was utilized as input for the well performance analysis. PVT models were created for main and west area of Abu Attifel field. In well performance analysis single well models were built for sixty wells. Flow correlation matching was done to ensure best estimation of flowing bottomhole pressure. Well performance models were calibrated using referenced well test results to simulate actual well condition at time of the test. The models were then connected to create the whole field network. The field network model consisted of 5 Manifolds, with two different pressure systems. Low pressure system, which is 7 wells connected directly to the second stage separator. The rest of 53 wells with an extra 7 sources were connected to the first stage separator as a high pressure system. However, all those gathering points and well headers were matched with the available pressure and flow rate measurements.

The network model was calibrated and matched globally by tuning the pipeline roughness and compared with the pressure measuring points at the gathering manifolds. As a result, reasonable match with a 2% difference between the final sink point flow rate and model calculated flow rates was achieved. However, locally some of wellhead pressures and flow rates are more than 60% difference. More investigation was done to find out the uncertain parameter(s) causing the model differences. Knowing that choke bean sizes have the highest uncertainty parameter, due to: Human errors and accuracy of old chokes. We start an optimizing process by altering the choke sizes to meet the available latest well test WHP and flow rate measurements. Consequently, a local matching is achieved locally and globally with a difference of 8%.

The network model was calibrated with surface pressure and rate measurements at different locations in surface production system. Production optimization cases were developed by either installing multiphase booster pumps for selected wells, or by converting some wells from high to low pressure system in the network.

The validated network provided a valuable tool to evaluate, optimize and enable enhancement of the oil production by defining strategies of solutions to increase oil production from Abu-Attifel.

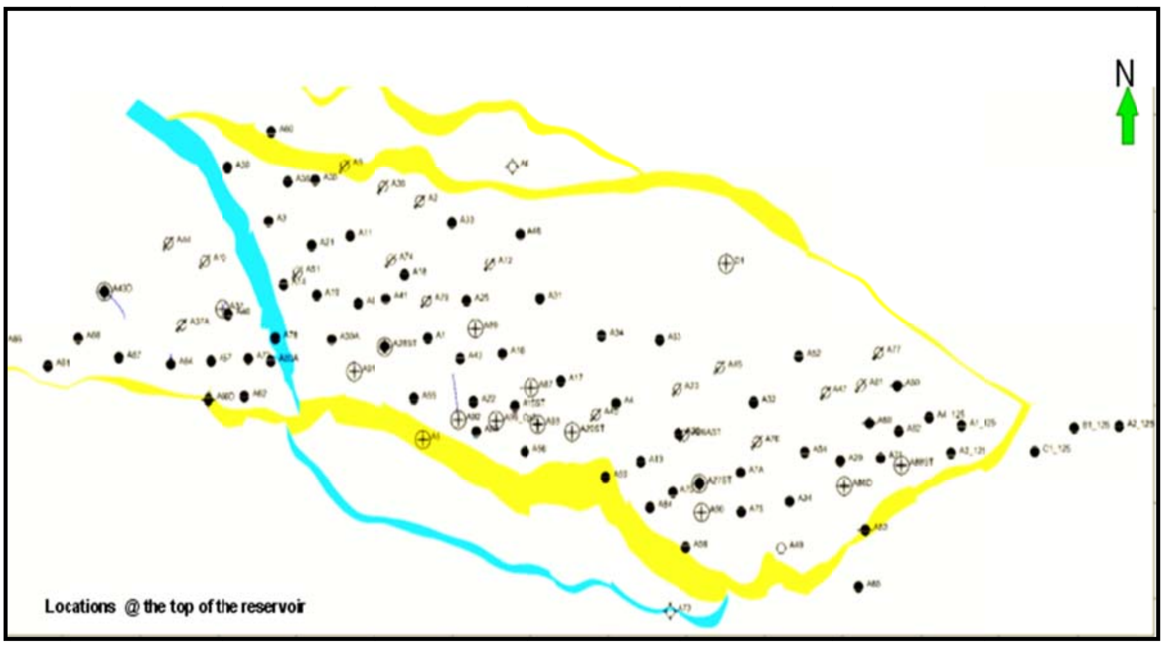

Figure 1: Abu Attifel Well Location Map

Field History

Abu Attifel field is Located in the East-Central part of the Libyan desert, the field was discovered in 1967 and started-up in February 1972. Abu Attifel field consists of two areas, main area with 44 wells and west area with 12 wells as shown in **Figure 1**. It is producing oil of about 66,000 STB/day, and 185 MM SCF/day of gas with water cut of 54 %. Most of the production comes from Upper-Nubian Sandstones layer. The Drive Mechanism is water aquifer, supported by water Injection scheme.

Objective

The objective of production network analysis is to build a representative model and apply engineering analysis to allocate the main network bottlenecks. Several cases to enhance field production are to be introduced including the possibility to install surface multiphase pumps.

Methodology:

The Methodology followed in this study was as follows:

1. **Building of the Network Model**
   1.1. Network model construction
   1.2. Linking wells as network sources.
2. **Integrating Well Models into the Full Field Network Model**
   2.1. Importing single Well models into network model.
   2.2. Run the complete model.
3. **System model validation**
   2.2 1 Local validation
   2.3 Global validation
4. **Bottlenecking identifications**
   4.1 High pressure gradient positions.
   4.2 High erosional velocity locations

De-Bottlenecking and Network Optimization Analysis

1. Installing multiphase pumps.
2. Converting more wells into low pressure System.

Building of the Network Model

Field network data (pipeline connections/geometries, network plan view maps, and wells elevations) were collected from the field. The following is the workflow used to build the complete network:

1- Network model construction

The complete field network was subdivided into five small sub-network models, in order to simplify the network construction and minimize unnecessary trial and error processes. Each sub-network model was built and validated individually.

2- Linking wells as network sources.

All sub-network models were linked together to build the complete network system. Abu Attifel field wells, R-82 arrival manifold, NC-125 wells (A1, A2, A3, & B1) and well A86 were introduced as a source of pressure and flow rate.

Integrating Well Models into the Full Field Network Model

Single well models were imported into the complete field network model, and then the complete system model was run. Pressure, and flow rate were calculated at all nodes.

System Model Validation & Matching

The complete model was run to calculate network flow parameters. The model has been matched with the available observed data at the final sink point (total liquid flow rate) and at the wells gathering points (M1, M2, M3, M5 and M4), and finally at the wellhead (WHP and Liquid rate).The location of the observed data is shown in **Figure 2.**

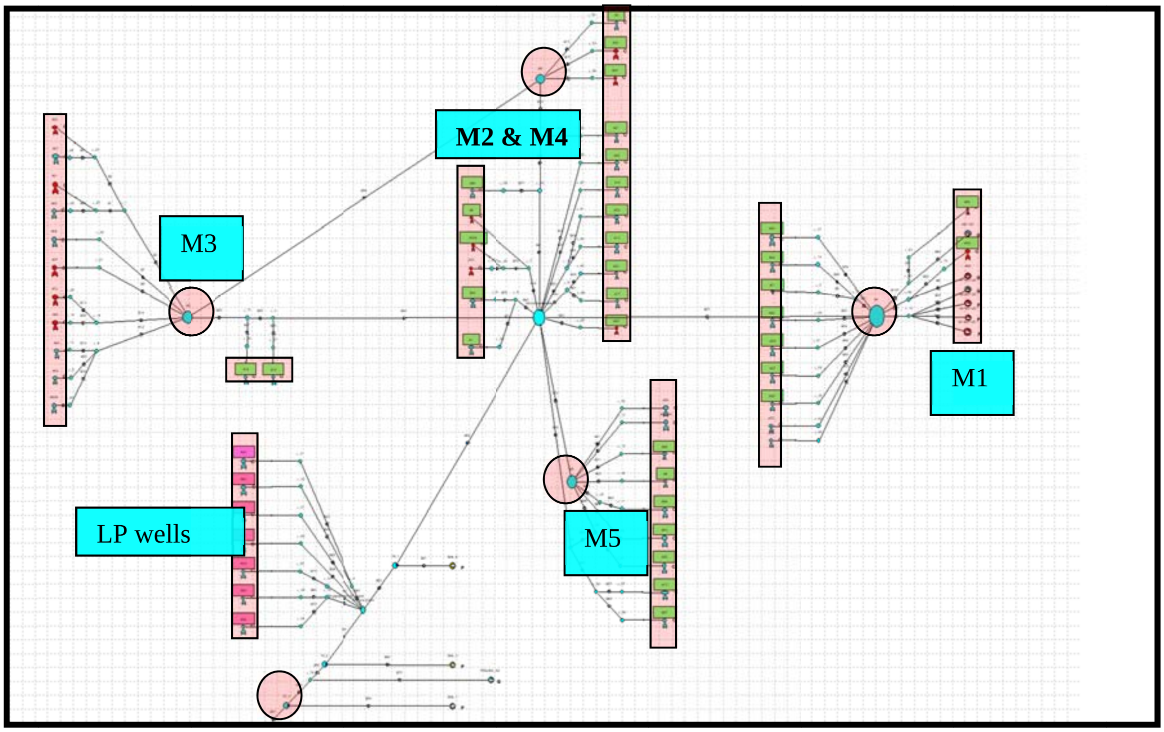

Figure 2: Locations of the observed pressure data.

The following parameters were considered for validating the network model:

1. Pipelines roughness
   Pipeline roughness is an important parameter that can be considered in pressure losses calculations. Since the pipelines are old, the possibility of corrosion, Salt, Asphaltene, or/and Wax precipitations exists. Roughness was chosen in the range between 0.0018 of wrought iron and (0.012-0.12 in) of concrete roughness. The roughness of 0.1 provided closer match with actual pressure and flow rate measurements. Based on this, final base case model was established and validated.

2. Well head choke sizes
   The individual wellhead and flow rates were compared with the observed production data and by comparing each calculated and observed data (WHP, and flow rate at well heads), it was found that the difference in flow rate was high in few wells as shown in **Figures 4 & 5.**
   With reference to the field data sheet, and due to the fact that, adjustable choke is not easy to read and because of the possible corrosion effect on theses chokes. Each well choke was tuned with the referenced well test results. The tuned choke settings were then imported into the complete network model. As a result, a better and reasonable match is achieved. **Figure 6, 7 & 8**

Bottlenecking Identifications

Main factors considered in the de-bottlenecking analysis were:

1- High pressure gradient positions

High pressure gradient was investigated and allocated in all the model branches. As it can be seen from **Figure 3** B64, B88 at M1, B43, B40 at Low pressure system manifold, B60, and B97 at M5 are branches that have high pressure gradient.

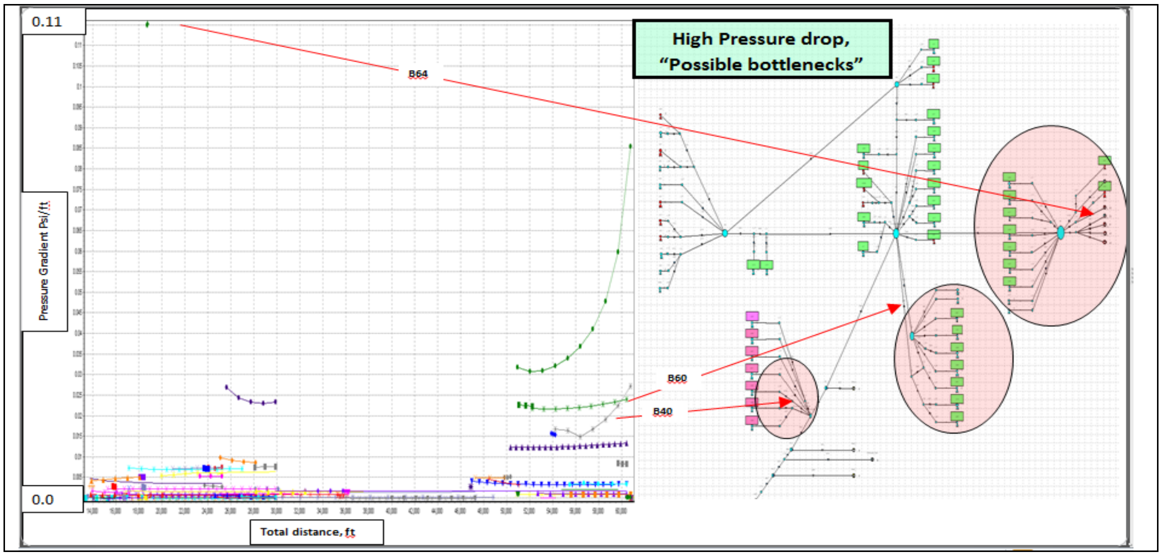

Figure 3: Pressure gradient cross the network pipelines

Consequently, most of the pressure losses exist at M1 and M5, hence back pressure is applied on wells A1-NC125, A27 at M1, A15, A87 at M5 and A22, A31 and A42.

2- Influent fluid Erosional velocity ratio

Fluid velocity ratio through all the net work has been checked. All of trunk lines fluid velocity ratios are below the maximum value of 1.0 above which, the flow line would be in danger of failure due to high velocities. However, some of connections have closer ratios to 1.0 such as B34 and B40 as in **Figure 9.** Those branches need to be monitored in the future, especially if the operation conditions such as downstream pressure will change.

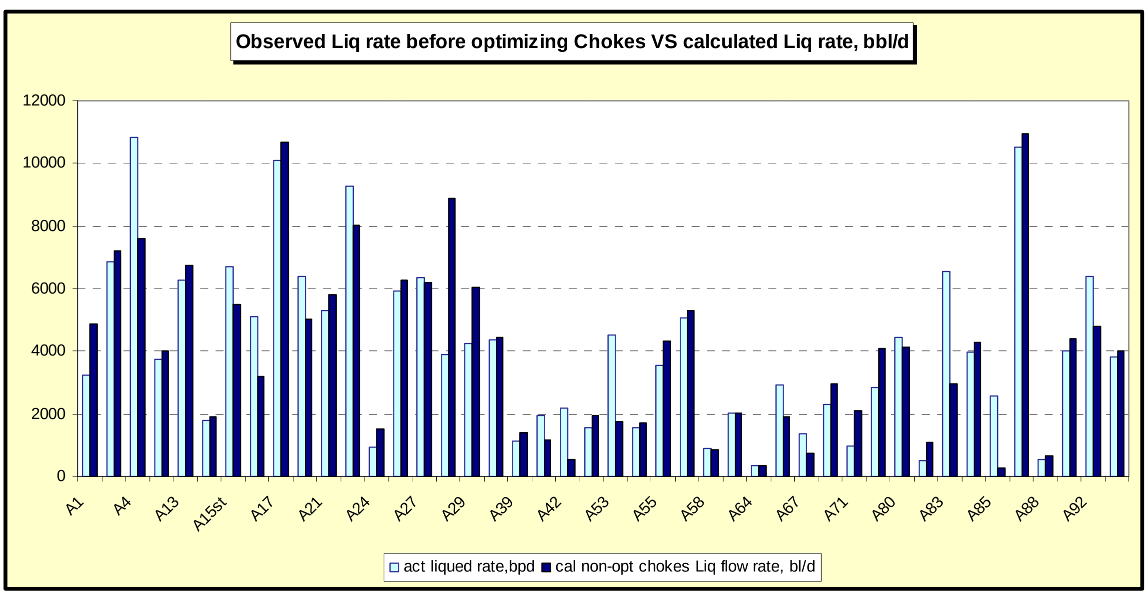

Figure 4: Observed and calculated Liquid rate before chokes optimization

Pressure Gradient

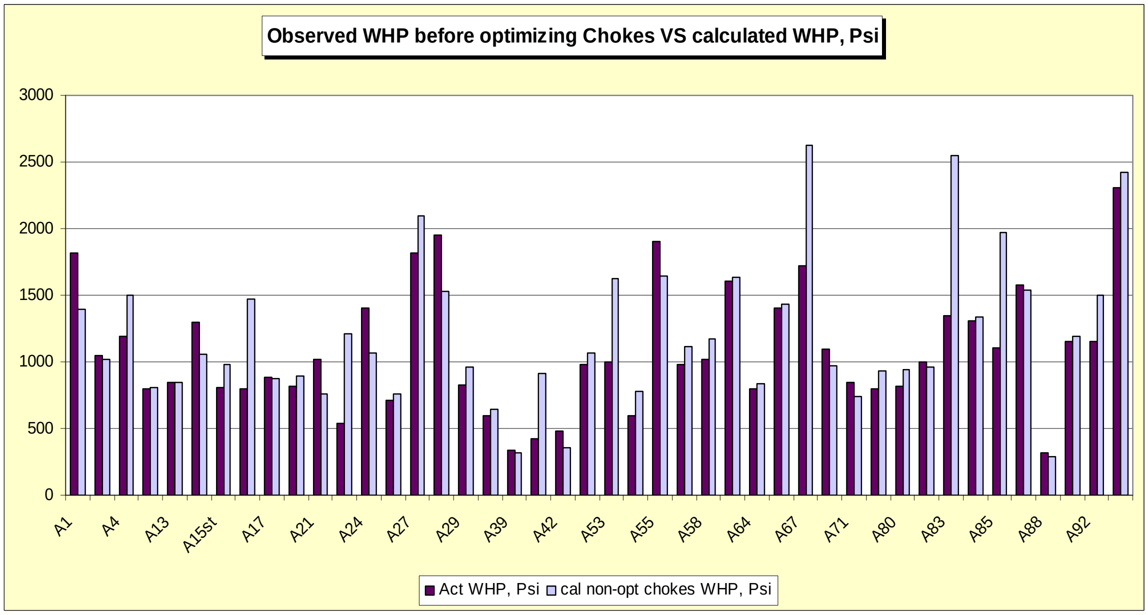

Figure 5: Observed and calculated WHP before chokes optimization

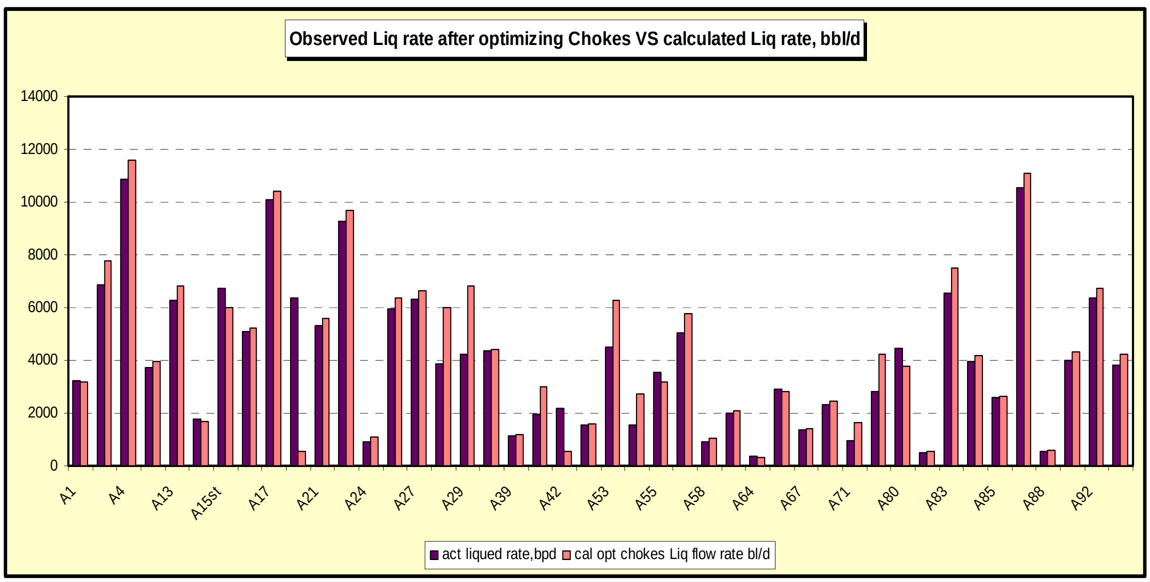

Figure 6: Observed and calculated Liquid rate after chokes optimization

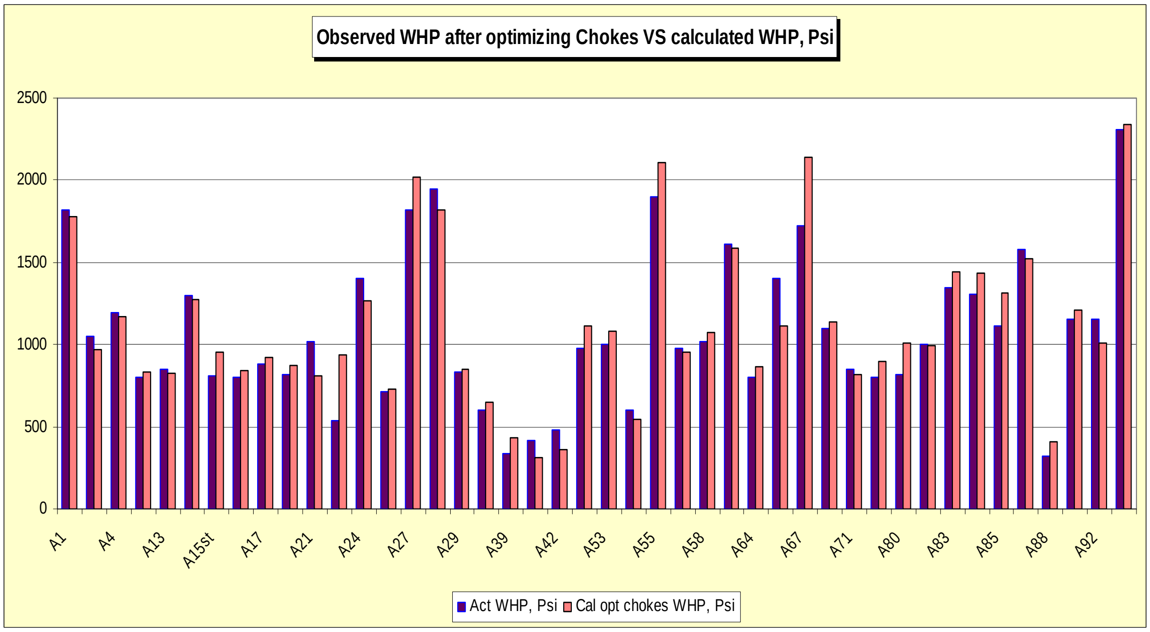

Figure 7: Observed and calculated WHP after chokes optimization

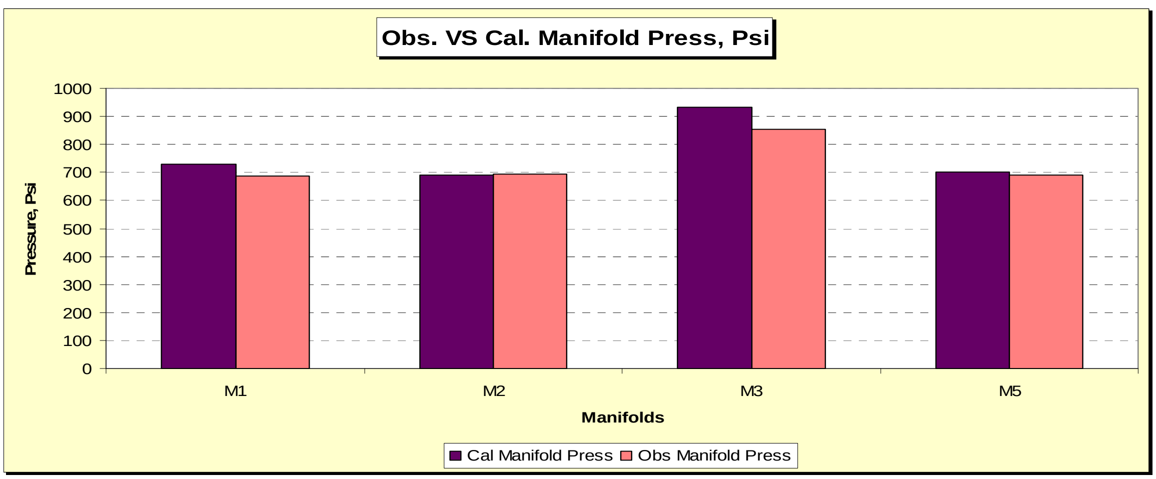

Figure 8: Observed and calculated Manifold Pressures

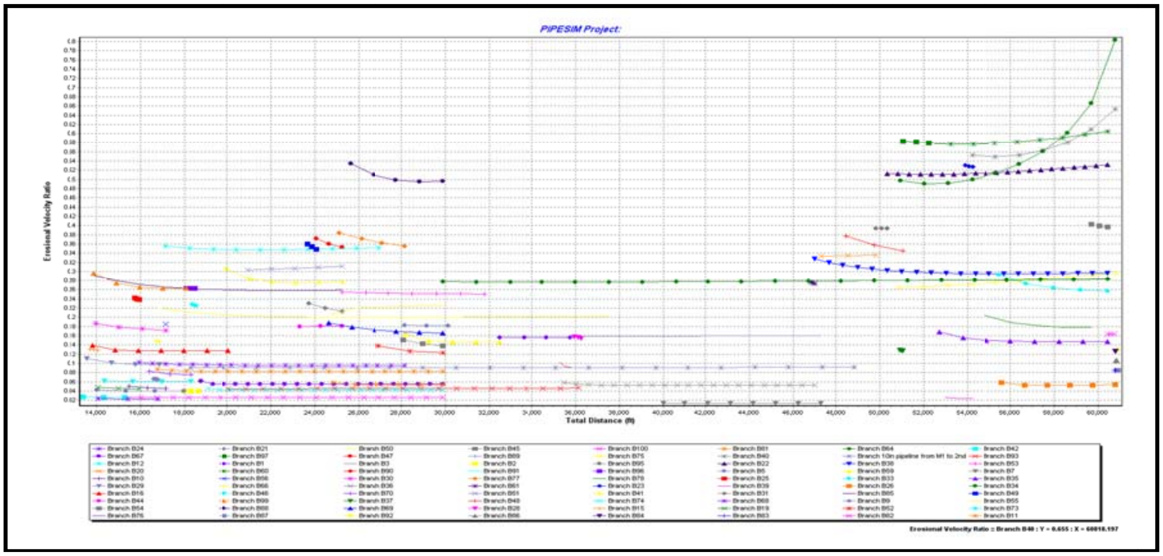

Figure 9: Erosional Velocity Ratio

Network Optimization Scenarios:

Considerations for well selection criteria

Based on the well single branch models and production history, ranking was performed to select the best successful wells to be either converted into low pressure system (LPS) or to install multi phase pump (MPP).

First, all the wells were grouped based on their WHP, wells that have comparatively low pressure (WHP Less than 1000 Psi) were selected to be converted into LPS. After that, those wells ranked based on their highest PI to produce (High PI wells are in the top priority). Consequently, wells A15, A13, A19, A17, A52, A29, A80, A75, A7, A71, A25, A16, A21, A64, and A56 are the proper wells to be converted into LPS.

Wells A15, A13, A19 and A17 were the selected wells to install MPP.

De-Bottlenecking and Network Optimization Analysis

Based on De-Bottlenecking and network optimization analysis, two technical scenarios to increase field production are considered. The results are summarized in **Table 1** and the histogram chart of **Figure 10**

N.	Scenarios	(1-WC)	Oil rate (STB/D)	Incremental Oil Production (STB/D)
	Actual operation case	**0.53**	**97,874**	**0**
	Base case	**0.5**	**106,131**	**0**
1.1	**Installing 4 MPP A15, A17, A13, and A19**	**0.49**	**108,742**	**2,611**
1.2	**Installing 2 MPP at A17, A19**	**0.5**	**108,057**	**1,926**
2.1	**Converting all 15 wells "WHP"< 1000 Psi into LP (A7, A13, A15, A16, A17, A19, A21, A25, A29, A52, A56, A64, A71, A75 and A80).**	**0.48**	**110,526**	**4,394**
2.2	**Converting maximum 11 wells into LP (A7, A13, A15, A17, A19, A25 A29, A52, A71, A75 and A80).**	**0.48**	**110,489**	**4,358**

Table 1: Results of De-Bottlenecking and Network Optimization Analysis

1. Installing Multi phase pump

1.1 Installing 4 MPP at A13, A15, A17, and A19

Based on the ranking criteria selection, A13, A15, A17, and A19 have the top priority to install MPP at their well heads. As it can be seen from the results table, the incremental of oil is 2600 STB/D.

1.2 Installing 2 MPP at A17 & A19

In this case, two MPP were installed at A17, and A19, and the incremental oil was 1920 STB/D. another case was made by installing two MPP at A13, and A15, but the incremental oil was less than the case for installing MPP at wells A17, and A19.

2. Converting more wells into low pressure system

2.1 Converting all WHP <1000 Psi into LP system (15 wells)

Based on engineering ranking criteria, wells that have less than 1000 Psi wellhead pressure and high productivity index (15 wells) are proposed to be converted into the LPS. The incremental of oil is 4390 STB/D, however, this cannot be applied as the second stage separator is constrained of a maximum oil rate of 31,500 STB/D whereas, and the anticipated oil rate from the model is 39,530 STB/D.

2.2 Converting Max 11 wells

As the second stage separator has capacity constrain, it cannot handle more than 31,500 STB/D, the number of the wells were reduced to meet the capacity of the second stage. After removing the last bottom prior wells and remain only the maximum 11 wells to be converted into the LPS (A15, A13, A19, A17, A52, A29, A80, A75, A7, A71, and A25), the incremental of oil is 30,310 STB/D which meets the separation system capacity.

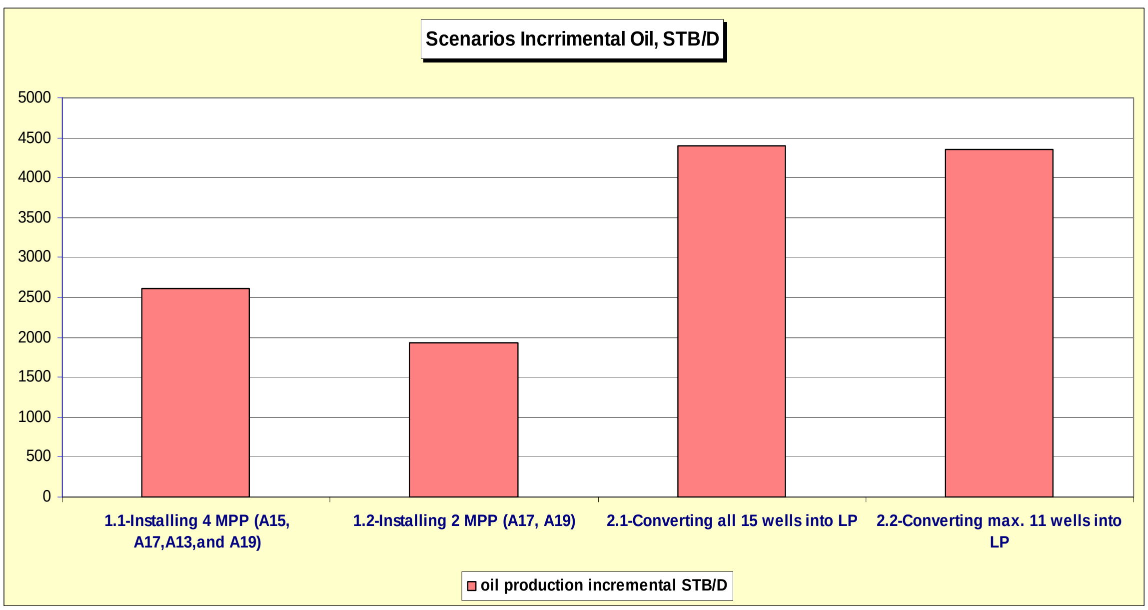

Figure 10: Network optimization results

Conclusions

1. Installing two Multi Phase Pumps for wells A17 and A19 can enhance field oil production by 1,930 STB/D.
2. Converting eleven wells into LP system would add about 4,400 STB/D of Oil. This is considering the current capacity of the second stage separator.
3. Erosional velocity ratios should stay below a maximum of 1.0
4. To conduct full production system optimization; it is recommended to integrate the study network model with the reservoir simulation model.
5. Based on model input quality review presented in Appendix 4; it is recommended to apply the proposed methods and procedures to improve data quality and reduce model uncertainty

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