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Bakı – 2022

I, Samir Muzaffarov, hereby declare that this thesis work submitted is entirely my own. All the works of other authors have been fully acknowledged and clearly cited. I also declare that this work is free from any plagiarism.

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Abstract

Living in a world where energy consumption is increasing rapidly, the need for petroleum is also escalating to meet this high demand. To optimize and enhance hydrocarbon production oil companies are trying to apply best suitable production techniques in producing oil and gas fields. However, achieving maximum hydrocarbon production under different technical and economic difficulties is a great challenge for production engineers. When the production profiles are generated for a production well under different scenarios, the relationship between reservoir performance and tubing performance should be considered in such a way that the modelled well will be able to produce hydrocarbons efficiently and well production rate will be stable.

There are different production techniques that can be selected to produce hydrocarbons from subsurface formations. Reservoir fluids can be lifted to the surface by either the means of natural energy available within the reservoir itself or they can be lifted by applying artificial lift methods. Despite the fact that hydrocarbons are generally produced by natural drive mechanism at the initial stage of field development where the reservoir pressures are strong enough to push hydrocarbons to the surface and then suitable artificial lifting techniques are implemented when the wells cannot flow naturally, artificial lifting can also be applied to maximize production rate when individual well production rate is low due to lower reservoir pressure available in the system.

The main objective of this thesis work is to do comparative analysis of effectiveness in implementation of natural drive and artificial lift methods (gas – lift and pumps) for hydrocarbon production in West Absheron oil field, which is located in Absheron archipelago, the Caspian Sea, by using a special computer software package (namely PROSPER) on the basis of a synthetic well data, namely Well WA-1. The Nodal Analysis is done for natural drive case and artificial lift techniques, specifically said, electrical submersible pump method and continuous gas lifting on PROSPER. Darcy method is used to construct inflow performance relationship curve (IPR) for reservoir performance and Petroleum Experts 2 method is selected to construct vertical lift performance (VLP) curve and intersection point between these two curves through system calculations menu is obtained (known as nodal analysis) for natural drive and artificial lift techniques, specifically said, electrical submersible pump method and continuous gas lifting.

All input parameters are inserted into the software and production profiles along with different sensitivity analysis are performed for natural drive case, ESP case and continuous gas lift case. Detailed investigation of natural drive, ESP and gas lift theory, their separate design and production results are achieved. The main idea and theory of artificial lift selection criteria is also given. The calculated oil production rates for each case are represented below:

- For the natural drive case calculated oil production rate is **17.6 sm^3/day** and flowing bottom hole pressure is equal to 67.37 atm. It should be noted that in case of natural drive, ***the modelled well is producing the lowest volume***.
- For the Electrical Submersible Pump case (ESP) system calculations show that the well can produce **53.8 sm^3/day** of oil which is ***quite high volume compared to natural drive case***.
- For the continuous gas lift case, calculated oil production rate is **50.8 sm^3/day,** and ***this volume is also high enough*** to be considered as an artificial lift technique to maximize hydrocarbon production.

From the obtained results it is obvious that natural drive case is the least favourable scenario to maximize hydrocarbon production in West Absheron oilfield. Although calculated oil production rates for ESP case and continuous gas lift case are almost similar, source for lift gas is the main challenge in case of applying gas lift system because production wells in West Absheron oilfield currently produce too little volume of gas (solution gas) which cannot be a source for gas lifting. That means gas should be obtained from somewhere else, possibly from a nearby gas producing field that requires much more investment before the system goes online. Besides, gas lift compression station and all required surface facilities and pipeline network should be installed in place, thus leading to higher CAPEX. In case of ESP lifting, they require detailed planning and administrative resources to put them into action. ESPs introduce a higher degree of complexity and risks in terms of planning and operation. Understanding and management of ESPs is much more troublesome and riskier. For that reason, it should be emphasized that in ESP designing, mistakes can be very costly and detailed planning and engineering is essential for achieving best performance from ESPs. In addition to that, ESPs are sensitive to changes occurring downhole and fluid properties and consequently have only a limited lifetime if planning and management of ESP lifting is poor. Hence there will be a need to change the downhole completion (workover, maintenance) in ESP lifted wells when they experience failure, leading to increased OPEX later in the project. Comparing this factor to that of gas lifting system, it should be noted that gas lifting is a very simple, commonly applied artificial lift method where little can go wrong. From the obtained results and specifically unavailability of source gas and required infrastructure in the study area, it can be deduced that implementation of ESPs to maximize and optimize hydrocarbon production in West Absheron oilfield seems to be superior choice. However, in reality this planning is far too complex and production optimization should be done for every well individually considering the available input data for each well. In case of field production optimization and enhancement, more sophisticated software is required to make an integrated approach considering the surface network of present wells and subsurface data. Apart from that, a detailed economical evaluation of both projects should be carried out to decide which technique is the most economically viable for hydrocarbon production enhancement in West Absheron oilfield.

Keywords: Production enhancement, production techniques, natural drive, electrical submersible pump method, gas lift method, nodal analysis, PROSPER software

Referat

Enerji istehlakının günü-gündən artdığı qloballaşan dünyada neftə olan tələbat da böyük sürətlə artmaqdadır. Karbohidrogen hasilatının intensivləşdirilməsi və optimallaşdırılması məqsədilə neft şirkətləri neft və qaz yataqlarını istismar etmək üçün ən uyğun istismar üsullarını tətbiq etməyə çalışır. Ancaq qeyd edilməlidir ki, müxtəlif texniki və iqtisadi çətinlik şəraitində karbohidrogen hasilatının maksimuma çatdırılması hasilat mühəndislərinin qarşısında duran böyük bir çətinlikdir. Müxtəlif ssenarilərə əsasən istismar quyuları üçün hasilat əyriləri qurularkən yatağın və nasos-kompressor borusunun performansı arasındakı əlaqə elə tənzimlənməlidir ki, modelləşdirilən quyunun uzun istismar dönəmində karbohidrogen ehtiyatları səmərəli şəkildə çıxarılsın və quyunun verimi sabit qalsın.

Karbohidrogen ehtiyatlarının çıxarılması üçün müxtəlif istismar üsulları mövcuddur. Bu ehtiyatlar yer səthinə yatağın öz enerjisi hesabına (hansı ki, bu, fontan üsuludur) və ya digər istismar üsullarının tətbiqi ilə çıxarıla bilər. Karbohidrogen ehtiyatları yatağın işlənməsinin ilkin mərhələsində laydakı təzyiqin onları yer səthinə çıxarmaq üçün kifayət qədər güclü olduğundan layın təbii rejimi hesabına və sonradan layın enerjisi tükəndiyindən digər istismar üsullarının tətbiqi ilə mənimsənilsə də, layın enerjisi azaldığına görə düşən hasilatın artırılması və eyni zamanda hasilatın intensivləşdirilməsi məqsədilə də digər istismar üsulları tətbiq edilə bilər.

Bu işin əsas məqsədi Xəzər Dənizində, Abşeron arxipelaqında yerləşən Qərbi Abşeron (QA) neft yatağında xüsusi bir proqram təminatı ilə (PROSPER) Quyu QA-1 nömrəli qondarma bir

quyunun məlumatları əsasında istismar üsullarının (fontan, qaz – lift və MEDN) tətbiq olunmasının effektivliyinin müqayisəli analizidir. PROSPER proqram təminatında fontan istismar üsulu, kompressor istismar üsulu və MEDN istismar üsulları üçün nodal analizlər aparılmışdır. Darsi metodu ilə yatağın performans əyrisi və Petroleum Eksperts 2 metodu ilə nasos-kompressor borusunun performans əyrisi qurulmuş və bu iki əyrinin kəsişmə nöqtəsi fontan, qaz-lift və MEDN üsullarının hər biri üçün əldə olunmuşdur.

Proqram təminatına ilkin məlumatlar daxil edilmiş və fontan, MEDN və qaz-lift istismar üsulları üçün hasilat əyriləri qurulmuş, eyni zamanda müxtəlif ssenarilər üçün hesablamalar aparılmışdır. Fontan, MEDN və qaz lift istismar üsullarının detallı analizi, hər birinin ayrı-ayrılıqda modelləşdirilməsi aparılmış və hər üç istismar üsulu üçün hasilat göstəriciləri əldə olunmuşdur. İstismar üsulunun seçilməsində ortaya qoyulan əsas şərtlər və mülahizələr də öz əksini tapmışdır. Hər üç hal üçün hesablanmış hasilat göstəriciləri aşağıda verilmişdir:

- Fontan istismar üsulu üçün gündəlik neft verimi və quyudibinə düşən təzyiq uyğun olaraq **17.6 sm^3/gün** və 67.37 atm hesablanmışdır. Qeyd edilməlidir ki, modelləşdirilən quyu fontan istismar üsulu ilə işlədiyi zaman ən aşağı nəticəni göstərməkdədir.
- MEDN üsulu ilə işləyəcəyi halda modelləşdirilən quyunun gündəlik neft verimi **53.8 sm^3/gün** hesablanmışdır və əldə olunan bu göstərici quyunun fontan istismar üsulu ilə işlədiyi halda verimindən təqribən 3 dəfə böyükdür.
- Fasiləsiz qaz lift istismar üsulunun tətbiq ediləcəyi halda modelləşdirilən quyunun gündəlik verimi **50.8 sm^3/gün** hesablanmışdır və bu göstərici də kifayət qədər yüksəkdir.

Əldə olunan nəticələr əsasında qeyd edilməlidir ki, Qərbi Abşeron yatağında karbohidrogen hasilatının artırılması üçün quyuların fontan istismar üsulu ilə işləməsi ən əlverişsiz variantdır. MEDN və fasiləsiz qaz lift istismar üsullarının tətbiq olunması halında hesablanmış gündəlik neft verim qiymətləri bir-birinə çox yaxın olsa da, qaz lift istismar üsulunun tətbiqi üçün qaz mənbəyi ən böyük çətinliklərin başında durur. Belə ki, Qərbi Abşeron yatağında hazırda işlək vəziyyətdə olan istismar quyuları çox az miqdarda qaz hasil edir (bu neftdə həll olmuş qazdır) və bu həcm də qaz lift sisteminin tətbiqi üçün kifayət deyil. Bu o deməkdir ki, qaz lift sistemi üçün lift qazı başqa bir mənbədən, böyük ehtimalla yaxınlıqda yerləşən qaz yatağından əldə edilməlidir. Belə olan halda isə, qaz lift sisteminin tətbiq olunması üçün böyük miqdarda kapital investisiyasına ehtiyac yaranır. Əlavə olaraq qeyd edilməlidir ki, qaz lift sisteminin tətbiqi üçün lazım olan bütün infrastuktur və qaz kompressor stansiyası da tikilməlidir ki, bunlar da daha çox kapital investisiyası tələb edir. MEDN istismar üsulunun tətbiqi də detallı planlama və administrativ resusrlar tələb edir. MEDN istismar üsulunun tətbiqi əlavə çətinliklər və mürəkkəblikləri də özü ilə birgə gətirir. Bu üsulun planlaması və idarə olunması daha çətin və daha risklidir. Bu səbəbdən MEDN istismar üsulunun planlama mərhələsində ediləcək yanlışlıqlar izafi xərclərin formalaşmasına gətirib çıxara bilər. Ona görə də, MEDN istismar üsulunun tətbiqi ilə maksimum nəticə əldə etmək üçün detallı planlama və mühəndisi yanaşma tələb olunur. Həmçinin MEDN – lar quyudibində və flüid parametrlərində baş verən dəyişikliklərə çox həssasdır və bu səbəbdən MEDN - larının işləmə müddəti limitlidir və MEDN üsulu ilə işləyən quyularda nasosların sıradan çıxması halında onların yenisi ilə əvəzlənməsi layihənin işlənmə xərclərinin artmasına gətirib çıxaracaq. Ancaq qaz-lift ilə işləyən quyularda sistem olduqca sadədir və bu üsul dünyanın əksər yerində tətbiq olunur, hansı ki, kifayət qədər öyrənilmiş təcrübələr əsasında quyuların uzun müddət qaz-lift sistemi ilə işləməsi mümkündür. Əldə olunmuş nəticələr və qaz-lift sisteminin tərbiq olunması üçün lazım olan lift-qazının və lazımi infrastukturun mövcud olmaması faktını əsas tutaraq Qərbi Abşeron sahəsində karbohidrogen hasilatının maksimallaşdırılması və optimallaşdırılması üçün MEDN istismar üsulunun tətbiq olunmasının daha üstün seçim olduğu ortaya çıxır. Ancaq reallıqda bu planlama olduqca mürəkkəbdir və əldə olan mövcud məlumatlar əsasında hasilatın optimallaşdırılması hər bir quyu üçün ayrılıqda aparılmalıdır. Əlavə olaraq qeyd edilməlidir ki, hər iki sistemin detallı iqtisadi analizlərini apararaq, Qərbi Abşeron sahəsində karbohidrogen hasilatının artırılması və optimallaşdırılması üçüm hansı istismar üsulunun iqtisadi cəhətdən ən səmərəli olduğu nəticəsinə gəlmək olar.

Açar sözlər: Hasilatın artırılması, istismar üsulları, fontan istismar üsulu, kompressor istismar üsulu, dərinlik nasosu istismar üsulu, nodal analiz, PROSPER proqram təminatı

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List of Symbols and Abbreviations

AL	Artificial Lift
AOF	Absolute Open Flow
BHFP	Bottom Hole Flowing Pressure
BP	British Petroleum
CAPEX	Capital Expenditure
EOR	Enhanced Oil Recovery
ESP	Electrical Submersible Pump
FVF	Formation Volume Factor
GLR	Gas-Liquid Ratio
GOR	Gas-Oil Ratio
HC	Hydrocarbon
HJP	Hydraulic Jet Pump
ID	Internal Diameter
IN	Inch
IPM	Integrated Production Modelling
IPR	Inflow Performance Relationship
KOP	Kick-Off Point
KS	Kirmaky Suite
MD	Measured Depth
OD	Outside Diameter
OPEX	Operating Expenditure
PCP	Positive Cavity Pump

PDP	Positive Displacement Pump
PETEX	Petroleum Experts
PI	Productivity Index
PKS	Pre-Kirmaky Suite
PS	Productive Series
PVT	Pressure-Volume-Temperature
SRP	Sucker Rod Pump
TD	Target Depth
TPR	Tubing Performance Relationship
TVD	True Vertical Thickness
UK	United Kingdom
VFD	Variable Frequency Drive
VLP	Vertical Lift Performance
VOC	Volatile Organic Compound
WA	West Absheron

Chapter 1: Introduction

It is undeniable fact that hydrocarbons and mainly crude oil is the most valuable source of natural energy around the globe and remarkable accomplishments of modern civilizations would not exist without crude oil. Crude oil has been still utilised for various purposes in our daily lives and apart from heavy industry, crude oil finds its applications on different types of chemical products including medicine, cleaning detergents, cosmetics and so on.

Although crude oil accumulations are classified as non-renewable resources, there are still tremendous amounts of proved crude oil reserves around the world. According to BP, total proved oil reserves of all oil producing countries are equal to 1732.4 billion barrels for the end of 2020 (BP, 2021). And it is estimated that almost 1 trillion barrels of crude oil have already been extracted. Taking the global demand on energy into consideration, daily production rates are extremely high compared to some decades ago. In addition to that, E&P companies are trying to discover new fields in deeper parts of the earth crust together with optimization and enhancement of hydrocarbon production in the producing fields.

The need for hydrocarbon production optimization and enhancement has always been the main target for E&P companies and technological advancements have provided required tools for petroleum engineers to discover the most efficient ways of exploiting hydrocarbon reserves and maximize hydrocarbon recovery factors as much as possible.

Problem Statement

This section highlights the problem of this research, the aims and objectives of the thesis work, and the importance of research is outlined here as well.

Thesis Problem

A decision has to be made to increase and optimize hydrocarbon production in the West Absheron oilfield (located in Absheron archipelago, The Caspian Sea.) where there are still too much recoverable hydrocarbon reserves in place. Here the main task is to do comparative analysis of effectiveness in implementation of natural drive and artificial lift methods (gas – lift and pumps) for hydrocarbon production by using a special computer software on the basis of a synthetic well data, namely Well WA-1 to accelerate hydrocarbon production in West Absheron oilfield.

Aims and Objectives of the Thesis

The thesis work aims to perform comparative analysis in implementation of natural drive and artificial lift methods including gas-lifting and ESP application in the West Absheron oilfield to select best production technique for hydrocarbon production acceleration purpose. Here the objectives include modelling a well with natural drive case and artificial lift methods in a computer software to determine how production rate changes for each case through finding the intersection point (solution node) between IPR curve and VLP curve. Moreover, this research targets to see how the production rate is affected with regards to changes in reservoir parameters for each scenario and decide on the most suitable one.

Importance of the Thesis Work

This thesis work is done to decide the most suitable production technique in the West Absheron oilfield, where there is still a significant volume of unrecoverable reserves in place. The main importance of this research includes:

- Choose the best production technique suitable for increased production rate on the basis of the well deliverability evaluation
- Make sensitivity analysis to understand the impact of changing parameters on reservoir performance and well performance for three different production techniques.

Thesis Plan:

This thesis work aims to define the best suitable production technique to implement in West Absheron oilfield to maximize and optimize hydrocarbon production. For this purpose, this paper is divided into four main chapters. The followings represent the structure of this thesis work:

- **Chapter 1** includes the main objective of this thesis work and fundamental knowledge behind reservoir performance and well performance. What is more, the flowchart of this thesis work, required input data and the computer software that the modelling is done are covered.
- **Chapter 2** provides elaborated information on natural drive mechanism and types of natural drive, definition of artificial lifting and their most common types applied in the industry, their working principle and artificial lift selection criteria based on advantages and disadvantages of each type.

- **Chapter 3** starts with brief info about the geology of the study area and volume of recoverable reserves. Then a detailed modelling of natural drive case, ESP case and continuous gas lift case is carried out on PROSPER and obtained results are provided by means of tables and graphs. What is more, sensitivity analysis is performed to see how production rates are affected by changing reservoir parameters.
- **Chapter 4** finalizes the findings of this work and provides the conclusion on the most suitable technique that can be considered to increase and optimize hydrocarbon production in West Absheron oilfield. It also includes some recommendations for further investigations.

Inflow Performance Relationship

A general definition for reservoir deliverability is that fluid (oil or gas) production rate that can be achieved from a reservoir at a determined bottom hole pressure. Reservoir deliverability is a key element in petroleum production engineering, and it plays a vital role in selection of well completion type and artificial lift methods. In reservoir deliverability modelling, the relationship between bottom hole pressure and fluid production rate is analysed and this relationship in petroleum engineering is also called "Inflow Performance Relationship (IPR)" (Guo, 2007).

A typical IPR curve that shows relation between flowing bottom hole pressure and fluid production rate is also used to define productivity index (PI or J in some literature). The slope of IPR curve is equal to productivity index and it is defined by the following equation:

$$J = \frac{q}{(P_e - P_{wf})}$$

Here:

q is liquid flow rate.

P_e is average reservoir pressure

P_{wf} is flowing bottom hole pressure.

It should be noted that, derivation of IPR curves for single (liquid)-phase reservoirs and two-phase reservoirs is different and for that reason different models must be deployed to construct IPR curves. (Michael & Curthis H, 1991) States that the simplest and commonly used IPR equation in production engineering is the straight-line IPR curve and it shows that surface flow rate is directly proportional to pressure drawdown in the reservoir. This relationship is given in the Figure 1 and some important features related to this curve are given below:

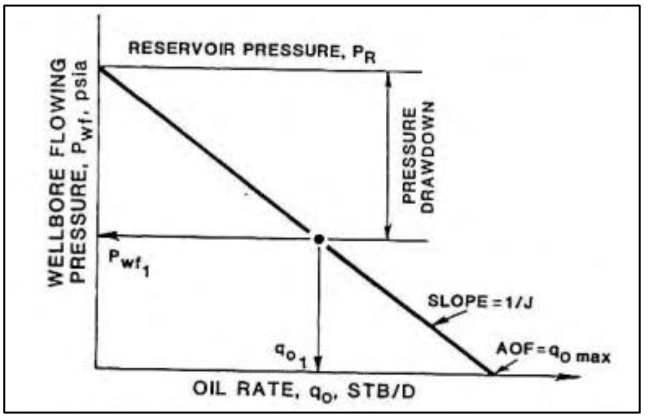


Figure 1. Straight-Line IPR Curve *(Beggs, 2008)*

- When the flowing bottom hole pressure is equal to reservoir pressure, then surface flow rate is equal to zero, meaning that there is not any pressure drawdown to initiate liquid flow.
- When the flowing bottom hole pressure is equal to zero, that means drawdown pressure will be maximum and surface flow rate will also be maximum. This is given by AOF (absolute open flow) or q_{max} which is practically impossible to achieve.
- Slope of IPR curve is equal to the reciprocal of the PI (productivity index, also known as J).

From the relationship between flowing bottom hole pressure and liquid flow rate, it is obvious that straight-line IPR curve is only applicable for under saturated oil reservoirs where there is only one phase present in the reservoir condition. So, construction of straight-line IPR curve assumes that oil is under saturated. However, this condition is not applicable to gas reservoirs or saturated oil reservoirs (because of having highly compressible nature) (Michael & Curthis H, 1991). In case of saturated oil reservoirs, the dissolved gas comes out of the solution and becomes a free gas. This free gas leads to reduction on relative permeability to oil and increase on oil viscosity. Both effects cause lower liquid production rate at a given pressure drawdown. Thus, there will be a deviation from linear trend in IPR curve when the reservoir pressure is below than bubble point pressure (Guo, 2007).

In literature there are several empirical equations to model IPR of two-phase reservoirs and among them Vogel's (1968) equation is more commonly used for modelling of oil well performances in saturated oil reservoirs (Economides & Nolte, 2000):

$$\frac{q_o}{q_{o,max}} = 1 - 0.2\frac{P_{wf}}{P} - 0.8\left(\frac{P_{wf}}{P}\right)^2$$

Here $q_{o,max}$ represent the maximum oil flow rate (AOF) when the flowing bottom hole pressure is equal to zero (P_{wf} = 0):

$$q_{max} = \frac{J * \bar{P}}{1.8}$$

In some cases, reservoir pressure is above the bubble point pressure, but flowing bottom hole pressure is below the bubble point pressure. In order to construct an IPR curve for this type of scenarios, a straight-line IPR model above the bubble point pressure and Vogel's IPR model below the bubble point pressure are deployed (Guo, 2007). The following comments are given to describe the ***Figure 2*:**

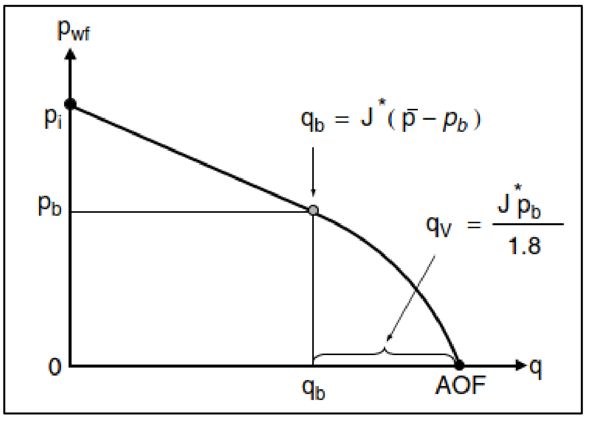


Figure 2. Typical IPR curve of partially two-phase reservoir *(Guo, 2007)*

- Linear IPR model at the bubble point pressure is defined by:

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

- Based on Vogel's IPR model, flow rate below the bubble point pressure is given by:

$$q = q_b + q_v\left[1 - 0.2\frac{P_{wf}}{P_b} - 0.8\left(\frac{P_{wf}}{P_b}\right)^2\right]$$

- Here:

$$q_v = \frac{J * P_b}{1.8}$$

Rearranging the equation leads to the below equation:

$$q = J * (\bar{P} - P_b) + \frac{J * P_b}{1.8} \times \left[1 - 0.2\frac{P_{wf}}{P_b} - 0.8\left(\frac{P_{wf}}{P_b}\right)^2\right]$$

Factors affecting IPR

There are some reservoir parameters which have an effect on IPR. Those parameters include rock and fluid properties, reservoir pressure, skin factor, well geometry and well flowing pressure. If viscosity of the oil increases, then flow velocity of the oil through the porous medium decreases, so that, this gives rise to a drop in productivity index. On the other hand, it is quite obvious that, high reservoir pressure will give higher oil production rate. Additionally, system deliverability rises to a point when the skin factor is decreased by well stimulation techniques such as acidizing or fracturing. After that point, reduction in skin factor will not cause any increase in system productivity (Beggs, 2008).

Outflow Performance Relationship

Wellbore flow performance is an essential tool to evaluate the performance of the production tubing by plotting the fluid production rate versus flowing bottom hole pressure. In literature outflow performance relationship is also called tubing performance relationship (TPR) or vertical lift performance (VLP). VLP is used to determine required bottom hole flowing pressure to transfer fluids flowing at different flow rates to the surface. (Lyons, 2016) As it is obvious from the Figure 4 there are eight pressure drops in the flow path of formation fluid and the fluid must overcome all pressure losses to move to the surface facility equipment (Economides & Nolte, 2000). VLP allows the production engineer to minimize pressure losses along the flow path and maximize the well production. In order to plot VLP for a typical well, either wellhead pressure or flowing bottom hole pressure is fixed at a given flow rate. Then the pressure drop along the production tubing is calculated on the basis of correlations or engineering charts. Then flowing bottom hole pressure is plotted against production rate and the resultant relationship gives VLP curve (Michael & Curthis H, 1991).

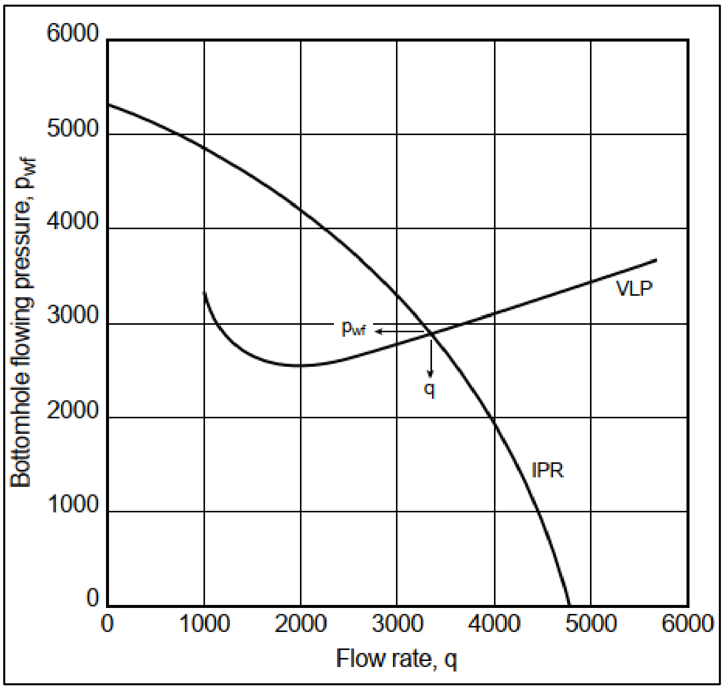


Figure 3. Typical IPR and VLP curve to predict well deliverability *(Economides & Nolte, 2000)*

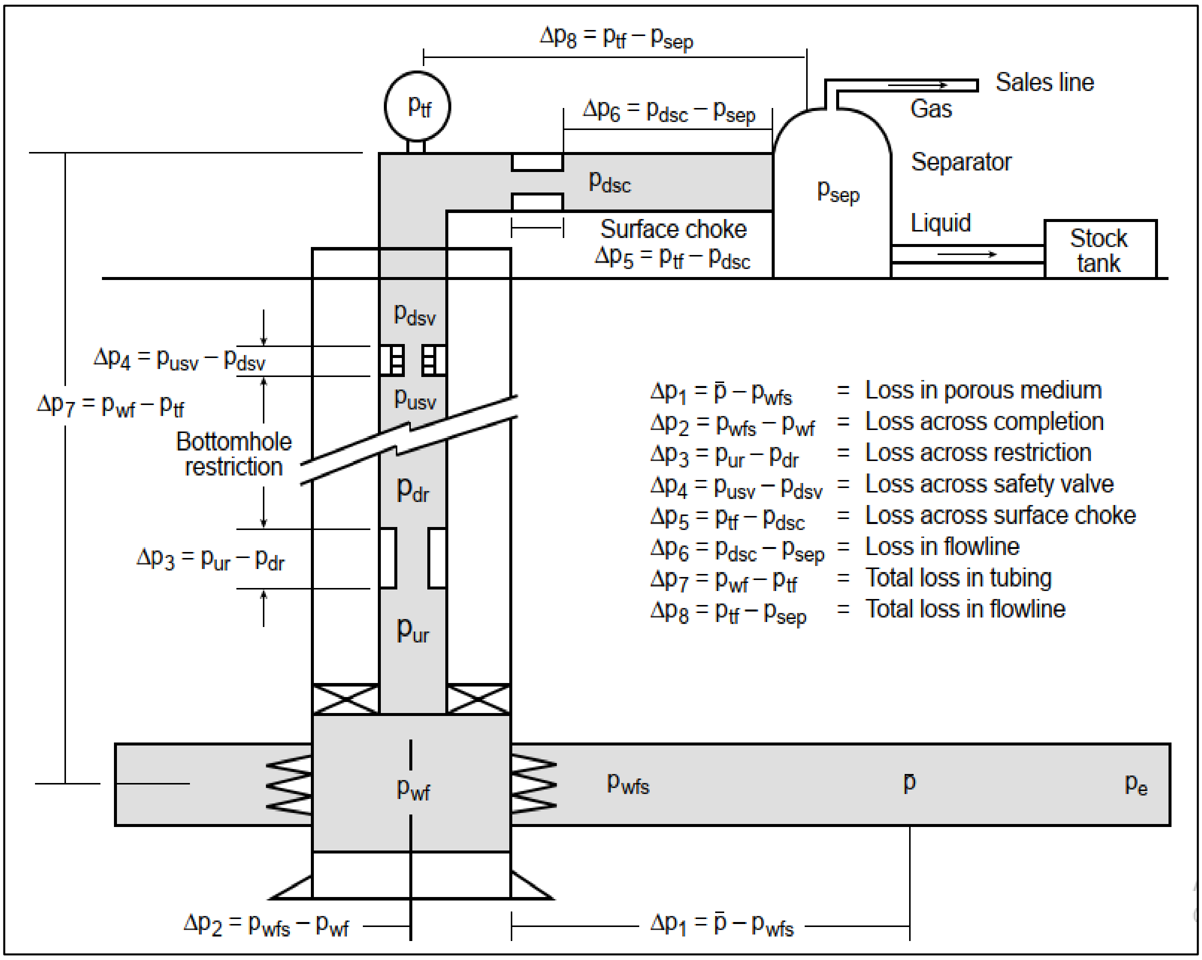


Figure 4. Pressure losses along the system *(Economides & Nolte, 2000)*

IPR and VLP curves are used to evaluate production capacity of a well. This evaluation in production engineering is known as Nodal Analysis where the well deliverability is analyzed based on reservoir performance and well performance. In the nodal analysis a solution node is selected within the system (Tetoros, 2015). At the solution node the system is divided into two sections. Either bottom hole or wellhead can be selected as a solution node. If for example, bottom hole is selected as a solution node that means fluid flow from reservoir into the bottom hole of the well is regarded as inflow that is reflected in IPR curve and the fluid flow from the bottom hole to the wellhead through the production tubing is regarded as outflow, which is displayed in VLP curve. The intersection point of IPR and VLP curves provide the stabilized flow rate which is also the natural flow point. It should be noted that when these two curves are not intersecting, that means the well will not naturally flow and some artificial lifting should be taken into consideration (Economides & Nolte, 2000).

Pressure drop calculations

The total pressure drop in a well is the sum of the pressure drop due to frictional forces (ΔP_f), gravitational energy change (ΔP_g) and kinetic energy changes (ΔP_k).

$$\Delta P = \Delta P_f + \Delta P_g + \Delta P_k$$

Pressure drop due to frictional forces:

$$\Delta P_f = \frac{2 f_f \rho u^2 L}{D}$$

Where f: The Moody friction factor

In laminar flow it is a simple function of the Reynolds number.

$$f = \frac{64}{N_{Re}}, N_{Re} = \frac{\rho u D}{\mu}$$

The Reynolds number is used to determine the type of flow which is recognized by certain boundaries between flow regimes.

$N_{Re} \leq 2000$: Laminar flow

$2000 < N_{Re} \leq 4000$: Transition between laminar and turbulent flow

$4000 < N_{Re}$: Turbulent flow

Pressure drop due to kinetic energy change:

$$\Delta P_k = \rho (u_2^2 - u_1^2)$$

Pressure drop due to potential energy change:

$$\Delta P_g = g \rho L sin\theta$$

where g: the acceleration due to gravity,

ρ: fluid density,

L: the length of the pipe and

θ: the angle between horizontal and the direction of flow

Factors affecting the VLP curve

VLP is influenced by some parameters including production rate, PVT properties, tubing size, well depth, surface pressure, water cut, GOR/GLR and restrictions such as scale, waxes. Generally, an increase in tubing size leads to higher production rate on the other hand, smaller tubing diameters give rise to increasing the pressure drop due to the frictional losses within the tubing and this in turn cause to increase the bottom – hole pressure. and this in turn, affects

VLP curve shape. Another significant parameter that should be taken into account is water cut. So, higher water cut results in decreasing the GLR eventually increasing average fluid density. This means, more pressure will be required to lift heavier fluid up to the surface (Production Technology - 1, 2015).

Methodology

This section briefly covers the flowchart of this research procedure, the available data to analyse reservoir performance (IPR) and well performance (VLP) for Natural Drive case, ESP case and Gas Lift case and the computer software that is required to perform calculations and sensitivity analysis for each production techniques.

Flowchart of Research Procedure

The following figure represent the flowchart to achieve the objective of this research.

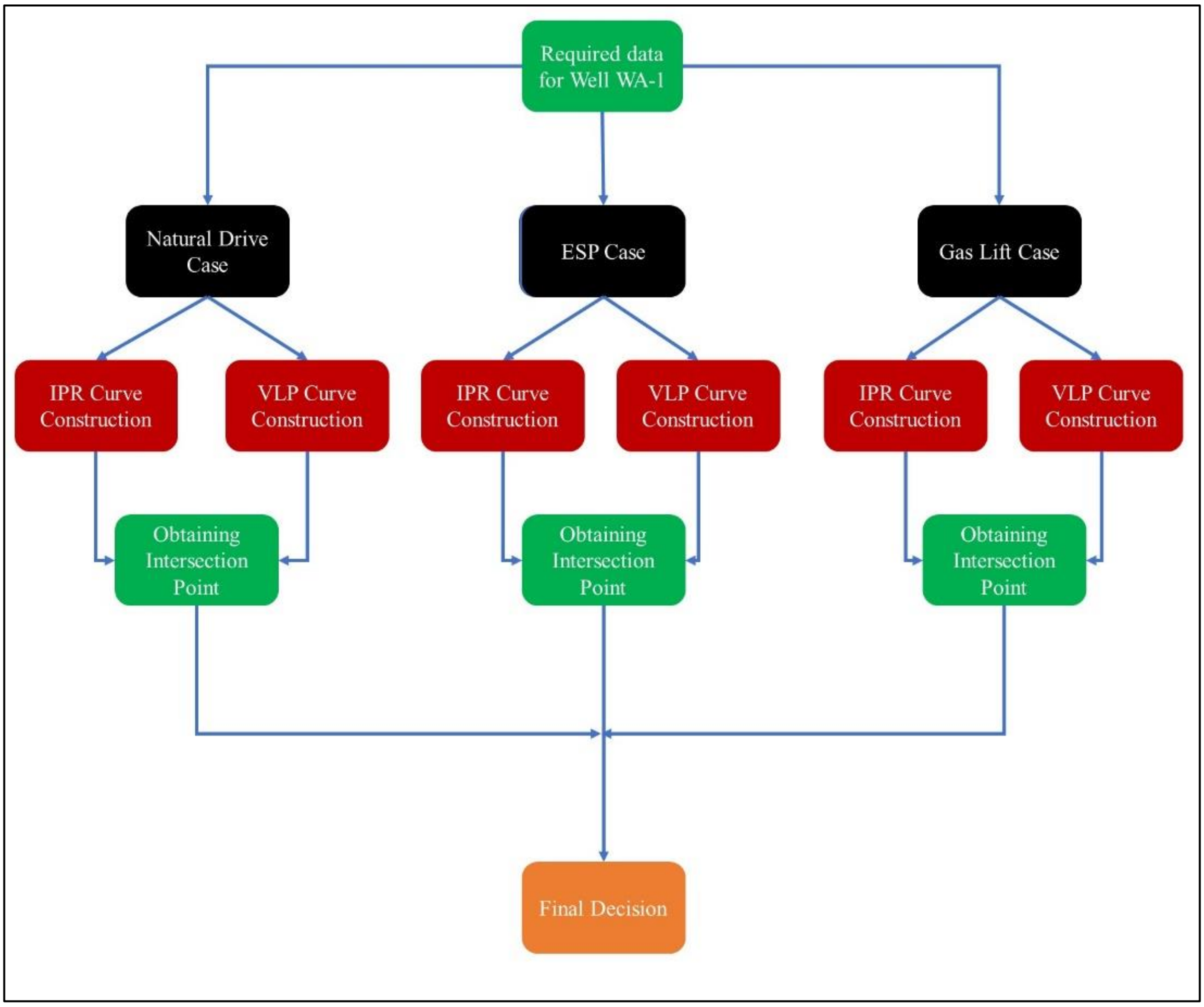


Figure 5. Flowchart of research procedure

Required Data

The data needed to perform calculations and make final decision is as follows:

- PVT data
- Reservoir Data
- Equipment data: this includes downhole equipment, deviation survey, geothermal gradient, and average head capacities
- Gas lift data for gas lift case
- ESP data for ESP case

Summary of required input data is for IPR curve generation is given in

Table 1. PVT data

PVT properties	***Value***	***Unit***
Solution GOR	31.632	m^3/m^3
Oil gravity	806.509	kg/m^3
Gas gravity	0.65	sg
Water salinity	76580.7	ppm
Mole percent H2S	0	%
Mole percent CO2	0.2	%
Mole percent N2	0	%

Table 2. Reservoir and wellbore properties

Properties	***Value***	***Unit***
Reservoir pressure	82	atm.
Reservoir temperature	34	°C
Water cut	5	%
Total GOR	31.632	m^3/m^3
Reservoir permeability	30	mD
Reservoir thickness	13	m
Drainage area	750000	m^2
Dietz shape factor	31.6	unitless
Skin factor	3	unitless
Wellbore radius	6	inches
TD	750	m MD
TD	620	m TVD

Required Software

In this research project, PROSPER software is used to perform calculations, construct IPR and VLP curves, obtain intersection points and do sensitivity analysis. PROSPER is a very useful and powerful tool that enables production engineers to obtain inflow/outflow performance curves, create IPR and VLP models, select best artificial lift method, do well perforation design and so on based on the minimum required data (IPM PROSPER User Manual ,Version 11.5, January 2010). The software is a product of Petroleum Experts Limited (PETEX), located in UK and one of most used software in the petroleum industry.

Chapter 2: Hydrocarbon Production Techniques

It is generally true that in newly developed fields the hydrocarbons can flow naturally to the earth surface through the production tubing due to sufficient reservoir pressure to push reservoir fluids. However, through time the reservoir pressure may drop due to depletion if pressure maintenance actions have not been taken in the field. In these cases, reservoir fluids may not flow naturally to the surface because of insufficient reservoir pressure and to lift hydrocarbons to the surface artificial lift techniques can be applied. Therefore, artificial lifting helps production engineers to make the “dead” wells alive and to achieve increased hydrocarbon production in the producing wells. In the following subsections the natural drive mechanisms, types of artificial lift methods and artificial lift selection criteria are covered in detail.

Natural Drive Mechanisms

Primary hydrocarbon recovery refers to the production of hydrocarbons by the help of natural energy available in the reservoir without supplementary aid from other sources like fluid injection into the reservoir. This natural energy is also known as “natural drive mechanism”. As (Tarek & D.Nathan, 2012) states, knowledge on reservoir drive mechanism is playing a vital role in understanding fluid behaviour within the porous medium and future fluid production forecasting. This drive mechanism is the main energy source to push hydrocarbons towards the producing wells. Generally, six reservoir drive mechanisms are present which provide the available natural energy support for hydrocarbon recovery (Tarek & D.Nathan, 2012):

- Gas cap drive
- Water drive
- Gravity drainage drive

- Solution gas drive
- Rock and liquid expansion drive
- Combination drive

Gas Cap Drive

Reservoirs with gas cap are characterized by having a free gas zone on top with negligible water production. Here the main drive mechanism is expansion of the gas cap. As the gas cap expands due to the oil recovery, reservoir pressure declines slowly and almost at a constant rate. Ultimate oil recovery due to the expansion of gas cap may range from 20% to 40%, but it largely depends on the factors like size of original gas cap (oil recovery is directly proportional with the size of gas cap), vertical permeability, viscosity of oil (high oil viscosities will lead to gas bypassing and lower oil recovery), conservation of gas cap (wells producing higher amount of gas should be shut in to keep gas cap support in place) and also dip angle of the formation rock (steeply dipping formations cause good oil drainage to the bottom of the structure and this will lead to higher recovery factors up to 60%) (Tarek & D.Nathan, 2012).

Water Drive

Many reservoirs in a worldwide are bounded by water-bearing formations that are known as aquifers. For that reason, water-drive reservoirs are also called aquifer-supported reservoirs (Tarek & D.Nathan, 2012). The size of aquifers may be so large compared to hydrocarbon bearing strata itself or it can be so small that its impact on hydrocarbon recovery may be neglected. In water drive reservoirs while the hydrocarbons are extracted waterfront advances to take place of the produced oil or gas and displaces the hydrocarbons towards the producing wells (George R, 1946). Thus, reservoir pressure compared to gas cap drive reservoirs remains at a higher levels and pressure reduction is almost gradual (mainly depends on production rate). In terms of ultimate hydrocarbon recovery water drive mechanism yields largest values compared to all other drive mechanism (may be in a range of 35-75%) (Djebbar & Erle C, 2015). However, degree of heterogeneity should be considered to achieve higher recovery factors when dealing with more heterogeneous reservoirs (waterfront moves faster in high permeability zones, leading to earlier water-cut and earlier economic limits) (Tarek & D.Nathan, 2012).

Gravity Drainage

Gravity drainage drive mechanism generally relies on the gravitational segregation of fluids in the porous medium due to differences on densities (Tarek, Ahmed, 2018). The reservoirs with gravity drainage are often characterized as being heavy oil reservoirs, but for gravitational segregation, it will need sufficient time (Djebbar & Erle C, 2015). Production rates from gravity drainage reservoirs are generally low because gravitational segregation process continues at a low speed, but ultimate recoveries may reach up to 70% (Tarek, Ahmed, 2018).

Solution Gas Drive

In reservoirs with solution gas drive (or depletion drive in some literatures) fundamental source of energy is gas liberation from the solution due to the reservoir pressure decline and subsequent solution gas expansion (Tarek & D.Nathan, 2012). In order to have this type of energy source, reservoir pressure should fall below the bubble point pressure, thus leading to gas expansion and this expansion forces oil droplets out of the pore space. Mostly reservoir pressure declines continuously due to the absence of external energy support like gas cap or aquifer (Cole, 1969). Absence of aquifer support below also leads to little or no water production during the entire life of the reservoir (Tarek & D.Nathan, 2012). Moreover, solution gas drive reservoirs are exemplified as having higher GOR ratios and formation of secondary gas cap due to the pressure fall below the bubble point pressure. However, to have a secondary gas cap formation vertical permeability must be good enough (Clark, 1969).

Rock and Liquid Expansion Drive

When the pressure of an oil reservoir is above its bubble point pressure, then this type of reservoir is called an undersaturated oil reservoir (Dake L, 1983). As the reservoir pressure declines due to the fluid withdrawal, the reservoir rock and formation fluids expand, and this expansion leads to the reduction in the pore volume. Drop on pore volume pushes oil and water out of the rock pore space towards the producers (Tarek, Ahmed, 2018). On the other hand, since both liquids (oil and water) and formation rock are considered as slightly compressible, there will be a sharp fall on reservoir pressure (Tarek & D.Nathan, 2012). For that reason, reservoirs having this type of natural energy source are achieving very low hydrocarbon recoveries, ranging between 3% and 5% (Djebbar & Erle C, 2015).

Combination Drive Mechanism

Generally, the hydrocarbons reservoirs are characterized as having more than one driving mechanism, which is called combination drive. Among the possible scenarios combination of solution gas drive with a small free gas cap (gas cap drive) and aquifer support (water drive) is more commonly encountered (Tarek & D.Nathan, 2012). Nevertheless, pressure support by both water encroachment below and gas expansion above is not adequate to keep reservoir pressure as high as possible and this leads to rapid pressure reduction. In addition to this, ultimate hydrocarbon recovery under this type of drive mechanism is between recovery factors from solution gas drive and water or gas cap drive (Tarek & D.Nathan, 2012).

Artificial Lifting

Depending on the natural energy available in the reservoir, hydrocarbons naturally flow to the surface at the early stages of the field development because the reservoir pressure is high enough to support natural flow. These naturally flowing wells have sufficient energy to push hydrocarbons to the surface. However, when the wells are not capable of flowing naturally since bottom hole pressure is inadequate to overwhelm the total pressure losses along the fluid flow path or the production rate is not high enough to be economic, then artificial lift (AL) is required to be implemented (Takacs, Sucker-Rod Pumping Handbook, 2015). As it is obvious from the Figure 6, this well cannot flow naturally because reservoir pressure is less than the hydrostatic pressure due to the liquid column in the wellbore and the well is only capable of pushing hydrocarbons up to some level. Thus, an artificial lifting must be deployed to "initiate" fluid flow in this well.

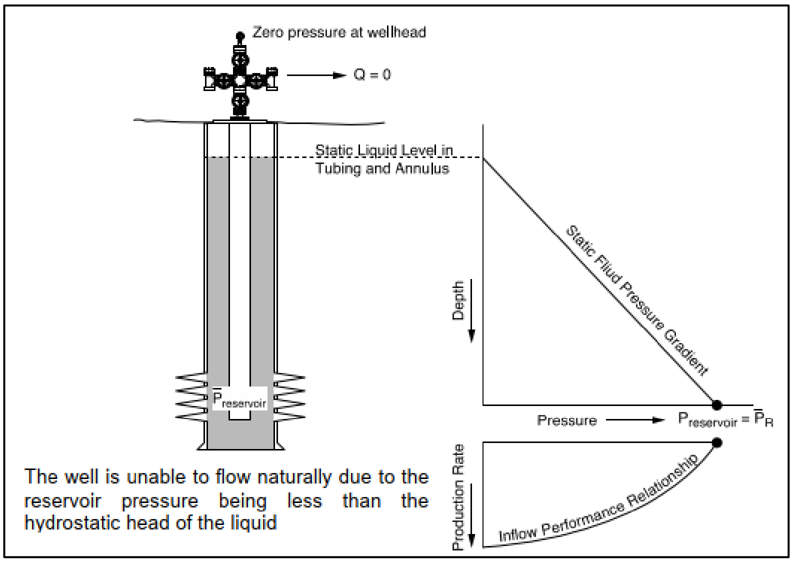


Figure 6. Typical well profile which is naturally unable to flow *(Production Technology - 1, 2015)*

Types of Artificial Lift Methods

Introduction

Basically, there are two artificial lift methods in production engineering. It can be either downhole pumping or gas lift (Michael & Curthis H, 1991). In case of downhole pumping a specially designed pump is lowered into the well and it operates at the bottom. This downhole pump aids the movement of hydrocarbons from the bottom hole to the wellhead by eliminating the backpressure when the fluids flow through the production tubing. In case of gas lifting, natural gas is injected into the tubing/casing annulus and from the annulus injected gas flows into production tubing through gas lift valves, and this injected gas mixes with the fluid column within the tubing, reduces its density and thus hydrostatic pressure at the formation rock.

Gas Lift

In gas lifting high-pressure gas (mainly natural gas, however N_2 or CO_2 may be used as well) is injected into the production tubing at some downhole point or points (Takacs, Sucker-Rod Pumping Handbook, 2015). There are two types of gas lift systems:

- Continuous Gas Lift
- Intermittent Gas Lift

In a continuous gas lift system, the high-pressure gas is continuously injected into the tubing/casing annulus to enhance potential of well flow. As the gas mixes with the fluid inside the tubing it aerates and its density decreases. This by nature reduces hydrostatic pressure due to the fluid column and frictional pressure drop within the tubing. All these factors lead to decrease in the flowing bottom hole pressure and well starts to flow (Abdin, 2000).

The high-pressure gas injected into the tubing/casing annulus forced through the gas lifts valves, kill fluid is displaced through the gas lift valves, which are open, into the tubing. As the injected gas goes on to displace and unload the annular kill fluid, casing pressure will rise and artificial lifting capability will be maximized. Several unloading valves are fitted on the production tubing that are used to unload the well and an operating valve or master valve that is an orifice type valve is fitted at the deepest position to control the gas injection point and it never closes (Tetoros, 2015) (Figure 7).

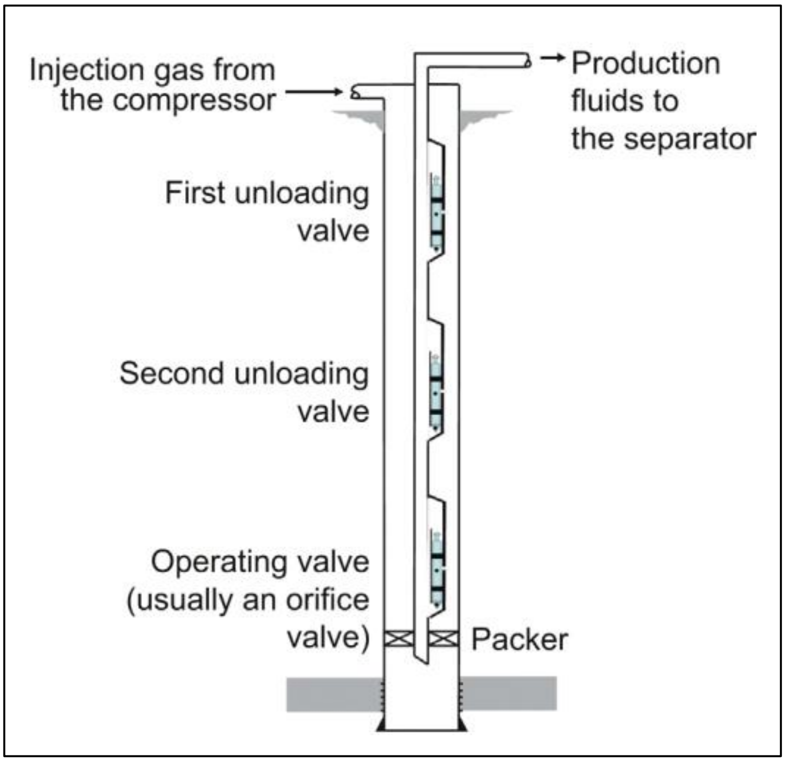


Figure 7. Typical completion of a gas lifted well *(Hernandez, 2016)*

When the fluid in annulus is unloaded through the first valve, the casing pressure will get its designed kick-off pressure. This pressure is quite enough to cause to fall level of the casing fluid below the first mandrel and allow gas injection through the top valve. This injected gas, as mentioned above, gives rise to a less gradient inside the tubing allowing the well to unload the kill fluid entering the tubing through the lower valves when the well proceeds to unload. When the fluid in annulus is transferred to the second valve, injected gas starts entering the tubing through the second valve. The injection of both the first and second valve exceeds the throughput of the surface input choke causing a casing pressure to reduce. This reduction leads to the top valve to close. During the unloading process, gas injection proceeds through the second valve, produced well fluids and displaced kill fluids are lifted. It should be noted that when the well is unloaded through the second valve, the static bottom hole pressure is greater than the pressure at the bottom of the tubing. This differential pressure, which is called a drawdown, give rise to produced fluids to flow into the well. The above procedure is done again, when the casing fluid is unloaded down below an extra valve, closing the upper valve when the unloading process goes on to the deepest point of gas injection. There is a pressure recorder at surface, which records a casing pressure drop every time a valve closes. An indication of the valve operating depth can be achieved by a reading of the recorded pressure, which is obtained during the well unloading (Shell, 1993).

In the continuous gas lifting operation, the well first is fully unloaded through the unloading valves and once the steady-state flow is established, only the operating valve will be in an open position and gas injection will continue through this valve. (Lyons, 2016)

In the intermittent gas lift operation, the high-pressure gas is injected periodically to displace a liquid slug within the production tubing to the surface. This type of AL is generally applicable for wells when PI of the well or reservoir pressure is very low. The mechanism behind intermittent gas lifting is that when a proper column of liquid slug builds up in the production tubing relatively high volume of pressurized gas is injected below this liquid column and it pushes that column to the surface. Then gas injection terminates until another liquid column at the bottom of production tubing forms. As it is obvious from the operations, intermittent gas lift is a cyclic process. (Hernandez, 2016)

Sucker Rod Pump

Sucker rod pump, rod pump, reciprocating pump or pump jack is the first type of artificial lift method applied in the petroleum industry and it is still in use worldwide, including Azerbaijan. This type of artificial lift method is generally applicable in wells that have very low fluid production rates. (Nguyen, 2020) Due to its mechanical simplicity and low operating cost rod pump is a good candidate to be applied in such low fluid volume operations. It should be highlighted that this type of pump is not capable of handling restrictions due to the friction between the tubing wall and rod in deviated or horizontal wells. In a simple definition, rod pump consists of surface unit, downhole pump and polished rod and sucker rods that provide connection between surface equipment and downhole pump (Figure 8). The basic principle behind rod pump is as followings (Takacs, Sucker-Rod Pumping Handbook, 2015):

- The surface equipment converts rotational motion provided by prime mover to the reciprocating motion via a mechanical configuration
- This reciprocating motion is transferred to polished rod and from that to sucker rods
- The sucker rods drive the downhole pump plunger

Inside the downhole pump unit there are pump barrel, plunger, traveling valve and standing valve. The standing valve (it is stationary) is placed at the bottom of the pump barrel. However, traveling valve is mounted at the top of hollow plunger. These valves act as non-return valves because they contain a ball and when this ball is seated it closes the passage for fluid movement. During the upward rod movement (upstroke) the pressure inside pump barrel decreases, standing valve opens and it allows formation fluids entering the pump barrel. During the upstroke traveling valve is in closed position due to the weight of liquid column above the plunger. The reverse process occurs during the downward rod movement (down stroke). At this time pressure inside the pump barrel increase due to the compressional action and this forces fluids inside the barrel to move upward through the traveling valve (it is

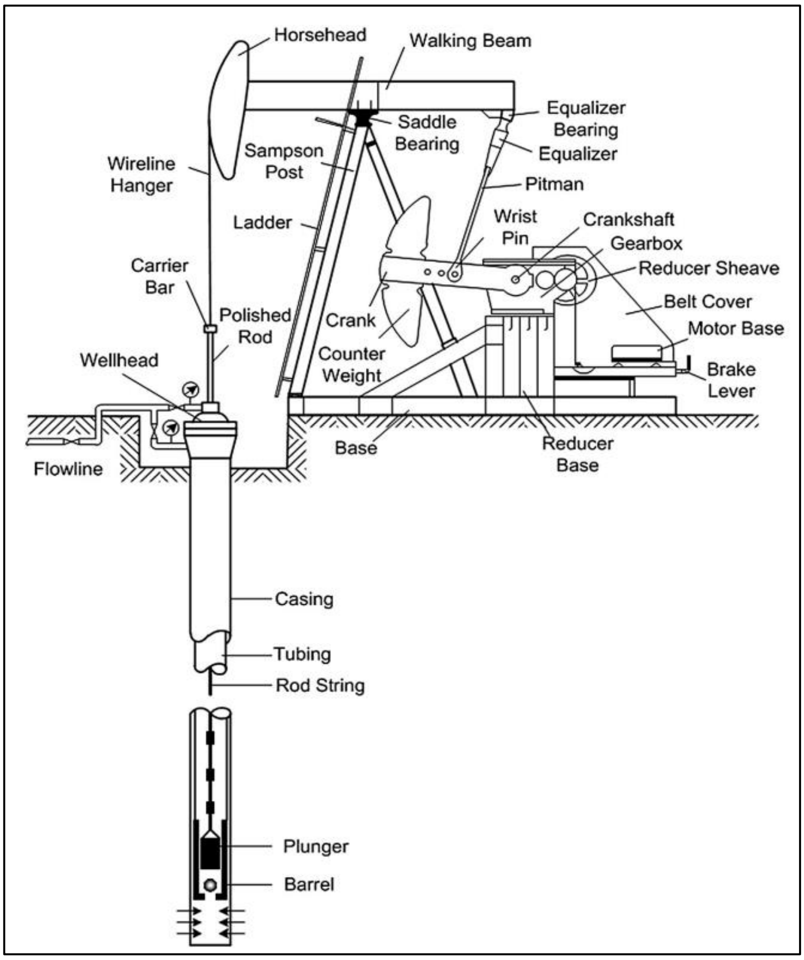


Figure 8. Typical schematic of SRP *(Beggs, 2008)*

in open position), while the ball of standing valve stays stationary due to the piston effect (Lyons, 2016).

Electrical Submersible Pump

Electrical submersible pump (ESP) is a multistage centrifugal pump that is commonly used to lift moderate or high volume of reservoir fluids in petroleum industry. As its name implies, ESP also utilizes a downhole pump to provide energy to the formation fluids within the wellbore and thus increases hydrocarbon recovery (Lyons, 2016). ESP systems include both surface and downhole components. Typical ESP system downhole components include the followings:

- Motor
- Protector or seal
- Pump unit
- Power cables
- Gas separator

Typical ESP system surface components include (Figure 9):

- Electric power supply
- Variable Speed Drive
- Vent box

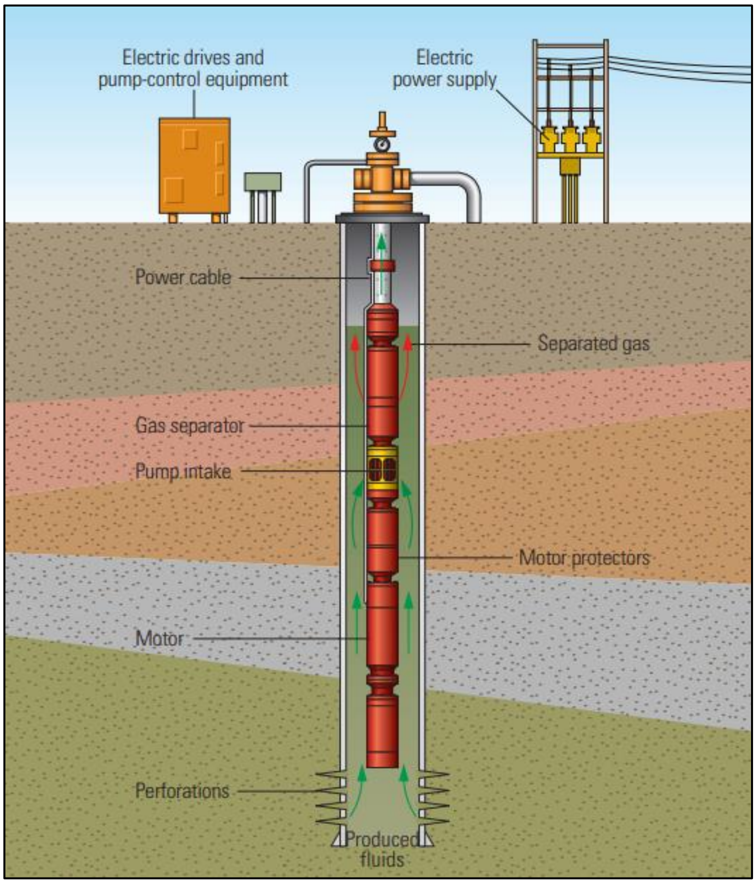


Figure 9.Typical ESP configuration *(Oilfield Review, 2016)*

The working principle of typical ESP system is as follows: because ESP is a multistage centrifugal pump, its pump unit is composed of a stacked series of rotating impellers on a central drive shaft and stationary diffusers. As the formation fluids enter the first stage, the rotating impeller accelerates the fluid, and it gains kinetic energy. Then centrifuged fluid is discharged into the stationary diffuser where its kinetic energy transforms into potential energy, meaning that fluid gains pressure. After that the fluid which has already gained some amount of pressure is forced into the next stage of pump unit. After passing through all impeller/diffuser pairs, the formation fluid gains enough pressure head to travel to the surface. Depending on the pressure head increase required, impeller/diffuser pairs may range between 10 to more than 100. ESP can be installed in deeper wells, and they are capable of handling some free gas in the fluid. But it should be noted that gas separators should be installed when the gas percentage is higher than 20 (Takacs, Electrical Submersible Pumps Manual, 2017).

There are some advantages and limitations of using ESP units are demonstrated in *Table 3* (H.Modahi, 2012)

Table 3.ESP advantages and disadvantages

Advantages	Disadvantages
It can be utilized in deviated and horizontal wells.	Abrasive materials or sand will reduce the efficiency, causing the ESP to fail.
It is capable of lifting a high volume of liquid.	Not suitable for high temperature wells.
Corrosion and scale treatment can be easily applied.	More power will be required, and less amount of liquid will be produced during production of high viscous fluid.
If proper installation of sub – surface equipment is done, it requires low maintenance.	Without rotary gas separators, free gas at the pump intake will reduce the ESP efficiency causing less fluid to flow.

Hydraulic Jet Pumps

The hydraulic jet pumps convert the kinetic energy from the pumped power fluid to pressure that lifts produced fluids. Water, condensate or HC liquids can be used as a power fluid. Although it has also quite high tolerance to both corrosive and abrasive fluids, in order to retard tubular corrosion and solve downhole flow problems, chemicals and inhibitors can be added to the power fluid. Simple downhole design and having no moving parts that may unavoidably wear out are the main advantages of HJP. Additionally, it effectively operates in both shallow and deep wells with high deviation angles and high temperature wells. Low operation and maintenance cost, reduced workover intervention, no VOC emissions are the other benefits of using HJPs. The pump is able to handle high volume of production stream with gas and heavy concentration of solids such as sand. Key components of HJP include the following and their functions are accordingly listed below:

- Nozzle – pressure of the power fluid is converted to high velocity at this point
- Throat – power fluid and produced fluid mix and get average velocity here
- Diffuser – converts velocity of fluid mixture to static pressure and mixture is forced up the surface through the annular space

The area ratio of nozzle and throat is known as the area ratio of the pump, and it defines the performance capability of the pump. Performance and efficiency curves will be the same when pumps have the same area ratio. The size of the nozzle will help to determine the volume of power fluid because they are proportional to each other. This means, the rate of production can be varied by adjusting rate and pressure of pumped power fluid.

There are two flow directions of power fluid: standard and reverse. In standard flow, power fluid is pumped into the tubing, in reverse flow, on the other hand, power fluid is pumped in the annulus. Basically, pressurized power fluid is injected to functionate the pump. When the power fluid is pumped at high pressure through the smaller area of the nozzle, the Venturi effect gives rise to increase the velocity and decrease the pressure. This drives the production fluids into the pump through the area between the nozzle and throat. This area also defines the pump cavitation characteristics.

Besides all above – mentioned advantages of using HJPs, there are also some limitations. Those limitations include lower pump efficiency (20 – 30 %) comparing to the other pump types due to more power requirement, higher cost for the upgraded surface facilities to handle high amount of fluid returning from the well and a probable fire issue in case of using oil as a power fluid. Another drawback of HJPs is that the rate of pumped power fluid is usually two times greater than rate of produced reservoir fluids. When the suction pressure is not high enough, means lower than vapor pressure, vapor cavities will form and leads to cavitation damage in other words, erosion of internal components of jet pump. HJPs are inclined to considerable internal friction and turbulence due to high – velocity fluid flow inside it. This, in turn, reduces the power efficiency to almost 35% (Oilfield Review, 2016).

Progressive Cavity Pumps

The progressive cavity pump is quite a sophisticated pump and can operate in diverse pumping applications. Is a rotating positive displacement pump and primarily consists of a specially designed, single helical – shaped metal rotor and double helical elastomer stator assembly. Rotational power from the motor is transferred to the rotor via the flex shaft, the rotor spin withing the stator, progressive cavities form and produced fluid is transferred through those opening and closing cavities. The liquid performs as the lubricant between pump components and PCP should not be run dry otherwise it will cause pumps to fail (Saveth & Klein, 1989).

Progressive cavity pumps are used when centrifugal pumps are not suitable for the given pumping applications. Using centrifugal pump is not preferable when the liquid has higher viscosities. Because it leads to low pump efficiency and high-power consumption. In this case, PCPs will be attractive choice for high viscous and abrasive fluids with high concentrations of solids. The abrasive solids in fluid are moving at low velocity environment and they are not abrading internal pump components. Regardless of the fluid viscosity PCP will easily provide a constant flow because rate of fluid flow is directly proportional to the operating pump speed which can be controlled by variable frequency drives (VFDs). Additionally, progressive cavity pumps apply less shearing to the fluids, so that, pumping of shear sensitive fluids will not be problematic. Fluid emulsification and agitation, which are the downstream processing problems, are noticeably reduced by share rate control. It should be noted that it requires little maintenance and PCPs are quite easy to maintenance.

On the other hand, there are also some disadvantages of PCPs and factors that should be considered in the pump selection. They are sensitive to high temperature fluids (more than 120-degree Celsius), because the material of stator – elastomer has a tendency to swell faster than metals. But the direction of this expansion will not be outward, because it is surrounded by heavy metal casing and there is no space. Eventually, inward expansion will happen and cause a decrease in the size of cavities inside the pump. This, in turn, will decrease pump life. A stator elastomer is inclined to expand or deteriorate when exposed to certain fluids which are used in acid stimulation treatments. In deviated and horizontal wells, failure of rod string and tubing due to excessive vibrations in high-velocity operations is probable threats to pump run life. In the case of waxy fluid production, PCPs become ineffective because of their internal design. Rotational movement of the rod string inside the pump makes use of paraffin scrapers impossible (Oilfield Review, 2016).

Artificial Lift Selection Criteria

As it is obvious from the above discussions, there are several artificial lifting methods and each of them has positive and negative sides. For these reasons, many fundamental factors should be considered to appropriately select artificial lift method to increase production rate and improve the life of an existing well. These factors can be categorized into four main groups:

Table 4. Artificial Lift Selection Criteria

	Property	Comments
Reservoir Characteristics	Reservoir drive mechanism	- Water cut issue in case of water drive reservoirs – ESP may be a good choice - GLR issue in case of gas cap drive reservoir – Gas lift may be a better option
	Formation fluid viscosity	- One of the main screening criteria for PCP, SRP and ESP pumps - PCP lifting may be a good choice in case of highly viscous hydrocarbons
	Presence of paraffin, scale, and salts	- Pumps may be damaged due to poor handling capacity - Gas lift method is an appropriate choice
	Reservoir IPR	- Determines production potential of the well
	GLR	- Choice should be made to select either gas lift or pumping - Designing downhole gas separators for ESP lift method
Wellbore Characteristics	Total depth of the well	- Some lifting methods may be screened out such as SRP - Energy required for lifting purposes is calculated
	Wellbore deviation	- SRP or PCP may not be applied in highly deviated wells due to rod

		failures and excessive production tubing wear
	Dimensions of casing and tubing	- Selection of downhole equipment based on tubing and annulus size - Liquid loading efficiency
Surface Characteristics	Field location	- Offshore wells require artificial lift methods that require minimum space - Water treatment concerns, noise and visual impact concerns, well spacing etc. should be taken into consideration for onshore fields
	Power availability	- Electricity and natural gas are the main power sources for artificial lift methods
Field Operating Characteristics	Application of EOR	- EOR processes may lead to changes in reservoir pressure and fluid properties, thus shifts in AL system may needed
	Pressure maintenance in the field	- Gas injection or water injection for pressure maintenance purposes may cause adjustments in AL requirements
	Local support services	- Some AL methods require regular maintenance and monitoring

Chapter 3: Production Data and Improvement of Hydrocarbon Production Techniques in Research Area – West Absheron Oilfield

This chapter includes the review of geological data and production history of the research area (West Absheron oilfield), improvement and optimization of the hydrocarbon production in the research area based on the comparative analysis of the results of selected production techniques on a computer software and assessment of economic efficiency of hydrocarbon production optimization measures.

Study Area

The study area of this research is West Absheron oil field, which is located in the Caspian Sea, 40 km north of the Absheron Peninsula (Figure 10). The field is located 25 km north of Shoulan Cape, in the north-western part of the Absheron archipelago. Despite its remoteness from the mainland, the depth of the sea in the area of Western Absheron varies between 2-20 m. The West Absheron field has a tectonic anticline structure and forms one of the middle rings of the Goshadash-Absheron Bank - Gilavar folded zone.

Figure 10. Location of West Absheron Oilfield

Structurally it is an anticline uplift in the north-west-south-east direction, and its core is composed of sediments of the Balakhany Unit of the Productive Series (PS). Productive Series is the main hydrocarbon bearing rock succession in South Caspian Basin and based on the microfauna composition, it is divided into Lower Productive Series and Upper Productive Series. On the basis of lithological composition, Lower Productive Series include Kala Suite, Pre-Kirmaki Suite, Kirmaky Suite, Kirmaky Suite, Post-Kirmaky Sand Suite and Post-Kirmaky Clay Suite. Upper Productive Series is subdivided into Fasila Suite, Balakhany Suite, Sabunchy Suite and Surakhany Suite (Abdullayev & Leroy, 2016).

According to the results of seismic works carried out in 1947-51 and 1952-54, the field consists of the Absheron and Aghburun-Deniz anticline uplifted zones, separated by a narrow shallow saddle. The dimensions of the main reservoir rock are 11x4 km. The structure of the fold is asymmetrical: dip angle of the layers is around 25-40° in south-west direction and 8-25° in north-east direction. There are two parallel longitudinal faults passing through the crest of anticline structure that have led to formation of horst in the crestal area.

Stratigraphic succession of West Absheron field was discovered and studied through drilled wells and seismic works and it has turned out that, from Cretaceous sedimentary complex till Quaternary sediments are present in sedimentary succession of West Absheron field. Main hydrocarbon bearing successions are Kirmaky Suite and Pre-Kirmaky Suite of Productive Series and some detailed information are given below:

- **Kirmaky Suite** (KS) mainly consists of thin rhythmically alternating layers of sand, siltstone - sand and shales of varied sizes. The upper and middle part of the suite is characterized as being very shaly, but the amount of sand and sandstone increases in the lower part. True thickness of this suite varies between 200-280 m.
- **Pre-Kirmaky Suite** (PKS) mainly composed of medium-sized quartz sands and interbedded shale layers. In the lower part of the suite amount of sand and sandstone increases and generally characterized as hydrocarbon bearing formation. Its true thickness varies around 90 m.

In the West Absheron oilfield, the first oil was extracted in 1985, when Pre-Kirmaky Suite was perforated in Well#35 (initial production rate was 61 tons of oil per day). The field has been in production since 1985. Initial reserve estimation in the West Absheron field based on Russian Federation Classification Scheme has revealed that commercial reserves under C1&C2 category was 64635 thousand tons of crude oil, 2587 million m^3 of dissolved gas and volume of recoverable reserves was 12359 thousand tons of crude oil, 2035.5 million m^3 of dissolved gas. Updated reserve estimation in 01.01.2022 has revealed that commercial reserves under C1&C2 category is 63884.4 thousand tons of crude oil, 2561.1 million m^3 of dissolved gas and volume of recoverable reserves is 11608.4 thousand tons of crude oil, 2009.1 million m^3 of dissolved gas.

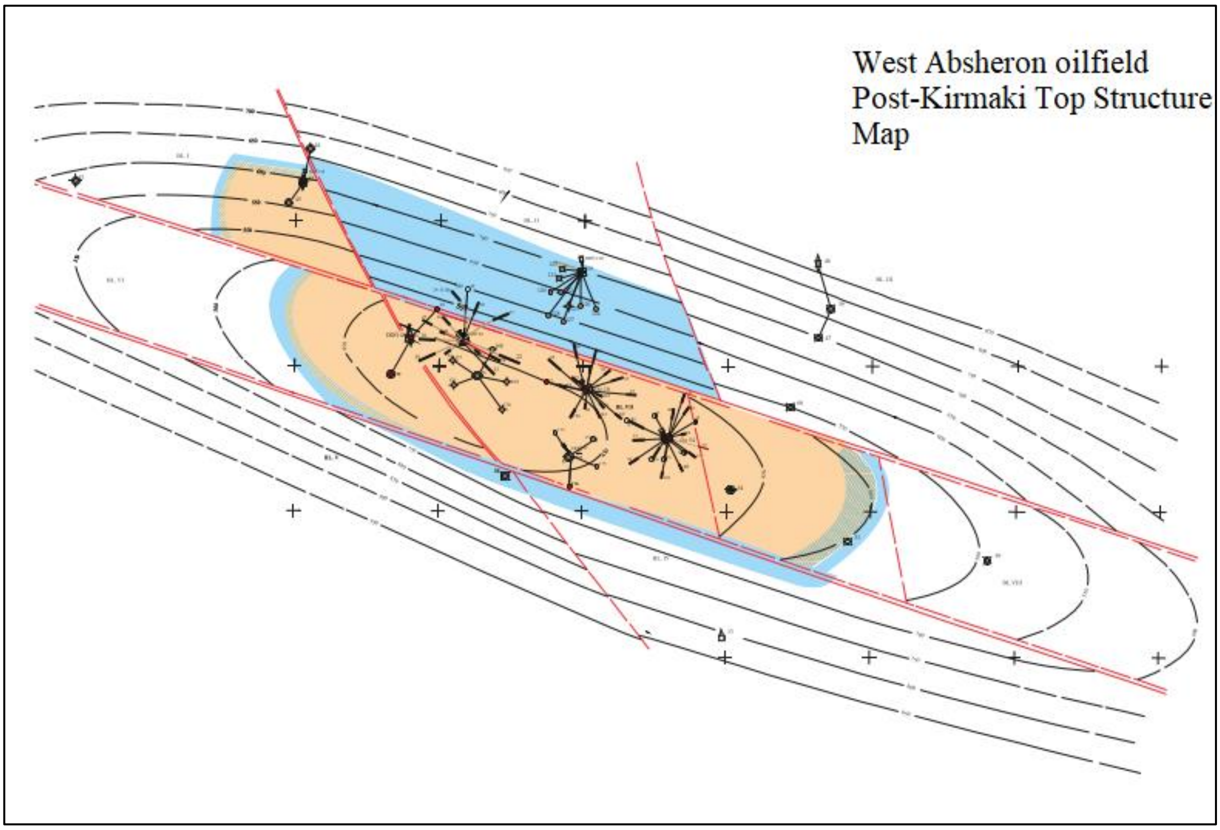


Figure 11. Pre-Kirmaky top structure map-West Absheron oilfield

In total, 80 wells were drilled in the field as of 01.01.2022 and 50 wells are currently producing hydrocarbons in the field (Figure 11). From these wells 750.6 thousand tons of crude oil, 25.9 million m^3 of dissolved gas and 27.6 thousand m^3 of water has been produced. 3.1% of recoverable crude oil reserves under C1&C2 category has already been extracted in West Absheron oilfield.

Model Setup on PROSPER Software

In this section of master thesis, the model setup is given in a step-by-step manner. To do simulations for natural drive and artificial lift techniques in PROSPER software, a synthetic offshore well named WA-1, in the West Absheron field is modelled. Based on the offset wells data and reservoir data provided, 750 meters deep, deviated wellbore is designed. To produce IPR and VLP curves and get the intersection point (which is stable flow point) between these curves on the basis of input data for Well WA-1, the following steps are followed in the software for **Natural Drive Case, Electrical Submersible Case and Gas Lift Case:**

Model Setup for Natural Drive Case

System Summary:

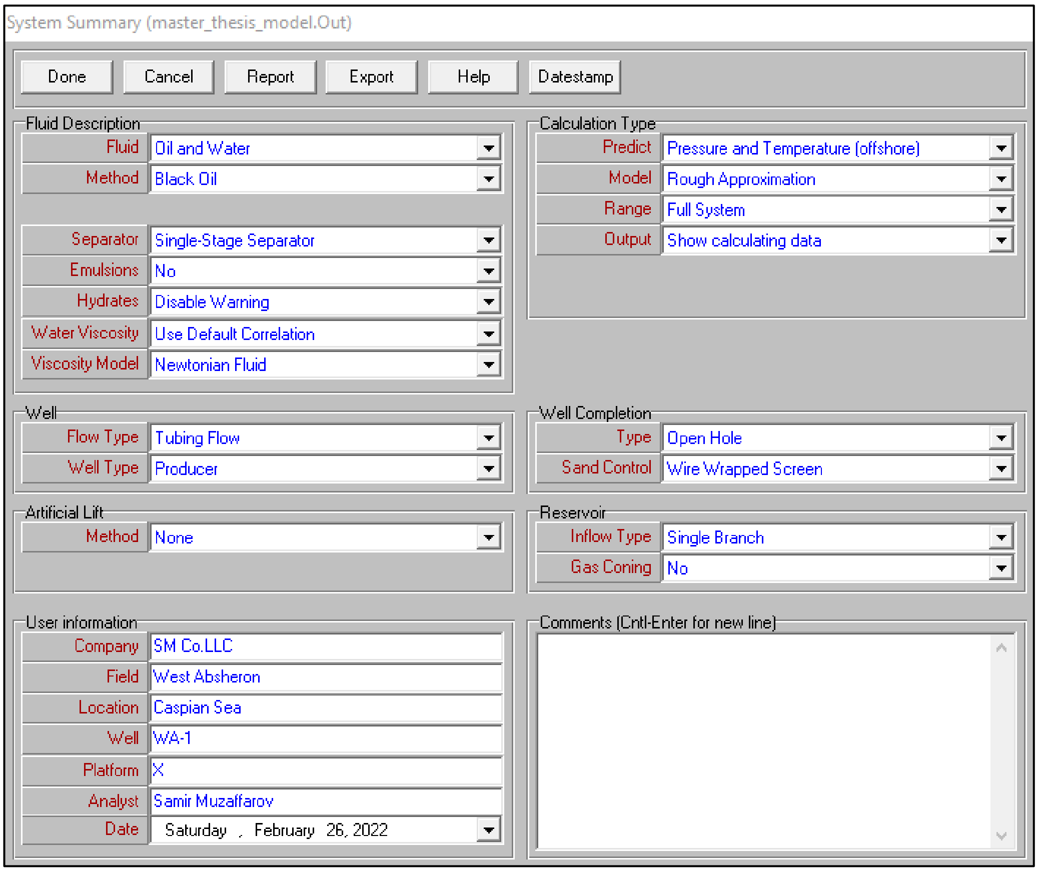


Figure 12.System Summary on PROSPER

This is the first interface window containing some basic information related to Well WA-1, including fluid description data, well data, artificial lift data, well completion data, reservoir data, calculation type and user information data. In the following figure, a system summary is provided:

As it is obvious from the Figure 12, Black Oil Model method with Oil and Water option is selected to describe the fluid. Here producer well with tubing flow option is selected. Because the first model is built for natural drive scenario, artificial lift method is selected as none. In West Absheron oilfield the wells are completed as open holes with wire-wrapped sand screen to handle sand production problem. So, in the system summary this option is selected as well. The user information is provided in the relevant section.

PVT Data:

This section details required PVT data input of Well WA-1 for the selected Black Oil model. This input data is needed to accurately predict how the properties of reservoir fluid change as a function of pressure and temperature. In the PROSPER software either the basic fluid properties data can be inserted and based on some traditional black oil model correlations (e.g., Glaso, Beggs, Petrosky etc.) the software can calculate fluid properties or basic fluid data and PVT laboratory readings can be introduced into the software and PROSPER can choose the best correlation to match the measured laboratory data. On the following figure, basic input parameters are given:

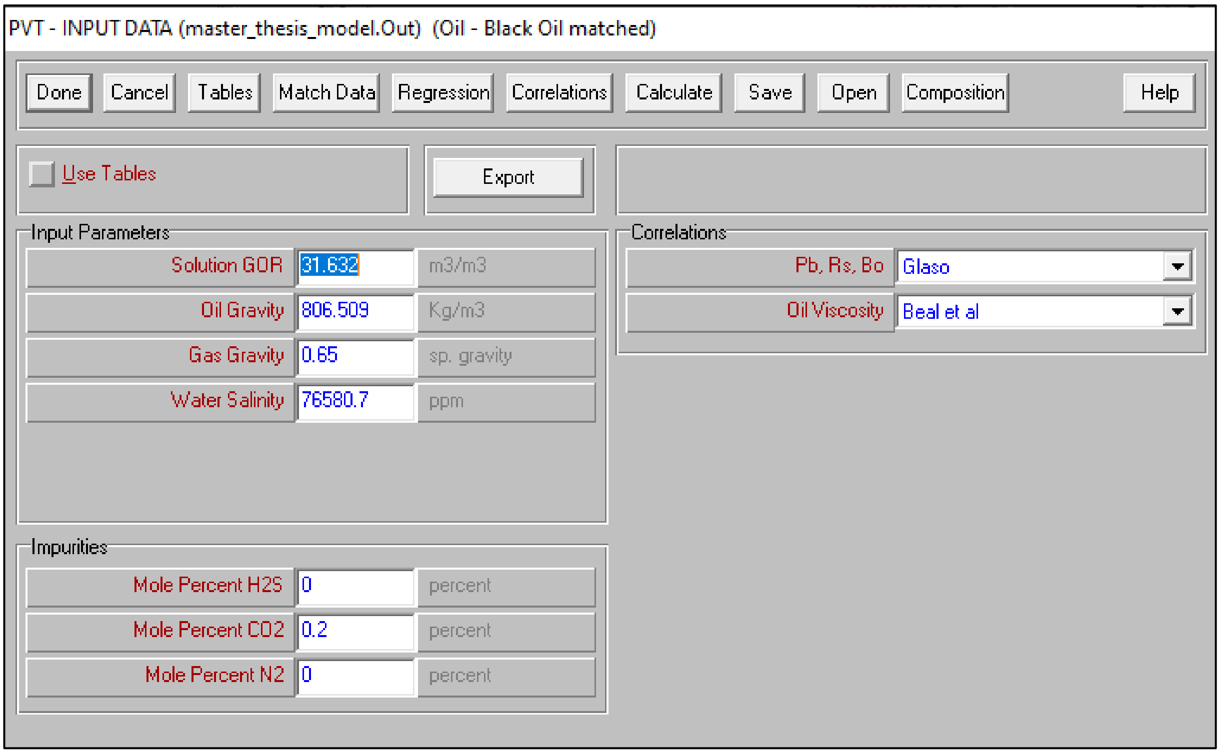


Figure 13. PVT input data

After basic PVT input data for the Black Oil model is introduced into the software, the laboratory measurements are entered to match PVT test data to the Black Oil correlations that are available on PROSPER. These laboratory readings include Bubble point pressure and GOR, Oil FVF an Oil viscosity values at different pressures. PROSPER performs all required calculations based on the input data and after all data is matched and analysed for the correlations on software, it is found that the best correlation with respect to Well WA-1 input the data for Bubble point pressure, GOR and Oil FVF is ***Glaso correlation*** which has the smallest standard deviation. For the oil viscosity, the best correlation is ***Beal et al*** which has the smallest standard deviation based on the available data provided.

IPR Data:

In this section construction of Reservoir Inflow Performance Curve (IPR) is achieved. As has already been stated in this paper, the IPR curve represents the relationship between flowing bottom hole pressure (P_{wf}) and production rate. IPR curve is an effective tool to simulate fluid flow from the reservoir into the well, hence, to understand the well deliverability. To estimate pressure loss in the reservoir that illustrates pressure losses as a function of fluid flow rate a well-defined mathematical equation is required. Considering the type of reservoir fluid and formation rock this mathematical equation has different versions. However, all these versions are fundamentally derived from Darcy's Law. PROSPER software is a great tool to handle this issue by selecting a solution node within the well. At the solution node the system is divided into two sections. Either bottom hole or wellhead can be selected as a solution node. In this research bottom hole is selected as a solution node. That means fluid flow from reservoir into the bottom hole of the wellbore is regarded as inflow that is reflected in IPR curve and the fluid flow from the bottom hole to the wellhead through the production tubing is regarded as outflow, which is displayed in VLP curve. So, to construct IPR curve for this case study, input data is introduced in the PROSPER and a screenshot from the software is provided in the following figure:

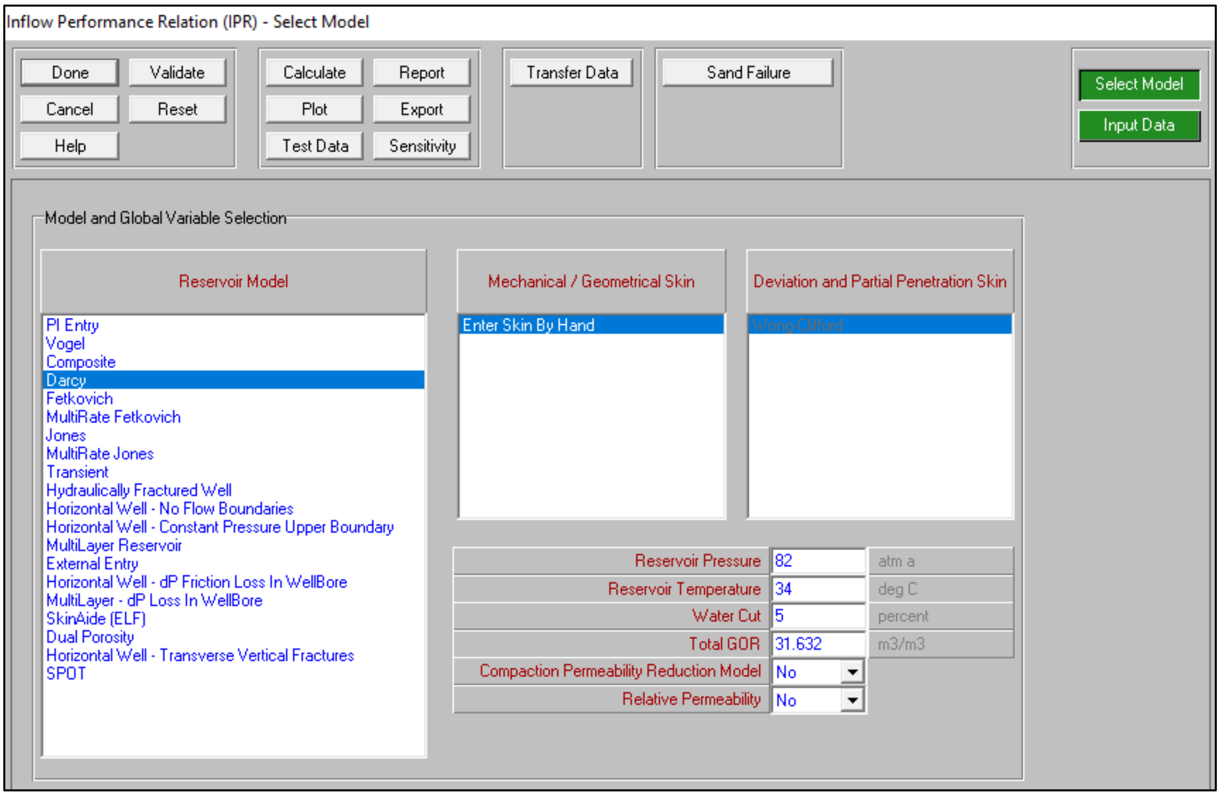


Figure 14. IPR data input main window

PROSPER suggests various IPR models depending upon data availability and type of inflow sensitivities to be made. Some of these models are given below:

- PI Entry
- Vogel
- Darcy
- Fetkovich
- Jones

To construct IPR curve for this case study Darcy Model is selected due to its simplicity and ease of convergence. Then the software applies Darcy's flow equation when the flowing bottom hole pressure is above the bubble point pressure and the Vogel's solution when the flowing bottom hole pressure is equal or below the bubble point pressure. Required input data for Darcy Model is given below considering a circular reservoir shape for DIETZ shape factor:

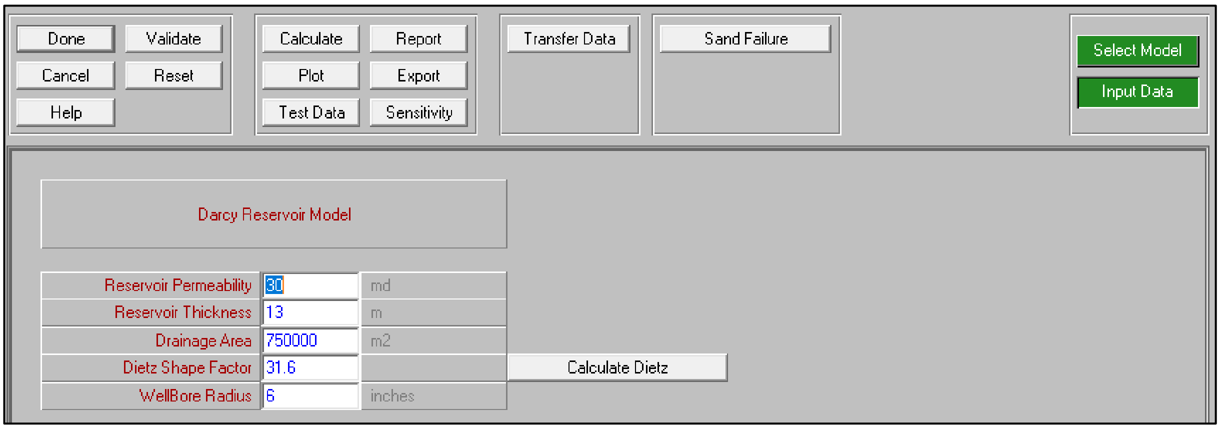


Figure 15. Darcy reservoir model input screen

Once selecting the reservoir model on PROSPER, mechanical skin value must be entered. Based on the offset well data provided, predicted skin value for this modelled well is 3. It should be noted that skin value is not constant, and it may be different from well to well. However, skin value equal to 3 might be considered as a good approximation since the wells drilled in West Absheron oilfield have experienced skin values equal to 3-5.

As the wells drilled in West Absheron oilfield have been completed with wire-wrapped sand screens to handle sand production issue, this option is also designed on PROSPER since there is a "Sand Control" option in the system summary window.

After selecting wire-wrapped sand screen option, required input data must be filled in related to the sand screen as it is given in the following figure:

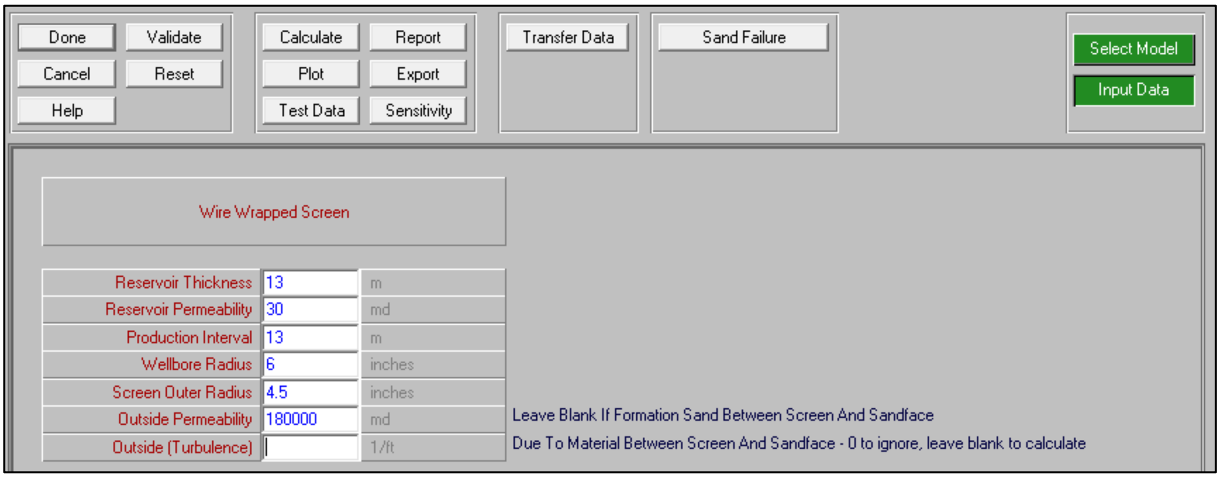


Figure 16. Wire-wrapped screen input data

After all required input data is introduced into the model, the IPR curve is generated by clicking the “Calculate” button. The figure below represents the construction of IPR curve applying Darcy Model:

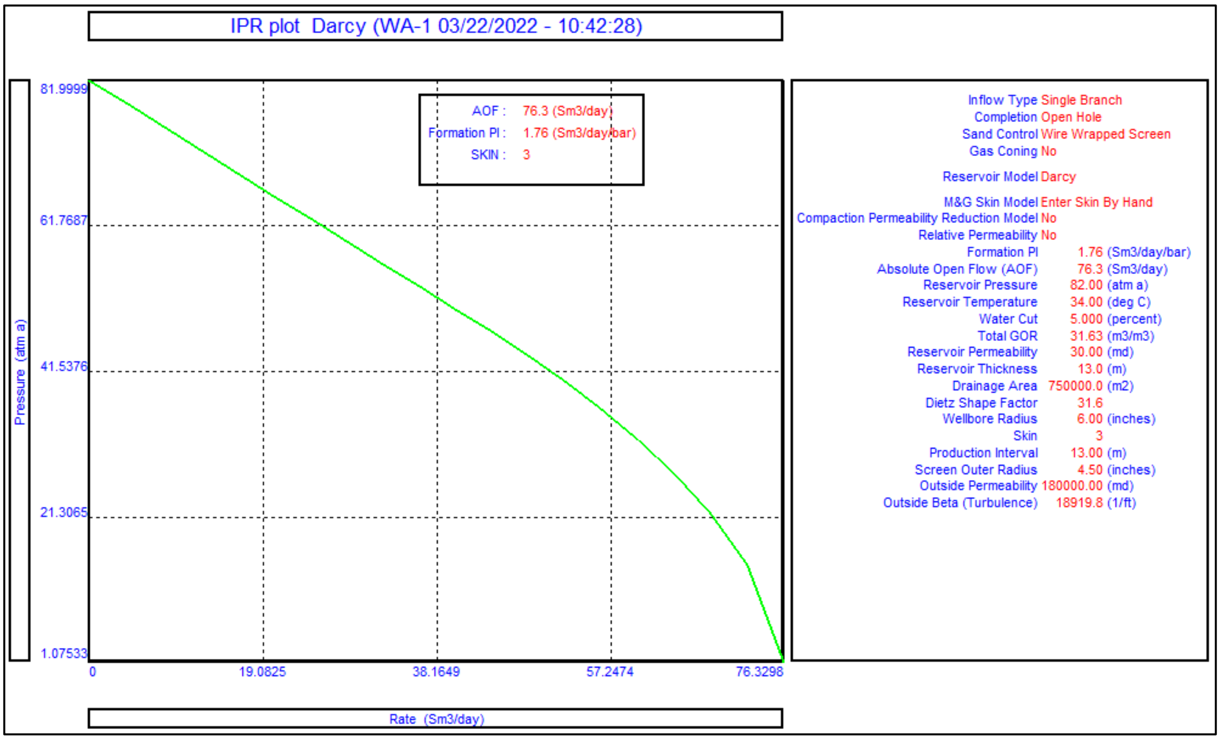


Figure 17. IPR Plot based on Darcy Reservoir Model

As it is obvious from the figure above, the absolute open flow (AOF) which has been calculated is **76.3 sm^3/day** and the formation productivity index (PI) is **1.76 sm^3/day/bar.**

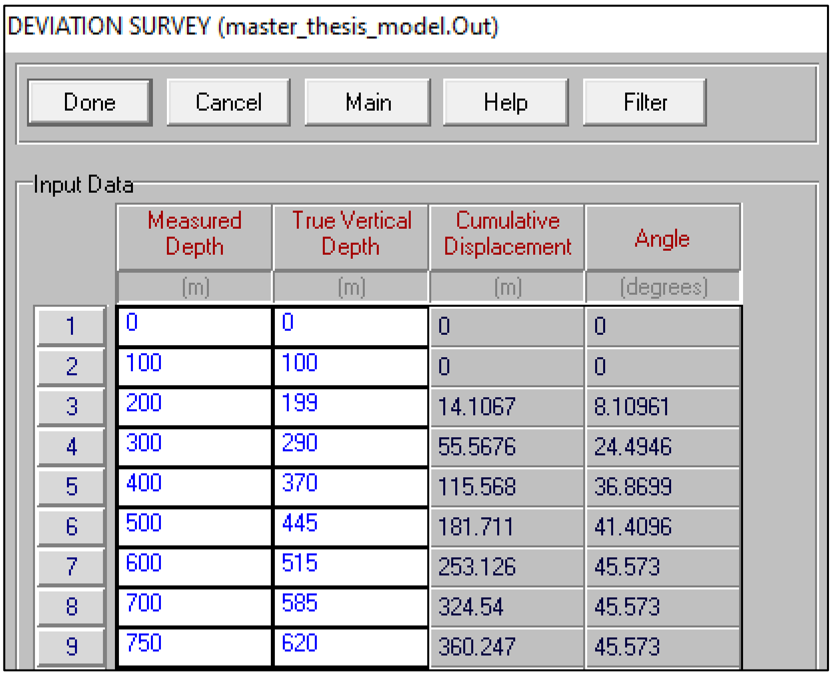
Equipment Data:

This section includes a detailed description of the equipment data that should be introduced into PROSPER software to calculate pressure and temperature profiles along the well path. This section is divided into five individual categories, including:

- Deviation survey
- Surface equipment
- Downhole equipment
- Geothermal gradient
- Average heat capacities

Deviation survey:

As it has already been stated, a new synthetic deviated offshore well is modelled on PROSPER. In West Absheron field, the wells generally have a “build and hold” trajectory. It means that well trajectory is vertical to a certain depth and below this point which is also known as Kick-Off-Point (KOP) the well builds an angle until the required maximum inclination angle is obtained. After that drilling continues keeping this angle constant (the well path is kept straight) till the target depth (TD). In order to make trajectory of a well on PROSPER some pairs of data points for measured depth (MD) and corresponding true vertical depth (TVD) must be entered. Based on MD and TVD pairs, the software produces well inclination angle and total horizontal displacement at each measured depth. This synthetic deviated well trajectory is modelled on PROSPER based on the deviation survey data of offset wells drilled in West Absheron oilfield. The following figure is a screenshot from the deviation survey window:



	Measured Depth (m)	True Vertical Depth (m)	Cumulative Displacement (m)	Angle (degrees)
1	0	0	0	0
2	100	100	0	0
3	200	199	14.1067	8.10961
4	300	290	55.5676	24.4946
5	400	370	115.568	36.8699
6	500	445	181.711	41.4096
7	600	515	253.126	45.573
8	700	585	324.54	45.573
9	750	620	360.247	45.573

Figure 18.Deviation Survey Data

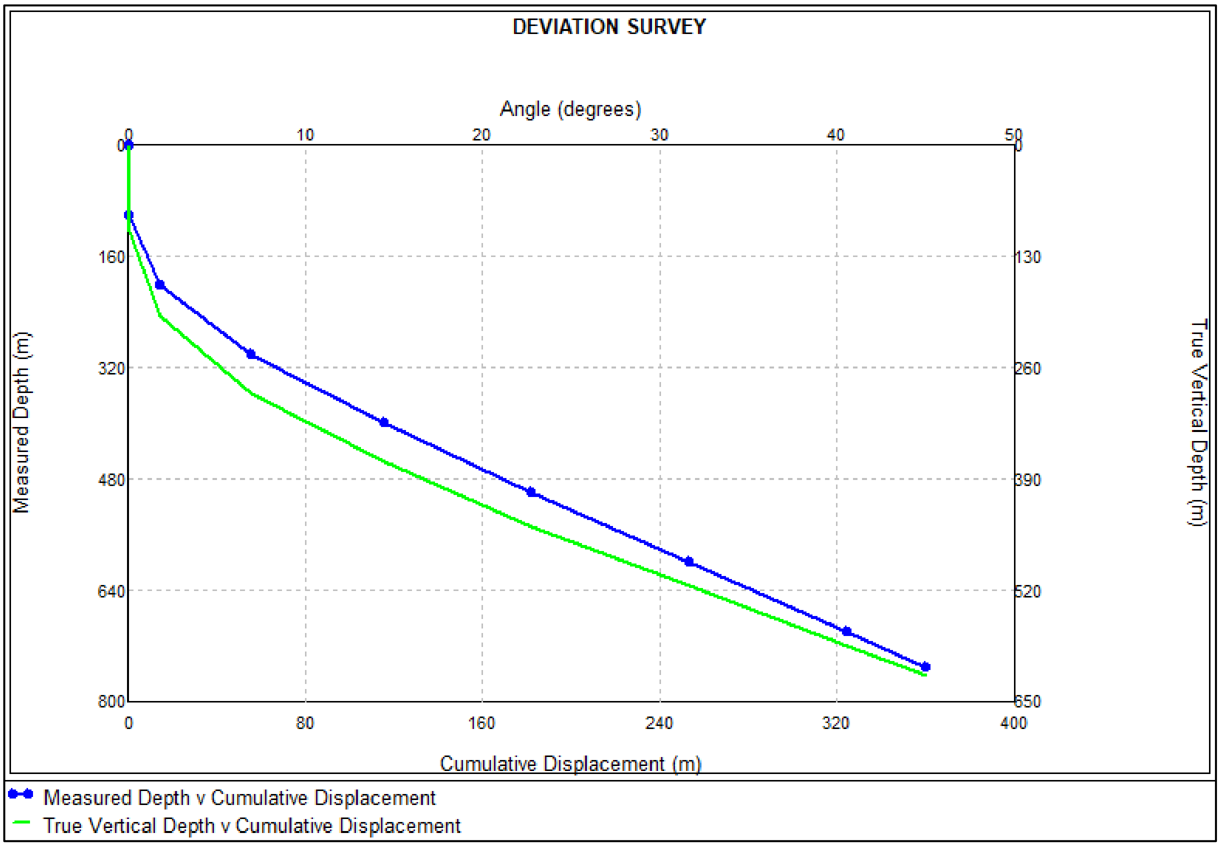


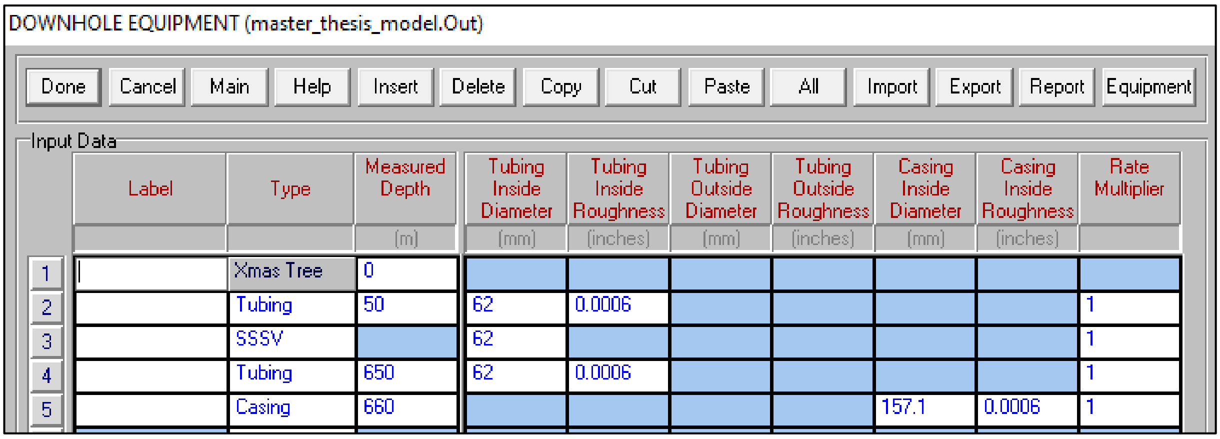
Figure 19. Well Trajectory

Surface equipment:

For this case study, the furthest top node is selected at the wellhead and the manifold TVD is chosen to be set at 0 TVD.

Downhole equipment:

To obtain VLP curve and pressure and temperature gradients in the well downhole equipment data must be filled up on PROSPER. The Xmas tress (Christmas tree) is set at the top of wellhead at 0 depth and all required information related to production tubing and casing is represented in the following figure:


DOWNHOLE EQUIPMENT (master_thesis_model.Out)

Done | Cancel | Main | Help | Insert | Delete | Copy | Cut | Paste | All | Import | Export | Report | Equipment

Input Data

	Label	Type	Measured Depth (m)	Tubing Inside Diameter (mm)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (mm)	Tubing Outside Roughness (inches)	Casing Inside Diameter (mm)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	0							
2		Tubing	50	62	0.0006					1
3		SSSV		62						1
4		Tubing	650	62	0.0006					1
5		Casing	660					157.1	0.0006	1

Figure 20. Downhole Equipment Data

It should be noted that rate multiplier enables calculation of pressure drop because of intermittent sections of dual production tubing completion. For this case study and as general information, wells completed in West Absheron oilfield have been completed with a single production tubing and for that reason value of rate multiplier is left at its default value of 1. Furthermore, wells on West Absheron oilfield have 177.8 mm (about 7 in) OD (Outside Diameter) / 157.1 mm (about 6.19 in) ID casing set at the top of reservoir section and then 152.4 mm (about 6 in) open hole section is drilled through the reservoir interval. A wire-wrapped sand screen with 114.3 mm (about 4.5 in) OD is then run through the reservoir section and is hung inside the 177.8 mm (about 7 in) casing. 73 mm (about 2.87 in) OD / 62 mm (about 2.44 in) ID production tubing is finally lowered around 5 meters above the packer of sand screen. The following figure represents the schematic illustration of the downhole equipment of the modelled well on PROSPER:

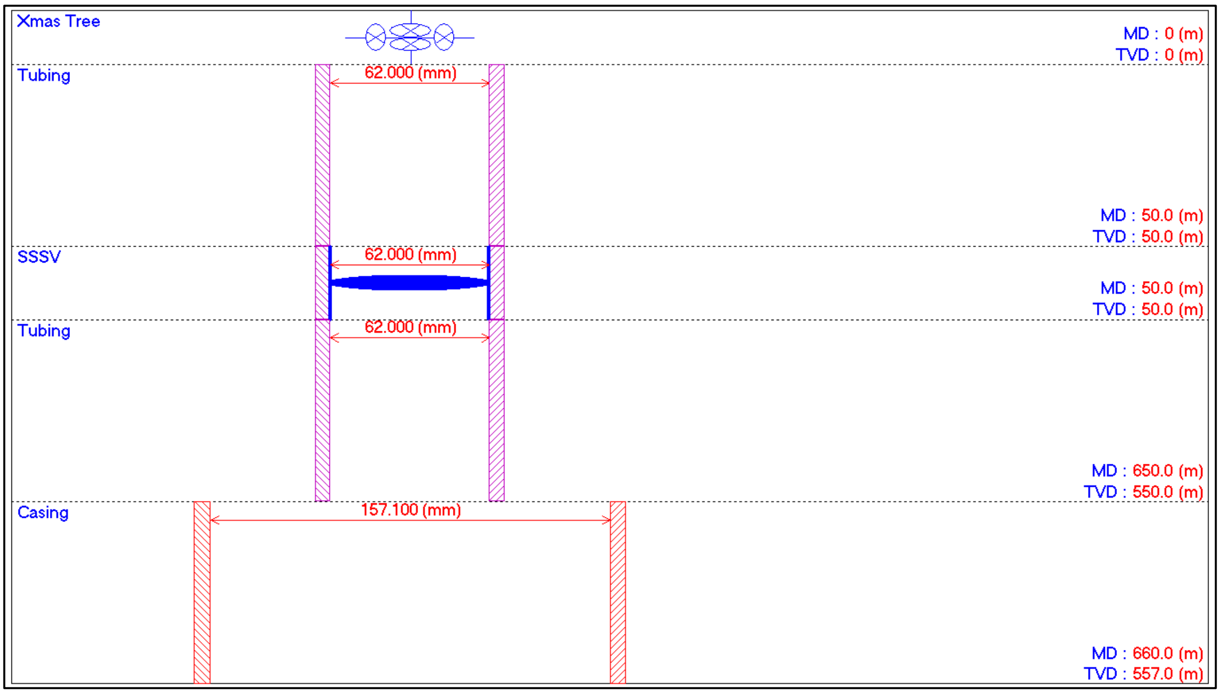


Figure 21. Downhole Equipment Drawing

Temperature survey:

This section enables computation of geothermal gradient on PROSPER. To achieve that temperature values corresponding to the measured depths must be entered into the model. PROSPER can model the temperature distribution throughout the drilled formations and it requires at least two temperature values introduced to the model. Overall heat transfer coefficient for this model is selected as default value of 8. This section enables us to predict the temperature of produced fluids in the system. The following figure represents the temperature survey for this model:

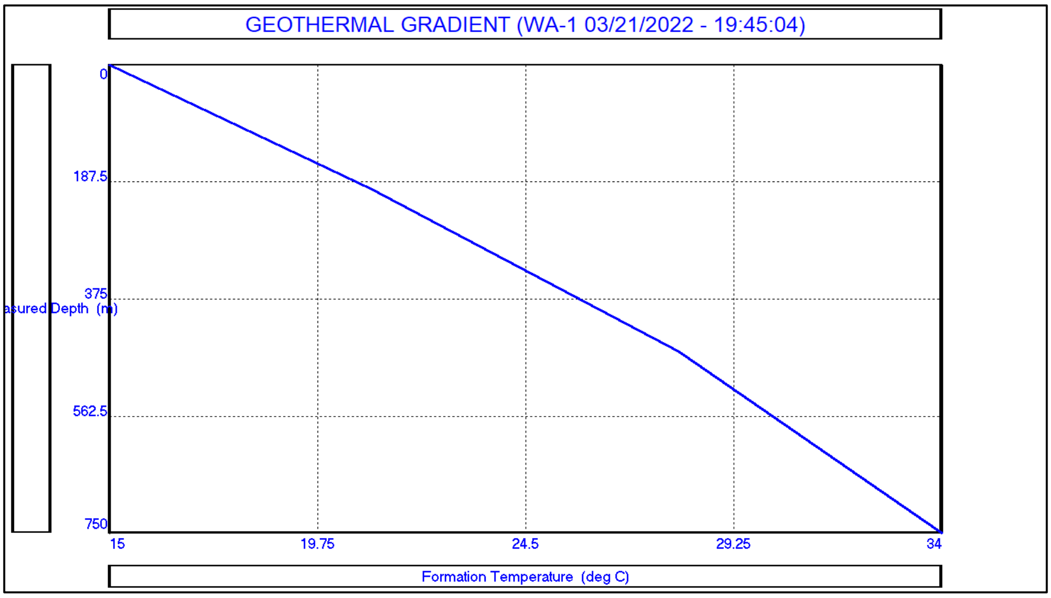


Figure 22.Geothermal Gradient Plot

Average heat capacities:

PROSPER by default suggests Cp values for oil, gas and water to predict the dissipated heat due to the changes in temperature when the fluids flow. It should be noted that these default values produce reasonable results, even though they are strongly dependent on pressure and temperature values. The following figure shows a screenshot from average heat capacities data input window:

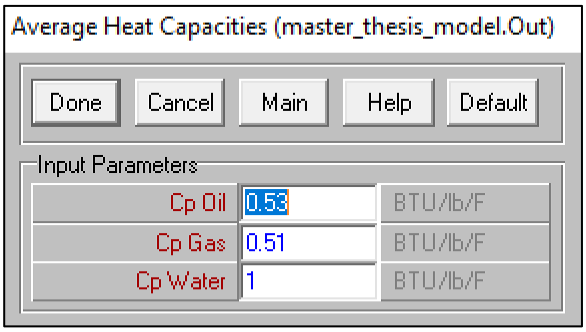


Figure 23. Average Heat Capacities Input Data

System calculations:

As the final step generation of VLP and IPR curves and determination of the solution node that is the intersection point between these two curves is achieved on PROSPER by system calculations. Here the input parameters are used to compute the reservoir response that is IPR curve, and the tubing response which is VLP curve. On the following figure, system calculations and solution node details are achieved on PROSPER:

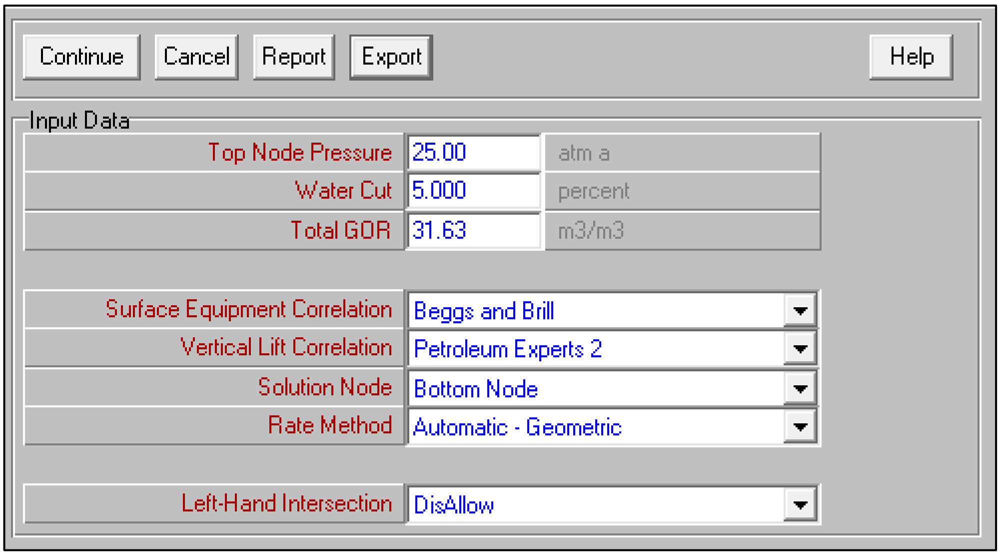


Figure 24. System calculations input data screen

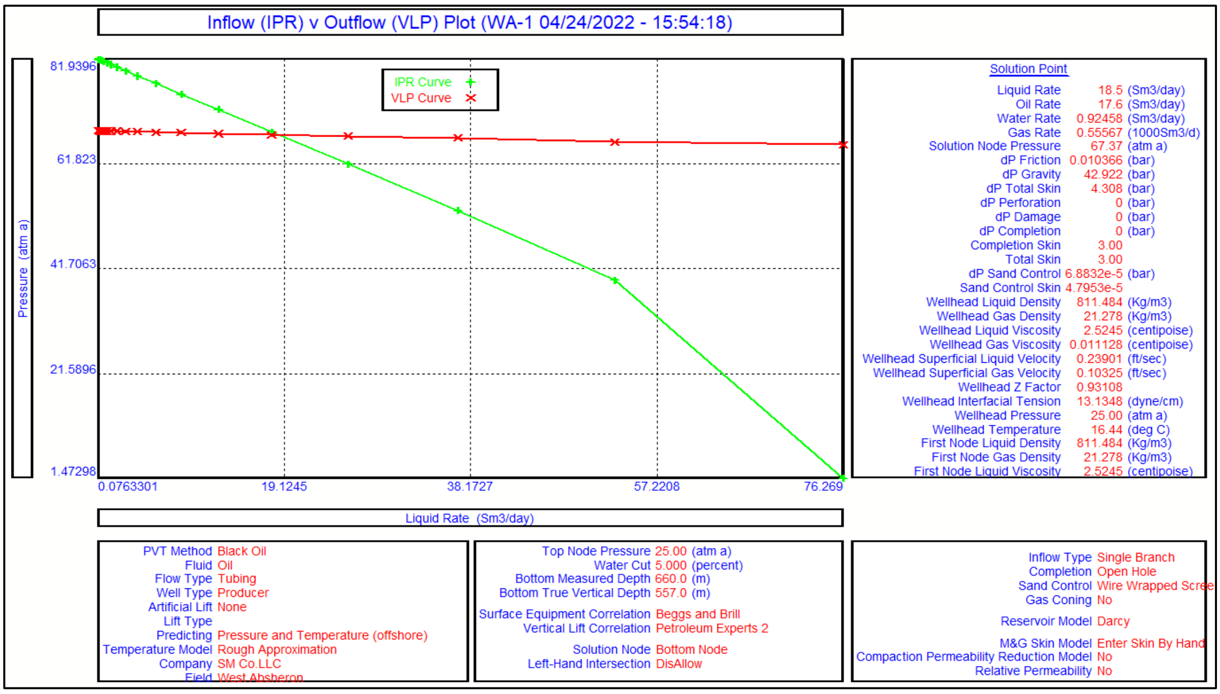


Figure 25. IPR and VLP curves plot for natural drive case

As it is clear from the figure above, the oil rate and bottom hole flowing pressure (BHFP) are **17.6 sm³/day and 67.37 atm** respectively. It means that the designed well can flow naturally based on the input parameters. Solution node details are given in the following table as well:

Table 5. Solution Node details for naturally flowing well

Parameter	***Amount***	***Unit***
Liquid Rate	18.5	sm^3/day
Oil Rate	17.6	sm^3/day
Water Rate	0.92458	sm^3/day
Gas Rate	0.55567	1000 sm^3/day
Solution Node Pressure	67.37	atm
dP Friction	0.010366	bar
dP Gravity	42.9222	bar

Sensitivity analysis for naturally flowing well:

PROSPER allows doing the sensitivity analysis by incorporating the changes that may happen on the main input parameters including water cut, GOR, reservoir pressure and so on. For this purpose, in this section sensitivity analysis is performed to see how reservoir performance (IPR curve) and wellbore performance (VLP curve) are responding to the changes. Here effects of changing reservoir pressure, water cut and GOR are simulated.

Impacts of Changing Reservoir Pressure:

Considering that the West Absheron oilfield is on the production for a good period of time and no pressure maintenance activities are done in the field, it is obvious that fluid production will eventually lead to a decrease in reservoir pressure and for that reason the effect of pressure reduction on outflow performance is investigated. To achieve that, three different reservoir pressure values along with the current reservoir pressure which is 82 atm are given on the software and the calculated results are represented in the table below:

Table 6. Results of system sensitivity analysis on reservoir pressure depletion

Parameter	***Reservoir Pressure (82 atm)***	***Reservoir Pressure (75 atm)***	***Reservoir Pressure (70 atm)***	***Reservoir Pressure (65 atm)***	***Unit***
Liquid Rate	18.5	9.2	2.5	---	sm^3/day
Oil Rate	17.6	8.8	2.4	---	sm^3/day
Water Rate	0.92458	0.46159	0.12453	---	sm^3/day
Gas Rate	0.55567	0.27742	0.0748	---	1000 sm^3/day

As it is clear from the results given in the table above, while the reservoir pressure decreases, well production rate decreases as well. However, if the reservoir pressure falls to 65 atm, then the well will not flow naturally because the intersection point between IPR curve and VLP curve will not be achieved.

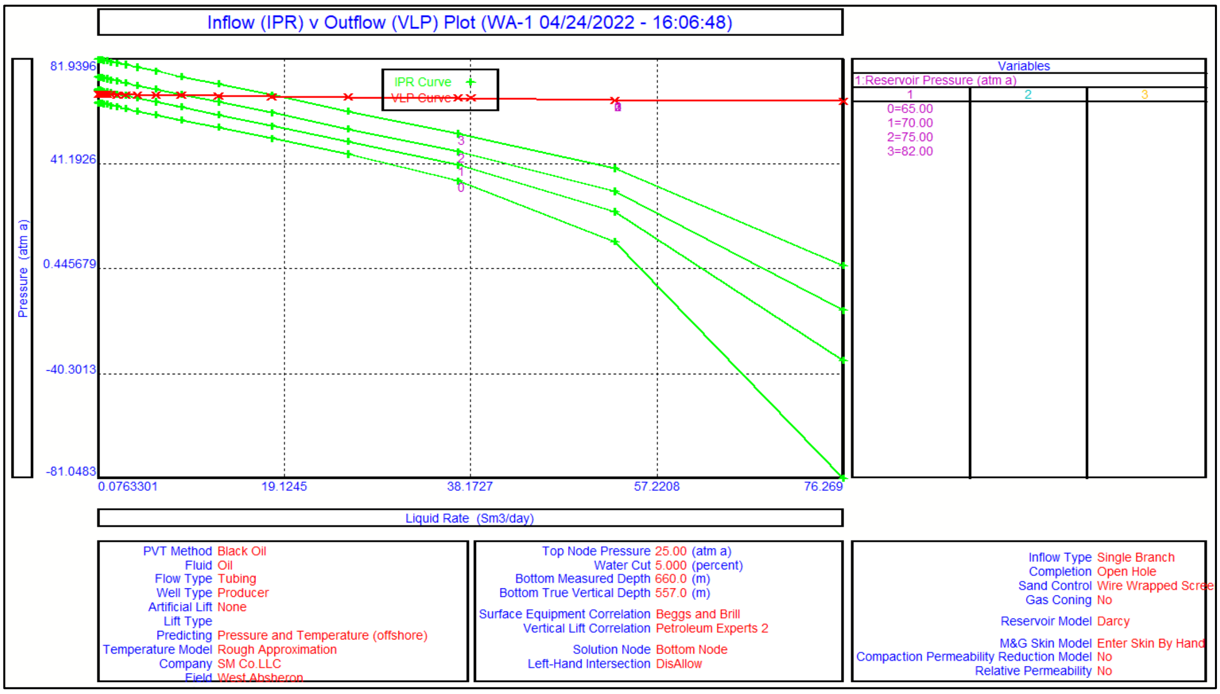


Figure 26. Impacts of changing reservoir pressure on IPR & VLP curves

The figure above perfectly displays how IPR curve given in green colour is dependent on reservoir pressure. As it is seen, there is no intersection between IPR and VLP curves when reservoir pressure is equal to 65 atm.

Impacts of Changing Water Cut:

Aquifer supported reservoirs have experience increasing amount of water cut while they are being depleted. Taking this fact into consideration, three different reservoir water cut values along with the current water cut which is 5% are given on the software and the calculated results are represented in the table below:

Table 7. Results of system sensitivity analysis on increasing water cut

Parameter	***Water Cut (5%)***	***Water Cut (30%)***	***Water Cut (50%)***	***Water Cut (70%)***	***Unit***
Liquid Rate	18.5	11.9	3.5	0.60417	sm^3/day
Oil Rate	17.6	8.3	1.7	0.18125	sm^3/day
Water Rate	0.92458	3.6	1.7	0.42292	sm^3/day
Gas Rate	0.55567	0.26285	0.055	0.0057	1000 sm^3/day

The table above shows that, when water cut increases from 5% to 30%, amount of produced oil and gas decreases, while the water rate increases almost 4 times. The main reason for that is now more water is entering into the reservoir. However, continuous increase on water cut leads to both reduction of oil rate and water rate (total liquid rate) because pressure drop due to gravity is increasing while water cut increases in the reservoir and more pressure is needed to produce heavier fluids to the surface.

On the following figure, impacts of increasing water cut on both reservoir performance (IPR curve) and wellbore performance (VLP curve) are visible:

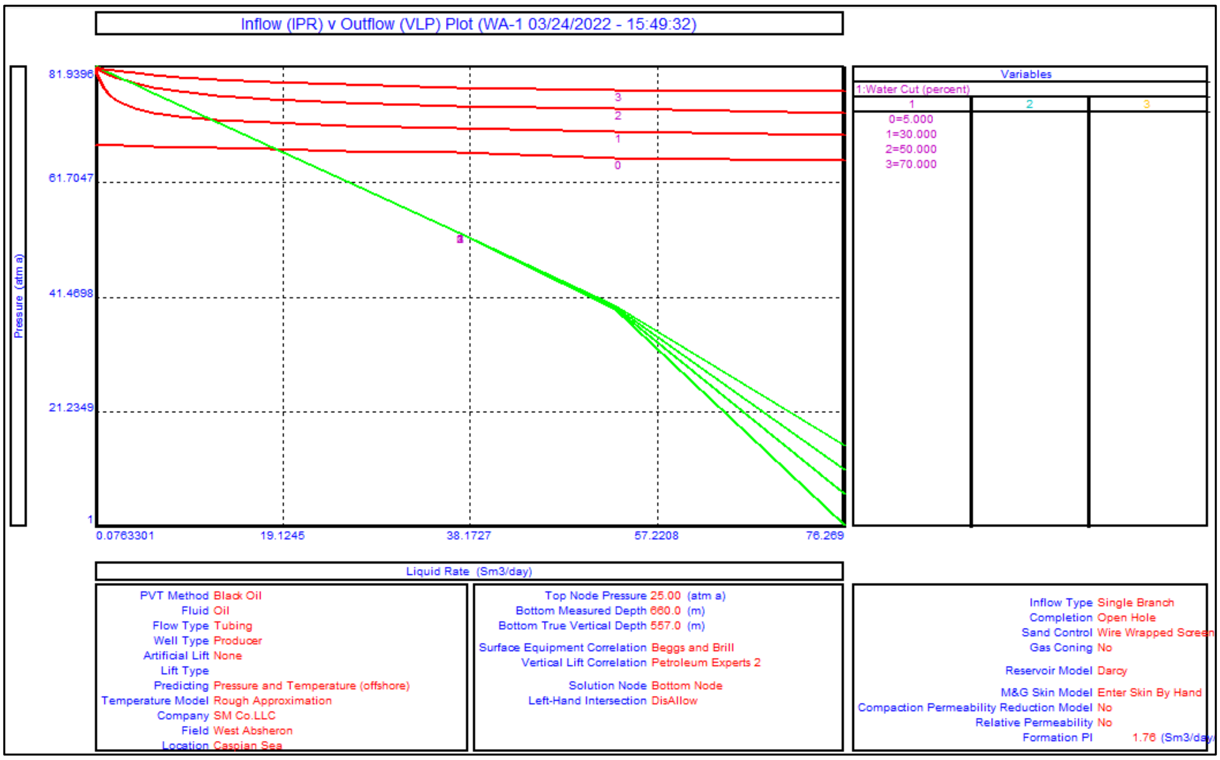


Figure 27. Impacts of increasing water cut on IPR & VLP curves

It should be noted that, while the intersection between IPR and VLP curves are achieved even the water cut is 70%, more water entering the wellbore creates higher hydrostatic pressure compared to the pressure created by oil column, thus leading to decreased liquid production.

Impacts of Changing GOR:

Next, the effect of changing (increasing) gas-oil ratio (GOR) is analysed. To achieve this, three different GOR values along with the current GOR which is 31.63 m^3/m^3 are given on the software and the calculated results are represented in the table below:

Table 8. Results of system sensitivity analysis on increasing GOR

Parameter	***GOR (31.63 m^3/m^3)***	***GOR (50 m^3/m^3)***	***GOR (80 m^3/m^3)***	***GOR (100 m^3/m^3)***	***Unit***
Liquid Rate	18.5	28.2	44.6	48.3	sm^3/day
Oil Rate	17.6	26.8	42.4	45.9	sm^3/day
Water Rate	0.92458	1.4	2.2	2.4	sm^3/day
Gas Rate	0.55567	1.341	3.389	4.586	1000 sm^3/day

As it is shown in the table above, while the GOR is increasing, liquid rate and gas rate are also increasing. However, larger increments on GOR do not lead to higher increments on total production rate. On the following figure, impacts of increasing GOR on both reservoir performance (IPR curve) and wellbore performance (VLP curve) can be seen:

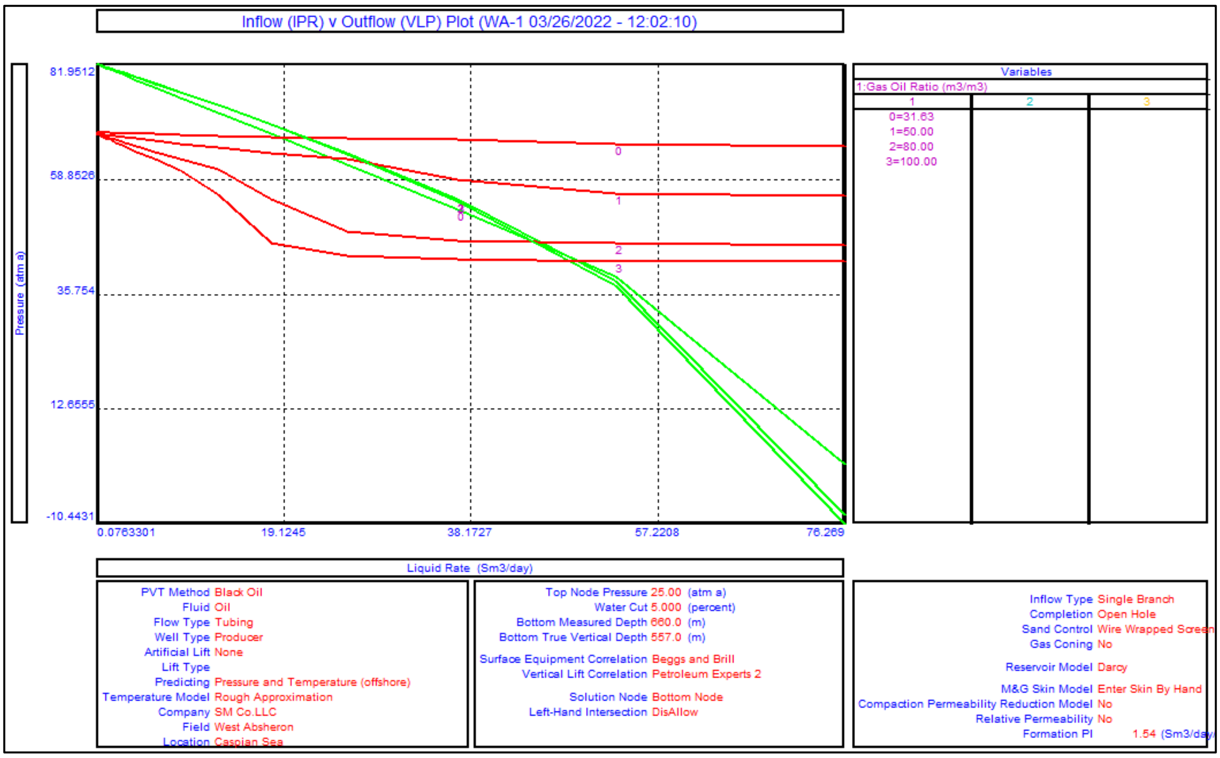


Figure 28. Impacts of increasing GOR on IPR & VLP curves

Relationship between IPR and VLP curves represent that, increasing GOR has effect on both reservoir performance as well as tubing performance. From the figure above it is clear that increasing GOR leads to higher production rates and the solution node pressure values are decreasing, meaning that lesser pressures are required to produce reservoir fluids to the surface. What is more, while the GOR is increasing, pressure drop due to friction is increasing and pressure drop due to gravity is decreasing and these are visible on the IPR&VLP curves.

Model Setup for ESP Case

In this section, well performance is analysed by applying ESP as an artificial lift technique. General data and working principle of ESP has already been covered in Chapter 2. On PROSPER software ESP designing is done in two steps where the required pump head must be calculated first to get the stated production rate and then the software enables us to select an appropriate pump, motor and cable for this application. So, in this section a well with ESP is modelled on PROSPER through the following steps:

System Summary:

This section includes the basic data about the Well WA-1 as it has already been done for the natural drive case. The main difference here is that we must select ESP as an artificial lift method in the relevant section. The following figure depicts the screenshot from the system summary window:

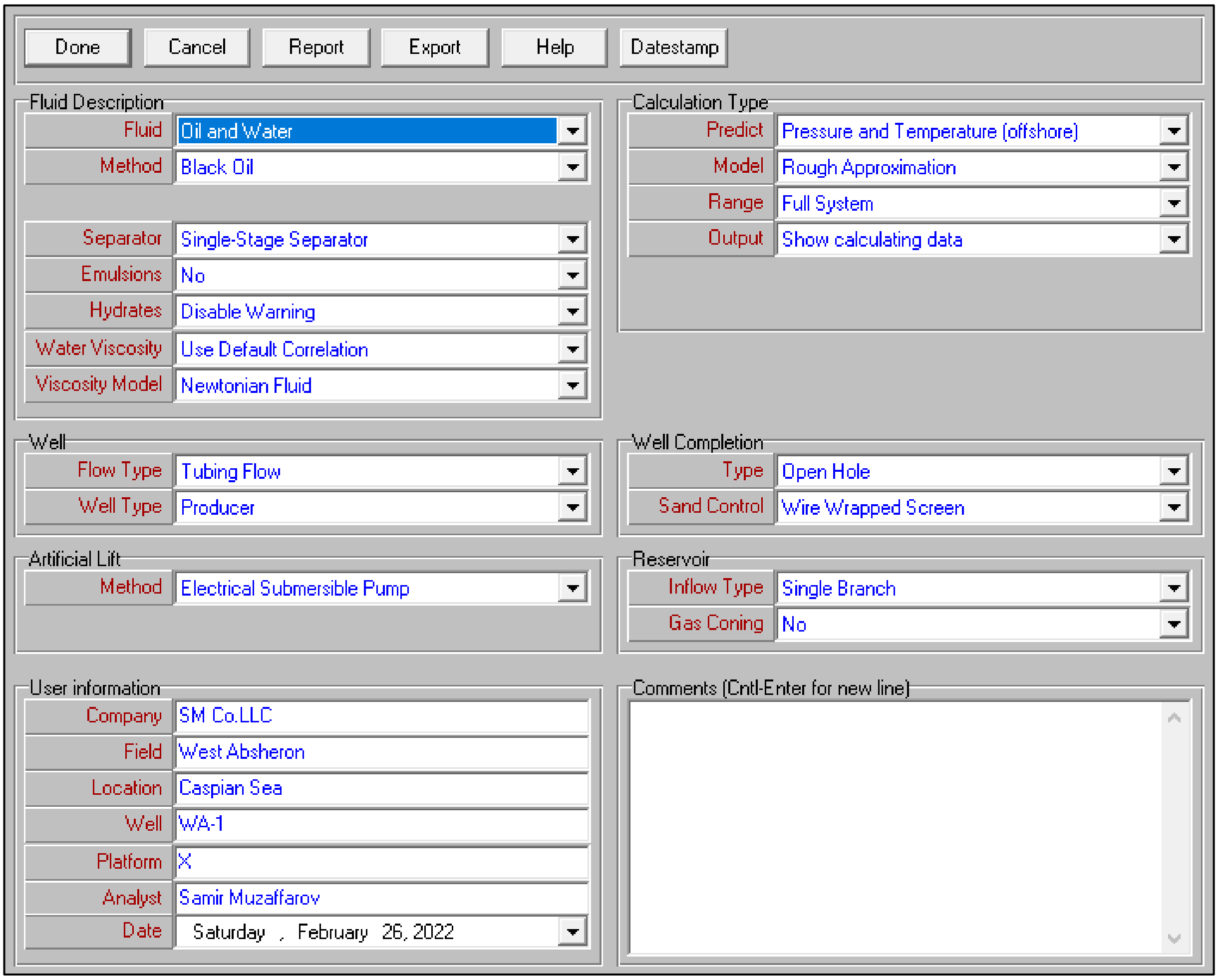


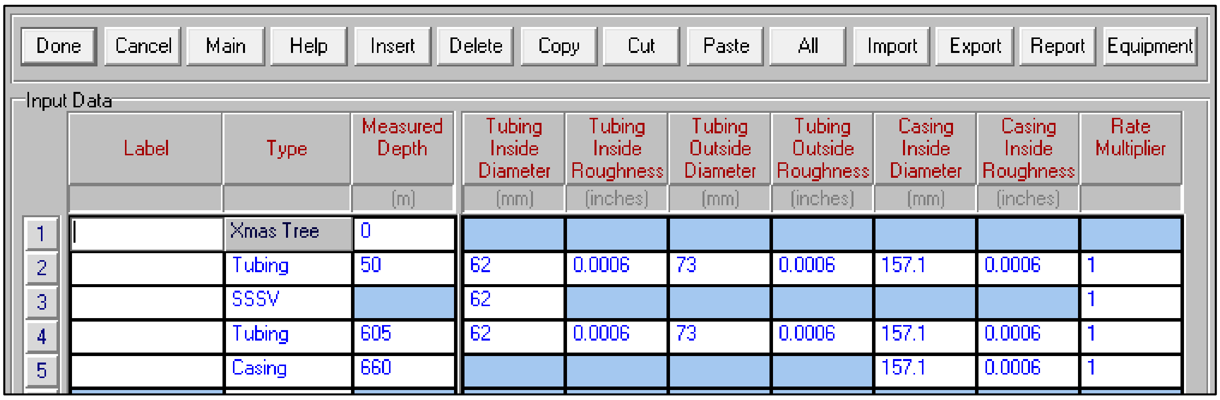
Figure 29. System summary for ESP design case

PVT and IPR Data:

These two sections remain the same as for the Natural Drive Case.

Equipment Data:

All subsections in this part remain the same except the downhole equipment where the tubing outside diameter must be filled to perform ESP design. A screenshot from the downhole equipment part is given in the following figure:



	Label	Type	Measured Depth (m)	Tubing Inside Diameter (mm)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (mm)	Tubing Outside Roughness (inches)	Casing Inside Diameter (mm)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	0							
2		Tubing	50	62	0.0006	73	0.0006	157.1	0.0006	1
3		SSSV		62						1
4		Tubing	605	62	0.0006	73	0.0006	157.1	0.0006	1
5		Casing	660					157.1	0.0006	1

Figure 30. Downhole equipment data for ESP case

ESP Design Parameters:

This section contains the main input data for ESP design stage. Here the following parameters are included on the ESP design window as follows:

- Pump depth is located at the end of the production tubing where it is generally lowered down 50 meters above the packer of sand screen based on industry experience.
- Pump operating frequency is set at 60 hertz as generally electrical submersible pumps operate at this frequency.
- Maximum outside diameter of the pump is controlled by the inside diameter of the 177.8 mm casing string and for this model 143 mm is set as maximum OD for ESP
- Length of cable is needed to evaluate surface voltage to operate the pump. It is recommended to select a cable that is at least 100 feet (30 meters) longer than pump setting depth (in MD) to be sure that surface connections will be made at a safe distance from wellhead and for this model it is set as 650 meters.
- Gas separator efficiency shows efficiency of gas separation when there is free gas and gas separator is installed at the pump inlet. It can be left as 0 and then the Dunbar Criterion can be used to check if this input value is acceptable for this design or not. It should be noted that when the design operating point is above the Dunbar Factor line which is given by a red line then inserted gas separator efficiency value is acceptable and there is no need

to install a downhole gas separator (IPM PROSPER User Manual ,Version 11.5, January 2010).

- Design rate here shows the target flowrate that is intended to reach, and it cannot be greater than AOF as the reservoir cannot contribute greater than this value.
- Top node pressure is fixed.
- Motor power safety margin is included to oversize pump motor power requirements. Based on the industrial experience a safety margin of 10% is inserted to increase the pump motor power requirement.
- Pump wear factor takes the deviation of designed pump performance from manufacturer's provided performance curve because of taking the wear into consideration. Generally, wear factor of 0.1 is included to simulate the reduction by 10% on the pump head required.

The following figure shows a screenshot from the ESP Design window on PROSPER:

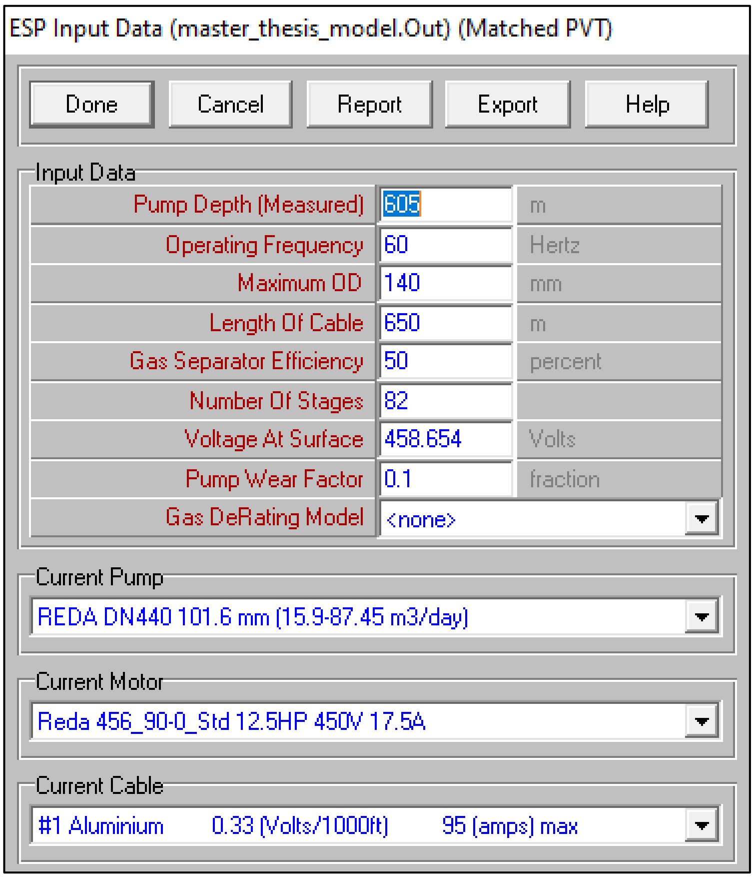


Figure 31.ESP design input data screen

After the required parameters are included, ESP design calculations are performed and all the parameters that are needed to select an appropriate pump system are shown on the screen:

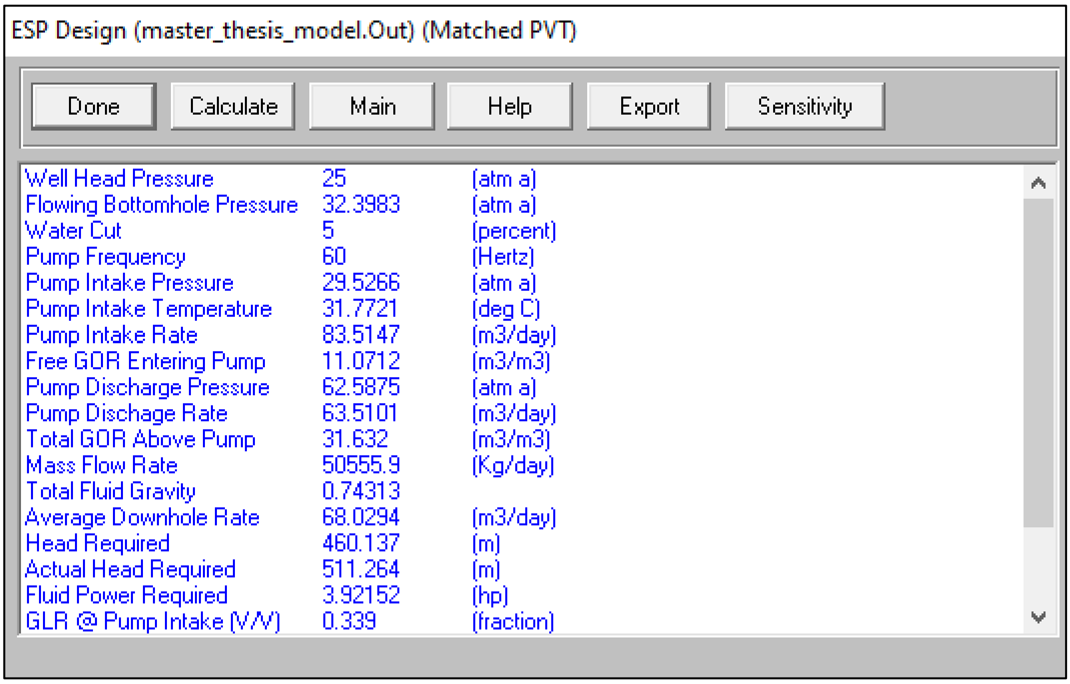


Figure 32.ESP design calculation results

Gas Separation Sensitivity Check:

After this step sensitivity analysis is done to evaluate the need for downhole gas separator. The following figure shows the relationship between pump intake pressure and gas liquid ratio with the operating point given in dark blue:

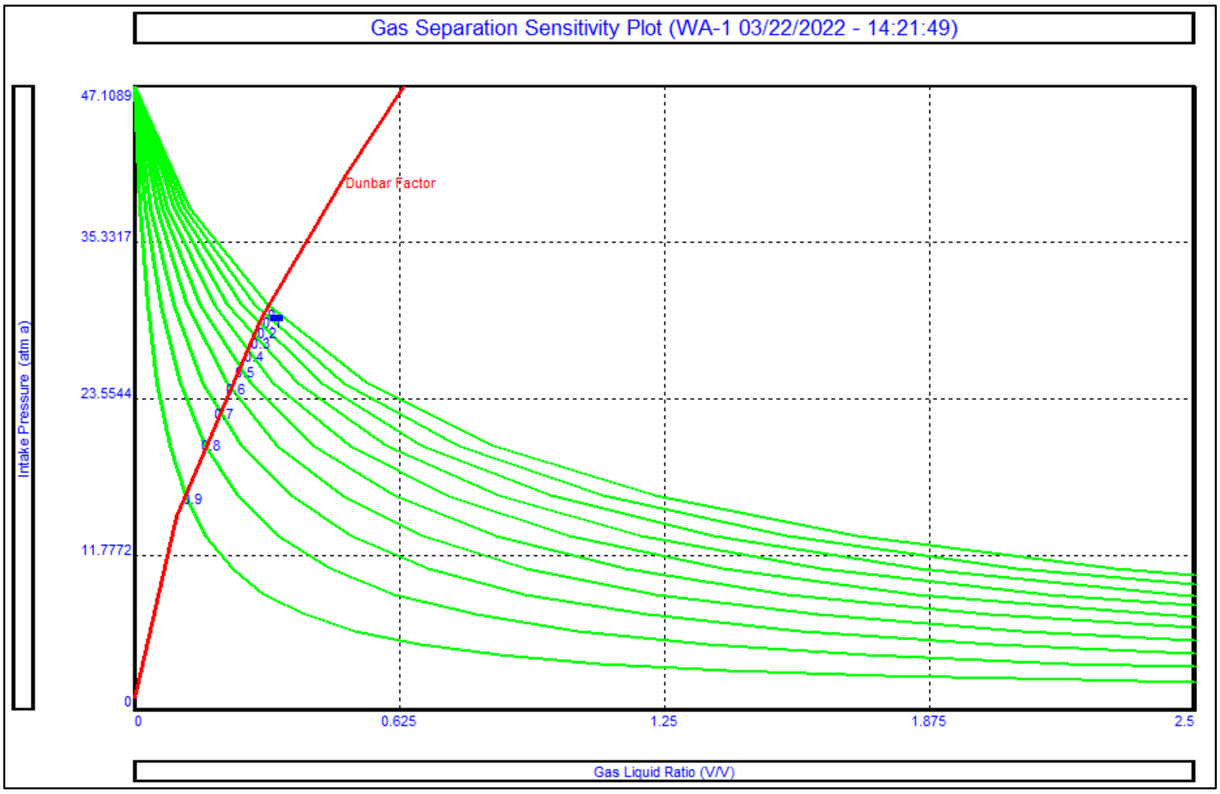


Figure 33. Gas Separation Sensitivity Check-1

As it is obvious from the figure, the design operating point lies below the Dunbar Factor line given in red. And this means that there is a need to install a downhole gas separator. For this reason, gas separator efficiency equal to 50% is chosen and sensitivity check is performed again:

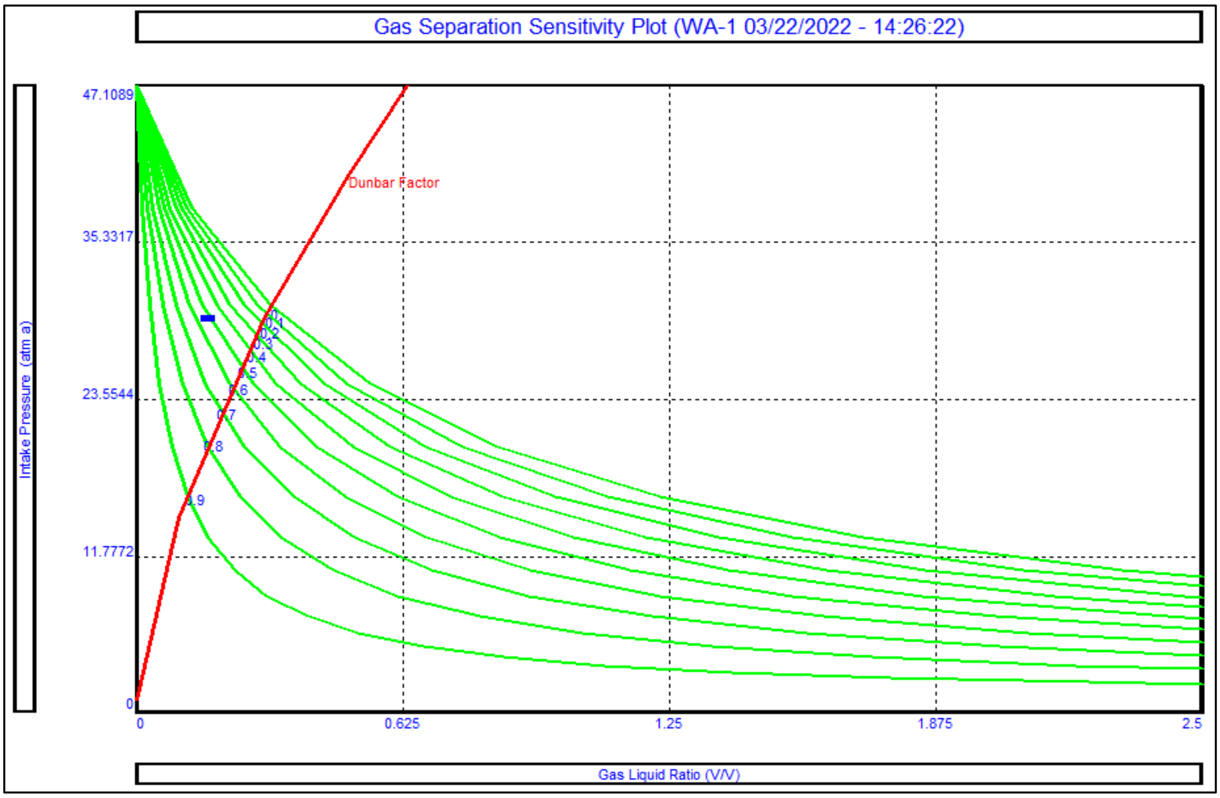


Figure 34. Gas Separation Sensitivity Check-2

It is clear from the above graph that the operating point now lies above the Dunbar Factor line given in red. Now ESP design stage can be carried out.

Pump, Motor and Cable Selection:

After the required calculations and sensitivity check are accomplished, we must select the suitable pump, downhole motor and cable combination from the list that PROSPER suggests achieving the target flow rate. It should be noted that Pump Performance should be examined to see if the operating point lies at or near the Best Efficiency Line. The pump performance is highest when the operating rate corresponds to the Best Efficiency Line. If the operating point is above or below the Best Efficiency Line, then the pump efficiency decreases (Oilfield Review, 2016). For this reason, care must be given to select the best combination of pump, motor, and cable to be sure that we are at the Best Efficiency Line. By this way we are sure that the pump will deliver highest efficiency. The following figure depicts the final ESP design stage on PROSPER:

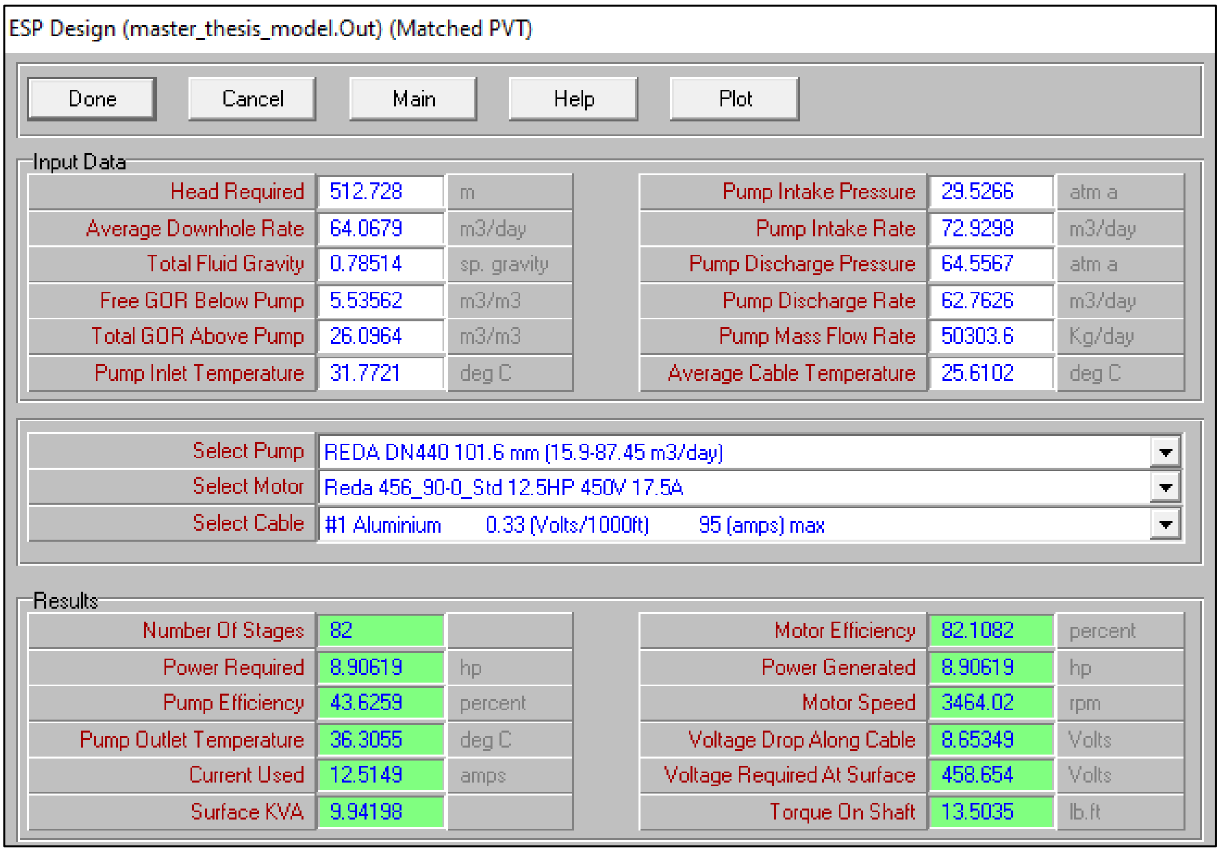


Figure 35. ESP, Motor and Cable Selection Screen

As the final stage of ESP design, a combination of pump, motor and cable is selected from the list provided by PROSPER. Taking the best performance of the pumps into consideration, REDA DN440 (101.6 mm OD) pump which is manufactured by Schlumberger is selected to achieve the best efficiency. On the below figure, performance curve of this pump is given, and it is obvious that operating point given as a red dot perfectly lies on the Best Efficiency Line.

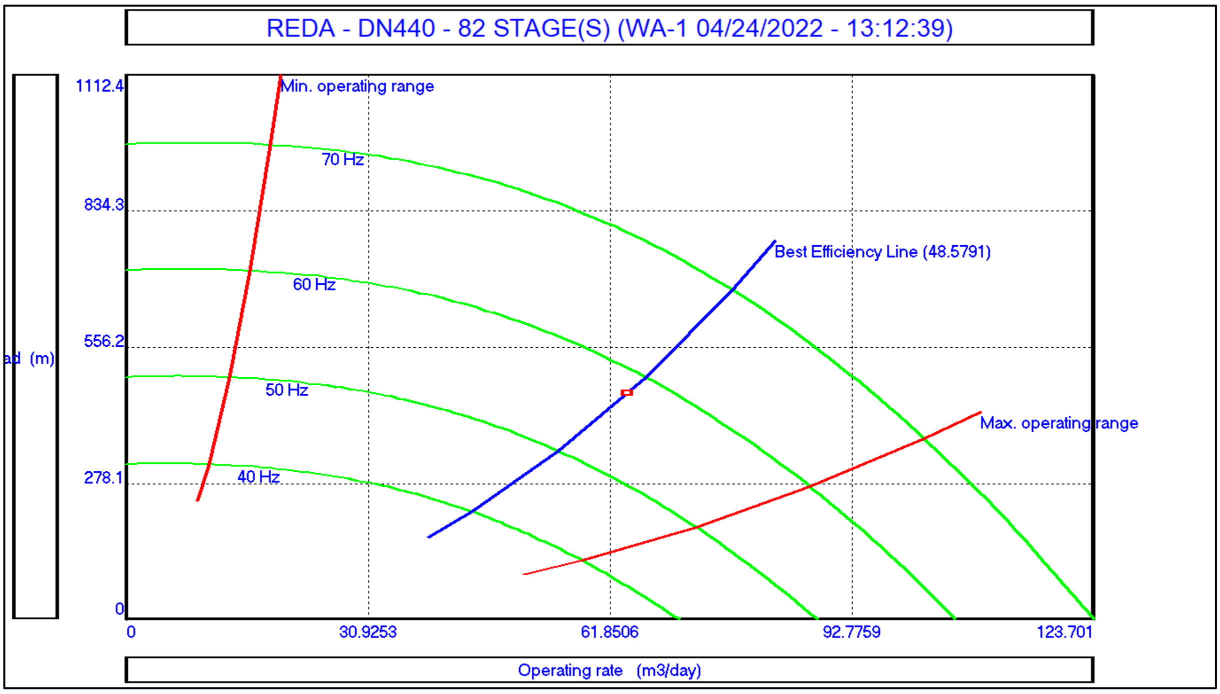


Figure 36. Performance Curve of REDA DN440 ESP

System Calculations:

As a final step, obtained design results are included in the software to perform system calculations and create IPR and VLP curves. To do that on PROSPER System ESP data menu should be filled up as described in the following figure:

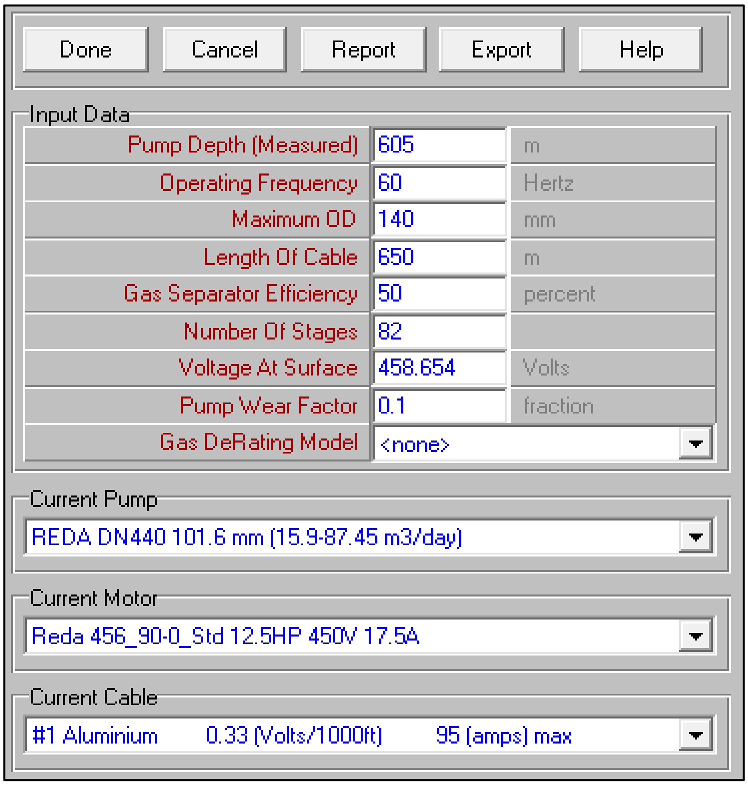


Figure 37. ESP input data screen

In the final step, the vertical lift performance curve is generated, and intersection point between **Pump Discharge Pressure (PDP) curve and VLP curve** is achieved which shows the solution point of ESP-lifted well:

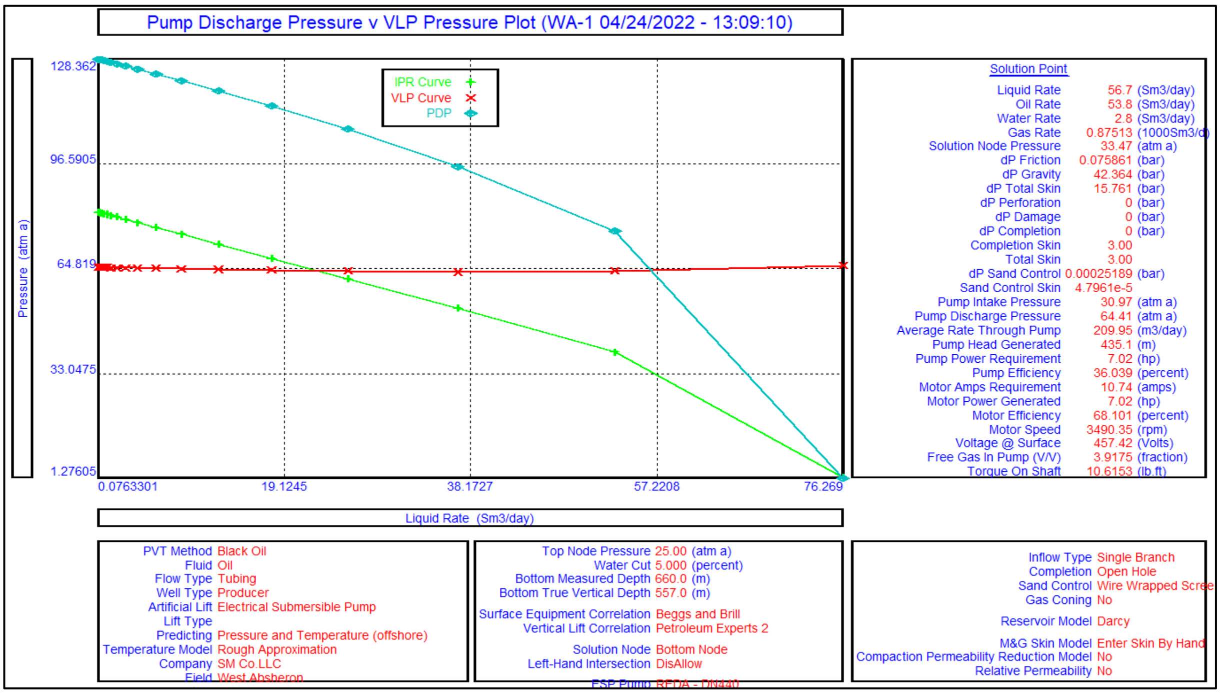


Figure 38. Pump Discharge Pressure vs VLP Plot for ESP-lifted well

On the figure above, Pump Discharge Pressure is given in blue curve, IPR in green curve and VLP is shown in red curve, from wellhead to the pump discharge. From the figure above, it is obvious that the calculated liquid rate and oil rate by PROSPER for this case is **56.7 sm³/day and 53.8 sm³/day** respectively.

Sensitivity analysis for ESP-lifted well:

In this section, sensitivity analysis based on different operating frequencies, reservoir pressure and water cut are performed to see how the solution node, PDP and VLP curves are affected.

Impacts of Changing Reservoir Pressure:

As the fluids are producing the reservoir pressure will decrease if pressure maintenance is not carried out. Taking this into account, three different reservoir pressure values along with the current reservoir pressure that is 82 atm are included on the software and the results are illustrated in the given table below:

Table 9. Results of system sensitivity analysis on reservoir pressure depletion (ESP case)

Parameter	***Reservoir Pressure (82 atm)***	***Reservoir Pressure (70 atm)***	***Reservoir Pressure (65 atm)***	***Reservoir Pressure (60 atm)***	***Unit***
Liquid Rate	56.7	47.9	41	---	sm^3/day
Oil Rate	53.8	45.6	39	---	sm^3/day
Water Rate	2.8	2.4	2.1	---	sm^3/day
Gas Rate	0.87513	1.047	0.75033	---	1000 sm^3/day

Obtained results show that decreasing reservoir pressure leads to reduced production rate. And if the reservoir pressure falls to 60 atm, then the well will not flow and production ceases. It means that there will be demanded to make changes to the downhole configuration. The following figure is a screenshot showing the PDP and VLP curves and the intersection points between these two curves:

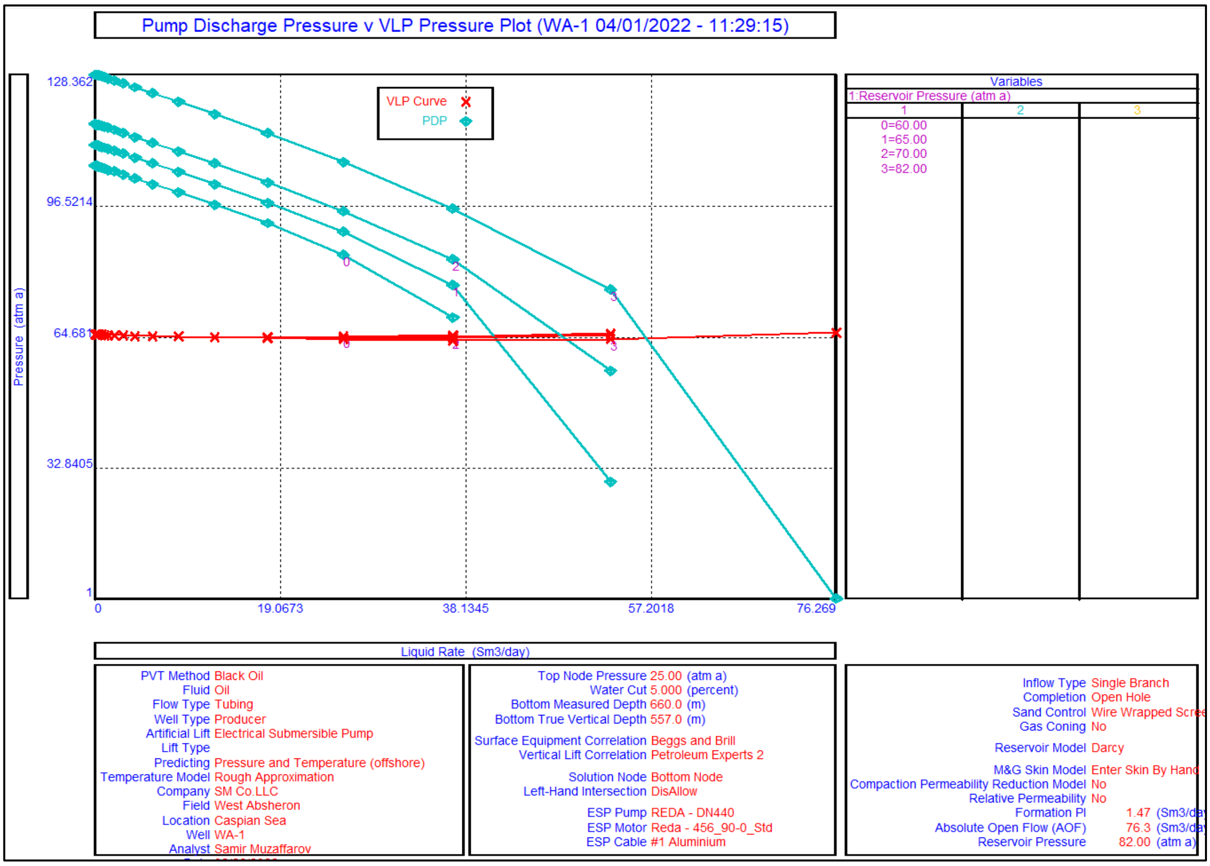


Figure 39. Impacts of changing reservoir pressure on PDP & VLP curves (ESP case)

From the figure above, it can be deduced that there is no intersection point between PDP and VLP curves when the reservoir pressure is equal to 60 atm. That means solution node is not achieved at this pressure.

Impacts of Changing Water Cut:

As it is mentioned above, reservoir depletion will lead to increasing water cut values with time and to simulate the impacts of increasing water production, three different reservoir water cut values along with the current water cut which is 5% are given on the software and the calculated results are represented in the table below:

Table 10. Results of system sensitivity analysis on increasing water cut (ESP case)

Parameter	***Water Cut (5%)***	***Water Cut (30%)***	***Water Cut (50%)***	***Water Cut (70%)***	***Unit***
Liquid Rate	56.7	56.6	56.5	58.5	sm^3/day
Oil Rate	53.8	39.6	28.2	17.5	sm^3/day
Water Rate	2.8	17	28.2	40.9	sm^3/day
Gas Rate	0.87513	0.70853	0.53788	0.35628	1000 sm^3/day

It is obvious from the above table that increasing water cut does not impact total liquid production significantly. However, the oil production rate dramatically decreases and there is a sharp increase in water production rate which is reasonable.

On the following figure, the impact of increasing water cut on VLP, and PDP curves are visible. It is clear that solution nodes are achieved at each case.

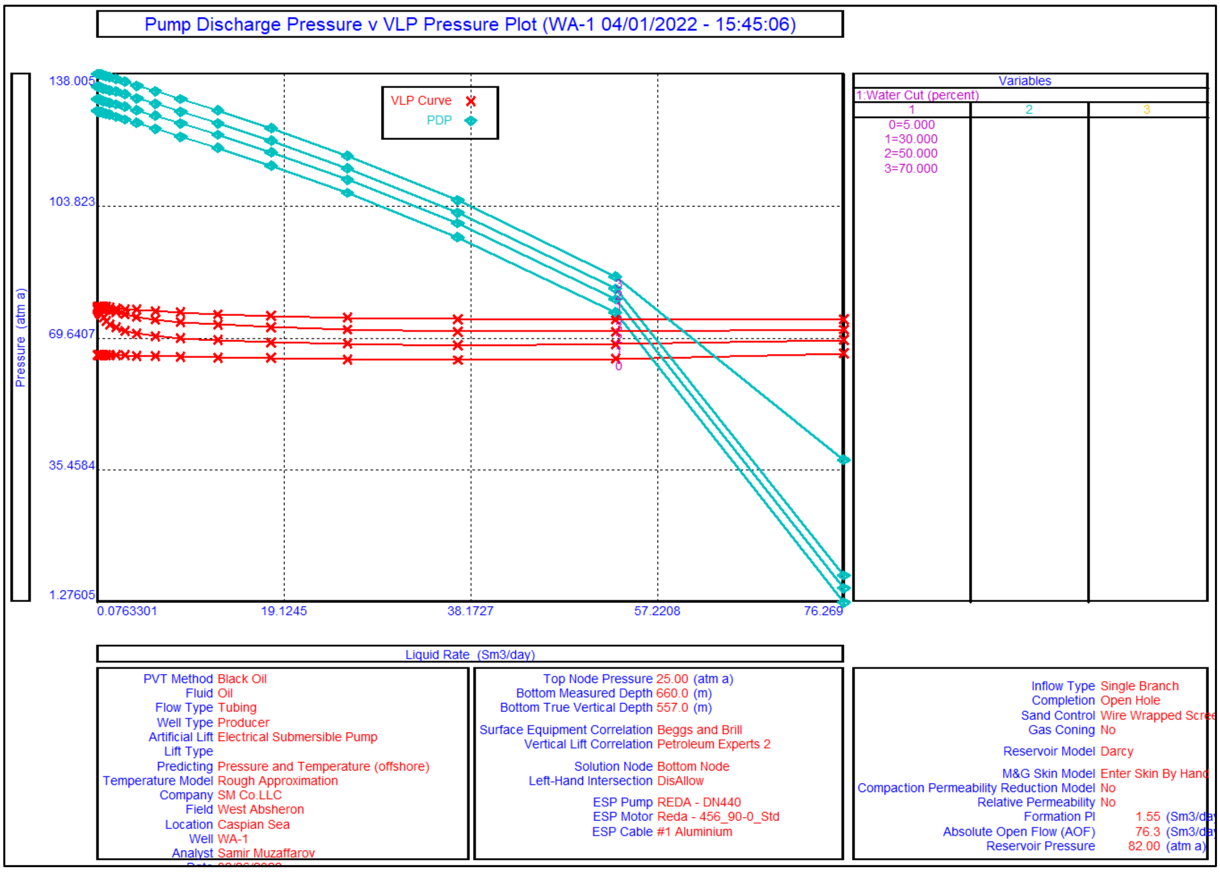


Figure 40. Impacts of increasing water cut on PDP & VLP curves (ESP case)

Impacts of Different Operating Frequencies:

It is obvious that higher production rates can be achieved at higher surface operating frequencies and to see the effects of various operating frequencies, sensitivity analysis based on four different frequencies are performed and the calculated results are represented in the table below:

Table 11. Results of system sensitivity analysis on different operating frequencies (ESP case)

Parameter	*Operating frequency (40 Hertz)*	*Operating frequency (50 Hertz)*	*Operating frequency (60 Hertz)*	*Operating frequency (70 Hertz)*	*Unit*
Liquid Rate	39.2	49.5	56.7	60.6	sm^3/day
Oil Rate	37.2	47.1	53.8	57.5	sm^3/day
Water Rate	2.0	2.5	2.8	3.0	sm^3/day
Gas Rate	1.055	1.334	0.87513	0.93527	1000 sm^3/day

It can be seen from the table above that increasing operating frequencies yield higher production rates. On the following figure, the effects of various operating frequencies on VLP and PDP curves and solution nodes are visible:

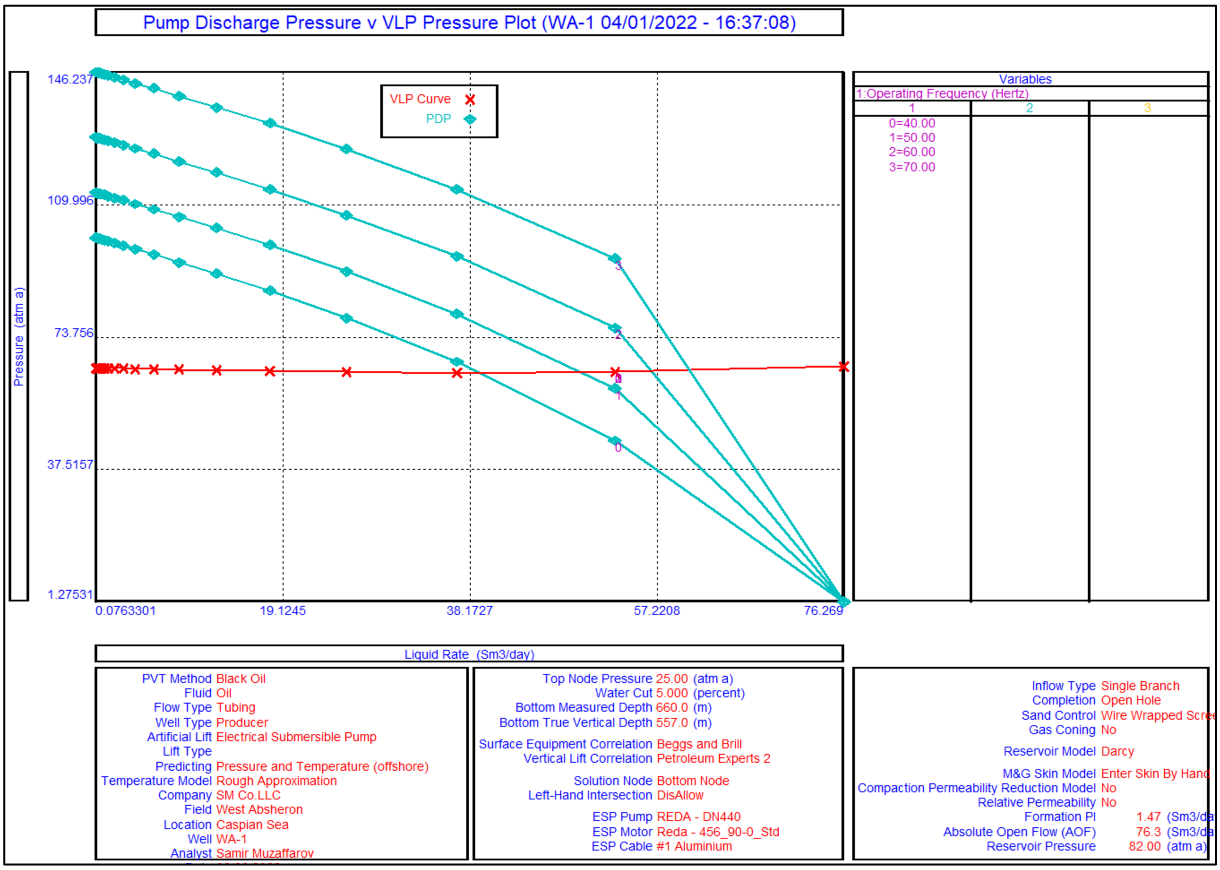


Figure 41. Impacts of different operating frequencies on PDP & VLP curves (ESP case)

Model Setup for Continuous Gas Lift Case

This section elaborates performance of the designed well by applying Continuous Gas Lift as an artificial lift technique. General data and working principle of Gas Lift System has already been covered in the previous chapter. On PROSPER software to design the Continuous Gas Lift system the following steps must be followed:

- Firstly, gas lift design parameters are introduced into the software on the design menu
- Then design production and gas injection rates are calculated
- From the calculations above corresponding depth and number of unloading valves and the operating valve are determined
- Then design results (valve positions) are transferred to gas lift input data window
- At the end system calculation for a continuous gas-lifted well is performed.

System Summary:

In this section, all required data for Well WA-1 is same as it was for natural drive case and ESP case, except here Continuous Gas Lift is selected as an artificial lift method. Moreover, pressure loss due to friction in annulus is taken into consideration. The following figure is a screenshot from the system summary window:

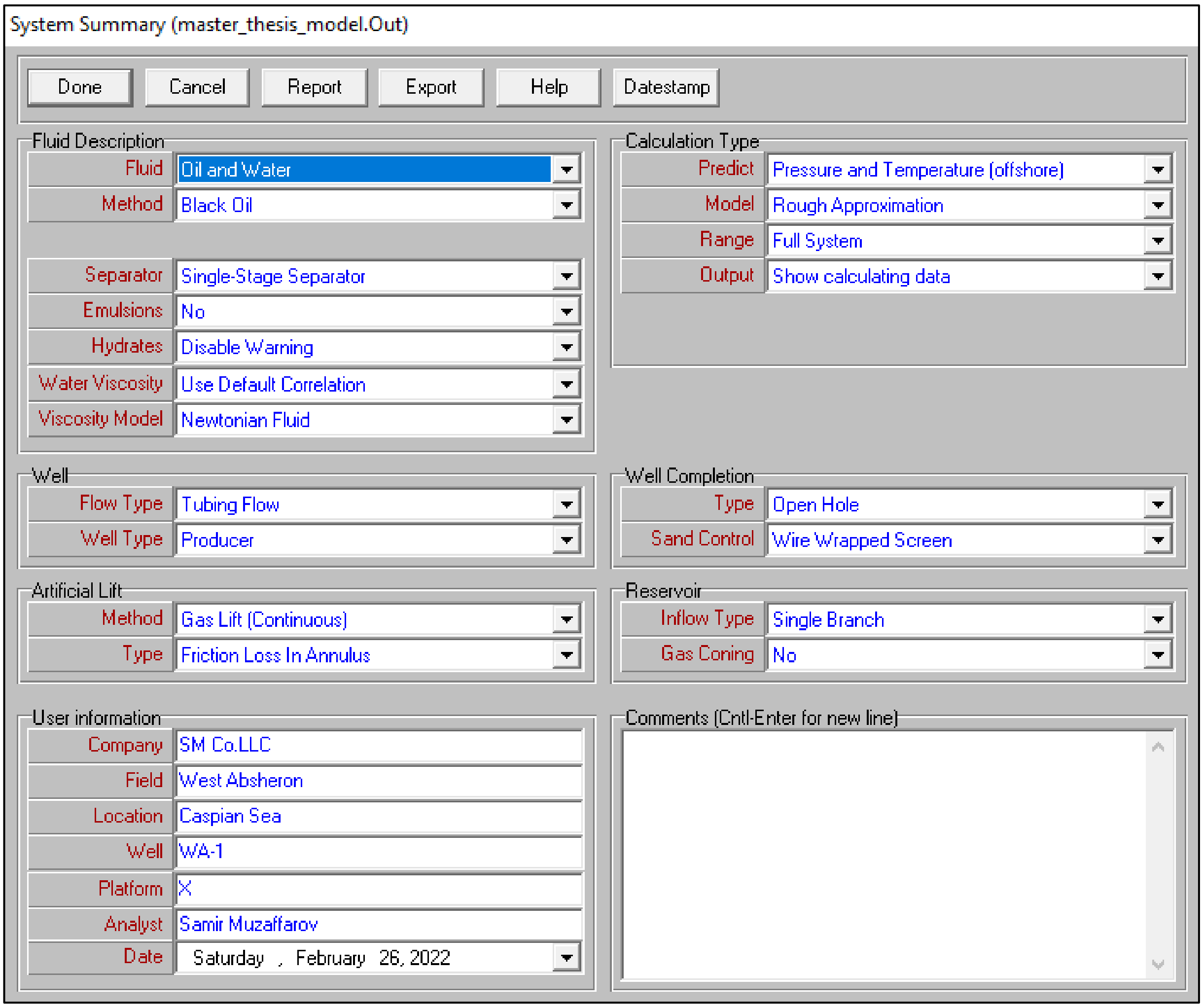


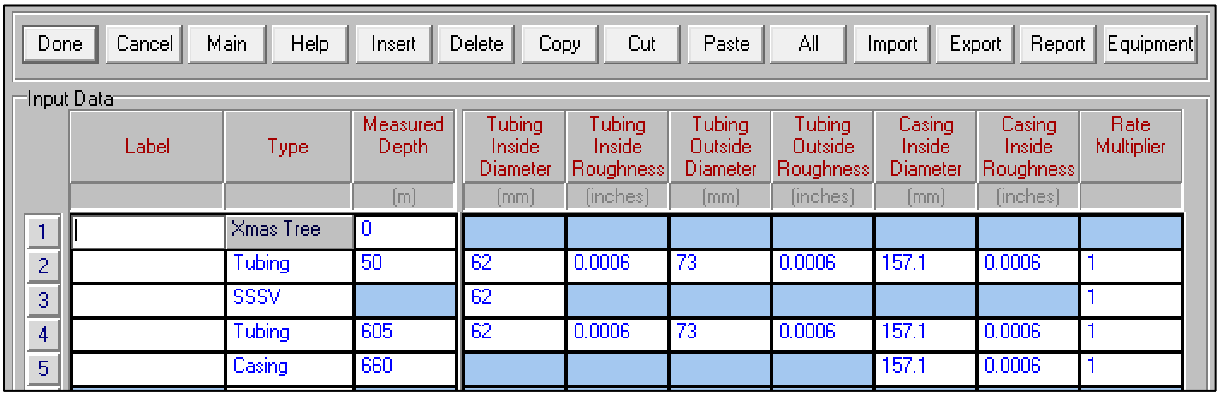
Figure 42. System summary for gas-lift design case

PVT and IPR Data:

These two sections remain the same as for the Natural Drive Case and ESP Case.

Equipment Data:

In this part all subsections remain the same except the downhole equipment where the tubing outside diameter must be filled to perform Continuous Gas Lift design. Taking the fact into consideration that injecting gas as much deeper as possible yields higher liquid rates and well schematics, setting depth of production tubing is given at 605 m MD (considering sand screen packer element and production packer). A screenshot from the downhole equipment part is given in the following figure:



	Label	Type	Measured Depth (m)	Tubing Inside Diameter (mm)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (mm)	Tubing Outside Roughness (inches)	Casing Inside Diameter (mm)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	0							
2		Tubing	50	62	0.0006	73	0.0006	157.1	0.0006	1
3		SSSV		62						1
4		Tubing	605	62	0.0006	73	0.0006	157.1	0.0006	1
5		Casing	660					157.1	0.0006	1

Figure 43. Downhole equipment data for gas-lift design case

Continuous Gas Lift Design Parameters:

In this section the main input data for Continuous Gas Lift design stage is introduced into the software. It should be pointed out that the fundamental idea behind gas lift design is achieving the highest production rate from the modelled well on PROSPER. Here the following parameters for the Continuous Gas Lift design window are as follows:

- First, for design rate method calculation from maximum production is selected to allow the software to find maximum possible hydrocarbon production rate. This is achieved by calculating optimum gas injection rate and gas injection depth by PROSPER.
- Maximum liquid rate is required to be included in for the above-mentioned calculation method. Taking AOF into consideration, maximum liquid rate is chosen as 76.3 sm^3/day for this case.
- The biggest obstacle for gas lift design scenario in West Absheron field is finding proper and good source for lift gas and installing compressor station to deliver lift gas at required injection rate. For this case and designed well 20000 sm^3/day volume of gas for daily injection purposes is thought as a good assumption considering the obstacles stated above (see the sensitivity analysis given in ***Table 13***).
- Maximum gas available for unloading shallowest valve is generally taken as same as maximum volume of available gas.
- Flowing top node pressure is generally equal to the manifold pressure if the surface equipment section is modelled on PROSPER. Otherwise, flowing wellhead pressure must be included in. Thus, for this scenario, 25 atm flowing wellhead pressure is taken as an input data.
- It is a general practice to leave the unloading top node pressure the same as flowing top node pressure.

- Operating injection pressure is the pressure available at the casing head that is provided by the gas injection system. It should be noted that 7” P-110 production casing in the wells that have recently been drilled in West Absheron oilfield can withstand at least 150 atm pressure. So, the well schematic is not a main constraint on well casing head pressure. For this scenario, 60 atm pressure is included in as an operating injection pressure (see the sensitivity analysis given in ***Table 13***).
- Kick off injection pressure is usually set equal to the normal operating injection pressure and this pressure is required by PROSPER to set depth of the first unloading valve. It is obvious that if higher pressure can be provided, then the injection will be only through the operating valve, meaning that there is no need to install unloading valves.
- Desired pressure loss across valve is usually set in the range of 100-250 psi (6.8-17.01 atm) to be sure that gas injection system and well is functioning properly. For this model desired dP across valve is set 17.2369 bar.
- Maximum depth of injection is constrained by the setting depth of production packer and for Well WA-1 considering packer setting depth, maximum depth of injection is set at 600 meters.
- Water cut remains the same as it is provided in IPR data input window.
- Minimum spacing between gas lift valves is left as its default value of 250 ft (76.2 meters) and normally spacing between valves is chosen from a range of 200-400 ft. This value is required to stop the calculations performed by PROSPER if the next valve is calculated to be set at the depth that is less than 250 ft.
- The wells in West Absheron oilfield are generally completed by 1.55 sg (0.67 psi/ft) completion brine and this value is set as static gradient of load fluid for modelling this scenario.
- Valve type is set as “Casing sensitive” on PROSPER. The value that is given for minimum casing head pressure drop for each valve shows that that amount of reduction in casing head pressure is needed to close the gas lift valves. For this model, 50 psi (3.447 bar) pressure drop is set which is a recommended value.
- For the valve settings, “All valves PVo = Gas pressure” is chosen. When this setting is chosen unloading valves will close by using either the maximum of pressure drops to shut the valves or closing pressure drop calculated by PROSPER. Even though this setting leads to a reduction on the available gas injection pressure and hence lower production rates, it is recommended to apply this setting when a new gas lift system is designed.

- Dome pressure correction above 1200 psig is enabled to ensure that valve dome pressure temperature correction at higher pressures is accurate. This option is the default and recommended by the software as well.
- Check rate conformance with IPR is enabled as well to be sure that the calculated liquid rates by PROSPER can be met by reservoir deliverability. When this option is enabled PROSPER tries to calculate the highest liquid rate possible in conformance with IPR.
- Use IPR for unloading is set to “Yes” that is a recommended option. This method enables using IPR for sizing unloading valves.
- As a final step, a gas lift valve should be selected from the PROSPER database which is visible on the right-hand side of the data input screen. For this scenario, Camco R-20 Normal Valves with port sizes in a range of 8 to 32 64 ^{ths} inch are selected. It should be stated that PROSPER tries to define which port sizes will deliver the optimal production rate. That means a different valve manufactured by another company may require different port size for the gas lift modelling. However, in any case the software still calculates optimal production rates. Considering this statement, the type of valve included on the software is not a big issue if the valves are casing sensitive.

The following figure shows the gas lift design input on the software:

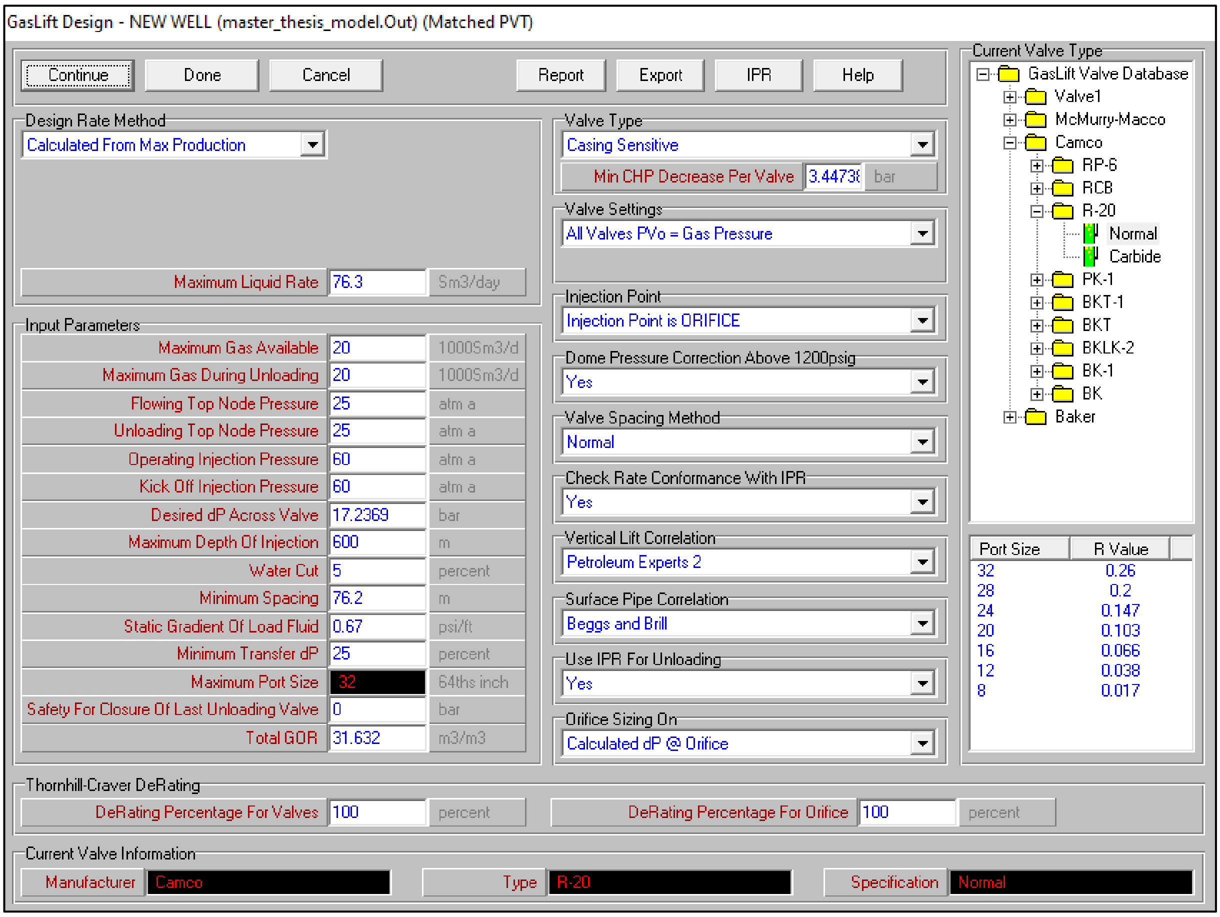


Figure 44. Gas-lift design input menu

Performing the Gas Lift Design

After the basic input data is introduced into the software the next step is designing a gas lift system. PROSPER calculates the Gas Lift Performance Curve and determines the optimum gas lift injection rate. Optimum gas lift injection rate yields the maximum oil production in the system. Maximum gas available is set 20000 sm^3/day and PROSPER calculates that optimum gas injection rate is 20000 sm^3/day, which is equal to maximum gas available. Nevertheless, this rate is not the final value, because the unloading process and valve setting depth is not yet considered. The figure below represents the gas lift performance curve:

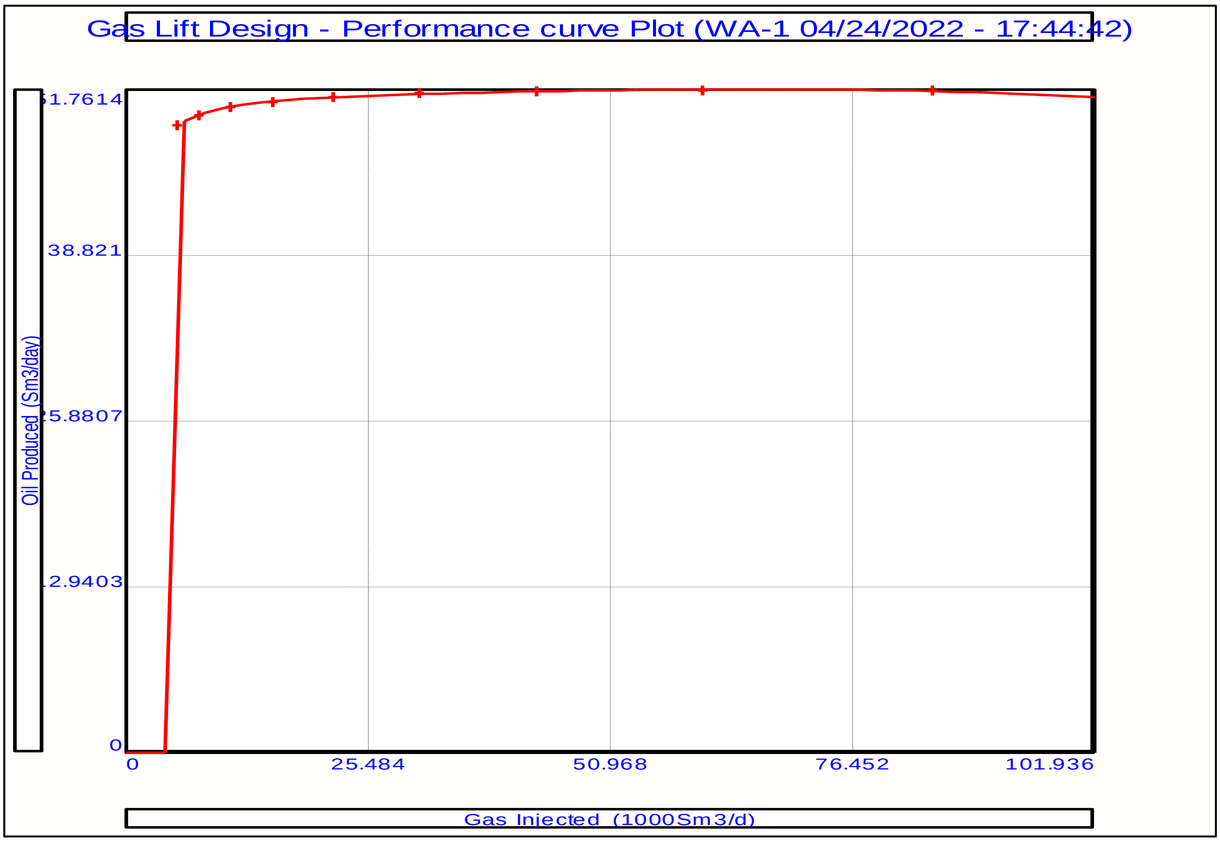


Figure 45. Gas lift performance curve

From the figure above, maximum oil production that the injection gas rate can deliver is around 51.76 sm^3/day. However, this may not be the optimum gas injection rate if the economics of the project is taken into consideration. Generally, the economic optimum of this curve lies on the left of technical optimum. It is clear from the above figure that injecting 42000 sm^3/day lift gas will deliver maximum oil production and then the production rate will be almost constant at this value. Nevertheless, after injecting nearly 76000 sm^3/day of gas, the curve starts declining because large amount of gas in the system leads to an increase in frictional pressure losses. Thus, production rate starts declining.

Valve Positioning:

Finally valve spacing procedure is carried out on PROSPER. During the calculations, the oil rate is checked for the conformance with the IPR and if necessary, the design rate is reduced by the software. It is worth mentioning that PROSPER checks the available gas injection rate to achieve designed rate and if the amount of available gas is less than required gas injection rate, then target oil production is reduced.

On the following figure positions of unloading valves and continuous injection depth are represented:

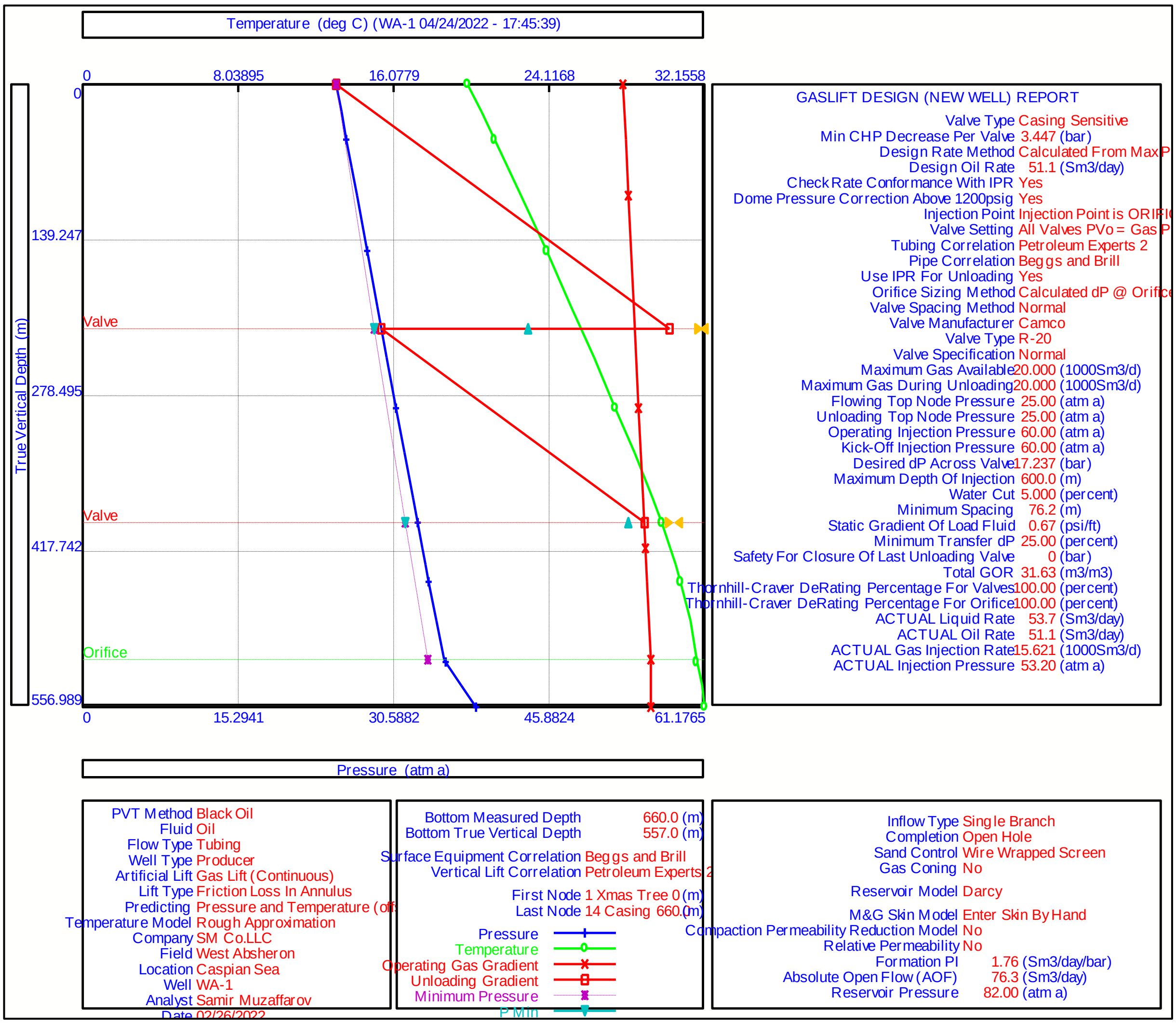


Figure 46. Gas lift valves setting

It becomes clear that 2 unloading valves and one orifice type valve are required for this gas lift design. The following figure is a screenshot from the gas lift design calculation window:

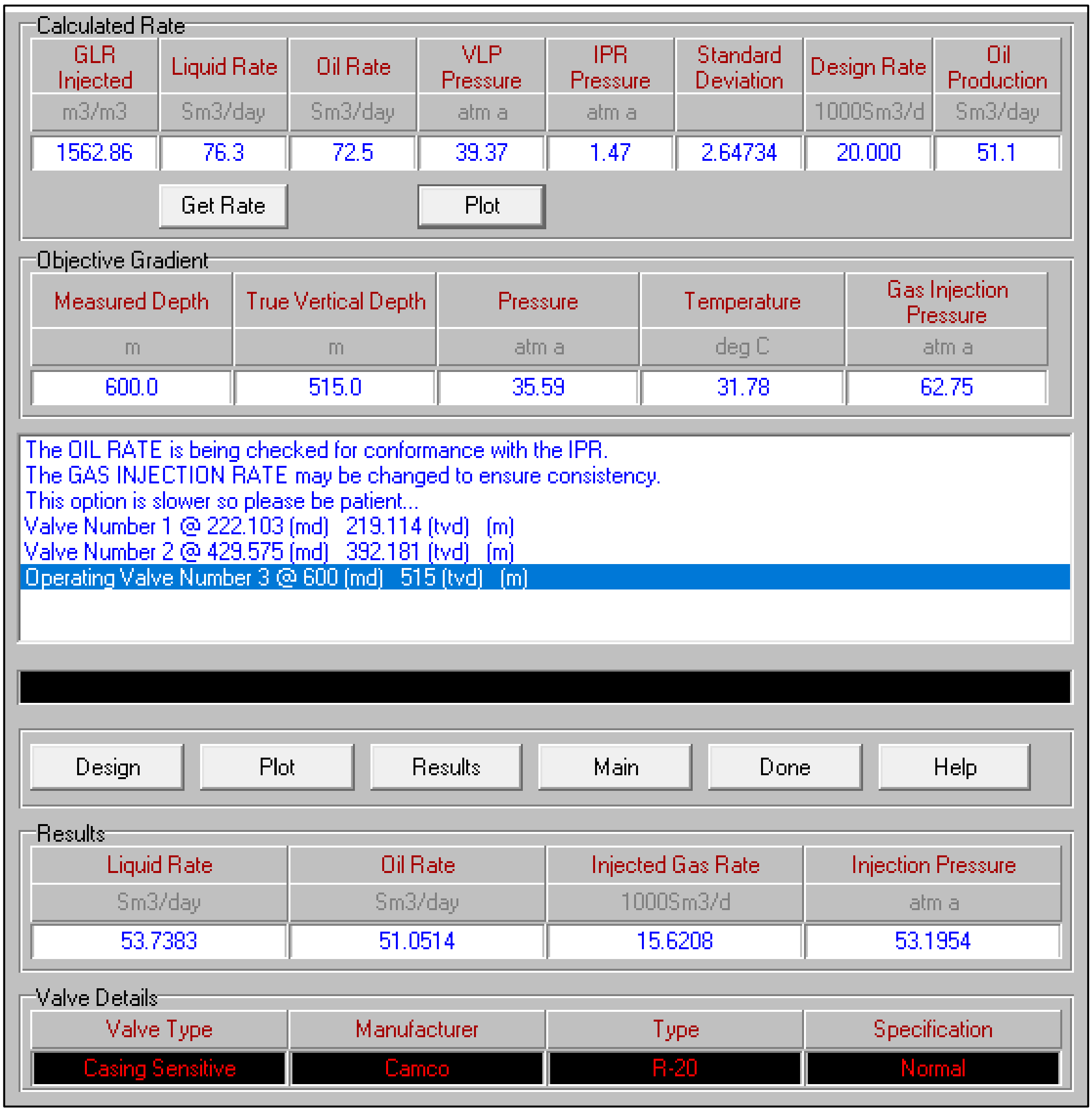


Figure 47. Gas lift design calculation window

The following table includes all calculations related to the gas lift valve positioning procedure:

Table 12. Gas lift valve spacing results

Valve Number	***Valve Type***	***Measured Depth (m)***	***True Vertical Depth (m)***	***Valve Opening Pressure (atm)***	***Valve Closing Pressure (atm)***	***Gas Lift Gas Rate (10000 sm^3/d)***	***Port Size (64^{ths} inch)***
1	Valve	222.103	219.114	61.1765	60.6364	1.56207	8
2	Valve	429.575	392.181	58.6963	57.7194	8.94982	12
3	Orifice	600	515			15.6208	11

After all calculations and valve spacing procedure, the final gas lift injection rate, design production rate and injection pressure are determined and given in the following table. It is noteworthy to mention that sensitivity analysis based on the gas injection rate and operating injection pressure values are performed to see how design results are affected. For this purpose, four different scenarios are considered. For a given gas injection rate, injection pressure values ranging from 50 atm to 70 atm are included in software and design results are obtained. Then another value for gas injection rate is selected and same injection pressure values are applied. The table below represents the obtained design results:

Table 13. Sensitivity analysis to decide gas lift gas injection rate and injection pressure

Scenarios	***Input data***		***Design results***		
	Gas injection rate, 1000 sm^3/d	**Injection pressure, atm**	**Oil rate, sm^3/d**	**Gas injection rate, 1000 sm^3/d**	**Injection pressure, atm**
Case 1	20	50	25.16	13.59	50
	20	55	29	2.13	55
	20	60	51.05	15.62	53.2
	20	65	45.57	3.9	61.6
	20	70	51.05	15.62	66.6
Case 2	25	50	25.17	14.11	50
	25	55	46.69	19.72	48.2
	25	60	51.23	17.24	53.2
	25	65	45.72	4.02	61.6
	25	70	51.23	17.24	66.6
Case 3	30	50	25.07	10.84	50
	30	55	46.8	20.18	48.2
	30	60	51.35	18.55	53.2
	30	65	49.33	29.4	61.6
	30	70	51.35	18.55	66.6
Case 4	35	50	25.16	13.83	50
	35	55	46.9	20.54	48.2
	35	60	51.46	19.66	53.2
	35	65	49.42	32.02	61.6
	35	70	51.46	19.66	66.6

Among the four different scenarios, Case 1 with 20000 sm^3/day injection rate and 60 atm injection pressure is considered as the best option. The main selection criteria here is that in West Absheron oilfield the lift gas source is the major challenge and for this reason injecting as small volume as possible to get highest production is the main target. It is noteworthy to mention that increase on gas injection rate is not affecting oil production rate and the obtained design results on oil production rate are very close to each other. So, by doing this sensitivity check, 20000 sm^3/day injection rate and 60 atm injection pressure can be quantified as the best design for gas lifting technique considering the economics of the project and source of lift gas.

Gas Lift Stability Check:

Finally, the gas lift valves should be checked for system stability. To achieve that PROSPER enables us to perform stability analysis. System stability analysis proposed by Harald Asheim is done based on two criteria, known as first criterion (F1) and second criterion (F2). The first criterion (F1) shows the well's inflow response (IPM PROSPER User Manual ,Version 11.5, January 2010). It states that in case of a decrease in tubing pressure there will be an increase in the average density of the mixture if the reservoir fluid rate is more responsive to pressure changes compared to the lift-gas rate. At the end tubing pressure will increase and this will stabile the flow. If the first criterion is not achieved, then decrease on tubing pressure will lead to an increase on the injected gas flow rate compared to the liquid flow rate. This in turn leads to a decrease in both tubing pressure and casing pressure. However, in case of decrease on the casing pressure is quicker than decrease on the tubing pressure, then pressure differential between the casing and tubing will also decrease and lift-gas injection rate will also decrease. This will lead to stabilization of the flow. It is known as the second criterion (F2). PROSPER can calculate the stability of gas lift system based on the two criterions mentioned above. To achieve the stability of the gas lift system, one of the two criterions should be greater than 1. In our case, calculated values of **F1 and F2** are equal to **1.10405 and -1.52578** respectively, showing that a stable flow can be achieved by this design work:

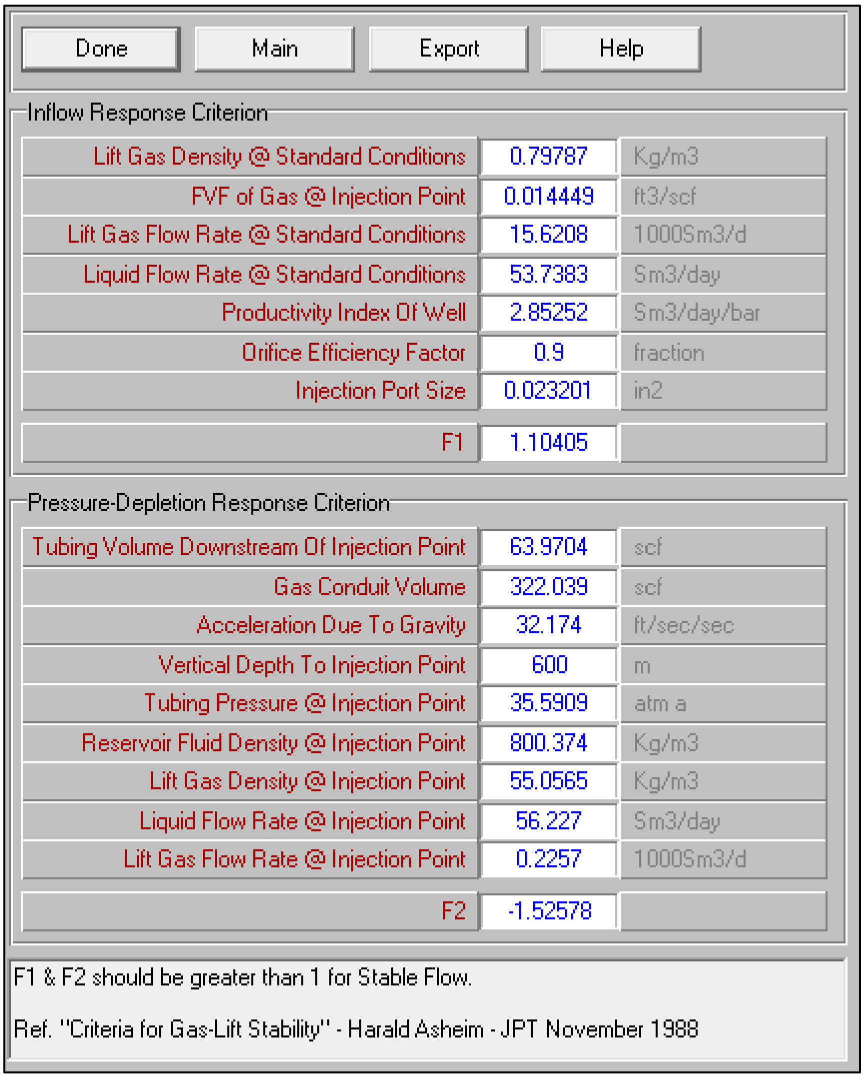


Figure 48. Gas lift valve stability criteria

System Calculations:

As a final step, obtained design results are included in the software to perform system calculations and create IPR and VLP curves. To do that on PROSPER System Gas Lift data menu should be filled up as follows:

- Gas lift gas properties: here gas lift gas gravity, any impurities present in the lift gas and predetermined injection gas rate are included in the system
- As the gas lift valves positioning has already been performed, Valve Depths Specified method is selected as gas lift method
- Designed injection pressure value and dP across the unloading gas lift valves are entered into the system
- Finally, predetermined valve positions are transferred from the earlier performed Gas Lift design.

The following figure is a screenshot from gas lift input data window:

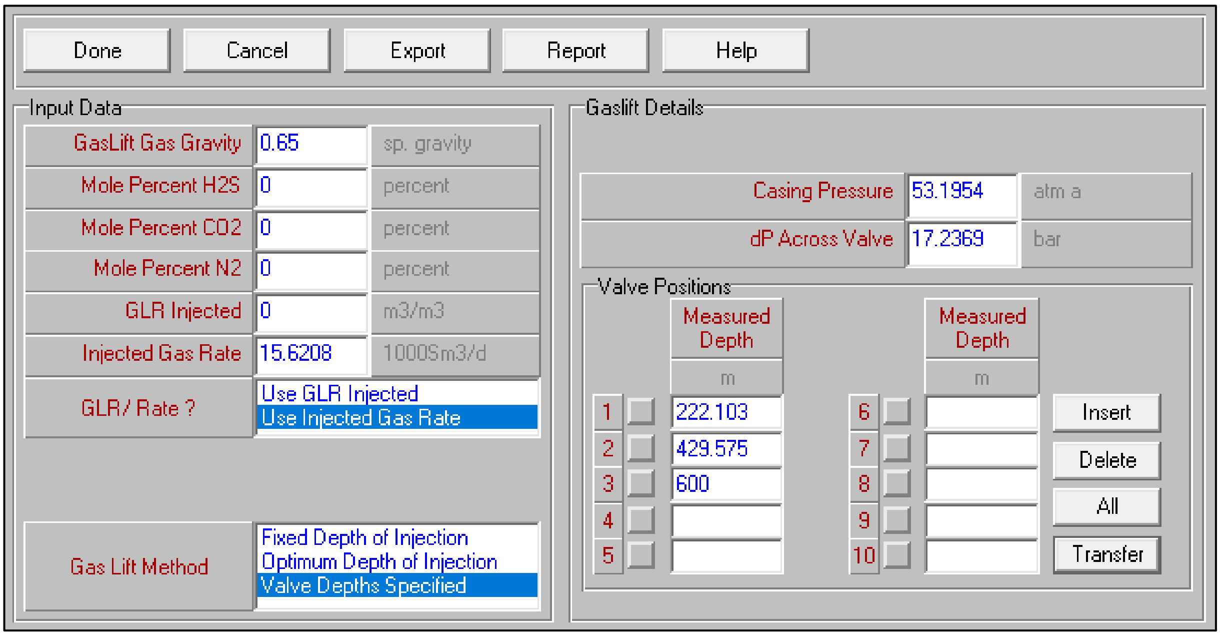


Figure 49. Gas lift input data screen

Finally, the vertical lift performance curve is generated, and intersection point between IPR curve and VLP is achieved:

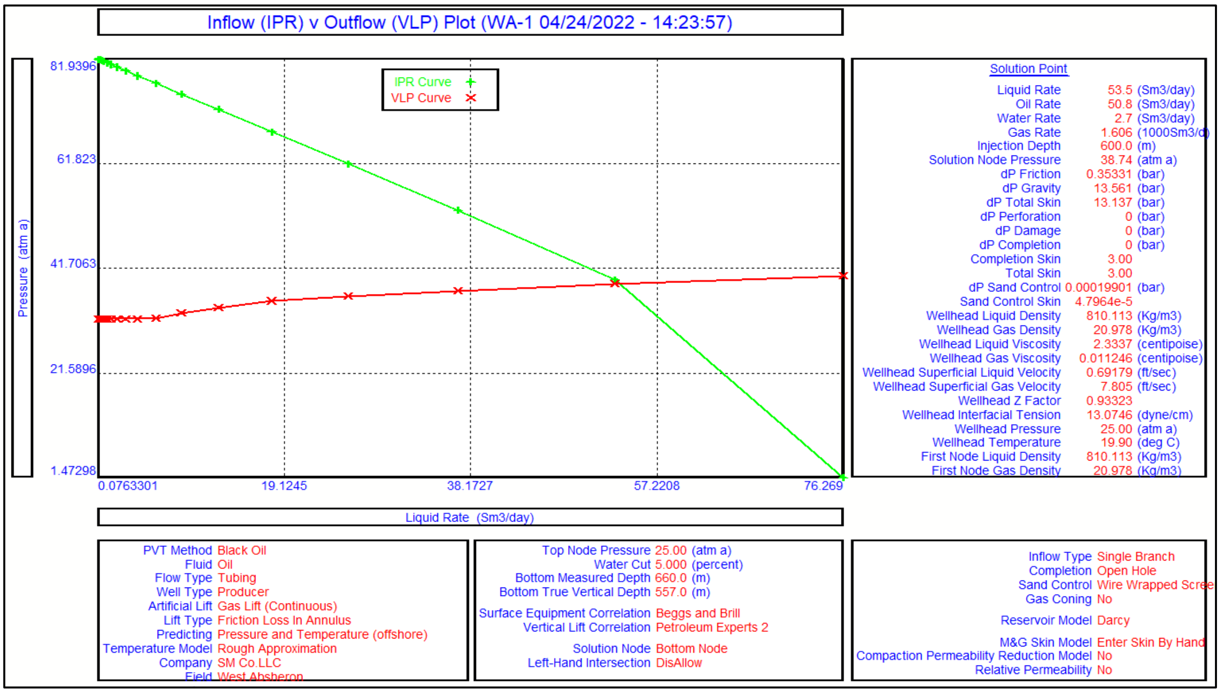


Figure 50. IPR and VLP plot for gas lift case

On the figure above, IPR is given in green curve and VLP is shown in red curve, and it is obvious that the calculated liquid rate and oil rate by PROSPER for this case is **53.5 sm^3/day and 50.8 sm^3/day** respectively.

Chapter 4: Discussion and Conclusions

The fundamental objective of this thesis work is to comparatively analyse the implementation of natural drive and artificial lift techniques, specifically said Electrical Submersible Pump (ESP) and Continuous Gas Lift for hydrocarbon production in West Absheron oilfield, which is in Absheron archipelago, the Caspian Sea. To make this comparison, a mathematical model including various sub models are created in a special computer software, namely PROSPER to predict the achievable hydrocarbon production rates for three different cases (natural drive, ESP, and continuous gas lifting) on the basis of a synthetic well data, namely Well WA-1. Based on the data collected from nearby wells drilled in West Absheron oilfield a new synthetic well is modelled on PROSPER. All required data with regards to PVT, deviation survey, geothermal temperature profile, and downhole equipment is introduced into the software and IPR curve is constructed. After that modelling of natural drive case, ESP case and continuous gas lift case are done and through system calculations menu the operating points in the intersection point of between IPR and VLP curves are generated for each case. The obtained results show that in case of natural drive case the modelled well oil production is equal to **17.6 sm^3/day** with the operating bottom hole pressure equal to 67.37 atm. However, if artificial lift techniques are applied, the production rate is significantly increased. So that for ESP case REDA DN440 (101.6 mm OD) pump which is manufactured by Schlumberger is modelled on PROSPER with downhole gas separator to achieve the best performance out of the pump and the system calculations yield that oil production rate is equal to **53.8 sm^3/day**. Finally designing of continuous gas lift is modelled on PROSPER and it turns out that gas lift system with 2 unloading valves and 1 operating valve with 15620.8 sm^3/day injection rate and 53.1954 atm injection pressure can produce oil equal to **50.8 sm^3/day w**ith a stable flow. Sensitivity analyses are also performed for each case separately and it is clear that changing reservoir pressure, water cut and GOR are badly affecting the oil production.

From the obtained results, it is obvious that application of ESP and continuous gas lifting yields higher production rates and by this way production enhancement and optimization can be achieved. For the application of continuous gas lifting, the biggest obstacle is the unavailability of source gas because production wells in West Absheron oilfield currently produce too little volume of gas (solution gas) which cannot be a source for gas lifting and what is more, a gas lift compression station and all required surface facilities and pipeline network should be installed in the field as well. The lift gas can be obtained from a nearby gas producing field if possible. However, if the CAPEX of this plan is considered, application of gas lift system seems unfavourable. For the ESP case, a detailed planning is highly demanded to realize this project because ESPs have a limited lifetime and there will be a need to change the downhole completion (workover, maintenance) in ESP lifted wells when they experience failure, leading to increased OPEX during the ongoing field development project. Comparing this factor to that of gas lifting system, it should be noted that gas lifting is a very simple, commonly applied artificial lift method where little can go wrong. From the obtained results and specifically unavailability of source gas and required infrastructure in the study area, it can be concluded that implementation of ESPs for hydrocarbon production enhancement purposes in future wells that will be drilled in West Absheron oilfield seems to be superior choice.

Recommendations

It should be emphasised that although the modelling done on PROSPER for this thesis work is successful and the best option to optimize and maximise the hydrocarbon production in West Absheron oilfield can be selected, in reality this planning is far too complex and production optimization should be done for every well individually considering the available input data for each well. In case of field production optimization and enhancement, more sophisticated software is required to make an integrated approach considering the surface network of present wells and subsurface data. Besides an elaborated economic analysis should be carried out to decide on the best suitable artificial lift technique for hydrocarbon production acceleration purposes.

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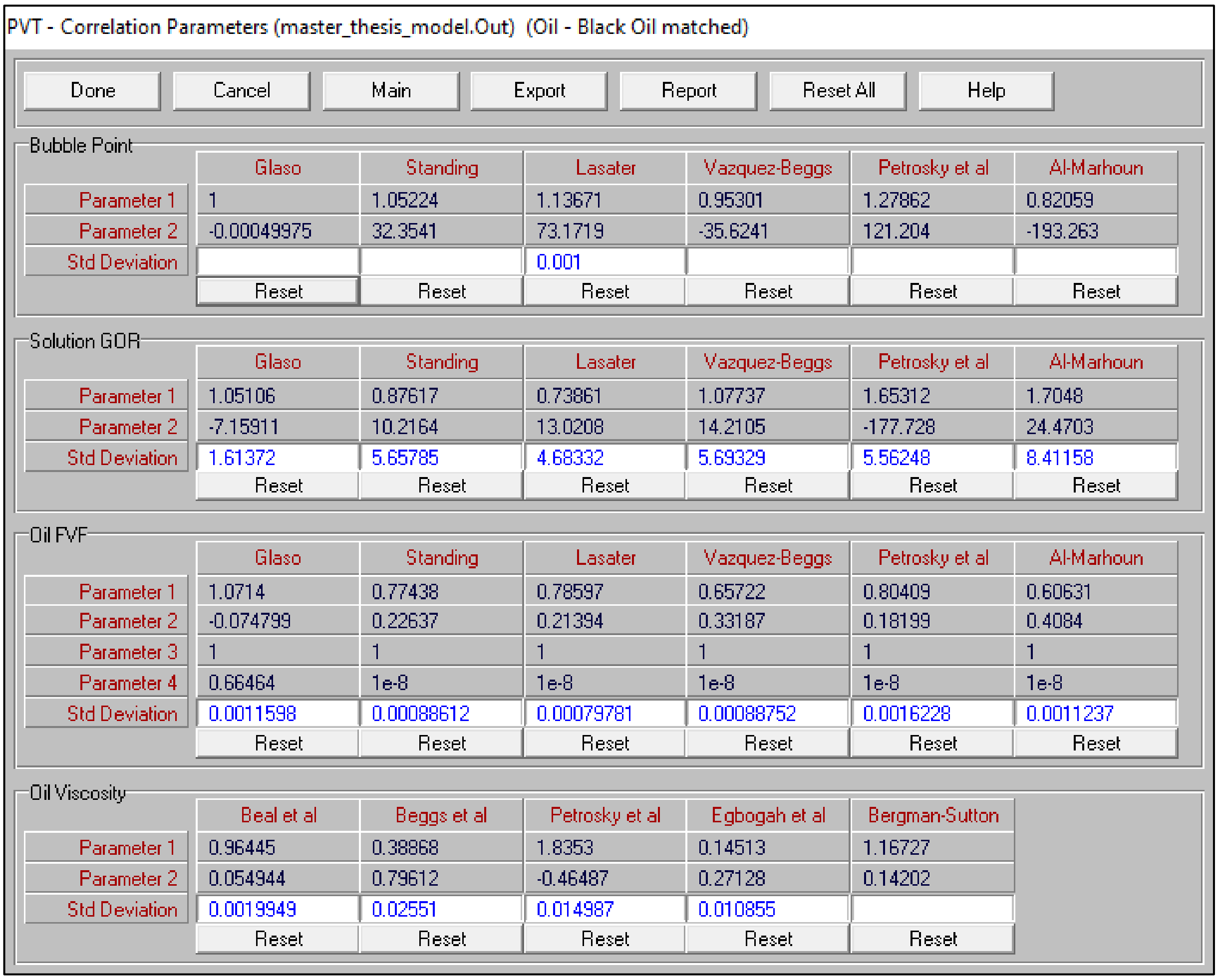
Appendix



PVT - Correlation Parameters (master_thesis_model.Out) (Oil - Black Oil matched)

Done | Cancel | Main | Export | Report | Reset All | Help

Bubble Point

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1	1.05224	1.13671	0.95301	1.27862	0.82059
Parameter 2	-0.00049975	32.3541	73.1719	-35.6241	121.204	-193.263
Std Deviation			0.001			
	Reset	Reset	Reset	Reset	Reset	Reset

Solution GOR

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.05106	0.87617	0.73861	1.07737	1.65312	1.7048
Parameter 2	-7.15911	10.2164	13.0208	14.2105	-177.728	24.4703
Std Deviation	1.61372	5.65785	4.68332	5.69329	5.56248	8.41158
	Reset	Reset	Reset	Reset	Reset	Reset

Oil FVF

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.0714	0.77438	0.78597	0.65722	0.80409	0.60631
Parameter 2	-0.074799	0.22637	0.21394	0.33187	0.18199	0.4084
Parameter 3	1	1	1	1	1	1
Parameter 4	0.66464	1e-8	1e-8	1e-8	1e-8	1e-8
Std Deviation	0.0011598	0.00088612	0.00079781	0.00088752	0.0016228	0.0011237
	Reset	Reset	Reset	Reset	Reset	Reset

Oil Viscosity

	Beal et al	Beggs et al	Petrosky et al	Egbogah et al	Bergman-Sutton
Parameter 1	0.96445	0.38868	1.8353	0.14513	1.16727
Parameter 2	0.054944	0.79612	-0.46487	0.27128	0.14202
Std Deviation	0.0019949	0.02551	0.014987	0.010855	
	Reset	Reset	Reset	Reset	Reset

Figure 51. PVT data match results

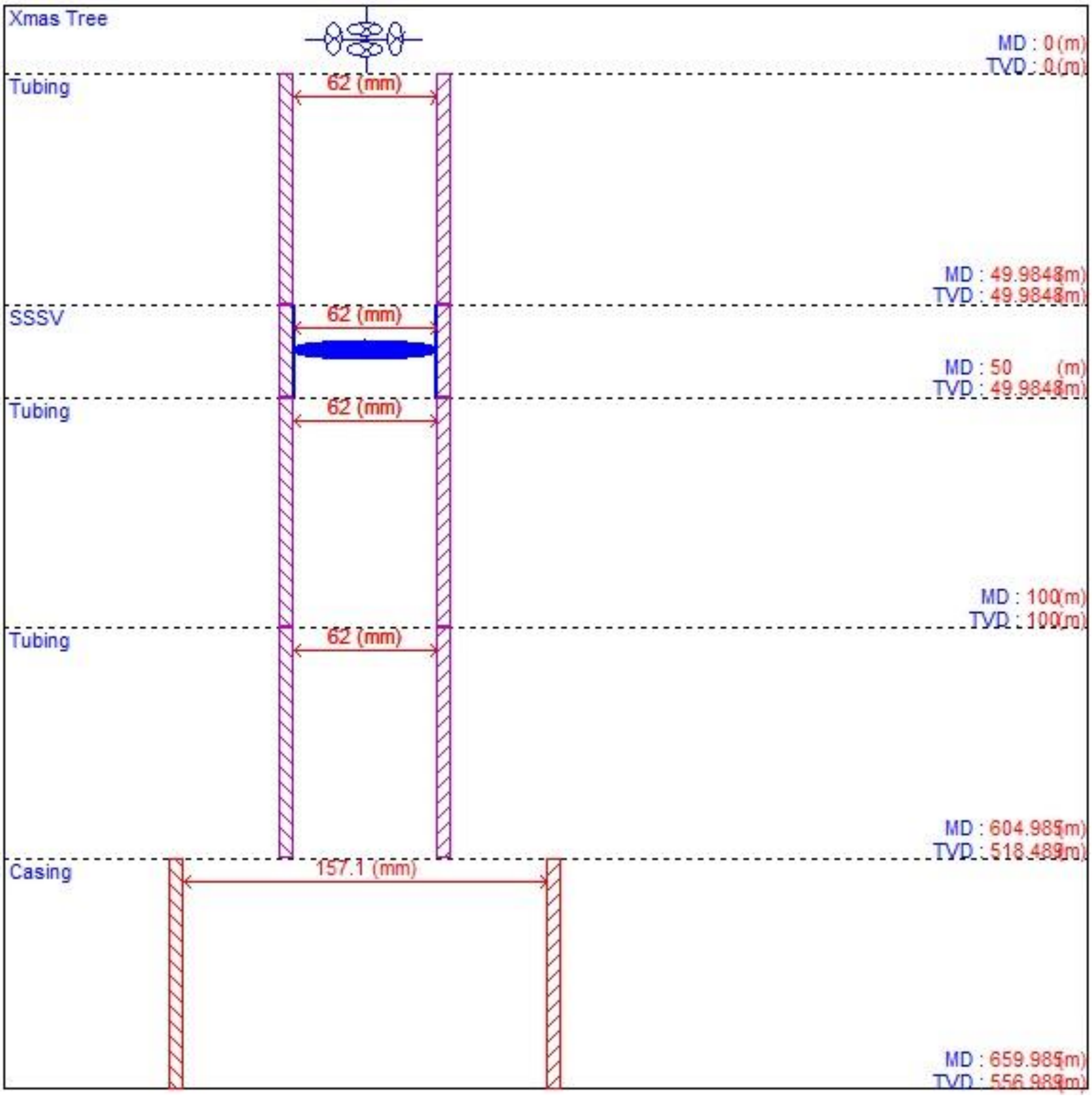


Figure 52. Downhole schematic of natural drive case

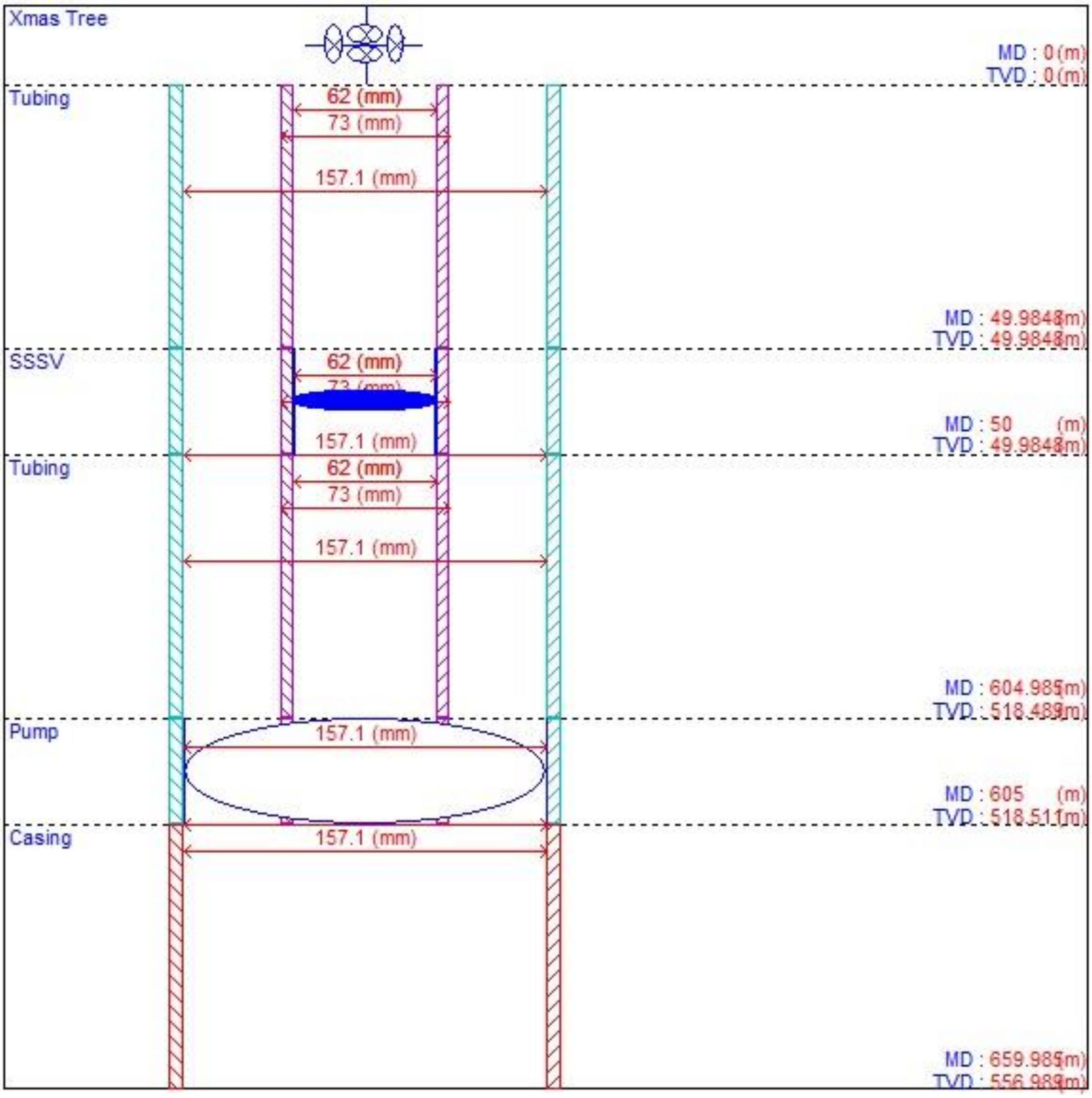


Figure 53. Downhole schematic of ESP case

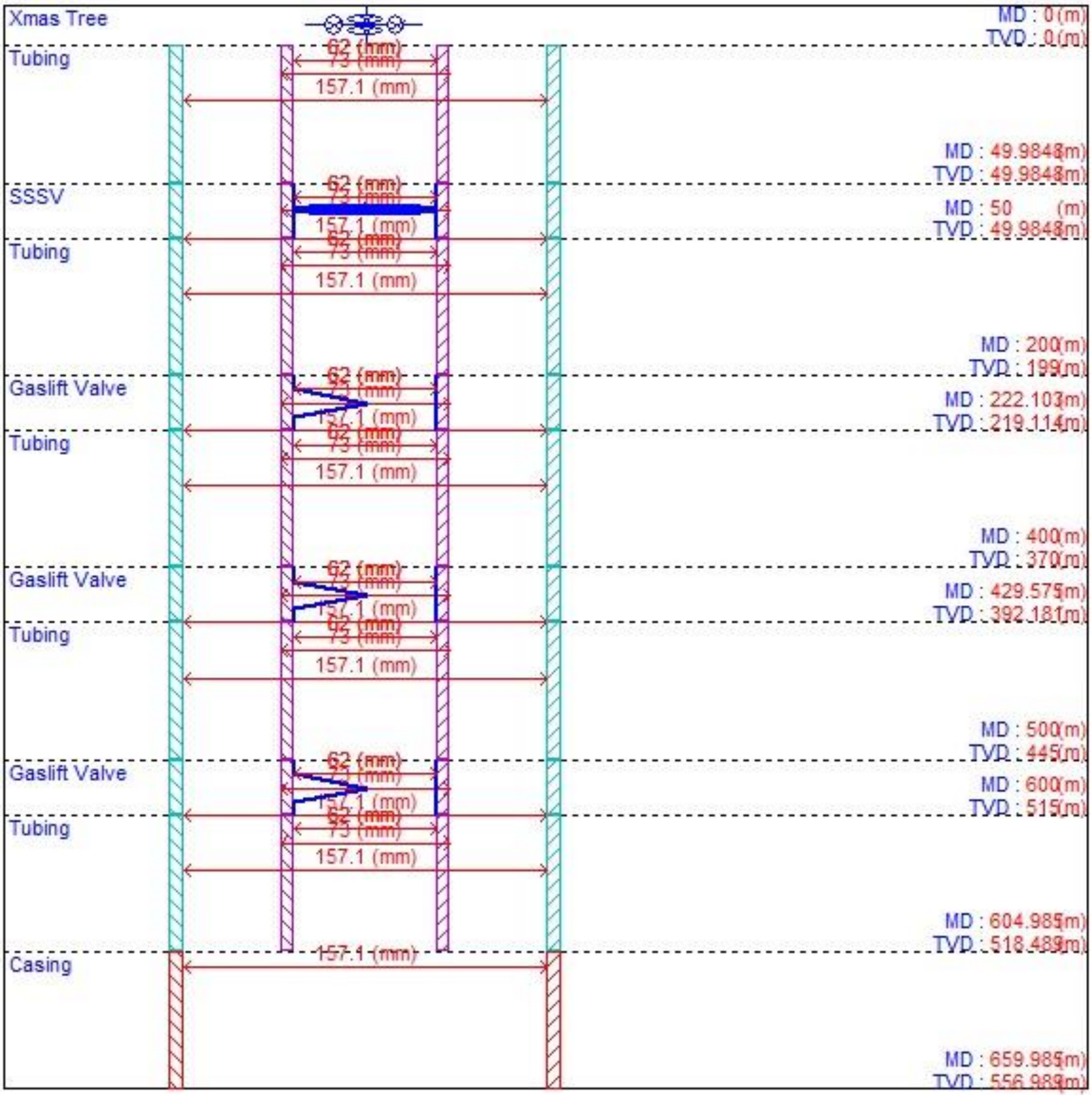


Figure 54. Downhole schematic of gas lift case

Valve Number	Number Of Valves	Valve Type	Measured Depth	True Vertical Depth	Tubing Pressure	Casing Pressure	Transfer Pressure	Temperature @ Valve	Gaslift Gas Rate	Port Size	R Value	Valve Opening Pressure	Valve Closing Pressure	Dome Pressure	TestRack Opening Pressure	Opening CHP	Closing CHP
			(m)	*(m)*	*(atm a)*	*(atm a)*	*(atm a)*	*(deg C)*	*(1000Sm*	*(64ths inc*		*(atm a)*	*(atm a)*	*(atm a)*	*(atm a)*	*(atm a)*	*(atm a)*
1	1	Valve	222.1	219.1	29.41	61.18	37.35	25.81	1.562	8	0.017	61.18	60.64	58.32	59.31	60.00	59.46
2	1	Valve	429.6	392.2	32.99	58.70	39.42	29.96	8.950	12	0.038	58.70	57.72	54.70	56.82	56.60	55.62
3	1	Orifice	600.0	515.0	35.59	62.75	35.59	31.78	15.621	11						53.20	

Figure 55. Gas lift valve positioning calculation results

Liquid Rate	Oil Rate	VLP Pressure	IPR Pressure	dP Total Skin	dP Perforation	dP Damage	dP Completion	Completion Skin	dP Sand Control	Sand Control Skin	Total Skin	WellHead Pressure	WellHead Temperature	dP Friction	dP Gravity
(Sm3/day)	*(Sm3/day)*	*(atm a)*	*(atm a)*	*(bar)*	*(bar)*	*(bar)*	*(bar)*		*(bar)*			*(atm a)*	*(deg C)*	*(bar)*	*(bar)*
0.07633	0.072514	68.17	81.94	0.017784	0	0	0	3.00	2.8409e-7	4.7947e-5	3.00	25.00	15.01	2.9536e-5	43.742
0.10979	0.1043	68.17	81.91	0.025578	0	0	0	3.00	4.0864e-7	4.7947e-5	3.00	25.00	15.01	4.2485e-5	43.740
0.15792	0.15003	68.17	81.88	0.036788	0	0	0	3.00	5.8778e-7	4.7947e-5	3.00	25.00	15.01	6.111e-5	43.737
0.22716	0.2158	68.16	81.82	0.052914	0	0	0	3.00	8.4545e-7	4.7947e-5	3.00	25.00	15.02	8.79e-5	43.734
0.32674	0.3104	68.16	81.74	0.076118	0	0	0	3.00	1.2161e-6	4.7947e-5	3.00	25.00	15.03	0.0001264	43.728
0.46998	0.44648	68.15	81.63	0.10948	0	0	0	3.00	1.7492e-6	4.7947e-5	3.00	25.00	15.04	0.0001818	43.721
0.67601	0.64221	68.14	81.47	0.15747	0	0	0	3.00	2.5161e-6	4.7947e-5	3.00	25.00	15.05	0.0002615	43.710
0.97237	0.92375	68.12	81.23	0.22651	0	0	0	3.00	3.6191e-6	4.7947e-5	3.00	25.00	15.08	0.0003762	43.694
1.4	1.3	68.10	80.89	0.32582	0	0	0	3.00	5.2057e-6	4.7947e-5	3.00	25.00	15.11	0.0005412	43.672
2.0	1.9	68.07	80.41	0.46865	0	0	0	3.00	7.4878e-6	4.7948e-5	3.00	25.00	15.16	0.0007784	43.641
2.9	2.7	68.03	79.71	0.67409	0	0	0	3.00	1.077e-5	4.7948e-5	3.00	25.00	15.23	0.0011198	43.596
4.2	4.0	67.97	78.71	0.96962	0	0	0	3.00	1.5492e-5	4.7948e-5	3.00	25.00	15.32	0.0016106	43.533
6.0	5.7	67.88	77.26	1.395	0	0	0	3.00	2.2284e-5	4.7949e-5	3.00	25.00	15.47	0.0023193	43.445
8.6	8.2	67.76	75.19	2.006	0	0	0	3.00	3.2054e-5	4.795e-5	3.00	25.00	15.67	0.0034452	43.324
12.4	11.8	67.60	72.20	2.886	0	0	0	3.00	4.6107e-5	4.7951e-5	3.00	25.00	15.96	0.0054481	43.161
17.8	16.9	67.39	67.90	4.151	0	0	0	3.00	6.6322e-5	4.7953e-5	3.00	25.00	16.38	0.0095447	42.946
25.6	24.3	67.13	61.73	5.970	0	0	0	3.00	9.5402e-5	4.7955e-5	3.00	25.00	16.99	0.019056	42.671
36.9	35.0	66.82	52.84	8.587	0	0	0	3.00	0.0001372	4.7958e-5	3.00	25.00	17.83	0.036557	42.335
53.0	50.4	65.95	39.44	12.975	0	0	0	3.00	0.0001974	4.7963e-5	3.00	25.00	18.99	0.069564	41.311
76.3	72.5	65.46	1.47	37.437	0	0	0	3.00	0.0002840	4.7971e-5	3.00	25.00	20.46	0.13191	40.716

Figure 56. Natural drive case system calculation results

Liquid Rate	Oil Rate	VLP Pressure	IPR Pressure	dP Total Skin	dP Perforation	dP Damage	dP Completion	Completion Skin	dP Sand Control	Sand Control Skin	Total Skin	WellHead Pressure	WellHead Temperature	dP Friction	dP Gravity	Pump Intake Pressure	Pump Discharge Pressure
(Sm3/day	(Sm3/day	(atm a)	(atm a)	(bar)	(bar)	(bar)	(bar)		(bar)			(atm a)	(deg C)	(bar)	(bar)	(atm a)	(atm a)
0.07633	0	65.20	81.94	0.017784	0	0	0	3.00	2.8409e-7	4.7947e-5	3.00	25.00	15.01	2.9539e-5	43.746	78.97	128.36
0.10979	0	65.20	81.91	0.025578	0	0	0	3.00	4.0864e-7	4.7947e-5	3.00	25.00	15.01	4.2488e-5	43.744	78.94	128.34
0.15792	0	65.20	81.88	0.036788	0	0	0	3.00	5.8778e-7	4.7947e-5	3.00	25.00	15.01	6.1115e-5	43.742	78.90	128.30
0.22716	0.2158	65.20	81.82	0.052914	0	0	0	3.00	8.4545e-7	4.7947e-5	3.00	25.00	15.02	8.7907e-5	43.738	78.85	128.25
0.32674	0.3104	65.19	81.74	0.076118	0	0	0	3.00	1.2161e-6	4.7947e-5	3.00	25.00	15.03	0.000126	43.733	78.77	128.17
0.46998	0.44648	65.18	81.63	0.10948	0	0	0	3.00	1.7492e-6	4.7947e-5	3.00	25.00	15.04	0.000181	43.725	78.66	128.06
0.67601	0.64221	65.17	81.47	0.15747	0	0	0	3.00	2.5161e-6	4.7947e-5	3.00	25.00	15.05	0.000261	43.714	78.49	127.91
0.97237	0.92375	65.16	81.23	0.22651	0	0	0	3.00	3.6191e-6	4.7947e-5	3.00	25.00	15.08	0.000376	43.699	78.26	127.68
1.4	1.3	65.13	80.89	0.32582	0	0	0	3.00	5.2057e-6	4.7947e-5	3.00	25.00	15.11	0.000541	43.677	77.92	127.36
2.0	1.9	65.10	80.41	0.46865	0	0	0	3.00	7.4878e-6	4.7948e-5	3.00	25.00	15.16	0.000778	43.645	77.44	126.89
2.9	2.7	65.06	79.71	0.67409	0	0	0	3.00	1.077e-5	4.7948e-5	3.00	25.00	15.22	0.001119	43.600	76.74	126.21
4.2	4.0	65.00	78.71	0.96962	0	0	0	3.00	1.5492e-5	4.7948e-5	3.00	25.00	15.32	0.001610	43.536	75.74	125.23
6.0	5.7	64.91	77.26	1.395	0	0	0	3.00	2.2284e-5	4.7949e-5	3.00	25.00	15.47	0.002319	43.448	74.29	123.81
8.6	8.2	64.79	75.19	2.006	0	0	0	3.00	3.2054e-5	4.795e-5	3.00	25.00	15.67	0.003445	43.326	72.22	121.73
12.4	11.8	64.63	72.20	2.886	0	0	0	3.00	4.6107e-5	4.7951e-5	3.00	25.00	15.96	0.005449	43.161	69.23	118.73
17.8	16.9	64.42	67.90	4.151	0	0	0	3.00	6.6322e-5	4.7953e-5	3.00	25.00	16.38	0.009547	42.942	64.94	114.16
25.6	24.3	64.16	61.73	5.970	0	0	0	3.00	9.5402e-5	4.7955e-5	3.00	25.00	16.98	0.019048	42.664	58.76	107.09
36.9	35.0	63.85	52.84	8.587	0	0	0	3.00	0.000137	4.7958e-5	3.00	25.00	17.83	0.036562	42.325	49.88	95.78
53.0	50.4	64.17	39.44	12.975	0	0	0	3.00	0.000197	4.7963e-5	3.00	25.00	18.98	0.067072	42.559	36.51	76.18
76.3	72.5	65.70	1.47	37.437	0	0	0	3.00	0.000284	4.7971e-5	3.00	25.00	20.46	0.12301	41.321	1.27	1.28

Figure 57. ESP case system calculation results

Liquid Rate	Oil Rate	VLP Pressure	IPR Pressure	dP Total Skin	dP Perforation	dP Damage	dP Completion	Completion Skin	dP Sand Control	Sand Control Skin	Total Skin	WellHead Pressure	WellHead Temperature	dP Friction	dP Gravity	Injection Depth
(Sm3/day)	*(Sm3/day)*	*(atm a)*	*(atm a)*	*(bar)*	*(bar)*	*(bar)*	*(bar)*		*(bar)*			*(atm a)*	*(deg C)*	*(bar)*	*(bar)*	*(m)*
0.07633	0.072514	31.95	81.94	0.017784	0	0	0	3.00	2.8409e-7	4.7947e-5	3.00	25.00	16.06	0.069125	6.973	600.0
0.10979	0.1043	31.95	81.91	0.025578	0	0	0	3.00	4.0864e-7	4.7947e-5	3.00	25.00	16.06	0.069457	6.973	600.0
0.15792	0.15003	31.95	81.88	0.036788	0	0	0	3.00	5.8778e-7	4.7947e-5	3.00	25.00	16.07	0.069936	6.972	600.0
0.22716	0.2158	31.95	81.82	0.052914	0	0	0	3.00	8.4545e-7	4.7947e-5	3.00	25.00	16.07	0.07063	6.972	600.0
0.32674	0.3104	31.95	81.74	0.076118	0	0	0	3.00	1.2161e-6	4.7947e-5	3.00	25.00	16.08	0.071637	6.972	600.0
0.46998	0.44648	31.95	81.63	0.10948	0	0	0	3.00	1.7492e-6	4.7947e-5	3.00	25.00	16.09	0.073106	6.971	600.0
0.67601	0.64221	31.96	81.47	0.15747	0	0	0	3.00	2.5161e-6	4.7947e-5	3.00	25.00	16.11	0.075259	6.970	600.0
0.97237	0.92375	31.96	81.23	0.22651	0	0	0	3.00	3.6191e-6	4.7947e-5	3.00	25.00	16.13	0.077992	6.969	600.0
1.4	1.3	31.96	80.89	0.32582	0	0	0	3.00	5.2057e-6	4.7947e-5	3.00	25.00	16.16	0.08094	6.967	600.0
2.0	1.9	31.96	80.41	0.46865	0	0	0	3.00	7.4878e-6	4.7948e-5	3.00	25.00	16.21	0.086208	6.965	600.0
2.9	2.7	31.97	79.71	0.67409	0	0	0	3.00	1.077e-5	4.7948e-5	3.00	25.00	16.28	0.094032	6.961	600.0
4.2	4.0	31.97	78.71	0.96962	0	0	0	3.00	1.5492e-5	4.7948e-5	3.00	25.00	16.38	0.10579	6.956	600.0
6.0	5.7	32.08	77.26	1.395	0	0	0	3.00	2.2284e-5	4.7949e-5	3.00	25.00	16.52	0.12045	7.055	600.0
8.6	8.2	33.09	75.19	2.006	0	0	0	3.00	3.2054e-5	4.795e-5	3.00	25.00	16.72	0.11637	8.083	600.0
12.4	11.8	34.16	72.20	2.886	0	0	0	3.00	4.6107e-5	4.7951e-5	3.00	25.00	17.01	0.12335	9.157	600.0
17.8	16.9	35.40	67.90	4.151	0	0	0	3.00	6.6322e-5	4.7953e-5	3.00	25.00	17.42	0.1401	10.392	600.0
25.6	24.3	36.36	61.73	5.970	0	0	0	3.00	9.5402e-5	4.7955e-5	3.00	25.00	18.00	0.18004	11.326	600.0
36.9	35.0	37.31	52.84	8.587	0	0	0	3.00	0.0001372	4.7958e-5	3.00	25.00	18.81	0.24873	12.217	600.0
53.0	50.4	38.71	39.44	12.975	0	0	0	3.00	0.0001974	4.7963e-5	3.00	25.00	19.88	0.35014	13.537	600.0
76.3	72.5	40.20	1.47	37.437	0	0	0	3.00	0.0002840	4.7971e-5	3.00	25.00	21.21	0.52226	14.870	600.0

Figure 58. Gas lift case system calculation results