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Novel Model For Simulating Performance Of Twin Screw Multiphase Pumps Capable Of Handling high (GVF) With Nodal Analysis to study Reservoir/well/pump Interactions.

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For everybody mentioned above, my dear friends and colleagues and all humans in this world, I hope you stay blessed and safe during this critical time of a global pandemic. May you and all your families cherish in perfect health, accomplish all your goals, and reach all your dreams.

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Abstract

For the last decades, the term artificial lift has mainly referred to the conventional techniques of downhole pumping systems (e.g., electrical submersible, sucker rod, progressing cavity, and others) and gas lift. Today, a more comprehensive definition is becoming evident, a definition which matches all the major changes happening in the oil & gas industry. Accordingly, artificial lift is not limited anymore to techniques conducted in the wellbore, however instead techniques used throughout the whole production system to "lift" the produced fluids towards their final destination should be included.

All petroleum wells' production lives are brought to an end when the downhole reservoir pressure cannot deliver fluids traveling up to the processing facility. Numerous advanced technological approaches were practically implemented at many fields to extend field exploitation which are approaching the end of their lives. One such technique is to introduce Multiphase Pumps (MPP), which are based on a technique used to add energy to the unprocessed crude from the well to transport the oil / gas / water mixtures to the CPF over several distances without the need for preliminary separation or any well interventions to install downhole equipment like other conventional artificial lift techniques and with maintaining a more environmental friendly performance as gas flaring is no longer required and oil spills are avoided.

This thesis is aimed at addressing the difficulties in field development studies involved in the evaluation of multiphase Pumps. These problems are related to uncertainty about the approach adopted to test the pump. Minimal information about the multi-phase pump performance results in difficulty for any new Pump model to evaluate its applicability. As the performance curve of a pump is dependent on the inlet fluid properties, such as fluid inlet pressure, temperature, water cut, gas volume fraction (GVF), etc. Therefore, the correct prediction requires the performance of the pump to be evaluated for each fluid property change throughout the field life. As well, a complete nodal analysis study is performed through industrial software package to study the MPP effect on the production system performance and quantify the production gains after introducing the MPP into the system.

The results of this study clearly demonstrate the tremendous effect of multiphase pumps in reactivating and enhancing production from dying wells or brown fields providing a cost-

effective solution rather than conventional methods. Some operation challenges are very important to be considered especially when operating the pump at high GVF above 90% as a liquid recirculation system is required coupled with precise evaluation of system parameters to avoid gas flashing within the pump leading to reduction of pump efficiency, and with respect to solids, handling measures upstream of the pump as well. Nevertheless, multiphase pumping proves its efficiency in de-liquification of liquid loaded gas wells which ceases to flow before pump introduction. Lastly, a novel model is produced to provide a detailed selection criterion for both pumps selected from different available models from different international vendors based on each production system parameters, and well selection plan to best choose well candidates to provide the optimum effect of the multiphase pump.

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Chapter 1 Introduction

For the last decades, the term artificial lift has mainly referred to the conventional techniques of downhole pumping systems (e.g., electrical submersible, sucker rod, progressing cavity, and others) and gas lift. Today, more comprehensive definition is becoming evident, a definition which match all the major changes happening in oil & gas industry. Accordingly, artificial lift is not limited anymore to techniques conducted in the wellbore, however instead techniques used throughout the whole production system to "lift" the produced fluids towards their final destination should be included.

All petroleum wells' production lives are brought to an end when the downhole reservoir pressure cannot sustain fluids traveling up to the processing facility. "Easy oil is over" throughout decades of using available reserves of oil and gas, these reserves are becoming more challenging to be recovered as the exploration and development of increasingly more difficult areas is undergoing. Average exploitation efficiency of 30 to 40% is achieved through the use of conventional techniques.

Numerous advanced technological approaches were practically implemented at many fields to extend fields exploitation which are approaching the end of their lives. One such technique is to introduce Multiphase Pumps (MPP), which is basically a technique used to add energy to the unprocessed crude from the well to transport the oil / gas / water mixture to the CPF over several distances without the need for a preliminary separation.

As energy demand continues to increase, it has become essential to recover from existing reservoirs as much as possible and expand the development of marginal fields. Petroleum producing companies' research is undertaken to expand life of reservoir and enhance recovery with new technologies such as multiphase pumping. In the early 1990s, the first multiphase oil field test of prototypes of pumps took place. Since that date, several hundred pump systems have been installed worldwide. These are onshore, offshore both subsea and topside.

The advantages of multiphase pumping (MPP) over traditional oil and gas production techniques are numerous. The following are some of the advantages:

- Multiphase pumping avoids the need for equipment including separators, compressors, flares and allows processing facility to be centralised.

• The recovery factor of the reservoir can be increased through multiphase pumping by extending the production life of mature fields which is achieved by reducing the wellhead flowing pressure as long as the reservoir has enough energy to supply the hydrocarbons.

• MPP can also perform gas well de-liquidation.

• Improving flow assurance by minimising possible problems. Multiphase pumps, for instance, break up terrain slugs and avoid flooding of separator and liquid carry-over.

• In some cases, the need for the injection of methanol will be eliminated as MPP lower the flowline pressure under the pressure of hydrate formation.

• The HSE aspects are enhanced by multiphase pumping. This is because the simpler installations, eliminate flares and minimise the possibility of spills which is highly appreciable by the trend of environmentally friendly operations Oil & Gas industry.

• For remote areas, Multiphase pumping is especially attractive.

• Run without interruption, even in the case of extreme conditions of slugging.

• Downtime coupled with single phase compressor and separator is effectively reduced

• Large volume size MPP has a small footprint.

• One pipeline for fluid export is needed instead of two pipelines.

• More versatility with variable frequency drive (VFD) device to provide flexibility and adapt to abrupt change of well flowing conditions. This system keeps constant suction pressure at the pump inlet.

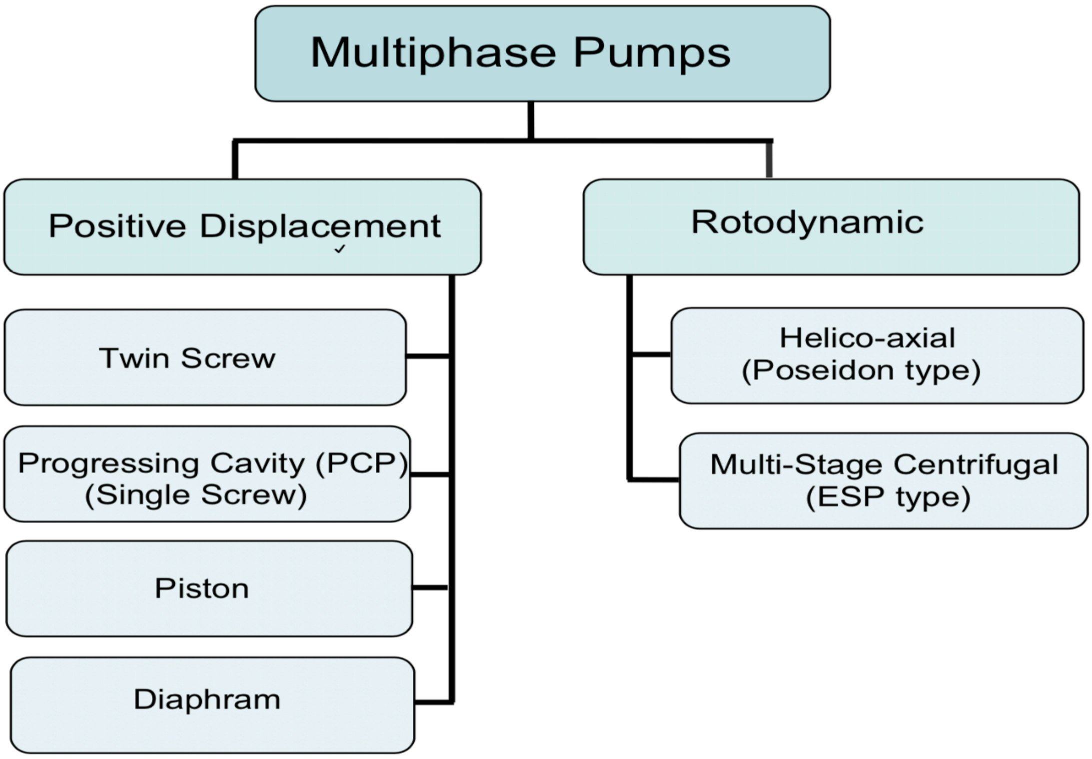

Figure 1.1 Different Multiphase Pumping Techniques

This thesis will discuss mainly the positive displacement type pumps including mainly Twin-screw pumps.

1.1 Positive Displacement Pumps

Main concept of Positive displacement pumps operation is that an exact amount of fluid will be displaced through the pump relying on the basis of the pump chamber volume as well as the velocity at which that volume is displaced. The differential pressure in the pump is dependent on the flow resistance of the pump downstream which is to say the pressure losses to be overcome to bring the fluid to a certain point downstream with a certain pressure (this is managed by the pressure set at the CPF). The interaction of the pump with the adjacent segments of the pipeline defines the pump efficiency for any positive displacement pump.

1.1.1 Twin-Screw Pumps

The twin-screw pump is the most commonly used multiphase pump. Twin-screws handle high gas volume fractions (GVF) and any fluctuating of inlet conditions in particular. The functionality of the abovementioned pumps is guaranteed even in 95% GVF, nevertheless 100 % GVF can be reached for short time with recirculation systems. The following figure 1.2 provides a twin screw pump schematic. The multi-phase mixture is divided inside a pump into two flow streams directed to inlets placed on opposite sides of the pump. This design equalises any stresses related to slugging. The flow then passes through an interlocking screws chamber which extends over the whole screws' length up to the pump outlet. The volumetric flow rate is dependent on the screws diameter, pitch and speed of rotation. When the gas is compressed, a small definite amount of fluid slips back via the small voids between the screws and the wall of the pump chamber, which results in lower volumetric efficiency.

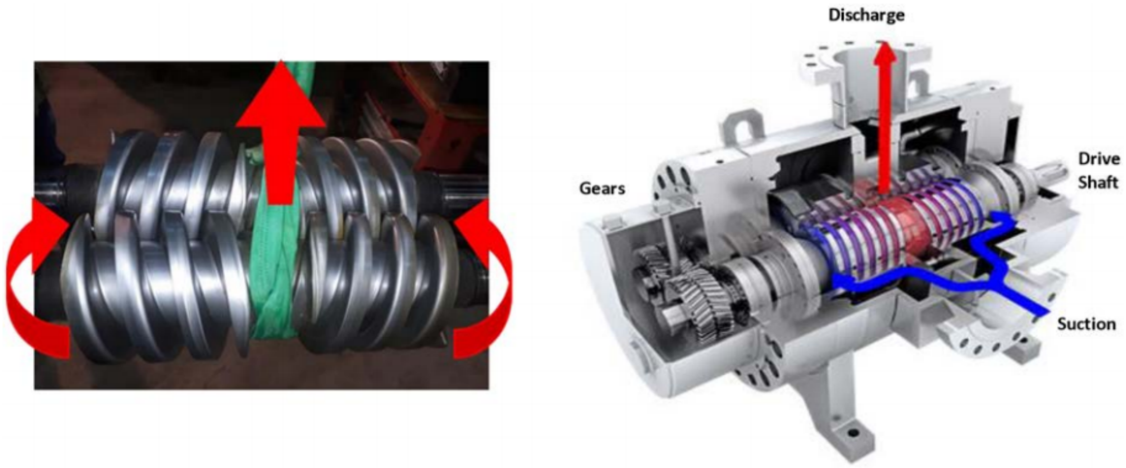

Figure 1.2 Twin screw pump cutaway and flow paths through a rotor assembly

1.1.2 Progressive Cavity Pumps

The Progressing Cavity Pump (single screw) which is mainly used as an artificial lift technique for shallow wells, has been successfully used for multiphase pumping applications. The design of this pump relies on a rubber stator and a rotating metal rotor (Figure 1.3). It is efficient at relatively low flow rates (<30000 barrel per day of total fluid volume) and low discharge pressure (max 50 bar). It is able to withstand relatively large amounts of solids content. The high output levels of sand, however, contribute to the need to periodically change the stator of the pump.

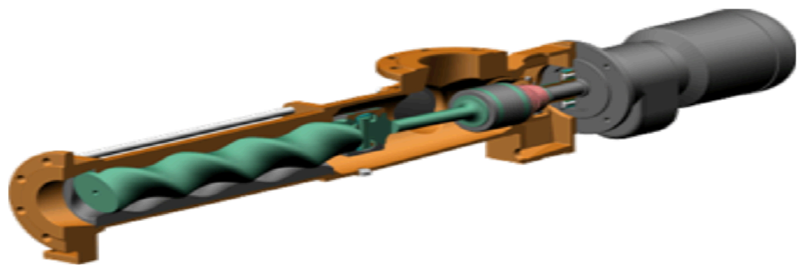

Figure 1.3 Progressive Cavity Pump

1.2 Study Objective

The thesis subject is aimed at addressing the difficulties in field development studies involved in the evaluation of multiphase Pumps. These problems are related to the non-accessibility in the available commercial simulators for production networks of a generalized multiphase pump model and to uncertainty about the approach adopted to test the pump. Minimal information about the multi-phase pump performance results in difficulty for any new Pump model to evaluate its applicability. As the performance curve of a pump is dependent on the inlet fluid properties, such as fluid inlet pressure & temperature, water cut, gas volume fraction (GVF), etc. Therefore, the correct prediction requires the performance of the pump to be evaluated for each fluid property change. Therefore, it is important to evaluate the efficiency of the pump in the variational fluid phases, fractions and properties since the fluid fractions of a hydrocarbon field differ throughout the production process and throughout the field life.

Furthermore, choosing a pump for a specific field usually results in operating configuration in parallel or series. Both these operation configurations require testing of the pump chosen for each configuration. Parallel operation of the pump does not incur much difficulties in selecting the booster, as fluid's properties remain unchanged for all the pumps. On the other hand, selection of pumps for series operation is much more challenging as the fluid's properties varies for the later staged pumps. These manual selections can contribute to inefficient booster selection, which can raise investment risks.

Beside pump selection and configuration, this thesis aims to quantify the ultimate advantages of the multiphase pumps and proving their viability to hydrocarbon recovery increase and production life extension for dying brown fields

1.3 Scope of Work

This research is consisted of a general introduction to multiphase flow, study of the whole multiphase pumping station design including different multiphase pumps' profiles and their limitations, introducing a typical workflow routine to study the production profile of candidate producing wells by performing Nodal analysis by the industrial software package of Petroleum Experts (Mbal, Prosper, Gap) to characterize the response of the production system to the multiphase pump and quantifying the production gains and any limitations exerted by the pump, determining the Reservoir compatibility with the MPP systems to introduce the critical criteria required to introduce the MPP as a viable solution such as production history profile, sand Production, water cut and water salinity, etc), introducing a simple workflow to select the suitable MPP for each field based on the system input parameters and characteristics.

Chapter 2 Literature Review

Traditional boosters are designed primarily for single flow. For fluid dominated flow regimes, liquid boosters or pumps are selected; for gas dominated flows, dry gas compressors are selected. The implementation of pressure booster equipment must be able to cope with the change of phase. The transformation of phases depends on the composition of the fluid in reservoir and fluid properties during fluid transportation. Variations in the fluid phase depend as well on different field properties like water cut, GOR, and others that may also lead to multiple different flow regimes through the production system. Suitable principles for choosing the appropriate method and selecting a multi-phase pump include sufficient knowledge of the fluid behavior in reservoir and the pressure / temperature variations of the reservoir and any expectations for water breakthrough or coning in the later stage of field life. Consequently, the idea of multiphase pumping is related to the physical characteristics of multi-phase flow and to the property of reservoir fluid requiring changes in the mode of flow.

The key group of fluid phases are solid, liquid or gas. Physical characteristics of any fluid phase defines it. Normally reservoir fluid is transformed into either a liquid or a gas phase within the well tubing and production line due to a change in temperature/pressure profile, while a temperature reduction can also lead to a solid phase formation for instance gas hydrates. Yet, the change in the size of particles of one phase leads to a new process, whose characteristics can be jointly described by one phase and another emulsion like phase and partly by another as emulsions (along immiscible liquids, foam or slurry (along solid and liquid phases).

In a certain segment of multiphase fluids, flow may turn into multiple phases and regimes, which directly impact transport loss of energy. The classification of various fluid regimes relies on the physical parameters of each multiphase flow system. The definition of fluid properties will be used to classify the phase distribution within vertically and horizontally lines

2.1 Multiphase Fluids

In order to understand how an MMP works, the meaning of a multiphase fluid must be understood. Any gas, liquid or solid particle combination can be referred to as a multi-phase fluid. For the simplest version the fluid flow consisting of a gas or even a liquid, a single-phase flow is called. The multiphase mixture can contain substances like crude oil, water, gas, wax and sand.

Volume Fraction

Through multiphase fluid flow lines, every different phase occupies a certain section of the line. Taking into consideration, the same segment length, each phase 's occupied area corresponds to every phase 's volume, If normalization is performed with the occupied area / volume of each fluid phase with respect to a total area / volume, then it is possible to classify the covered area/volume as area/volume fractions. When considering multiphase flow, the volume fractions are defined for each phase (Liquid or gas) as follows;

$$Liquid\ volume\ fraction,\ \alpha_L = \frac{Liquid\ Volume}{Total\ Fluid\ Volume}$$

$$Gas\ volume\ fraction\ (GVF), \alpha_G = \frac{Gas\ Volume}{Total\ Fluid\ Volume}$$

It is vital to recognize that the quantities above are in current pressure and temperature conditions. For liquid driven flow, a pressure change effect does not involve significant volume changes, but such a change causes considerable volume fraction changes for gas controlled flow.

Holdup

Holdup is typically the term for showing the fraction of a phase which is present in the line segment. It is used mainly in the liquid phase, as changes in the liquid phase within the production system are creating drastic flow regime changes. Liquid holdup also constitutes a liquid volume fraction, but is calculated by considering gas volume fraction

Liquid Holdup, $\alpha_L = 1 - \alpha_G$

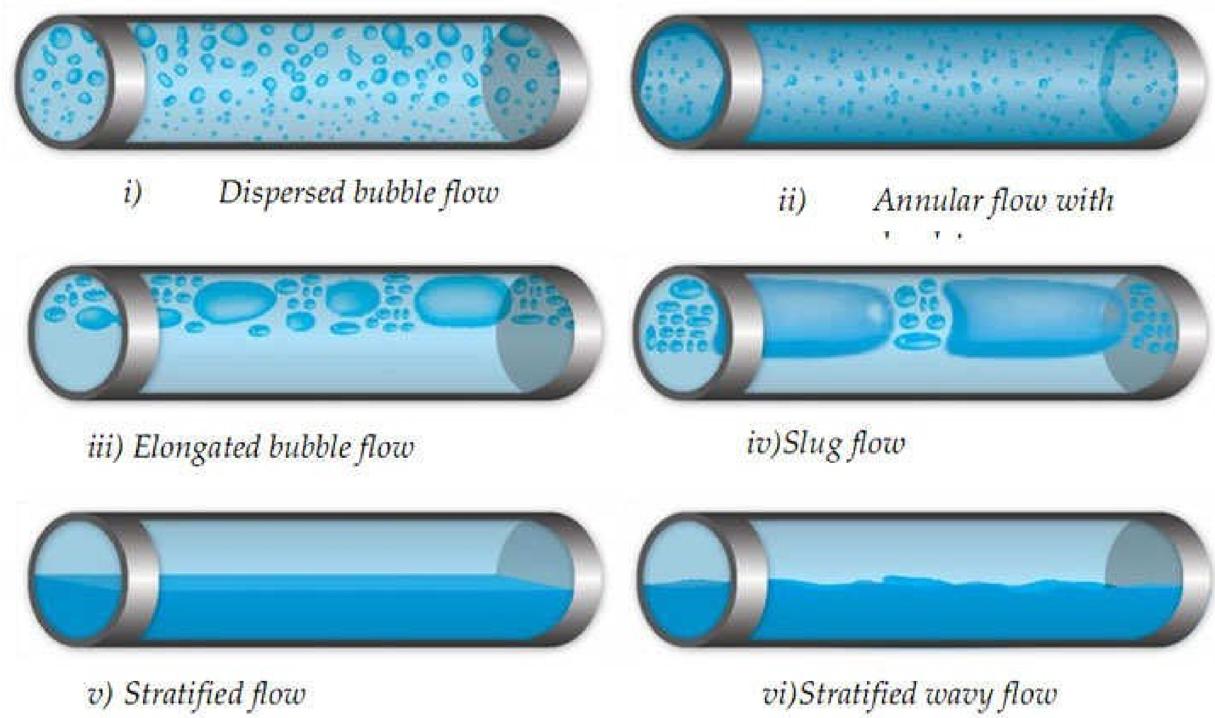

Figure 2.1 Different Flow Regimes of gas/liquid in Horizontal Pipes

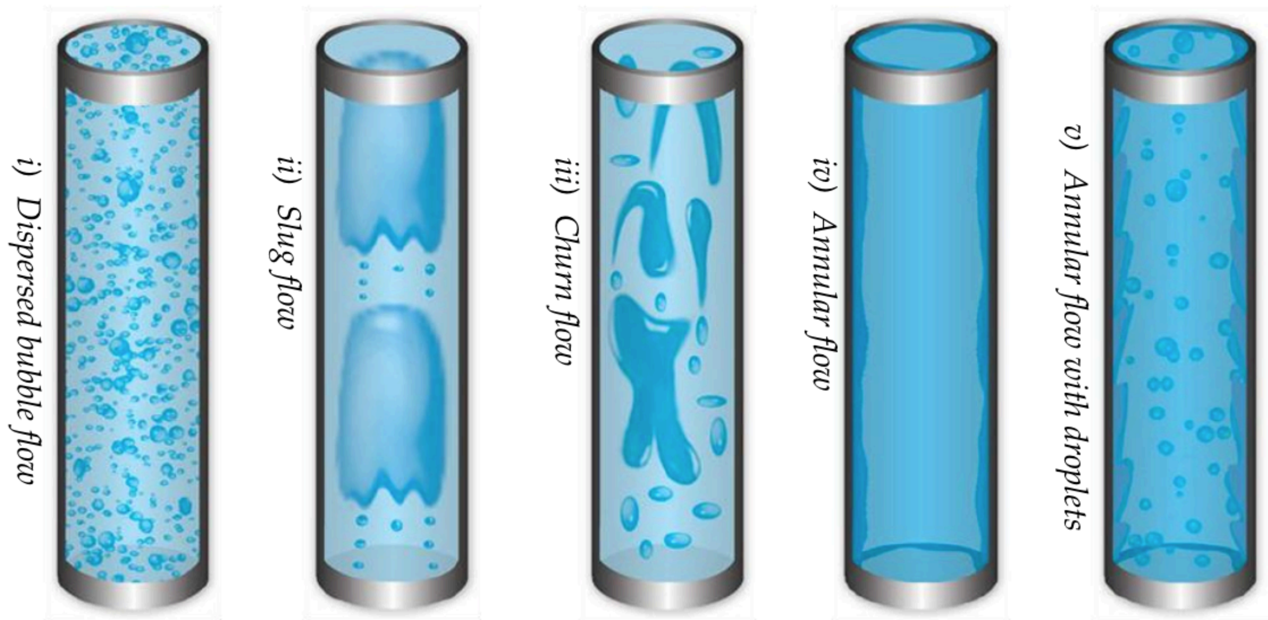

Figure 2.2 Different Flow Regimes of gas/liquid in Vertical Pipes

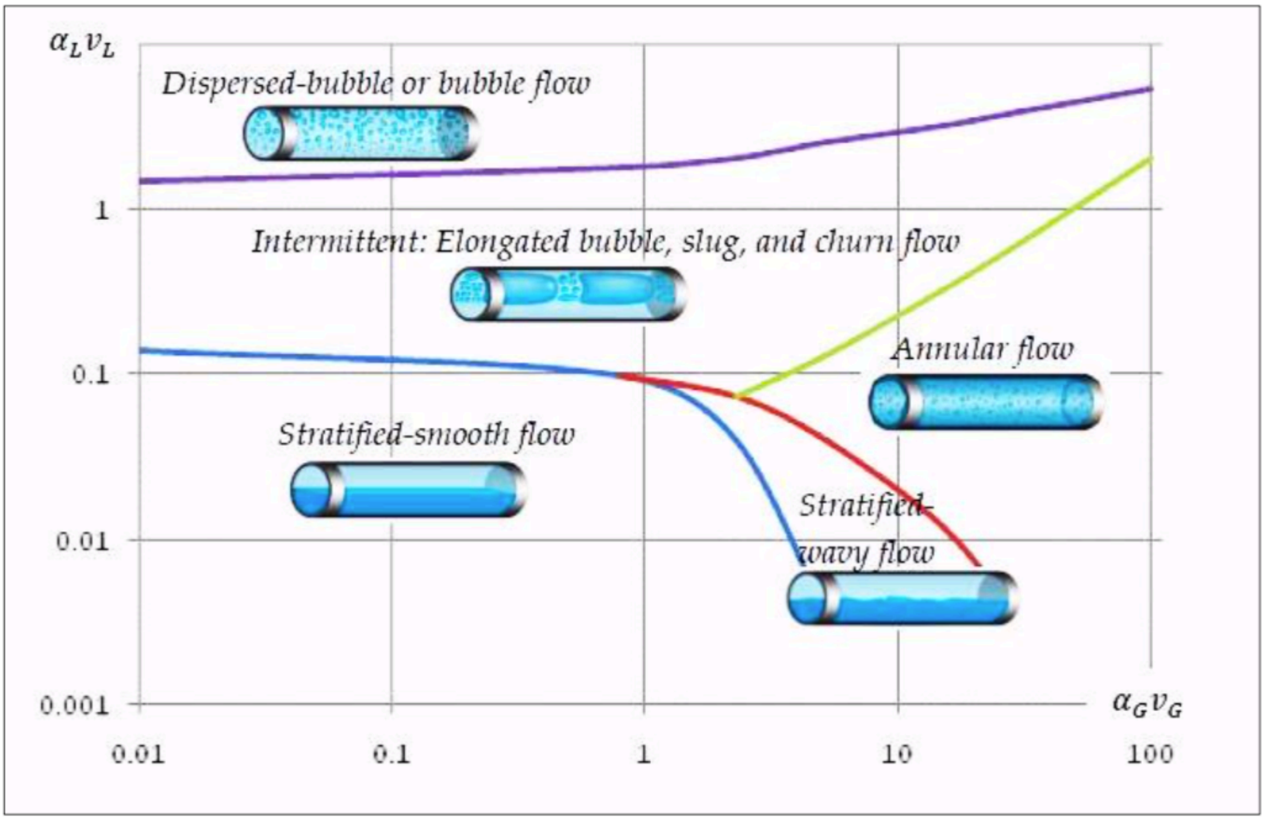

Figure 2.3 Flow regime steady state in horizontal pipes

In the figures above, there are many flow regimes of multiphase fluids. The criteria determining the flow regime depend on the gas volume fraction GVF and the relative flow velocity of each fluid phase. In this current study analysis, the flow regime or the conditions at pump inlet cannot be measured directly because visual lenses cannot be installed into the pump assembly; thus, an overall understanding of these flow regimes is needed.

2.2 Multi-Phase Fluid Flow Considerations

Understanding the upstream and downstream flow scenarios plays a vital role in operating the multiphase pumping system efficiently. Nevertheless, detailed study of the entire pumping process is essential for selecting the optimum technical design for each scenario. As well, it should be taken into consideration the potential solids production and the solid limitations of each pump.

Multiphase flow can be encountered starting from the downhole which consequently extends to the first stage of separation at the central process facilities. Fluid flow scenario is fully transient with the possibility of slugging occurrence along the way. Given that, design of each pump should align with GVF ranging from 0% to 100%. Furthermore, it should be noted that the further the distance from the wellhead or manifold, the longer is to consider gas phases existing in the flow line. As a result, upon installing multiphase pumps, they should be placed as close as possible to the fluid appearance at surface to avoid gas slugging (as much as possible), and furtherly lower the wellhead pressure. However, it is advised to install the pump at manifold level in order to minimize the footprint and avoid recurrent installations for single wells. Upon installation, management of flow patterns with a proper system design of multiphase pumps is essential.

As matter of fact, pumps are conventionally designed to produce either liquid or both liquid and gas but not dry gas or 100% GVF, due to the risk of overheating and a potential "no flow" scenario upon system shutdown. In this case a compressor should be used, however compressor will not be able to manage an increased liquid production in the case of high water cut wells. Therefore, pumps will be a more suitable option with superior advantage.

A continuous operation of multiphase pumps, to produce lean gas, is mainly achieved by artificially reducing GVF actually entering the pump to a level that can be properly managed by the pump. This is achieved by installing an internal or external recirculating system genuinely designed to keep the pump operating regardless any change in fluid composition or phases.

The "no contact" design between screws, screw, and liner enables fluid to inevitably flow back from the discharge to the suction (slippage), which reduces the volumetric efficiency (flow rate) of the pump. Pressure is built up by successive slip flows between cavities, creating liquid holdup leading to help to cool down the pump. It is worth mentioning that it is recommended to run a downstream separated liquid source to avoid dry running of the pump which results in overheating and subsequently possible system shut down. Separation of this liquid can be in a pump casing chamber at the pump discharge side or independent downstream or upstream vessel. Recirculation of the separated liquid is carried out with a constant fraction of 3% - 5% of pump total capacity. The abovementioned operational condition slightly reduces the pump efficiency; however, it limits temperature increase and prevent overheating of pump parts during encountering 100% GVF fluid.

2.3 Twin Screw Pump Description and Function Principles

The most commonly used multiphase pump in the oil&gas industry is Twin Screw Pump. It is considered as a positive displacement pump. Following the terminology of the naming, twin screw pump comprises two intermeshing screws. The drive shaft connects one screw to the motor while driving force is transferred to the other screw by the mean of timing gears. When both screws rotate counter to each other, they generate a number of sealed C-shaped chambers allowing the fluid inside the chambers to be pushed from the screws suction end to the pump discharge as shown in the following figure. The double screw main function is to displace continuously the volume of fluids at the inlet to the discharge point by moving them along the double screw. The configuration of "no contacts" among the screws, liner and screws helps the pump to withstand some fluid sand content or solids. Nevertheless, the abovementioned clearances as well provide a way for the fluid to back flow towards the suction from discharge reducing the pump volumetric efficiency. Pressure is generated by continuous slippage flows through cavities that produce less and less liquid-related gas volume at each consecutive screws' turn.

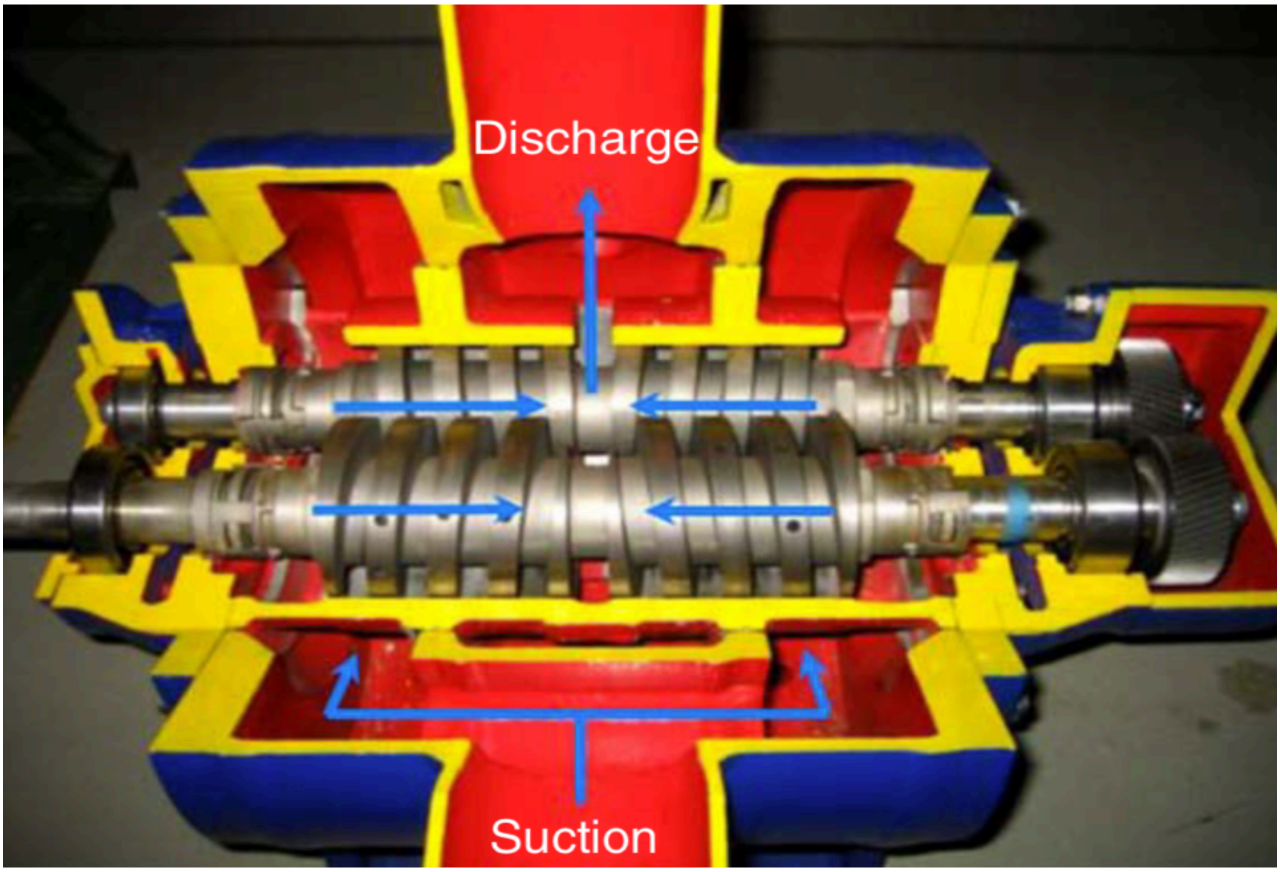

Figure 2.4 Cutaway of Twin Screw pump

There is also a liner inserted in the casing, which can be seen as a wear element, among several other features. In order to provide better wear resistance to sediment and solid production, the liner and tips of the screw can be hard coated. The screws have a special flank profile, which is vital to minimize the backflow through the clearances. The process of lathing provides the possibility of having a decreasing pitch up to the screws' discharge end, which allows internal compression of multiphase flow in higher efficiency. The Pitch size defines the pump operating parameters, therefore smaller pitch size provides higher differential pressure produced by the pump at low rate. A larger pitch, however, permits higher flow rates at lower pressure differentials. The following plots presented on the Fig.2.2 below illustrates the pitch performance for a 600KW pump and a 2.2 MW pump respectively.

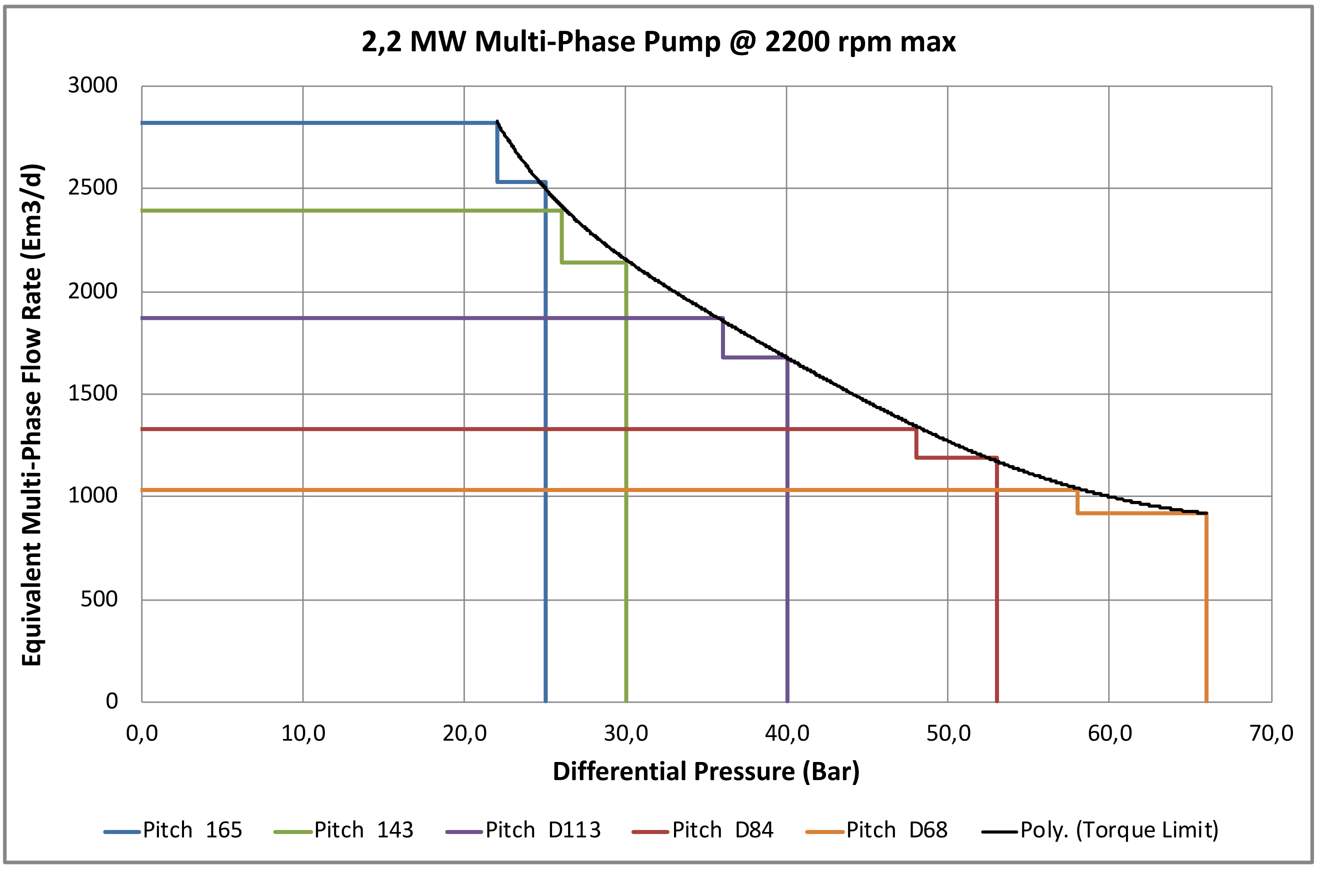

Figure 2.5 Twin-Screw 2.2 MW pump performance and pitch selection

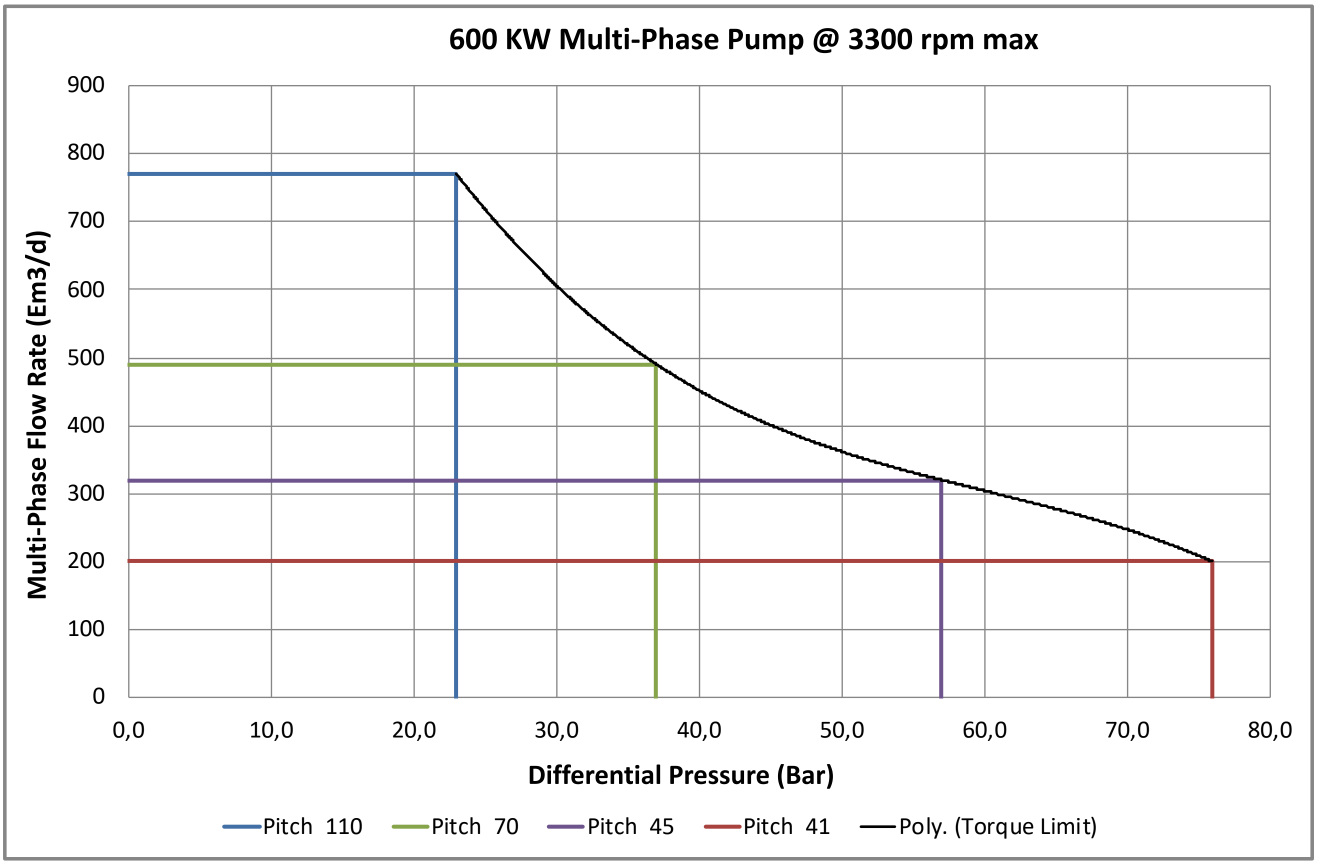

Figure 2.6 Twin-Screw 600 KW pump performance and pitch selection

Heat is generated during pumping due to compression of gas and friction. Under all circumstances, local internal overheating must be avoided not to lead to severe damages to the pump surfaces as cold welding between running surfaces leading to a subsequent shut down of the pump. Another limitation for the pump surface temperature is due to external zone specification, therefore liquid recirculation and cooling before being recirculated is tremendously important to keep the pump temperature within the allowable design values.

2.4 Main Engineering Components of the Multiphase Pumping Plant

Usually the proposed candidate wells are highly depleted, with very high GVF at inlet pressure conditions. The scope of the service is to provide Multiphase Boosting Installation capable to perform within the production data and PVT reports provided by the oil company. The pumping technology is mainly selected based on the high GVF required for operating the wells, relating fluid production rates with each pump capacity, and taking into consideration of any special requests such as (regarding for instance : High water cut wells, high solid content, high produced water salinity) .

2.4.1 Process

The handled fluid is a multiphase mixture containing natural gas, oil, water and solids particles. Multiphase Pumping Plants (MPP) has been designed to pump the multiphase mixture, directly from the well/manifold to the final destination. The material of construction of the system is generally finalized based on the available information about the stream content and chemical composition. As the production profiles change during the operation time, the hydraulic design of the pumps, as well as the functional logic regulating the system operations, is usually customized to cope with the continuously changing requirement of the field operators.

By installing a reliable optimum multiphase pump suited with the production system of the field, the production company benefits from the following proven advantages, when compared with conventional separation and single-phase gas compression:

1) Wet gas compression or multiphase gas compression, boosts pressure to transport gas to market, thus eliminating the requirement of additional equipment;
2) Uninterrupted flow, even under severe slugging conditions;
3) Small footprint for large volumes: systems are easy to install, operate and move, and reduce the down time associated with a traditional well separation equipment and single-phase compression station;
4) High flexibility to adapt to the well-condition changes by means of a variable frequency drive system (VFD), and customized hydraulic design;
5) Keeping a constant suction pressure by means of a VFD unit.

2.4.2 Basic of design

The basic of design of the main items are as following:

a) Boosting Process data

- Inlet Pressure
- Outlet Pressure
- Oil Flowrate

- Water Cut
- Gas Flowrate
- Suction Temperature
- Fluid type: multiphase mixture
- Water Salinity [ppm]
- TSS and grain size [micron]
- H_2S content [ppm]
- CO_2 content [mol%]
- Maximum Allowable Operating temperature
- Oil Viscosity
- Oil S.G.

b) Piping Design

- Design Code
- Inlet Line
- Outlet Line
- Design Pressure
- Design Temperature
- Corrosion allowance

c) Tie-Ins

- Inlet : on the existing tie-in flange (by Operating Petroleum Company)
- Outlet: on the existing tie-in flange (by OPC)
- PSV: on the existing cold/hot flare line (to be confirmed by OPC)
- Blow down: on the existing blow down network

d) Area Classification

Hazardous areas are classified according IEC60079-10-1:

- Zone 2: Area in which an explosive gas atmosphere is not likely to occur in normal operation but, if it does occur, will persist for a short period only
- Non-hazardous area: (safe area) A non-hazardous area is an area in which an explosive atmosphere is not expected to be present

Equipment included in the pumping solution, are designed to be installed in the following Zone:

- Pumping skid will be suitable to be installed in Zone 2. Electrical and instruments apparatus will be suitable for Zone 2, and provided with ATEX certificate and/or Division 2 as per API RP 500 Section C.
- Integrated Local Electric Room & Local Instrument Room containers (called ECR-electric and control room) suitable to be installed in Zone 2. Electrical and instruments apparatus, outside the ECR, will be IP55 minimum and inside the ECR, will be IP20 minimum.
- Electrical generators (optional) to be installed in safe area

e) Environmental Data

The multiphase pumping station design must be properly designed for extreme working condition. For the proposed application, design should be based on a forecasted ambient temperature of the expected site considering whether desert or low temperature environment for instance, a typical desert package configuration includes strong sand presence, windy and with large temperature gap, considering night & day process.

2.5 EQUIPMENTS

The proposed pressure boosting technology is based on either a twin screw or Progressive cavity multiphase pump. In those cases, in which the natural well pressure is not enough to overcome the pressure drops, the multiphase pumping technology is the right solution for oil production enhancement.

The installation of a multiphase pump can give an evident benefit such as

- Increase oil rate coming from the wells after decreasing WHP
- Increase the flow line discharge pressure

- No need of separators, pumps for oil and water, gas compressors or flares and other equipment required by the conventional exploitation method by separation.
- Installation with multiphase pump is much smaller than an installation by conventional separation.
- Multiphase pump avoids gas flaring reducing air pollution. This allows Oil Company to be in compliance to environmental issues even stricter.

The typical proposed pumping installation is composed by:

1. One multiphase pumping package, including the main items:
    - Single lift fabricated CS base frame
    - Twin screw multiphase pump
    - Squirrel cage Electric Motor
    - Inlet & outlet piping lines, including Instrumentation for control and monitoring
    - Basket strainer on the inlet line
    - External separation unit, including instrumentation, valves, recirculation & discharge lines
    - Pump LOS
    - API PLAN 54 for seal flushing process
    - Interconnecting piping set
    - Interconnecting cabling for power and instrumentations
    - JBs and cable trays
    - Electric and Control Room container (ECR)
2. Air cooled Heat Exchangers for recirculation stream
3. Diesel or Gas generators set, including interconnecting power cables
4. Water refilling system, if necessary, including:
    - Water refilling pump
    - Water stock tank (40000 lt)
    - Interconnecting piping and necessary instrumentation for control and monitoring

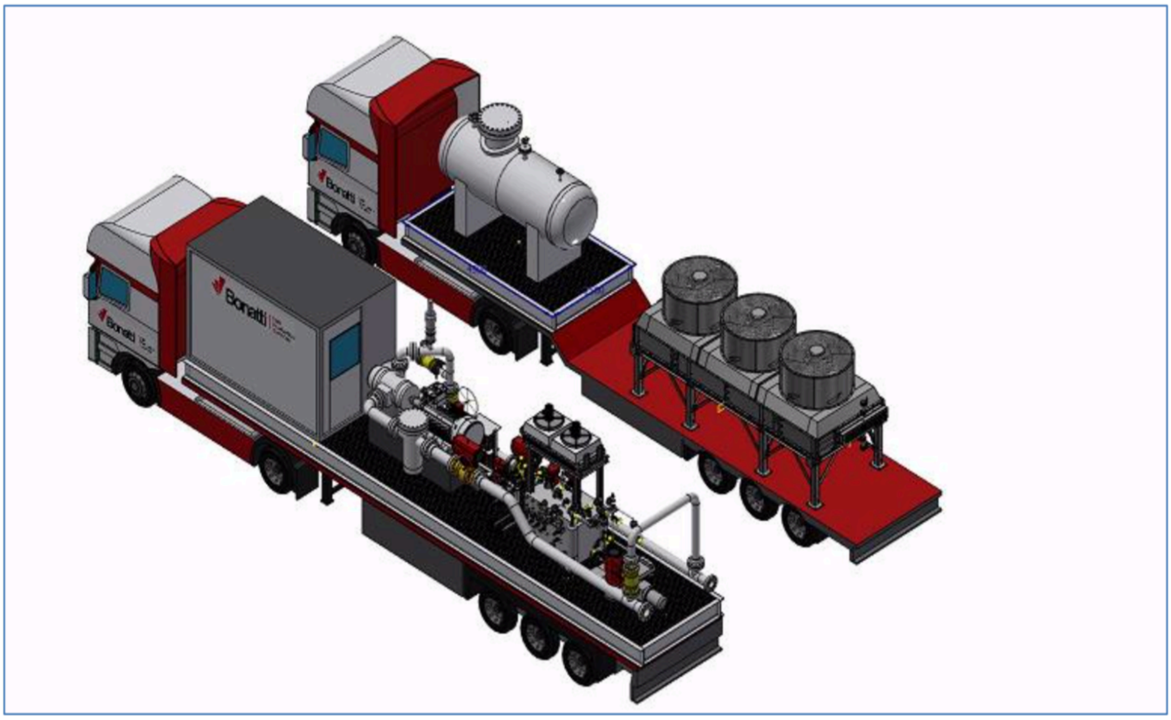

Figure 2.7 Two Trailers; on the left with the Multiphase Pumping system and ECR , on the right with air cooler and external liquid management system (Courtesy of Bonatti)

This trailer mounted solution is very efficient for fast mobilization-installation/Start-up/Commissioning and demobilization.

Here below, some description of main items, embedded inside skid.

- Baseplate
  - ♣ Made by Structural Carbon Steel of suitable dimensions to be moved by bed track It is suitable for four point lifting operations
  - ♣ Designed to guarantee the necessary structural stiffness and limit the vibration level, according to API 676 3rd Edition.

- Twin Screw Multiphase Pump

  The multiphase pump system uses twin screw pumps, that are positive displacement machines working independently of density and inlet pressure as well as backpressure and changes in GFV without slug catchers or inlet scrubbers. The system is ideal for multiphase production (rich and lean gas) because it can handle up to 100% GVF. During the life of the field, the multiphase flow can be controlled by controlling the speed of the pumps, so it can manage the wide range of production scenarios required by the Operating Oil Company.

The pumps are tailor made to cope with slug flow with no impact on operations. High GVF as well as wet gas are handled with an integrated recirculation of liquids. The compression heat is removed with the liquid, however for lean gas wells (100% GVF) process coolers are required.

The total volume produced through the pump is a function of the required differential pressure by installing different screws of different hydraulic design. However, the pumps can be arranged in series or parallel to cover the different scenarios.

Pump is built according to the following requirements:

- ♣ In compliance with API 676 3rd Edition
- ♣ Helicoidally timing gear for torque transmission
- ♣ Rotor dynamic balancing in compliance with ISO 1940 G 2.5

The proposed Material of Construction (MoC) are the standard ones, which has to be validated after the confirmation of pumped stream compositions:

- ➢ Pump casing: P-355 NH Nace compliant
- ➢ Liner: Ni-Resist D2 with surface hardened coating Shaft
- ➢ Screws: properly hardened to reach 1200 HV Bearing Housing: Carbon Steel
- ➢ Sealing Housing: Carbon Steel
- ➢ Baseplate: Fabricated Carbon Steel

MoC solution is defined only once the composition in terms of H_2S, CO_2, Chlorides, solids, ect are studied and analyzed.

2.5.1 Mechanical Seals

Mechanical seals are made by a primary firm seal provided by OEM company, according design, to fulfill the specific requirement of this service.

The optimum mechanical seal solution is a dual pressurized mechanical seal, specifically designed to withstand the extremely demanding operating conditions (pressure spikes/multiphase mixtures/dirty content/high rotational speed).

The new patented face groove technology ensures a stable and safe functioning of the seals, reduced power consumption, less wear on the sliding surfaces and increased product life. The new optimized cartridge and components design makes installation and the management of spare parts easier, thus reducing service time and maintenance costs.

- Each pump is equipped with nos. 4 API 682 4th Edition compliant double mechanical seals
- Mechanical seals work with 20 – 70 bar of constant differential pressure between barrier fluid and stuffing box pressure

2.5.2 Electric Motor

- Three-phase squirrel cage Electric Motor
- IEC / EN 60034-1
- Different kW packages @ different rpm max based on the system characteristics
- 2 poles, 400 V, 60 Hz
- Duty S1
- ATEX execution Exn, IIC, T3
- Ingress Protection IP55
- Energy efficiency class IE3
- Starting method VFD
- Mounting IM B3
- Insulation class F
- Temperature rise B
- Cooling method IC416
- Design Temperature -5°C /+55°C
- Altitude: <1000 m a.s.l.
- Humidity: < 95%
- Complete of vibration and temperature monitoring
- Anti-condensation heater
- VFD operated

2.5.3 Variable Frequency Drive

The variable frequency drive is a low voltage, AC fed drive designed for high-efficiency and power-friendly operation for industrial applications. It is made by a primary firm, according to the company's request, with high reliability, low harmonic distortion, and high power factor operation, in order to reduce the losses and optimize the load.

2.5.4 Coupling

Motor and pump are linked with a proper flexible coupling, with spacer, with the following features:

- OSHA coupling API 671 compliant
- Anti-sparking coupling guard

2.5.5 Process Piping Section

It includes all piping, control & safety valves and instrumentation required for the remote monitoring and control of pumping unit.

Every pumping skid is equipped with:

- Inlet branch with remotely controlled shutdown valve (SDV), basket strainer, drainage valves and instruments for control and monitoring;
- discharge branch with the safety valve (PSV), a remotely controlled shut down valve (SDV), a manual drainage valve, a remotely controlled blow down valve and instruments for control and monitoring;
- by-pass branch with a remotely controlled by-pass valve;
- inlet/outlet branches to liquid management system (LMS) for recovering of liquid to be recirculated (and cooled) when operating at high GVF, and separation of natural gas required to feed the gas engine driven generating sets

The MPP drainage circuit and pressure relief circuit are connected at operator company drainage and pressure relief circuit unless otherwise specified.

The proposed Material of Construction (MoC) are the standard ones, to be verified upon the confirmation of pumped stream compositions, as previously stated:

Suction/Discharge piping: Carbon Steel
Valve body: Carbon Steel
Valve internals: AISI 316 L
Baseplate: Fabricated Carbon Steel

2.5.6 Liquid Management System (LMS)

The LMS is required to catch the liquid in the stream, cool it down by means of an air cooler heat exchanger, then recirculated in the pump suction line, in order to guarantee the minimum required liquid to allow the multiphase pump to handle the gas coming from the line.

The LMS is installed on a dedicated trailer, positioned beside the MPP, then interconnected by means of weco pipeline.

It includes a manhole, the required instrumentation, suction/discharge/recirculation/drainage lines, automatic and manual valves, as required. The proposed Material of Construction (MoC) are the standard ones, to be verified after the confirmation of pumped stream compositions, as previously stated:

- Liquid Management Vessel: Carbon Steel internally coated
- Baseplate: Fabricated Carbon Steel
- LMS structure: Fabricated Carbon Steel
- Heat Exchanger: Carbon Steel

2.5.7 Bearing Lube Oil System

It includes the oil recirculating circuit, in order to provide lubrication of the internal rotating parts of the pump such as roller bearing and timing gears.
It is mainly composed of:

- Lube Oil Pump (1 operating + 1 back-up)

- Air coolers for the lubrication oil
- Oil Tank
- Piping recirculation circuit
- Control and remote monitoring instrumentation
- Lube Oil System material of construction is Carbon Steel

2.5.8 Seal oil system

Plan 54 is designed to guarantee performance, from 20 to 70 bar of constant pressure gap between barrier fluid pressure and stuffing box pressure. Stuffing box pressure is detected by a pressure transmitter and is sent via PLC to the pneumatically actuated pressure modulating valves PCV installed on the PLAN 54.

Differential pressure value across the seals faces shall be selected in the range of 20 to 70 bar by pumps operator acting on PLC /HMI.
The API plan 54 Oil System function is to ensure that:

- The double pressurized mechanical seals are properly oil flushed
- The required pressure is kept steady
- Sealant barrier fluid is filtered
- Heat generated by mechanical seals is removed

The plan 54 is normally equipped with:

- Oil Tank (approx. 600 lt)
- Electrically driven flushing pumps (1 operating + 1 back-up)
- Electrically driven air cooler (1 operating + 1 back-up)
- Seal oil heater
- Bladder accumulator
- Duplex filter with by-pass and differential pressure transmitter
- Back-pressure control valve (1 automatic + 1 manual as back-up)
- Required instrumentation for control and remote monitoring

Plan 54 material of construction is Stainless Steel grade 316/316L

2.6 Electrical and Control Room container (ECR)

2.6.1 Design and fabrication

The Local Electrical and Control Room Container (ECR) is installed on the common skid baseplate. It contains the Power panel, switches and Control Panel necessary for local and remote management of the MPP. It also includes normal and emergency lighting, receptacles, switches, power panels, HVAC system, F&G detection system (FDS), doors, hardware, wiring and other components required for the remote supervision.
The integrated system consisting of control room, pump and auxiliary systems is designed to be transported, mobilized and demobilized, in easy and workable way.

ECR contains specified electrical equipment which are listed below:

1. Low-voltage distribution boards and Motor Control Centre (MCC)
2. Variable Frequency Driver (VFD)
3. UPS systems (UPS, UPS-DP)
4. Pump Control panels HMI (PLC-P),
5. Fire & Gas detection system (F&G)
6. Communication Satellite System (CSS)
7. Air compressor system for instrument

Electrical equipment shall meet IEC classification.
Above mentioned equipment are completely installed and cabled inside the containers prior the shipping. All equipment shall be securely bolted to the containerized packaged substation. All openings into the packaged substation shall be sealed to provide a weather-tight seal against sand or other aggressive elements.
The ECR is pressurized for being installed in ATEx certified Zone 2 locations.

2.6.2 Structural cabinet frame

The ECR container is based on full-welded container solution, designed to be bolted on the skid baseplate, common to process equipment.

2.6.3 Roof and ceiling

Roof ribbed steel panels shall be minimum 1,25 mm thickness.
The metal ceiling system is built of metallic insulated panels as a minimum of 50 mm thickness.

2.6.4 Walls

Outer wall ribbed steel panels shall be minimum 1,25 mm thickness.
The inner wall panels are built of metallic insulated panels as a minimum of 50 mm thickness, interlocked or overlapped having the same characteristics of the ceiling's panels.

2.6.5 Bottom of the container

The bottom is 4 mm steel sheet as a minimum, welded to the perimeter beam and cross beams. The bottom shall be dust tight to prevent sand penetration.

2.6.6 Insulation

Container is insulated with mineral wool panels or similar. All structural frame panels are cleaned by sand blasting method. All shot blasted structural steel shall be coated with epoxy zinc phosphate primer. The whole enclosure shall be over coated with epoxy paint and a pack acrylic.

2.6.7 Heating, ventilation, and air-conditioning (HVAC)

The ECR is air conditioned. The HVAC system shall consist of a packaged air conditioner unit, cooling only, useful for outdoor installation, using scroll compressors technology, centrifugal fans, thermostatically controlled with range 25 – 40°C.

2.6.8 Lighting and socket outlet systems

ECR is equipped with a service panel integrate in PC-MCC that provide the electrical supply to all service users and internal minor equipment (HVAC, lighting, sockets, etc. ...). Sockets are 3x16+N+PE and 2x16A+PE IP 55 type.

Normal lighting 230 V - 50 Hz within the rooms shall be achieved using fluorescent high efficiency electronic Lamps 230 V – 50 Hz bulkhead fittings shall be supplied and installed on the external skin of the container above each the external exit doors.

Exterior lighting shall be enclosed into a globe and guard having as a minimum IP55 protection degree. The exterior lighting system for the access stairways and platforms, shall be provided and wired, lighting installation shall be erected and assembled at site.

2.6.9 Fire & gas alarm and extinguishing system (F&G)

A detection and alarm system, using smoke detectors, infrared detectors and manual call point, is supported by F&G Alarm Panel with output contacts for remote fire alarm and system failure indication. An alarming strobe light at each door, shall be installed.

2.7 Electrical Supply

2.7.1 Power supply by Power Generator Station (PGS)

As base configuration, electrical supply of pumps can be provided as follow:
No. 1 containerized Power Generator Station (PGS), composed of minimum No. 2 Gas Generator Sets (GGS) rated 400/230V-50Hz and able to supply the pump including auxiliary and LER equipment The power sizing is minimum 625kVA/500kW but may be increased according the finally pump configuration. The generators work in automatic parallel and there is a minimum redundancy of X+1 to ensure continuous running.

Each GGS includes:

- Gas Gen Set: number of installed GGSs will be finalized based on available and suitable frame size
- Automatic parallel system for all the GGSs (the system shall be arranged and able to increase the generation capacity adding new GGSs)
- Spare part and special tools to assure the service
- Tests and inspections at Manufacturer factory before installation
- Supervision by TCP-IP Modbus protocol for electrical parameters (power, current, energy, etc...) engine parameters and alarms (oil pressure, water, temperature, fuel level, etc...) operating hours, etc...; Here below there are the basic data of power generation set:

Engine	.Gas
Engine speed 50 Hz	1500 rpm
Rated power: **Prime Running Power (PRP - ISO 8528)** **Continuous Operating Power (COP)**	 780 kVA / 625 kW at 08 p.f. 625 kVA / 500 kW at 08 p.f.
Rated Voltage	400 V
Frequency	50 Hz

The PGS is fed directly with gas coming from the operator company's process facilities, hence it is equipped with Gas conditioning system to enhance fuel gas quality by eliminating condensate, filtering particulates, regulating pressure and controlling temperature. Depending on the fuel gas inlet conditions, fuel gas systems may be equipped with heaters or coolers.

A pressure control valves is installed, to reduce the pressure of the production gas to a constant level required by the PGS.

2.8 Outdoor Lighting

Lighting system is mounted on the skid and on the container. Floodlight florescent type suitable for the field, will be properly installed, if not available

2.9 Interconnecting system

All electrical, conduit, components and wiring are per the latest version of IEC International Standards. Cable routing inside the skid or container is laid in metallic raceways system. Interconnecting cables between equipment are installed buried and/or above ground in conduits and cable trays.

2.10 Grounding and Lightning Systems

Equipment is provided of grounding ring for connection at the ground grid by equipotential bar. Underground connection is crimped type and above ground connections is bolted type.

2.11 Piping

2.11.1 Interconnecting piping

Interconnection process/auxiliaries piping are foreseen to connect the pumping skid to the existing Operating Oil Company (OOC) 's piping installation. Material, size and schedule will be suitable for the process parameters.

Provided interconnecting piping includes:

- Piping from existing surface installation tie-in valve to multiphase pumping plant (inlet)
- Piping from the multiphase pumping plant to existing surface installation tie-in valve (outlet)
- Piping from drainage/vent of the pumping plant to the tie in valve on the existing flare (burning pit), or as advised by the Client
- Fuel piping to feed diesel/gas engine generator from diesel tanks/gas conditioning skid

The installed pipe is placed above ground and properly painted.

2.12 Tie-ins

All tie-ins are executed on the existing valves or spare connections on the operator’s battery limit.

2.13 Testing

All main components are properly tested according to manufacturer ITP, including Control and Power distribution cabinet, prior shipping.

2.14 Multiphase Twin-Screw Pumps System Design for Up To 100% GVF

The most suitable multiphase pumps system identified within the industrial commercial solutions are the twin screw pumps, which are positive displacement machines that can work independently of density and inlet pressure as well as backpressure and changes in GVF assisted by inlet separators and internal recirculating system.

The system has been proved ideal for multiphase production (rich and lean gas) to handle up to 100% GVF. During the life of the field, the multiphase flow can be controlled by controlling the speed of the pumps to manage a wide range of production scenarios. The total volume produced through the pump is a function of the required differential pressure.

The pumps systems have been designed to cope with slug flow with no impact on the operations, high GVF as well as wet gas are handled with an integrated recirculation of liquids. The compression heat is removed with the liquid recirculation. However, for lean gas flow (100% GVF) process the coolers has been included as well.

The twin-screw pumps depend on liquid availability to seal the internal clearances and remove compression and friction heat generated. Different technical solutions have been analyzed and to overcome this issue a separation, storage and recirculation system of the produced liquid has been designed. All the separators has been provided with an internal demister before the outlet to further separate any residual liquid on the gas stream. In case of need the liquid can be also sourced externally.

To this end, the Twin-screw pumps essential components such as the cooler and the lubrication oil, along with all safety devises are complimented with secondary equipment to create a complex system, which has been ensuring a continuous optimum performance of the installed pumps so far. Two different scenarios have been considered. As such, single and multiple pump installations have been properly designed and successfully installed at manifold level and close to the central process facility.

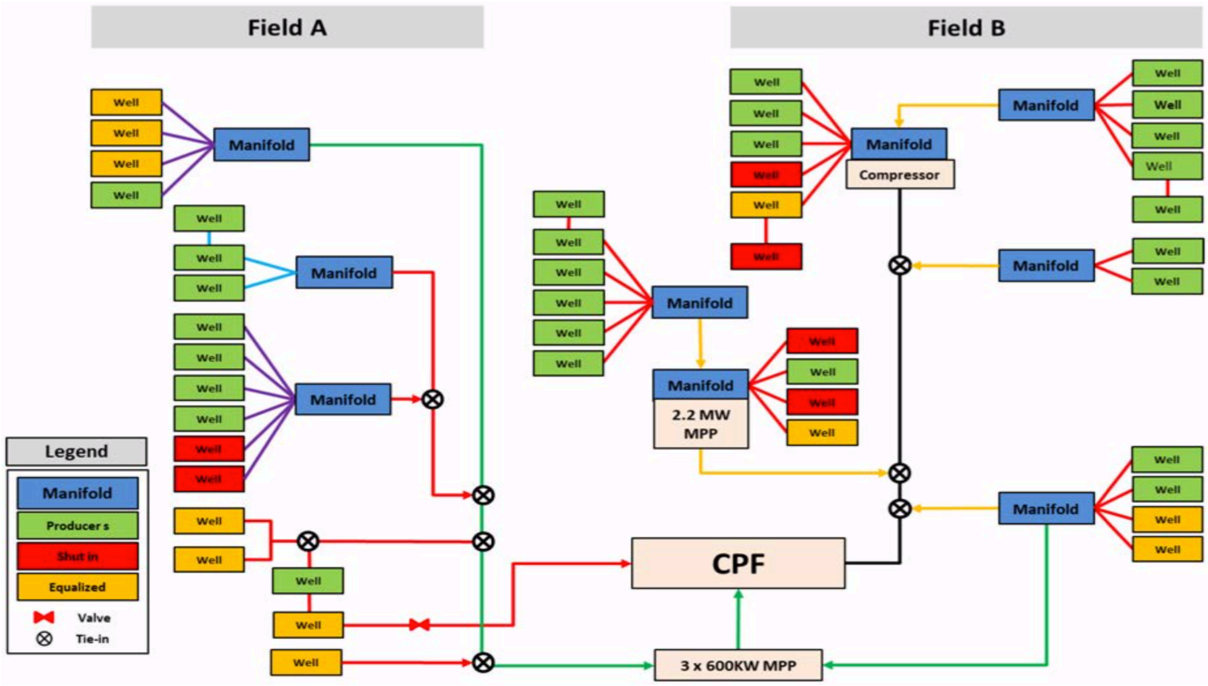

Figure 2.8 Example of Production network with Multiphase pump (MPP) (Courtesy of Bonatti S.P.A)

The pumps installed in parallel have required special attention to split the upstream flow and includes a general inlet separator to manage any potential slugs arriving from wells which is far away while provide more liquid to the recirculating system in addition to the internal separator vessel on every pump.

The basis of design for both configuration are concentrated to properly address all the fluid flow constrains and include the following components that are graphically shown in Fig. 2.9.

1. Inlet Separator.
2. Fluid manifold.
3. 3 Multiphase Twin Screw Pumps on a portable skid, that includes:
   i. 600KW Pump,
   ii. Base frame with an electric motor,
   iii. Shaft Pump Coupling,
   iv. Internal Separator or KO drum

v. Lube Oil system,

vi. Instrumentation and Local control panel.

4. Piping skid connections, safety devises and a filtering package.
5. 3 Cooler Skid.
6. 9 Diesel Electric Generators with 3 electric control rooms.
7. 3 Cabin containing the control and data transition system.
8. 4 Diesel tank, for generators fuel supply.
9. External injection point to aid the recirculating system.
10. Satellite data transmission system.

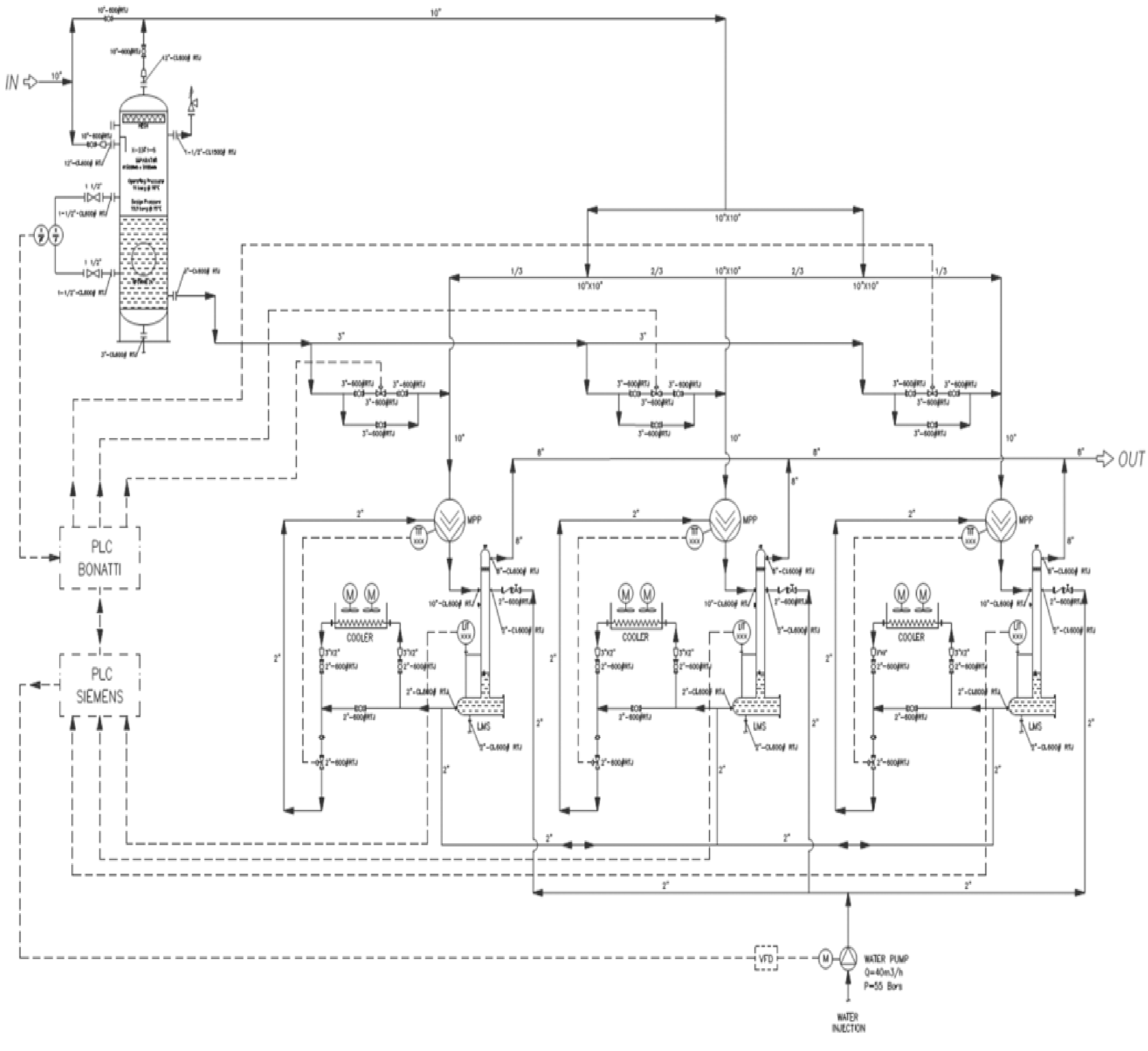

Figure 2.9 process and complete instrument diagram of three 600Kw twin screw pumps in parallel (Courtesy of Bonatti S.P.A)

For the single pump installation (Fig.2.10), the configuration and components are basically the same. The main difference is that the pump does not has the internal separator and been included externally downstream the pump. The separator provides the necessary liquid to keep the system within the temperature range and the components are presented as follow:

1. Inlet manifold system for future pumps installation,
2. 1 Multiphase Twin Screw Pump on a portable skid, that includes:

    Base frame with an electric motor,
    2.2MW Pump,
    Shaft Pump Coupling,
    Lube Oil system,
    Instrumentation and Local control panel.

3. Piping skid connections, safety devises and inlet strainer.
4. Cooler Skid.
5. 8 Diesel Electric Generators, with 1 electric control rooms.
6. 1 Cabin containing the control and data transition system.
7. 4 Diesel tank, for generators fuel supply.
8. Downstream separator and external injection point to aid the recirculation system.
9. Satellite data transmission system.

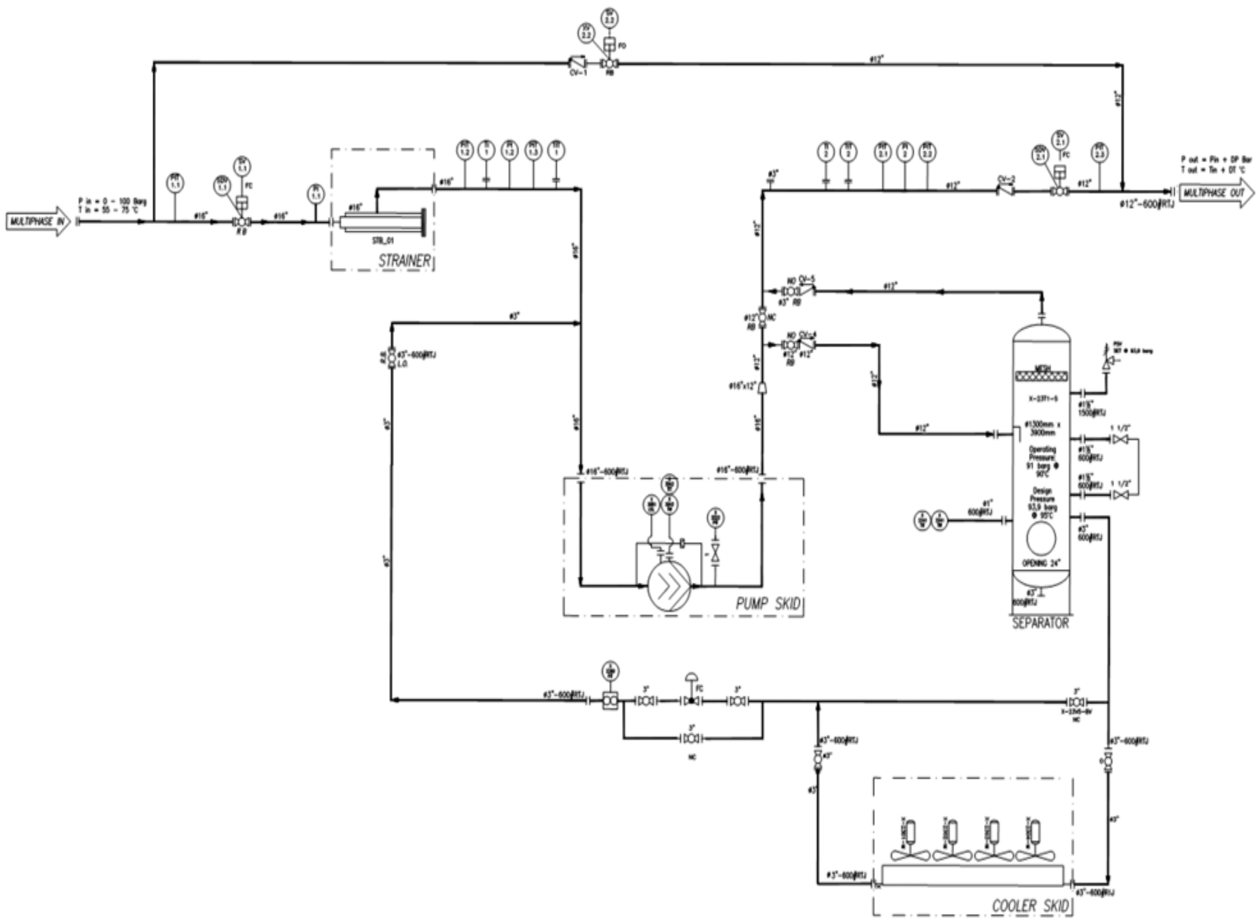

Figure 2.10 Process and instrument diagram for a single twin-screw pumps of 2.2 Mw (Courtesy of Bonatti S.P.A)

2.15 Multiphase Twin-Screw Pumps System Performance

All the multiphase pumps installed so far with different configurations and capacities have proved to be very effective to manage wells head pressure decline and flow stream with almost 100% Gas Volume Fraction while showing important production increase sustained over the time. The performance of two different systems are presented in Fig. 2.11, 2.12, with the highlighted reliability of the designed configurations.

The performance continues to improve with time although it is affected by the necessary and programmed maintenance after a certain number of hours continuous service.

The main issues that caused the down times are related to change of the pitch, material upgrade for some corrosion, mechanical seals, vibrations and some power generators issues.

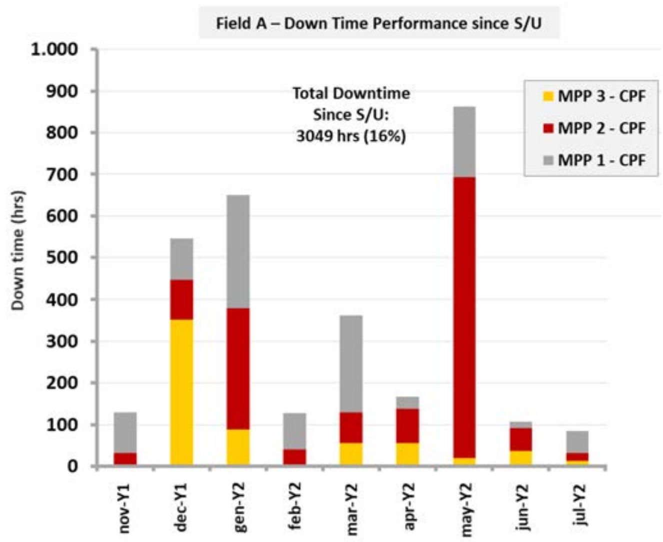

Figure 2.11 3 × 600KW MPPs Performance since start Up (Courtesy of Bonatti S.P.A)

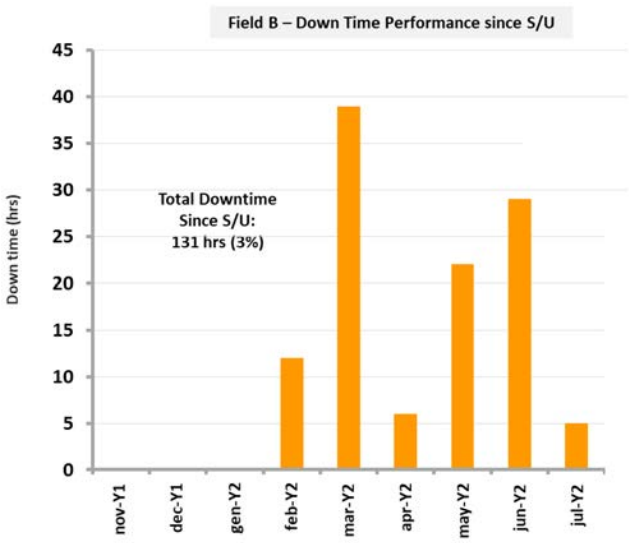

Figure 2.12 2.2 MW Pump performance since the Start Up (Courtesy of Bonatti S.P.A)

The downtime for all the pumps installed has been minimized due to a 24hrs satellite monitoring system that shows all the critical parameters in real time, while allowing data storage for trends analytics and system optimization (Fig 2.13). This provides the response maintenance team with fundamental data to either predict problems in the system or quickly assess the potential problems in case of unscheduled shut downs.

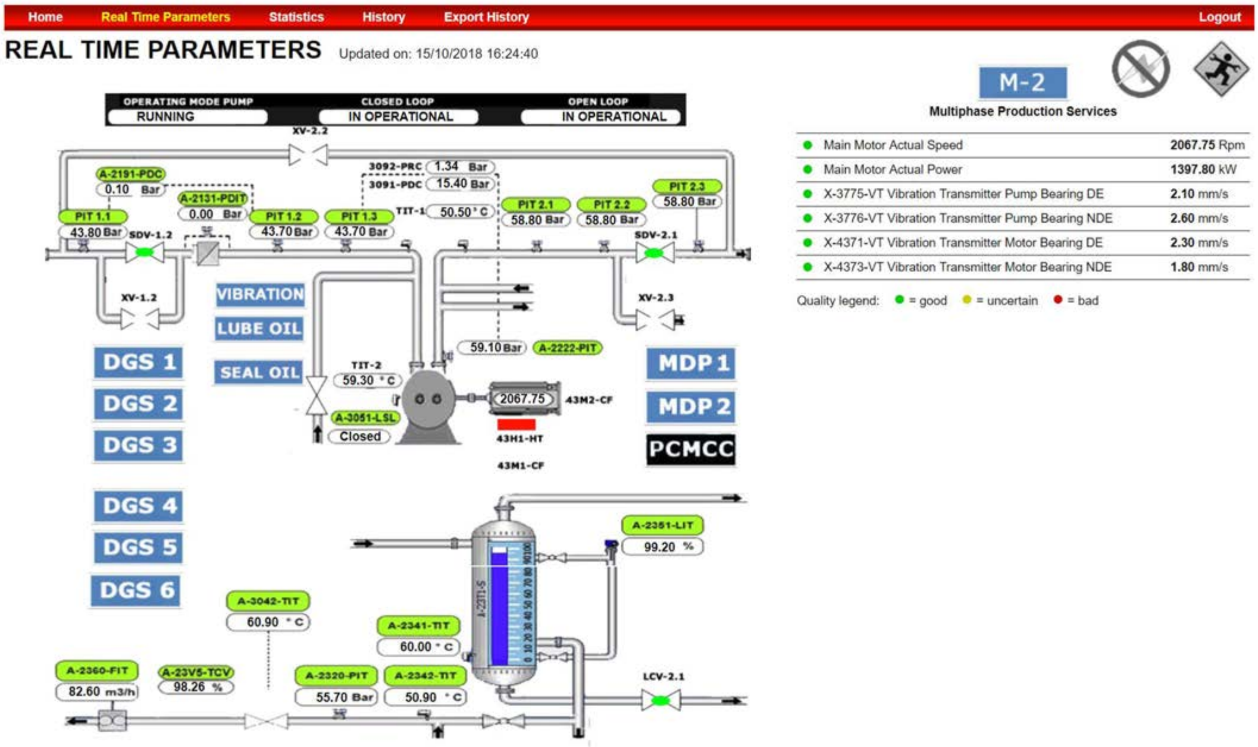

Figure 2.13 2.2MW pump system real time monitoring (Courtesy of Bonatti S.P.A)

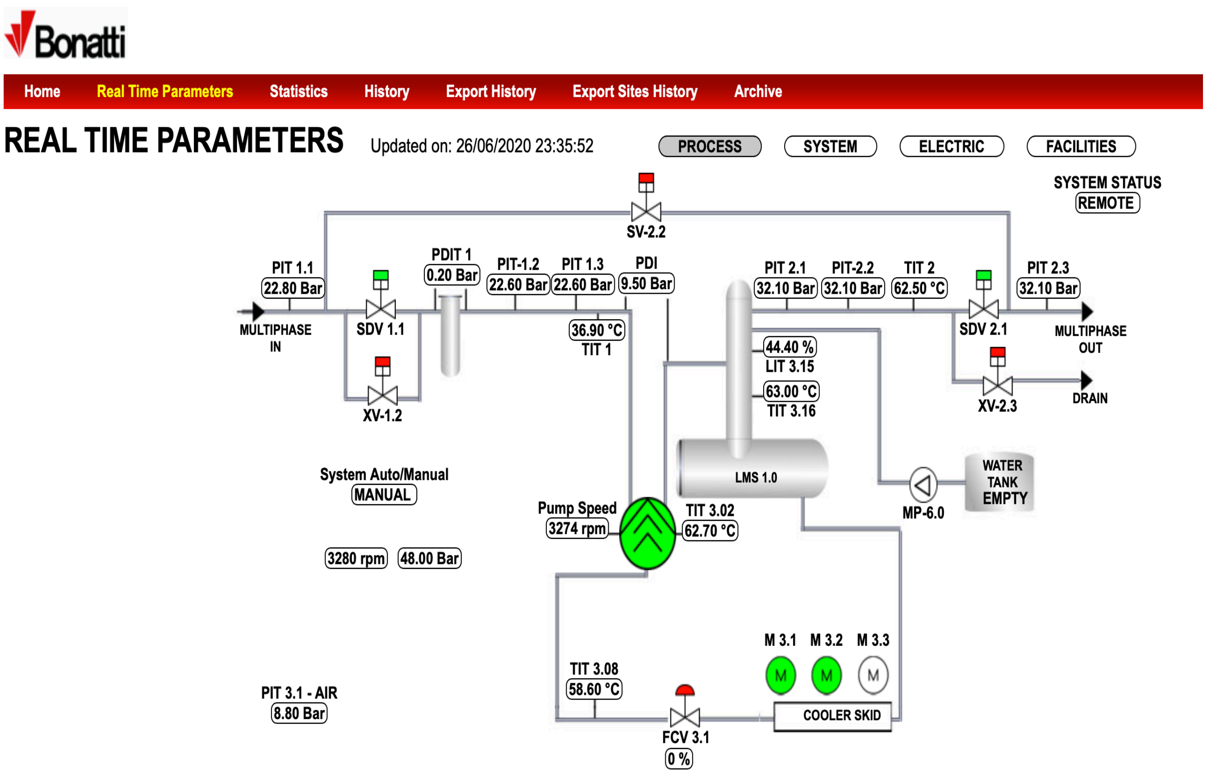

Figure 2.14 Real Time Parameters Monitoring System

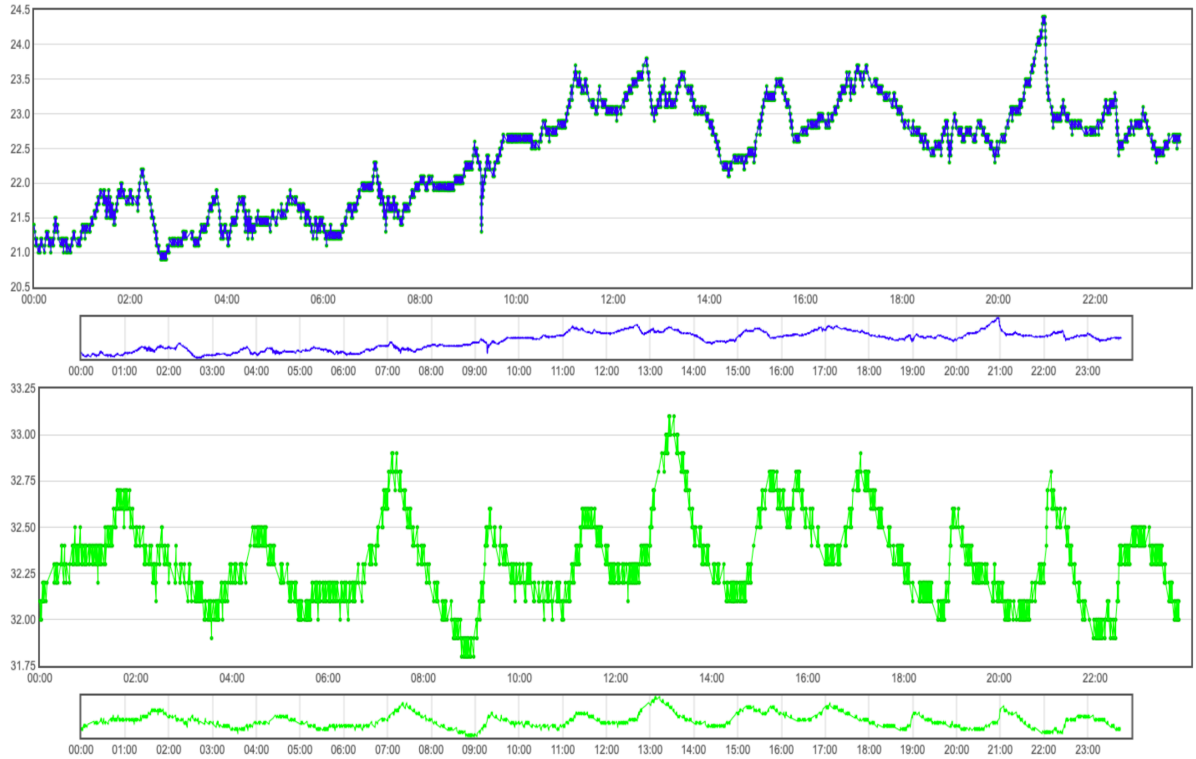

*Figure 2.15 Suction and Discharge **Pressure** Variation of an MPP*

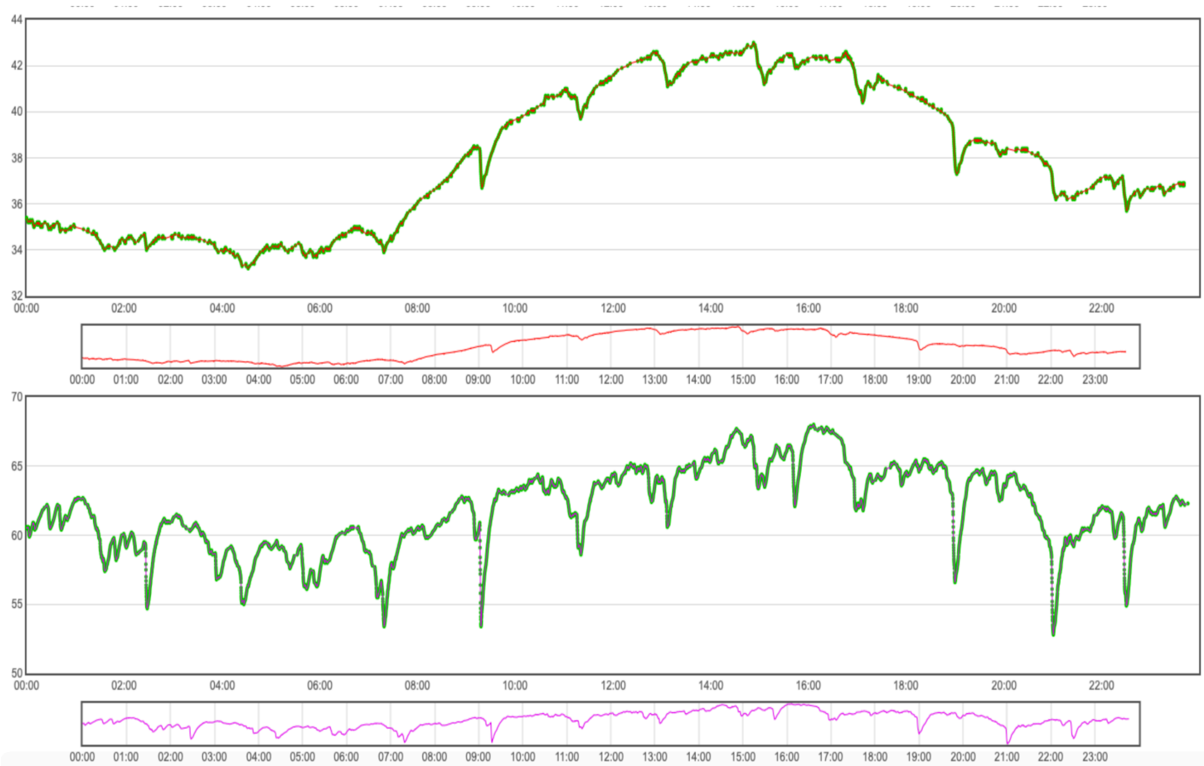

*Figure 2.16 Suction and Discharge **Temperature** Variation of an MPP*

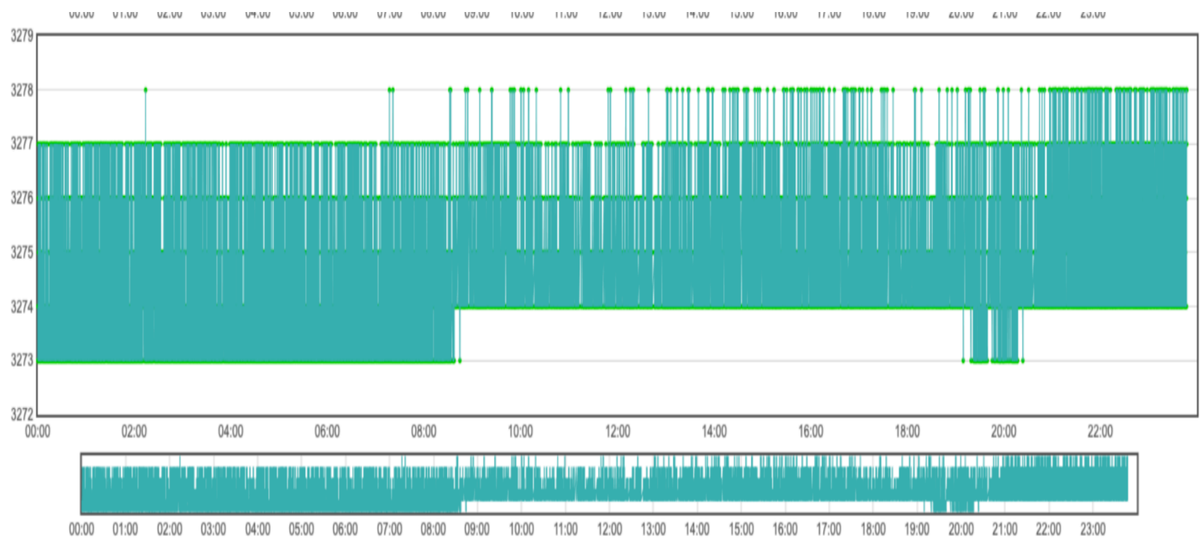

Figure 2.17 VFD Speed monitoring of MPP

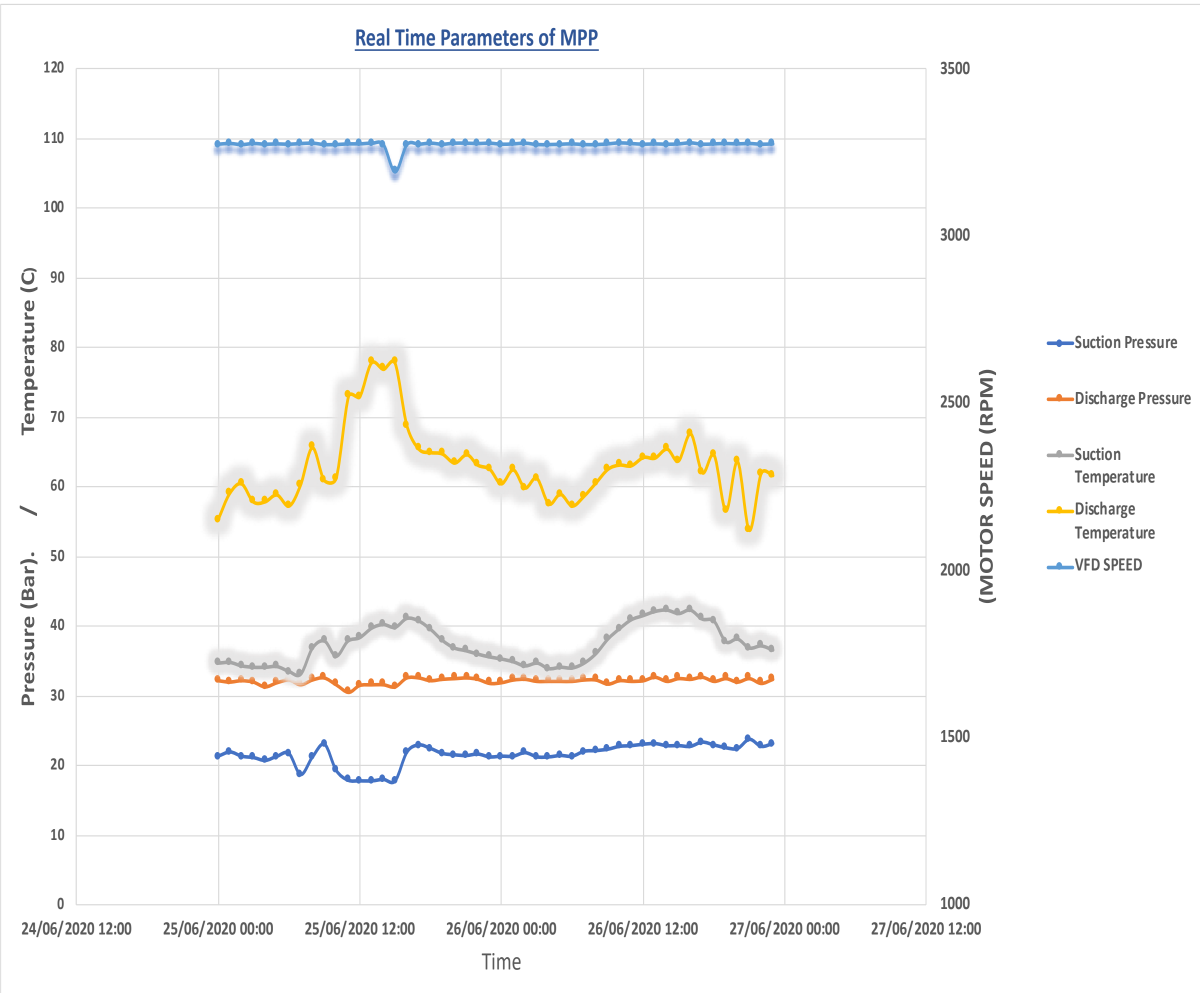

Figure 2.18 Real Time Parameters of MPP

2.16 Multiphase Pump Performance Analysis

In contrast to single-phase pumps and compressors, there is no generalized model that can characterize the performance of multiphase pumps precisely. The reason is partly that internal pump geometries are complex and very unique for each pump manufacturer. Furthermore, the various fluid properties including in-situ phase variances make a rigorous description of the thermohydraulic within the pump extremely difficult. For such causes, multi-phase pumps are characterized by performance curves of the type shown in the following figure 2.19 which is common practice. These curves are built on the basis of specified fractions of the gas volume GVF, suction pressure and liquid viscosity and density. Upon changing the inlet conditions, the curve becomes invalid therefore other curves have to be applied.

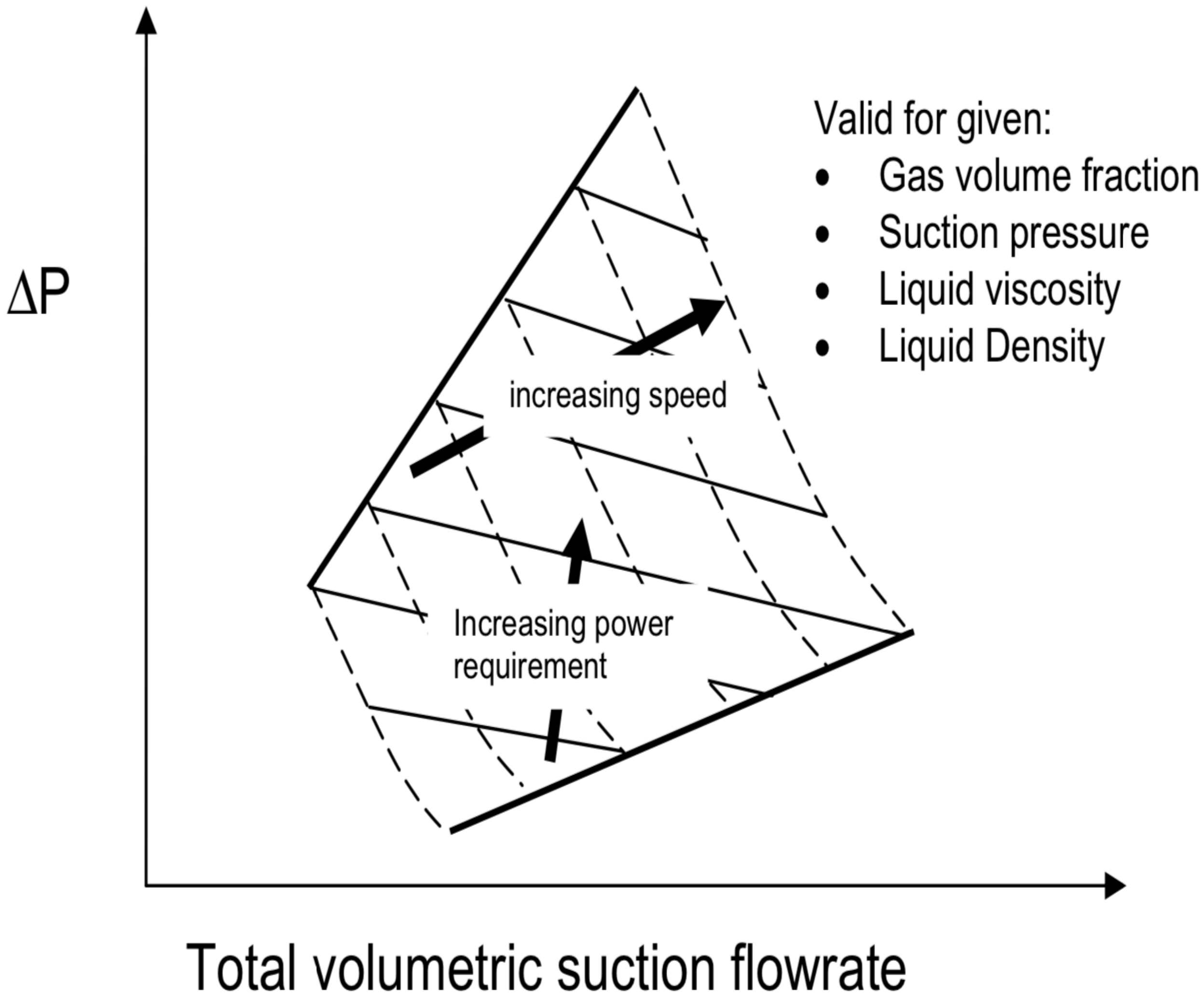

Figure 2.19 Typical multiphase pump performance curve

Commercial simulators frequently use initial conditions established upstream of the pump inlet to justify designs. For instance, if the pressure is adjusted at this reservoir or at its manifold which is situated some distance upstream of the pump, the pressure at the pump suction is dependent on the flow rate. Therefore, the performance curve cannot be used to move across this curve to explore different possible flow rates without inducing a variation in the suction pressure, invalidating the curve itself. In such cases the use of different individual curves for pumps sizing and the discovery of the operating envelope with varying conditions is inefficient and impractical. Based on this fact, there is a need for a model that adapts to those changes not solely through iterative calculations for some set of conditions, but also for sensitivities based on system parameters and the analysis of system characteristics that vary through time. The multi-phase steadystate fluid flow simulator used in the industry (PIPESIM) comprises of three types of characteristic curve models: a generic model, a two-screw model and a helicoaxial model. The most basic solution is to use the generic model which treats the multi-phase pump as a parallel liquid pump and gas compressor. The standard pump/compressor theory is useful for calculating the required shaft horsepower. Pump and compressor output efficiency can be modified depending on standard field conditions values. Because of restricting assumptions in this approach, it is only a preliminary analysis to use the generic multiphase pump model.

The performance model of twin-screw pump efficiency is a result of empirical data from observational evidence including a wide spectrum of fractions of gas volume, inlet pump pressure at suction and speed of the pump. Pump output performance at particular inlet conditions is determined using a stringent interpolation procedure that specifies the differential pressure through the pump, fluids flow rate, pump speed and pump power requirement.

Twin-screw pumps-as is often mentioned-do not provide a pressure rise, just as every volumetric pump does, but at least as long as inner backflows can be avoided a constant volume of fluid at each shaft revolution is provided. Nevertheless, the resulting increase in pressure, affects the flow rate due to internal backflows. Normally the total response of a twin screw pump is as shown in Figure 2.20.

When the pump rotational speed is increased, the response curve is transformed right to higher flow rates and steeper as it relatively reduces the backflows improving the volumetric efficiency.

When the rotational speed of the pump is increased, the response curve is translated to the right, towards higher flowrates, and it becomes steeper because relative backflows are reduced, giving higher volumetric efficiencies.

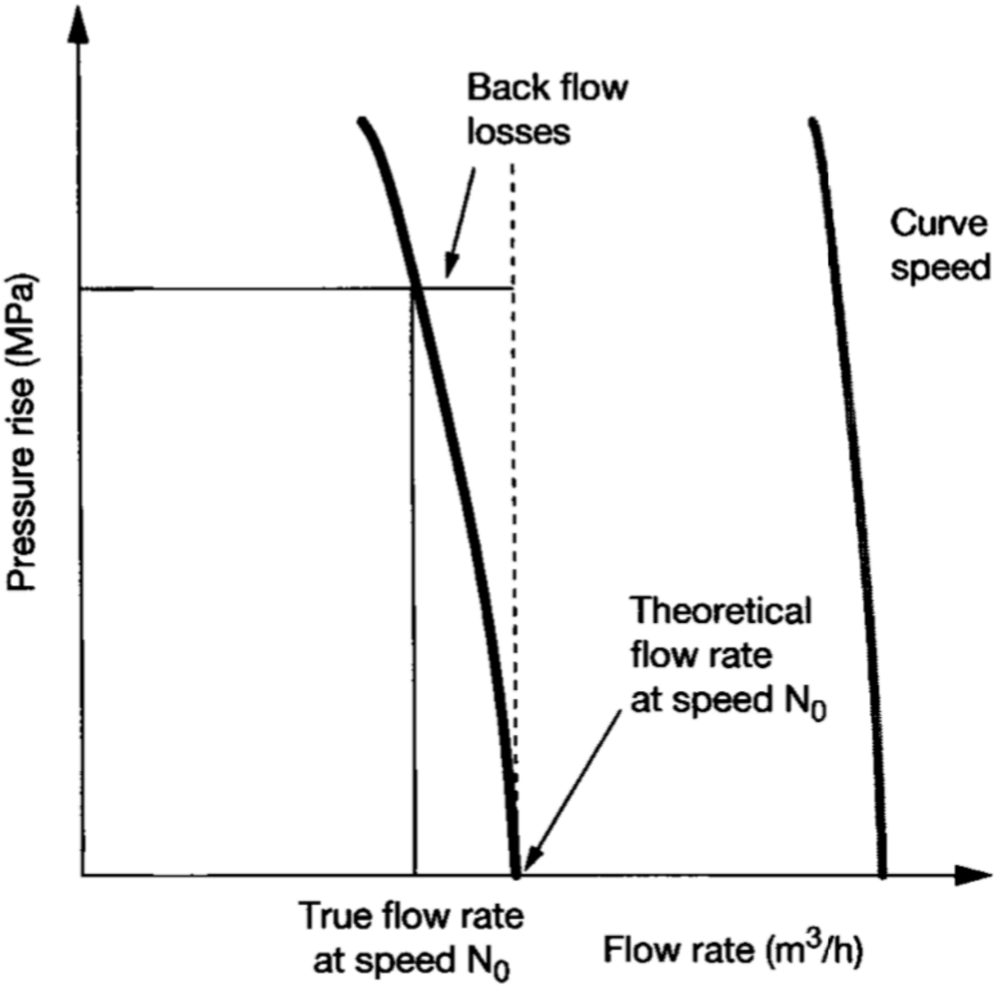

Figure 2.20 Typical performance curve of a twin screw pump

The pressure rise depends on the resistance of the hydraulic system to the imposed flow rate. As the flow path is not continuous through the pump, the upstream and downstream systems are practically isolated by the pump. The suction pressure results from the response of the upstream conditions to the flowrate taken in by the pump (piping, well and reservoir). The discharge pressure is dictated by the response of the downstream system (piping, separator, etc.)

If a valve is closed and stops the flow on the downstream side, the discharge pressure can build-up quickly and can produce serious damage. For this reason, a pressure-relief safety valve must always be installed at the outlet of a volumetric pump. In some designs of twin- screw pumps, the relief valve is included in the pump body. If the pressure increases above the setpoint, the valve opens and the fluid is re-circulated to the inlet.

2.17 Definition of Operating Domain

The main parameters which influence the selection of an MPP are:

- the gas and liquid flowrates, or a flowrate, a gas fraction (GVF) and a water fraction (or water cut);
- the fluid densities (gas and liquid);
- the required pressure rise;
- the suction pressure and fluid temperature;
- the oil viscosity at least.

These parameters must be given, or calculated, for suction conditions. The gas-liquid ratio (GLR) in suction conditions is also used instead of the GFV. In order to optimise selection of the type of pump, the materials, the sealing and bearing components, additional information on operational factors are also required:

- fluid characteristics and gas composition (presence and concentrations of corrosive components, possible wax deposition, specific heat coefficients if temperature rise can be a problem);
- possible presence of solid particles (sand, scale formation).

The gas content is often characterised by the gas volumetric fraction GVF which is the ratio of the actual gas volumetric flowrate to the total flowrate in suction conditions. The gas-liquid ratio GLR in suction conditions is also used instead of the GVF.
The GLR must not be confused with the gas oil ratio GOR, which describes the relative volume of gas and oil produced once the two fluids are brought to standard conditions.

As already mentioned, it is often difficult to specify a single duty point in oil production due to flow variations on several time scales. Short-term variations in the operating point and hydrodynamicphenomena such as slug flow, are usually handled by the natural flexibil- ity of the pump or, if required, by a flow homogeniser, a recycle loop or a control system with speed

variation to increase the possible operating domain. Medium-term variations are handled by the flow homogeniser, recycle loop or control system with speed variations of the pump.
The above parameters are often given with a range of possible variations or a profile of evolution versus time. If the variation is large, speed variation may be insufficient to cover thc anticipated operating domain. After some time, the pump may be retrofitted to adjust its characteristics to actual production, by modification of the screws for twin-screw pumps.

2.18 Pump Selection Criteria

The selection of an MPP for an application usually begins with a preliminary approach focusing on the main duty point.
The first step consists in selecting the type of pump (twin-screw, progressing cavity, helico-axial or others). This is usually done mainly on the basis of the total volumetric flow- rate (gas plus liquid) with certain additional criteria taken into account: suction pressure and pressure rise, liquid viscosity, type of system curve. Two types are often pre-selected for assessment on a cost-competitivebasis.

The second step consists in selecting a pump model from the manufacturer documentation. Manufacturers generally propose a range of standardised pump sizes based primarily on the total flowrate. At this step, it is possible to verify that the required pressure rise is within the capability of the selected pump model and to estimate the driver power. This requires an estimate of the efficiency from the manufacturer.

The third step consists in finalising the pump design to optimise the standard model for the considered application, for example to adjust the number of stages (for helicoaxial pumps), select the nominal rotation speed, perform a predictive calculation of performance, etc. In general, this step must be performed by the manufacturer. Definition of the pump operating domain is one of the outputs of this step. It is then possible to verify that this domain matches the anticipated evoluion of production with time, and to determine whether or not speed variation is required.

2.5.3.3 Efficiency

Energy losses are not governed by the same phenomena in twin-screw pumps and helico- axial pumps. Due to these differences, it is difficult to establish a fair comparison of the two concepts based on the energy consumption criteria. It is often possible to find a situation where one concept is better-suited, in term of efficiency, than the other. The actual operating point of the pump, compared to the nominal best efficiency point (BEP), also has a considerable influence on the effective efficiency of the pump for both types.

In twin-screw pumps, the mechanical energy is mainly transferred to the multiphase mixture by an isochoric process (at constant volume). The compression work received by the fluids follows a near-isothermal process. The difference between the two energies, represented by the two areas in Figure 2.21 (PV diagram) is lost by backflows and pressure drops clearances to compress the gas. The corresponding efficiency depends on the pressure ratio. It drops from some 70% at a compression ratio of 2, to some 37% at a ratio of 6, and even less at higher values. Additional efficiency losses are produced by the volumetric efficiency and fluid friction in screw clearances.

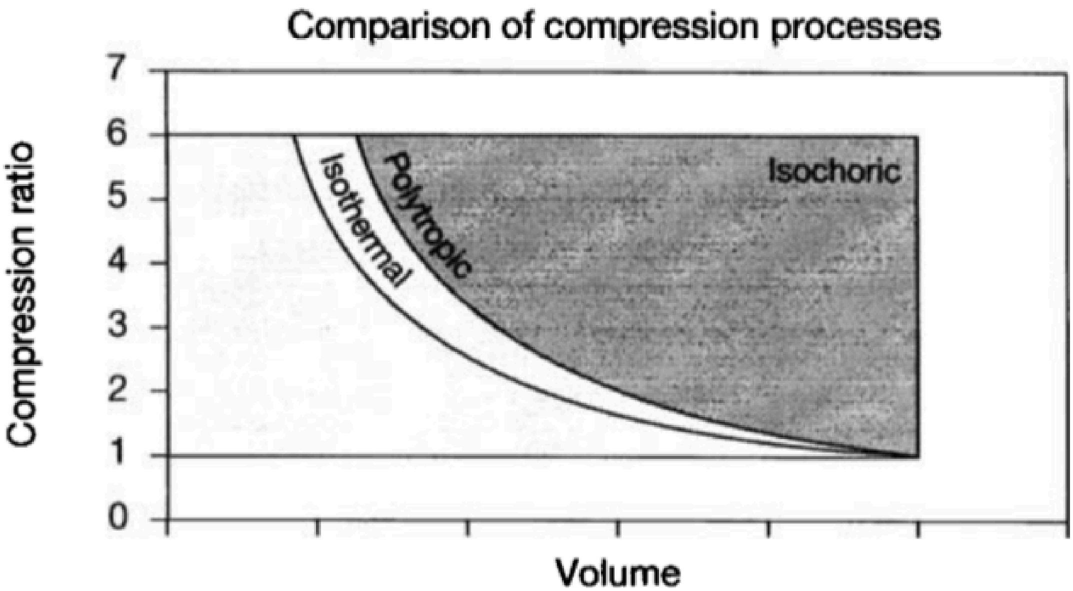

Figure 2.21 Compression work areas in a twin screw pump

Chapter 3 Challenges of Multiphase Pressure Boosting

The multiphase pressure boosting of an unprocessed crude oil poses particular issues related to various characteristics of this unprocessed crude such as:

- Changes in flow conditions and operating area over several time scales;
- The gas properties, for instance compressibility and thermo-dynamic behaviour, should be taken into consideration; as MPPs are surely hybrid machines, lies somewhere between pumps and compressors;
- Composition of the flow fluids: for instance; presence of any solid particles (production sands, formation of scales) which generate abrasion and wear to the pump internal parts, corrosive and toxic components like H_2S presence, and possible deposition of wax.

3.1 Variation of Flow Conditions

A pump is often designed to operate at a given duty point and is normally selected so that its best operating conditions or efficiency are at or close to the duty point.

In oil production, it is usually challenging to specify a single defined duty point. As flowrates, gas volume fractions, water cut %, and pressures, etc follow short term variations as well as a long-term evolution over the life of the field owing to reservoir depletion. Moreover, actual operating conditions can be different from initial predictions due to several uncertainty and operating changes. All these flow variations and uncertainties broaden the range of possible operating points. This is why an MPP must offer a broad operating envelope. For oil production, flexibility is preferable to very good efficiency optimised in a narrow operating band.

3.1.1 Long-Term Operating Domain

Over the years, the production of a field evolves. A typical profile is shown on Figure 3.1.

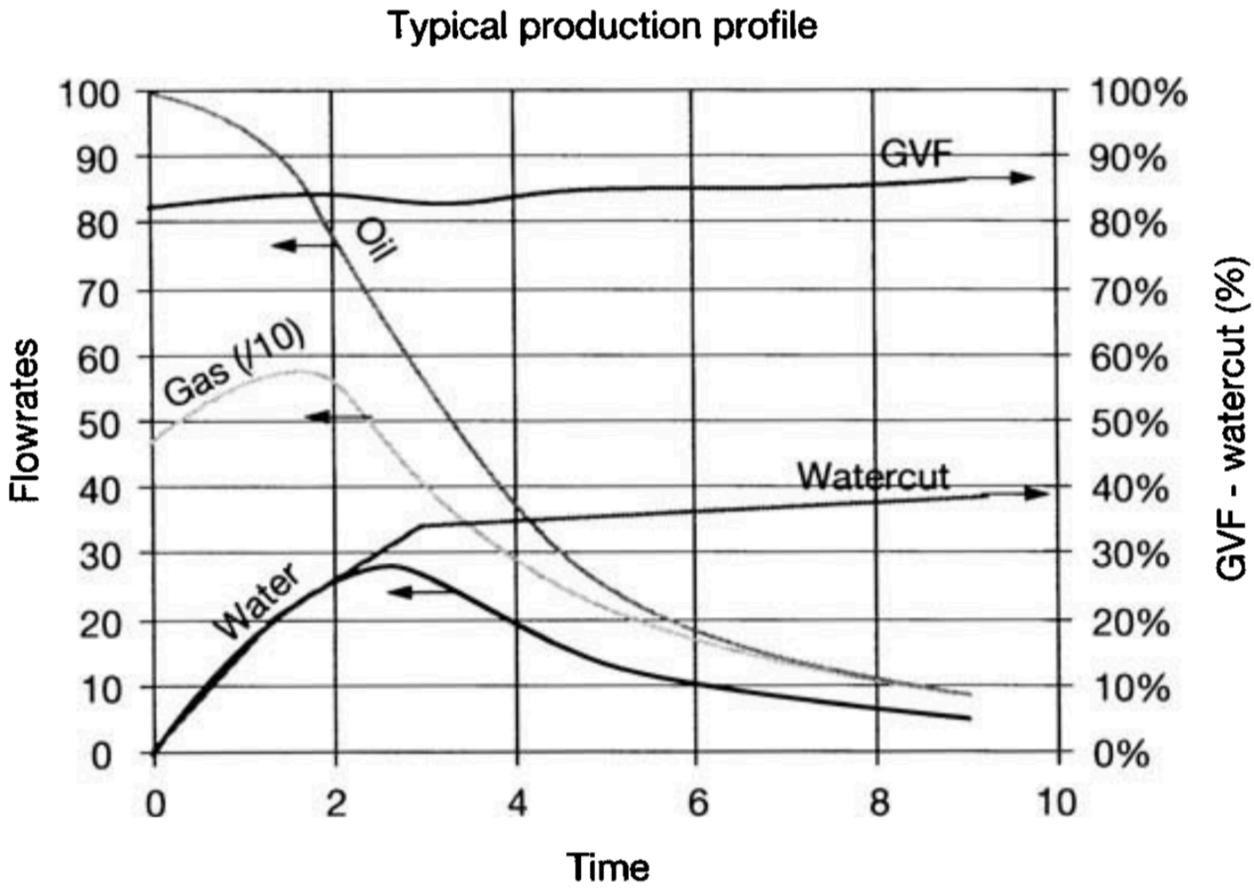

Figure 3.1 A typical production profile for long term prediction

The production profile corresponds to a set of operating points which defines an operating domain for the pump. MPP must generally accommodate wide operating domain of flowrates and GVF.

Production predictions are generally based on extrapolation from well tests and reservoir studies during the exploration and delineation phase. For this reason, flowrate and pressure predictions often contain a degree of uncertainty and actual production data may be somewhat different.

To be able to implement the needed operating envelope, a variable-speed drive may be required, and sometimes a change of the pump internals may be planned after a certain period. Retrofitting can be more economical than choosing an initial operating domain that is too large.

It can be also required if actual production is far from the initial forecasts and exceeds the adjustment capability.

3.2 Short-Term Flow Fluctuations and Slugs

Medium or short-term fluctuations of the operating point can be also observed under transient operations such as well start-up or shut-down, well tests, pipeline pigging operations, etc. Flow fluctuations on such time scales are also generated by hydraulic instabilities in wells or pipelines (hydrodynamic slugs, terrain-induced slugging, severe slugging in risers, etc.)

Figure 3.2 for instance shows a short-term record of total flowrate and pressure for a relatively stable well. Some wells may have unstable behaviour, as shown in Figure 3.3, where the well has cyclic behaviour characterised by relatively stable production periods alternating with a sequence of large gas pockets and liquid slugs. This is often observed with low- pressure wells in mature fields. The flow variations and uncertainties broaden the range of possible operating points for the pump.

In various situations, an MPP can be exposed to long liquid slugs or gas pockets. The pump group must be able to sustain high torque and high power demand in the event of liquid slugs and be tolerant to dry-running or low pressure rise in the event of gas pockets.

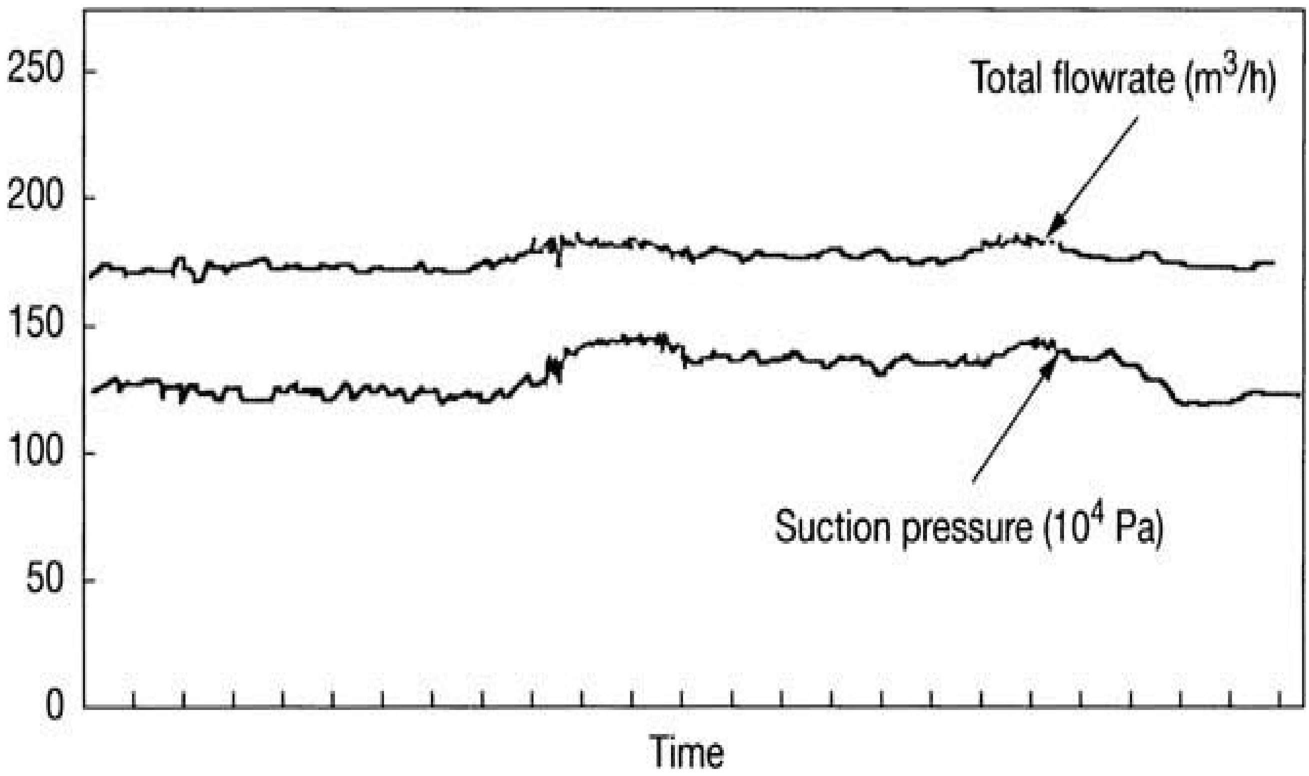

Figure 3.2 Pump Inlet Flow Variations

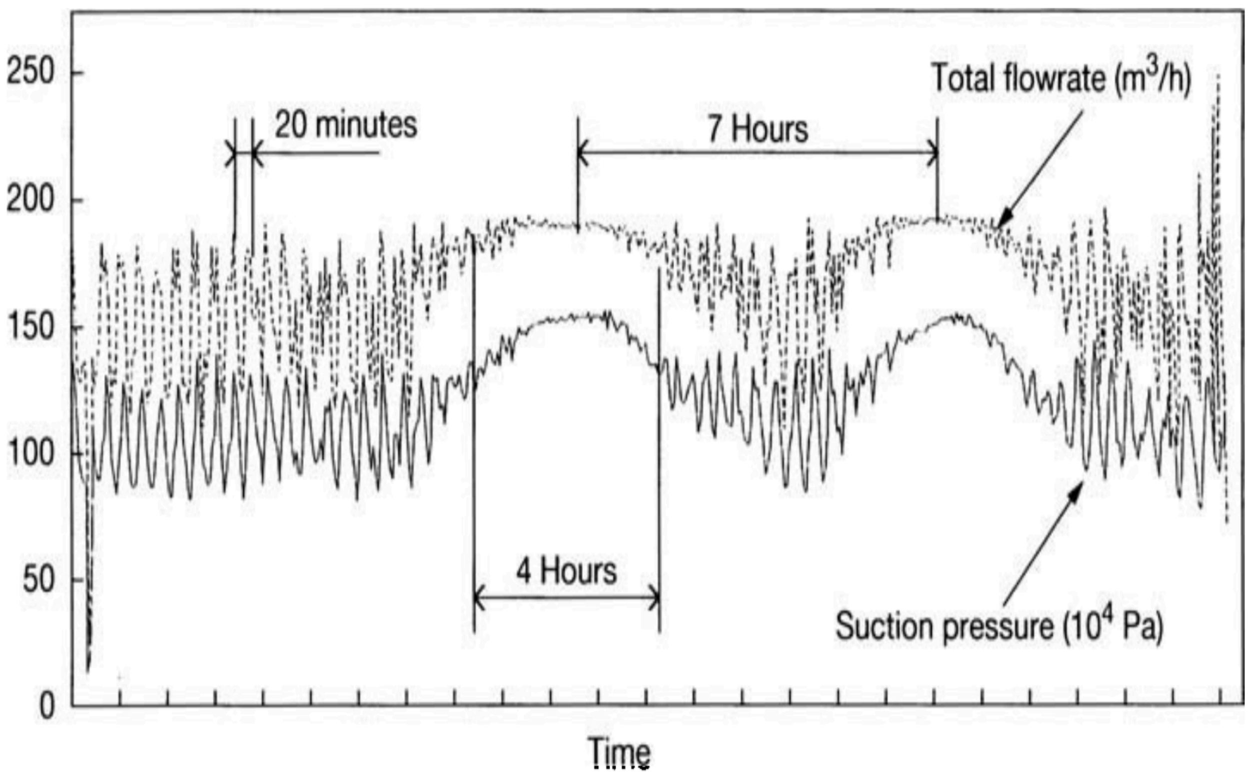

Figure 3.3 Extreme Variation of inlet parameters

It is hard to predict the length and true density of slugs. They are neither fully liquid nor fully gas. Even though some pumps can, from a mechanical point of view, run continuously from

100% gas to 100% liquid, the power required is very different for the two extreme cases. It would not be economical to size the driver for the full power at 100% liquid. The driver would be oversized and would work most of the time at partial load.

For this reason, short-term flow variations are generally managed by a "process" approach, using a flow homogeniser or liquid recycle, described below in the "process control'' section.

3.3 Gas Compressibility

The pump maximum capacity flow rate, the amount of real liquid and gas volumetric flowrates in suction conditions, is usually stated in the manufacturer's documents. The same pump can be used, dependent on the vacuum pressure, different values of standard gas mass flowrates or standard gas volumetric flowrates.

The most visible effects of gas compressibility are volumetric flowrate reduction and gas volumetric fraction (GVF) reduction between inlet and output of the MPP. Apparently, the apparent density of the mixture increases. Depending on the pump type (positive displacement or helico-axial), the significance of these effects is somewhat different.

The main effects visible of compressibility of gas are a volumetric flow rate decrease and a GVF decrease from the inlet to the outlet of the MPP. Therefore, the perceived density of the mixture increases. The influence of these effects is likely different dependent on the pump type (positive displacement or helicoaxial) which were described in the previous chapters.

There are also important consequences of the thermodynamic gas proprieties, regardless of the pump type. Gas compression, for example, causes the mixture to increase its temperature. The temperature rise in an MPP is usually low to mild as the liquid sufficiently cools the gas. However, a very high GVF mixture and the high ratios of compression, or a low flow rate, can lead to large temperature increase. The required compression energy of the gas phase also affected by gas compressibility. The corresponding compression ratio, (the rate of the discharge pressure to the suction pressure) is the important parameter that controls these results, not the pressure increase which is the same case as compressors.

3.4 Gas Redissolution

The liquid and gas thermodynamic properties can also result in mass transfer among phases during the operation of compression. It can be instant or delayed mass transfer. It is generally generated by the redissolution of the gas in the liquid phase or by gas condensation.

The gas redissolution in oil has an effect on reducing the volumetric flow rate of gas and reduces the gas fraction in the entire pump. As a result, the effect of compressibility increases again.

In the process of compression, how much natural gas is dissolved into oil is a tricky question. It is difficult to perform accurate measurements of full-size pumps and test results have shown a broad data dispersion. The process of redissolution is low however the pump has fluid transfer very quickly. Consequently, gas re-dissolution is often considered insignificant within the pump. When selecting the capacity and stage of a helicoaxial MPP, re-dissolution is often overlooked. The prediction of the pressure increase produced by the pump is required so this conservative assumption is usually made. In some cases, it can be non-conservative, for example, to make sure the flow rate does not achieve the lower limit of the pump.

In heavy oil fields produced with steam EOR, multiphase pumps are sometimes used. Due to the fact that the increase in temperature during compression is typically small, steam condensation can take place inside the pump. Unlike the re-dissolution, the steam condensation is a fast and should not be disregarded when the pump is selected. As the steam volume fraction is usually large in the vapor phase, the gas fraction reduction can be considerably significant.

3.5 Reliability and Availability

Statistics of MPPs reliability and availability have been indicated in the previous chapter which was very satisfying with minimal down time.

The main incidents which influence the reliability and availability of MPPs are:

- seal leakage: the sealing system has a major impact on pump reliability;
- bearing failures;

- wear of rotating or static components (sand);
- long dry-running.

3.6 Sealing

The multiphase mixture will fluctuate rapidly, as mentioned before. Modification of the flow composition involves many mechanical components. Elements should tolerate large gas pockets. Consequently, there are torque and power shifts in the pump and its drive in particular. The axial shaft thrust varies also with potential effects on the bearing of the thrust. Flow composition variations also play a significant influence upon certain critical components such as seals.

Multiphase Pumps have either single or double mechanical seals. Inside the mechanical seal, the two sealing faces move relative to each other, in direction normal to the rotating axis. These faces has to be lubricated by an intermediate fluid that is usually the injected oil. For a long time, mechanical seals were used in pumps and gas compressors under almost static conditions. Inside the multiphase pump, flowrate variation and gas fraction changes as well as solid particle presence lead to severe operating conditions for mechanical seals.

Carbon graphite or silicone carbide are used to manufacture the seal faces. Seals made of carbon graphite are more susceptible to solid particles induced damage but can tolerate the temporary lack of lubricant. Silicon carbide scales are resistant to wear and are recommended when there is sand, but they need permanent lubrication which with single seals is difficultly guaranteed.

In the case of double mechanical tables, the lubricant fluid usually is used as an intermediate barrier fluid. This fluid is slightly pressurized to prevent the liquid leakage and to lubricate the faces using the clean fluid. To prevent the lubricant loss in the processing fluid, the differential pressure must be controllably limited.

When any leakage in the seal can lead to a poisonous or explosive environment, such as if the pumped mixture contains H2S or if the pump is placed in a locked area or container, double mechanical seals are highly recommended.

Steady-State PerformanceAnalysis

2.5.2.1 Characteristic and System Curves

In steady-state conditions, pump performance is usually described by a set of curves which provide the pressure rise (or head) and efficiency (or power) versus the flowrate at constant speed. Curves are sometimes given for several rotation speeds. When a single speed is available, affinity laws enable the adequate data to be derived.

The pump must deliver a pressure rise which boosts the flow in the production system. The required pressure rise depends on the flowrate and can be calculated from the difference in responses of the downstream system (export pipeline plus receiving separator) and the upstream system (piping, well and formation). The resulting curve is the system characteristic. The system characteristics generally have a positive slope since pressure losses in pip- ing, valves, chokes, etc., increase with flowrate. In multiphase flow, this is not always true due to the influence of the liquid hold up.

The system curve is given by the difference between the discharge pressure required to boost the fluid at a certain flowrate in the downstream pipeline and the available pressure at suction for that flowrate in the pump. The pump operating point is located at the inter- section between the pump characteristic curve and the system characteristic curve. If the system characteristic curve is modified (addition of a well, restriction of flow by wax or scale deposition, increase of water cut, etc.), the operating point changes. If the character- istic curve of the pump is modified (change in rotation speed), the operating point also changes. This is true for any type of pump, including positive displacement and helico- axial.

Pumps are usually designed for a given duty point on the system curve.

Flow stability requires that the slope of the pump curve is negative at the intersection point. This is always the case with a positive displacement pump.

Parallel and Series Operations

Parallel operation of volumetric pumps does not raise specific problems. However connection of volumetric pumps in series must be approached with care. Theoretically,the use of two pumps enables a degree of energy saving, since the capacity of the downstream pump can be reduced.

As the flow is compressible, the volumetric flowrate is reduced at the discharge of the upstream pump. The inlet volumetric flowrate of the downstream pump must be set accord- ingly. If this flowrate is too low, the intermediate pressure will increase dangerously. If this flowrate is too high, the intermediate pressure will decrease. In practice, the intermediate pressure is unstable and the rotation speed of one pump must be controlled.

2.5.4 Transient Behaviour

In actual field conditions, an MPP must be able to handle several typcs of unsteady or transient flows in operating conditions. In these conditions, the pump must not impair the stability offlow.

Good knowledge of transient behaviour is required when establishing operational proce- dures such as shutdown or restart, but also when selecting and designing the control system. Transient behaviour depends on the complete production system and is influenced by the control system.

The usual approach is to study the response of the system to sudden changes in flow parameters such as flowrates, gas fraction, pressurc, etc. A more sophisticatedway is to sim- ulate performance in slug flow and with certain specific process trips, incidents or failures, such as a sudden shutdown of a well, closure of a downstream valve, or a sudden loss of drive power.

Such studies are made easier by the availability of a multiphase pump performance model coupled to a dynamic process simulation software or a transient pipeline multiphase flow simulation code.

2.5.5.3 Process Control

Well flowrates at a given time depend essentially on the wellhead flowing pressure (WHFP). As the pump discharge pressure is appreciably constant, as explained above, flow fluctua- tions mainly involve suction pressure fluctuations which in turn will affect well production.

In normal conditions, a constant oil flowrate is generally required with a pump operating at constant speed. To keep well output constant, the pump rotation speed can be controlled. A speed reduction (or rise), decreases (or increases) the pump differential pressure. The suc- tion pressure will therefore rise (or fall) to balance the influence of the flow fluctuations.

However, fixed speed installations are possible as long as one can tolerate a certain amount of back-pressure fluctuation in the wells (or the upstream pipeline, if any) and in field production. For more critical applications,variable speed drive allows full process control.

A first level of process control can be achieved by manual adjustment of the pump speed. The field operator can, every day or every week, set a predetermined speed to produce the required output.

A manual control system can still offer the required mechanical protections, but it only allows manual speed setting. The system will not by itself be able to adjust the speed auto matically. The pump will either run at the pre-determined speed or be shut-down. Obvi- ously, the speed setting can be changed manually by the operator at any time. Such control would also enable adjustments to be made over a period of time to balance out the natural depletion of the field.

More complex process control can also be accomplished by automatically controlling the pump speed. This allows the operator to set and maintain the required level of production by avoiding influences fiom upstream or downstream disturbances such as changes to controlling valves, chokes, well control, and avoiding unnecessary shut-downs.

In some cases, fixed-speed operation provides enough operational flexibility. In other cases, where back-pressure control on the wells is more critical or where adaptability to evolution of operational parameters is essential, a variable speed system is preferable. Pump control and monitoring can be more or less sophisticated depending on the application, expected well behaviour, pump redundancy, importance of maintaining a continuous production flow, manned or unmanned facilities.

Fixed speed service provides gives operational flexibility in some situations . In addition, where backpressure regulation of the well is more important or as adaptability to operational parameter evolution is necessary, it is desirable to use a variable speed system. Based on function, planned well performance, redundancy of the pump, the importance of maintaining continuous production, manned or unmanned facilities may require more or less sophisticated pump control and monitoring.

3.7 Solids and Sediments Flow Control

Sand production is among the serious challenges facing oil and gas producing wells. There are several instances in which wells produced no sand before water production starts, then produced inappropriate quantities afterward. The major two phenomena which are: movement of water-wet fine and relatively permeable effects lead to the increased production of sand. Majority of formations' fines are water-wet and therefore stable if a hydrocarbon phase is the only fluid produced because most of the pore space is filled with hydrocarbons. But as the water saturation increases up to the point that the water moves, the formation fines start to move with water, which leads to localised plugging in porous media's pore throats. Therefore, if there is two-phase flow, a rising drawdown exists, since two fluids that flow together have greater flow resistance than any fluid alone. The abovementioned relative permeability effects can lead to an increase of drawdown as much as 5 per production unit around the well. The result that fines migration, pore throat plugging and a decreased relative permeability around the well raises the drawdown such that exceeds the formation strength. Excessive production of sand will result. Fines migration and sand production varies from formation to another affected by whether the formation produces gas or liquid.

Unconsolidated reservoirs and extreme drawdowns of wellhead and bottom hole pressure may deliver a considerable contribution of solid production. All types of surface equipment are sensitive to solid production due to their severe abrasion and wear effects.

Given the presence of tight clearances between pump screws, the screws and liner, a potential damage can be caused to the pump by solids abrasion which opens gaps of 10th of millimeters size, leading to increasing fluid back flow which can be hardly compensated by pump speed increase but not for long time. As a result, removal of solids upstream of the multiphase pump is a necessity which must be achieved. Therefore, single pots filtering packages have been installed successfully to eliminate any solid particles in the flow with size bigger than 70 microns.

A double acting seal design is used to increase the seal life. In order to achieve this target, the clean barrier fluid is providing an optimum operational environment for the seal. This barrier fluid protects against produced solids. The wear rate is, among other parameters, dependent on grain size and absolute quantity of the sand present in the pumped fluid. Therefore, effective protection against excessive wear is an important factor for extending the mean time between maintenance. A surface layer with effective wear protection and good bonding with these materials is essential. Sand particles tend to break through the thin hard surface. As a consequence, tungsten carbide was applied on screw tips and hard chrome to the liner. In case of no precaution in this regard, pump internals may need exchange after only few months. Different treatment procedures and materials should be taken into account for CO2 and H2S production.

3.8 Case study of Pump Failure due to solid Particles

Pump Running Hours	227
Pump RPM	1640.32
Suction Pressure (bar)	26.8
Discharge Pressure (bar)	55.10
Discharge Temperature (°C)	74.40
API Plan Pressure (bar)	65.40

This multiphase pump with the operating parameters mentioned above tripped due to electrical shut down

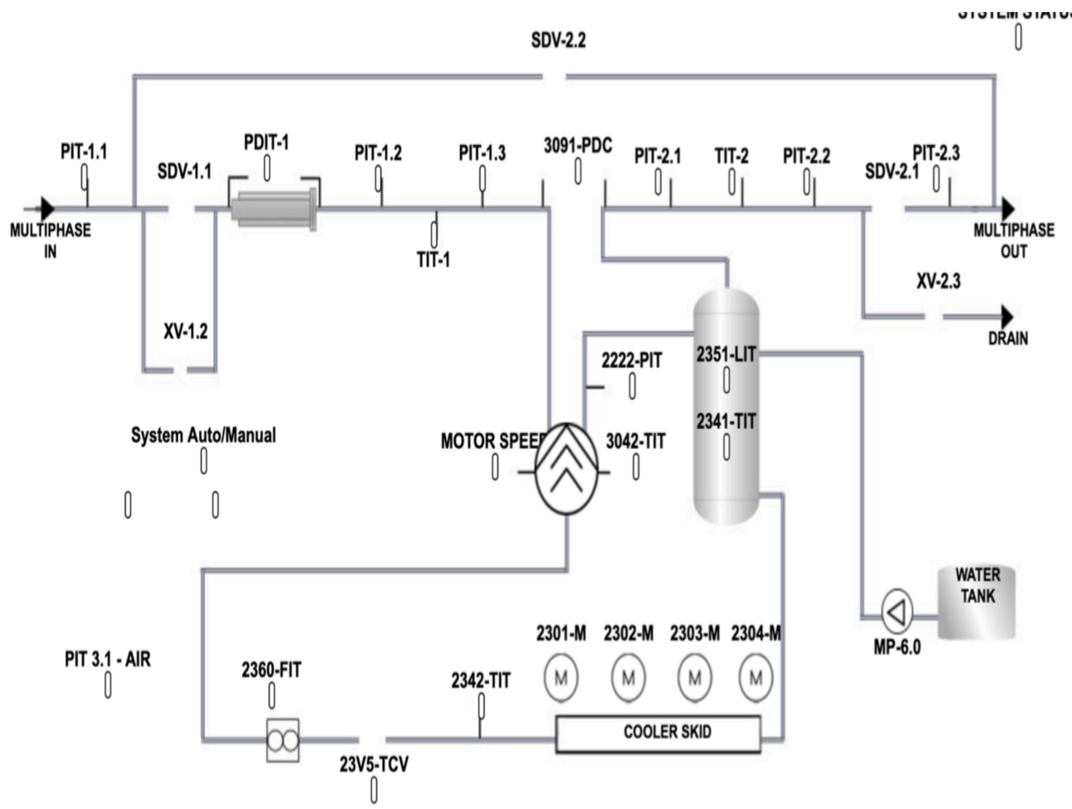

Figure 3.4 Pump Plant Scheme

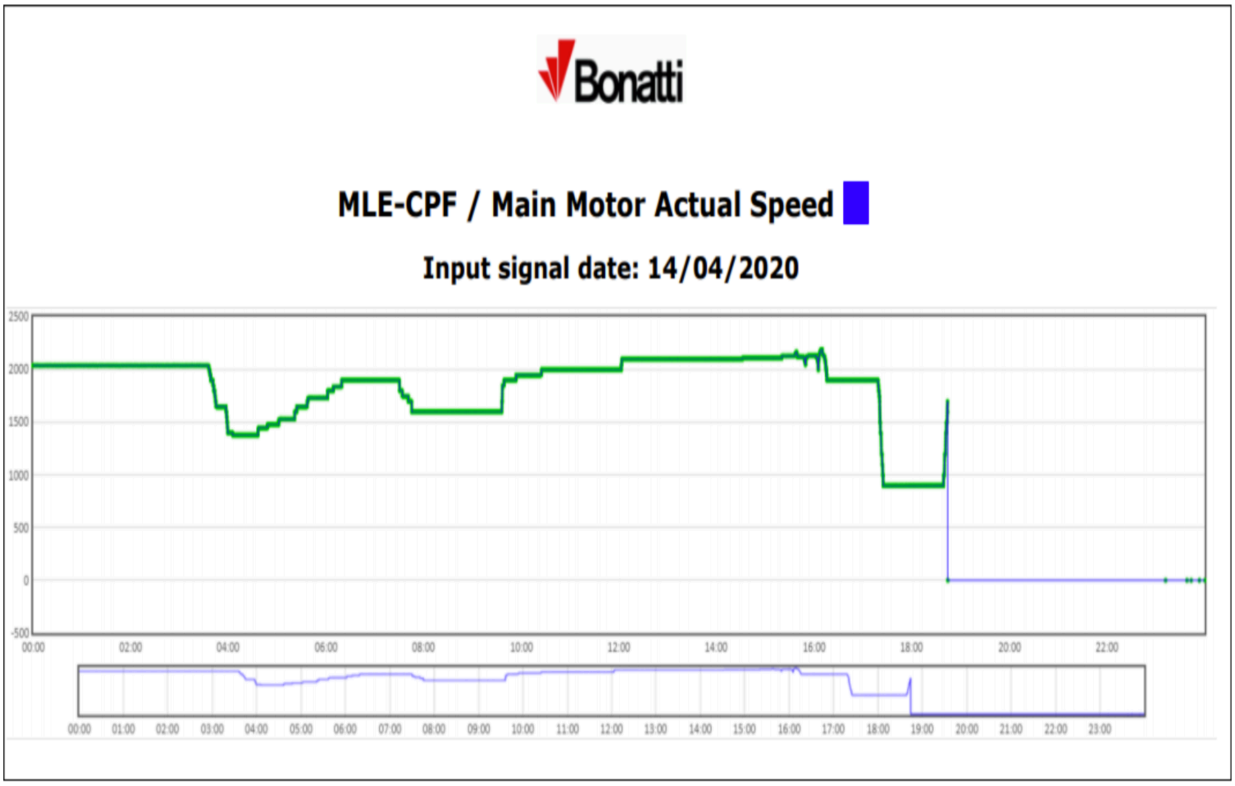

Figure 3.5 Pump Motor Speed (RPM)

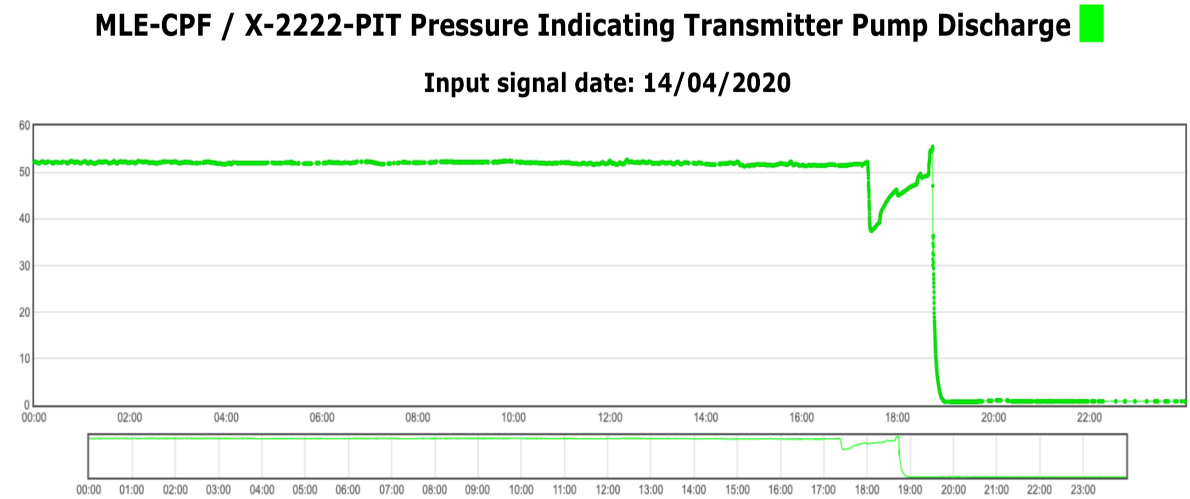

Figure 3.6 Pump Discharge Pressure Profile

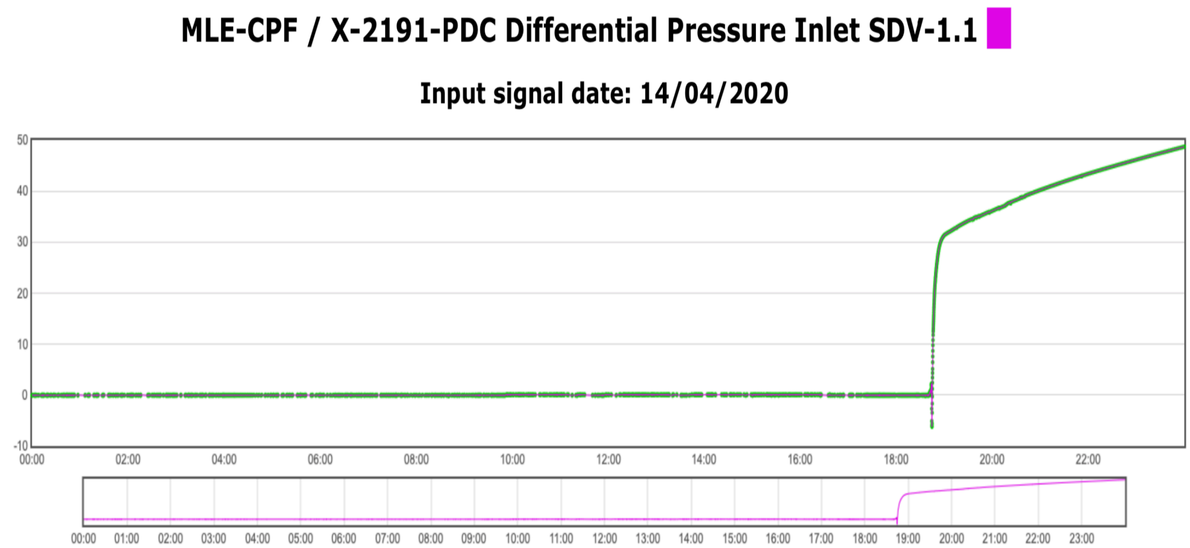

Figure 3.7 Shut Down Valve Pressure Differential

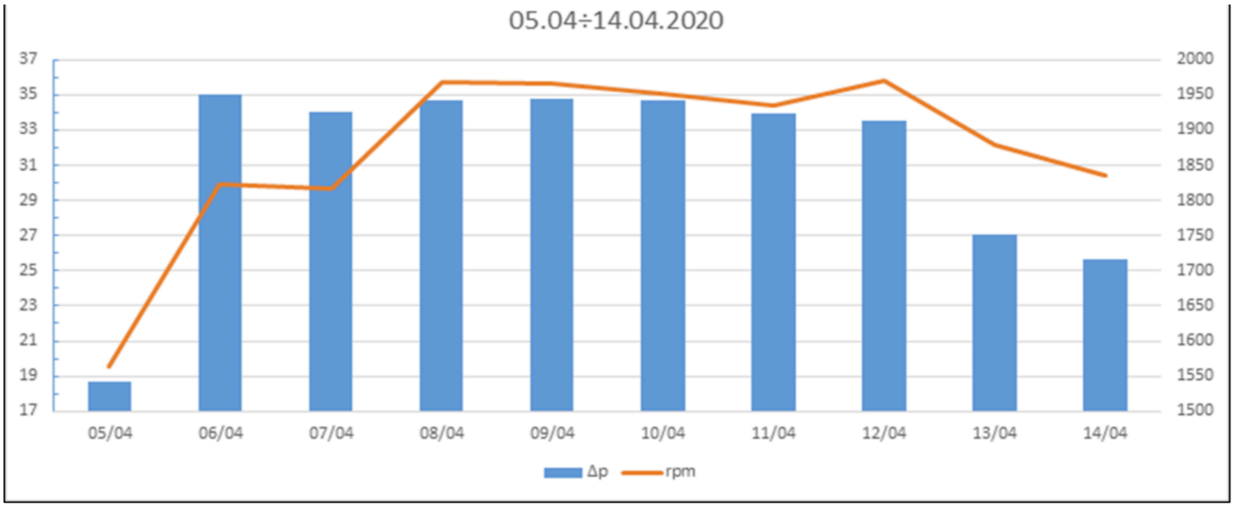

Figure 3.8 Pump Performance up to failure

After pump examination, severe erosion has been detected due to solid particles

Figure 3.9 Stationary ring gasket completely damaged

Figure 3.10 Shaft sleeve gasket splitting pattern and tear out

Figure 3.11 NDE (Non Drive End Bearing) (Driving shaft side)

Figure 3.12 DE (Drive End Bearing) (Driven shaft side) top view

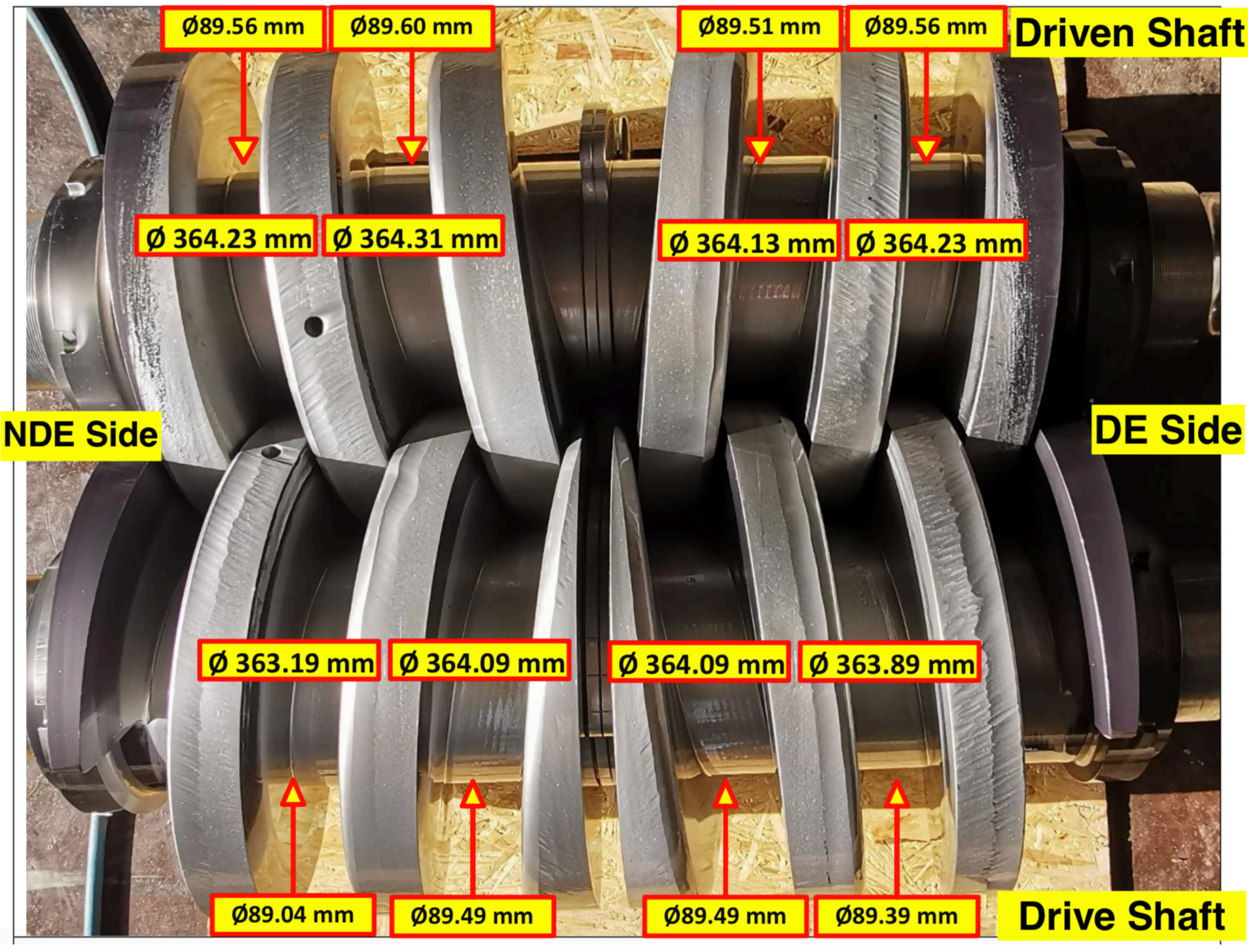

Figure 3.13 Pump Shafts with erosion evidences

After reviewing the pump status upon failure and studying what kind of solid removal technique was already in place, my team started to look for reliable solutions for this serious problem within viable industry techniques. Many techniques from Schlumberger Wellhead Desander Cyclone, Suzler Sand Removal Cyclones, and other companies' techniques.

Upon verifying the viability of each technique, its suitability for the pumping site and its cost, the team decided to go for "Triple Sand Catcher" as per the following figures. As this technique provide a simple way to remove sand while having more than flowline so if a line needs maintenance, production should not be interrupted. As well, this technique is cost effective and proved its effectiveness in many other sites in Italy.

The filtration unit is constituted by n° 3 filter with a horizontal axis positioned on a skid. The filter is a particular type of trap having a cylindrical shape and an internal basket with suitable mesh.

It consists essentially of the following components:

- an outer casing flange having a length of about 3.5 m, diameter 10";
- a filter 8" constituted by a perforated tube over its entire outer surface, which allows to retain the solid particles with a particle size from 1 to 25 mm.

Table 3-1 Desander Specifications

General Features	
Skid length	6400 mm
Skid width	2500 mm
Skid height	3050 mm
Total weight	8500 kg

The equipment is H_2S service.	
Design Features	
Working pressure	95 bar
Temperature	- 10 °C : 80 °C
Capacity of each element	255 liters
Grain size	4 : 25 mm

Figure 3.14 Triple Sand Catcher

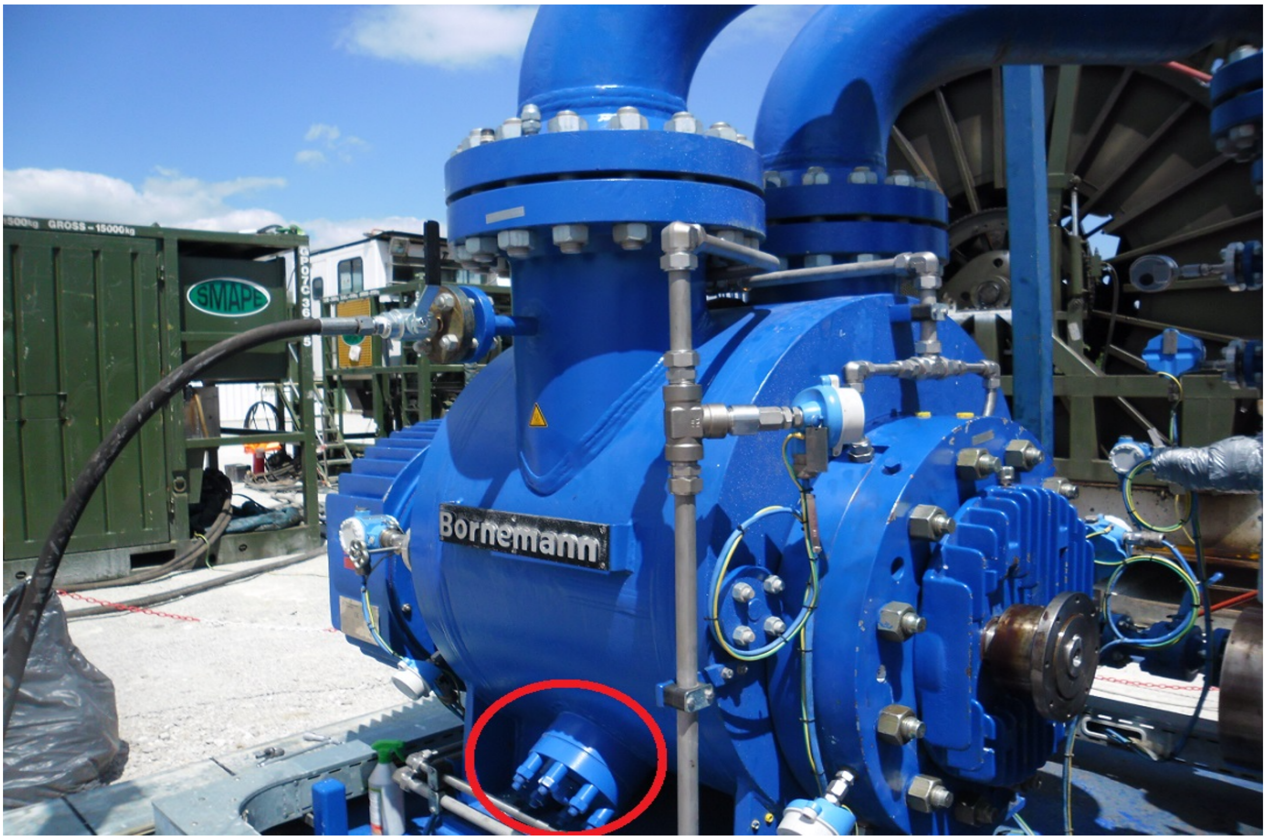

Figure 3.15 New installed pump with Sand Removal Technique

Chapter 4 Nodal Analysis Study

The system analysis in petroleum Engineering which is used for the calculation of system pressure and fluid production rates is referred to as 'Nodal Analysis'. It is commonly used in oil production technologies to address problems concerning multiphase flow in wells and pipelines.

Fluid characteristics vary with the pressure which is dependent on location and temperature in the petroleum production system. In order to simulate the flow of fluids in the system, it is required to “divide” the system into some discrete nodes which Separate system components (different equipment). The fluid properties of the elements are locally evaluated.

The performance of the production well is affected by such interconnected elements which play a vital role in maximizing the production well performance and efficiency:

- Reservoir’s Pay zone
- Type of Completion (e.g., perforation, sand gravel pack, etc.)

- Configurations of tubing system (e.g., length and size of the tubing, degree of inclination, existence of safety valve, any flow restriction, etc.)
- Surface network components, (e.g., flowline length and size, presence of chokes and their configurations, etc.)
- The first separator pressure “p_{sep}”

Well performance will be altered and impacted by any variation in the abovementioned well system components. The system analysis of the production well flow is, typically referred to as NODAL™ Analysis (which is a trademark of Flopetrol Johnson, Schlumberger Technology Corporation subsidiary, and is registered as a US Patent #4442710). Nodal analysis is described as an approach system to combine the components listed above into one unit consisting of a suitable number of Nodes. As fluids flow from the reservoir pay zone towards the central separation facilities, all possible nodes of the wellbore production system begin with either the reservoir pressure “p_r” and ending with the first separator pressure “psep”. The detection and placement of nodes is strongly linked to the pressure drops of the fluid flow across different components of the well structure. The total pressure drop in this flow system consists of the following seven different pressure losses as can be shown schemetically in the figure:

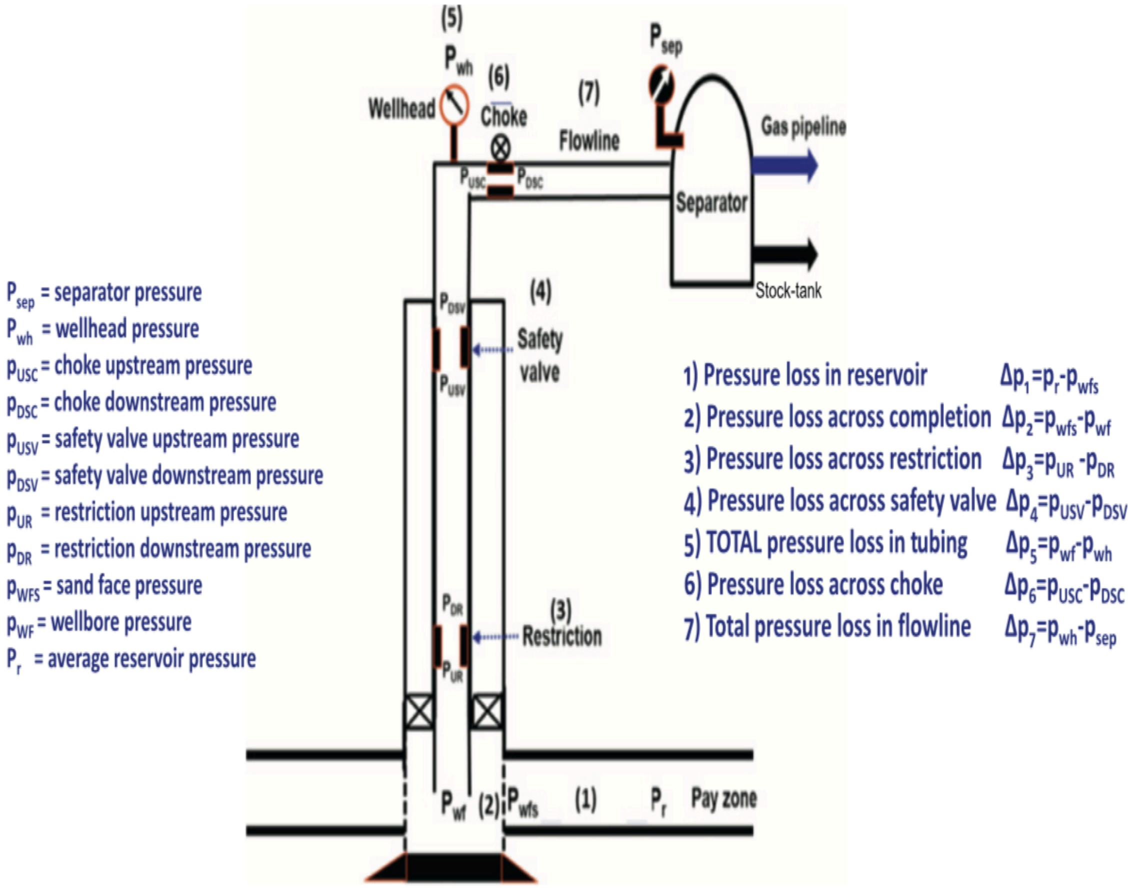

Figure 4.1 location of All 8 possible nodes in the well production system

1) Pressure drop inside the porous media: $\Delta p_1 = p_r - p_{wfs}$

2) Pressure drop through completion: $\Delta p_2 = p_{wfs} - p_{wf}$

3) Pressure drop through restriction: $\Delta p_3 = p_{UR} - p_{DR}$

4) Pressure drop through the safety valve: $\Delta p_4 = p_{USV} - p_{DSV}$

5) Overall Pressure drop in Tubing: $\Delta p_5 = p_{wf} - p_{wh}$

6) Pressure drop through surface Choke: $\Delta p_6 = p_{USC} - p_{DSC}$

7) Overall Pressure drop in Flowline: $\Delta p_7 = p_{wh} - p_{sep}$

The overall pressure drop "Δp_{total}" is the total addition of every single pressure drop in every single component of the well production system, which is:

$$\Delta p_T = \Delta p_1 + \Delta p_2 + \Delta p_3 + \Delta p_4 + \Delta p_5 + \Delta p_6 + \Delta p_7$$

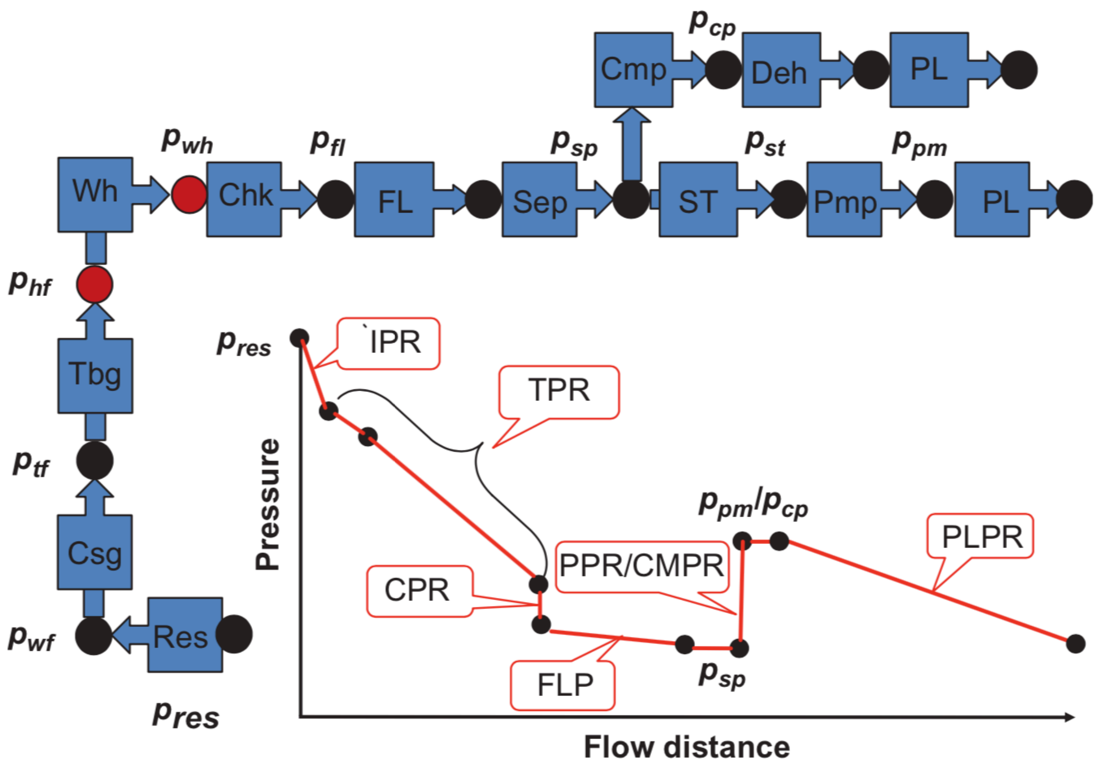

Figure 4.2 Behavior and position of different system nodes

Elements' flow performance relations are represented by:

IPR = inflow performance relationship

TPR = tubing performance relationship

CPR = choke performance relationship

FLP = flowline performance relationship

PPR = pump performance relationship

CMPR = compressor performance relationship

PLPR = pipeline performance relationship

Since fluids emitted from the reservoir to the surface production system are dependent on the total pressure drop "Δp_T"; a commonly utilized methodology which encompasses all nodes together is needed to optimize productivity of the well. Therefore, nodal analysis can be described as an integrative approach to analyze the influence of each component in the well system on the well performance with the goal of maximizing the flow rate "Q" to the maximum economical level. Consequently, Any node through the well system is generally considered as point of division separating the inflow section to the node from the outflow section from the node. While all elements which are upstream from the node represent the inflow part, and downstream elements represent the outflow from the node. It is important to note that two pressures remain constant at any point in the well production system and regarded as independent of the flow rate “Q”; these pressures are:

- Average reservoir pressure “p_r”
- Primary Separator pressure “p_{sep}”

After node selection, the pressure of any node is typically calculated from both node directions (i.e., upstream direction of inflow and downstream direction of outflow). All paths are determined by means of two fixed pressures (p_r and p_{sep}). The abovementioned figure illustrates that the wellbore has been referred to as (Node 3) mentioned in the 8 nodes production system. By using the following two terms, Node 3 pressure (p_{wf}) can be concurrently calculated both from upstream inflow and downstream outflows by these following formulas :

- Upstream Fluid Inflow to the Node 3: $p_{wf} = p_r - (\Delta p)_{\text{upstream components}}$
- Downstream Fluid Outflow from the Node 3: $p_{wf} = p_{sep} + (\Delta\ p)_{\text{downstream components}}$

Note that, irrespective of the node location, two fixed pressures "p_r and p_{sep}" are being used. The following two boundary requirements must be fulfilled, regardless of the node location:

a) any fluid flow into the node should equates the flow out of the node
b) solely one pressure should exist at any node.

There is an implication given by the above boundary conditions and continuity equations that the relation between the pressure drop and the flow rate for each node of the well-producing system designated must be described in mathematical terms.

The curve representing the upstream division is called the inflow curve, while the curve representing the downstream division is the outflow curve, this graphical relationship is schematically illustrated in the following figure.

If a node pressure graphical plot determined from above equations vs. the fluid flow rate can be defined as a pressure drop function of rate, then two curves are formed, intersecting them in order to indicate a combination of the anticipated boundary conditions which satisfy the above boundary requirements of node pressure and flow. The curve describing the upstream division is referred to as the inflow performance relationship (IPR), however the downstream division is referred as the vertical lift performance (VLP) or tubing performance relationship (TPR), the following figure illustrates this graphic relationship.

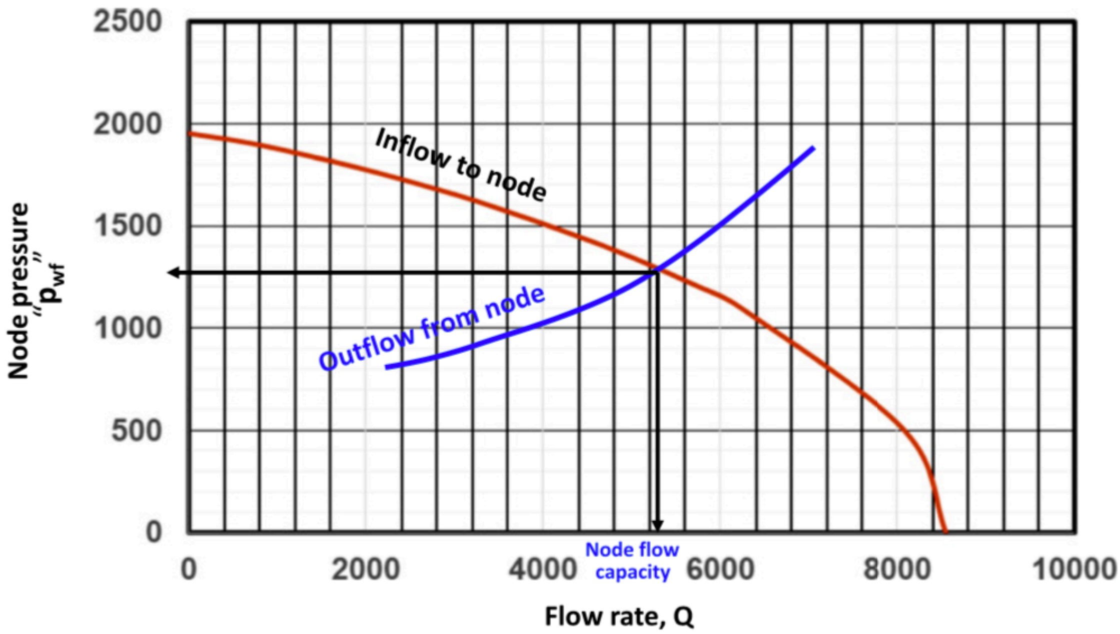

Figure 4.3 Node Flow Capacity

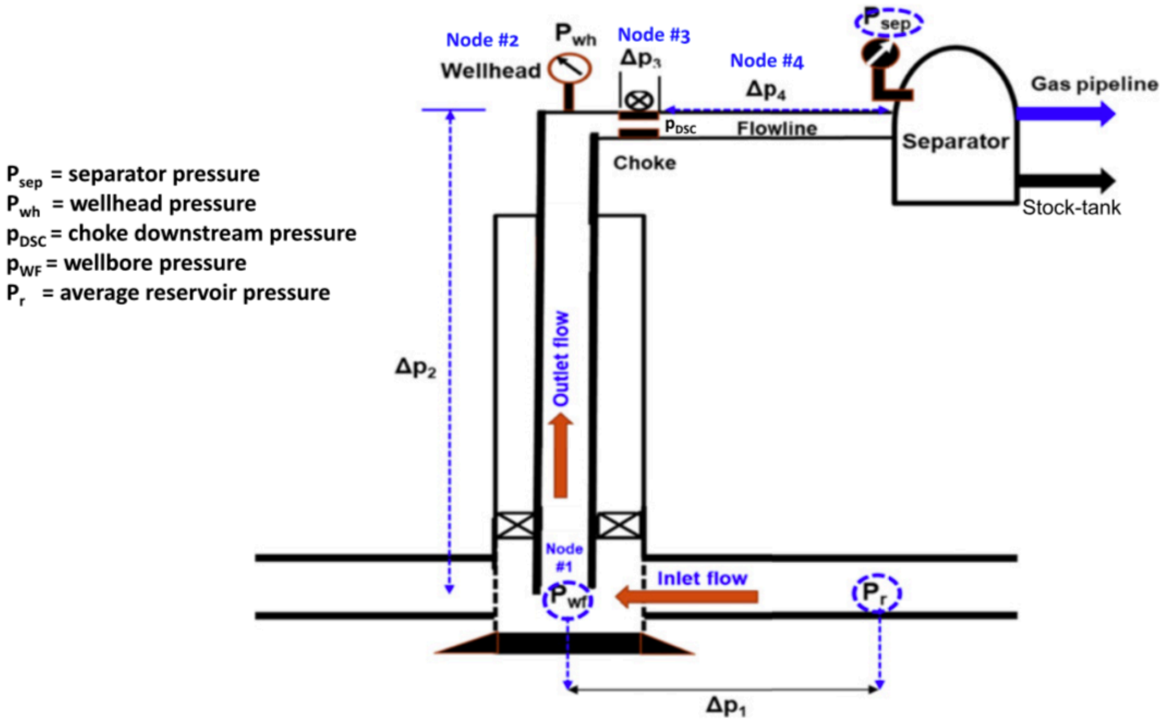

Figure 4.4 Typical well production system consists of 4 nodes

The Inflow Performance Relationship of Node 1

The reservoir ability to deliver hydrocarbon fluids to the wellbore is conveniently described by the Inflow Performance Relationship (IPR). The inflow performance relationship of a well is a relationship between the bottom-hole flowing pressure “pwf” and the well production rate “Q” under a given average reservoir pressure “p_r” through different computational methodologies that are designed to construct the reservoir inflow curve as shown in the figure above.
Inflow Performance Relationship (IPR) describes how the reservoir can deliver hydrocarbons to the wellbore. The well inflow performance is an association between pressure of the bottom hole "pwf" and the well production rate "Q" at a predetermined average reservoir pressure "p_r" via various computational methods designed to build up the inflow of reservoir fluid curve as indicated in the figure above.

Outflow Tubing Performance of Node 1

Regarding the 4 node flow systems as illustrated above, the wellbore outflow performance is typically influenced by the properties of the tubing and pipes system including:

- Tubing length and size
- Tubing degree of inclination
- Pressure at the wellhead (P_{wh})
- Characteristics of surface choke and flowline
- Parameters of existed surface facilities

The well ability to deliver fluids to the surface is linked to the piping system's ability to deliver them to the central processing facility (CPF). The pressure drop inside the tubing is one of the main factors that affect the well production performance. Many studies have shown that 80 % of the total pressure drop inside a producing well may occur when the fluid is lifted to the surface. This significant tubing pressure drop is dependent on the tubing size, resulting in the discovery of the optimal size of tubing.

The optimal size of the tubing means that if a tubing which has a smaller diameter than the optimal tube size is chosen, the following consequences occur:

- a larger reduction of pressure as a friction pressure drop

- leading to reduction in flow rates.

In contrast, oversized tubing can cause:

- excessive loss of liquid phase because of effect of slippage
- or excessive liquid loading inside the tubing which can lead to the cease of the well flow (Dead Well).

The Tubing Performance Relationship (TPR) as shown in figure 4.3 in the form of outflow curve, is a representation of the needed bottomhole flowing pressure P_{wf} to:

- deliver the multiphase fluid flow concurrently at different rates towards the wellhead, and
- tackle all pressure drop inside the tubing.

Changes to any component inside the system requires recalculating the pressure at the node to abide with new system characteristics. The fluid inflow curve will be changed when any alteration occurs through upstream section of the node, while the outflow curve remains unchanged. Nonetheless, no changes will occur to the inflow curve during any changes in the downstream part leading to output flow curve changes. In the event of changes of the set system pressure (end pressures) that can be seen when measuring the effects of depletion of reservoir or taking into account various separator conditions or flowing wellhead pressures, both the inflow and outflow curves are modified.

The multiphase fluid movement in tubes of varying angles from horizontal to vertical is much more challenging and dynamic than the singlephase flow. Considering that a multiphase flow is accomplished in the vertical tubing and taking into account the resulting loss of pressure in different tube elements through their physical properties, the fluids produced undergo significant changes. Where fluids flow concurrently with different physical properties, a wide range of fluid flow patterns can exist. The distribution of every fluid phase inside the pipe control these types of flow regimes. Several investigators have suggested methods for calculating pressure drops in multiphase flows through the measurement of pressure drops on flow patterns which demonstrate that pressure calculations are dependent on a well defined flow regime.

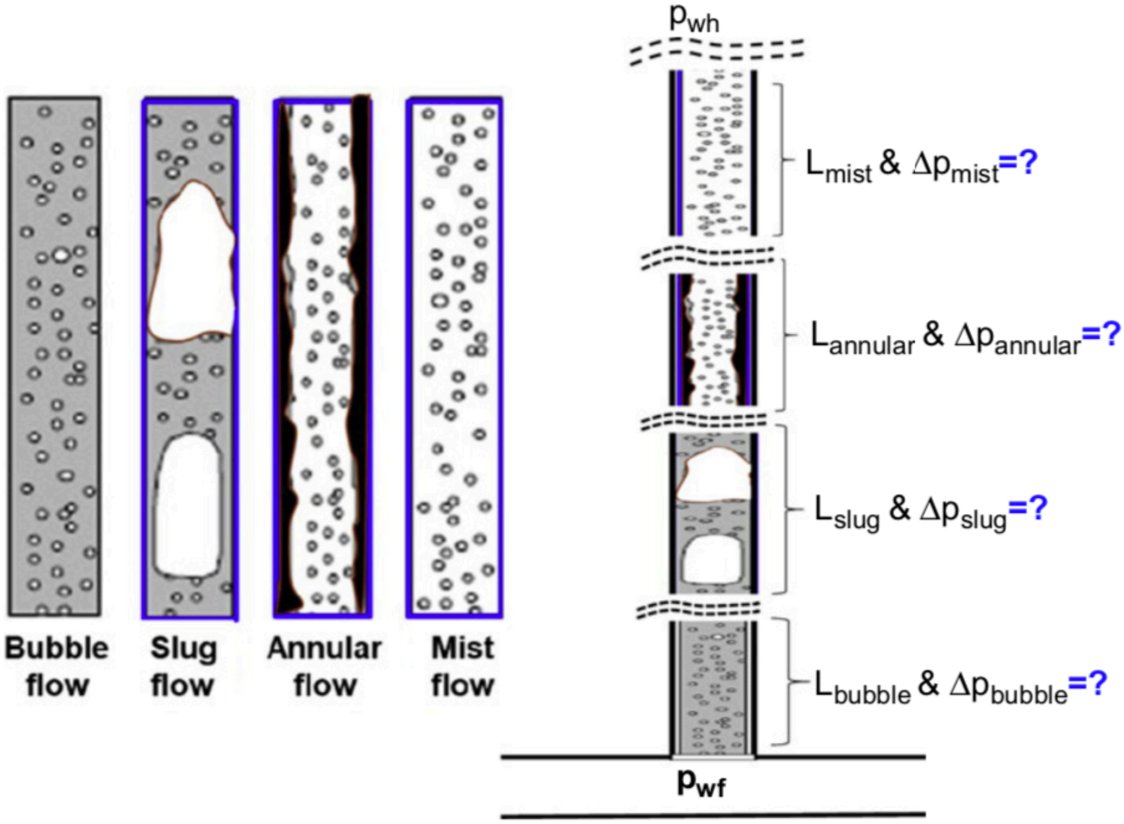

Figure 4.5 different 4 flow regimes inside a vertical pipe.

Figure 4.5 gives an example of a schematic explanation of flow regimes; which are as:

1. Bubble flow : defined as the flow regime where there is homogeneously mixture of liquid and gas as the gas phase is represented by as small bubbles distributed randomly in the liquid phase.

2. Slug flow: defined as the state of flow where bubbles of gas form larger bubbles with diameters of about the pipe diameter approximately. The slug flow results in considerable fluctuations of pressure in the pipe due to the continued segregation of phases in flow direction which is more severe case when the pump is placed far from the wellhead so more slugging occur and fluctuations in the pump inlet pressure occur.

3. Annular flow: defined as the state of flow regime in which the gas phase flows along the pipe center, while the liquid flows as an adjacently annular film to the wall of pipe which occur at a high gas velocity.

4. Mist flow: upon a continuous increasing of vapor fraction starting from bubble form to mist form flow, the gas phase becomes continuous including liquid droplets dispersed inside.

4.1 Main Uses of Nodal Analysis

Nodal analysis is widely used for several purposes such as it is used in designing oil and gas producing wells and analyzing their production performance. The technique is ideal for evaluating the performance of both producing wells and applicability of artificial lift techniques. The analysis offers a clear insight for the initial design of a well completion. In order to provide a qualitative evaluation of expected well production behaviour, different completion scenarios can be assessed even with limited data. This is very useful to analyze existing producing wells' performance through assessment of flow restrictions or performance improvement opportunities.

Main applications include flow rates estimation, optimum tubing size selection, optimum flowline size selection, selection of the most beneficial wellhead pressure value and determining size of surface choke, estimation of the reservoir pressure depletion effects on the production system response, as well identification of any flow restrictions.
There are some other valuable typical uses including subsurface safety valves sizing, perforation density evaluation, design of any needed gravel pack, design of the proposed artificial lift technique, finding an optimum values of injected gas liquid ratio used for gas lift, evaluation of the major effects of inducing lower wellhead pressures or installation of pressure boosting equipment as in the case of the multiphase pump, and evaluation of any needed treatments for well stimulation. furthermore, Nodal analysis is used for the evaluation of multiwell producing systems. Nodal analysis is characterized by high efficiency and robustness.

4.2 Nodal Analysis of Multiphase Boosting system

The overall production system characteristics dictate the major response of a producing well to further reduction of wellhead pressure P_{wh}, upon the use of a multiphase pump. It generally includes the characteristics of reservoir, well completion and used tubulars.

4.2.1 Bottomhole Effects.

Although the cost effectiveness of a given multiphase pump project is calculated by economical analysis , system analysis may assist in identifying and selecting potential field candidates.

In the case of single-phase oil producing wells, deliverability equation stated for the case of undersaturated reservoirs is in the following form:

$q_o = J \cdot (p_r - p_{wf})$ …………………. (4.1)

To comprehend the reservoir response to changes in bottomhole pressure, p_{wf}, the derivative of the previous equation Eq. 4.1 with respect to p_{wf} can be calculated as:

$\frac{dqo}{dpwf} = -J$ .... (4.2)

It is then concluded that any change of the flow rate (q) is directly proportional to the bottom hole pressure (P_{wf}) changes for undersaturated oil reservoirs, while the term (–J) is the constant of this proportionality. Therefore, it is approved that for any case when all points or locations inside the reservoir are above the bubble-point pressure P_b, the influence of any induced reduction in P_{wf} bottomhole pressure is totally the same. However, Single phase flow case analysis is often applied by mistake to perform multiphase pumps selection which is not the right case. Knowing that majority of reservoirs do operate at pressures well less than P_b bubble point pressures, therefore equations specified for two phase flow inside the reservoir should be utilized.

Regarding the case of saturated reservoirs, or while producing with p_{wf} below the bubble-point, this semiempirical equation was proposed by Fetkovich:

$Q_o = J'_{oi} \cdot \frac{Pr}{pri} \cdot (P_r^2 - P_{wf}^2)^n$ ……………………………(4.3)

In Eq. 4.3 this ratio between current and initial reservoir average pressures give a simple approximation of the reduction of relative permeability of the rock to oil (k_{ro}) with depletion. It is illustrated that the so called “backpressure exponent”, “n”, is generally used to address nonDarcy flow effects, therefore when value of n=1 for a well characterized by solely Darcy flow, while when n= 0.5 it describes a well with very severe nonDarcy flow effects. Value of the backpressure exponent (n) ranges only from (0.5) to (1) knowing that wells characterized by high flow rates or high permeability values generally exhibit nondarcy effects. It is required to perform a multirate test measuring P_{wf} as Q changes to get the value of the backpressure exponent (n).

Nevertheless, it is clearly observed that unlike the single-phase fluid flow case, the effect of bottom hole pressure reduction on the two phase fluid flow response of the reservoir is not linear relationship.

$$\frac{dq_o}{dP_{wf}} = -2n \, . J_{oi} \, . \frac{P_r \, . \, P_{wf}}{P_{ri}} \, (P_r^2 - P_{wf}^2)^{n-1} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.. (4.4)$$

Consequently, it is observed that the system response is mainly a function of bottomhole pressure P_{wf}, non-Darcy effects (which is reflected by value of n), and the pressure of the reservoir. This gives a direct indication that some reservoirs will react better to any decrease of P_{wf} bottomhole pressures than other reservoirs. As well, it is observed from the equation that generally wells characterized with severe nonDarcy effects (when n ~ 0.5) would have less response to any induced reductions in bottomhole pressure P_{wf} than other wells which exhibit a value of n equal 1.0. Another figure Fig. 4.6 provides a clear illustration of this concept, which shows a normalized plot of relationship between flow rate Q and the derivative of (Q) with respect to p_{wf}. Different lines are indicating different values of n.

It is clearly observed that when pwf/pr is less than nearly 0.8, the well will trigger a better response for higher values of n. But this is simply an economic decision in all situations..

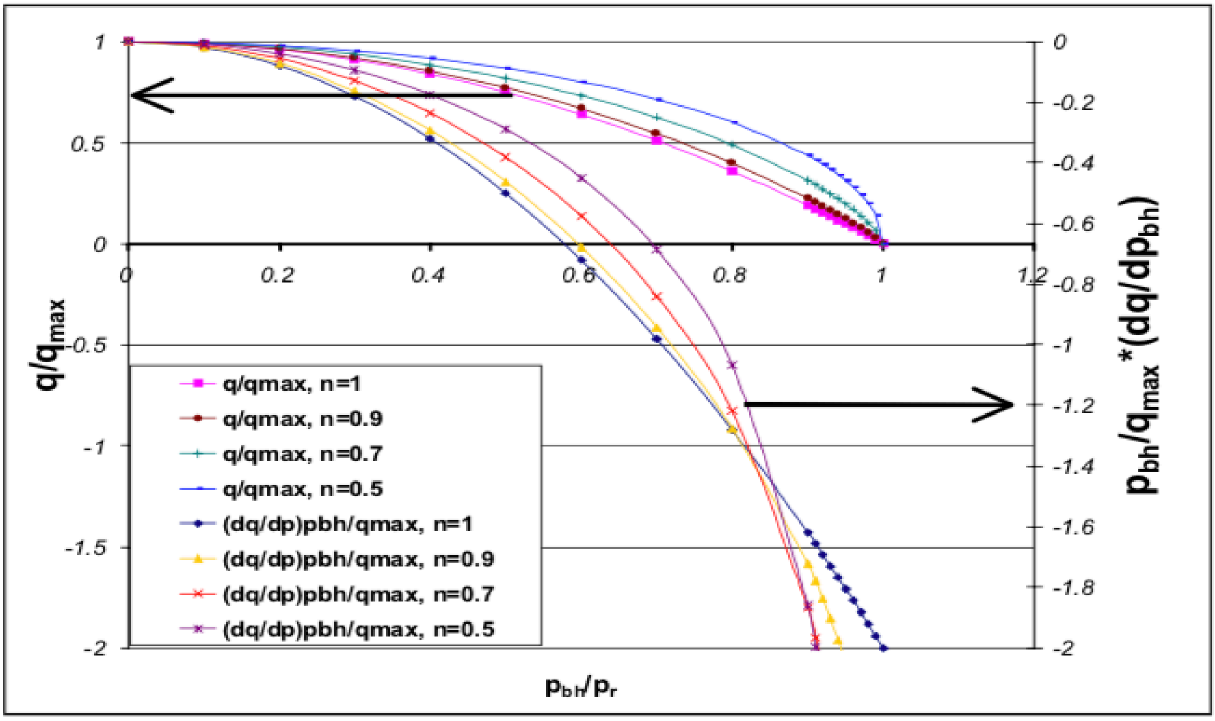

Figure 4.6 relationship between normalized rate and rate derivative vs p_{bh} / p_r

Figure 4.7 represents the plot for Nodal analysis of a well inside a saturated reservoir indicating that the average reservoir pressure lies in the values below the pressure of the bubble point. An outflow curve or tubing curve for a specific wellhead pressure is also shown in this graph. For this reservoir / tubing well production system, the intersection of the these 2 curves gives the operating point of the system flow rate(q), and bottom hole pressure (p_{wf}).

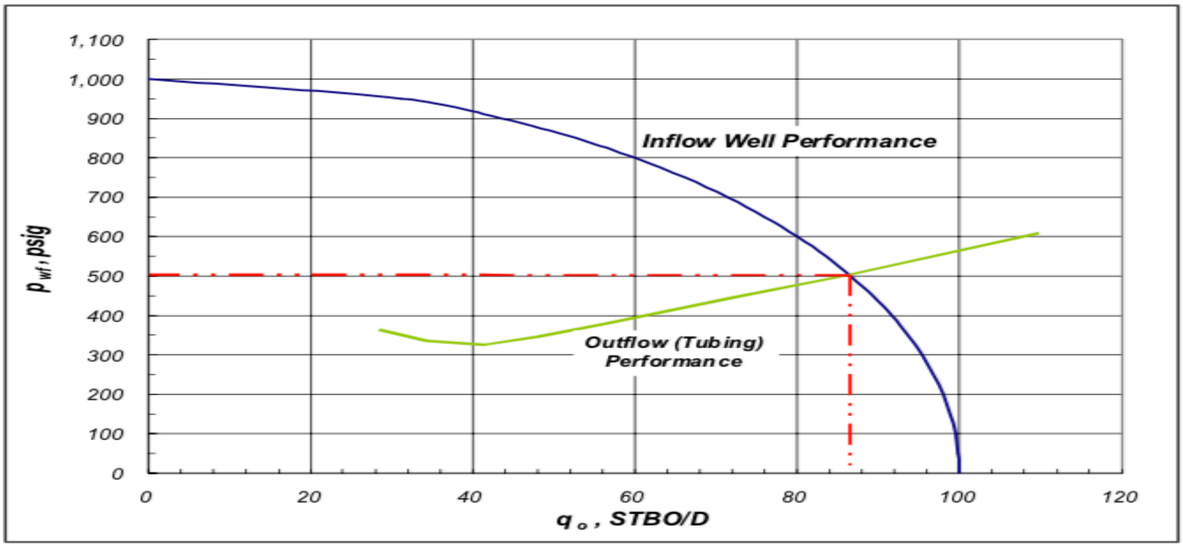

Figure 4.7 Typical Nodal Analysis plot with intersection of fluid inflow and outflow curves with vs production rate

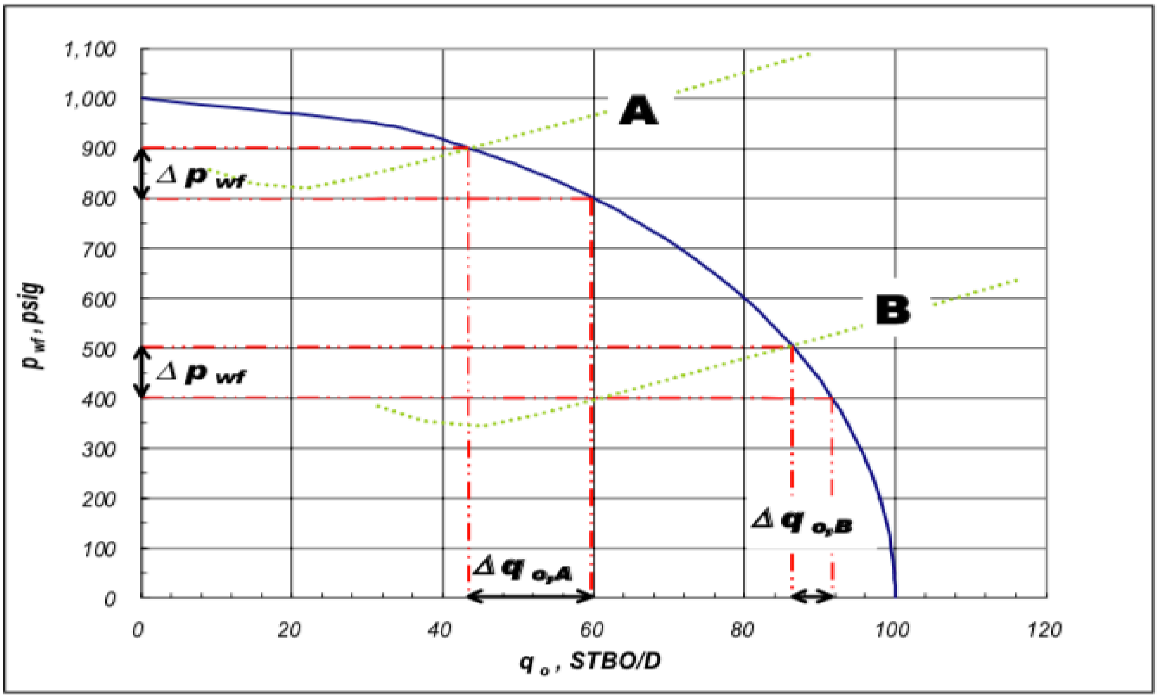

Figure 4.8 Nodal analysis shows how the initial backpressure level affects the reaction of well in saturated reservoirs.

Fig. 4.8 shows that for this specific well, there are two distinct tubing curves which intersect the inflow Performance curve indicating the operating system condition for the 2 tubing configurations. Thess different tubing flow curves refer to various values of wellhead pressure. Considering system (A), an induced reduction of bottomhole pressure (p_{wf}), will lead to an increase in flow rate, ($\Delta q_{o,A}$). In system B, though, the same pressure reduction will result in a change of flow rate, ($\Delta q_{o,B}$), but with value of much lower than the induced flow difference for system A.

Likewise, Fig. 4.9 shows that the required value (Δp_{wf}) varies with the original p_{wf}, if it is intended to have a particularly the same incremental production; this value of required bottom hole pressure change relies on the current condition of the well bottomhole pressure whether it is at high or low bottomhole pressure with respect to the initial reservoir pressure which is an indication of the life of the reservoir whether it is new or old producer .With great confidence, this will be translated to a different pump power requirement.

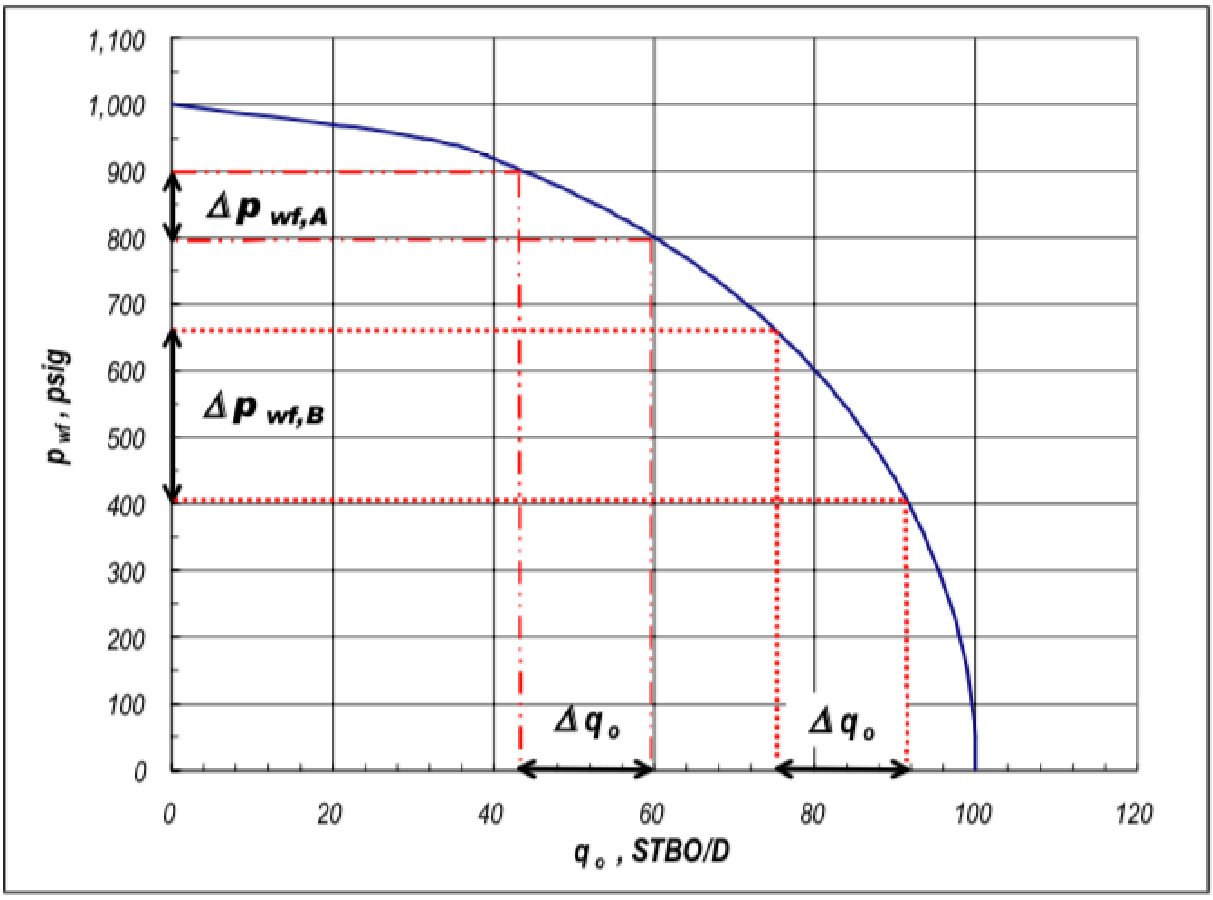

Figure 4.9 This Nodal analysis plot describes how the required p_{wf} reduction to have the same oil rate increase.

4.2.2 Wellhead Effects.

It is necessary that analysis is carried out at the wellhead rather than the bottom hole in order to select candidates and evaluate multiphase pumps performance. In addition to losses in reservoir pressures, wellhead studies require analysis of pressure losses in the tubing.

In order to fully define the well deliverability a multirate test is required. This test type can as well, give vital information regarding selecting well candidates for multiphase pumping systems. Clearly, A well with limited tubing, or severe nondarcy flow, is less favorable to any induced reduction of wellhead pressure by the multiphase pump leading to less impact value of the pump.

4.2.3 Liquid Loaded Wells.

In addition to reducing flow rates as a result of reservoir depletion, the fluids' velocity is lost along the well. At a certain point the gas phase velocity may not be enough to "drag" the fluids and transport them out of the well. It results in continuous liquids accumulation in front of the perforation leading to a possible well killing scenario. liquid loading will lead to a decreased well production and intermittent well flow behavior with a heading flow type. On the wellhead back-pressure graph, these types of wells are easy to identify. When liquid loading occurs, the well production data will appear as a cluster of points to the left of the already established line of results. Turner et al. approach has been used successfully to estimate the flow rate below which the start of the liquid loading behavior occurs. As illustrated in the following equation the set minimum gas velocity to lift liquids in gas condensate wells

$$v_{\min} = \frac{4.02(45 - 0.0031 p_{tf})^{0.25}}{(0.0031 p_{tf})^{0.5}}$$

The abovementioned velocity can be converted into values of flow rate using the tubing area, (A), and the real gas law:

$$q = \frac{3.06\, v_{\min} A\, p_{tf}}{TZ}$$

When the flow rate has fallen below this pre calculated minimum flow rate for liquid lifting, a certain kind of investment is needed to sustain well continuous production . The configuration of this can include pressure boosting equipment at the well head or the artificial lift techniques. Liquid loaded wells respond significantly to an induced decrease of wellhead pressure, as what a multiphase pump provides. Upon reducing the wellhead pressure, fluids' velocity increase in wellbore by the mean of two distinguished mechanisms. A reduction of the wellhead pressure generally results in bottomhole pressure reduction, leading to an increase the flow rate of fluids from reservoir to bottom hole. Furthermore, the reduction in the pressure on the wellhead leads to an increase in the gas expansion close to the surface and thus an increase in insitu gas velocity. To summarize, the reaction from liquid loaded wells will not solely include the effects of the induced lower pressures in the reservoir, but also the effect of the elimination of backpressure from a nearly stagnant liquid column inside the wellbore.

4.2.4 Tubing Limited Wells.

In some situations, the installed well tubing is sometimes too small, restricting flow and serving as a choke in the whole production system. The friction losses in the tubing represented by a slope of 2 on the log-log wellhead backpressure diagram, for n equals 0.5, are dominant for the wellhead behavior in these wells. The response to the reduction of pressure at wellhead is anticipated to be less favorable as only a small fraction of the pressure drop is translated to the pressure drop in the bottomhole. Since the form of the wellhead equation is identical to that of the bottomhole equations, certain important conclusions can be drawn with respect to pressure reductions. The backpressure concept in the bottomhole was earlier reported as the response of the reservoir to reduced bottomhole pressures when p_{wf} / p_r is less than 0.8 is reduced for small n values describing nondarcy flow. Likewise, when p_{tf} / p_{ws} is less than 0.8, tubing/reservoir system response towards wellhead pressure reductions is not significant for small n values as a result of tubing limited scheme.

Maintaining low backpressure ratio throughout the whole field production time , especially very early during the life of the reservoir, would probably need an artificial lifting technique. however it means also that the flow pressure will be dropping below the bubble point pressure at an earlier time than in the case of higher backpressures. In addition to the aforementioned production gains acceleration and hydrocarbon recovery increase, the multiphase pumps are precisely designed to provide this particular service and, in many cases, are the best investment tools because they reduce the amount of needed equipment to be installed on the wellhead such as separators, or two pipelines, as well as the small footprint of the equipment needed on site.

Therefore, This nodal analysis study lead to the following conclusions that:

1. Wells characterized by a low wellhead backpressure coefficient (n) (having non darcy flow) are very poor candidates for selecting multiphase pumping. These wells are mainly the ones with limited tubings, wells exhibiting nondarcy flow pattern near the perforations or sometimes the ones equipped with gravel packs.

2. Constructing a plot of the wellhead backpressure equation derivative gives a way of establishing a threshold, which should be reached before a good value is provided by a multiphase pump.

3. The best response to an installed surface multiphase pump is given by liquid loaded wells. The rise in flow rates higher than minimum defined flow rate corresponds to an exact lift velocity can provide a significant enhancement for oil & gas production however it may limit the remaining life of the well.

4. Using the multiphase pump to reduce the backpressure on the well will consequently increase the final recovery factor of this field and well.

5. Following a strategy of a fast recovery of the predetermined reserves by the mean of installing a multiphase pump during the phase of initial development, would be very preferable to the late retrofitting of the pump lately during the field life.

4.3 First Case Study

An oil well is planned to be drilled in a 3600 ft deep water and 8 miles from a host platform. In a traditional development, a satellite platform would be fixed directly above the wellhead with fluids producing up a riser to a separator operating at 200 psia. As gas is compressed and liquid is pumped through separate lines to the host platform. Alternatively, a twin-screw multiphase pump can be installed subsea to facilitate full wellstream production through a single subsea tieback to the host platform at an arrival pressure of 200 psia.

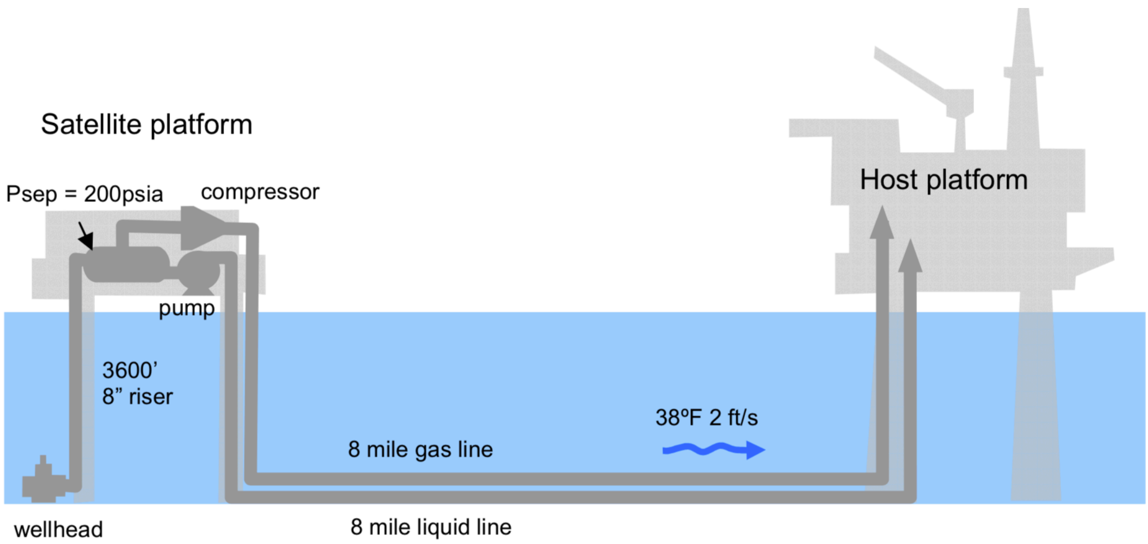

Figure 4.10 Scheme of the well platform Production System by the use of satellite platform

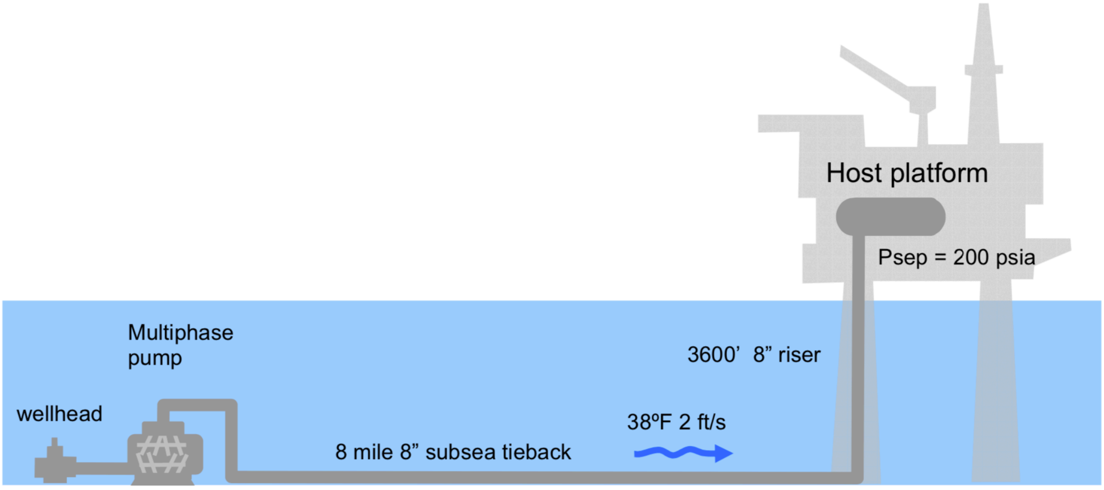

Figure 4.11 Scheme of the well Production System with the use of subsea multiphase pump

Pressure specified boundary conditions are set at the reservoir (which changes over time) and the separator (assumed constant at 200 psia for both cases). A simple productivity index is applied to determine pressure losses across occurring in the reservoir and the Hagedorn-Brown and Beggs-Brill flow-correlations are utilized to calculate the two-phase pressure loss for vertical flow and horizontal flow respectively. The ambient temperature along the flowline is 38° F and the water current is 2 ft per second, typical values for deepwater environments.

4.4 Initial Producing Conditions

Initial producing conditions are represented with a nodal analysis plot (Fig. 4.12). The intersection of the well curve with the flowline curve shows that the well is capable of naturally flowing at 23,500 STBD with a wellhead pressure of 1100 psia. To achieve higher rates, a pressure boost is provided to reduce the wellhead pressure. The amount of differential pressure required for a specific rate is equivalent to the difference of these two curves and is represented as a single curve in Fig 4.13 . The key difference between this figure and typical curves (Fig. 2.19) is that the different rates correspond with different suction conditions specific to the system being modeled. This allows one to determine the pump speed required for various rates and corresponding differential pressure required to meet the delivery pressure. As shown, at maximum speed, the pump is able to produce 33,100 STBD with a differential pressure of 937 psia. A marginally higher rate can be achieved using a larger pump, though at the expense of higher upfront capital costs and lower operating efficiencies later in life.

The pressure profile for this case (shown in Figure 4.14) indicates that pressure losses in the 8 mile flowline are roughly equivalent to that in the 3600' vertical riser. The pressure losses occurring in the flowline are 100% frictional, while the pressure losses occurring in the riser are 90% elevational. while rates decrease over time, the losses due to elevation in the riser will be the dominant fraction in the total pressure loss.

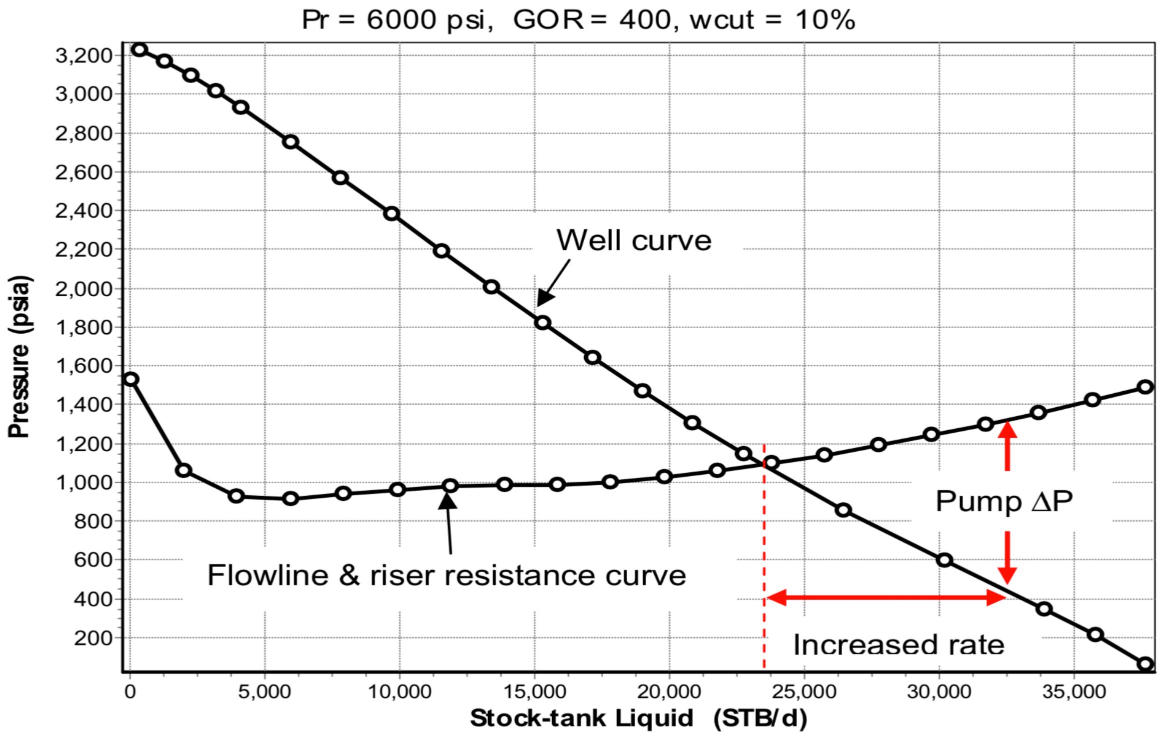

Figure 4.12 Nodal Analysis at Initial Producing Conditions

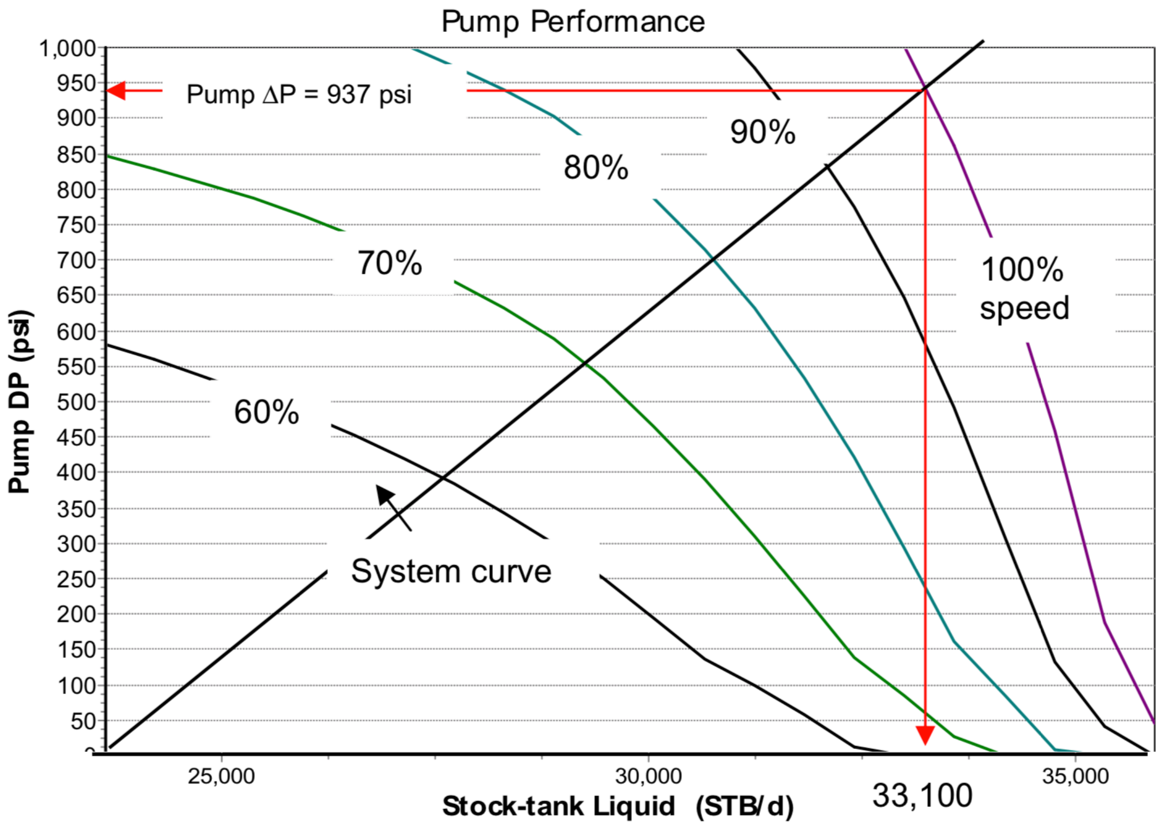

Figure 4.13 Twin screw pump performance at initial Producing Conditions

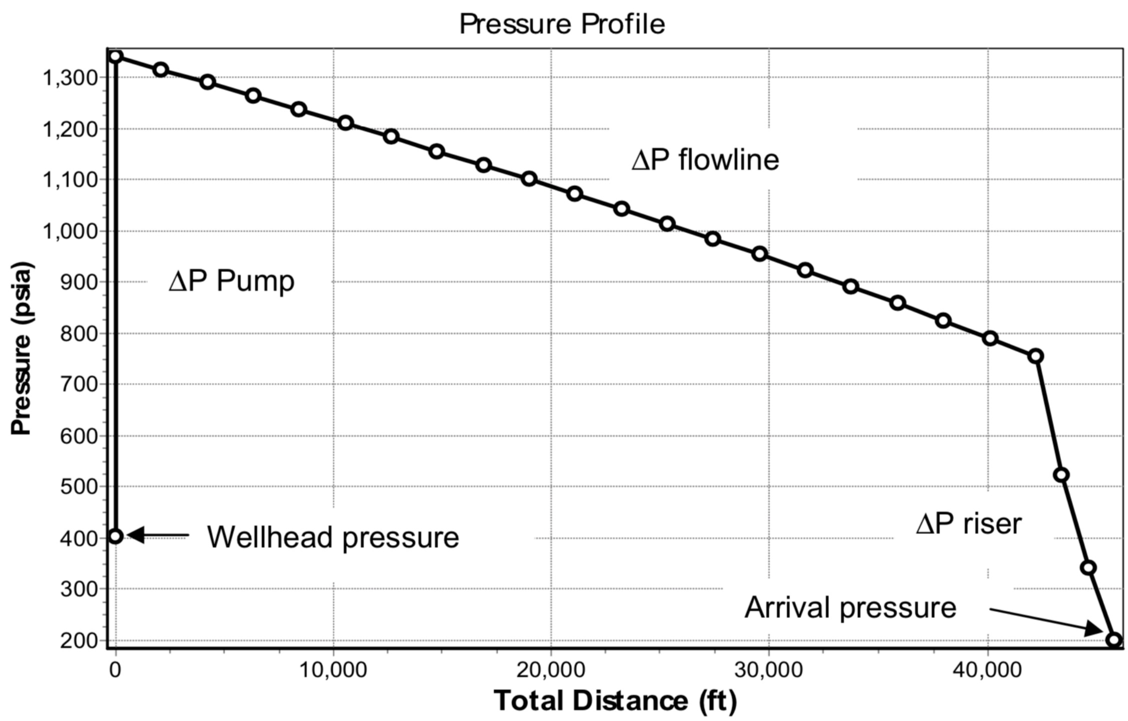

Figure 4.14 Pressure Profile at Initial Producing Conditions

Future Performance Forecast

To account for system performance over time, a reservoir performance table is used which correlates pressure decline to cumulative production (Fig 4.15). The reservoir is initially undersaturated with a bubble point pressure of 3700 psia. As the reservoir depletes, the watercut and gas-oil ratio increase. Production continues until an economic watercut is 85% is reached.

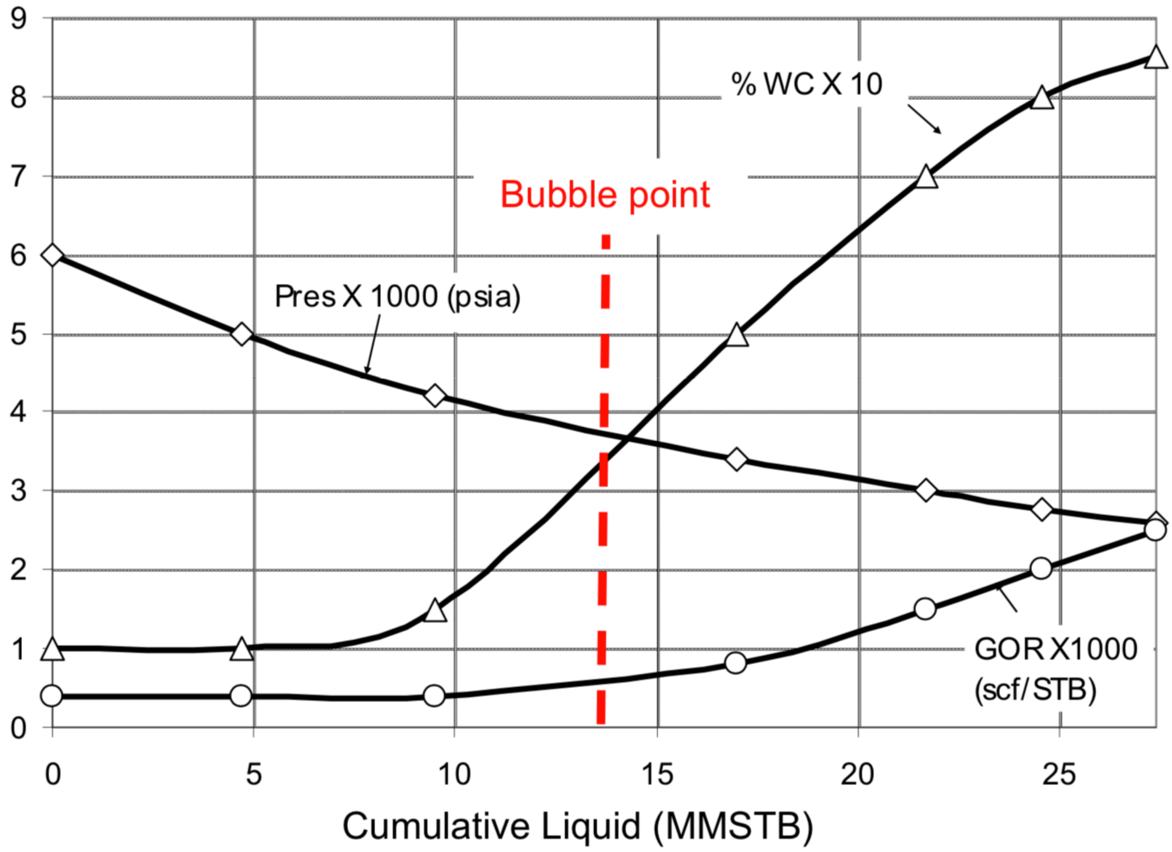

Figure 4.15 Reservoir Performance Table

The performance of several twin screw pump models was considered on the basis of operational flexibility throughout the life of the well. The pump is designed to initially operate at maximum capacity while not exceeding a maximum pressure differential of 1000 psi. As rates decline and watercut and gas-oil ratio increase, the pump speed is reduced to maintain the wellhead pressure at 200 psia while still operating at an acceptable efficiency. In this example, a Nuovo Pignone PSP 210 having a nominal rate of 151,000 BPD (1000 m3/hr) was selected to best meet changing conditions.

Table 4.1 shows pump performance over time. For the first year of production the pump operates at a speed of 100%, after which the pump speed is adjusted to maintain a wellhead (suction) pressure of 200 psia. The gas volume fraction increases as suction pressure drops then remains fairly constant with countering effects of increasing watercut and GOR. At initial conditions, the pump operates efficiently at 54% dropping off to 41% prior to abandonment. At a watercut of 50% a water-oil emulsion is present which significantly increases the overall liquid viscosity resulting in lower pump efficiency and a higher pump differential pressure to accommodate higher frictional pressure losses in the line.

Table 4-1 Pump Performance Over Time

Cum Liquid MMSTB	time (years)	Liquid rate (STBD)	tot. suct. vol. rate (BPD)	Wcut (%)	GVF (%)	suction liq. visc. (cp)	suction pressure (psia)	pump ΔP (psi)	pump speed (%max)	power req. (HP)	pump eff. (%)
0.0	0.0	33,100	121,800	10	70	1.2	403	937	100	2573	54
4.7	0.4	26,650	123,300	10	76	1.3	306	856	100	2365	50
9.5	0.9	21,320	123,300	15	81	1.6	225	848	100	2345	44
17.0	1.8	14,770	100,400	50	84	8.3	200	906	86	2154	39
21.7	2.7	13,500	102,000	70	86	0.3	200	600	85	1428	44
24.6	3.3	11,000	77,600	80	85	0.3	200	591	68	1125	42
27.4	4.0	10,000	73,500	85	86	0.3	200	566	66	1039	41

A forecast of both development scenarios (Fig. 4.16) was made based on the reservoir performance table. The higher rates achieved with the multiphase pump allow for a shorter production cycle (4 years vs. 6 years for conventional separation). Additionally, in the satellite platform scenario, the well is not able to naturally produce at reservoir pressures less than 3000 psia (wellhead pressure of about 520 psia) and must be abandoned. By lowering the backpressure on the wellhead, the multiphase pump is able to produce to the economic watercut (85%) which corresponds to a reservoir pressure of 2600 psia. The result is an overall recovery of 15.1 MMSTB vs. 13 MMSTB, or an increased recovery of 16%.

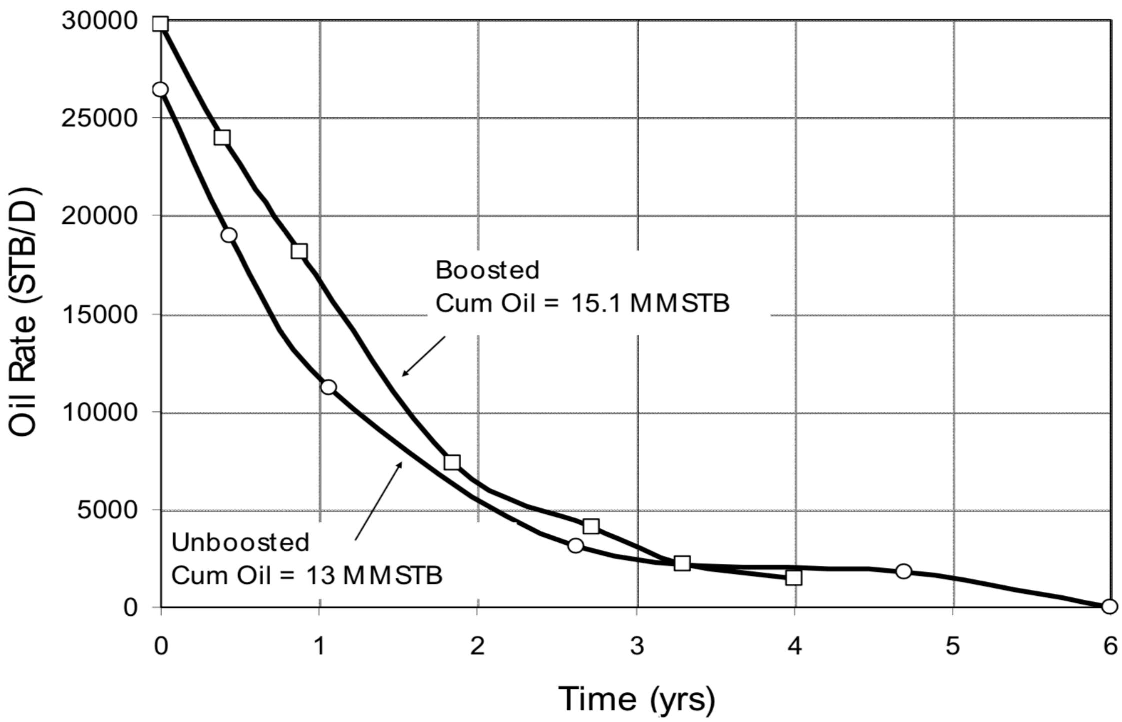

Figure 4.16 Oil Rate Vs. Time

4.5 2nd Case Study

In this case study a complete Nodal analysis and simulation of all field components was carried out using Petroleum Experts (PE) software package starting by characterizing the reservoir using (Mbal) software defining all the initial parameters of the reservoir, followed by complete nodal analysis by (prosper) software, lastly by performing the structure of the whole production system linked by the obtained results from reservoir and well nodal analysis combined by characteristics of choke, flowline, surface Multiphase Pump used and the last separation condition and constraint at the central processing facility (CPF) by (Gap) software.

This reservoir is Badri in the Belayim formation in Egypt, exactly near the coast of Gulf of Suez, Red sea.

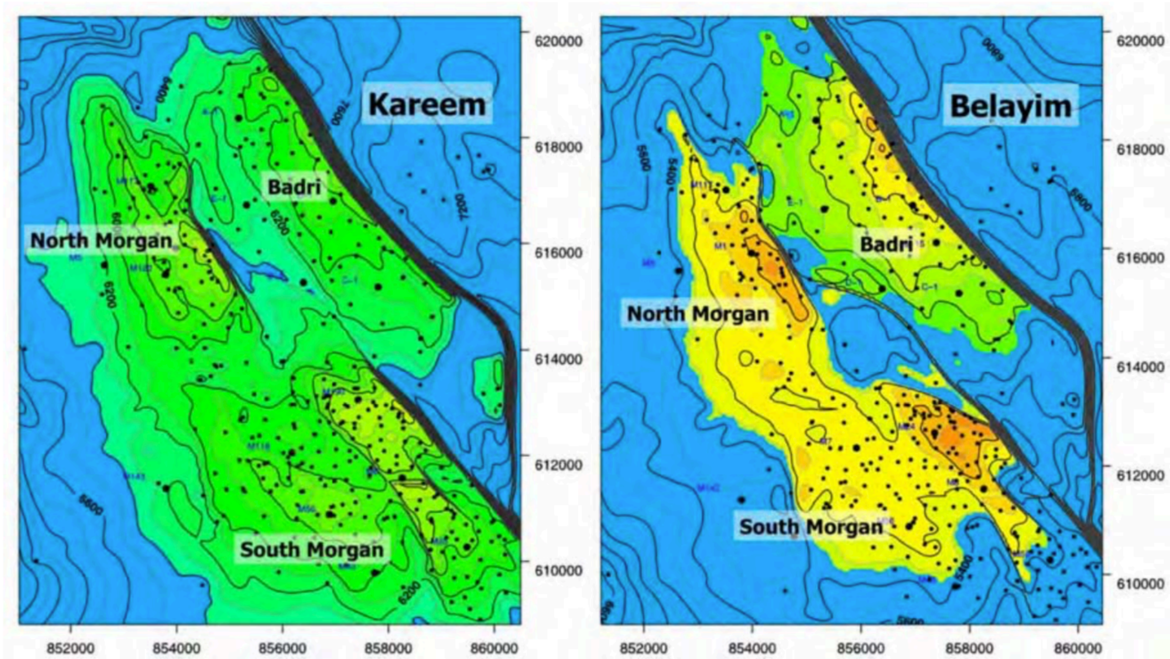

Figure 4.17 Structure Contour Maps of the reservoir

These simulations involve two wells drilled in this field to reach Belayim formation with the following characteristics mentioned in the following plots

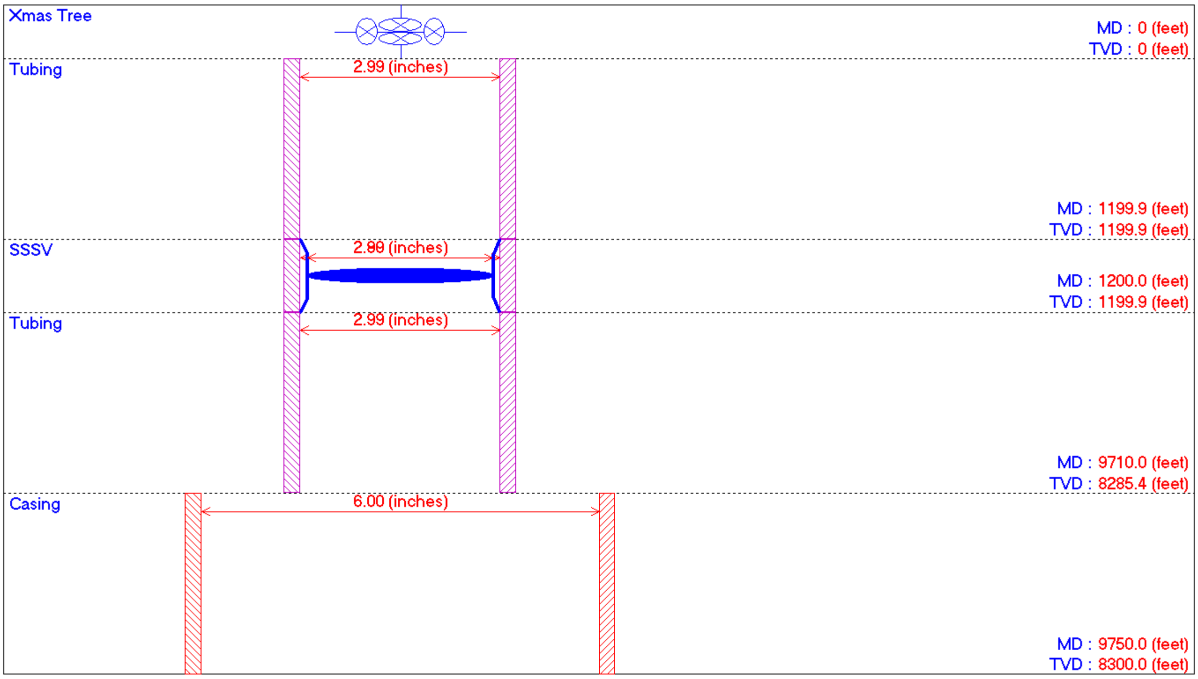

Figure 4.18 Schematic of Well "A" subsurface components

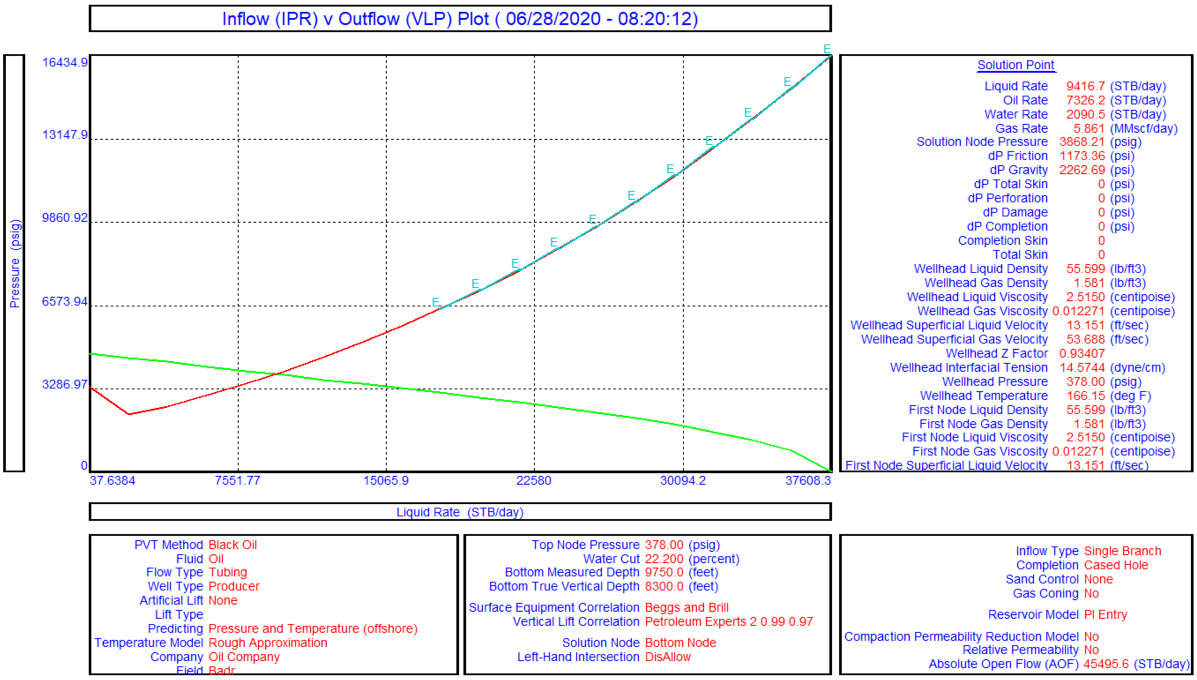

Figure 4.19 IPR vs VLP Curves of Well "A"

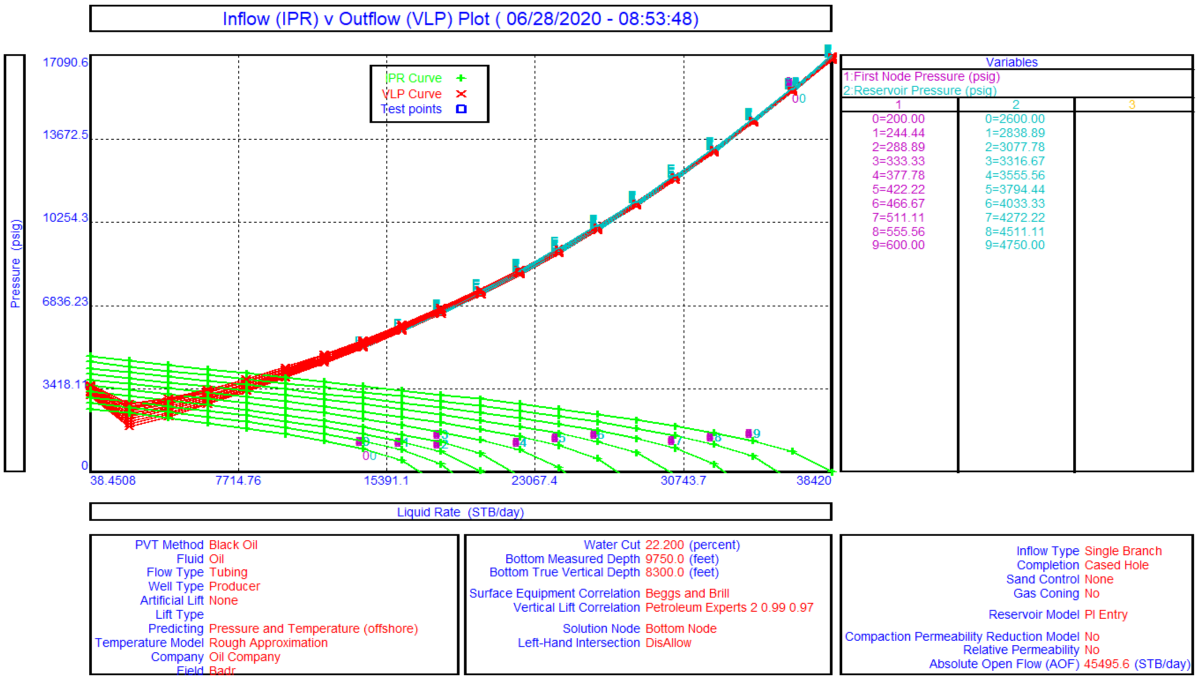

Figure 4.20 IPR vs VLP sensitivity Analysis of Well "A"

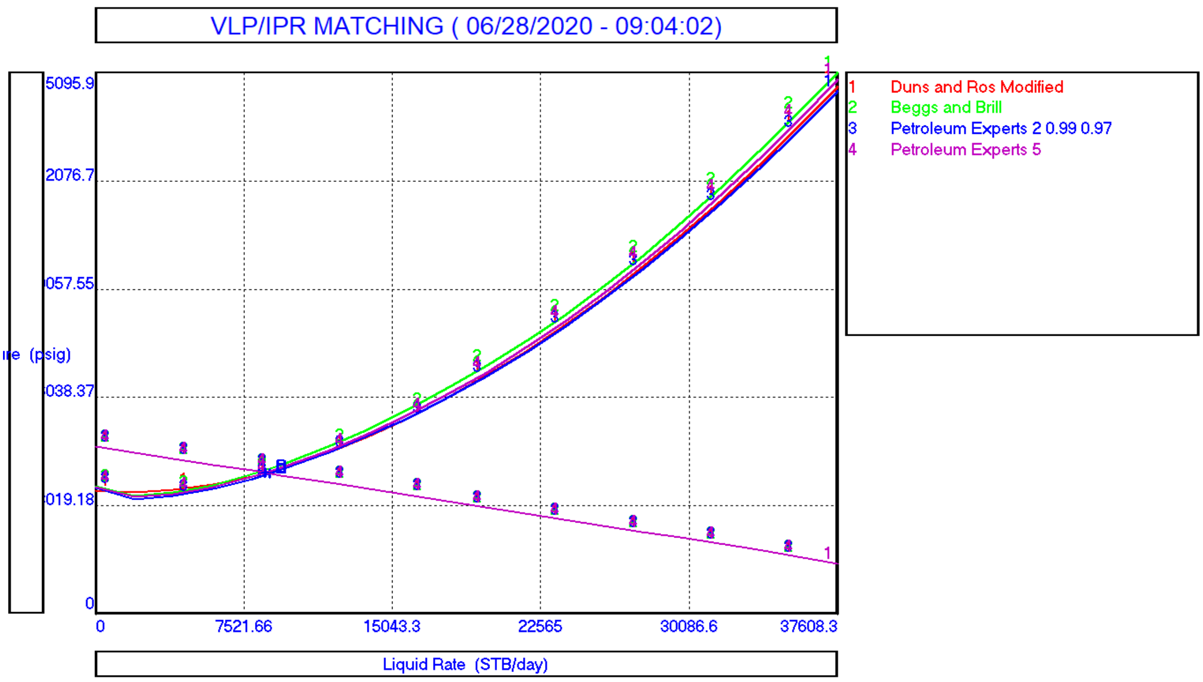

Figure 4.21 Matching of VLP/IPR curves of Well "A" using different multiphase flow correlations

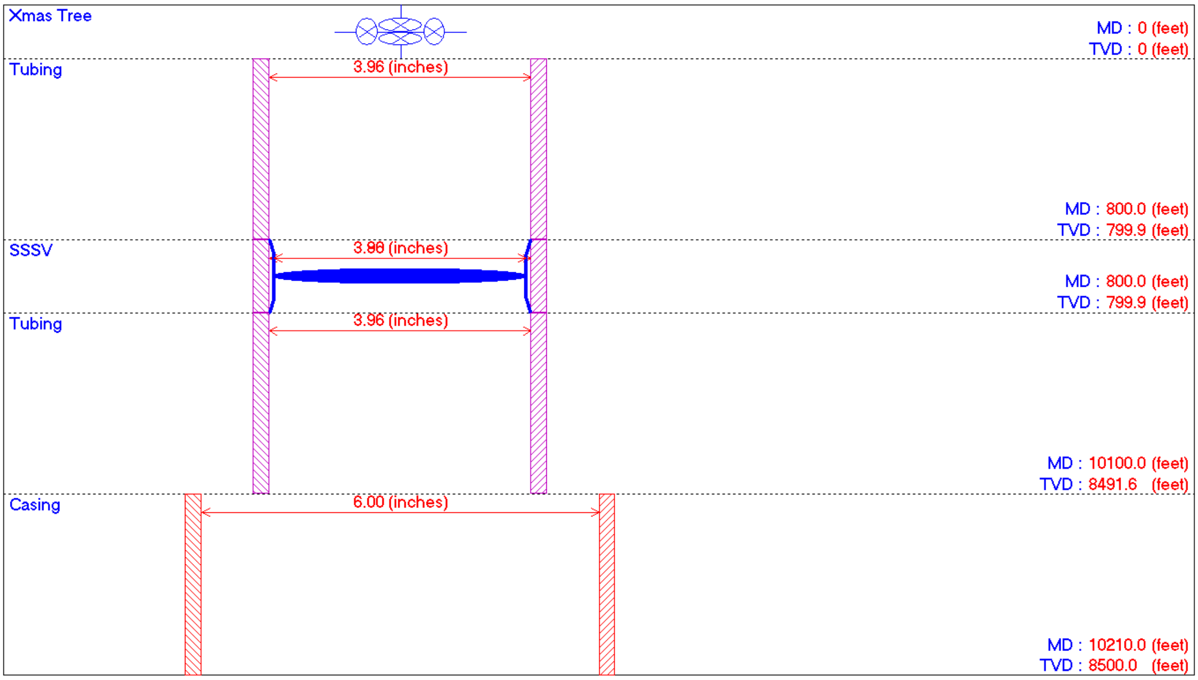

Figure 4.22 Schematic of Well B Subsurface Components

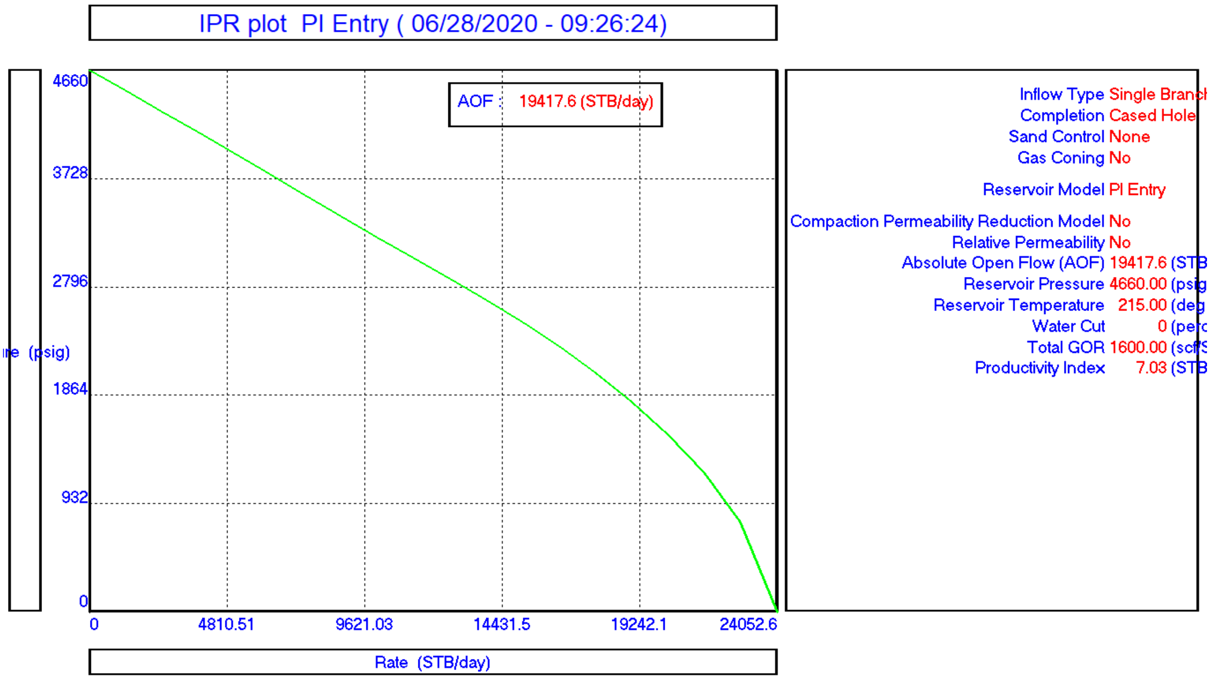

Figure 4.23 Well B IPR Plot in Prosper

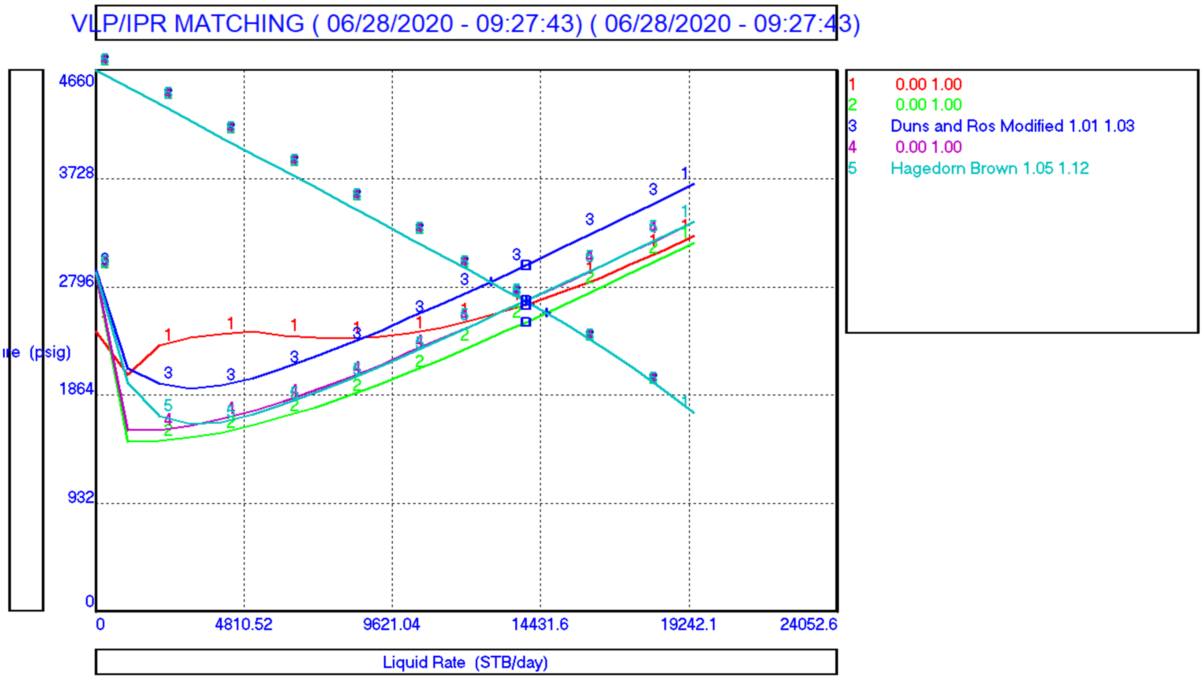

Figure 4.24 Well "B" VLP/IPR Matching of Well "B" with different multiphase flow correlations

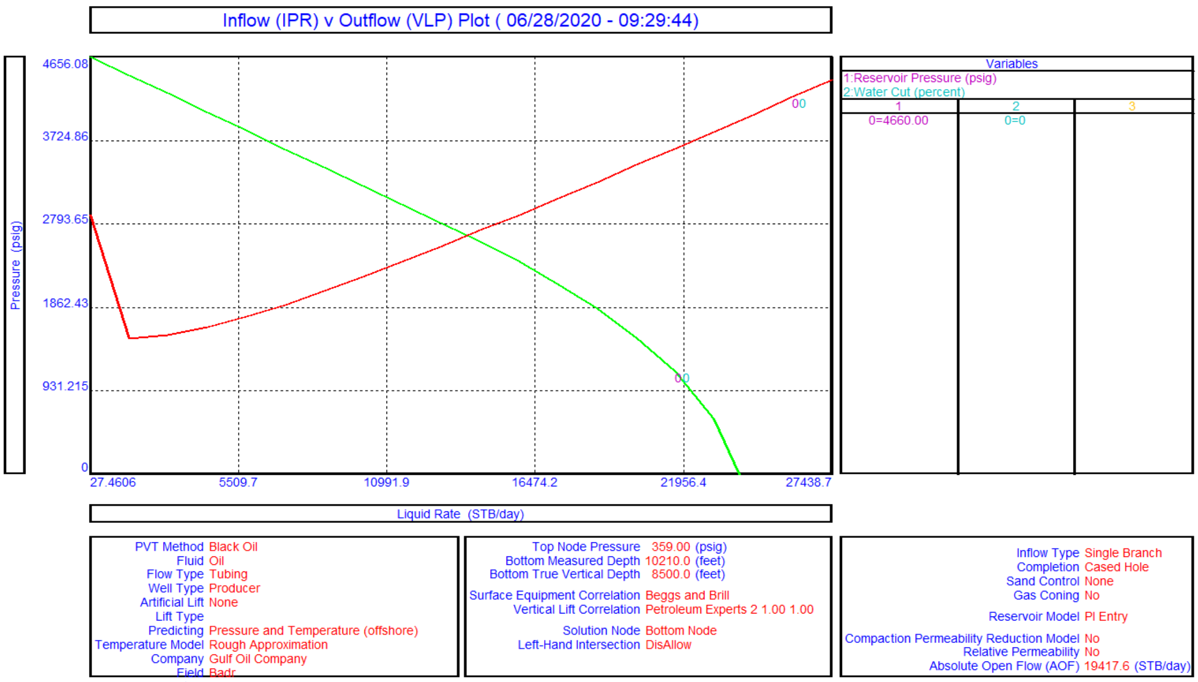

Figure 4.25 IPR vs VLP of well "B"

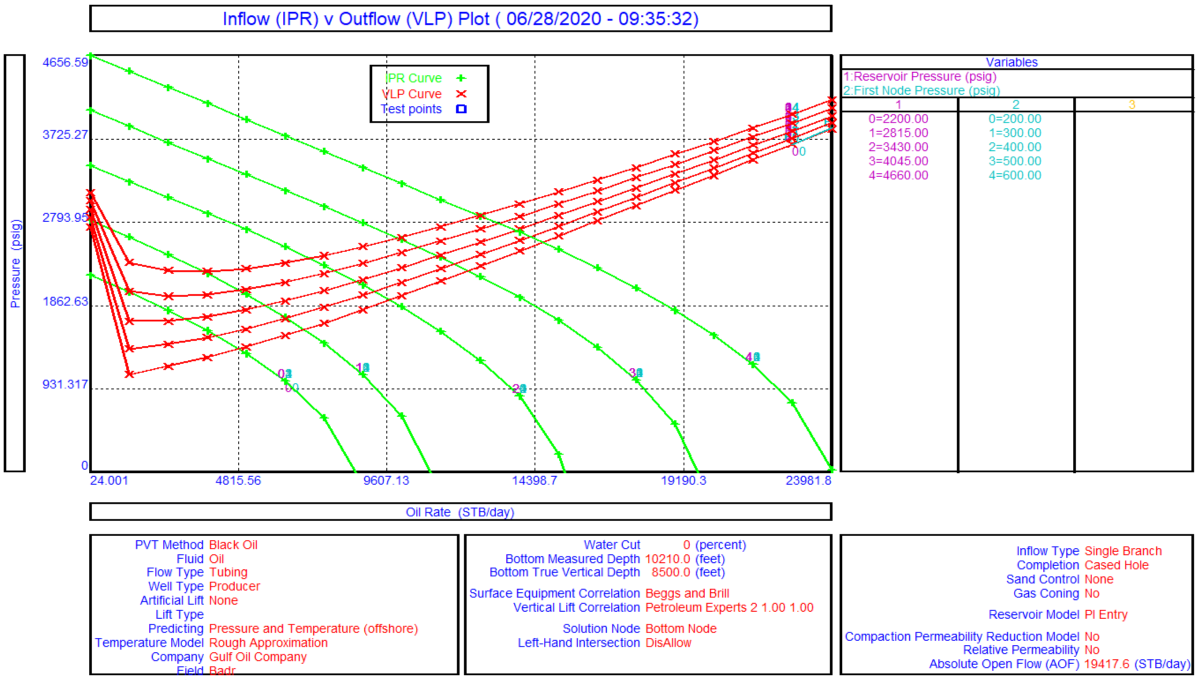

Figure 4.26 IPR vs VLP curve of well "B" with sensitivity analysis

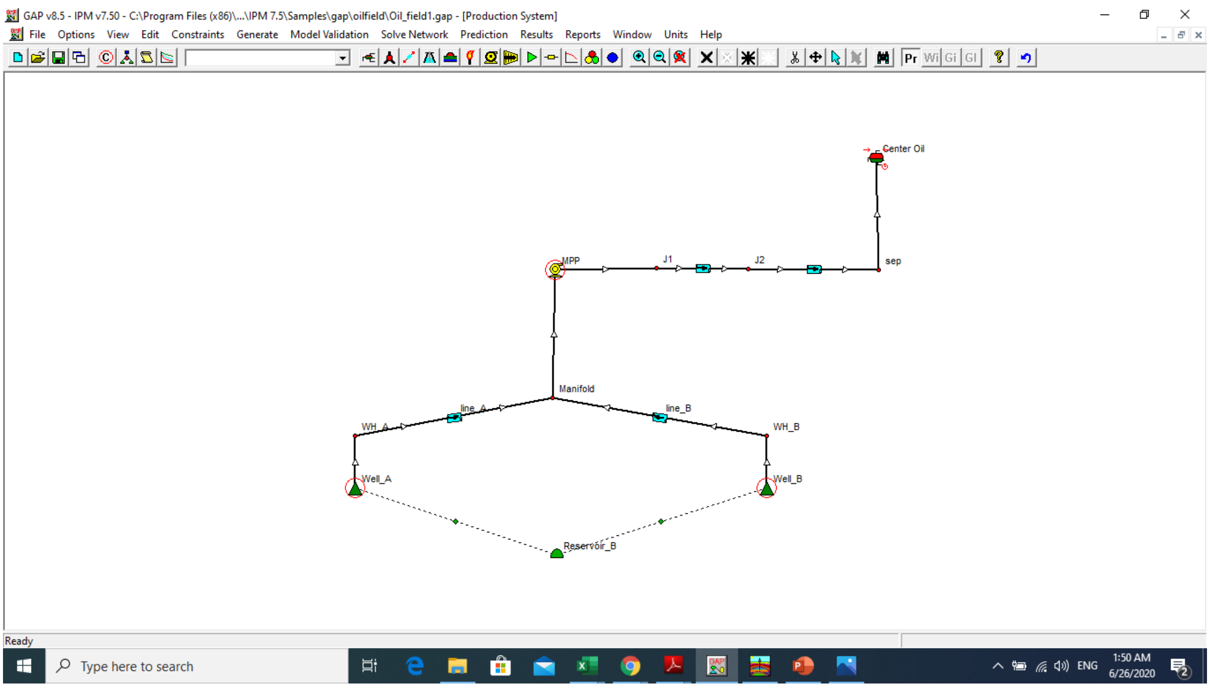

Figure 4.27 Total Production system components from Reservoir till Separator in GAP

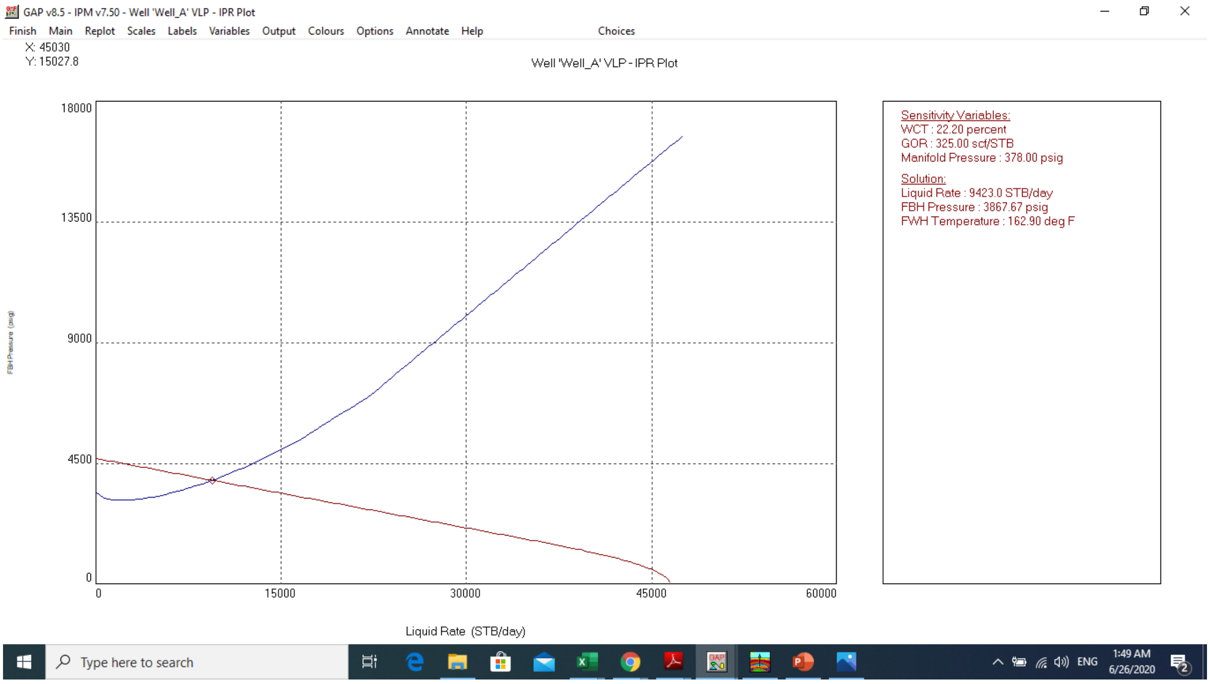

Figure 4.28 IPR vs VLP of Well A in GAP

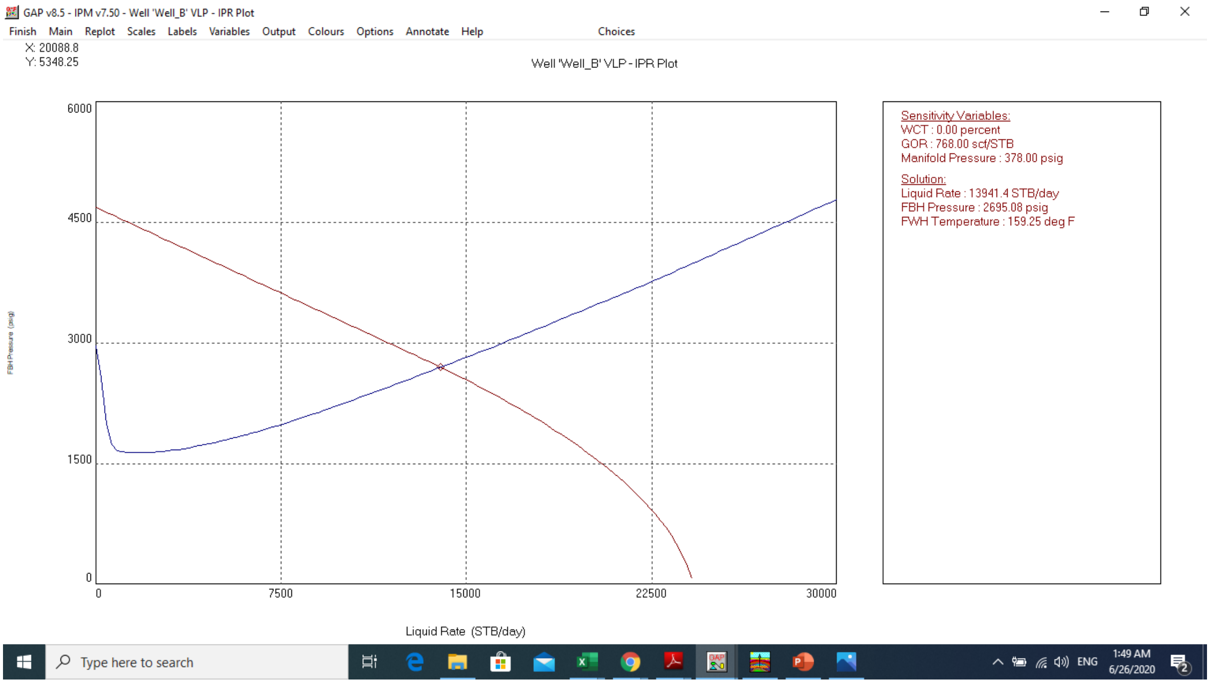

Figure 4.29 IPR vs VLP of Well B in GAP

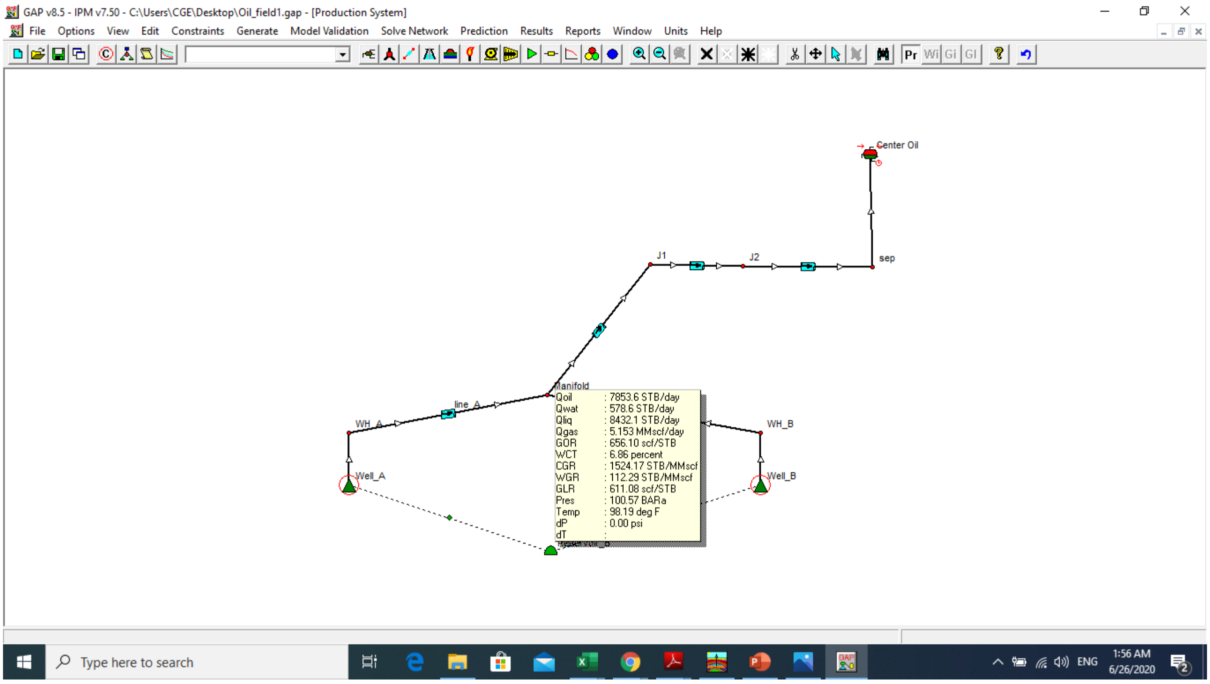

Figure 4.30 Field Production without the MPP

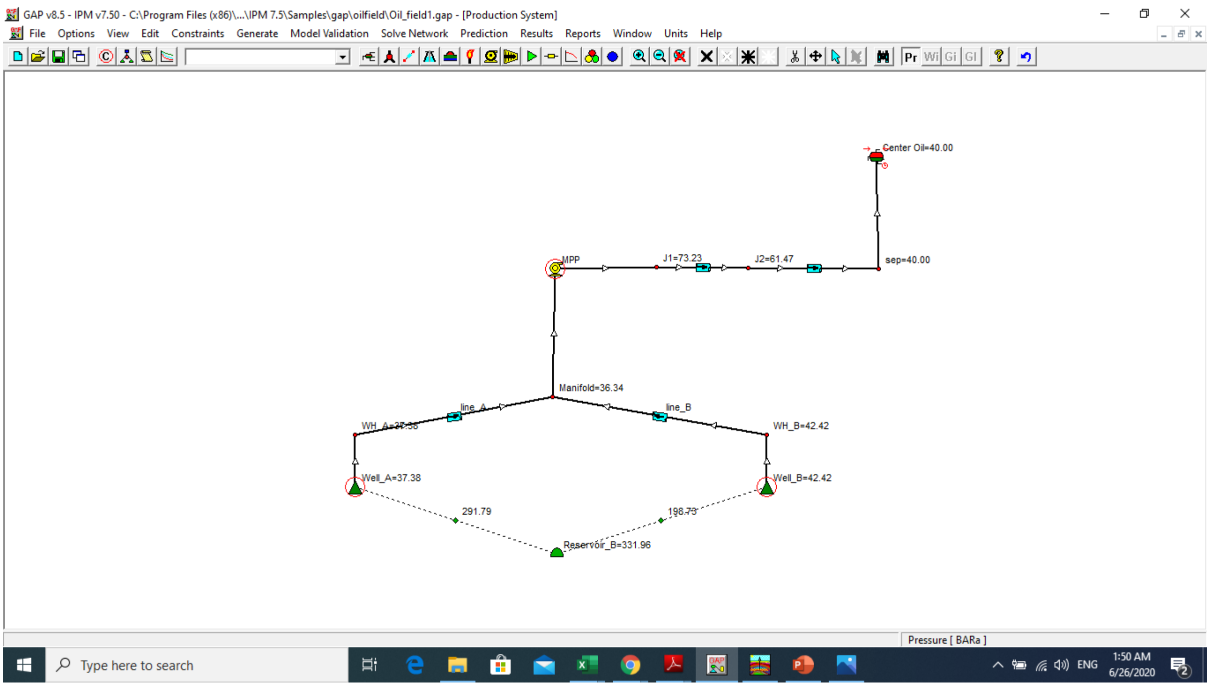

Figure 4.31 System final Run with pressure results at each node.

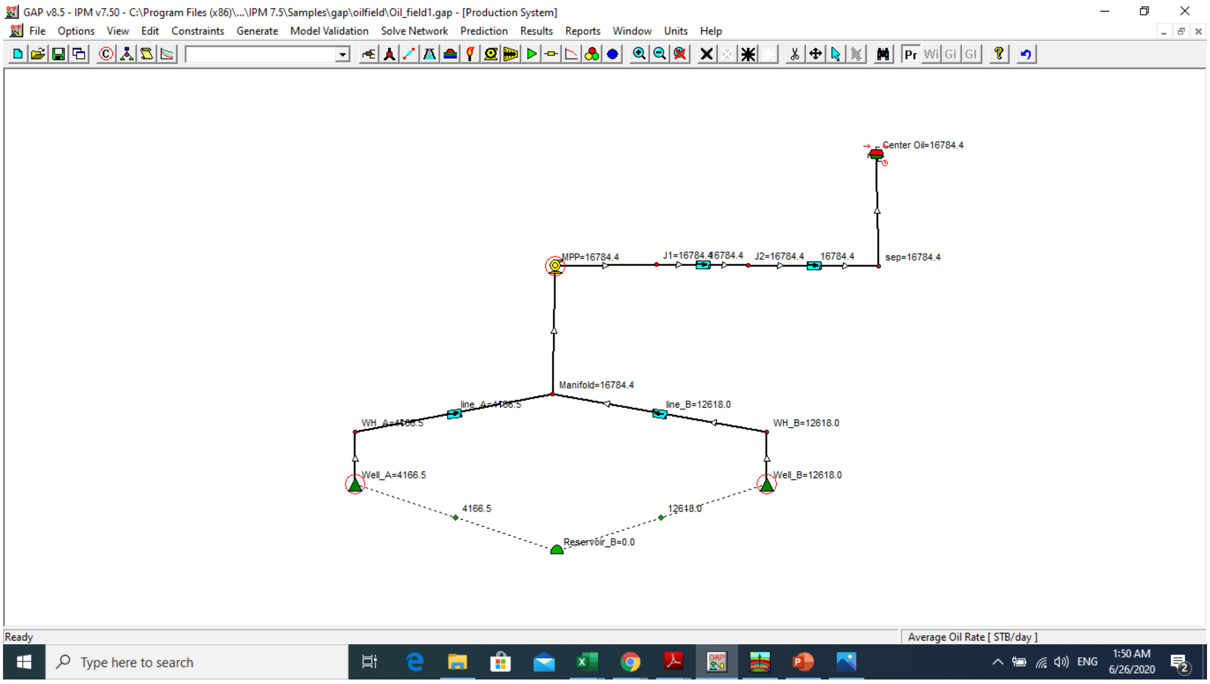

Figure 4.32 Final Run Results of the system with the MPP installed and its influence on the production values in STB/day with increment of 6000STB/day and 6MMscf/day

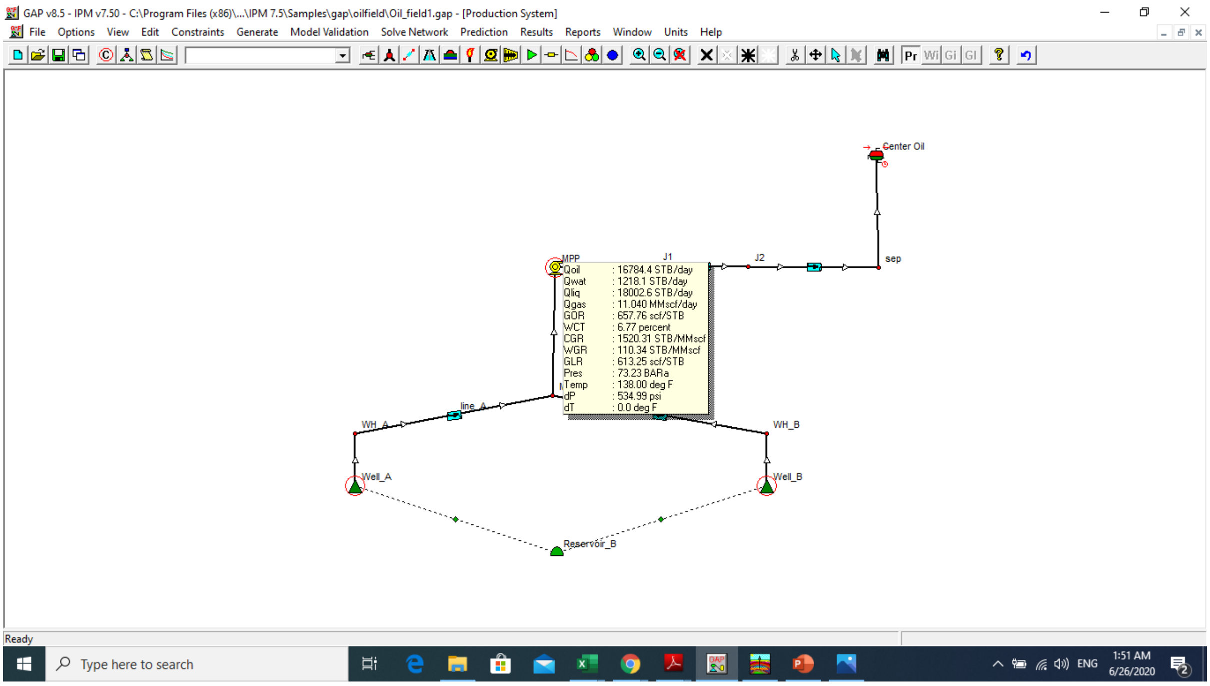

Figure 4.33 Pump operating parameters to deliver flow till the separator

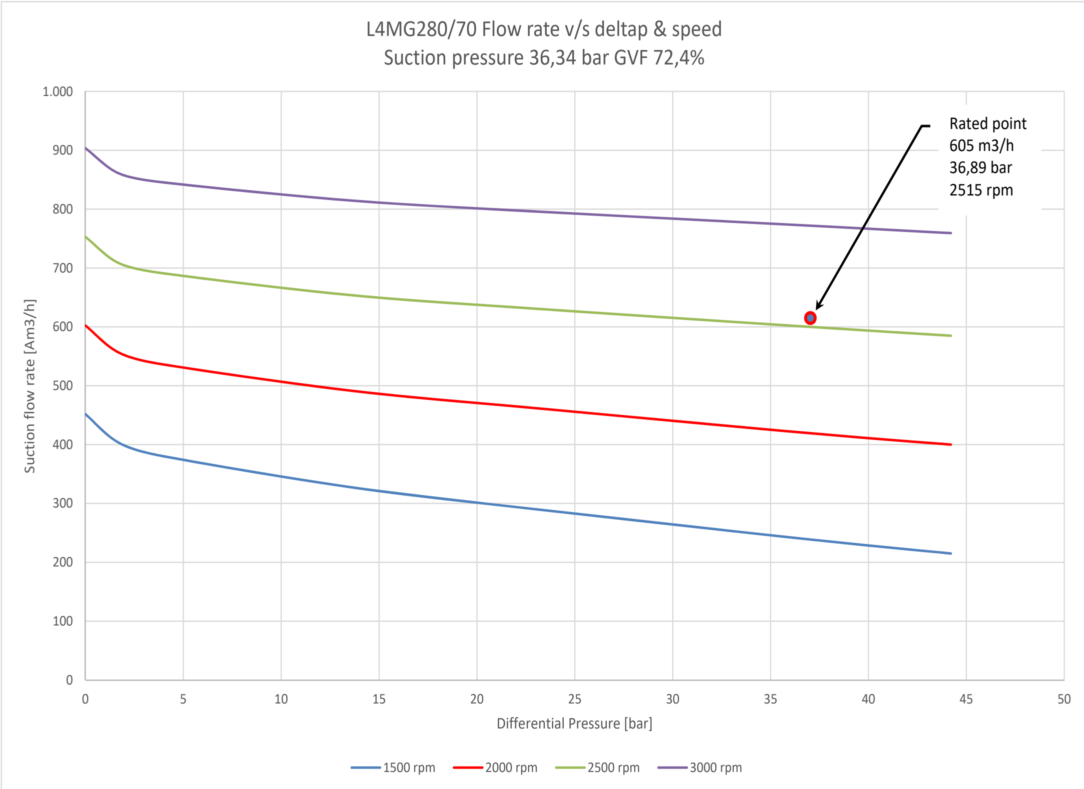

Figure 4.34 Selected Twin Screw MPP characteristic Curve indicating the current operation point

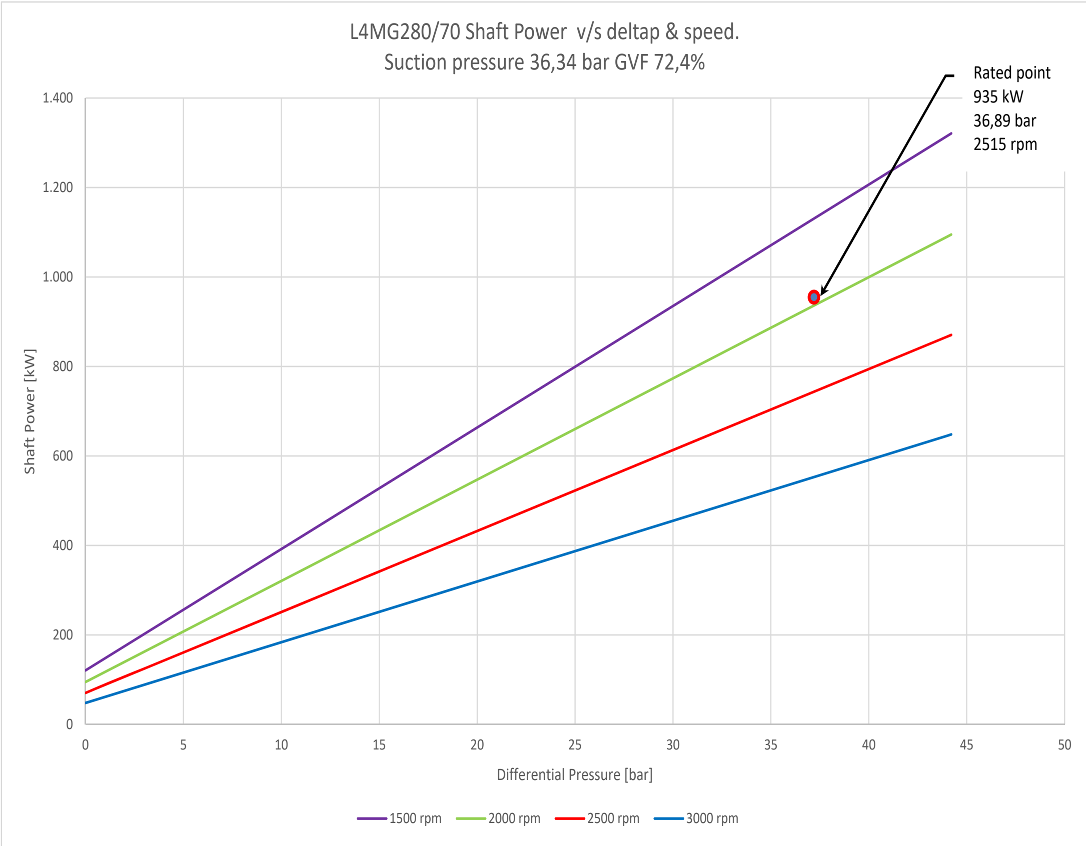

Figure 4.35 Selected Twin Screw Pump Power Requirement with different differential pressures.

Chapter 5 Conclusion

The Multiphase Pumps particularly the Twin-Screw model have shown itself to be highly effective for the management of multiphase fluids with changing parameters that even reach a GVF value of 100 percent after carefully tackling all the complexities of multiphase pumping with a true process understanding.

The successful operation of multiphase pumps has been shown to be much more than just bare machinery supplies but a deep understanding of the entire scenario from the reservoir to the first level of CPF separation.

In order to achieve success, the multi-phase pump itself and the expertise combined with various disciplines, such as reservoir, production, engineering, construction and maintenance are crucial.

The capability to install additional pumps in parallel or series at the same manifold in order to further minimize the suction pressure gives installed systems more stability to sustain the production output of the wells over a long period of time.

The twin-screw pump system outperforms compressors regarding their footprint and flexibility which can accommodate to a variation of multiphase flow scenarios (gas, condensate, oil and water).
To run the pump efficiently and safely, it is recommended to use externally provided sealflush liquid or install a heat exchanger for the cooling of recirculated sealflush liquid on twin-screw pump skids with similar designs.

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