Chapter 1 - Introduction

1.1. Background

Pipeline networks are systems with hundreds or thousands of kilometers of pipes and production facilities, storage and distribution centers, compression stations, and many other devices like valves and regulators.

These types of systems work at high pressures and use compression stations and pumps to supply to the oil enough energy to be moved along long distances.

For a mature oil field gas and liquid compositions tends to change due to the aging of the field because water cut will increase thus may increase the artificial lift requirement. Also the smaller accumulations nearby tend to be developed as satellite to the main facilities.

Analyzing the entire upstream supply chain in an integrated manner, compared to looking at the individual elements, is becoming increasingly important in the current business, because the system bottlenecks could shift from year to year (Thijssen and Mittendorff 2007).

Network analysis will look at the impact of changes on the entire network over the entire time period with the aim to determine the optimal timing of developments of new fields, to identify bottlenecks in the network and evaluate options for removal of these bottlenecks. This analysis can also be used to underpin investment decisions, to help optimize the product slate and analyze trade-offs between, for example, energy efficiency, production and overall recovery. Overall it supports the activity known as strategic or investment planning.

Modeling approach is often used in energy master planning studies, where the focus is on the commercial value of oil & gas and related value streams in the market while balancing the costs of production, transport, processing and storage. It provides a structured framework for analysis across the whole energy value chain in order to focus on the key business opportunities.

The same approach can be used for a smaller section of the energy value chain, for example when the focus is only on the upstream sector. In this sector all individual elements in the oil & gas upstream supply chain are typically modeled in isolation using simulation programs. Analyzing the upstream supply chain in an

integrated manner, compared to looking at the individual elements, is becoming increasingly important in the current business, because the system bottlenecks could shift from year to year (Lasschuit and Thijssen 2004).
For these integrated studies, one typically considers the oil & gas supply chain starting from wellhead platforms via multi-phase pipeline to a production platform, then through a network of pipelines to the export facilities.

1.2. Problem Statement

Hamra field is facing challenges to sustain its production, which is decreasing annually.
Flow lines network plays important role in delivering the production from wellhead to Field Processing Facility (FPF).Bottlenecks in pipeline can cause rise in wellhead pressure, which can have a very strong impact on production sustainability.

1.3. Research objectives

1. To build physical model and compare simulation result with field data
2. To identify production bottlenecks and constraints
3. To optimize production from the networks

1.4 HAMRA FIELD BACKGROUND

Hamra field is located in block 4 & operated by Greater Nile operating company (GNPOC) which has concession in Western Upper Nile area includes the field from sedimentary basin of Muglad in interior Sudan. This Basin is characterized by thick clastic sequence of cretaceous and tertiary age. The depositional sequence includes thick lacustrine shale and clay stones, flood plain clay stone, and lacustrine, fluvial, and alluvial sandstone and conglomerates.
These lacustrine clay stones deposited in a suboxic environment provide good oil-prone source rocks. Reservoir sandstone has been found in wide variety of no marine sandstone faces. Tectonic activity created formation of several deep fault bounded troughs, major interbasinal highs and complex basin flanks. Thus variety of structure has been created and many of them have hydrocarbon traps.
Hamra field consist of 38 wells connected to four oil gathering manifolds.
Most of the wells are completed in multiple formations and being produced

commingled. These formations have wide variation in reservoir properties, oil type and pressure regime.

Chapter 2 - Literature Review

2.1. Modeling approach

Recent studies confirm that network modeling approach is often used in energy master planning studies, where the focus is on the commercial value of oil & gas and related value streams in the market while balancing the costs of production, transport, processing and storage (Lee & Thijssen, 2007), It provides a structured framework for analysis across the whole energy value chain in order to focus on the key business opportunities.

For these studies, one typically considers the oil & gas supply chain starting from wellhead platforms via multi-phase pipeline to a production platform, then through a network of pipelines to the export facilities.

The aim of the network analysis is to help determine the optimal timing of developments of new fields, to identify bottlenecks in the network and evaluate options for removal of these bottlenecks. This analysis can also be used to help underpin investment decisions, optimize the product slate and to analyze trade-offs between, for example, energy efficiency, production and overall recovery (Thijssen and Mittendorff 2007).

In 1995 a published literature showed that Bottlenecks that arise in the upstream supply chain can be a result of:

1 Field composition (gas-liquid) changing over time and increased water content in the oil-water liquid stream due to ageing of fields.

2 Increasing use of existing infrastructure for the implementation of new projects to compensate the production of ageing fields or to increase overall production.

3 New projects that come on stream typically will use part of the existing facilities, which may have sufficient capacity to handle increase of production from one individual project, but will not be adequate for other projects (Litvak and Darlow1995).

The model helps to optimize flow and production of oil and gas, between wellhead platforms and demand locations over the defined time period given the infrastructure

Production, Pipelines, and Compressor constraints. The economic analysis converts output from the program into analysis of individual assets and scenarios based on costs, capabilities and prices.

The model can be split into four key modules. These are the Supply Module, which include production profiles for each existing and future wellhead platform (the so-called technical potential); the Processing Module describing production/processing facilities & constraints; the Demand Module, which covers any demand point (oil & gas demand, fuel- and re-injection gas requirement, etc); and the Interconnection Module, which ties together supply, processing and demand to account for pipeline or distribution constraints and capacities. General data input is required of supply sources (wellhead platforms), production and processing facilities infrastructure and capacities (processing platforms, compressors, pumps etc.), transportation capacity (pipelines), costs of processing (operating cost and fuel gas consumption), and other business constraints in production, processing and distribution (e.g. minimum and maximum demands, no venting after a specific year).

The model can help to optimize the entire network over the entire time horizon. The objective function is based on the variables in the system and is typically the Net Present Value of the profit margin over the time-horizon, based on the GOR & Water cut of the respective wellhead platforms and the Unit Production Cost.

$$Profet\ Margin = [(Oil\ production \times Oil\ Price) - (Operating\ Cost) - (CAPEX)]$$

The profit margin is in general the revenues from oil and gas sales minus fixed and variable operating costs (including cost of venting/carbon dioxide) minus investment costs (as illustrated above).

This means that the model will only drive towards producing oil and gas if the value of the oil and gas exported is greater than all associated costs (operating, fixed and capital expenditures). Depending on the oil, gas and water content of the production from a wellhead platform and the constraints in the entire network, the model will maximize production from certain wellhead platforms. For example, when the bottleneck occurs only in the oil pipelines and the driver is the oil price the model will try to maximize oil production from those wellhead platforms, which have relative low water content. If there is also gas export restrictions in the network the model will try to maximize the wellhead platforms that have relative low water content and a low gas/oil ratio (GOR), because it does not want to produce the gas with the oil as the gas evacuation system might constrain the oil production (Lee & Thijssen,2007).

2.2 Surface pipeline network Model

In most simulations, well production rates are constrained by limited oil, gas, and water handling capacities of separator banks and gas plants as well as pressure limits in separation facilities. Therefore, integrated reservoir, well tubing string, and surface-pipeline modeling is required for accurate prediction of well rates from reservoir and facility constraints.

The surface pipeline-network model simulates steady-state multiphase flow in well tubing strings from wellbores to wellheads, well chokes, and pipeline systems from wellheads to separator banks. It also determines well artificial lift rates and well connections to different pressure systems. Different elements of the surface-pipeline-network model are described below.

2.2.1 Well Inflow Performance.

Molar rates of the hydrocarbon components and water for production wells are determined by the reservoir model as functions of well bottomhole pressure and grid block properties saturations, compositions, and pressure for grid blocks with well perforations(Litvac 1993). a Newton-Raphson iteration procedure is applied to obtain the solution of the nonlinear reservoir flow equations at each time step. If the values of the grid-block variables from a previous Newton-Raphson iteration are used, the well inflow relationships can be represented as functions of the bottom hole pressure only

$$q_{hj} = f_h(p_j) \quad \text{(2.1)}$$

$$q_{wj} = f_w(p_j) \quad \text{(2.2)}$$

2.2.2 Tubing Strings.

Different methods available in the petroleum industry ~e.g., Hagedorn and Brown are applied for pres-sure gradient calculations in well tubing strings. In these methods, the pressure distribution along the tubing is calculated from the solution of the following ordinary differential equation (Hagedorn, and Brown1965)

$$\frac{dp}{dl} = f(p, q_{hj}, q_{wj}) \quad \text{(2.3)}$$

To evaluate the pressure gradient on the left-hand side of Eq. (2.3), the density, viscosity, and in-situ velocities of oil, gas, and water phases need to be determined. The equation of state is used to obtain the oil and gas compositions and their densities as a function of the pressure, temperature, and molar rates of the hydrocarbon components. Oil and gas viscosities are then calculated using viscosity correlation ~e.g., the Lohrenz-Bray-Clark correlation (Lohrenz and Clark 1964).

2.2.3 Well and Flowlines.

Production wells are tied to separator facilities by means of a surface-pipeline-network system. Different correlations available in the petroleum industry ~e.g., Beggs and Brill are applied for pressure gradient calculations in the flow-lines. Therefore, the pressure distribution along each flow line is calculated from the solution of the ordinary equation similar to Eq. (2.3).

2.2.4 Chokes.

The Perkins method is applied for modeling of critical and subcritical multiphase flow in well chokes. Look-up tables are used to correlate choke setting to internal diameter.

2.3 Coupling of reservoir simulators with surface networks

The design of a multiphase flow gathering network requires an estimate of flow potential from each well. Rarely is the aerial extent of the reservoir so well defined at the outset that all potential well locations can be identified. The flow potential of the fluid phases produced up the wellbore into the gathering network vary between wells depending upon the characteristics of the reservoir, and pressure depletion or “drive” mechanism of the reservoir. Accordingly, the efficient transport of reservoir fluids through the gathering network is usually difficult to predict over the producing life of the wells. (Ghorayeb, 2003).

The forecast of production rates from wells using a numerical reservoir simulation model is likewise dependent on backpressures caused by pressure losses in the wellbore and surface gathering network. The historical approach taken by the reservoir engineer has been to prepare flowing bottom hole pressure versus flow rate (VFP) “look-up” tables to approximate the backpressure caused by the wellbore and surface network (Kosmala,2003). Each table is unique with respect to tubular dimensions, lengths, etc. When dealing with multiphase flow many permutations (e.g. different water-gas ratios, condensate-gas ratios) are often required to construct a VFP table over potential range of flowing conditions. Such an approach is suitable for single well, single flow line gathering networks however; such configurations are not typical of most pipeline networks. It is not uncommon for networks to include numerous wells, tubing descriptions, pipeline branches and loops, as well as a variety of surface equipment such as pumps, compressors, line heaters, separators, etc.

Attempts by the reservoir engineer to forecast the flow rate potential of the reservoir, and the pipeline design engineer to design a network to efficiently transport reservoir fluids is particularly difficult in high rate, low pressure systems. Simplification of the hydraulic component of the gathering network or the reservoir model component usually introduces an unacceptable error to engineering calculations. The use of conventional surface network models, that use one-dimensional, tank-type reservoirs, may address the backpressure problem, but they cannot accurately forecast transient production profiles. This is especially true in low permeability, hydraulically or naturally fractured reservoirs, or those reservoirs exhibiting multiphase flow effects.

Reservoir management is normally achieved using numerical simulation to model the performance of the reservoir under different scenarios of well placement, number of wells, and production and/or injection profiles. However, reservoir simulators do not generally model the production downstream of the wellhead, and so the production network effects on the behavior of the overall system are not fully acknowledged. Flow simulation of the reservoir system also does not account for all the boundary conditions set at the surface, such as the suction pressure of the separator. This may have a direct impact on the evaluation of the production targets that will actually be achieved. On the other hand, production management typically uses surface network nodal analysis tools that fully account for those effects but can only model the reservoir as a homogeneous ‘tank’ of uniform properties.

Moreover, reservoir management aims at optimizing the reservoir performance over the field life by maximizing the recovery factor at the minimum cost, while production management is concerned with optimizing the production system capabilities on a day-to-day basis. Thus, reservoir and production management have complementary goals in field development, but on different time scales, and by using separate tools there is no guarantee that one will achieve a solution that satisfies both aims. Therefore, the integration of the capabilities of both reservoir and production system simulators appears to be a critical technology for field development and optimization.

The problems described have long been understood as an impediment to improving the accuracy of reservoir simulation forecasts and the design of pipeline networks to transport the produced fluids. The solution to the problem demands integration of various engineering disciplines, and their software technologies.

Recently, some vendors of reservoir simulation software have created interfaces allowing third party pipeline. (Beliakova, 2000)

The system that was developed therefore consisted of a reservoir simulator coupled to a network modeling and optimization tool through a controller (Ghorayeb,2003) The controller acts as a data link between the two simulators to facilitate optimal reservoir and production management and achieve realistic targets while respecting defined field and/or well constraints. The reservoir simulator models the flow from the reservoir to the bottom of the wells (either to the sand face or upstream of the downhole valves) and the production network from this point up to the separator, so there is no overlap in the models.

Two functionalities appear as essential in the development of a coupling tool between the reservoir and production network simulators: 1) the creation of a “physical” link between the two systems so that the results of the simulations are dynamically passed from one simulator to the other and 2) the design of a component that can optimize the overall system.

2.4 Modeling software

The PIPESIM steady-state multiphase flow simulator offers complex production and injection networks analysis. The well, pipeline, and flow assurance capabilities are all within a shared common environment, powered by the most rigorous field wide solver. The solver is suitable for networks of any size and topology, including complex loop structures and crossovers. By modeling the entire production or injection system as a network, the interdependency of wells and surface equipment can be accounted for, and the deliverability of the system can be determined.

PIPESIM network simulation and optimization capabilities enable users to

- Engineer the best well, pipeline, and facilities design
- Identify production bottlenecks and constraints
- Optimize production from complex networks
- Handle multiple system constraints
- Quickly identify locations in the system most prone to flow assurance issues such as erosion, corrosion, and hydrate formation
- Quantify the benefits of adding new wells, compression, pipelines, etc.
- Determine optimal locations for pumps and compressors
- Design and operate water or gas injection networks
- Analyze hundreds of variables such as pressure, temperature, and flow assurance parameters through complex flow paths
- Evaluate benefits of loops and crossovers to reduce backpressure
- Calculate full field deliverability to ensure contractual delivery rates can be met
- Optimize the allocation of lift gas amongst wells

Modern production systems require designs that ensure safe and cost-effective transportation of fluids from the reservoir to the processing facilities. Once these systems are brought into production, the ability to ensure optimal flow is critical to maximizing economic potential. From complex individual wells to vast production networks, the PIPESIM steady-state multiphase flow simulator enables production optimization over the complete lifecycle (Brill, 2012).

2.4.1Continuous innovation

For over 30 years, the PIPESIM simulator has been continuously improved by incorporating not only the latest science in the three core areas of flow modeling—multiphase flow, heat transfer, and fluid behavior—but also the latest innovations in computing, and oil and gas industry technologies. The simulator includes advanced three-phase mechanistic models, enhancements to heat transfer modeling, and comprehensive PVT modeling options. The ESRI-supported GIS map canvas helps deliver true spatial representation of wells, equipment, and networks. Networks can be built on the GIS canvas or generated automatically using a GIS shape file. The interactive graphical wellbore enables rapid well model building and analysis. Faster simulation runtime has also been achieved for all modeling though the implementation of a new parallel network solver to spread the computational load across all processors.

2.4.2 Steady-state flow assurance, from concept to operations

The PIPESIM simulator offers the industry's most comprehensive steady-state flow assurance workflows for front-end system design and production operations. The flow assurance capabilities of the simulator enable engineers to ensure safe and effective fluid transport—from sizing of facilities, pipelines, and lift systems, to ensuring effective liquids and solids management, to well and pipeline integrity. In addition, where dynamic analysis is needed to add further insight, the PIPESIM-to-OLGA converter tool enables rapid conversion of models. Shared heat transfer, multiphase flow, and fluid behavior methodologies ensure data quality and consistency between the steady-state and transient analyses.

2.5 Modeling History

According to recent literature many surface network modeling has been conducted in variety of networks configuration and in combination of deferent simulator in this section we will discuss three case studies that were conducted in the last decade and how they are related to this study in term of network configuration, type of field,wells type, procedure and optimization result in addition to type of soft ware used in conducting the study.

2.5.1 ADCO Abudhabi 2012

A giant onshore field producing from multilayered under saturated carbonate reservoir was presenting many challenges. The field is producing since early seventies supported with peripheral water injection leading to wide variation in reservoir pressure and water cuts. The field has been produced with the help of 6 gathering manifolds. The northern manifold presents additional challenges as this area is affected with asphaltenes deposition problems in production tubing and flow lines. Tubing obstruction due to asphaltenes adversely affects flow besides cause difficulty in lowering pressure gauges resulting into scarcity of pressure survey data. Additionally, some wells are operating on gas lift and a gas injection pilot is located on the western side leading to Gas Oil Ratio (GOR) variations. The horizontal wells completed in the low permeability layer tend to cease production as the water cut reaches >35%. Production allocation, optimization and de-bottlenecking become difficult in such a scenario. It was, therefore, decided to build a production network model as a tool to overcome such problems.

It was decided to construct an integrated network model of the field to address various issues as enumerated above. Well modeling and conducting Nodal Analysis to ascertain well behavior is an industry practice. Connecting the well models with surface facilities through flow lines and transfer lines has been attempted by many workers (Nader et al. 2006 and Kumar et. al. 2012). The calculation of flow rates and pressure drop in such a network is attempted by linear programming method. Network modeling by utilizing this method has reportedly provided excellent match with the field data. Jha et. al. (2009) has attempted to elaborate a plan for implementing a field wide integrated network optimization model incorporating real time data measurement for Bombay High Field. Many operators are implementing smart field solutions with real-time network modeling through collaborative working environment (Bin Amro et. al. 2010). The cost of implementing smart field solutions to this maturing giant carbonate field would be cost intensive as well as time consuming. It was, therefore, decided to build a network model for the field to address various issues.

A network model was built using PIPESIM software using workflow

Data gathering All the data regarding each well was collected in an Excel sheet. The data included depth reference, well diagram, deviation survey data, and pressure survey data of the well and nearby wells, production test data and well history. These Excel sheets would serve as reference documents during the model construction. An area was allocated in the sheet to keep a log of modeling activity like calibration and any changes made in the model. All the information was validated to avoid any uncertainty in the future.

PVT Matching the giant carbonate field, which is producing from three distinct pays, is presumed to be behaving like a single under saturated reservoir unit. Review of the PVT studies conducted in the field does not show wide variation. Therefore, the results of only available PVT study for this area were adopted. Slight tuning of the PVT parameters was done to match separator conditions as well as during flow correlation matching. Standing (gas solubility), Vasquez and Beggs (OFVF) and Chew Connelly (viscosity) were found satisfactory.

Build well Models Individual well models were constructed based on well diagram and deviation data. In case of vertical wells PI model for completion was adopted but horizontal completions were formed on the basis of Joshi model with zero anisotropy along the open hole. Each string of the dual completion well was modeled separately. GLV sizes were included as per latest design.

Pressure Traverse Matching Several pressure traverse matching's conducted to select the most appropriate correlation for the project. This exercise was conducted on many bottom hole pressure data having good control on production test data. Many correlations like Beggs and Brill, Hagedorn and Brown, Duns and Ros, and Orkiszewski were tried. Hagedorn and Brown correlation was selected with holdup factor as 1.

Network model of one of the manifolds of a giant carbonate field was built. Satisfactory PVT tuning and well calibration was achieved for all the wells. Calibration of wells in this area proved challenging due to lack of pressure data. The model predicts oil production in excess of 6-10% with the allocation data. Unstable flow in many of the horizontal wells, outflow constraint in asphaltenes affected wells and pressure fluctuation in RDS-CDS transfer line may be the reason behind over estimation besides allocation methodology. Further tuning of model for such factors and conciliation with production allocation would greatly reduce this uncertainty. Horizontal wells producing from low permeability reservoirs tend to flow in unstable flow regime because of larger tubing size. Such unstable flow also causes uncertainty in flow prediction by the model. Premature shut down of these wells may be avoided by reduction in tubing size (Al Sayari, 2013). It can be seen that network modeling is an effective tool for production estimation, optimization, allocation and debottlenecking.

2.5.2 Shell 2007

To support integrated network analysis Shell Global Solutions International has developed the strategic planning tool: GMOS/NetSim (Global Manufacturing & logistic Optimization System/Network Analysis and **S**upply Chain Opt**i**mization System.

The model helps to optimize flow and production of oil and gas, between wellhead platforms and demand locations over the defined time period given the infrastructure (e.g. production, pipelines, and compressor) constraints. The economic analysis converts output from the program into analysis of individual assets and scenarios based on costs, capabilities and prices.

The GMOS/NetSim model can be split into four key modules. These are the Supply Module, which include production profiles for each existing and future wellhead platform (the so-called technical potential); the Processing Module describing production/processing facilities & constraints; the Demand Module, which covers any demand point (oil & gas demand, fuel- and re-injection gas requirement, etc); and the Interconnection Module, which ties together supply, processing and demand to account for pipeline or distribution constraints and capacities. General data input is required of supply sources (wellhead platforms), production and processing facilities infrastructure and capacities (processing platforms, compressors, pumps etc.), transportation capacity (pipelines), costs of processing (operating cost and fuel gas consumption), and other business constraints in production, processing and distribution (e.g. minimum and maximum demands, no venting after a specific year).

GMOS/NetSim helped to optimize the entire network over the entire time horizon. The objective function is based on the variables in the system and is typically the Net Present Value of the profit margin over the time-horizon, based on the GOR & Water cut of the respective wellhead platforms and the Unit Production Cost.

The potential or the results of the study are typically expressed in oil and/or gas that can be accelerated through the debottlenecking exercise.

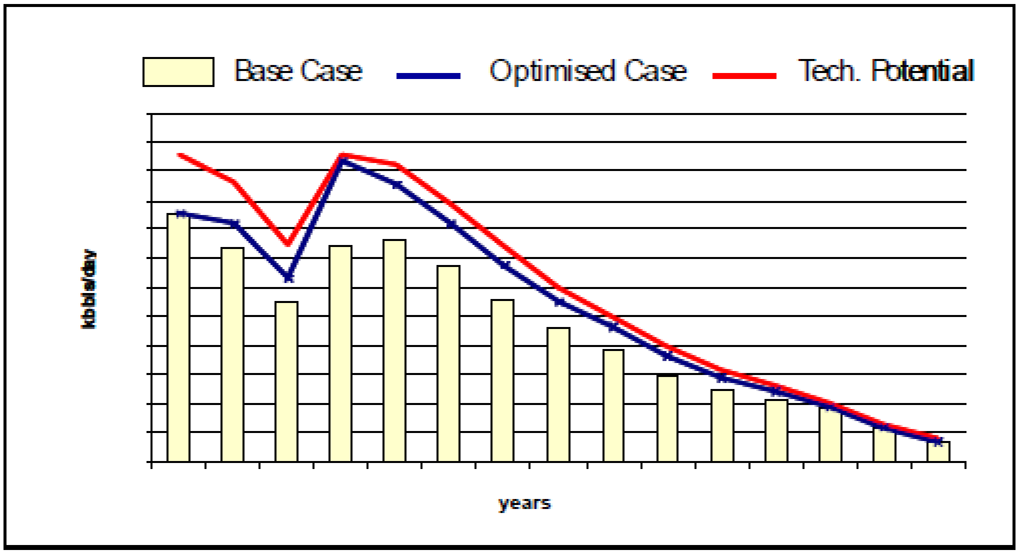

Figure (2.1) Shell optimized oil production (Lee & Thijssen, 2007)

Approximately ten percent of the fifteen years figure (2.1) oil production can be accelerated if the debottlenecking options will be implemented substantiation required for this still These options vary from extra processing facilities, via small piping changes to bypassing compressors and swapping lines in direction or by type of flow going thru the pipeline. The thick line indicates the maximum of oil that can be produced if all wellhead platforms are producing at their technical potential.

2.5.3 Aramco Khafji field 2005

Khafji field commenced oil production in 1961, and currently 300MBOPD of average daily crude production, among which 260MBOPD is sweet crude as Khafji crude and 40MBOPD is sour crude as Hout crude, has been maintained from seven (7) oil reservoirs (Ghoniem, 2005).

The offshore production facilities consist of approximately 180 production wells on the scattered 80 unmanned well jackets, a lot of different size of flowlines connecting from wells to one of four (4) gas oil separation platforms for Khafji crude, gathering station complex (gas lift compressor platform and pump platform, offshore control center, living quarter platform, utility platform, and gas oil separation platform for Hot crude). The gas lift operation by means of artificial lift in Khafji field has successfully contributed to sustain field target since it was introduced in 1988with the capacity of 25MMSCF/D lift gas.

Field study was conducted to establish the most optimum Al-Khafji Joint Operations (KJO)long term field development plan (FDP), which includes finding the optimum target rate over 30 years and optimum artificial lift among different artificial lift methods with facility scenarios.

FDP study concluded the necessity of a lot of capital investment in near future to sustain the optimum target rate for Khafji crude, such as additional infill wells, expansion of handling capacity of GOSPs, and expansion of gas lift gas compression facility, introduction of ESPs, and etc. due to the increase of field water cut and depletion of reservoirs. However, most of the above facilities require a longer lead time until their installations and commissioning.

In order to make up production decline and prolong to sustain the field target rate until the commissioning the new facility expansions and possibly to defer such a large investment, production optimization, which comprise lift gas optimization and de-bottlenecking of the existing flowlines network to reduce backpressure, was found one of the cost effective solutions to be able to be executed shortly.

The production optimization study, for Khafji field, was successfully conducted in two steps as the followings:

Lift Gas Optimization. The lift gas optimization study, by using the models, involves two activities, the first is screening sensitivity run between the existing gas lift wells (65 wells), and then the available lift gas capacity (21 MMSCF/D allocated for Khafji sweet crude facilities) was optimized.

As a result, the most effective gas lift wells to increasing oil rate were prioritized for lift gas re-allocation. Also, it was found that a total of forty two (42) wells can be lifted successfully by the available lift gas capacity. The saved amount of gas was re-allocated to open more wells on gas lift and for some high productivity wells.

Result shows the comparison of gas injection rate and oil rate for the forty two (42) gas lift wells between before and after lift gas optimization. it shows also 2,800 BPD of oil gain from well No.38, can be obtained by applying lift gas optimization, although it was closed before conducting the optimization study due to lack of gas lift volume. Also, three (3) well Nos.5, 40 and 42, were producing by natural flow

With lower oil rates of 1600, 2200, 1200 BPD respectively before lift gas optimization.

However, after applying the screening by the models, approximately 1.3 MMSCF/D of lift gas was allocated hence producing with higher oil rates of 3850, 4600, and 3700 BPD respectively, which can obtain additional oil gain of 7150 BPD (Ghoniem, 2006). The rest of saved amount of lift gas was allocated for some high productivity wells like wells Nos. 7, 9, 15, 25, 35 and 37, which also resulted in higher oil rate. Figure (2.2) shows the oil rate for the forty two (42) wells before and after lift gas optimization.

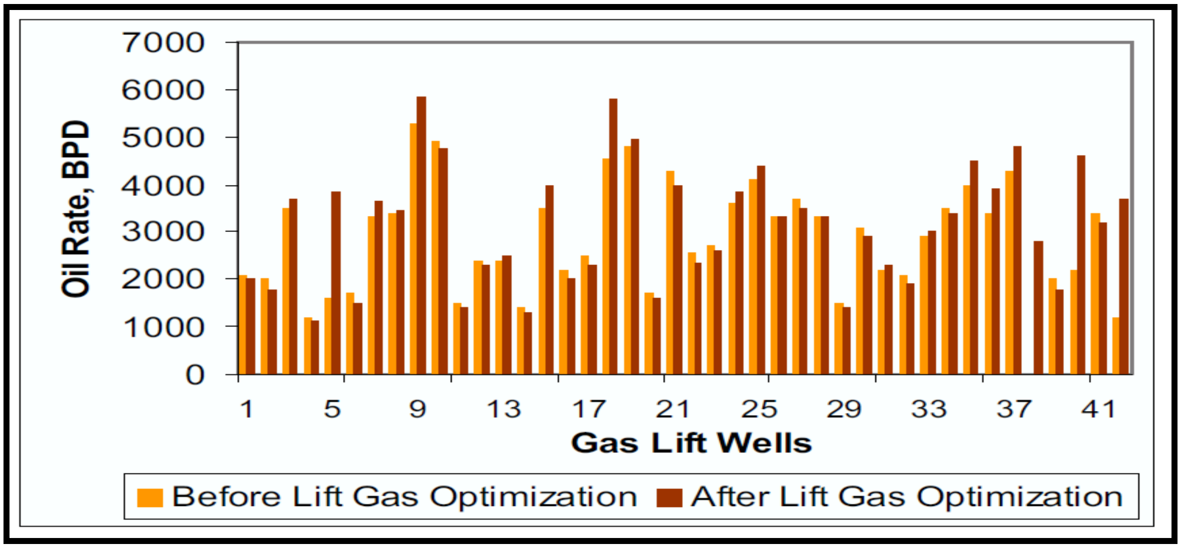

Figure (2.2) Gas Lift Wells Optimization (Ghoniem,2005)

Also, as the results of lift gas optimization, a performance curve at the optimum operating conditions was obtained for each gas lift well. As an example, gas lift performance curves for wells Nos. 4, 9 & 10 at optimum gas injection rate.

Consequently, a marginal gain of approximately 12,000 BOPD was obtained by optimizing lift gas within the existing lift gas capacity with the proper utilization of the existing flow line network.

Chapter 3 Methodology

In this study it was decided to follow following steps while and building network model and various sensitivity study:

- Data Collection and Validation (QC)
- Physical Model Building and Validation
- PVT modeling
- Multiphase Flow Correlation Matching
- Network Balancing and fine tuning

3.1 Data Collection

Data Collection is the first and foremost requirement of a model building effort. Since field is structurally and otherwise a dynamic environment it was essential that model building and validation should be done by matching model result to certain cut-off date instead of trying to match a moving target.

In order to ensure speed and efficiency on data Collection process, a detailed list of data requirement was prepared upfront. The data included depth reference, well diagram, deviation survey data, and pressure survey data of the well and nearby wells, production test data and well history. Meetings among various discipline and groups were organized to ensure clear understanding of data requirement and objective of the study. The data were manually collected from various groups and locations of GNPOC.

3.2 Physical Model Building

A hydraulic network in PIPESIMTM is made up of single branches or segments connected at points called nodes. The segment may be just a connector or it may contain pressure loss devices such as pipes and piping equipment connected in series. Nodes can be boundary nodes (Sources and Sinks) or internal nodes (junctions). The net flow in a junction node is zero. A boundary node can be a:

1. Source node: where fluids flow into the network; node flow rate is positive.
2. Sinks node: where fluids flow out of the network; node flow rate is negative.

3.2.1 Layer 1: FPF, OGMs and Trunk lines

In PIPESIMTM Graphical user interface (GUI), the network layout has been logically organized using PIPESIM's folder option to enable easy navigation to various parts of the model Figure (3.1)

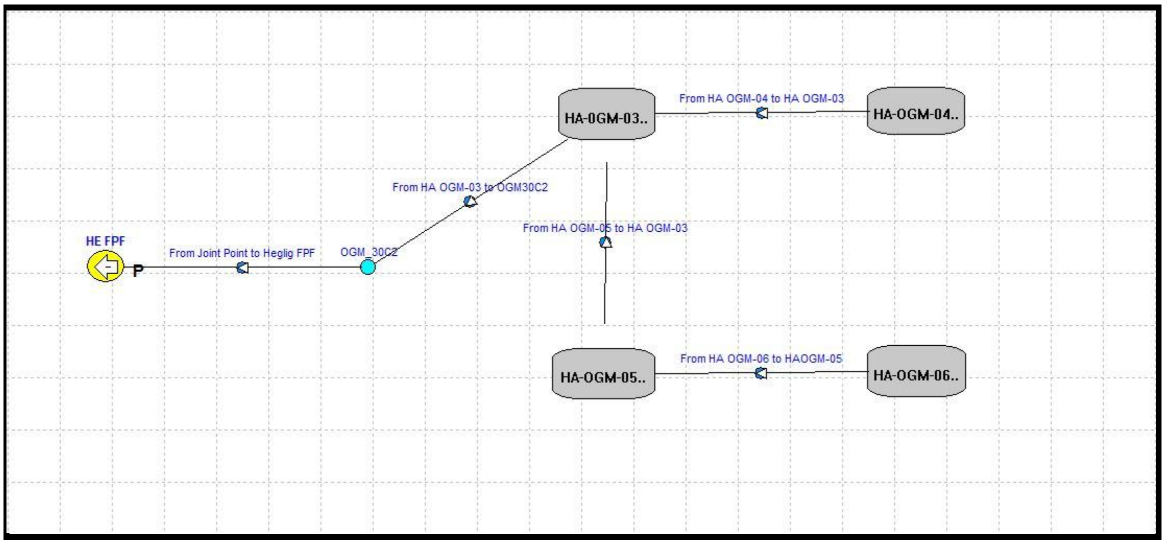

Figure (3.1) Network Layout

Three trunk lines connecting OGM's together and one trunk line connects to HE FPF these trunk lines data such as:

1. Horizontal distance.
2. Inner diameter.
3. Wall thickness.
4. Roughness
5. Ambient temperature was input for each line. Figure(3.2)

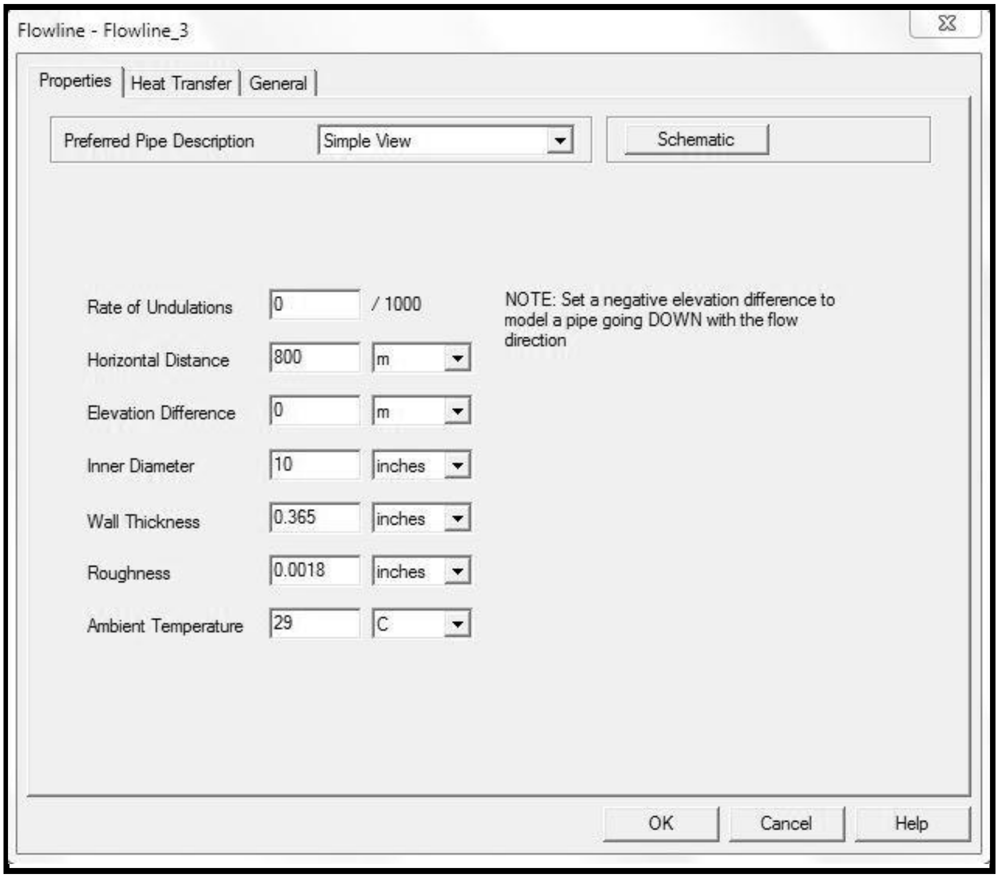

Figure (3.2) Flow lines Data

3.2.2 Layer 2 Sources and flow lines connected to OGMs

Sources and production wells are connected to each OGM by a flow line data were input to this flow line as same as the data used to build the trunk lines illustrated earlier

Figure (3.3) show how these wells and flow lines are distributed.

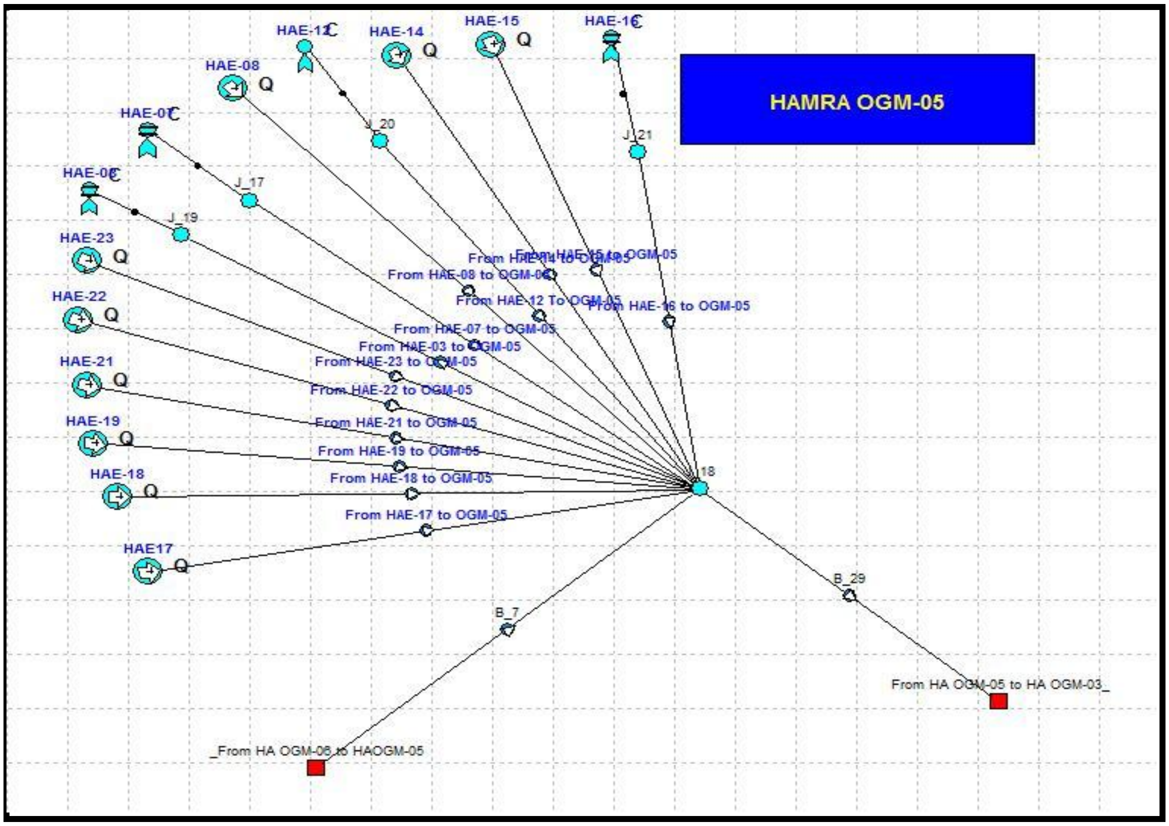

Figure (3.3) Wells and Flow lines layout

3.2.3 Layer 3: Wells Model

1. Wells operated by PCP and sucker road pump were treated as sources due to PIPESIME 2011 version limitation and for the fact that they are operated at surface input data required are:
   1) Daily production rate
   2) Temperature,
   3) Fluid properties

   As illustrated in the figure (3.4)

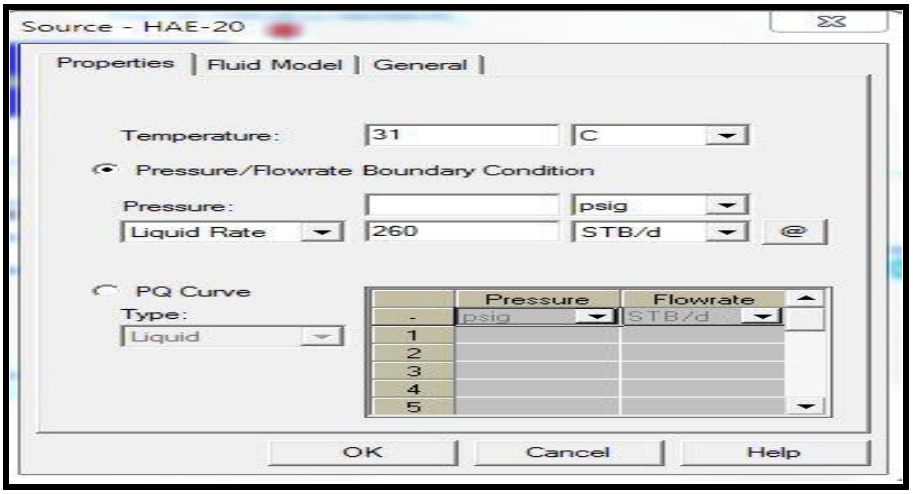

Figure (3.4) Sources Well Data

2. Wells with Electrical submersible pumps

ESP wells were treated with different approach since PIPESIM allow production optimization for this kind of wells with downhole data in term of determining optimum operating condition to obtain pump performance curve but required additional data include

a) Pump manufacturing design such as:
   i. Frequency.
   ii. Number Of Stages.
   iii. Pump Efficiency.
b) Completion Data
c) Fluid Properties

Minimum data entry was uploaded as shown in figure (3.5).

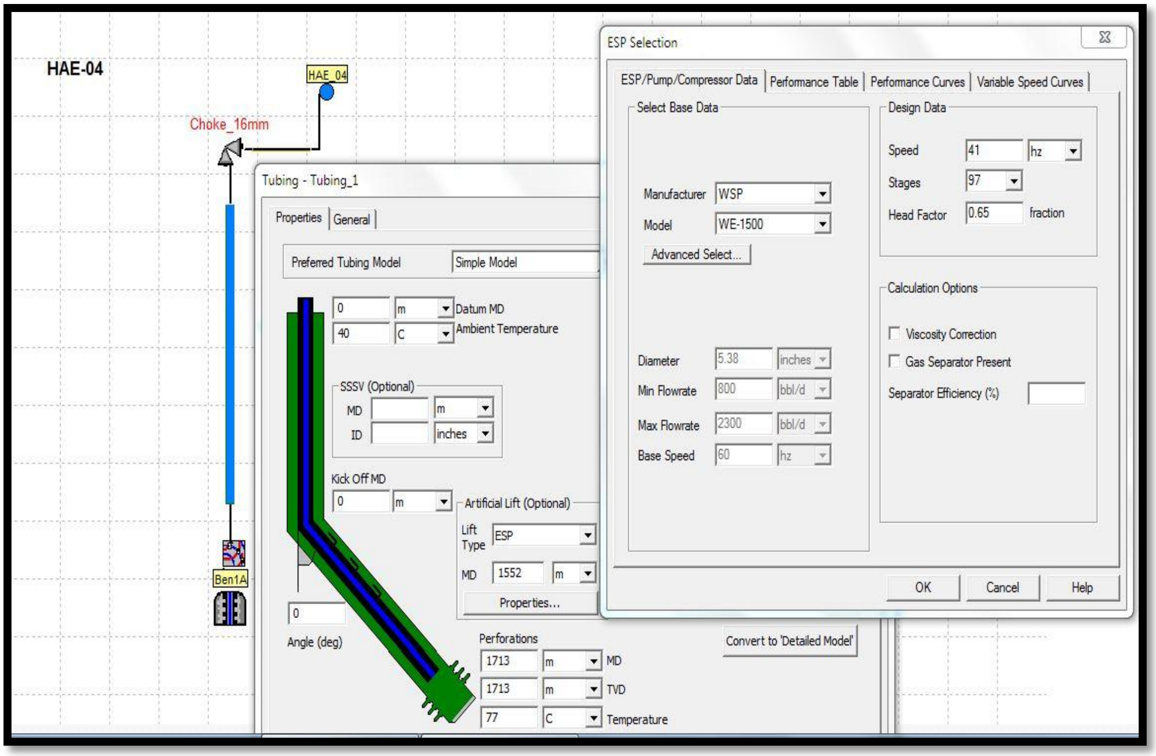

Figure (3.5) ESP Wells Data

3.2.4 PVT Data and fluids properties

A black oil model was selected since it is typically applicable for GOR less than 2,000 STB/SCF and compositional data were not available, data required include

1) GOR
2) API
3) WOR

This data were input as illustrated in figure (3.6).

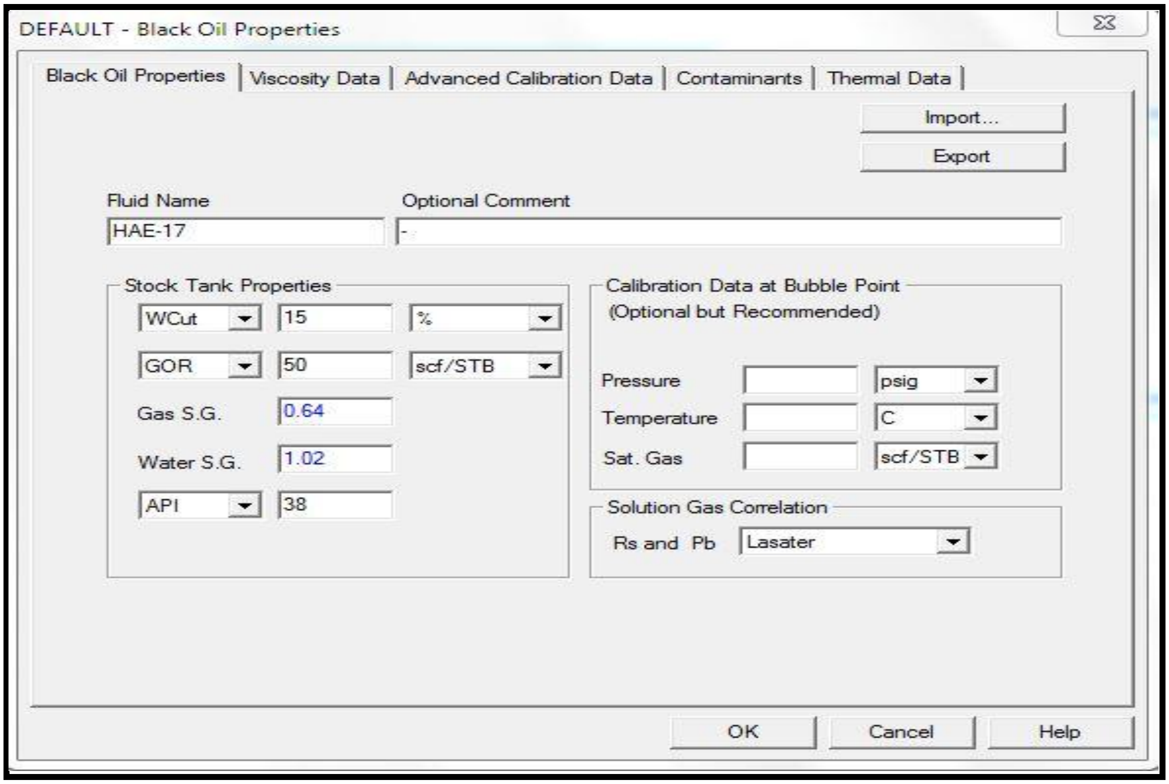

Figure (3.6) Black Oil Model Data

Viscosity data were collected from the laboratory and it was input as specified viscosity in a specified temperature as illustrated in figure (3.7).

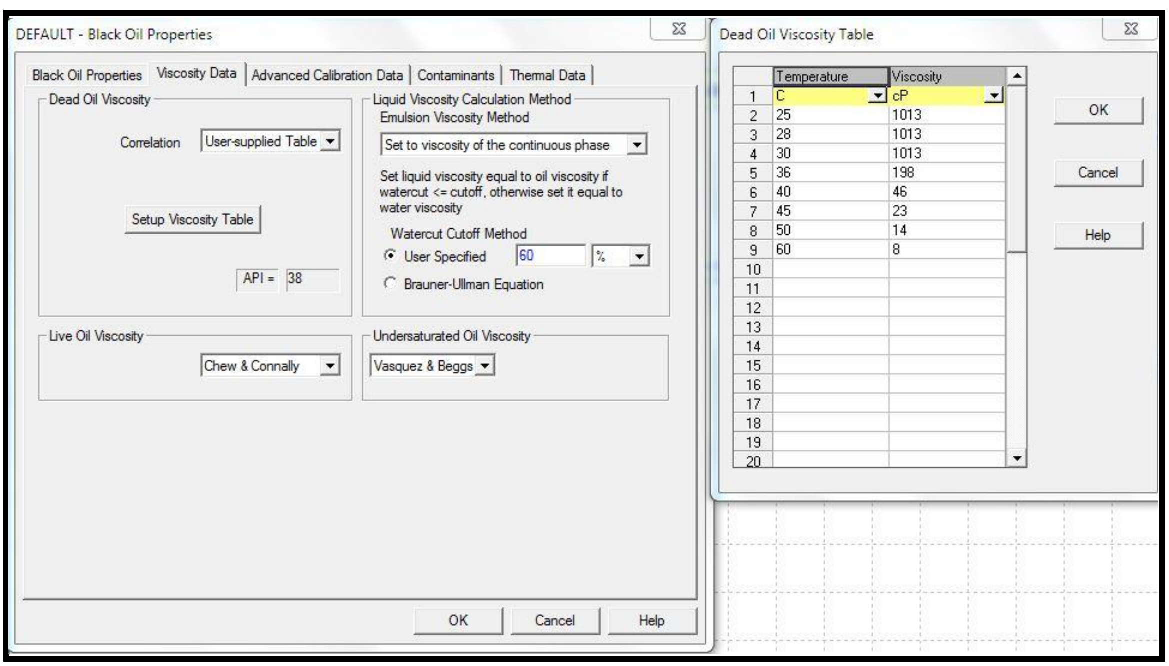

Figure (3.7) Black Oil Viscosity Data

3.2.5 Flow Correlations

Flow correlation was selected from variety of correlation provided by software based on best match for vertical flow correlation Hagedom & Brown correlation was selected
And For horizontal correlation Beggs & Brill revised correlation was selected as illustrated in figure (3.8).

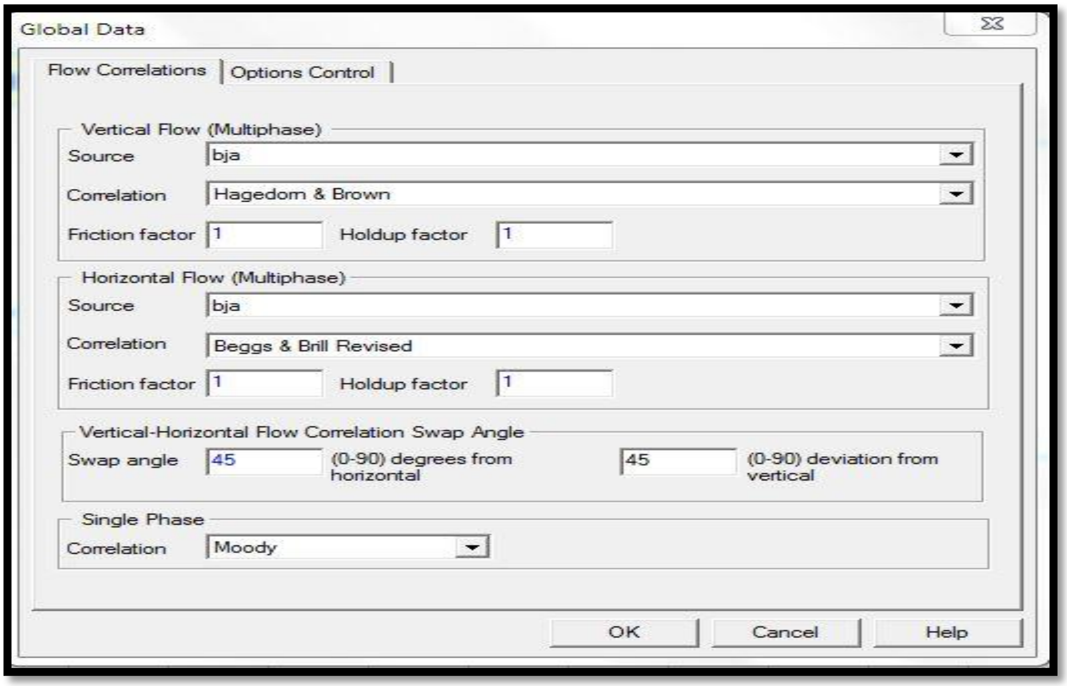

Figure 3.8 Flow Correlation Selections

Flowlines inlet pressure matching was carried out to ensure that the measured flowlines inlet pressure and that calculated by the models are consistent. Matching the surface flowlines pressure was done to confirm the applicability of selected flow correlations for surface network.

3.3 Running the model

After applying previous steps to construct the model and balancing the data a model was checked and verified for errors, no error was found and the model became ready for running and execution as illustrated in figure (3.9).

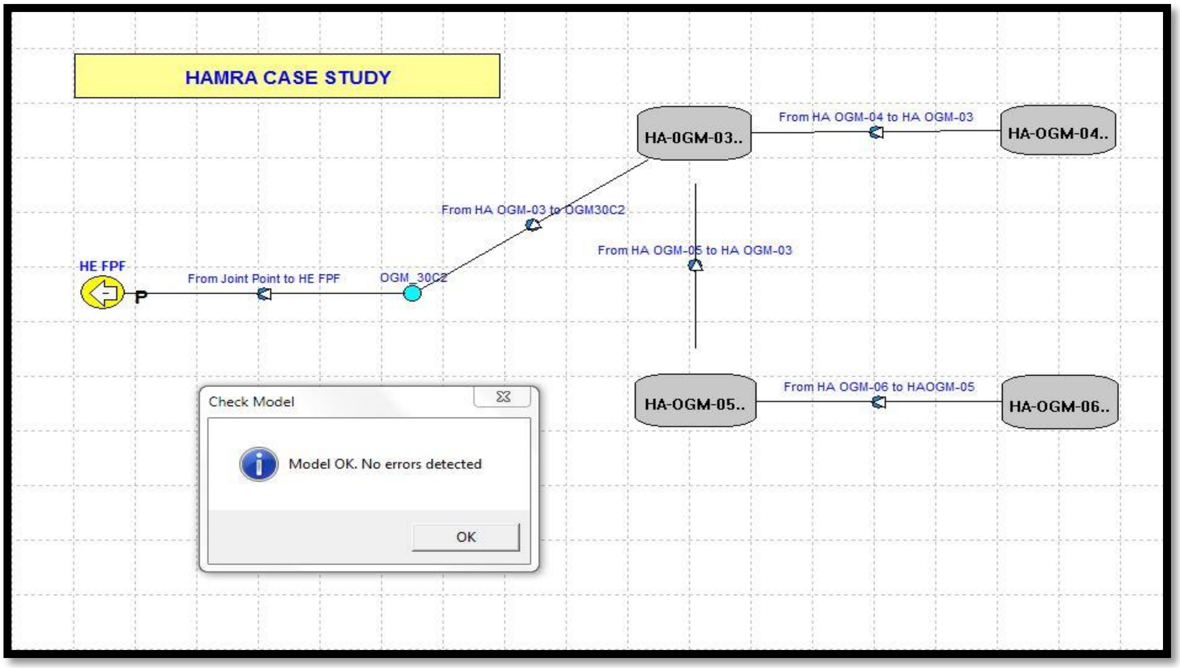

Figure (3.9) Model Data Check

The model then was run successfully as illustrated in figure (3.10) and detailed result will be discussed in next chapter.

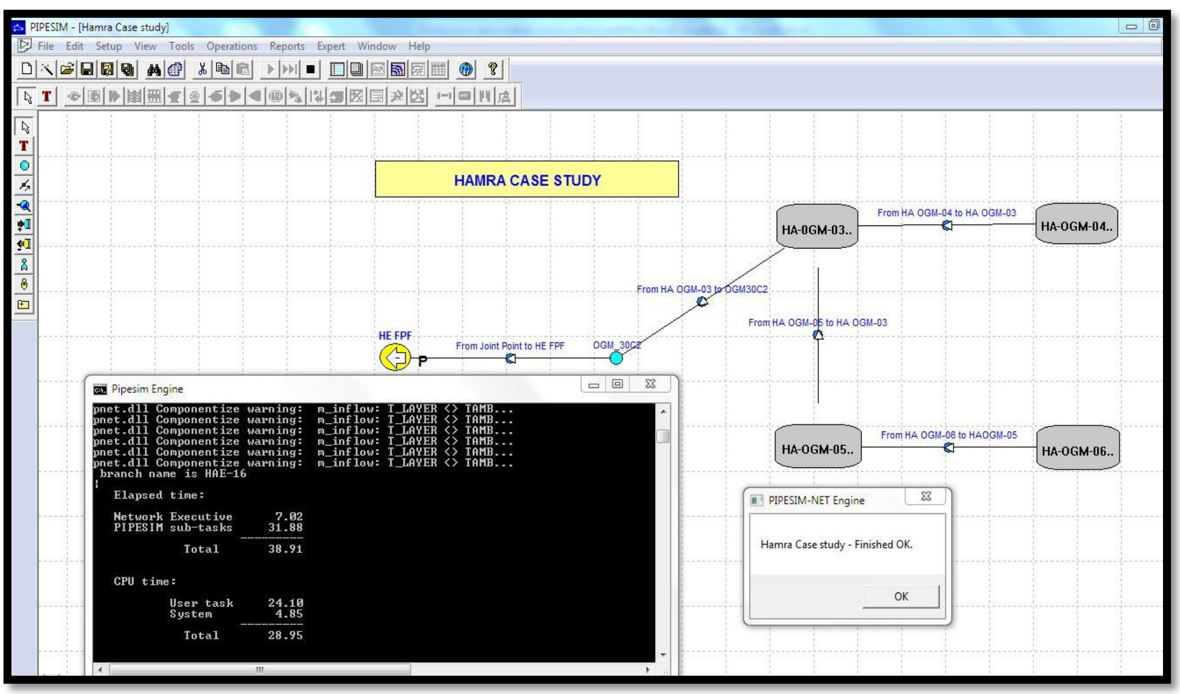

Figure (3.10) Successful Model Running

CHAPTER 4- RESULT

In this chapter we will discuss the result after running and validating the data
A flow correlation matching result concluded based on best match correlation of the actual data for vertical flow correlation Hagedom & Brown correlation was selected and For horizontal correlation Beggs & Brill revised correlation was selected as illustrated in figure (4.1)

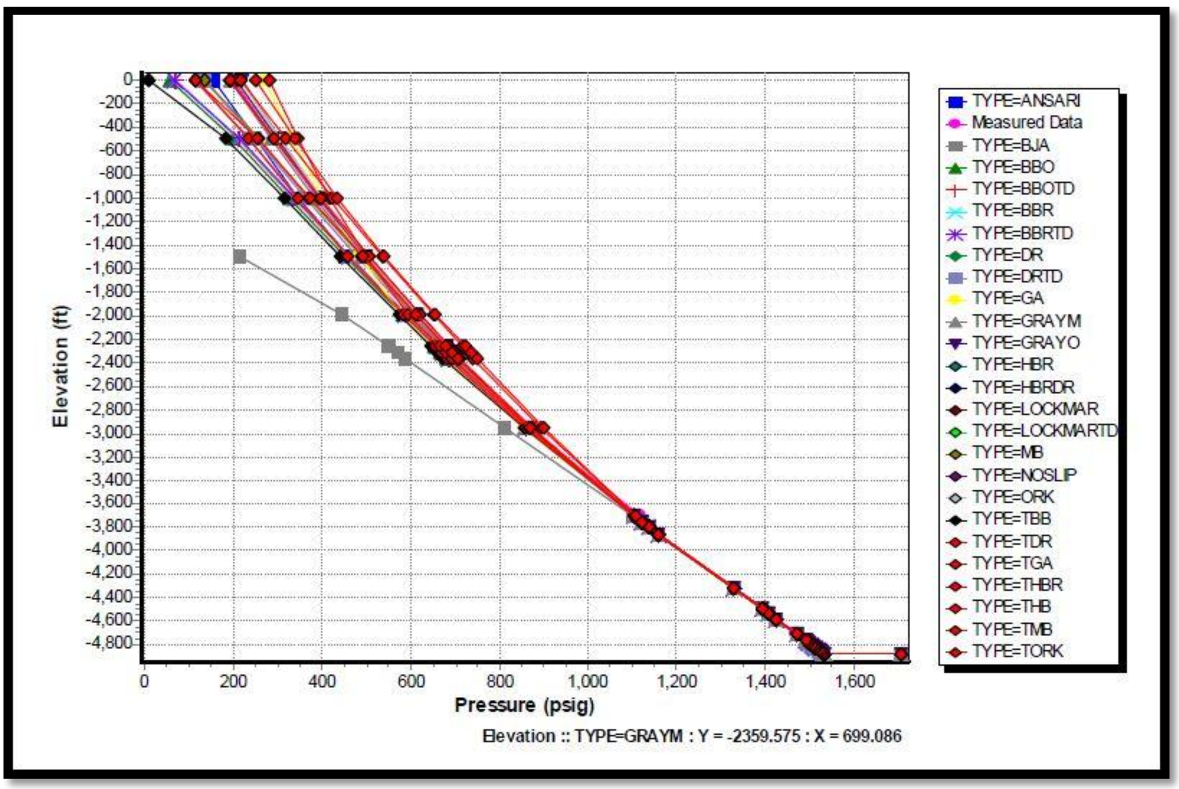

Figure (4.1) Vertical Flow Correlation Matching

The production optimization study for Hamra field was successfully conducted and the result and main findings are illustrated in two steps as the followings:

4.1 OGM's Trunk Lines

The trunk lines at all OGM's (OGM3~OGM6) which have excessive pressure in comparison with the model pressure were identified and assessed table (4.1) illustrate the comparison between the actual data and the model data in term of pressure

OGM	Actual outlet pressure (Psi)	Model outlet pressure (psi)	Difference (psi)	Trunk line size (in)	Equivalent trunk line size (in)	Percentage of area opened (%)	Remark
OGM-3	170	155	15	10	10	100	Ok
OGM-4	185	162	23	6	4.7	61	partially blocked
OGM-5	185	156	29	10	10	100	Ok
OGM-6	190	174	16	6	5.5	84	Started to block
Key : **(0%=ok), (less than 25%= Mostly blocked), (25-75%= partially blocked), (above 75% started to block)**							

Table (4.1) Actual Data And Model Data Comparison For OGM's

The trunk lines which have an excessive backpressure were successfully identified by using the prediction mode of the models. As a result, the excessive backpressure was observed in many 10" size flowlines and some commingled flowlines which handle high rate and in 6'' lines due to wax or asphaltenes deposition.

The trunk line that connects between OGM 4 and OGM 3 there is one bottleneck due to long distance (6562 ft) and the high rate handled (3,200 BPD). A pressure drop of 23 psi is created through the line, which shall cause the 119 BPD of production reduction for the connected wells Figure (4.2). It was found that Cleaning the line using hot water and pigging technique will enable us to reduce the back pressure and gain 119 BPD this is in short term for long term solution laying an additional new line to the nearby jacket to another OGM is the most cost effective de-bottlenecking solution, which results in an oil gain of at least 207 BPD as listed in Table (4.3) And figure (4.3)

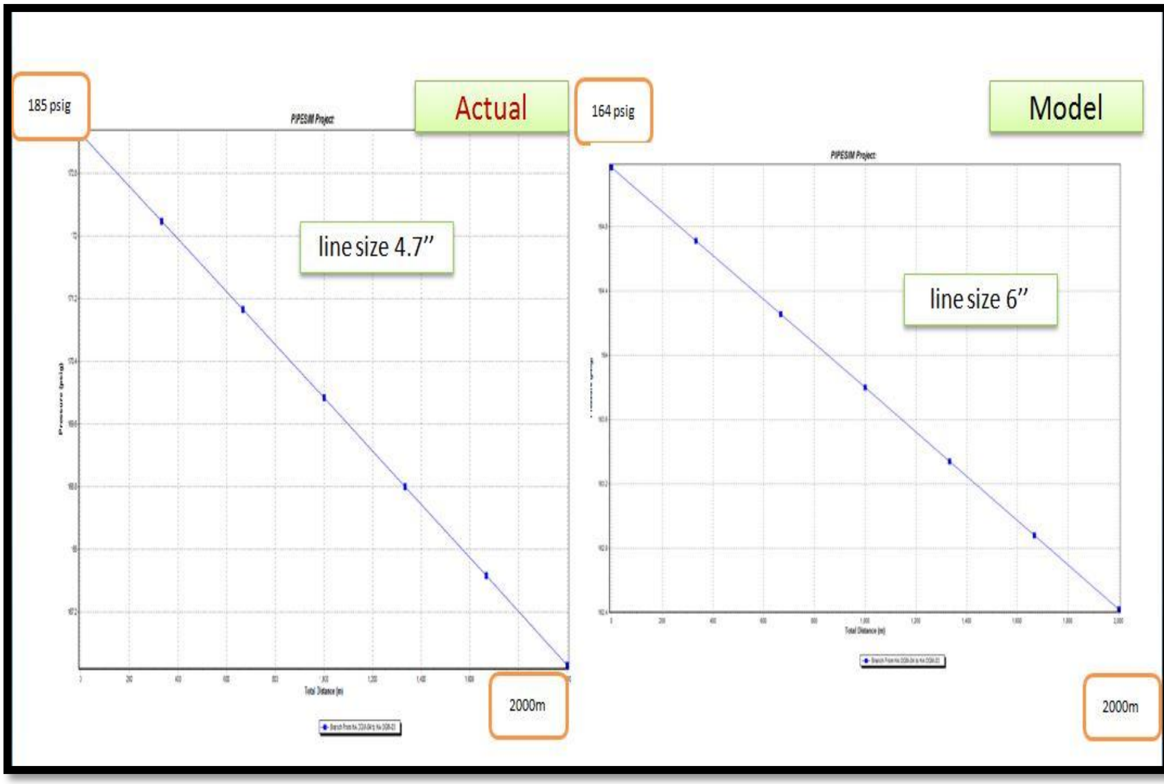

Figure (4.2) Pressure Drop simulation For OGM-4 Trunk line

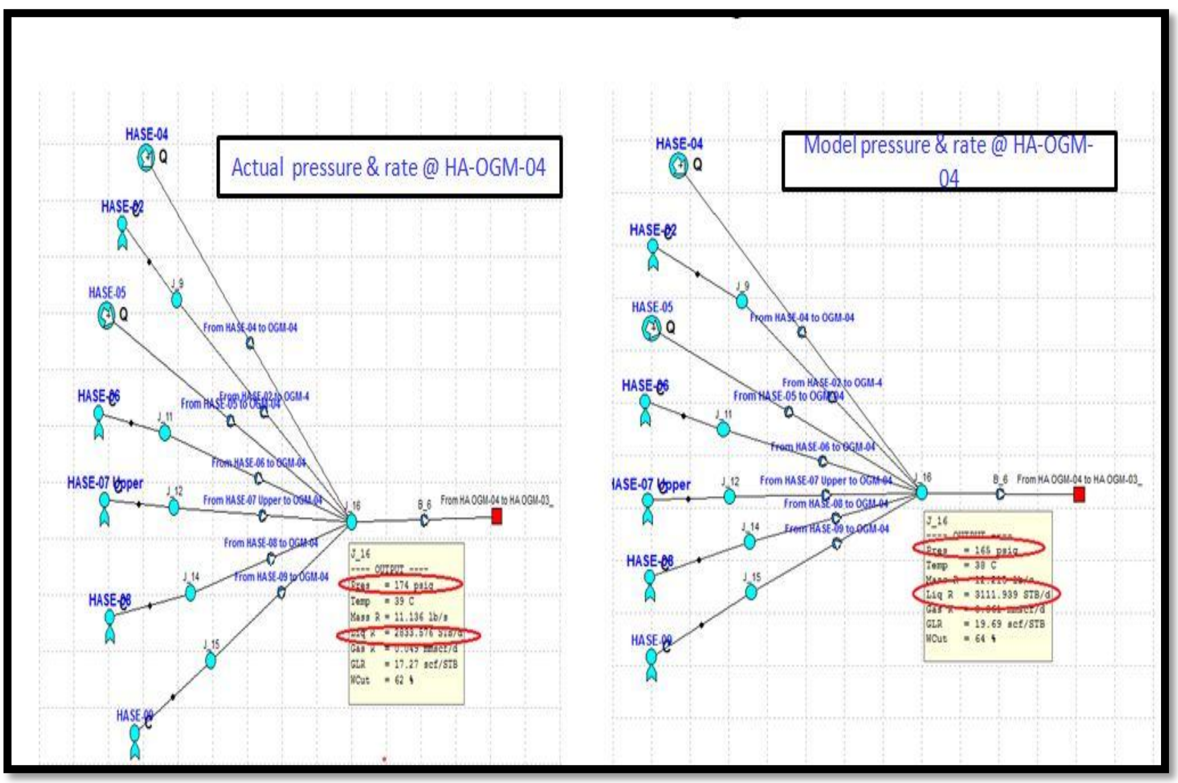

Figure (4.3) Oil Production Rate Comparison for OGM -04

OGM	No of wells	Actual pressure (Psi)	Model pressure (psi)	Difference (psi)	Actual flow rate (BPD)	Model flow rate (BPD)	Difference (BBL)
OGM-03	10	170	155	15	9067	9049	-18
OGM-04	7	185	174	11	3112	3231	+119
OGM-05	13	185	156	29	4505	4502	-3
OGM-06	8	190	174	16	1296	1383	+87
Total OIL gain							207

Table (4.2) Actual Flow Rate and Model Flow Rate Comparison

The other observation is in trunk line that connect OGM -06 to OGM-05 the model show a 16 psi difference and the prediction mode showing a reduction in equivalent pipe diameter of 0.5 in indicating that the line is starting to face a bottlenecking issue that cause a loss of 87 bbl in compare with the model , this line has to be considered for clean up and pigging before the severity of bottlenecking increases and cause further reduction in production Figure (4.4) showing the model detailed tabular report of the 4 OGM's being examined .

Flowing from		HA05	J_18	J_8	J_16	_From HA OGM-06 to H	From HA OGM-03 to OG	From HA OGM-04 to HA	From HA OGM-05 to HA	From HA OGM-06 to HA
to		J_2	From HA OGM-05 to HA	From HA OGM-06 to HA	From HA OGM-04 to HA	J_18	OGM_30C2	_From HA OGM-04 to H	_From HA OGM-05 to H	_From HA OGM-06 to H
Flow direction		Forward	Forward	Forward	Forward	Forward	Forward	Forward	Forward	Forward
Inlet										
Temperature	F	138.91697	106.63501	84.708457	106.19912	84.788973	123.68272	106.19912	106.63501	84.708457
Pressure	psia	171.31168	171.69380	188.66157	203.03703	171.69380	170.98005	203.03702	171.69377	188.66157
Enthalpy	Btu/lb	93.232986	56.286316	43.041756	83.906441	43.023580	92.718104	83.906441	56.286316	43.041756
Mass Flowrate	lb/sec	3.8194186	20.821217	4.9056271	12.611416	4.9056271	69.307488	12.611416	20.821217	4.9056271
Stock-tank Liquid	sbbl/day	1030.1347	5887.2218	1383.0000	3231.3351	1383.0000	18164.117	3231.3351	5887.2218	1383.0000
Stock-tank Oil	sbbl/day	669.58757	5238.4940	1274.2860	1381.1182	1274.2860	9215.6505	1381.1182	5238.4940	1274.2860
Stock-tank Gas	mmscfd	.03347940	.20499873	.02548573	.04980000	.02548573	.41353909	.04980000	.20499873	.02548573
Flowing Liquid	bbl/day	1069.6225	6072.2019	1406.7778	3291.7883	1406.8809	18642.234	3291.7883	6072.2019	1406.7778
Flowing Oil	bbl/day	703.62117	5418.8037	1297.7434	1428.6159	1297.8389	9594.1880	1428.6159	5418.8037	1297.7434
Flowing Gas	mmscfd	.01316075	.03361214	0.0000000	.00301611	0.0000000	.13270759	.00301611	.03361216	0.0000000
Flowing Gas	cf/min	.88912945	2.1360342	0.0000000	.16130245	0.0000000	8.7413137	.16130263	2.1360359	0.0000000
Outlet										
Temperature	F	124.50942	106.63501	84.708457	106.19912	84.788973	115.85718	103.82159	105.02351	84.788962
Pressure	psia	171.00305	171.69380	188.66157	203.03703	171.69380	101.41067	170.02752	170.95682	171.69546
Enthalpy	Btu/lb	83.635169	56.286316	43.041756	83.906441	43.023580	86.828074	81.993346	55.444819	43.023580
Mass Flowrate	lb/sec	3.8194186	20.821217	4.9056271	12.611416	4.9056271	69.307488	12.611416	20.821217	4.9056271
Stock-tank Liquid	sbbl/day	1030.1347	5887.2218	1383.0000	3231.3351	1383.0000	18164.117	3231.3351	5887.2218	1383.0000
Stock-tank Oil	sbbl/day	669.58757	5238.4940	1274.2860	1381.1182	1274.2860	9215.6505	1381.1182	5238.4940	1274.2860
Stock-tank Gas	mmscfd	.03347940	.20499873	.02548573	.04980000	.02548573	.41353909	.04980000	.20499873	.02548573
Flowing Liquid	bbl/day	1063.2295	6072.2019	1406.7778	3291.7883	1406.8809	18548.675	3286.4164	6067.4462	1406.8809
Flowing Oil	bbl/day	698.59618	5418.8037	1297.7434	1428.6159	1297.8389	9515.3306	1423.9645	5414.2677	1297.8389
Flowing Gas	mmscfd	.01263309	.03361214	0.0000000	.00301611	0.0000000	.26077983	.01122597	.03389301	0.0000000
Flowing Gas	cf/min	.83326688	2.1360342	0.0000000	.16130245	0.0000000	28.780555	.71672256	2.1567901	0.0000000
Mass Loss	lb/sec	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Heat Loss	Btu/hr	131969.08	0.0000000	0.0000000	0.0000000	0.0000000	1469603.4	86856.612	63075.593	320.98770
State		Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable
Frictional Drop	psia	.30863202	0.0000000	0.0000000	0.0000000	0.0000000	69.569378	33.009497	.73695211	16.966105
including choke	psia	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Elevational Drop	psia	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Static Drop	psia	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000

Figure (4.4) OGM’s Trunk lines Tabular report

4.2 Wells Flow Lines

Extending the analyses to the OGM-06 wells flow lines predicted another issues where by six bottlenecks were identified as shown in table (4.2) and figure (4.5).

HA-OGM-06(wells)	Actual outlet pressure (Psi)	Model outlet pressure (psi)	Difference (psi)	Trunk line size (in)	Equivalent trunk line size (in)	Percentage of area opened (%)	Remark
HAE-20	250	213	37	6	2.3	15	Mostly blocked
HAE-25	235	203	32	6	3.8	40	partially blocked
HAE-27	210	184	26	6	4	45	partially blocked
HAE-29	215	190	25	6	5.5	84	Started to block
HASE-10	220	181	39	6	4	45	partially blocked
HASE-11	235	195	40	6	2.8	21	Mostly blocked
HASE-12	176	173	3	6	6	0	ok
HASE-14	210	176	34	6	3.5	34	partially blocked
Key : **(0%=ok), (less than 25%= Mostly blocked), (25-75%= partially blocked), (above 75% started to block)**							

Table (4.3) Actual Data and Model Data Comparison for OGM-06 Wells

It crucial to remove this bottlenecks by identifying it as early as possible and clean it before it comes to point of costly process such as pigging or replacing the line in order to restore all wells productivity and minimize back pressure exerted by strong wells on weaker ones.
This practice if implemented regularly will help on maintain optimum production from all the wells in addition to minimize the cost of pigging and new lines installation.

Branch Name		From HASE-10 to HA-OGM-06	From HASE-11 to HA-OGM-06	From HASE-12 to HA-OGM-06	From HASE-14 to HA-OGM-06	Frrom HAE-02 to HA-OGM-03	Frrom HAE-09U to HA-OGM-03
Branch No		41	42	43	44	47	49
Branch Type		Source	Source	Source	Source	Source	Source
Boundary condition		Flowrate	Flowrate	Flowrate	Flowrate	Flowrate	Flowrate
Flowing from		HASE-10	HASE-11	HASE-12	HASE-14	HAE-02	HAE-09
to		J_8	J_8	J_8	J_8	J_2	J_2
Flow direction		Forward	Forward	Forward	Forward	Forward	Forward
Inlet							
Temperature	F	80.600000	95.000000	84.200000	111.20000	104.00000	122.00000
Pressure	psia	195.47418	209.91329	190.53286	190.77280	172.08649	172.02820
Enthalpy	Btu/lb	39.560639	44.102993	55.068580	64.639156	48.081272	78.315095
Mass Flowrate	lb/sec	.26345681	.84175371	.72984325	.36283438	.36826725	.20065633
Stock-tank Liquid	sbbl/day	75.000000	240.00000	197.00000	100.00000	105.00000	55.000000
Stock-tank Oil	sbbl/day	71.250000	237.60000	133.96000	80.000000	103.95000	38.500000
Stock-tank Gas	mmscfd	.00142500	.00475200	.00267920	.00160000	.00207900	.00077000
Flowing Liquid	bbl/day	76.173627	245.61158	199.61086	102.65902	107.91857	56.573059
Flowing Oil	bbl/day	72.415207	243.20023	136.39087	82.496416	106.86160	39.896326
Flowing Gas	mmscfd	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Flowing Gas	cf/min	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Outlet							
Temperature	F	83.957479	88.156271	84.205764	88.424854	85.140496	92.870457
Pressure	psia	188.66157	188.66157	188.66157	188.66157	170.98012	170.98012
Enthalpy	Btu/lb	41.157638	40.902134	55.066156	51.519972	39.462769	59.745316
Mass Flowrate	lb/sec	.26345681	.84175371	.72984325	.36283438	.36826725	.20065633
Stock-tank Liquid	sbbl/day	75.000000	240.00000	197.00000	100.00000	105.00000	55.000000
Stock-tank Oil	sbbl/day	71.250000	237.60000	133.96000	80.000000	103.95000	38.500000
Stock-tank Gas	mmscfd	.00142500	.00475200	.00267920	.00160000	.00207900	.00077000
Flowing Liquid	bbl/day	76.296255	244.79372	199.61222	101.69385	106.94272	55.944129
Flowing Oil	bbl/day	72.535677	242.38522	136.39177	81.622032	105.88948	39.370612
Flowing Gas	mmscfd	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Flowing Gas	cf/min	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Mass Loss	lb/sec	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Heat Loss	Btu/hr	-1514.665	9699.6058	6.3676985	17136.327	11426.085	13414.118
State		Stable	Stable	Stable	Stable	Stable	Stable
Frictional Drop	psia	6.8126059	21.251722	1.8712841	2.1112324	1.1063707	1.0480789
including choke	psia	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Elevational Drop	psia	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000

Figure (4.5) OGM-06 Wells Flow Lines Tabular report

4.3 Findings:

Hamra OGM-04 to OGM-03 trunk line excessive pressure, the recommended approach to tackle this issue in short term solution is to flush with hot water.

Study the pigging possibility because the effectiveness of 6" trunk line

On the long term solutions it is recommended to install a Surface Heater that will increase the temperature in the line and thus reduce wax and asphaltenes accumulation resulting in decreasing of flowing pressure.

Hamra- OGM-06 to OGM-05 trunk line:-

Since the line is just started to bottleneck the recommended solution is to flush the line with hot water and study the pigging possibility to reduce the pressure to the model pressure.

Chapter 5 Conclusion and recommendation

5.1 Conclusion

Hamra field models which comprise surface flowlines network and wells have been successfully constructed.

Hamra Field surface flowlines network deliverability was investigated in the current operating condition.

The more economic and effective network de-bottlenecking was successfully assessed.

A net oil gain of approximately 207 BPD is expected.

A net production gain by the above production optimization can assist to sustain Hamra target production rate for coming years.

The models are ready for field optimization under different operating conditions and should be updated regularly.

This study confirms that modeling network analysis can help to bring production closer to the technical potential of the Field production. It can help to identify the impact that all changes together have on the performance of the network.

. 5.2 Recommendation

1. As this studies focus on identifying actual bottlenecks and future bottlenecks, accurate representation of the network is crucial. This means that accurate data is key to success and that design data of equipment and pipelines alone is not sufficient. If actual performance data is not available on site, performance testing prior/during these types of studies will be required. It is crucial that the client is a member of the study team.
2. This study would present more accurate data if it is been merged with OLGA flow assurance software in order to upload dynamic data .

References

- Beliakova, N. et al.: "Hydrocarbon Field Planning Tool for Medium to Long Term Production Forecasting from Oil and Gas Fields Using Integrated Surface-Sub-Surface Models," paper SPE 65160 presented at the SPE European Petroleum Conference, Paris, France (October 24-25, 2000).
- Ghoniem, E.O., et al.: “Dynamic Production Optimization in Khafji Offshore Field”, SPE 101388 paper presented at the 2006 Abu Dhabi International Petroleum Exhibition and Conference held in Abu Dhabi, U.A.E., 5–8 November 2006.
- Ghoniem, E.O., et al.: “Successful Application of Production Optimization Models to Sustain Field Target and Defer Capital Investment in Offshore Khafji Field”, SPE 93555 paper presented at the 14th SPE Middle East Oil and Gas Show, Bahrain, March 12-15, 2005.
- Hagedorn, A.R. and Brown, K.E.: ``Experimental Study of Pressure Gradients Occurring During Continuous Two-Phase Flow in Small Diameter Vertical Conduits," JPT ~October 1965! 475; Trans., AIME, 234.
- Jim Brill "Multiphase Flow Technology- Past, Present and Future "PIPESIM User Group Meeting, Houston, September 5, 2012.
- Kassem Ghorayeb A General Purpose Controller for Coupling Multiple Reservoir Simulations and Surface Facility Networks, SPE,
- KJ Li, Nort Thijssen, and Ilse Mittendorff(2007), “Enhancement of Oil and Gas Production using Integrated Network Analysis” paper SPE IPTC 11638 presented at the International Petroleum Technology Conference held in Dubai, U.A.E., 4–6 December 2007.
- Lasschuit, Winston, Thijssen, Nort (2004), “Supporting supply chain planning and scheduling decisions in the oil & chemical industry”, Computers and Chemical Engineering 28, 863-870, Elsevier.
- Litvak, M.L. and Darlow, B.L.: ``Surface Network and Well Tubing-head Pressure Constraints in Compositional Simulation," paper SPE 29125 presented at the 1995

SPE Symposium on Reservoir Simula-tion, San Antonio, Texas, 12-15 February.

- Litvak, M.L.: ``New Procedure for the Phase-Equilibrium Computa-tions in the Compositional Reservoir Simulator," paper SPE 25252 presented at the 1993 SPE Symposium on Reservoir Simulation, New Orleans, 28 February±3 March.
- Lohrenz, J., Bray, B.G., and Clark, C.B.: ``Calculating Viscosities of Reservoir Fluids From Their Compositions," JPT ~October 1964! 1171; Trans., AIME, 231.
- Thijssen, Nort, Li, K.J., Mittendorff, Ilse (2007), “Enhancement of Oil & Gas Production via Network optimization”, Process Systems Engineering Vol. 3; Supply Chain Optimisation, Wiley.

Appendix

WELL	THP(psi)	VISCOSITY (CP)	W.C (%)	API	PUMP TYPE	RATE (BBLS/D)	Flow line DISTANCE(m)
HAE-20	230	142	0.0	36	BPU	300	100
HAE-25	220	354	0.4	35.29	BPU	500	900
HAE-26	135	870	0.0	34	BPU		700
HAE-27	210	227	2.0	34.32	PCP	500	450
HAE-28	Water Injection Well						
HAE-29	215	880	2.0	32.59	PCP	505	500
HASE-10	220	225	4.8	34.95	BPU	600	1450
HASE-11	235	249	0.3	33	PCP	500	1600
HASE-12	230	179	70.0	27	PCP	700	1700
HASE-14	210	150	50.0	29.62	PCP	1860	1350

Table 1 OGM-06 wells Actual data

WELL	THP (PSI)	VISCO SITY	W.C (%)	API	PUMP TYPE	RATE (BPD)	INTAKE.PR ESS(PSI)	DISC.PRE SS(PSI)	DSITANCE (M)
HAE-03	200	251	10.0	32.07	ESP	500	343	2249	650
HAE-07	190	285	96.3	34	ESP	2500	1285	1610	50
HAE-12	200	114	0.0	33	ESP	300	1530	2083	300
HAE-16	200	60	16.0	32	ESP	600	1717	2056	600

Table 2 OGM-05 ESP wells Actual data

GREATER NILE PETROLEUM OPERATING CO. LTD.
Heglig Operation Base, Sudan
Tel: +249-18-7037-2691
PRODUCTION DEPARTMENT
HEGLIG LABORATORY

GNPOC

HAMRA [OGM#04 & OGM#05

Oil Samples

Sampling Information

Samples Name	HA OGM-04 & HA OGM-05
Date of Sampling	*Oct.05.2013*
Receiving Date	*Oct.05.2013*
Receiving Time	*15:30*
Receiving Quantity	*2 Liter*
Sample Collector	*Wells Site Operator (Hamad)*
Analysis Date	*Oct.05.2013*

Physical Property Analyses:

Sample Source	HA OGM-04	HA OGM-05
BS (Vol %)	Nil	Nil
Water Cut (Vol %)	1.2	10.0
Emulsion (Vol %)	Nil	2.0
API Gravity @ 60 °F (15.6 °C)	29.80	32.64
Relative Density g/cm³ @ 60 °F (15.6 °C)	0.8764	0.8613
Pour Point (°C)	36	36
Gel Point (°C)	33	33

Rheological Property Analyses:

Temperature °C		25	30	35	40	45	50	55	60	65	70	75	80
Viscosity mPa.s (cP) @ Shear rates $20s^{-1}$	1- HA OGM-04	ODL	672.38	161.82	76.26	47.43	35.34	24.18	19.53	17.67	14.88	12.09	12.09
	2- HA OGM-04	ODL	574.73	98.58	41.85	24.18	13.95	11.16	8.37	8.37	8.37	8.37	7.44
Flow Model		NN	N	N	N	N	N	N	N	N	N	N	N

Figure 1 OGM-05 & OGM-05 Laboratory data

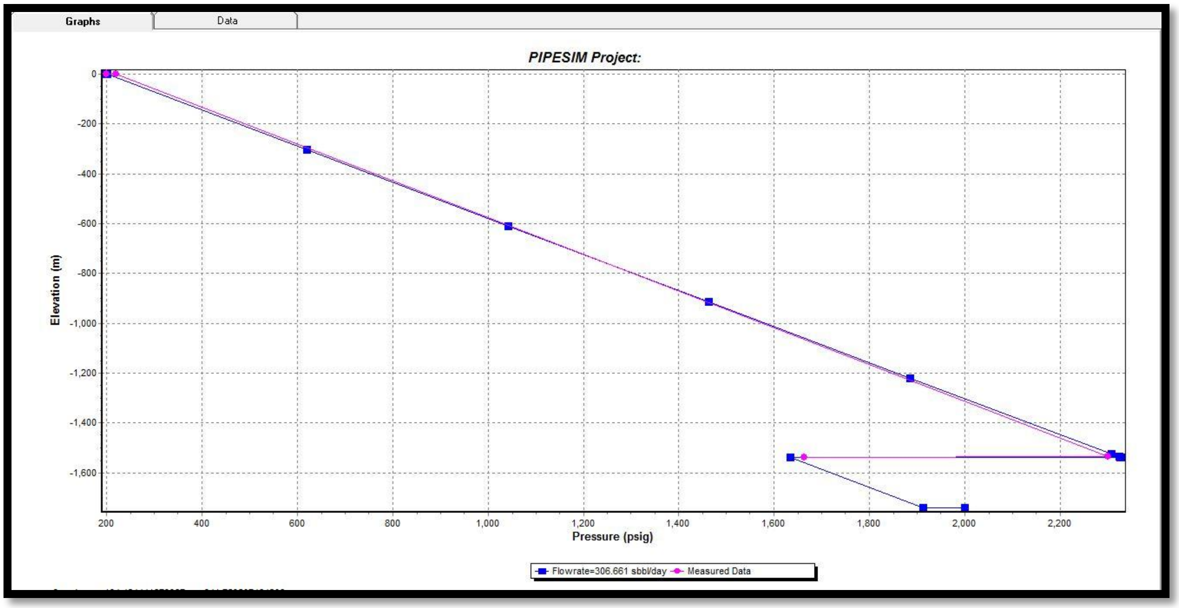

Figure 2 HAE-02 Data Matching

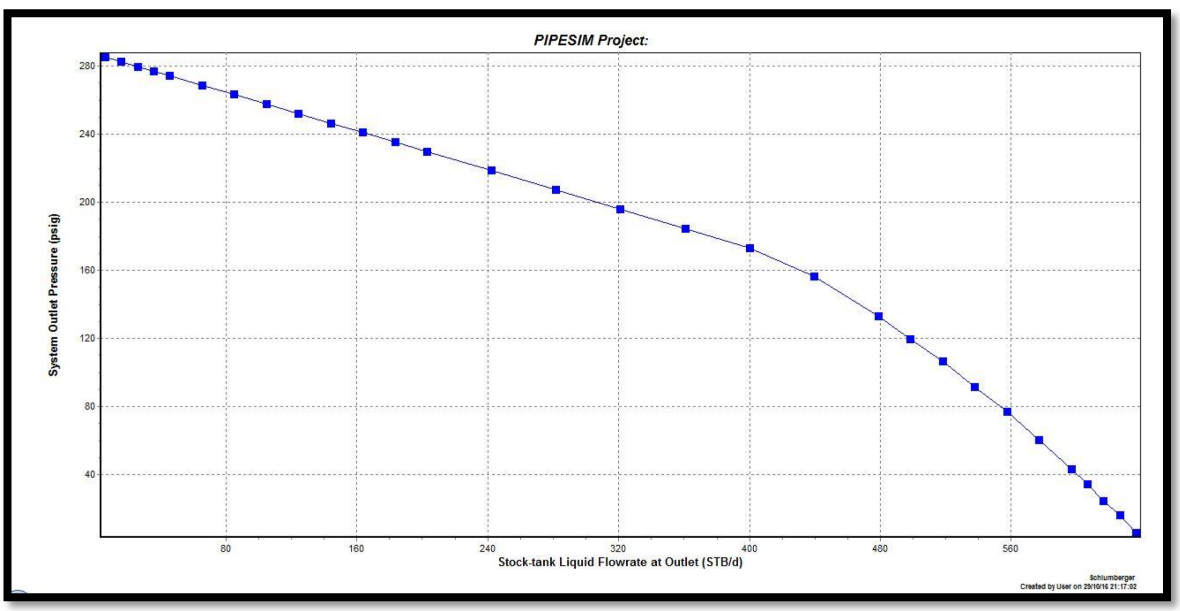

Figure 3 HAE-02 Performance curve

```
************  PIPESIM  ************                                                                          Date : 29/10/16
*    (Release 4.60   21/07/12)    *                                                                         Time : 20:57:05
*    MULTIPHASE FLOW SIMULATOR    *       BRANCH From HA OGM-03 to OGM30C2    Primary Output
*          pipesim-bld1:202       *       BRANCH From HA OGM-03 to OGM30C2    Primary Output                     PC-32/Intel
*           Schlumberger          *       BRANCH From HA OGM-03 to OGM30C2    Primary Output
*             Houston             *
***********************************

Project   : HAMRA Case Study
User      : User
Data File : From HA OGM-03 to OGM30C2.pst

Job       : 'PIPESIM Job'
Branch    : From HA OGM-03 to OGM30C2



       Dist.   Elev. Horiz. Vert.  Pres.   Temp.    Mean   Pressure Drop  Liquid    Free    Total     Densities     Slug   Flow
                     Angle  Devn.                   Vel.       (psi)       Flow     Gas     Mass       (lb/ft3)    Number  Pattern
       (feet)  (feet) (deg) (deg)  (psia)     (F)   (ft/s)   Elev. Frictn. (bbl/d) (mmscfd)  (lb/s)  Liquid     Gas (PI-SS)
Flowline_4
   1  0.0000  0.0000 0.000 90.00  170.98  123.68  2.4883  0.0000  0.0000  18642.  .132709  69.307  57.149  .51550        B/B INTERMITTENT
   2  1637.0  0.0000 0.000 90.00  168.15  123.24  2.5023  0.0000  2.8275  18638.  .137741  69.307  57.161  .50722   0.30 B/B INTERMITTENT
   3  3274.0  0.0000 0.000 90.00  165.27  122.81  2.5173  0.0000  2.8857  18633.  .142897  69.307  57.173  .49875   0.15 B/B INTERMITTENT
   4  4910.9  0.0000 0.000 90.00  162.32  122.38  2.5332  0.0000  2.9473  18628.  .148183  69.307  57.185  .49007   0.10 B/B INTERMITTENT
   5  6547.9  0.0000 0.000 90.00  159.31  121.96  2.5501  0.0000  3.0128  18624.  .153605  69.307  57.196  .48118   0.08 B/B INTERMITTENT
   6  8184.9  0.0000 0.000 90.00  156.22  121.54  2.5682  0.0000  3.0848  18619.  .159176  69.307  57.208  .47206   0.06 B/B INTERMITTENT
   7  9821.9  0.0000 0.000 90.00  153.06  121.13  2.5876  0.0000  3.1633  18614.  .164909  69.307  57.220  .46268   0.05 B/B INTERMITTENT
   8  11459.  0.0000 0.000 90.00  149.81  120.72  2.6085  0.0000  3.2475  18610.  .170815  69.307  57.231  .45303   0.05 B/B INTERMITTENT
   9  13096.  0.0000 0.000 90.00  146.47  120.32  2.6310  0.0000  3.3380  18605.  .176906  69.307  57.243  .44309   0.04 B/B INTERMITTENT
  10  14733.  0.0000 0.000 90.00  143.04  119.92  2.6553  0.0000  3.4360  18600.  .183198  69.307  57.254  .43284   0.04 B/B INTERMITTENT
  11  16370.  0.0000 0.000 90.00  139.52  119.53  2.6816  0.0000  3.5202  18596.  .189664  69.307  57.266  .42232   0.03 B/B INTERMITTENT
  12  18007.  0.0000 0.000 90.00  135.95  119.14  2.7096  0.0000  3.5643  18591.  .196230  69.307  57.277  .41165   0.03 B/B INTERMITTENT
  13  19644.  0.0000 0.000 90.00  132.34  118.75  2.7397  0.0000  3.6098  18586.  .202899  69.307  57.289  .40084   0.03 B/B INTERMITTENT
  14  21281.  0.0000 0.000 90.00  128.68  118.38  2.7719  0.0000  3.6582  18581.  .209676  69.307  57.300  .38986   0.03 B/B INTERMITTENT
  15  22918.  0.0000 0.000 90.00  124.98  118.00  2.8067  0.0000  3.7096  18577.  .216567  69.307  57.311  .37872   0.02 B/B INTERMITTENT
  16  24555.  0.0000 0.000 90.00  121.21  117.63  2.8442  0.0000  3.7646  18572.  .223581  69.307  57.322  .36740   0.02 B/B INTERMITTENT
  17  26192.  0.0000 0.000 90.00  117.39  117.27  2.8849  0.0000  3.8234  18567.  .230723  69.307  57.333  .35589   0.02 B/B INTERMITTENT
  18  27829.  0.0000 0.000 90.00  113.50  116.91  2.9292  0.0000  3.8865  18563.  .238003  69.307  57.344  .34418   0.02 B/B INTERMITTENT
  19  29466.  0.0000 0.000 90.00  109.55  116.55  2.9776  0.0000  3.9544  18558.  .245431  69.307  57.355  .33225   0.02 B/B INTERMITTENT
  20  31103.  0.0000 0.000 90.00  105.52  116.20  3.0307  0.0000  4.0279  18553.  .253018  69.307  57.366  .32009   0.02 B/B INTERMITTENT
  21  32740.  0.0000 0.000 90.00  101.41  115.86  3.0894  0.0000  4.1077  18549.  .260777  69.307  57.377  .30767   0.02 B/B INTERMITTENT


Case    1 complete
```

Figure 4 OGM -03 Tabular Reports

```
************  PIPESIM  ************                                                                          Date : 29/10/16
*    (Release 4.60   21/07/12)    *                                                                         Time : 20:57:05
*    MULTIPHASE FLOW SIMULATOR    *                BRANCH HASE-02    Primary Output
*          pipesim-bld1:202       *                BRANCH HASE-02    Primary Output                              PC-32/Intel
*           Schlumberger          *                BRANCH HASE-02    Primary Output
*             Houston             *
***********************************

Project   : HAMRA Case Study
User      : User
Data File : HASE-02.pst

Job       : 'PIPESIM Job'
Branch    : HASE-02



       Dist.   Elev. Horiz. Vert.  Pres.   Temp.    Mean   Pressure Drop  Liquid    Free    Total     Densities     Slug   Flow
                     Angle  Devn.                   Vel.       (psi)       Flow     Gas     Mass       (lb/ft3)    Number  Pattern
       (feet)  (feet) (deg) (deg)  (psia)     (F)   (ft/s)   Elev. Frictn. (bbl/d) (mmscfd)  (lb/s)  Liquid     Gas (PI-SS)
       n/a     n/a   n/a   n/a    2014.7  104.00    n/a    0.0000  0.0000  349.10  0.00000  1.3777  60.730
*** VertWell_1 Production:  pws= 2014.7 psia  pwf= 1915.6 psia  Q= 1.3777 lb/sec  twf= 104.35 F
TUBING Q10 - 165
Mid Perfs
   1  0.0000  -5710. 90.00 0.000  1915.6  104.35  .10564  0.0000  0.0000  349.24  0.00000  1.3777  60.706                        LIQUID
   2  0.0000  -5049. 90.00 0.000  1637.0  103.93  .10571  278.64  .00318  349.48  0.00000  1.3777  60.665                        LIQUID

** PUMP : Speed = 2333.3  Power = 8.0832 hp  DP = 693.6 psi  DT = 2.3876 F  Eff = 51%
  (centrifugal)  Curve = Q10  Stages = 105  Qin = 349.48 bbl/day  Qout = 349.02 bbl/day  Head = 1646.4 ft
*** WARNING: Flowrate of     349.48 (bbl/d) is out of supplied pump curve bounds:   422.40     to   661.36     ***
   2  0.0000  -5049. 90.00 0.000  2330.6  106.32  .10557  0.0000  0.0000  349.02  0.00000  1.3777  60.744                        LIQUID
   3  0.0000  -5047. 90.00 0.000  2329.8  106.31  .10557  .78887  .89e-5  349.02  0.00000  1.3777  60.744                        LIQUID
   4  0.0000  -5039. 90.00 0.000  2326.5  106.29  .10558  3.3215  .38e-4  349.02  0.00000  1.3777  60.744                        LIQUID

Q10 - 165_Tub#1
   4  0.0000  -5039. 90.00 0.000  2326.5  106.29  .46421  0.0000  0.0000  349.02  0.00000  1.3777  60.744                        LIQUID
   5  0.0000  -5000. 90.00 0.000  2309.8  106.22  .46422  16.607  .00636  349.03  0.00000  1.3777  60.742                        LIQUID
   6  0.0000  -4000. 90.00 0.000  1888.0  104.57  .46457  421.67  .16201  349.29  0.00000  1.3777  60.698                        LIQUID
   7  0.0000  -3000. 90.00 0.000  1466.5  102.95  .46492  421.35  .16281  349.55  0.00000  1.3777  60.652                        LIQUID
   8  0.0000  -2000. 90.00 0.000  1045.3  101.35  .46527  421.03  .16360  349.82  0.00000  1.3777  60.606                        LIQUID
   9  0.0000  -1000. 90.00 0.000  624.42  99.754  .46562  420.71  .16440  350.08  0.00000  1.3777  60.560                        LIQUID
  10  0.0000  -1.640 90.00 0.000  204.55  98.172  .46598  419.70  .16494  350.35  0.00000  1.3777  60.513                        LIQUID
  11  0.0000  0.0000 90.00 0.000  203.86  98.170  .46598  .68935  .00027  350.35  0.00000  1.3777  60.513                        LIQUID
Well Head
** CHOKE       : Bean Diam.=  0.79 ins.  DP=    0.818 psi  Pres. ratio=  0.99599  Mach no.= 0.04811  Flow is sub-critical
                 Crit corr= THEORY     Sub-crit corr= THEORY     Current flowrate= 346.81 Opt flowrate= 582.64 (std.bbl/d)
  11  0.0000  0.0000 n/a   n/a    203.04  98.173   n/a     n/a     n/a    350.36  0.00000  1.3777  60.513
```

Figure 5 HAE-02 Tabular report

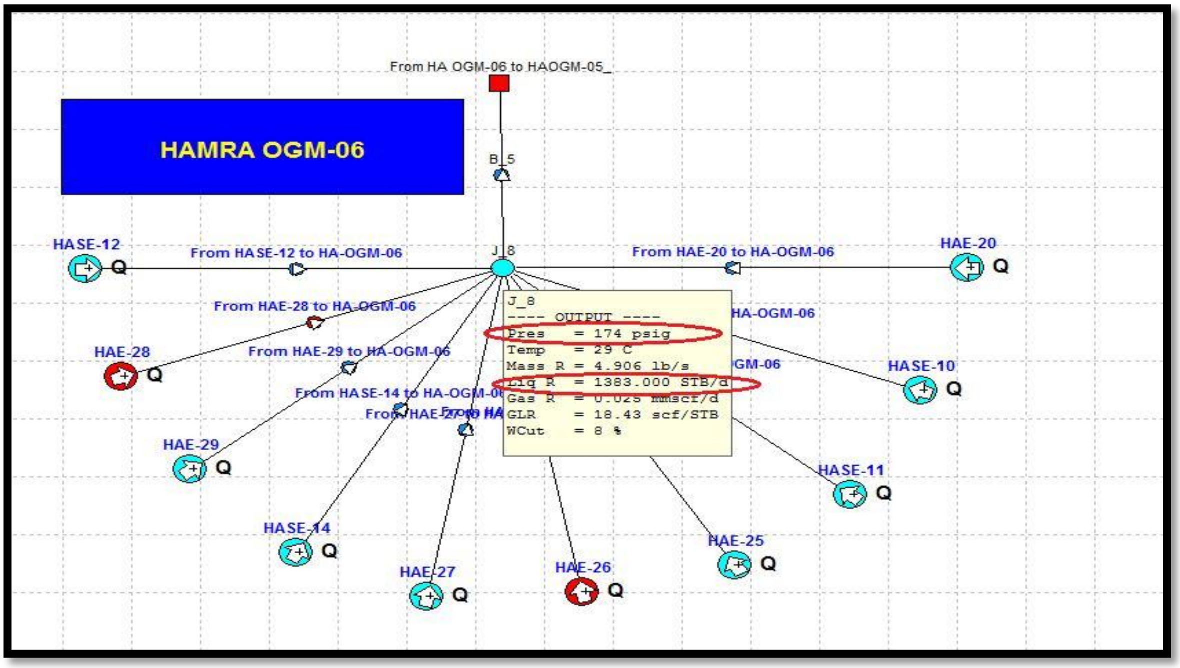

Figure 6 OGM-06 Model Data