EFFECT OF AVAILABILITY ON MULTI-PERIOD PLANNING OF SUBSEA OIL AND GAS PRODUCTION SYSTEMS

A Thesis

by

KARLA RUIZ VASQUEZ

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2008

Major Subject: Chemical Engineering

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Committee Members, Mahmoud El-Halwagi
Gioia Falcone
Head of Department, Michael Pishko

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ABSTRACT

Effect of Availability on Multi-Period Planning of

Subsea Oil and Gas Production Systems. (August 2008)

Karla Ruiz Vasquez, B.S., Pedro Ruiz Gallo University, Peru

Chair of Advisory Committee: Dr. M. Sam Mannan

Natural gas and petroleum are non-renewable and scarce energy sources. Although, it is well known that hydrocarbon reserves are depleting through the years, oil and gas remain the principal source of energy upon which our society is strongly dependent. Hence, optimization and accurate planning of hydrocarbon production are the main keys to making it safer, more efficient, and cheaper. One of the tools commonly used to evaluate the optimization of oil/gas production system is the process simulation modeling.

A hydrocarbon production system typically consists of at least one underground reservoir where several wells have been drilled into the hydrocarbon-bearing rock to form a fixed topology network. Wells are interconnected with manifolds to transport the gas or oil to a storage or sale location. The process simulation consists of calculating the total hydrocarbon production for the given production system. The pressure in the wellbore is the main variable in determining the hydrocarbon production process. When oil/gas is produced, the pressure decreases until production cannot be sustained. If the well is shut down, the pressure at the wellbore increases because of the natural gas flow coming from the reservoir. In addition, artificial lift techniques, such as water injection, gas lift and pump systems can be incorporated into the simulation program. The oil/gas production has been also modeled as a multi-period optimization case to incorporate the possibility of different demands, cost and overall time behavior.

The current field optimization approaches take in account the availability in a general way, adding to the planning a lot of uncertainty. The proposed study includes a suitable analysis of the likelihood of equipment failure, which will predict the availability of the equipment in a certain period of time to perform a more accurate planning.

In this work, we have integrated the availability analysis to the model described above. The availability of a system is analyzed by Monte Carlo simulation, which involves the modeling of the probabilities of failure, the type of failure, the time to repair associated with each failure, and time of occurrence for a field system.

The availability model performed reduces significantly the uncertainties on a multi-period planning production of either oil or gas, predicting the probability of failure and the downtime related to the hydrocarbon production through its lifetime.

In this study, the unavailability of the equipment was quantified, reporting a subsea equipment downtime of approximately 7%. As a result, new production planning is accomplished in the effective work period, which will be beneficial in financial risk decisions such as a government's deliverability contracts.

DEDICATION

To my loving parents, Mario and Lila, for their love, never-ending motivation and encouragement, being a source of inspiration to me throughout my graduate program.

To my brothers and sister, Mario, Robert and Cecy, for their constant support, love and always believing in me.

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I am also very grateful to Dr. Vazquez for his timely help, excellent guidance and knowledge in computer programming. I want to thank all my friends and the staff of the Mary Kay O'Connor Process Safety Center; and especially to Dr. Zhang, for reviewing my ideas and thesis.

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NOMENCLATURE

A	Drainage area, m^2, ft^2, acres
Bg	Gas formation volume factor, L^3/L^3, RB/Mscf
Bgi	Initial gas formation volume factor, L^3/L^3, RB/Mscf
Bo	Oil formation volume factor, L^3/L^3, RB/STB
Boi	Initial oil formation volume factor, L^3/L^3, RB/STB
Bw	Water formation volume factor, L^3/L^3, RB/STB
C_A	Drainage shape factor, dimensionless
Cf	Rock pore volume compressibility, 1/Pa, 1/psi
c_t	Total system compressibility, 1/psi
Cw	Water compressibility, 1/Pa, 1/psi
Gi	Cumulative gas injection, L^3, Mscf
Gp	Cumulative gas production, L^3, Mscf
h	Reservoir thickness, m, ft
J	Productivity index, m^3/sec/Pa, STB/d/psi
k	Permeability, m^2, md
m	Ratio of gas cap OGIP to oil zone OOIP at reservoir conditions, dimensionless
N	Original oil in place (OOIP), L^3, STB
Np	Cumulative oil production, L^3, STB
p	Pressure, Pa, psi
P	Average reservoir pressure, Pa, psi

pi	Initial reservoir pressure, Pa, psi
p_s	Pressure due to skin, Pa, psi
p_{wf}	Flowing bottomhole pressure, Pa, psi
q	Production rate, m^3/sec, STB/d
q_{max}	Absolute open flow production, m^3/sec, STB/d
r	Radial distance, m, ft
re	Drainage radius, m, ft
Rs	Solution-gas/oil ratio, L^3/L^3, Mscf/STB
Rsi	Initial solution gas/oil ratio, L^3/L^3, Mscf/STB
r_w	Well radius, m, ft
s	Skin effect, dimensionless
Swc	Connate water saturation, fraction of pore volume
t	Time, hr, sec
We	Cumulative water influx, L^3, RB
Wi	Cumulative water injection, L^3, STB
Wp	Cumulative water production, L^3, STB
γ	Euler's constant, dimensionless
μ	Viscosity, Pa-sec, cp
ϕ	Porosity, fraction

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CHAPTER I

INTRODUCTION

Petroleum Engineering is a well developed industry, where many areas of engineering and related disciplines such as geophysics, petroleum geology, formation evaluation, drilling, economics, reservoir simulation, well engineering, artificial lift systems and facility engineering are conjugated.

Petroleum is essential for the world economic, since that this hydrocarbon is the principal source of energy for many industrialized civilization. Oil is consumed around the world in a range of 30 billions of barrels per day and approximately 24 percent is utilized by United Stated[1]. Thus, the optimization and accurate planning in the hydrocarbon production is of paramount importance.

Process simulation is one of the areas that have been improved vertiginously in the recent years. Nowadays, this tool is commonly used to predict the behavior of the hydrocarbon flow in reservoir and well, optimizing the production of oil/gas in the system by using certain programming. The most common optimization methodologies available in the literature are: linear programming, which can be applied to system of naturally flowing wells; and non-linear algorithms, which is a more complicated approach but can be used to express the non-linearity of a field in gas-lifted systems.

The oil and gas production has been also modeled as a multi-period optimization case to incorporate the possibility of different demands, cost and overall time behavior. Ortiz-Gomez et al. (2002)[2] proposed a Mixed Non Linear Programming (MINLP) to model these planning decisions for an oilfield production.

This thesis follows the style of the *SPE Journal*.

More recently, the works by Barragán-Hernández et al. (2005)[3] have been used to improve the predictability of the model. The hydrocarbon production is limited by the oil and/or water displacement in porous media inside the reservoir, physical system limitations such as pipe diameters and lengths, and pressure gradient between the wellbore pressure and surface pressure. Pressure gradient should include the extra energy incorporated into the system to achieve production such as gas lift, pumps, etc. All these constraints equations are included to model this pressure effects.

Although the simulation process is a known solution for the optimization of a hydrocarbon field, the exploration and production of oil and gas are still a high risk venture, in which are found a lot of uncertainties in several related areas. For instance, geologic aspects of the reservoir simulation are uncertain with respect to structure, reservoir seal and hydrocarbon charge derived from its primary properties: permeability, porosity, natural pressure, depth, etc. Another source of uncertainty is related to the economic aspects, such as probability of finding and producing economically viable reservoirs, future oil price and operational cost, demand of petroleum products, taxation, political stability, environmental liabilities, among others[4,5]. The technological uncertainty is other aspect that must be included in our analysis[6]. Parameters related to the development and availability of the production system is the key piece to reduce incertitude in a process.

A model that includes geological uncertainties into reservoir simulations was enunciated by Zabalza et al. (2001)[7]. Edwards and Hewett (1994) formulated an approach to measure the financial risks[8]. In addition, a couple of works have been conducted by Aseeri et al. (2004) to propose a model for economical uncertainties[9,10]. Aziz et al. (2004) presented a good approach combining geological uncertainties as well as risk of failure of the control devices[11].

In this research, we are interested in developing and adding an availability model to take in account the failure risk in the optimization model of hydrocarbons production systems. Some models have been analyzed by several approaches: Reliability block diagrams, fault tree, Markov methods, flow networks, Petri nets and Monte Carlo next event simulation (Rausand and Høyland[12], 2004; Rausand and Vatn[13], 1998). Thus a restoration time will be generated from a specific repair time distribution. Then, Monte Carlo simulation will be carried out by simulating typical lifetime scenarios for a system on a computer and the availability could be reported in different periods regarding to the hydrocarbon production forecasting.

This thesis consists of six chapters. Chapter I discusses the motivation, objectives and methodology of this research. The Chapter II is focused on the Process Simulation Modeling, which covers the reservoir modeling, well modeling, network system and also analyzes a common production problem. Chapter III gives us a brief description of the subsea equipments that were included in the availability analysis, the boundaries and subdivision in subunits and components will be discussed in this chapter. In the Chapter IV, the availability analysis will be performed. The principal concepts, the procedure, assumptions and equations will be provided through this chapter. Chapter V recaps the results of this research, through a case study; while Chapter VI gives conclusions and future works that can be done based on this research.

1.1 Objectives

The principal purpose of this project is to develop an Availability Model, which will be added into an Optimized Model of Oil and Gas Production System. The objective is to create a realistic model to evaluate the oil and gas production availability under realistic operation and maintenance conditions. This approach is going to reduce the uncertainties related to the subsea equipment in an offshore production field, which will be helpful to take important financial risk decisions.

1.2 Motivation

It is well known that the world has experienced an increment in its hydrocarbon consumption and at the same time the hydrocarbon reserves becoming smaller through the years. As a consequence, the hydrocarbons prices have been continuously increased in an accelerated pace. However, oil is still the principal source of energy around the world.

A feasible proof of this phenomenon is showed in the **Figure 1.1**, which shown the trend in the oil price through the last twelve years. We can observe that in the last four years the petroleum prices are increased significantly, and according to expert opinion this tendency is going to remain as it is because of the fast increment in hydrocarbon consumption in developing economies. Thus, the optimization in the production is a fundamental issue.

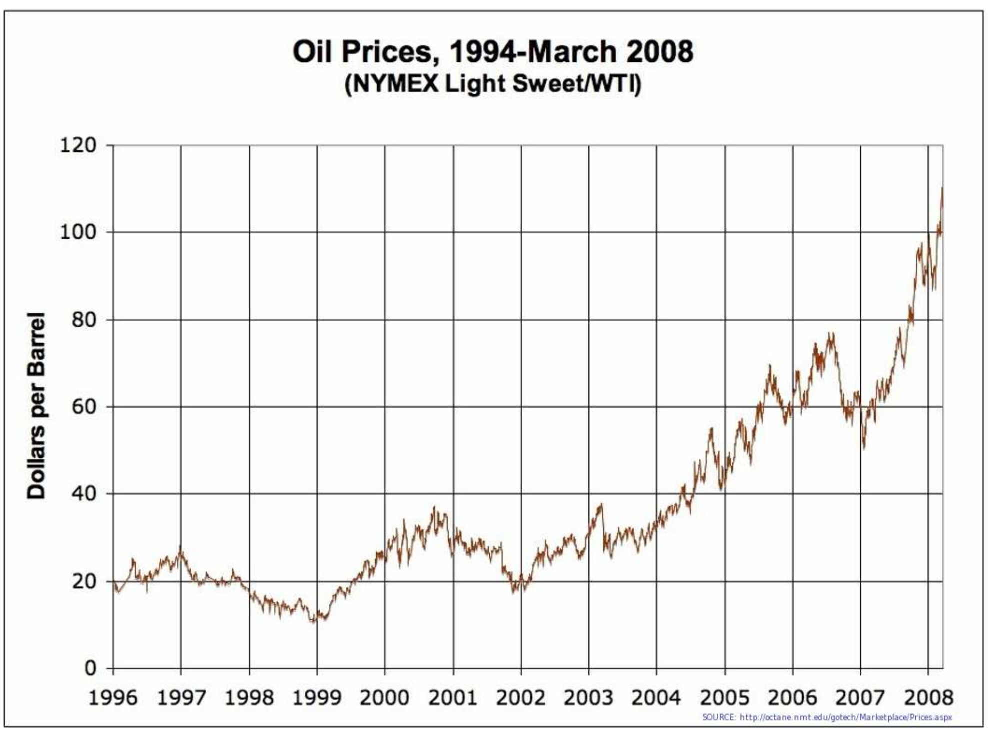

Figure 1.1 Oil prices[14]

Another problem that hydrocarbon industry faces is the penalties for breach of supply contract. It is usual that oil companies sign a contract to deliver certain amount of hydrocarbons to their client list in a stated period of time. If the companies fail to meet the supply contract due to a wrong production forecast, they have to pay huge penalties. For this reason, the accurate prediction of the hydrocarbon production is the main key to avoid this kind of situations. As an example, “Venezuela, which is the fifth-largest oil exporter, did a not accurate production prediction; and now it is buying oil from Russia to avoid defaulting on deliveries to clients. Venezuela could incur penalties if it fails to meet its supply contracts”[15].

1.3 Methodology

This work is divided into two main parts: the process simulation modeling and the availability analysis.

The process simulation modeling is one of the common tools used to evaluate the optimization of oil/gas production system. In this work the process optimization modeling is basically divided into tree sections: the reservoir modeling, well modeling and the network system modeling, which are going to enable to perform a production forecast.

The availability model was achieved by Montecarlo simulation methodology. This approach is included into the previous process simulation modeling in order to reduce uncertainty on the planning of hydrocarbon. As a result, a new production prediction in an effective work period is developed. **The Figure 1.2** schematizes the methodology employ in this work.

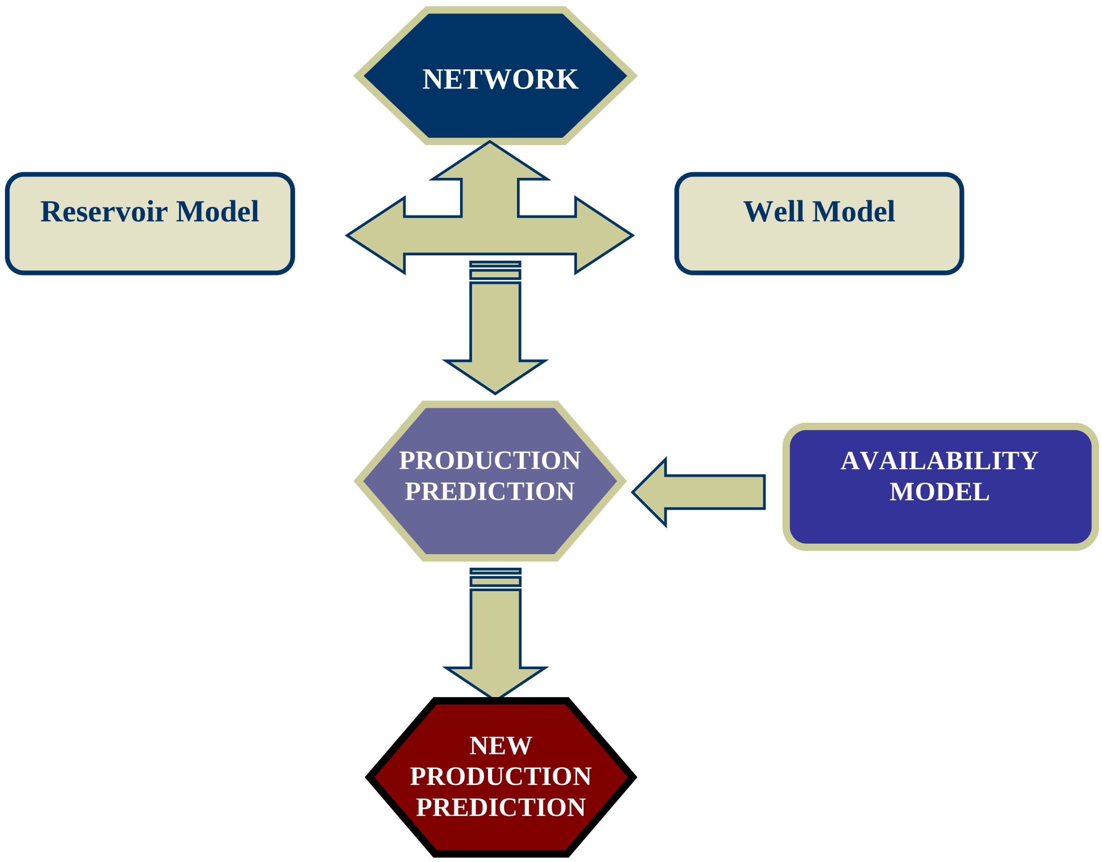

Figure 1.2 Methodology of this research

CHAPTER II

PROCESS SIMULATION MODELING

The petroleum engineering is a multidisciplinary discipline where a group of geologists and engineers are grouped in order to maximize economic recovery of hydrocarbons, ensuring that the reservoir is developed to its best potential.

Petroleum engineering comprises a complex system which involves three distinct but intimately connected systems: the reservoir, the well and the surfaces devices. The reservoir is a porous medium with particular rock and flow characteristics; the well deal with drilling techniques and inflow performance; and the surface structures include: the surface gathering, separation and storage facilities[16].

One of the tools that petroleum engineers have been used and improved in the past years is the process simulation modeling for hydrocarbon system, which uses computer models to predict the behavior of the flow of hydrocarbons through the porous media, well and surface equipment.

In this chapter, the basis related to the three principal models for a hydrocarbon system will be described. The software employed to perform the modeling task was provided by Petroleum Experts and the Integrated Production Modeling (IPM) includes: the reservoir model (MBALL), production modeling (PROSPER) and the gathering and surface device modeling (GAP).

The target of this chapter is to have the basic cognitions for developing a hydrocarbon process simulation and to understand that the success of the petroleum engineering lies in the suitable combination of the knowledge in the three major areas: reservoir engineering, production engineering and surface equipment technology.

2.1 Reservoir Modeling

Reservoirs are complex geological formations which may contain different rock type, stratigraphic interfaces, faults, barriers and fluid fronts, storing oil, gas and water. These reservoir conditions may influence the pressure transient behavior affecting the reservoir performance. For the reservoir description purpose, well testing, well log, seismic analysis, PVT and rock properties, will be the key elements to the forecasting of reservoir performance. In addition, reservoir characterization is essential to achieve the production planning of petroleum systems[17].

Nowadays, the simulation is a common procedure in the reservoir analysis; predicting the behavior of the flow of hydrocarbons through the porous media by computer models. The most common models are the classical material balance equation and the simulation, which uses the principal simulator models: black oil, compositional and thermal.

The material balance equation is zero dimensional model (0-D) which is considered as a homogeneous tank that does not require a geological model to be applied in the classical manner. The simulations can be 1-D, 2-D or 3-D; these consider the flow effects, mass balance and heterogeneous models. The material balance is suggested as a necessary step prior to perform a simulation study[18,19].

In this work, the reservoir model is performed by software called MBALL from Petroleum Experts Packet. This software allows us to simulate the reservoir dynamics by analytic tools, such as Material Balance Equation (MBE).

MBALL required some parameters, such as oil in place (N), water influx (We) and PVT data, as an input to the simulation process. Then, a history matching is performed to find the value of N and We that best reproduce the relationship between reservoir pressure and cumulative production[19]. The process is repeated if the match is not obtained, taking new model assumptions until the data matches. A brief description of the MBE will be explained through this section.

2.1.1 Material Balance Equation

The material balance equation is based on the principle of conservation of the mass of oil, gas and water in the reservoir. This equation is principally used to quantify the oil in place and gas cap size, determine the type and size of an aquifer, find out the water influx and predict the reservoir behavior as well as the reservoir pressure profile[5,8]. The simplest form to express the material balance expression on volumetric basis was stated in 1936 by Schilthuis and can be summarize as[19,20]:

$$\boxed{\text{Mass of fluids originally in place} = \text{Fluids produced} + \text{Remaining fluids in place}} \qquad (2.1)$$

In MBAL, the material balance program works by using a "conceptual model of the reservoir to predict the reservoir behavior based on the effects of reservoir fluids production and gas to water injection"[19]. The material balance calculations are based on a tank model as represented in **Figure 2.1.** The following assumptions apply throughout the reservoir: homogeneous pore volume, gas cap and aquifers, constant temperature, uniform pressure distribution, uniform hydrocarbon saturation distribution, gas injection in the gas cap.

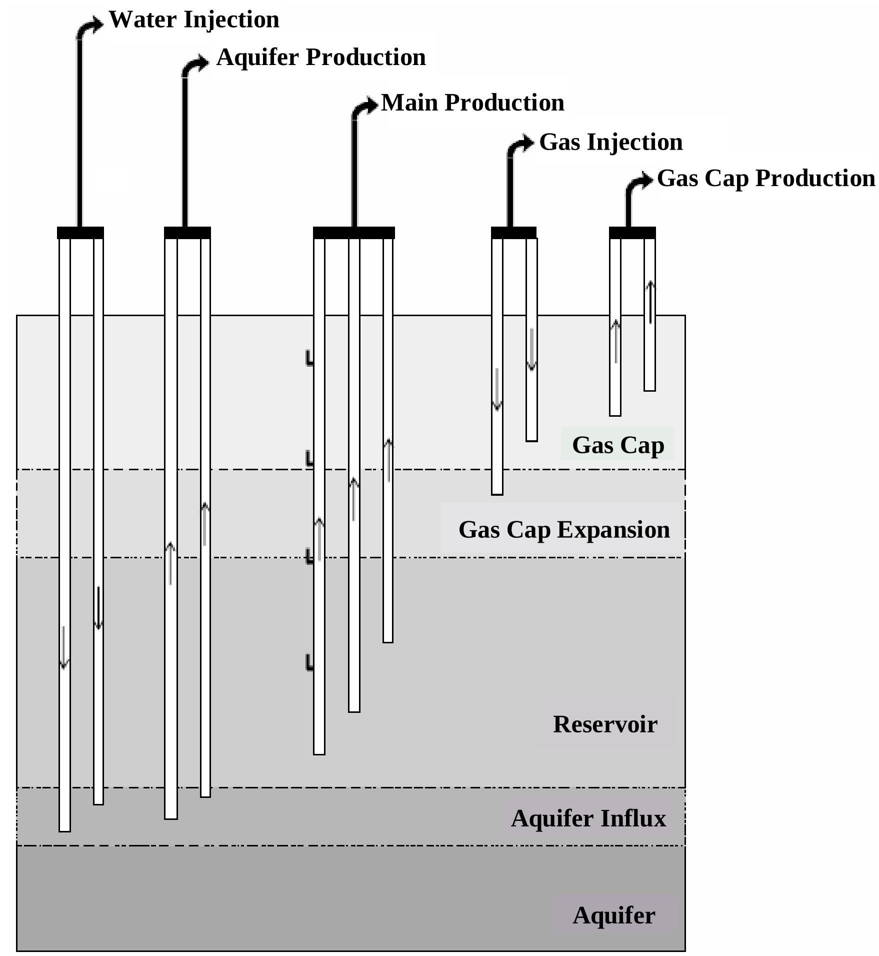

Figure 2.1 Material balance tool - tank model assumption[19]

The material balance tools that this program uses are divided into three main sections: input data, history matching and production prediction.

In the input section the reservoir parameters, the types of aquifers, rock properties and relative permeability curves are incorporated. Also it is recommendable entering transmissibility parameters and pore volume fraction versus depth, if this kind of information is available.

The history matching is calculated by graphical methods, such as, Havlena-Odeh, Campbell and Cole. These graphical methods are performed by suitable manipulation of the MBE into straight line equation when some extrapolation may be possible[19,21,22]. The Equation 2.2 shows the Havlena and Odeh MBE.

$$F = N * E + We \qquad Rvol \qquad (2.2)$$

The original oil in place is N stock tank barrels and E is the per unit expansion of oil and its dissolved gas, connate water, pore volume compaction and the gas cap. The value of F is the fluid production measurements (oil, water and gas) corrected to the reservoir conditions.

$$F = Np * (Bo - Bg * Rs) + Bg * (Gp - Gi) + (Wp - Wi) * Bw \qquad Rvol \qquad (2.3)$$

Where: Np is the cumulative oil production, Bg represents the gas formation volume factor, which is the “gas volume at reservoir conditions divided by gas volume at standard conditions”[32]; Bo is the oil formation volume factor, which symbolizes “the ratio of the volume of oil saturated with the gas at reservoir temperature and pressure and the volume reduced to stock tank oil conditions”[23]; and Bw is water formation volume factor, which represents the “water and dissolved gas volume at reservoir conditions divided by water volume at standard conditions”[32]. Gi and Gp are the cumulative gas injection and cumulative dry gas production respectively, Rs is the instantaneous producing gas-oil ratio. Finally, Wi represent cumulative water injection and Wp cumulative water produced.

The expansion of oil and its initially dissolved gas, expansion of the gas cap, hydrocarbon filled pore volume and expansion of connate water are represented by E in equation 2.4.

$$E=(Bo-Boi)+(Rsi-Rs)*Bg+m*Boi*\left(\frac{Bg}{Bgi}-1\right)+(1+m)*Boi*\left(\frac{Swc*Cw+Cf}{1-Swc}\right)*(pi-P) \qquad \frac{Rvol}{Stvol} \tag{2.4}$$

Where Boi, Rsi, Bgi and Pi are: the single-phase oil formation factor, the instantaneous producing gas-oil ratio, gas formation volume factor and the reservoir pressure at initial conditions. Swe is water saturation, Cf is the formation compressibility and Cw defines the water compressibility.

By suitable manipulation and using PVT (Pressure-Volume-Temperature) and production data, the MBE can be plotted as a straight line when the assumptions of the plotting method are valid. For instance, for a gasfield N = 0. For an undersaturated reservoir when no gas cap is presented, m = 0. In the case where there is not water influx, We = 0, and the value of oil in place (N) is relatively easy to determine as is shown in Equation 2.5[19,23].

$$\frac{F}{E}=N \qquad Stvol \tag{2.5}$$

The equation for undersaturated reservoir below the bubble point with no gas cap but with water influx may be best plotted as:

$$\frac{F}{E}=N+\frac{We}{E} \qquad Stvol \tag{2.6}$$

This plot is a good diagnostic for identification of the reservoir drive mechanism. If the plot of F/E vs. We/E yield a straight line at 45 grades, then, the influx model (We) has been determined correctly. F**igure 2.2** represents the plot of F/E vs. We/E, which yields a straight line with unit slope and a y-axis intercept equal to the oil-in-place N.

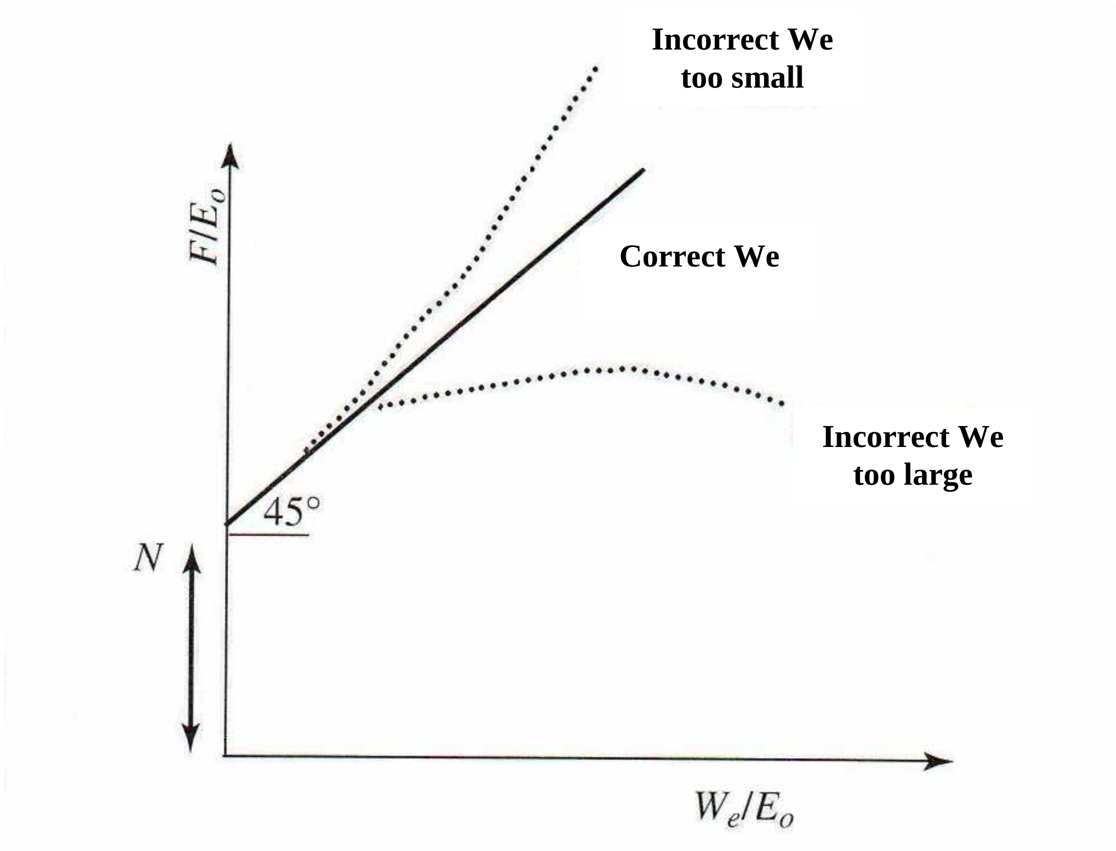

Figure 2.2 The Havlena and Odeh analysis for water influx for an undersaturated reservoir, with an error in the water influx[23]

Production prediction is used to forecast the reservoir performance. Predictions can be made using well performances (IPR, VLP) and relative permeabilities to predict the amount of associated phase productions and evaluate future reservoir behavior based on different production strategies. A production history is recommend, but not necessary to run a production prediction.

The model for production forecast assumes the following:

- All the producers are connected to the same production manifold.
- All the water injectors are connected to the same water injection manifold.
- All the gas injectors are connected to the same gas injection manifold.
- All the aquifer producers are connected to the same aquifer production manifold.
- All the gas cap producers are connected to the same gas cap production manifold.
- The pressure of the five manifolds can be set independently[19].

2.2 Well Modeling

Production engineering is part of petroleum engineering which has principal objective maximize the production in a cost-effective manner[24]. The well is the connection between the reservoir and the surface equipment: gathering, separation and storage facilities. So, well modeling involves also reservoir model and the surface network system.

The typical route to produce hydrocarbons is from the depths of the reservoir, via wellbore, where a series of perforations allow the hydrocarbon to flow through the tubing to the wellhead. In the wellhead a complex of valves, called Christmas tree that is located to regulate and control the production. The produced hydrocarbons follow their way along a flowline to topside facilities, where several stages of separation and processing may occur. Finally, the separated hydrocarbon phases go to their respective terminals or sale points[23]. The **Figure 2.3** represents the scheme of produced hydrocarbon route described above.

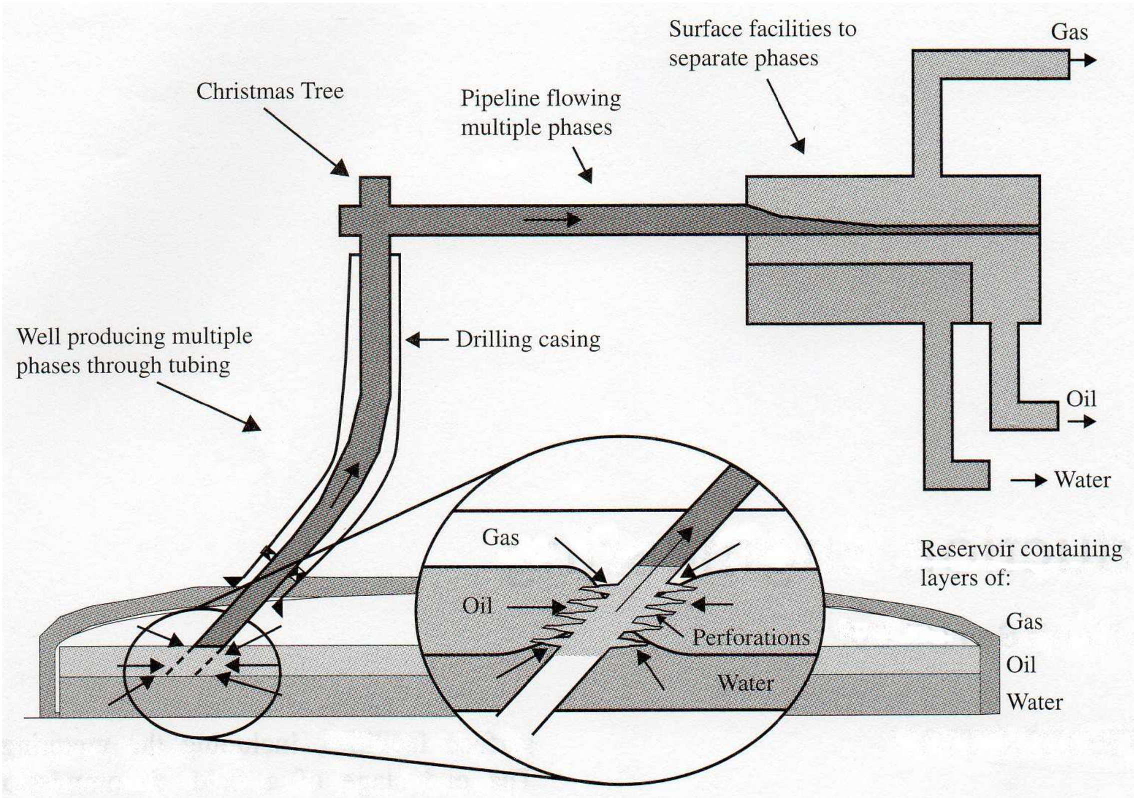

Figure 2.3 Produced hydrocarbon route from the reservoir to surfaces facilities[23]

The Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) are the main parameters upon which the well modeling has to deal, describing the reservoir variables that control the production rate under different conditions. Porosity (ϕ), net thickness (h), and permeability (k) are the most common and useful rock properties data employed. Darcy Law is a simple expression used to understand the process of flow from the reservoir and into the well. Darcy's equation is expressed in radial coordinates as[24]:

$$q = \frac{K * A}{u} * \frac{dp}{dr} \tag{2.7}$$

Where A is the radial area at a distance r and is given by A=2πrh, k is the permeability of the reservoir and μ is the viscosity of the fluid.

2.2.1 Transient Flow (Undersaturated Oil)

The pressure profile in an infinite-acting is described by the diffusivity equation, which assumes slightly compressible and constant viscosity fluid. The diffusivity equation in its classic form can be expressed as:

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{\Phi u c_t}{k}\frac{\partial p}{\partial t} \tag{2.8}$$

Introducing the variables in oilfield units and doing some assumptions we can generate the expression know as the pressure drawdown equation. This equation (2.9) describes the declining flowing bottomhole pressure (p_{wf}), with the well flowing at a constant rate.

$$p_{wf} = pi - \frac{162.6 * q * Bo * u}{k * h} * \left(\log t + \log \frac{k}{\phi * u * c_t * r_w^2} - 3.23 \right) \tag{2.9}$$

The above equation can be adjusted for typical well conditions, where the producing well is usually flowing for long times with the same wellhead pressure and the result bottom pressure is also constant[14]. The new equation with the appropriate inner boundary conditions is an approximation of the analytical solution of equation 2.8 which yields to the equation 2.10; where the time is represented by t and q is the flow rate[24]:

$$q = \frac{k * h * (pi - p_{wf})}{162.6 * Bo * u} * \left(\log t + \log \frac{k}{\phi * u * c_t * r_w^2} - 3.23 \right)^{-1} \tag{2.10}$$

2.2.2 Steady State Well Performance

From Darcy's Law, the area of flow at any distance r is given by 2πrh. Then, Darcy equation becomes:

$$q = \frac{2\pi rkrh}{u} * \frac{dp}{dr} \tag{2.11}$$

The steady state condition implies that the outer boundary (re) exhibits constant-pressure (pe). From the above equation, we can assume that q is constant; rearrangement the equation by separation of variables and integration; and also including the concept of the skin effect that Van Everdingen and Hurst created in 1949. We can get the following equation in oilfield units[24].

$$pe - p_{wf} = \frac{141.2 * q * Bo * u}{k * h} * \left(\ln \frac{re}{r_w} + s \right) \tag{2.12}$$

The effective wellbore radius is denoted by r_w and s is the skin factor.

2.2.3 Pseudo-Steady-State Flow

For pseudo-steady-state condition, the outer boundary does not have constant pressure; however, this pressure declines at a constant rate time, which is represented as:

$$\frac{dpe}{dt} = cons\tan t \tag{2.13}$$

Then, we can derive the pressure (p) from the radial diffusivity equation; at any radius (r) in the reservoir. This expression was stated by Dake (1978) as follow:

$$p = p_{wf} + \frac{141.2 * q * Bo * u}{k * h} * \left(\ln \frac{r}{r_w} - \frac{r^2}{2re^2} \right) \tag{2.14}$$

However, a more useful expression for pseudo-steady-state can be obtained from the average pressure reservoir (P) that was given by the pressure buildup test. After a series of assumption, manipulations and introducing the skin effect, the above equation leads to the inflow relationship for a no-flow boundary oil reservoir:

$$P - p_{wf} = \frac{141.2 * q * Bo * u}{k * h} * \left(\ln \frac{0.472 * re}{r_w} + s \right) \quad (2.15)$$

This equation is particularly useful because it provides the relationship between the average reservoir pressure (P) and the flow rate q. The drainage area, the fluid and rock properties can determine the average pressure of the reservoir. Material balance calculations permit combination of depletion mechanism and inflow relationships to predict the well performance and cumulative production[24].

2.2.4 Wells Draining Irregular Patterns

The wells rarely have regular shape drainage areas. The drainage areas change after production commences, either because of the presence of natural boundaries or because of lopsided production rates in adjoining wells. In 1965, Dietz developed a series of shape factors to take into account irregular drainage shapes or asymmetrical positioning of a well within its drainage area[19,24].

The equation including the irregular drainage shapes or asymmetrical position of a well can be generalized for any shape as the following equation:

$$p - p_{wf} = \frac{141.2 * q * Bo * u}{k * h} * \left(\frac{1}{2} * \ln \frac{4 * A}{\gamma * C_A * r_w \wedge 2} + s \right) \quad (2.16)$$

Where the Euler's constant is denoted by γ. Some common Dietz shape factors (C_A) and well positions are expressed in the **Figure 2.4.**

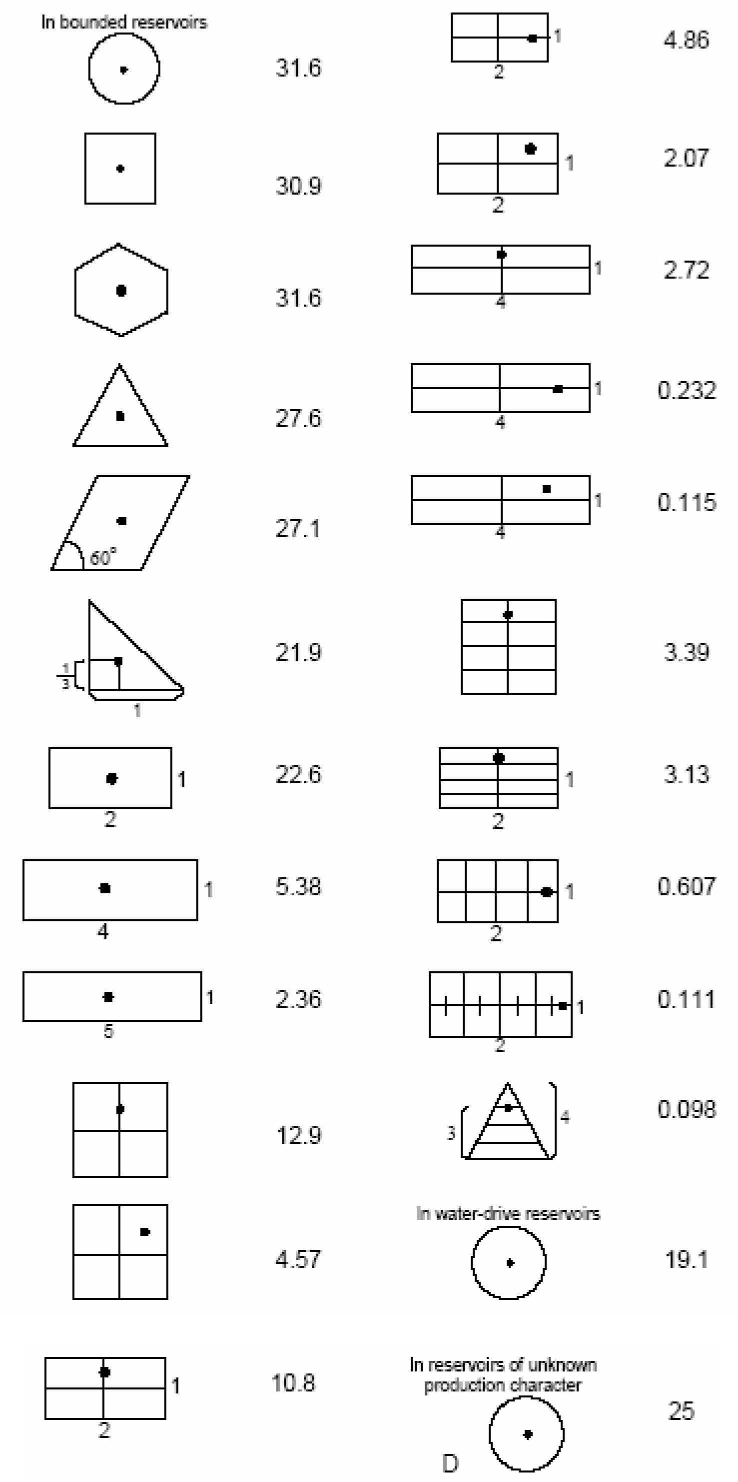

Figure 2.4 Dietz shape factors[19]

2.2.5 Inflow Performance Relationship (IPR)

The well deliverability equation is related to the well production rate and the driving forces in the reservoir. The difference between the flowing bottomhole pressure (p_{wf}) and the static pressure of the well (p_s) is called drawdown, which is represented symbolically as:

$$\text{Drawdown} = p_s - p_{wf} \tag{2.17}$$

The production index (PI) is the ratio of the producing rate of a well to its drawdown at a particular rate, denote by J[12]:

$$J = \frac{q}{p_s - p_{wf}} \tag{2.18}$$

The equations 2.10, 2.12 and 2.16 can be used for transient, steady state and pseudo steady state IPR curves.

One of the principal parameters to be modeled in the well simulation is IPR, which is performed using software called Prosper from Petroleum Experts. Prosper have more than twenty options for inflow models that are available for the well simulation. Given below are some of the principal inflow models that Prosper provide, which are going to be described briefly.

2.2.5.1 Vogel

An empirical expression was developed by Vogel for the IPR of a well producing from a depletion drive reservoir. Vogel equation applies when the average reservoir (P) pressure is less than the bubble point (Pb). The equation can be stated as[19,16]:

$$\frac{q}{q\max} = 1 - 0.2\frac{P_{wf}}{P} - 0.8\left(\frac{P_{wf}}{P}\right)^2 \tag{2.19}$$

Prosper program uses the straight-line inflow relationship above the bubble point and the Vogel empirical solution below the bubble point. After the IPR calculations are performed, this IPR and the bubble point pressure are used to evaluate the Petroleum Index (PI) for the straight-line part of the inflow above the bubble point[19].

2.2.5.2 Composite

The composite model is the modification of the Vogel that accounts water cut. This model is known as Petrobras Method. In the Vogel method the inflow decreases below the bubble point because of gas formation. However, if the water cut is very high, the inflow potential will increase, approaching a straight line IPR due to single-phase flow. The program requires to be entered: a test flow rate (Fo), flowing bottom hole pressure (p_{wf}) and water cut (f_w). The composite model uses the following formulation[19]:

$$J = \frac{q}{Fo\left\{P - Pb + \frac{P_b}{1.8}\left(1 - 0.2\frac{p_{wf}}{P} - 0.8\left(\frac{p_{wf}}{P}\right)^2\right)\right\} + f_w\left\{P - p_{wf}\right\}} \tag{2.20}$$

2.2.5.3 Darcy

The Darcy IPR is the classic radial flow equation productivity index. In this software (Prosper), Darcy IPR is used in terms of drainage area and Dietz shape factor. The program uses the Darcy inflow equation above the bubble point and the Vogel solution below the bubble point. The Darcy IPR is useful for estimating productivity from petrophysical data and evaluating completion options.

$$Q_o = \frac{4\pi kh\left(P - p_{wf}\right)}{u\;B_o\left[\ln\left(\frac{4A}{\gamma C_A r_w^{\,2}}\right) + s\right]} \tag{2.21}$$

Some data is required to perform the model and it is listed following:

- Reservoir permeability (total permeability at the prevailing water cut and GOR)
- Reservoir thickness (thickness of producing reservoir rock)
- Drainage area (usually > 500 acres)
- Well bore radius
- Dietz shape factor (to account for the shape of the drainage area)
- Skin

The skin factor can be assumed or calculated by models, such as Locke, McLeod and Karakas & Tariq. The last one (Karakas & Tariq) gives good results in many field applications, but required more input data[19].

2.2.5.4 Fetkovich

In the Fetkovich model, the Darcy equation is modified to allow two phase flow below the bubble point. The Fetkovich equation can be expressed as:

$$q = J'(P_s^2 - P_{wf}^2)^n \qquad (2.22)$$

The assumption made is that J' will decrease in proportion to the decrease in average reservoir pressure. Thus the static pressure is Ps, which is lower than the initial formation pressure (Pi). The program use the same data input that in Darcy equation, plus the relative permeability of oil.

Other methodologies to calculate the inflow performance relationship, such as multi-rate Fetkovich, Jones, multi-rate Jones and transient are also included in Prosper software. A list of all the methods to calculate IPR and the cases where these are applicable are listed in the **Table 2.1.**

Table 2.1 IPR Methods[19]

IPR Method	Oil and Water	Dry and Wet Gas	Retrograde Condensate
Back Pressure		x	x
C and n		x	x
Composite	x		
Darcy	x		
Dual Porosity	x	x	x
External Entry	x	x	x
Fetkovich	x		
Forcheimer		x	x
Horizontl well - Bounded reservoir	x	x	x
Horizontal well - Constant Pressure upper boundary	x		
Horizontal well - dP friction	x	x	x
Horizontal well - transverse vertical fractures	x	x	x
Hydraulically fractured	x	x	x
Jones	x	x	x
Multi-lateral	x	x	x
Multi-layer	x	x	x
Multi-layer - dP Loss	x	x	x
Multi-rate C and n		x	x
Multi-rate Fetkovich	x		
Multi-rate Jones	x	x	x
Modified Isochronal IPR		x	x
Petroleum Experts		x	x
P.I. Entry	x		
Skin Aide	x	x	x
Thermally Induced Fracture (Injection Only)	x		
Transient	x		
Vogel	x		

2.3 Network System (Surface Facilities)

This section is focused on the transport of fluid from the wellhead to surface facility. The surface facilities usually comprise two or three phase separators in an oil production system. If we are producing gas, the surface facility can be a gas plant or a compressor station[24].

Flowlines from individual wells are interconnected through a manifold for commingling of fluids from several wells in a single pipeline. The hydrocarbon is finally transported to a storage or sale location. In an onshore facility, the wells are spread and the gathering lines usually are several kilometers length. In an offshore facility, the processing facilities are often situated adjacent to the wellheads at the manifold. For this reason, the gathering lines used are quite short.

Sizing of oil and gas pipelines and processing facilities is generally complex because the fluid rates and composition vary with respect of time. In general, hydrocarbon (oil and gas) production will be decreased over time and water rates will increase through the life of the field. Therefore, the initial facility design must be flexible enough to handle a very broad range of production rates and compositions.

To perform the network system modeling, we employed software called GAP, which is used to connect the reservoir and well modeling with the surfaces facilities. Furthermore, GAP is going to perform the optimization of the system by using a non-linear algorithm, which is the Sequential Quadratic Programming (SQP) for naturally flowing, gas lifted and injection wells.

GAP is capable of handling a variety of wells in the same network, such as naturally flowing oil wells, gas-lifted wells, ESP operated wells, condensate or gas producers, water producers, water or gas injectors, etc.

The optimization of oil production system is carried out by simultaneously adjusting well chokes, gas lift gas injection rates, ESP frequencies and pump/compressor speed as applicable.

There are two objective function chosen, including the maximization of hydrocarbon produced and maximization of revenue. Several constraints can be given in different levels of the network. However, we analyze that the principal disjunctions and constrains are related to the system pressure. In the next section a common production problem will be described and its disjunctions will be stated.

2.4 Principal Production Constraints

The production system consists of a given number of reservoirs where several wells have been drilled and are ready to produce. Manifolds allow interconnectivity of the wells to surface facilities and the produced oil/gas is sent to common sale and storage points. Once the process is defined, the next step is its optimization, where the objective function and constraints will be defined.

In the oil/gas production, the objective function is maximizing the production (q) during a stated period of time (T). The objective function can be represented as[25]:

$$Max \sum_{w} \sum_{t} q_{w,t} .T$$

The principal constraints of the problem include the pressure decrease in wellbores and the resistance to flow from this point to the surface, because of the pipe characteristics and pressure at interconnectivities points. The principal drop pressures are included in the modeling and are represented by:

$$\left[\frac{dp}{dL}\right]_{total} = \left[\frac{dp}{dL}\right]_{elev} + \left[\frac{dp}{dL}\right]_{friccion} + \left[\frac{dp}{dL}\right]_{acel.}$$

Gas and oil production requires that wellbore pressure not to decrease below a minimum value. Thus, the pressure in the wellbore is the main variable to determine and control in the optimization process. When hydrocarbon is produced the pressure in the reservoir decreases until the production cannot be sustained. Then, the production decreases until the wells stops producing. If the well is shut down, then the pressure at the wellbore increases because of the natural flow coming from the reservoir. Vazquez Roman et al analyzed the behavior of the well pressure through a MINLP (Mixed Integral Non-Linear Programation). The next scheme represents the disjunctions for a well on the producing and shutdown states, without including the availability concepts[25].

Disjunctions for well in Production and Shutdown

Production		Shutdown

$$
\begin{bmatrix}
Y_{wt} \\
p_{wt}^{f} = p_{wt}^{in} - D_{wt} \\
p_{wt}^{in} - D_{wt} \geq p_{w}^{low} \\
D_{wt} = D_{wt}(q_{wt}, t_{Pwt}^{f}) \\
I_{wt} = 0.0 \\
P_{wt}^{out} = P_{wt}^{out}(p_{wt}^{f}, q) \\
q_{wt} > 0.0 \\
t_{Pwt}^{f} = t_{Pwt}^{0} + T \\
t_{nPwt}^{f} = 0
\end{bmatrix}
\vee
\begin{bmatrix}
Y_{wt2} \\
p_{wt}^{f} = p_{wt}^{in} - I_{wt} \\
p_{wt}^{in} + I_{wt} \leq p_{w}^{up} \\
D_{wt} = 0.0 \\
I_{wt} = I_{wt}(t_{nPwt}^{f}) \\
\\
q_{wt} = 0.0 \\
t_{Pwt}^{f} = 0.0 \\
t_{nPwt}^{f} = t_{nPwt}^{0} + T
\end{bmatrix}
\vee
\begin{bmatrix}
Y_{wt3} \\
p_{wt}^{f} = p_{t}^{up} \\
p_{wt}^{in} + I_{wt} > p_{w}^{up} \\
D_{wt} = 0.0 \\
I_{wt} = I_{wt}(t_{nPwt}^{f}) \\
\\
q_{wt} = 0.0 \\
t_{Pwt}^{f} = 0.0 \\
t_{nPwt}^{f} = t_{nPwt}^{0} + T
\end{bmatrix}
$$

This model represents the pressure flow behavior in the wells when those are in production or shutdown states. The period of production planning is fixed in T and wells produce the maximum amount of hydrocarbon at each time period. This Disjunctive Generalized Program (DGP) uses Boolean variables to indicate a particular situation for each well. The following paragraph explains the three main situations proposed for the formulation of the pressure flow behavior in wells.

The first situation indicates that the well *w* is producing in a period *t*, represented by the Boolean variable Y_{wt}. After some period (t^{f}_{pwt}) of production (q_{wt}) the initial pressure in the well (p^{in}_{wt}) decrease (D_{wt}) until reach the minimum allowable production pressure (p^{low}_{w}). In the second case, Y_{wt2} indicates that well *w* is not producing, then the pressure in the well increase during the shutdown time (I_{wt}). The final pressure (p^{f}_{wt}) at period *t*, does not exceed the maximum allowable pressure (p^{up}_{w}). The last case, the Boolean variable is given by Y_{wt3}, which states that if the well *w* is not producing but the calculated p^{f}_{wt} would exceed the maximum allowable value. The variables t^{f}_{pwt} and t^{f}_{npwt} represent the periods in which the well is production or shutdown respectively. Both t^{f}_{pwt} and t^{f}_{npwt} must reset to zero when the opposite operation is carried out and they depend on the corresponding time at the beginning of the period (t^{o}_{pwt} and t^{o}_{npwt}) and the time size period T. In the second and third case is experimented a recovery of the pressure in the reservoir (I_{wt}). According to real operation conditions, the last case is almost impossible to reach, since the recovery of pressure never exceeds the reservoir pressure (p^{up}_{w}). However for calculation purposes, this disjunction has to be established[25].

CHAPTER III

SUBSEA TECHNOLOGY - DESCRIPTION OF PRINCIPAL EQUIPMENT

It is well known that the world has experienced an increment in its hydrocarbon consumption and at the same time the onshore hydrocarbon reserves becoming smaller through the years. As a result of the current energy needs, the oil and gas industry had to push the frontiers of discovery, moving from the traditional hydrocarbons onshore techniques to offshore exploration and production technologies.

The offshore production started in 1897, when the first offshore well was drilled, 300 feet out into the ocean in the end of a wharf. At that time, offshore drilling was limited to areas where the water was less than 300 feet in depth. Through the years, offshore technology has been advancing in a faster pace, reaching depths as much as two miles and producing almost 25 percent of the oil and gas production in U.S.A[26]. However, as the water depth level increases, the costs and the risk associated with the subsea equipment go up.

In this thesis, we are focus on the subsea equipments, because of the high risk involved on offshore facilities, and also due to the lack of information about the availability of petroleum equipment data in onshore facilities. During the searching data process, several databases and papers were reviewed. However, the most suitable information was found in the Offshore Reliability Data book (OREDA), which contents crucial information for the availability analysis performed, such as, probability of failure and time to repair. OREDA compiles offshore equipment data from several petroleum companies through 20 years. A brief description of the principal equipment that was included into the availability analysis, the boundaries and subdivision in subunits and components will be discussed in this chapter.

3.1 Control System

In the last years, the application of subsea systems for the production of oil and gas from subsea wellheads have been increased in an accelerated pace. A subsea production system includes several components, such as, x-mas tree, wellhead, riser, flowlines, manifolds, structures, etc. In many instances, a certain number of wellheads have to be controlled from a single location. For this reason, a subsea control system is crucial part of a subsea production system to ensure a reliable and safe operation.

A subsea control system has to provide satisfactory operational and safety characteristics. The control system regulates choke and control valves on subsea completions, templates, manifolds and pipelines, as well as provide means for a safe shutdown on failures of the equipment or another safety features that prevent dangerous situations. The levels of redundancy throughout the system will ensure a satisfactory time response that may have a dramatic effect on reliability and safety of environmentally critical operations[27].

According to offshore reliability data, the subsea control system comprise: surface installed master control station, hydraulic and electric power units, static and dynamic umbilicals, chemical injection unit, subsea control and distribution modules and the control equipment installed on the tree or the template.

The control system manages daily production operations by a topside located computer. A control umbilical is the connection between the topside and subsea parts of the system. The principal unit is the subsea control module, which comprises electronic pieces and hydraulic instrumentation for efficient operation of subsea and downhole valves and also, provides interfaces for the communication with the topside for production process monitoring and optimization. A typical production control system is shown in **Figure 3.1.**

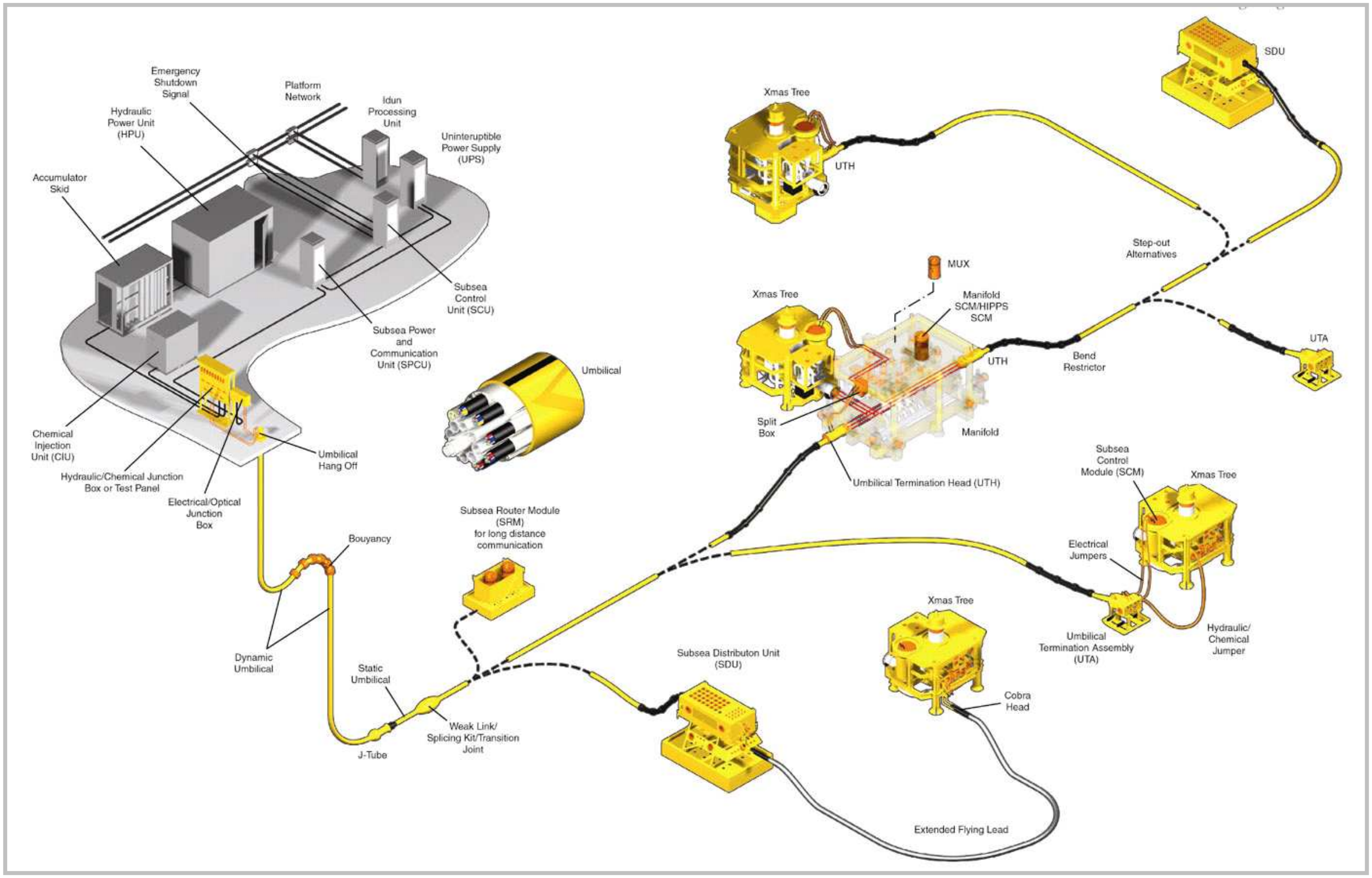

Figure 3.1 Scheme of control production system [28]

The interface between the control system and its surroundings (boundary) stated by OREDA database is shown in **Figure 3.2.** This boundary applies to subsea production/injection control systems, which control both single satellite wells and more complex subsea production facilities such as multi-well manifold template systems[29]. The subdivision in subunits and components is shown in **Table 3.1.**

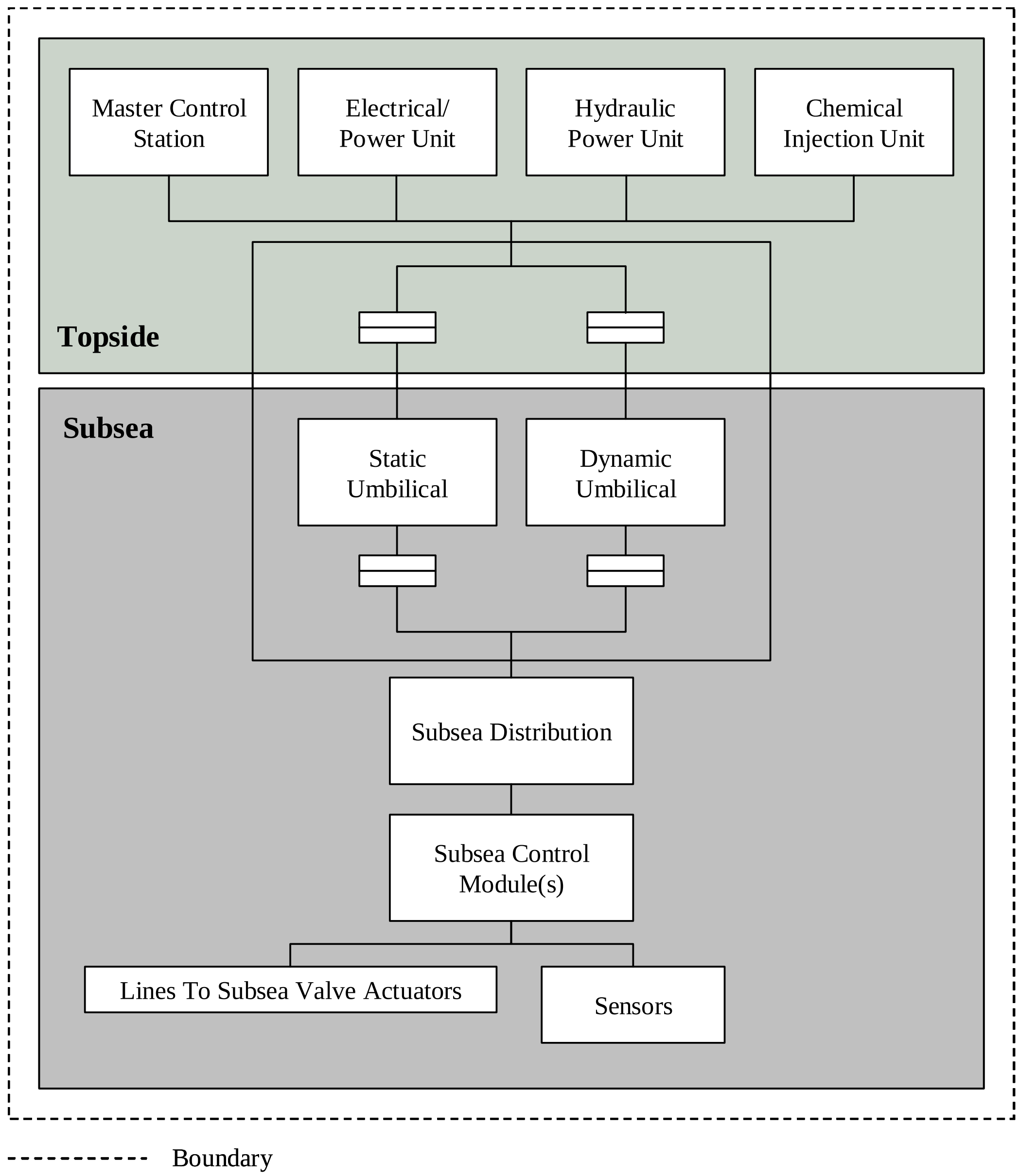

Figure 3.2 Control system boundary[29]

Table 3.1 Control Systems, Subdivision into Subunits and Components [29]

CONTROL SYSTEM								
Chemical injection unit (topside)	**Electrical power unit (topside)**	**Hydraulic power unit (topside)**	**Master control station (topside)**	**Dynamic umbilical**	**Static umbilical**	**Sensors**	**Subsea control**	**Subsea distribution**
Subunit	Power supply unit	Hydraulic power unit	Subunit	Hydraulic/chemical line	Hydraulic/chemical line	Comb. Pressure and temperature	Accumulator - subsea	Accumulator - subsea
	Subunit	Subunit		Power/signal line	Power/signal line	Flow sensor	Chemical injection	Chemical injection coupling
				Sheath/amour	Sheath/amour	Pressure sensor	Filter	Hydraulic coupling
				Subsea umbilical termination unit	Subsea umbilical termination unit	Sand detection sensor	Hydraulic coupling	Hydraulic/chemical coupling
				Topside umbilical termination unit	Topside umbilical termination unit	Temperature sensor	Module base plate	Hydraulic/chemical jumper
				Unknown	Unknown	Valve position sensor	Other	Power/signal coupler
							Power supply unit	Power/signal jumper
							Power/signal coupler	Unknown
							Soleniod control valve	
							Subsea electronic	
							Unknown	

3.2 Manifold

A manifold is constituted by a complex of pipes, which interconnect several incoming lines with one or more outlets, providing an interface between the production pipeline, flowline and the well. The manifold commingle produced fluids from wells, incorporating valves and instrument to monitor and control fluids flowing in individual lines, and also allows injecting and distributing gas and chemicals to template wells or satellites.

In a subsea production system the manifold is housed in a manifold centre, bringing support and protection to all pipe work and valves. The manifold center constitutes the gathering point in a subsea production system, into which wellhead cellars and other manifold centers are connected by flowlines. The oil from a manifold center is conducted to a subsea or fixed platform production station[4]. "The manifolds may vary considerably in design from large and complex multi-well template manifolds to simpler free standing manifolds"[29].

The reliability data considered in this analysis comprises the manifold and piping units. The x-mas tree choke module, template and control system/pods are outside the boundary, as is shown in **Figure 3.3.** A list of subdivision in subunits and components is shown in **Table 3.2.**

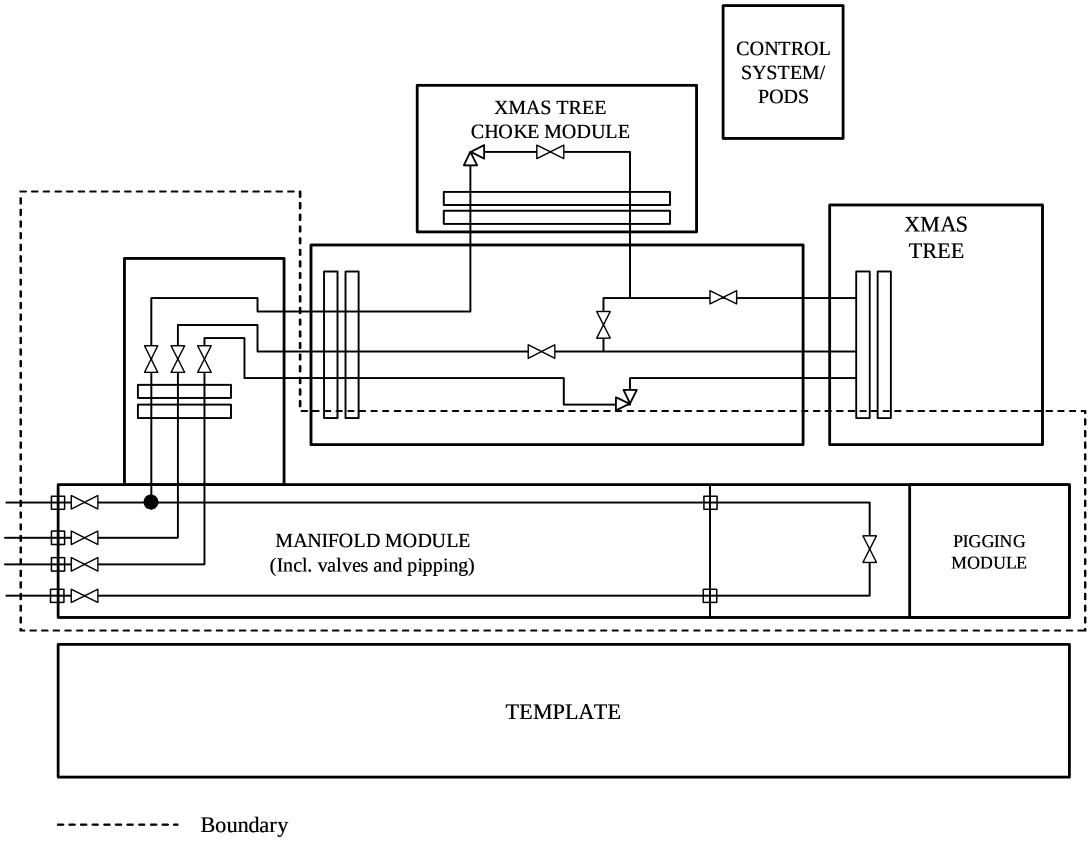

Figure 3.3 Manifold, boundary definition[29]

Table 3.2 Manifold, Subdivision into Subunits and Components [29]

MANIFOLD	
Manifold module	**Pipping module**
Chemical injection coupling	Connector
Connector	Piping (hard pipe)
Control valve	Valve, process isolation
Hydraulic coupling	
Piping (hard pipe)	
Structure-protective	
Structure-support	
Valve,check	
Valve,control	
Valve,process isolation	
Valve, utility isolation	

3.3 Flowline

These pipes carry oil from wellheads to manifold and to production receiving terminal. The flowline comprises flexible or rigid pipes from the sea floor up to and including the hang-off on the receiving installation belong to the riser equipment class.

The boundary definition is shown in **Figure 3.4** and applies to all subsea flowlines from a subsea production facility to a topside production facility or another subsea production. The connector at the subsea facility is not included as a part of the flowline components; however, topside connector is incorporated in this analysis. **Table 3.3** shows the flowline taxonomy in subunits and components[23,29].

Table 3.3 Flowline, Subdivision into Subunits and Components [29]

FLOWLINE	
Pipe	**Subsea process isolation system**
Coating - external	Valve, process isolation
Connector	Structure - protective
Flexible pipe spool	Structure - support
Rigid pipe spool	
Sealine	

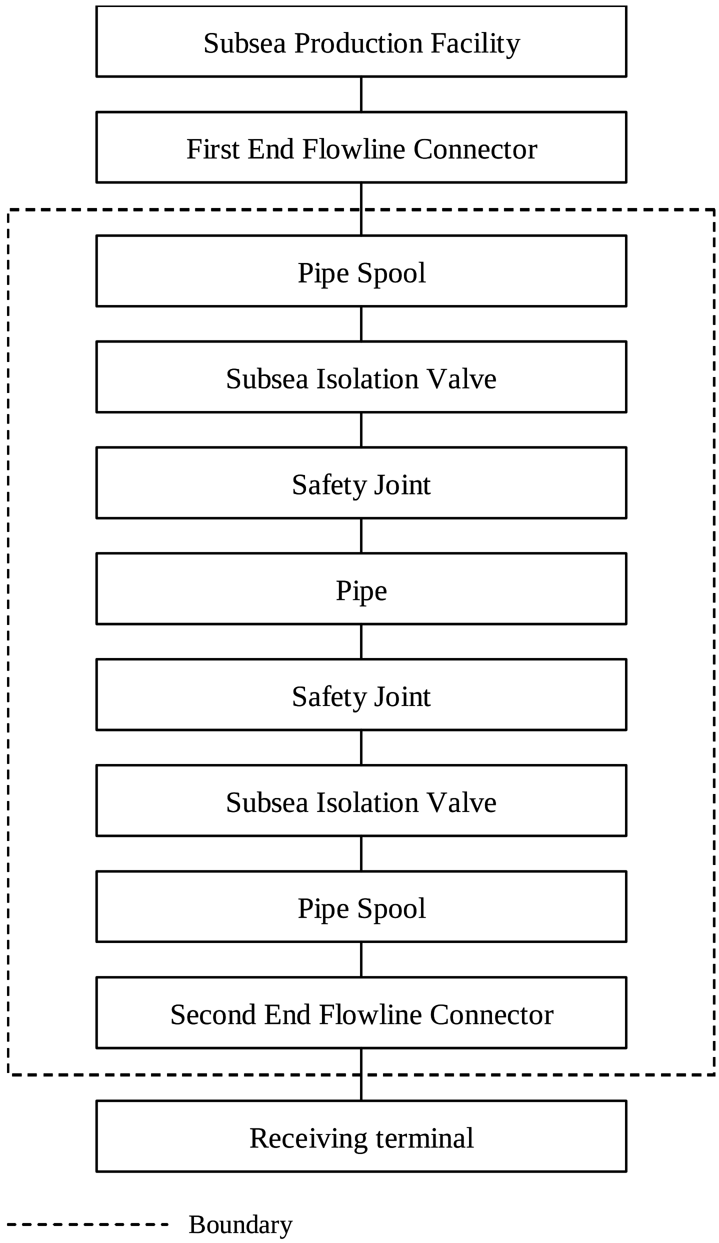

Figure 3.4 Flowline, boundary definition[29]

3.4 Subsea Isolation System

A Subsea Isolation System (SSIS) consists of several valves, such as, single valve with bypass or two serial valves. The Subsea Isolation Valves (SSIV) includes local accessories, e.g. the actuator, and use the same equipment taxonomy as the current subsea control system.

The classification in subunits and components stated by OREDA database is shown in **Table 3.4** and the interface between the SSIS and its surroundings is captured in **Figure 3.5.**

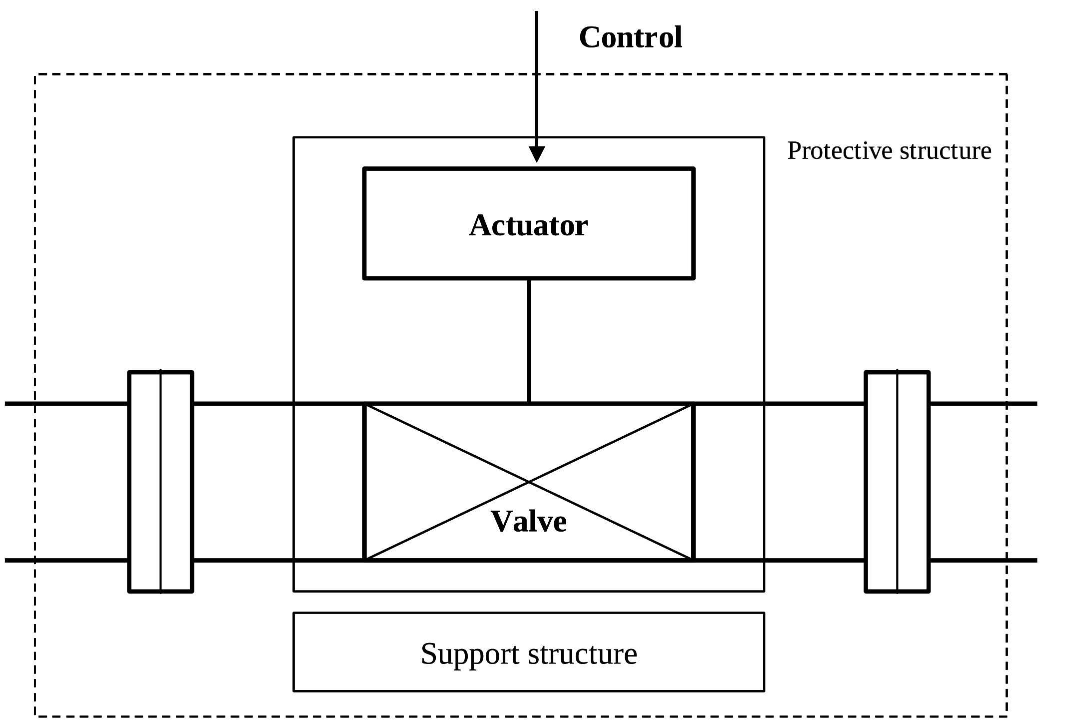

Figure 3.5 Subsea isolation system, boundary definition[29]

Table 3.4 SSIS, Subdivision into Subunits and Components [29]

Subsea isolation system
Valve, subsea isolation
Structure - protective
Structure - support

3.5 Riser

The riser is constituted by flowline that carry oil or gas from the base of a production platform to the processing plant[30]. In offshore facilities, there are three different types of risers: rigid risers in shallow water, rigid risers in deep water and flexible risers.

Rigid risers in shallow water are set of vertical steel pipes, which are extended between the seabed and the topside of the fixed platform. A fixed platform supports laterally this kind of risers.

There are usually two types of rigid riser in deep water: Top Tensioned Risers (TTRs) that are subject to mechanical tension by a system on the platform; and Steel Catenary Risers (SCRs), which are connected to the platform piping through a flex joint forming an angle.

Flexible risers can adopt different shapes, such as, a catenary, an S, a wave, etc. Flexible risers are mostly fabricated by multiple layers of steel textile and an inner layer of elastomer or polymer material[31].

For our analysis, we are going to take into account the failure data from fixed and flexible production riser that extend between the riser base/manifold and the installation surface tree. The riser components include riser joints for rigid risers or single pipe lengths for flexible risers, connectors and various accessories. The boundary is defined in **Figure 3.6** and its taxonomy in subunits and components are presented in **Table 3.5.**

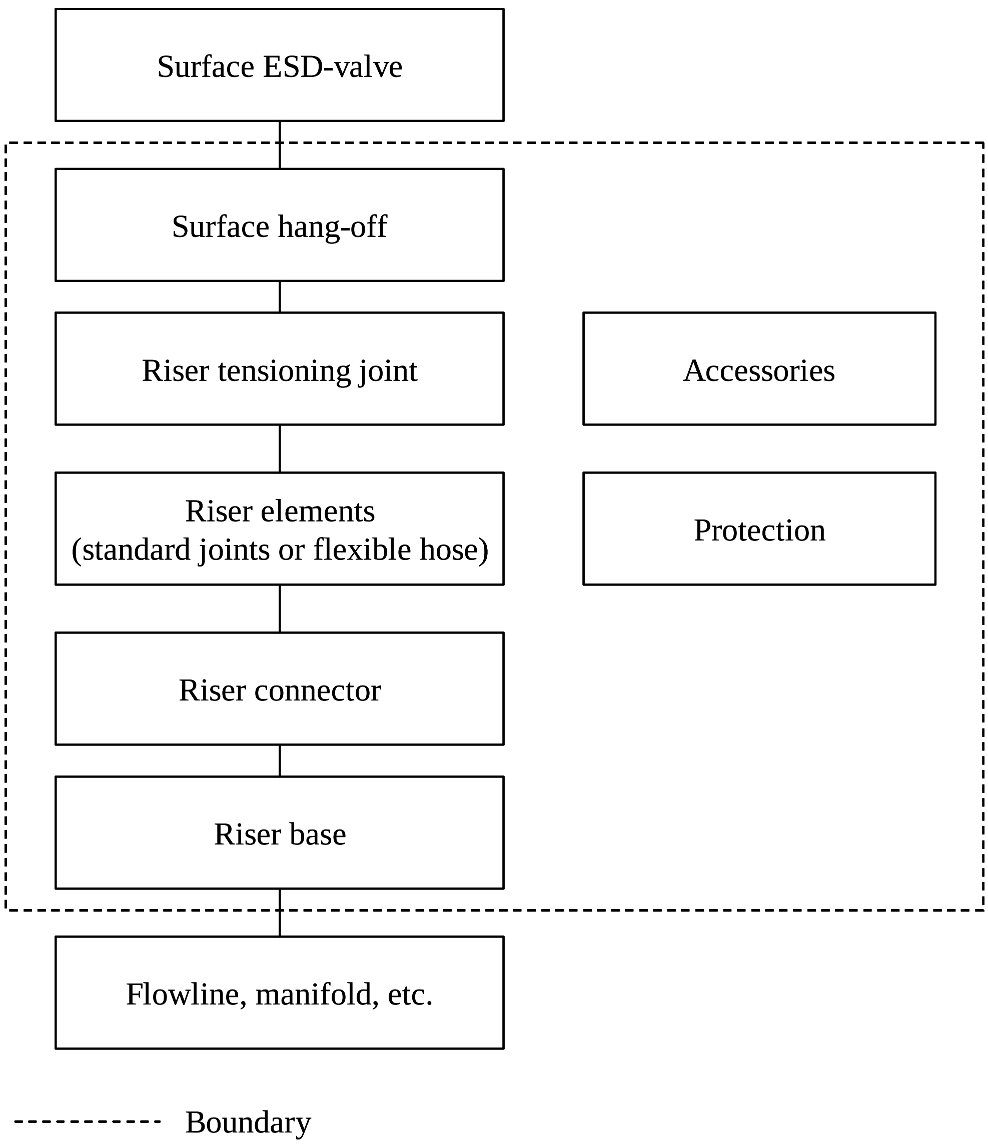

Figure 3.6 Riser, boundary definition[29]

Table 3.5 Riser, Subdivision into Subunits and Components[29]

RISER			
Accessories	**Protection**	**Rise base**	**Rise elements**
Bend restictor	Anode	Gas lift system	Connector
Buoyancy device	Coating - external	Structure	Pipe
J/I-tube seal		Valve, process isolation	
Stabilizing & guidance equipment		Valve, utility isolation	
Tension & motion compensation equipment			

3.6 Running Tool

It is a special device used to run and set downhole plugs or similar equipments[32]. The reliability data comprises in this analysis includes the valve block, connectors, soft landing system, the running tool itself and the local control and monitoring, as is shown in **Figure 3.7.** Running tool subdivision in subunits and components are shown in **Table 3.6.**

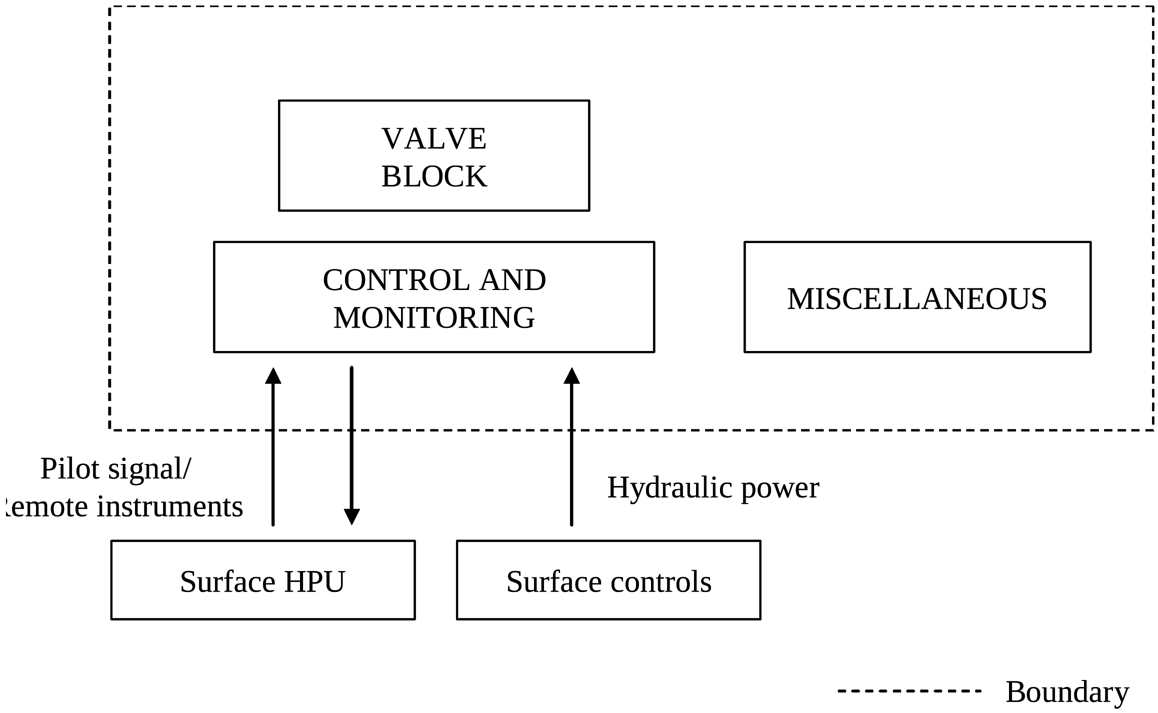

Figure 3.7 Running tool, boundary definition[29]

Table 3.6 Running Tool, Subdivision into Subunits and Components[29]

RUNNING TOOL		
Control & monitoring	**Valve Block**	**Miscellaneous**
Accumulator - subsea	Ram preventer	Connector
Junction plate w/couplers	Main block	Soft landing system
Pilot control valve	Valve, process isolation	
Soleniod control valve	Valve, shear	
Umbilical		

3.7 Wellhead and Christmas Tree

Wellhead is a hardware complex that incorporates spools, valves and adapters installed either on the casing surface string or on the conductor pipe. The wellhead provides pressure control in the borehole and regulates the well production. Devices for hanging the upper casing and the production tubing are provided for the wellhead. Surface flow control or X-mas tree can be installed in the upper termination of the wellbore (wellhead)[30,32].

The boundary definition is shown in **Figure 3.8**, which includes the subsea wellhead and X-mas tree on single satellite wells and multiple wells. All the valves and connectors are considered as a part of the wellhead and X-mas tree. The valves were classified according to functional features, for instance, process isolation, utility isolation, check, choke and control valves; and the connectors were analyzed within three nodes: tree to wellhead connector, flowspool to sealine/manifold connector and tree to flowbase. The subsea control system, pressure and temperature sensors or any other detector installed on the X-mas tree are outside the boundary[29]. **Table 3.7** shows the subdivision in subunits and components.

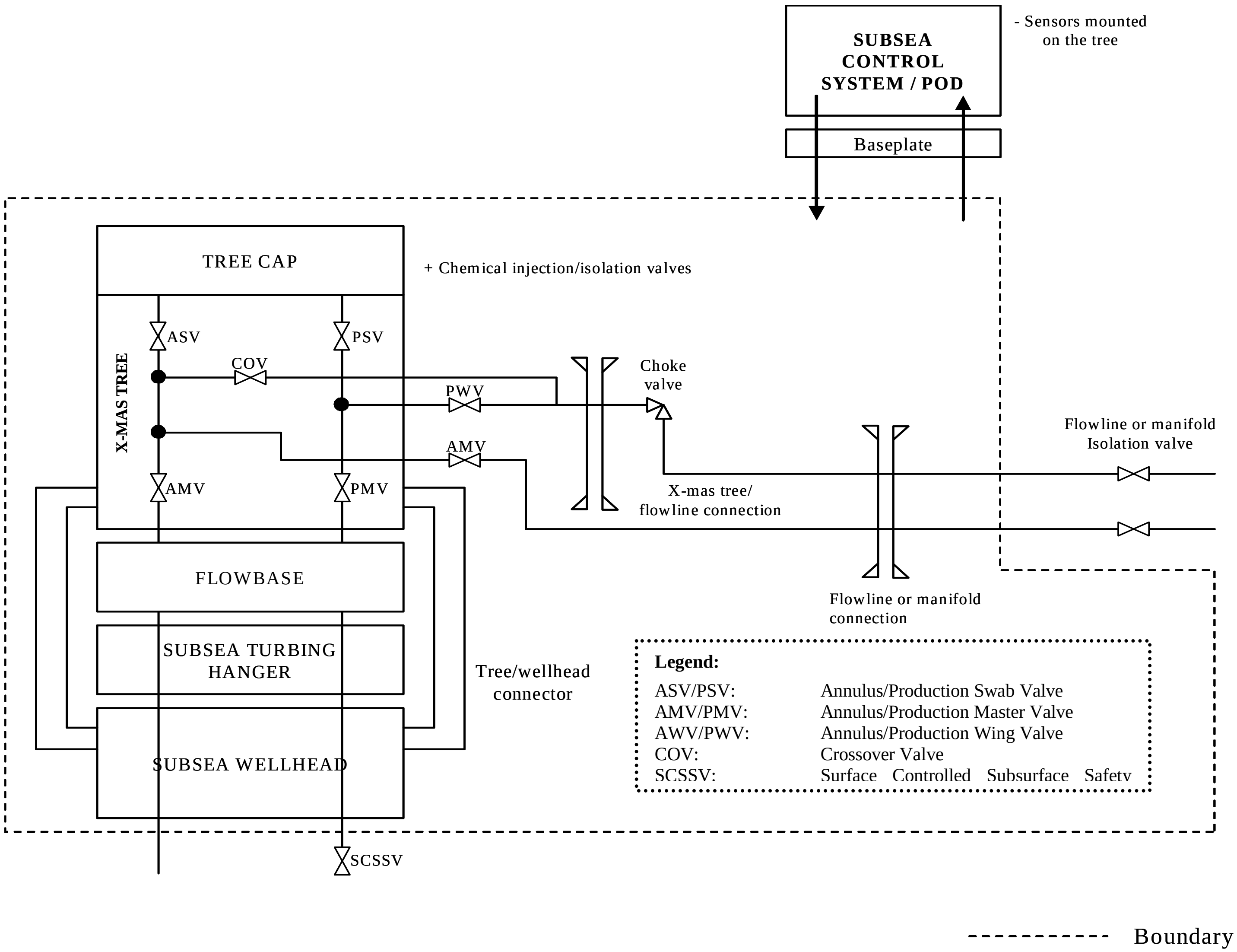

Figure 3.8 Wellhead and X-mas tree, boundary definition[29]

Table 3.7 Wellhead and X-mas Tree, Subdivision into Subunits and Components[29]

WELLHEAD AND X-MAS TREE			
Flowbase	**Subsea wellhead**	**Subsea X-mas tree**	**Tubing hanger**
Frame	Annulus seal assemblies (packoffs)	Chemical injection	Chemical injection coupling
Hub/mandrel	Casing hangers	Connector	Hydraulic coupling
Valve, check	Conductor housing	Debris cap	Power/signal coupler
Valve, process isolation	Permanent guidebase (PGB)	Flowspool	Tubing hanger body
Valve, Utility isolation	Temporary guidebase (TGB)	Hose (flexible piping)	Tubing hanger isolation plug (H)
	Wellhead housing (high pressure	Hydraulic coupling	
		Piping (hard pipe)	
		Tree cap	
		Tree guide frame	
		Unknown	
		Valve, check	
		Valve, choke	
		Valve, control	
		Valve, other	
		Valve, process isolation	
		Valve, utility isolation	

CHAPTER IV

AVAILABILITY MODEL

The petroleum and gas industry have to go beyond the frontiers of traditional discovery, since the onshore hydrocarbon resources are day by day scarcer. For this reason, there was a push to explore for hydrocarbons offshore. However, once the barrier of operating in water was broken, the offshore engineering had other challenge, which was increasing water depth at which these operations take place. As the water depth rise, the costs and the risk associated with the subsea equipment increase. Therefore, an accurate measure of its failures applied in reliability, availability and maintainability analysis, is a fundamental part to quantify the risk involved in the process.

The techniques for quantifying and predict frequency of failures were previously applied mostly in the domain of availavility, where the cost of equipment failure was the prime concern. In the last few years, the tendency for these techniques has been extended to be used in the field of the hazard assessment[33]. To analyze the failure risk, systems modeling have been developed over the last 20 years, by means of fault tree analysis, reliability block diagrams, Markov method and Monte Carlo simulation.

Montecarlo Simulation is used in this work to model probabilities of failure, types of failure, time to repair and time of occurrence associated with each failure in an oil/gas production field. By this methodology, the failure rates of specific component parts can be accurate assessed and predicted through successive computer runs. Then, this downtime forecast is introduced in a process simulation modeling to perform a new production planning in an effective work period, reducing the uncertainty due to unavailability on the subsea equipment employed in the production of either oil or gas. Thus, financial risk decision, such as deliverability contract, can be improved by using this efficient approach. Furthermore, a precise prediction of the trend of failure may be used to adjust the design configuration and maintainability philosophy can be made early in the design cycle in order to optimize the reliability and availability.

In this chapter we are going to discus: the principal definitions, reliability, availability, maintainability and failure concepts, the procedure, assumption and equation used to perform the availability model, Montecarlo simulation and the new disjunctions gotten after include the availability model into the process simulation modeling.

4.1 Terms Definition

In order to perform the availability modeling it is first necessary to define the terms that are being used through this chapter.

- **Boundary:** The interface between an item and its surroundings[29].
- **Mean Time Between Failures (MTBF):** This is the mean of times between failures for a particular item. It includes both operating and repair time[33].
- **Mean Time To Failure (MTTF):** This is the mean of operating times, for example, the time from when an item is put into operation to the time when it fails[33].
- **Mean Time To Repair (MTTR):** MTTR is the mean of the times from when repair stars on an item to the time when the repair work is complete ("Total corrective maintenance time divided by number of corresponding maintenance actions during a given period of time"). MTTR excludes other maintenance times such as transportation and installation[34].
- **Mean Down Time (MDT):** MDT is the mean of times needed to restore an item to service. It includes not only repair time, but also other shut down activities such as waiting for spare parts, and moving an item to and from the workshop. The sum of MTTF and MDT is MTBF[35].

- **Calendar Time:** The interval of time between the start and end of data surveillance for a particular item[29].
- **Component – Subsea:** These are subsets of each subunits (subsea inventory) and will typically consist of the lowest level items that are repaired/replaced as a whole (e.g. valve, sensor, etc)[29].
- **Subunit – Topside:** An assembly of items that provides a specific function that is required for the equipment unit to achieve its intended performance. Corresponds frequently with sub-tag numbers[29].
- **Subunit – Subsea:** A subsea equipment unit is subdivided in several subunits, each with functions required for the equipment unit to perform its main function. Typical subunits are e.g. umbilical, HPU, etc. The subunits may be redundant, e.g. two independent HPUs[29].
- **Taxonomy:** A systematic classification of items into generic groups based on factors possibly common to several of the items, e.g. functional type, medium handled[29].
- **Item:** A common term used to denote any level of hardware assembly; i.e. equipment unit, subunit, maintainable items and parts[29].
- **Numbers of demands:** The total number of times an item is required to perform its specified functions during the operational time[29].
- **Operational time:** The period of time during which a particular item performs its required functions, between the start and end of data surveillance[29].

4.2 Reliability

The reliability of a component or of a system is the probability that it will perform a required function without failure under stated conditions for a stated period of time[36].

Reliability is mathematically expressed as:

$$R(t) = \int_{t}^{\infty} f(x)dx \tag{4.1}$$

Where f(x) is the failure probability density funtion and t is the length of the period (which is asumed to start from time zero).

4.3 Availability

The definition of reliability provided above is usually understood to contain the implicit assumption that, once an item has failed, it is immediately discarded and replaced. The assumption of single use is reasonable applications such as electronics, where spares can often be obtained cheaply and installed quickly. However, the assumption of single use is generally not appropriate for process plants because almost all the equipment is much too expensive to be discarded after one failure, and so it has to be repairable. Therefore, when engineers in the process industries discuss reliability, they are, in fact often referring to availability, which is defined as follow:

The availability of a repairable component or system is the fraction of time that it is able to perform a required function under stated conditions[36].

Even in a repairable system, not all types of failures can be repaired. For example, if a storage tank were to catch fire and burn to the ground, it is obviously not repairable and has to be replaced with a new tank. In practice, this distinction is not usually important in availability analyses because the repairable failures are usually much more common than non-repairable failures.

There are several representations of availability, which differ in the conception of the component cycle, the most common ones are:

4.3.1 Limiting Point Availability

This concept of availavility includes as component cycle: the time in service (MTTF) and the time to repair (MTTR). Then, the time cycle can be represented as:

$$t_{cycle} = MTTF + MTTR = \frac{1}{\lambda} + \frac{1}{\mu} = \frac{\mu + \lambda}{\lambda\mu} \qquad (4.2)$$

Where, λ is the failure rate and μ represents the repair rate.

Availability is defined as[36]:

$$a = \frac{MTBF}{MTTR + MTBF} = \frac{\mu}{\lambda + \mu} \tag{4.3}$$

4.3.2 Availability Including Test and Time to Repair

This approach is more realist that the previous one. The component cycle include a test of equipment in a stated period of time. The time in service (MTTF) and the time to repair (MTTR) are also part cycle component. **The Figure 4.1** shows the effect of the test and repair duration on the availability, appearing the residual unavailability concept, which proposes that a component can not return to its original state once, it has been repair. The only exception to this approach is when the component is total replaced for a new device[36].

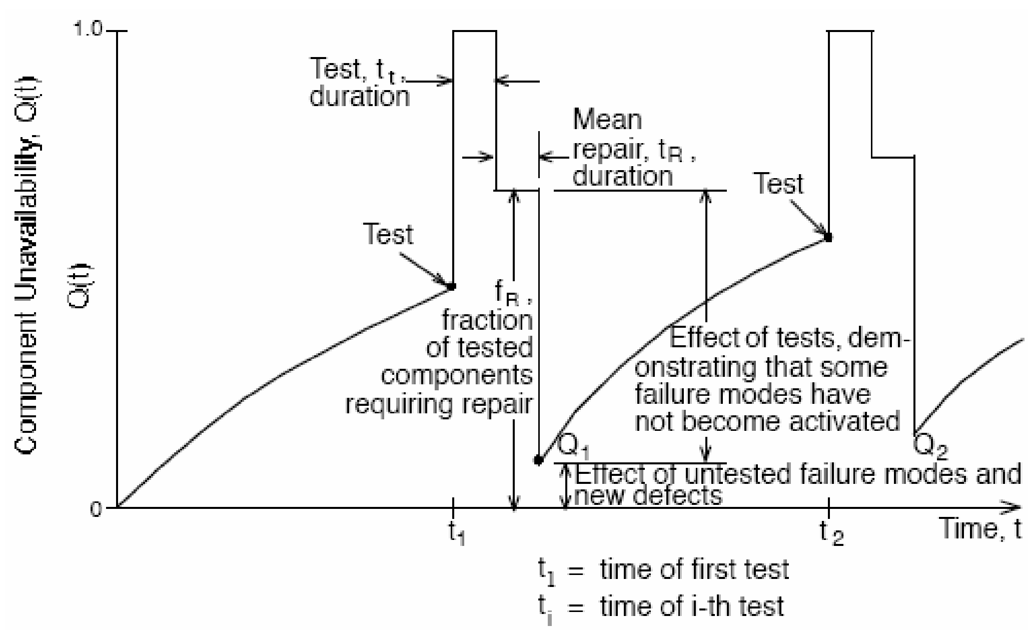

Figure 4.1 Unavailability for a periodically tested item including test and repair outages[36]

4.3.3 Availability Including Standby, Test and Time to Repair

This availability approach is the most precise in the real life. Since that it proposes similar field conditions, including standby, test and repair periods. However, it is very hard to collect and find this kind of data. The average unavailability (Q) is obtained from[34,36]:

$$Q = \left(\frac{\lambda t_s{}^2}{2} + t_t + f_R t_R \right) / \left(t_s + t_t + t_R \right) \tag{4.4}$$

Where, t_s is the standby time, t_t is the test time preventive maintenance or both, t_R is the repair time and f_R frequency of repair.

The cycle time is represented as:

$$t_{cycle} = t_s + t_t + t_R \tag{4.5}$$

The total downtime is:

$$t_D = t_{Ds} + t_{Dt} + t_{DR} \tag{4.6}$$

Downtime during standby:

$$t_{Ds} = \frac{\lambda t_s{}^2}{2} \tag{4.7}$$

Downtime during testing:

$$t_{Dt} = t_t \tag{4.8}$$

Downtime during repair:

$$t_{DR} = f_R t_R \tag{4.9}$$

In our case study we are going to use the first approach due to the lack data for the standby and test period. The general assumption in this study is that when a component fails, it is totally replace or return to service in “as good as new” state.

4.4 Maintainability

The maintainability of a failed component or system is the probability that it is returned to its operable condition in a stated period of time under stated conditions and using prescribed procedures and resources[35].

The combined topics of Reliability, Availability and Maintainability are sometimes referred to as RAM.

4.5 Failure Concepts

Failure is "the termination or the degradation of the ability of an item to perform its required function"[29]. In this project the failure concept includes:

- Complete failure of the equipment.
- Failure of part of the item, causing equipment unavailability for corrective action.
- Failure found during inspection period, testing, or preventive maintenance, which necessitates repair actions.
- Failure on control/monitoring or safety devices that requires shutdown or reduction of the items capability below specified limits.

The following outages are not considered as failures:

- Preventive or planned maintenance that causes unavailability.
- Shutdown of the item due to external conditions or where no physical failure condition of the item is revealed. A shutdown is not to be considered as failure unless there is some recorded maintenance activity[29].

A required function is defined as any function necessary to maintain the item's capability of providing its output at specified capacity and quality. The failure could be either complete loss of function degradation below an acceptable limit.

4.5.1 Failure Mode

"The failure mode is the effect by which a failure is observed on the failed unit"[29]. The loss of required system function that results from failures or an undesired change in state or condition is described by the failure mode. In this work, the failure mode is related to the equipment unit level. The failure mode is a description of the various abnormal conditions of an equipment unit and the possible transition from correct to incorrect state.

The failure mode is divided in two main categories:

- Demand change of state is not achieved.
- Undesired change in conditions[29].

Events like fail-to start/stop and fail-to open/close are included in the first category, which are directly related to the function unit failure. The second class is related to either function or condition as follows:

- Undesired change in manner of operation.
- Undesired change of condition, for example, vibration and leakage. This category does not affect the function immediately, but may do so if not attended to within a reasonable time.

4.5.2 Failure Severity Class Types

- **Critical Failure:** A failure which causes immediate and complete loss of a system's capability of providing its output.
- **Degraded Failure:** A failure which is not critical, but prevents the system from providing its output. If it is not attended, could result in a critical or degraded failure in the near future.
- **Unknown:** Failure severity was not recorded or could not be deduced[29].

The severity class is used to describe effect on the severity of loss of system output and system operational status. Each failure is related with only one severity class, critical, degraded or incipient, independently of the failure mode and failure cause.

4.5.3 Failure Rate

The failure rate function is the likelihood of an item, which has survived in a time t, will fail during the next unit of time. This probability will increase with the age t, when the item is deteriorating. For instance, a man who has reached the age of 95 years will obviously have a higher probability of dying during the next year than a 20 years old man. The failure rate function will therefore usually be a function of the time or the age of the item[35].

The mathematical definition of the failure rate function start with the time to failure T of an item; where T is the time from the item is put into operation until the first failure occurs. It is generally impossible to predict the exact value of the time to failure, and T will therefore be a random variable with some distribution. The failure rate function λ (t) can be defined mathematically as[29]:

$$\lambda(t) * \Delta t \approx Pr(t < T \leq t + \Delta t \,|\, T > t) \qquad (4.10)$$

The probability that the item will fail in the time interval (t, t+Δt) is stated in the right hand side of this equation, when the item is still functioning at time t. In other words, failure rate is the probability that an item that has reached the age t will fail in the next interval (t, t+Δt). "The approximation is sufficiently accurate when Δt is the length of a very short time interval"[29].

4.5.4 Life of a Technical Item

The life of a technical item is generally divided into three different phases: burn-in (or debugging) period, the useful life period, and the wear-out period. The failure rate function will usually have different shapes in the three phases. In the burn-in phase, the failure rate function decreases; then, in the useful life phase (normal operation region), the failure rate is close to constant; and increase in the wear-out phase. This trend is illustrated in **Figure 4.2** and is called a "bath-tub" curve because of its characteristic shape, and is often claimed to be a realistic model for mechanical equipment.

In this analysis, we are assuming that the item is not deteriorating during the useful life phase this phase, this means that the failure rate function is constant during this period. The deterioration will start when the item enters to wear-out phase.

For subsea equipment, installation problems have been disregarded. In others words, the data collection starts when the equipment is installed and ready for its intended service (useful life phase), this mean that the burn-in phase is neglected.

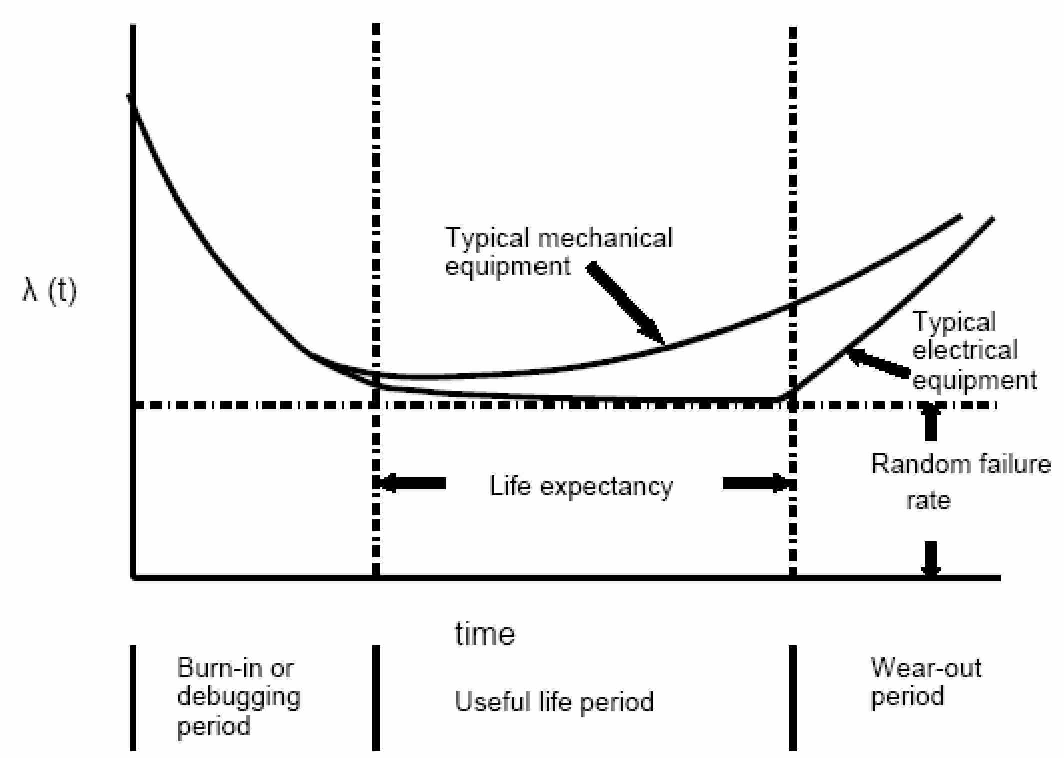

Figure 4.2 Typical life-cycle of a technical item[36]

The majority of the items are subject to some maintenance or replacement procedures, which are frequently replaced before they reach the wear-out phase. An important implication is that the repaired item is considered to be “as good as new. Therefore, the main part of the failure events will come from the useful life phase, where the failure rate is close to constant, $\lambda(t)=\lambda$.

The mean time to failure, MTTF, may be calculated as:

$$MTTF = \frac{1}{\lambda} \tag{4.11}$$

4.6 Estimators and Uncertainty Limits

The procedure for estimation of probability of failure, demand probabilities and uncertainty limits for homogeneous and multiple samples is stated as follow, according to OREDA DATABASE metodologhy[29].

4.6.1 Homogeneous Sample

When we have failure data from identical items that have been operating under the same operational and environmental conditions, we have a homogeneous sample. The only data we need to estimate the failure rate (λ) in this case is the observed number of failures (n) and the aggregated time in service (τ).

The estimator of $\hat{\lambda}$ is given by:

$$\hat{\lambda} = \frac{Number\_of\_failures}{Aggregated\_time\_in\_service} = \frac{n}{\tau} \tag{4.12}$$

The aggregated time in service, may be measured either as calendar time or operating time. This approach is valid only in the following situations:

- Failure times for a specified number of items, with the same failure rate λ, are available.
- Data (several failures) is available for one item for a period of time, and the failure rate λ is constant during this period.
- A combination of the two above situations[30].

The uncertainty of the estimate $\hat{\lambda}$ may be presented as a 90% confidence interval. This is an interval (λ_L, λ_U), represented by:

$$\Pr(\lambda_L \leq \lambda < \lambda_U) = 90\% \qquad (4.13)$$

With n failures during an aggregated time in service τ, this 90% confidence interval is given by:

$$\left(\frac{1}{2\tau} z_{0.95,2n}, \frac{1}{2\tau} z_{0.05,2(n+1)} \right) \qquad (4.14)$$

Where $Z_{0.95,V}$ and $Z_{0.05,V}$ denote the upper 95% and lower 5% percentiles, respectively, of the X^2- distribution with v degrees of freedom (Chi-Square distribution).

4.6.2 Multi-Sample

In many cases we do not have a homogeneous sample data. The aggregated data for an item may come from different installations with different operational and environmental conditions. In these situations we may decide to combine several homogeneous samples, this concept is called multi-sample.

The various samples may have different failure rates and different amounts of data; and for this reason, different confidence intervals.

If we plan to merge all the samples and estimate the average failure rate as the total number of failures divided by the aggregated time in service, we can not always obtain an accurate result, because the confidence interval will be unrealistically short.

We therefore need a more advanced estimation procedure to take care of the multi-sample problem.

To deal with this multi-sample situation, Spjøtvoll (1985) formulated an estimator procedure to get the average failure rate in a multi-sample problem with a 90% of uncertainty interval. The estimator was based on the following assumptions:

- We have k different samples. A sample may correspond for example to a platform and we may have data for similar items used on k different platforms.
- In sample *no i* we have observed n_i failures during a total time in service τ_i, for $i=1, 2\ldots k$.
- Sample *no i* has a constant failure rate λ_i, *for* $i=1,2\ldots k$.
- Due to different operational and environmental conditions, the failure rate λ_i may vary between the samples[30].

The variation of the failure between samples may be modeled by assuming that the failure rate is a random variable with some distribution given by a probability density function π (λ).

The mean or "average" failure rate is then: $\theta = \int_0^\infty \lambda \pi(\lambda) d\lambda$ (4.15)

And the variance is: $\delta^2 = \int_0^\infty (\lambda - \theta)^2 \pi(\lambda) d\lambda$ (4.16)

To calculate the multi-sample estimator, the following procedure is used:

1. Calculate an initial estimate $\hat{\theta}_1$ of the mean (average) failure rate θ by:

$$\hat{\theta}_1 = \frac{Total\_no\_of\_failure}{Total\_time\_in\_service} = \frac{\sum_{i=1}^{k} n_i}{\sum_{i=1} \tau_i} \tag{4.17}$$

2. Calculate:

$$S_1 = \sum_{i=1}^{k} \tau_i \qquad S_2 = \sum_{i=1}^{k} \tau_i^2 \tag{4.18}$$

$$V = \sum_{i=1}^{k} \frac{\left(n_{i-}\hat{\theta}_1 \tau_i\right)^2}{\tau_i} = \sum_{i=1}^{k} \frac{n_i^{\;2}}{\tau_i} - \hat{\theta}_1^{\;2} S_1 \tag{4.19}$$

3. Calculate an estimate for σ^2, measuring of the variation between samples.

$$\hat{\sigma}^2 = \frac{V - (k-1)\hat{\theta}_1}{S_1^{\;2} - S_2} x S_1 \qquad \text{When greater than zero, else 0.} \tag{4.20}$$

4. Calculate the final estimate θ^* of mean ("average") failure rate θ by:

$$\theta^* = \frac{1}{\sum_{i=1}^{k} \frac{1}{\frac{\hat{\theta}_1}{\tau_i} + \hat{\sigma}^2}} x \sum_{i=1}^{k} \left(\frac{1}{\frac{\hat{\theta}_1}{\tau_i} + \hat{\sigma}^2} x \frac{n_i}{\tau_i} \right) \tag{4.21}$$

5. Let SD= $\hat{\sigma}$

Where θ^* is the mean, and SD the standard deviation.

The lower and upper "uncertainty" values are given by:

$$\int_{Lower}^{Upper} .\pi(\lambda) d\lambda = 90\% \tag{4.22}$$

6. $\pi(\lambda)$ is assumed to be the probability density function of a Gamma Distribution with parameters α and β.

7. The parameters α and β are estimated by:

$$\hat{\beta} = \frac{\theta^*}{\hat{\sigma}^2} \qquad \hat{\alpha} = \hat{\beta}.\theta^* \tag{4.23}$$

8. The following formulas are now applied:

$$Lower = \frac{1}{2\hat{\beta}^{z0.95,2\hat{\alpha}}} \tag{4.24}$$

$$Upper = \frac{1}{2\hat{\beta}^{z0.05,2\hat{\alpha}}} \tag{4.25}$$

Where $z_{0.95,v}$ and $z_{0.05,v}$ denote the upper 95% and lower 5% percentiles, respectively of the x^2 distribution with v degrees of freedom.

However, in the case of k=1, the procedure cannot be used. In this case, the n/τ estimate is given for the mean, and the lower and upper values should be interpreted as a traditional 90% confidence interval.

If no failures are observed for an item the following approach is used to obtain lower, mean and upper values for “all failure modes”:

1. Let $\hat{\lambda}_p$ denote the failure rate estimate (mean) one level up in the taxonomy hierarchy.
2. Let τ denote the total time in service (operational or calendar) for the item of interest.
3. Let $\alpha = 1/2 \qquad \beta = \frac{1}{2\hat{\lambda}_p} + \tau$ (4.26)
4. An estimate for the failure rate is now $\hat{\lambda} = \frac{\alpha}{\beta}$ (4.27)

5. The standard deviation is given by

$$SD = \sqrt{\frac{\alpha}{\beta^2}} \tag{4.28}$$

6. A 90% uncertainty interval is given by

$$\left(\frac{1}{2\beta^{z0.95,2\alpha}}, \frac{1}{2\beta^{z0.05,2\alpha}} \right) = \left(\frac{0.002}{\beta}, \frac{1.9}{\beta} \right) \tag{4.29}$$

4.6.3 Estimation of Demand Probabilities

The demand probability is estimated if information about number of demands is provided. The demand probability is always related to one specific failure mode, for instance a critical fail to start. The demand failure probability is calculated by:

$$\hat{p} = \frac{n}{d} \tag{4.30}$$

Where n is the number of failures with the appropriate failure mode and d is the number of demands.

4.7 Active Repair Time

The total calendar time required to repair and return the item to a state where it is ready to resume its functions is called active repair time.

In the active repair time is neglected: the time to detect the failure, time to isolate the equipment from the process before repair, delay and waiting for spare parts or tools, and any time after the repair has been completed if the item is not put into service immediately. Time for testing is included when such testing is an integrated part of the repair activity[29].

4.8 Availability Modeling - Program Developed

The availability of a system is analyzed by Monte Carlo simulation. A program was built by using C++ and Visual Base environments to model the probabilities of failure, the type of failure, the time to repair associated with each failure, and time of occurrence for a field system.

A total of 129 failures from the principal subsea components were included in the analysis, assuming that the probability of failure is constant and all the failures are independent. Therefore, common failures were excluded in this study. The methodology to estimate the probability of failure was explained through the section 4.6.

The availability was calculated using the limiting point availability approach, which assumes that component cycle includes: the time in service (MTTF) and the time to repair (MTTR). So, the availability is only function of the time to repair and the time between failures, as is stated:

$$a = \frac{MTBF}{MTTR + MTBF} = \frac{\mu}{\lambda + \mu} \tag{4.31}$$

Furthermore, according to this approach we can assume that when a component fails, it is totally replace or return to service in "as good as new" state. For this reason, the time to repair is equal to the downtime.

The subsea components included in the analysis are listed: Manifold, Flowline, Subsea Isolation System, Riser, Running Tool, Wellhead & Christmas tree and Control System. The data used for the availability model, such as type of failure, probability of failure and time to repair, correspond to the Offshore Reliability Data and are represented through **Tables 4.1** to **4.7.**

Table 4.1 Failure Data for Manifold[29]

	Taxonomy No		Item:					Manifold			
	Population 29	**Installations** 11	**Failure Data**					**Aggregated time in service (10^6)** Calendar Time (1.3342)			
Failure #	**Component**	**No of Units**	**#**	**Severity Class**				**Failure Data (per 10^6)**			**Active Repair Time (hours)**
				C	**D**	**I**	**U**	**Mean**	**SD**	**n/t**	**Mean**
	Manifold Unit										
1	Chemical Injection coupling	19*						0.2570	0.3635		7.00**
2	Connector	214	1	1				0.1093	0.1791	0.0993	2.00
3	Hydraulic coupling	87						0.0591	0.0836		7.00**
4	Piping (hard pipe)	38*						0.1792	0.2534		7.00**
5	Structure-protective	15						0.4128	0.5838		7.00**
6	Structure-support	6						1.1738	1.6600		7.00**
7	Valve, check	14						0.4534	0.6412		7.00**
8	Valve, control	13						0.3419	0.4835		7.00**
9	Valve, process isolation	298	9	8	1			0.8313	0.9593	0.6708	8.00
10	Valve, utility isolation	148*						0.0849	0.1201		7.00**
	Pigging module										
11	Connector	2*						0.2478	0.3505		7.00**
12	Piping (hard pipe)	1*						0.3643	0.5152		7.00**
13	Valve, process isolation	11*						0.4184	0.5917		7.00**
	Equipment level manifold	**29**	**10**	**2**	**7**	**1**		**0.4756**	**7.4826**	**7.4950**	**7.00**

Comments	
	For components with no failures, n is set to 0.5 based on a non-informative prior. * Mean failure for the common components used in the estimator. ** Data assumed, taking the average time to repair of the component.

Table 4.2 Failure Data for Flowline[29]

	Taxonomy No		Item:	Flowline							
	Population 59	**Installations** 11	**Failure Data**					**Aggregated time in service (10^6)** Calendar Time (2.0850)			
Failure #	**Component**	**No of Units**	**#**	**Severity Class**				**Failure Data (per 10^6)**			**Active Repair Time (hours)**
				C	**D**	**I**	**U**	**Mean**	**SD**	**n/t**	**Mean**
	Pipe										
14	Coating-external	38						0.1624	0.2297		2.00**
15	Connector	91*						0.0876	0.1239		2.00**
16	Flexible pipe spool	26	1	1				1.1956	1.6546	0.7209	2.00
17	Rigid pipe spool	74						0.0800	0.1132		2.00**
18	Sealine	55						0.1374	0.1943		2.00**
	Subsea Isolation System										
19	Valve, process isolation	17*						0.2727	0.3856		2.00**
20	Structure Protective							0.2835	0.4010		2.00**
21	Structure Support							0.2835	0.4010		2.00**
	Equipment level flowline	**29**	**1**		**1**			**0.4346**	**0.8654**	**0.4796**	**2.00**
	Comments	For components with no failures, n is set to 0.5 based on a non-informative prior. * Mean failure for the common components used in the estimator. ** Data assumed, taking the average time to repair of the component.									

Table 4.3 Failure Data for Pipeline[29]

	Taxonomy No		Item:	Pipeline - SSIV (Subsea Isoltion System)							
	Population 85	Installations 32	Failure Data					Aggregated time in service (10^6) Calendar Time (2.3683)			
Failure #	**Component**	**No of Units**	**#**	**Severity Class**				**Failure Data (per 10^6)**			**Active Repair Time (hours)**
				C	**D**	**I**	**U**	**Mean**	**SD**	**n/t**	**Mean**
	Subsea Isolation System										
22	Valve, subsea isolation	146	9		5	4		2.0040	3.5684	2.5014	36.00
23	Structure - protective							3.0865	9.6702	3.8001	29.00**
24	Structure - support							3.0865	9.6702	3.8001	29.00**
	Equipment level pipeline	**85**	**9**		**2**	**6**		**3.0865**	**9.6702**	**3.8001**	**29.00**
	Comments	For components with no failures, n is set to 0.5 based on a non-informative prior. * Mean failure for the common components used in the estimator. ** Data assumed, taking the average time to repair of the component.									

Table 4.4 Failure Data for Riser[29]

Failure #	Component	No of Units	#	C	D	I	U	Mean	SD	n/t	Active Repair Time (hours) Mean
	Taxonomy No		**Item:**			**Riser**					
	Population 42	**Installations** 8	**Failure Data**					**Aggregated time in service** Calendar Time (2.0633)			
				Severity Class				**Failure Data (per 10^6)**			
	Accessories										
25	Bend restrictor							8.3103	11.7526		76.00**
26	Buoyancy device							8.3103	11.7526		76.00**
27	J/I - tube seal							8.3103	11.7526		76.00**
28	Stabilizing & guidance equipment							8.3103	11.7526		76.00**
29	Tension & motion compensation equipment							8.3103	11.7526		76.00**
	Protection										
30	Anode	1						7.2466	10.2482		76.00**
31	Coating-external	1						7.2466	10.2482		76.00**
	Riser base										
32	Structure							3.1408	6.6488	2.4233	76.00**
33	Valve, process isolation							3.1408	6.6488	2.4233	76.00**
34	Valve, utility isolation							3.1408	6.6488	2.4233	76.00**
35	Other							3.1408	6.6488	2.4233	76.00**
	Riser elements										
36	Connector	81*						0.0857	0.1212		76.00**
37	Pipe	44	5	4	1			3.3088	7.2821	2.3597	76.00
	Equipment level Riser	**42**	**5**	**4**	**1**			**3.1408**	**6.6488**	**2.4233**	76.00
	Comments	For components with no failures, n is set to 0.5 based on a non-informative prior. * Mean failure for the common components used in the estimator. ** Data assumed, taking the average time to repair of the component.									

Table 4.5 Failure Data for Running Tool[29]

	Taxonomy No		Item:	Running Tool							
	Population	Installations	Failure Data					Aggregated time in service			
	6	2						Calendar Time (0.3032)			
Failure #	Component	No of Units	#	Severity Class				Failure Data (per 10^6)			Active Repair Time (hours)
				C	D	I	U	Mean	SD	n/t	Mean
	Control & Monitoring										
38	Accumulator - subsea	1*						0.7785	1.1010		40.00**
39	Junction plate w/couplers	7	2			2		5.1754	5.2628	5.9221	40.00
40	Pilot control valve	1						7.2466	10.2482		40.00**
41	Umbilical	1						7.2466	10.2482		40.00**
42	Other	1						7.2466	10.2482		40.00**
	Valve block										
43	Main block	1						7.2466	10.2482		40.00**
44	Valve, process isolation	4*						0.4628	0.6545		40.00**
45	Valve, shear	5	1			1		3.9712	4.3856	4.3435	40.00**
46	Other	1						7.2466	10.2482		40.00**
	Miscellaneous										
47	Connector	6	1			1		3.1344	2.6314	3.2979	36.00
48	Soft landing system	3						1.7607	2.4900		36.00**
49	Other	1						7.2466	10.2482		36.00**
	Equipment level running tool	**6**	**4**			**4**		**11.2412**	**10.5256**	**13.1918**	**38.00**
	Comments	For components with no failures, n is set to 0.5 based on a non-informative prior. * Mean failure for the common components used in the estimator. ** Data assumed, taking the average time to repair of the component.									

Table 4.6 Failure Data for Well Head and X-mas Tree[29]

	Taxonomy No		Item:					Wellhead & Xmas Tree			
	Population 83	Installations 13	Failure Data					Aggregated time in service (10^6) Calendar Time (3.0208)			
Failure #	Component	No of Units	#	Severity Class				Failure Data (per 10^6)			Active Repair Time (hours)
				C	D	I	U	Mean	SD	n/t	Mean
	Flowbase										
50	Frame	38	5		5			3.6968	9.5439	4.1016	8.00
51	Hub/mandrel	47						0.1751	0.2476		7.00**
52	Valve, check	2						2.1961	3.0157		7.00**
53	Valve, process isolation	18	1	1				1.6114	1.4650	1.7954	6.00
54	Valve, utility isolation	5*						0.3479	0.4920		7.00**
	Subsea wellhead	**82**						**0.0839**	**0.1187**		7.00**
55	Annulus seal assemblies (packoffs)	130						0.0490	0.0693		7.00**
56	Casing hangers	106						0.0590	0.0834		7.00**
57	Conductor housing	74						0.0889	0.1257		7.00**
58	Other	10						0.5900	0.8344		7.00**
59	Permanent guidebase (PGB)	49						0.1524	0.2155		7.00**
60	Temporary guidebase (TGB)	13						0.7206	1.0190		7.00**
61	Unknown	5						3.3613	4.7536		7.00**
62	Wellhead housing (high pressure housing)	72						0.0907	0.1283		7.00**

Table 4.6 Continued[29]

	Subsea X-mas tree										
63	Chemical injection coupling	124*						0.0782	0.1106		33.00**
64	Connector	212	1			1		0.6193	1.3502	0.1381	33.00**
65	Debris cap	44						0.1504	0.2127		33.00**
66	Flowspool	77	1		1			0.4525	0.8316	0.3594	72.00
67	Hose (flexible piping)	20						0.3692	0.5222		33.00**
68	Hydraulic coupling	1266	3	3				0.0678	0.1066	0.0692	9.00
69	Other	25						0.2368	0.3349		33.00**
70	Piping (hard pipe)	49	1	1				0.6033	1.6847	0.6005	33.00**
71	Tree cap	76	8		8			2.7429	4.8396	2.8281	17.00
72	Tree guide frame	42	2			2		1.3889	1.1862	1.4530	6.00
73	Unknown	6						2.4527	3.4687		33.00**
74	Valve, check	75						0.0729	0.1031		33.00**
75	Valve, choke	75	22	7	15			11.3278	7.2845	9.0909	35.00
76	Valve, control	163						0.0370	0.0523		33.00**
77	Valve, other	24	1			1		0.9924	0.9924	0.9924	33.00**
78	Valve, process isolation	550	8	4	3	1		0.4085	0.2360	0.3903	92.00
79	Valve, utility isolation	181	3	3				1.0345	1.3412	0.5020	10.00
	Tubing hanger										
80	Chemical injection coupling	6*						0.3647	0.5157		7.00**
81	Hydraulic coupling	104*						0.1124	0.1590		7.00**
82	Power/signal coupler	41*						0.2109	0.2983		7.00**
83	Tubing hanger body	75	2	2				0.6806	1.7175	0.7265	7.00**
84	Tubing hanger isolation plug (H)	23						0.2605	0.3685		7.00**
	Equipment level Wellhead & Xmas Tree	**83**	**58**	**10**	**34**	**14**		**23.0976**	**17.3006**	**19.2000**	**29.00**
	Comments	For components with no failures, n is set to 0.5 based on a non-informative prior. * Mean failure for the common components used in the estimator. ** Data assumed, taking the average time to repair of the component.									

Table 4.7 Control System[29]

Failure #	Component	No of Units	#	C	D	I	U	Mean	SD	n/t	Mean
	Taxonomy No		**Item:**			**Control System**					
	Population 17	**Installations** 13	**Failure Data**					**Aggregated time in service (10^6)** Calendar Time (0.8531)			
Failure #	**Component**	**No of Units**	**#**	**Severity Class**				**Failure Data (per 10^6)**			**Active Repair Time (hours)**
				C	**D**	**I**	**U**	**Mean**	**SD**	**n/t**	**Mean**
	Chemical Injection Unit (topside)										
85	Subunit							0.5419	0.7664		9.00**
86	Other							**0.4854**	**0.6864**		9.00**
	Electrical power unit (topside)										
87	Power supply unit							21.6396	13.3025		10.00
88	Subunit							4.9412	4.7225		12.00
	Hydraulic power unit (topsite)										
89	Hydraulic power unit							25.4930	8.2222		7.00**
90	Subunit							12.7661	19.0370		7.00**
	Master Control station (topside)										
91	Subunit							73.9949	66.6081		8.00**
92	Other							59.3623	61.7183		8.00**
	Dynamic umbilical										
93	Hydraulic/chemical line							0.1149	0.1625		9.00**
94	Power/signal line							0.9179	0.8047		9.00**
95	Sheath/armour							5.5056	7.7861		9.00**
96	Subsea umbilical termination unit							0.8785	1.2424		9.00**
97	Topside umbilical termination unit							4.1813	4.1813		9.00**
98	Unknown							5.5056	7.7861		9.00**
	Static Umbilical										
99	Hydraulic/chemical line							0.4435	0.8196		2.00
100	Power/signal line							2.4052	1.9714		24.00**
101	Sheath/armour							0.6108	0.8638		24.00**
102	Subsea umbilical termination unit							1.9223	3.4519		50.00
103	Topside umbilical termination unit							0.6248	0.8836		24.00**
104	Unknown							2.2023	3.1145		24.00**

Table 4.7 Continued[29]

	Sensors										
105	Combined pressure and temperature sensor							0.9210	1.9983		12.00
106	Flow sensor							0.1758	0.2485		11.00**
107	Pressure Sensor							1.7656	1.6276		11.00**
108	Sand detection sensor							2.2023	3.1145		11.00**
109	Temperature sensor							0.2563	0.1198		11.00**
110	Valve position sensor							4.5779	4.7561		11.00**
	Subsea control module										
111	Accumulator - subsea							2.4156	2.7680		7.00
112	Chemical injection coupling							1.4074	1.8459		12.00
113	Filter							0.0745	0.1054		7.00**
114	Hydraulic coupling							0.0587	0.0768		12.00
115	Module base plate							0.1100	0.1555		7.00**
116	Other							20.3726	1.8064		24.00
117	Power supply unit							0.2674	0.3781		7.00**
118	Power/signal coupler							0.1587	0.2501		12.00
119	Soleinod control valve							1.1628	2.3078		12.00
120	Subsea electronic module							12.7556	25.2314		3.00
121	Unknown							50.9948	20.8190		21.00
	Subsea distribution module										
122	Accumulator - subsea							0.3925	0.5550		24.00
123	Chemical Injection coupling							0.1310	0.1853		24.00**
124	Hydraulic coupling							0.2743	0.3408		3.00
125	Hydraulic/chemical coupling							2.3023	3.2507		16.00
126	Hydraulic/chemical jumper							0.5856	1.0209		104.00
127	Power/signal coupler							7.7878	7.8465		8.00
128	Power/signal jumper							3.4682	6.4322		43.00
129	Unknown							47.1876	47.1876		24.00**
	Equipment unit level Control System	**17**	**287**	**14**	**123**	**150**		**293.2740**	**343.2050**		**9.00**
	Comments	For components with no failures, n is set to 0.5 based on a non-informative prior. * Mean failure for the common components used in the estimator. ** Data assumed, taking the average time to repair of the component.									

4.8.1 Monte Carlo Simulation

Numerical simulations were used for the first time in 1942 at Los Alamos to solve problems that could not be solved by traditional means. Monte Carlo method was invented for Stanislaw Ulam, when he worked in a theory of nuclear chain reaction. Ulam suggested that numerical simulation could be used for the evaluation of complicated mathematical integrals, which can not be solved by conventional techniques. John Von Neumann, Nicholas Metropolis and others continue this work to reach a more formal development of Montecarlo methods.

The basic concept behind Monte Carlo approach is to simulate repeatedly a random process for the variable of interest covering a wide range of possible situations. These variables are a drawn from pre-specified probability distributions that are assumed to be know, including the analytical functions and its parameters[37].

In our study, several situations were created. The first situation generated by running Monte Carlo simulation was the probability of failure, where gamma distribution was employed to generate the failure trend. Then, we can use the probability of failure to define the type of failure. At the same time, the time to repair can be obtained according to the failure class. Finally, by using this random process we can find the time of failure occurrence. These predictions are included into a Process Simulation of Hydrocarbon Production to develop a production forecast in an effective work period.

The **Figure 4.3** shows the created software screen input. A scheme of Monte Carlo simulation methodology is used to explain easily the procedure for the availability modeling. The scheme is shown as follow:

1 Probability of Failure in Subsea Equipment

Call Random (mean failure)

If $\left(\lambda(t) \leq 51\,x10^{-6}\right)$ Then:

Well-1A fails

else

Well-1A works

end if Well-1A works

if Well-1A fails

2 Type of Failure

If $\left(47\,x10^{-6} \leq \lambda(t) \leq 51x10^{-6}\right)$ Then

Fails number 121

else

If $\left(0.16x10^{-6} \leq \lambda(t) \leq 0.18x10^{-6}\right)$ Then

Fails number 4

.
.
.

3 Reparation Time

If Fails number 121 Then

Reparation Time = 21 hours

else

If Fails number 4 Reparation Time = 7 hours

.
.
.

4 Occurrence Failure Time

Call Random (period of planification,n)

Mean Failure $\left(\lambda(t) \; = \; 6\,x10^{-4}\right)$

If n = 1000 hours Then

T fail = 2 day
T fail = 7 day
T fail = 15 day
T fail = 35 day
T fail = 37 day
T fail = 40 day

After introduce all the data in the code, we created software to measure the availability in a stated period of time.

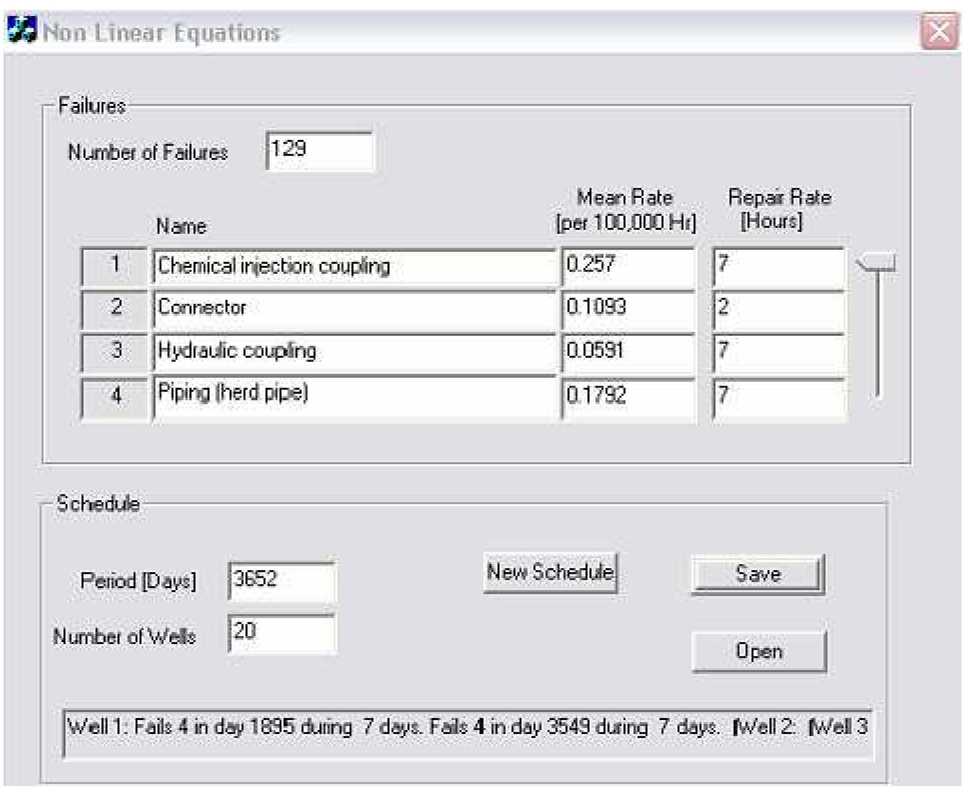

Figure 4.3 Availability software

Disjunctions for well in Production and Shutdown including the availability concept

$$
\overset{\boxed{\text{Production}}}{\begin{bmatrix} Y_{wt} \\ p^{f}_{wt} = p^{in}_{wt} - D_{wt} \\ p^{in}_{wt} - D_{wt} \geq p^{low}_{w} \\ D_{wt} = D_{wt}(q_{wt}, t^{f}_{Pwt}) \\ I_{wt} = 0.0 \\ P^{out}_{wt} = P^{out}_{wt}(p^{f}_{wt}, q) \\ q_{wt} > 0.0 \\ t^{f}_{Pwt} = t^{0}_{Pwt} + T \\ t^{f}_{nPwt} = 0 \\ T^{f}_{R} = 0 \\ T^{f}_{NR} = T^{0}_{NR} + T \end{bmatrix}}
\vee
\overset{\boxed{\text{Shutdown}}}{\left\{ \begin{array}{l} \neg Y_{wt} \\ \left[\begin{bmatrix} Y_{wt2} \\ p^{f}_{wt} = p^{in}_{wt} - I_{wt} \\ p^{in}_{wt} + I_{wt} \leq p^{up}_{w} \\ D_{wt} = 0.0 \\ I_{wt} = I_{wt}(t^{f}_{nPwt}) \\ \\ q_{wt} = 0.0 \\ t^{f}_{Pwt} = 0.0 \\ t^{f}_{nPwt} = t^{0}_{nPwt} + T \end{bmatrix} \vee \begin{bmatrix} Y_{wt3} \\ p^{f}_{wt} = p^{up}_{t} \\ p^{in}_{wt} + I_{wt} > p^{up}_{w} \\ D_{wt} = 0.0 \\ I_{wt} = I_{wt}(t^{f}_{nPwt}) \\ \\ q_{wt} = 0.0 \\ t^{f}_{Pwt} = 0.0 \\ t^{f}_{nPwt} = t^{0}_{nPwt} + T \end{bmatrix} \right] \wedge \left[\overset{\boxed{\text{Fail}}}{\begin{bmatrix} T^{f}_{R} = T^{0}_{R} + T \\ T^{f}_{R} \leq T^{\max}_{R} \end{bmatrix}} \vee \overset{\boxed{\text{No Fail}}}{\begin{bmatrix} T^{f}_{R} = 0 \end{bmatrix}} \right] \end{array} \right\}}
$$

After the availability analysis we can suggest new constrains for the previous program, which are going to include the time repair predicted in the availability software. The new set of disjunction is shown in the above scheme.

Note:

GAP software also has an option to measure the downtime applying Montecarlo simulation, called Open Solver. However, this option does no allow as predicting in detail the downtime, for instance, does not predict the type of failure and the time in which the failure occurs. Also, to use this function is needed the maximum and minimum time to repair and its standard deviation. In our analysis, we infer the time to repair from the probability of failure and also a more complete analysis is performed, taking in account the principal surface equipment.

CHAPTER V

CASE STUDY

One of the tools commonly used to evaluate the optimization of oil/gas production system is the process simulation modeling. This work will use three programs for the process simulation modeling, which are: M-Ball (Reservoir Modeling), Prosper (Well Modeling) and Gap (network system).

After the optimization modeling is completed, we are going to integrate the availability analysis to the above model description. The availability of a system is analyzed by Monte Carlo simulation, which involves the modeling of the probabilities of failure, the type of failure, the time to repair associated with each failure, and time of occurrence for a field system. As a result, a new production planning is accomplished in an effective work period.

5.1 Statement of the Problem

This synthetic case is based on data from a real field development, which was kindly provided by Petroleum Expert. The following data is available:

Table 5.1 Reservoir Data

	Reservoir A	Reservoir B
Reservoir Temperature (T_R)	250 F	180 F
Reservoir Pressure (T_P)	9800 psig	4500 psig
TVD	11000 ft	10000 ft
Permeability (k)	400 mD	80 mD
Oil density	39 API	32 API
Gas density	0.67	0.62
Bubble Point (P_b)	3900 psig	3200 psig
GOR	680 scf/stb	480 scf/stb
Reservoir Thickness (h)	200 ft	200 ft
Oil in Place (N)	650 MMstb	380 MMstb

The distant between the two reservoirs is 15 km and is represented in **Figure 5.1.**

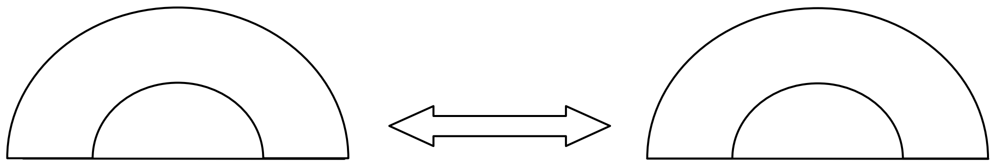

Figure 5.1 Reservoirs scheme

Surface Equipment:

- Use a separator placed between the two reservoirs, which have not constrains on rates.

Economic Data:

- The cost of each well in reservoir A is 1.5 MM$.
- The cost of each well in reservoir A is 1 MM$.
- The price of oil is 25 $/stb.
- The price of gas is 2000 $/MMscf.

The target is optimizing economically the system within 10 years of production life.

5.2 Process Simulation Modeling

5.2.1 Methodology

As was explained previously in Chapter II, the Process Simulation Modeling is a common tool used to optimize and predict the performance of a hydrocarbons field. Process Simulation Modeling is divided into three main sections: the reservoir modeling, well modeling and the network system.

The basic theory related these models were discussed through Chapter II and the methodology that was used to reach some meaningful conclusions about the best optimization alternative, using the current simulation technology, is stated below.

First, a scheme of the tentative production systems will be sketched by GAP. Second, a reservoir model will be built using MBAL. Then, PROSPER will be the tool used to develop the well modeling. Finishing the GAP model will be the next step in the process simulation. After that, a forecasting of the system will be performed for 10 years of production life. Finally, an economic analysis will be achieved to decide the most feasible production option.

5.2.2 Reservoir Modeling (MBAL)

To predict the behavior of the hydrocarbons flow through the porous media, the classical Material Balance Equation is used as an analytical tool. The general options selected to perform the reservoir model are shown in the following:

System Options:

- Reservoir Fluid: Oil.
- Tank Model: Single Tank.
- PVT Model: Simple PVT.
- Production History: By Tank.

Fluid Properties:

- Formation GOR: 680 sfc/STB
- Oil gravity: 39 API
- Gas gravity: 0.67 sp. gravity
- Water salinity: 100000 ppm
- Mole percent H_2S, CO_2 and N_2: 0 percent
- Separator: Single State
- Correlation for Pb, Rs, Bo: Vazquez-Beggs
- Correlation for oil viscosity: Beal et al

The PVT correlations are found after matching the data to get the most approximate solution, as are showed in the **Figures 5.2** and **5.3.** One correlation for Bubble point (Pb), Gas Oil Ratio (GOR or Rs) and Formation Volume Factor (FVF or Bo) is selected, while other correlation is chosen for viscosity.

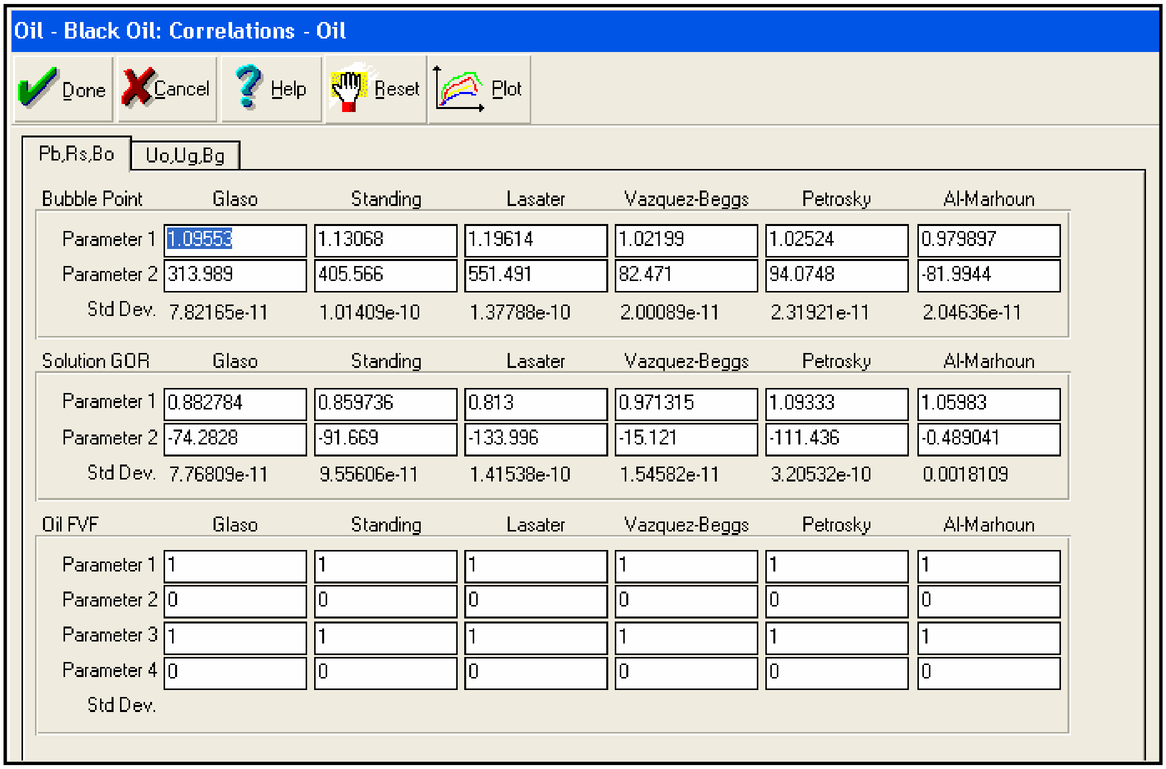

Figure 5.2 Correlation result after matching for Pb, Rs and Bo

A list of match parameters for all the PVT properties for each correlation is reported in these tables. The formation volume factor shows additional parameters, which indicate that Bo has independent behavior below the bubble point, using parameters 1 & 2. Parameters 3 & 4 are employed to match data above the bubble point. In general, the parameter that has a value closer to 1 represents the best correlation. The standard deviation is displayed to shows how well the matching process converges. If the standard deviation is high, the matching is not suitable.

For our Case Study, the best overall fit for Pb, GOR and FVF was obtained by Vazquez-Beggs correlation, while that Beal et al fits best for the oil viscosity. The matched data is plotted and shown in the **Figure 5.4.**

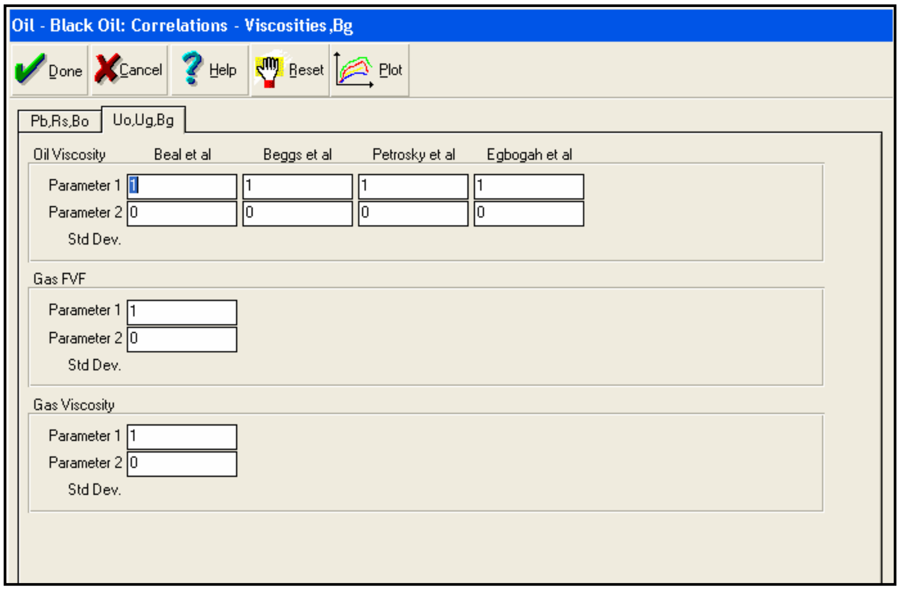

Figure 5.3 Correlation result after matching for viscosities

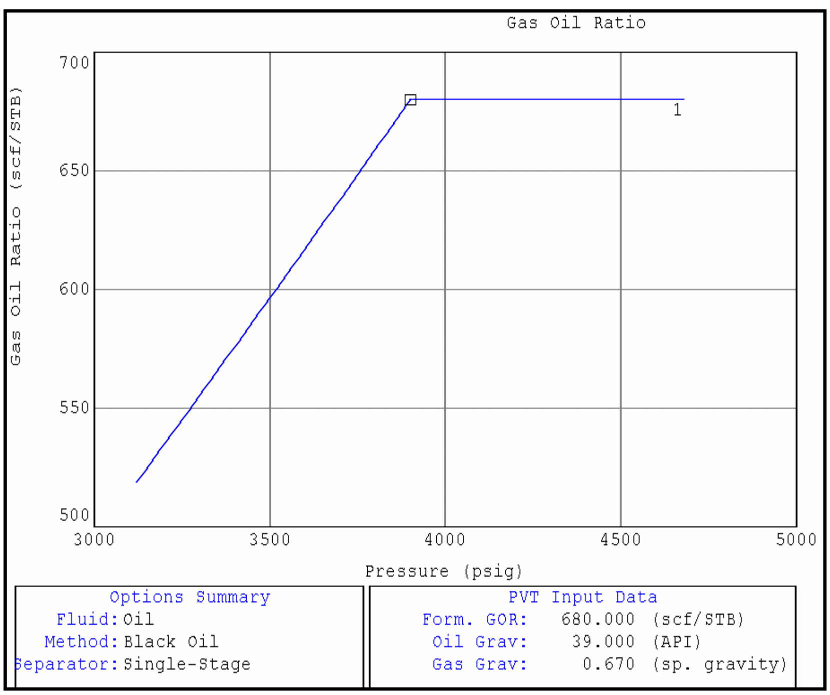

Figure 5.4 The matched data

Tank Parameters:

- Tank Type: Oil
- Temperature: 250 F
- Initial Pressure: 9800 psig
- Porosity: 0.245
- Connate water saturation: 0.15
- Original Oil in Place: 650 MMSTB
- Start production: 01/01/2008

5.2.3 Well Model (Prosper)

Well modeling is an essential tool in production engineering that has as principal objective to maximize the production in an economically feasible way. The well modeling is performed following these options and assumptions:

System Summary

Fluid Description:

- Fluid: Oil and Water.
- Method: Black Oil.
- Separator: Single-Stage.
- Viscosity Model: Newtonian Fluid.

Well Description:

- Flow Type: Tubing Flow.
- Well Type: Offshore Producer.
- Well completion type: Cased Hole.

PVT Input Data

- Solution GOR: 680 sfc/STB
- Oil gravity: 39 API
- Gas gravity: 0.67 sp. gravity

- Water salinity: 100000 ppm
- Mole percent H_2S, CO_2 and N_2: 0 percent
- Correlation for Pb, Rs, Bo: Vazquez-Beggs
- Correlation for oil viscosity: Beal et al

The PVT correlations are found after matching the data, following the same procedure that was explained in the previous section for PVT parameters in the reservoir modeling (MBAL). **Figure 5.5** shows that the best correlation for Pb, GOR and FVF was obtained by Vazquez-Beggs correlation, while that Beal et al fits best for the oil viscosity.

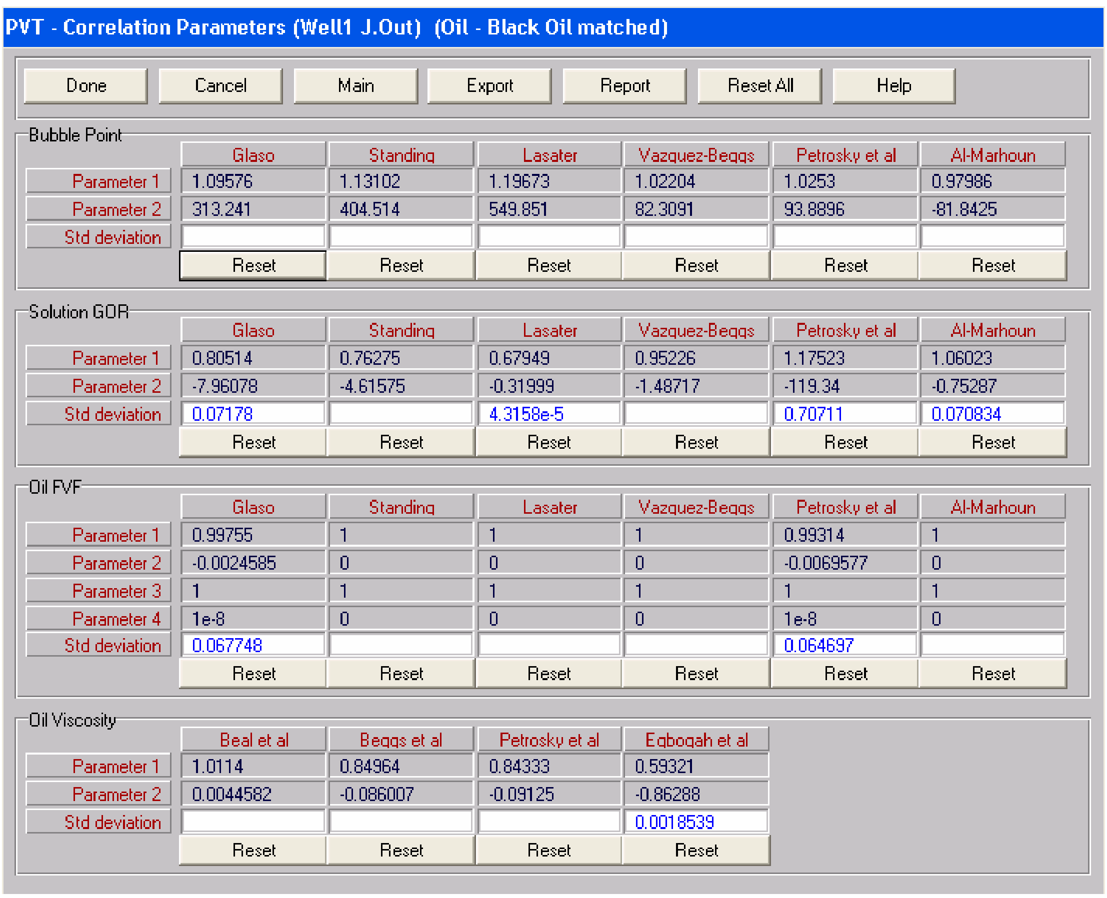

Figure 5.5 Correlations for PVT matched data

<u>Equipment Data</u>

- Deviation survive: Vertical Tubing (11,000 feet)

<u>Dowhole Equipment:</u>

Tubing

- Measured depth: 10,750 feet.
- Tubing inside diameter: 3.96 inches
- Tubing inside roughness: 0.0006 inches.

Casing

- Measured depth: 11,000 feet.
- Tubing inside diameter: 6.00 inches
- Tubing inside roughness: 0.0006 inches.

<u>Geothermal Gradient:</u>

- Overall Heat Transfer Coefficient: 8.00 BTU/h/ft^2/F

<u>Average Heat Capacities:</u>

- Cp Oil: 0.53 BTU/lb/F
- Cp Gas: 0.51 BTU/lb/F
- Cp Water: 1 BTU/lb/F

<u>Inflow Performance</u>

One of the principal parameters to be modeled in the well simulation is Inflow Performance Relationship (IPR), in which Prosper have several options that are available for the well simulation.

For the case study, the model selected was Darcy IPR because this model is used for drainage areas usually bigger than 500 acres, which is the case of the problem stated. Furthermore, Darcy IPR have some advantages compared to others method, such as take into account the skin and Dietz shape factor.

The skin factor was calculated by Karakas & Tariq model, which gives good results, but requires more input data. **Figure 5.6** shows the IPR input screen and the selected methods to perform the analysis.

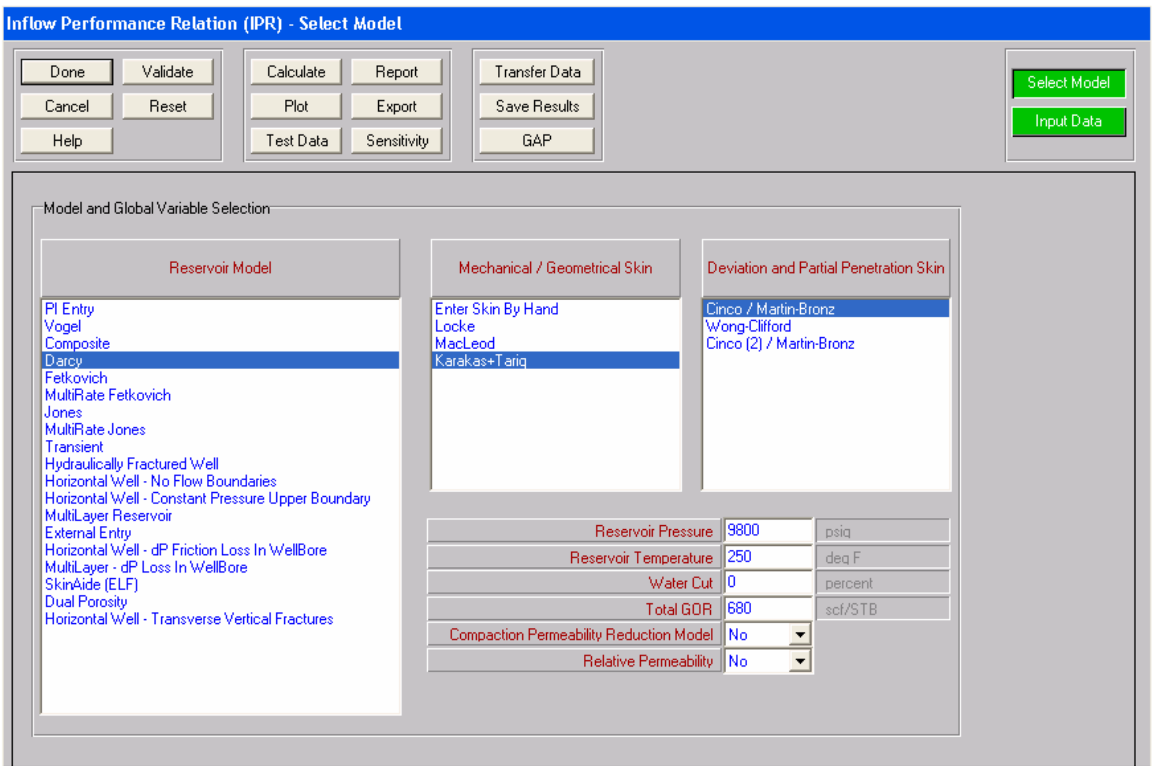

Figure 5.6 IPR input screen

The following data is needed to achieve the Darcy Inflow Performance model:

Reservoir Model

- Reservoir Permeability: 400 md
- Reservoir Thickness: 200 feet
- Drainage area: 500 acres
- Dietz Shape Factor: 30.9972 (Calculated by software)
- Wellbore Radius: 0.354

Mechanical Geometrical Skin

- Reservoir Permeability: 400 md
- Shot density: 12 1/feet
- Perforation diameter: 0.5 inches
- Perforation length: 16 inches
- Perforation efficiency: 1
- Damage zone thickness: 8 inches
- Damage zone permeability: 200 md
- Crushed zone thickness: 0.2 inches
- Damage zone permeability: 100 md
- Shot Phasing: 120 degrees
- Wellbore radius: 0.354 inches
- Vertical permeability: 40 md

Figure 5.7 shows the Inflow Performance Relationship calculated by Darcy model above the bubble point and Vogel solution below the bubble point.

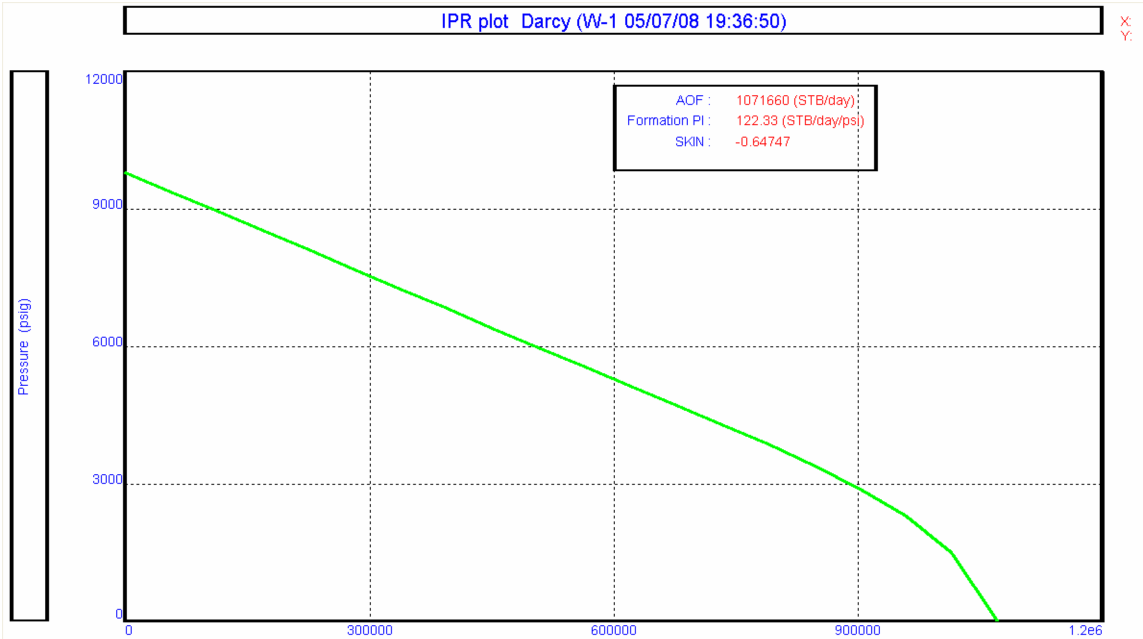

Figure 5.7 Inflow Performance Relationship - Darcy

The IPR obtained for the wells in the reservoir A shown an absolute open flow (AOF) production of 1’071,660 STB/day and a production index of 122.33 STB/day/psi and we can reach the conclusion that our well is stimulated due to the skin result that present a value of -0.65.

The same procedure is followed for the wells in the reservoir B, in which the results were: 37,800.7 STB/day for the AOF production, production index of 11.10 STB/day/psi and skin of -0.65.

For the well simulation, the topside effects are usually included with the tubing performance calculations. Using this computer simulation model a large number of Inflow Performance Relationships (IPR) and Vertical Lift Performance (VLP) can be generated by variation in some parameters. The **Figures 5.8** and **5.9** show the inflow and outflow performance for the wells in reservoir A and B respectively. Five nodes for First Node Pressure and Total GOR were created.

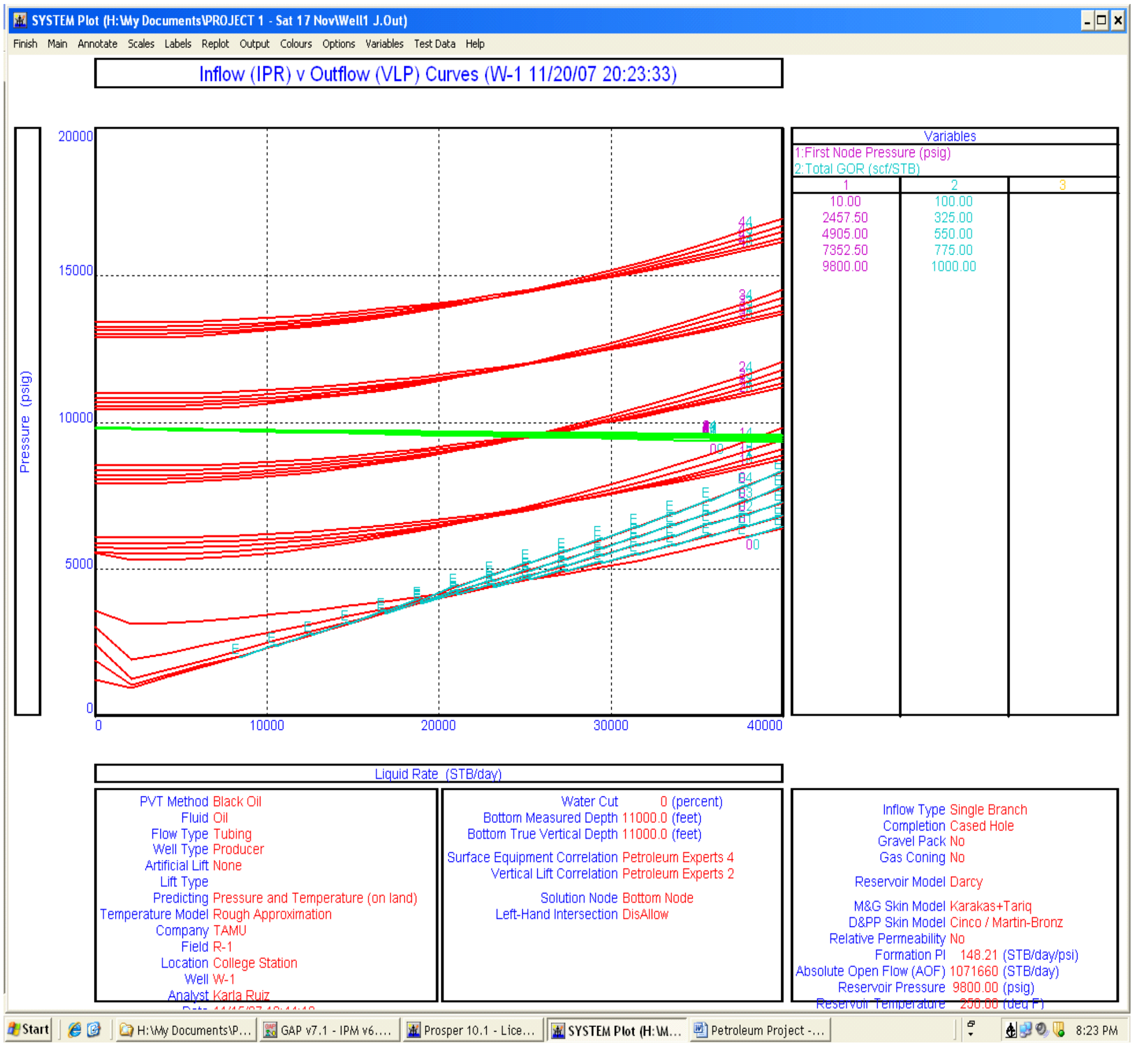

Figure 5.8 Inflow Performance Relationships (IPR) vs. Vertical Lift Performance (VLP) for wells in Reservoir A

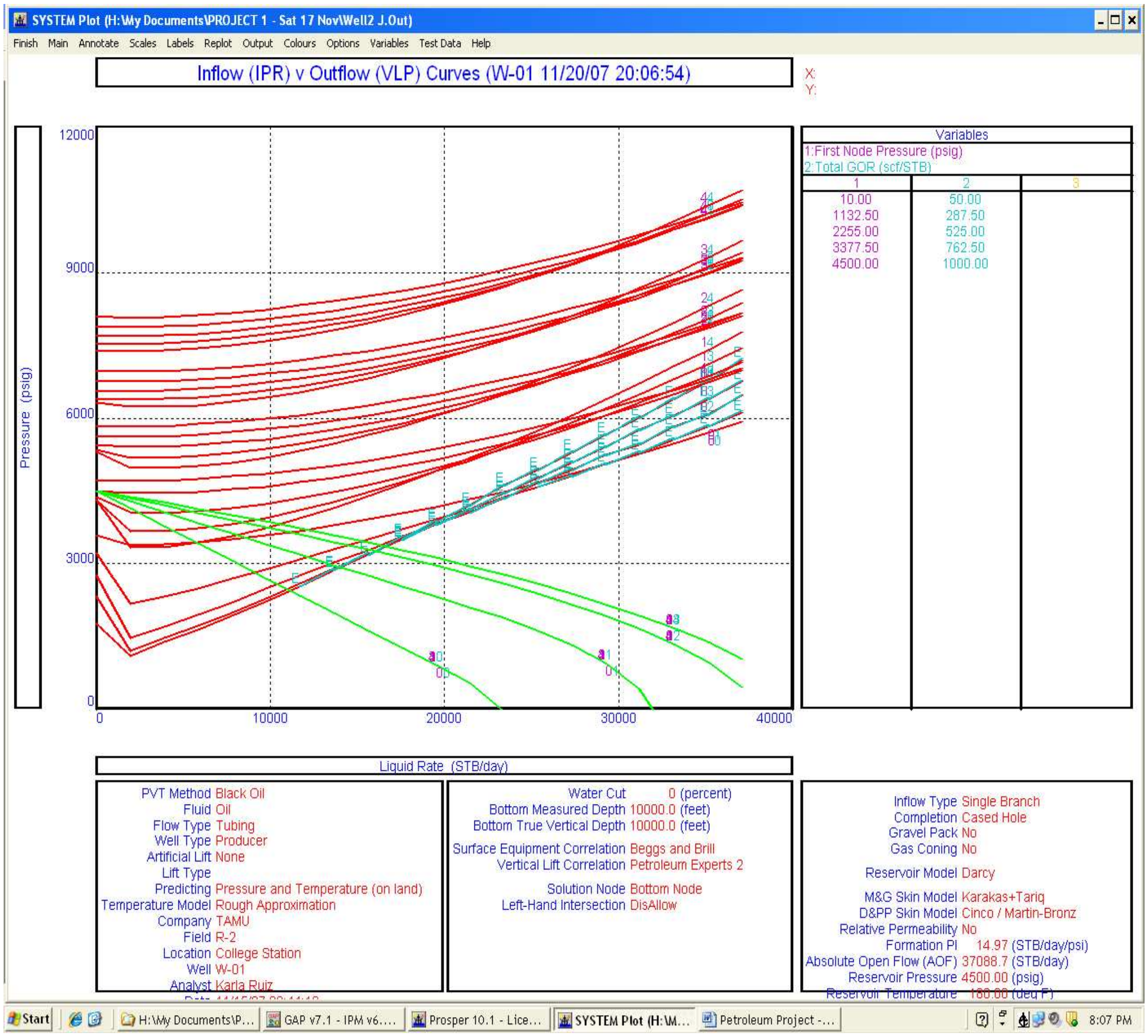

Figure 5.9 Inflow Performance Relationship (IPR) vs. Vertical Lift Performance (VLP) for wells in Reservoir B

5.2.4 Network System (GAP)

A hydrocarbon production system comprises of at least one underground reservoir where several wells have been drilled, conforming a fixed topology network. Flowlines from individual wells are interconnected through a manifold for commingling of fluids from several wells in a single pipeline, transporting the gas or oil to a sale location. The process simulation consists of calculating the total hydrocarbon production for the given production system.

The network system was developed by GAP that connects the reservoir and well modeling with the surfaces facilities. GAP performs the optimization of the system, calculating the maximum cumulative hydrocarbon production for a stated period.

5.2.4.1 Building the GAP Network

The simplest model was built to start the analysis. One well was drilled into each reservoir, A and B to predict the reservoir and well behavior. The wells are interconnected through pipes and manifolds to transport the oil/gas to a separation station and then to a sale location. Once the flow behavior is known, we probed more production alternatives, drilling more wells in each reservoir, depending of the reservoir pressure tendency and the production index predicted.

In this work, a very careful analysis of 30 configurations of hydrocarbon production systems was carry out in order to select the best optimization alternative. We found that the best solution was to produce with 10 well in each reservoir. In the **Table 5.2**, a list of production configuration to optimize the hydrocarbon production is given.

Table 5.2 Production Configuration

Option 1	1 well reservoir A and 0 well reservoir B
Option 2	2 well reservoir A and 0 well reservoir B
Option 3	3 wells in reservoir A and 0 in reservoir B
Option 4	4 wells in reservoir A and 0 in reservoir B
Option 5	0 wells in reservoir A and 1 in reservoir B
Option 6	0 wells in reservoir A and 2 in reservoir B
Option 7	0 wells in reservoir A and 3 in reservoir B
Option 8	0 wells in reservoir A and 4 in reservoir B
Option 9	1 wells in reservoir A and 1 in reservoir B
Option 10	1 wells in reservoir A and 2 in reservoir B
Option 11	1 wells in reservoir A and 3 in reservoir B
Option 12	1 wells in reservoir A and 4 in reservoir B
Option 13	2 wells in reservoir A and 1 in reservoir B
Option 14	2 wells in reservoir A and 2 in reservoir B
Option 15	2 wells in reservoir A and 3 in reservoir B
Option 16	2 wells in reservoir A and 4 in reservoir B
Option 17	3 wells in reservoir A and 1 in reservoir B
Option 18	3 wells in reservoir A and 2 in reservoir B
Option 19	3 wells in reservoir A and 3 in reservoir B
Option 20	3 wells in reservoir A and 4 in reservoir B
Option 21	4 wells in reservoir A and 1 in reservoir B
Option 22	4 wells in reservoir A and 2 in reservoir B
Option 23	4 wells in reservoir A and 3 in reservoir B
Option 24	4 wells in reservoir A and 4 in reservoir B
Option 25	6 wells in reservoir A and 4 in reservoir B
Option 26	10 wells in reservoir A and 10 in reservoir B
Option 27	10 wells in reservoir A and 0 in reservoir B
Option 28	0 wells in reservoir A and 10 in reservoir B
Option 29	10 wells in reservoir A and 8 in reservoir B scheduled
Option 30	10 wells in reservoir A and 10 in reservoir B scheduled

5.2.4.2 Gathering System (Pipelines and Manifolds)

All the connection pipelines and manifolds are carried out using Beggs and Brill correlation. The input data as following:

Pipeline 1

- Length: 15 km
- Inside diameter: 24 inches
- Roughness: 0.0006

Pipeline 2

- Length: 1 km
- Inside diameter: 24 inches
- Roughness: 0.0006

Pipeline 3

- Length: 25 km
- Inside diameter: 36 inches
- Roughness: 0.0006

Separator constrain

- Pressure: 200 psig.

5.2.5 Results

After a detail analysis the best option to optimize the system within 10 years of production life is to drill 10 wells in the reservoir A and another 10 wells in reservoir B, performing an production schedule, which allows us to close the well when the pressure decreases until reaching some point where is not economically feasible to produce. After the well is shutdown, the pressure at the wellbore increases and the well becomes available to produce, extending the well life-time.

The production schedules for reservoir A and B are expressed in **Tables 5.3** and **5.4**, respectively. The optimization model scheme is captured in **Figure 5.10**, getting a cumulative oil production of 186.798 MMSTB and cumulative gas production of 117,258 MMscf, reaching recovery factors of 18.14 % for oil and 34.85 % for gas. These results and its details are shown in **Table 5.5.** Finally, a forecast of the reservoirs behavior for oil production in a period of ten years (1/1/2008 to 1/1/2018) is plotted in **Figure 5.11.**

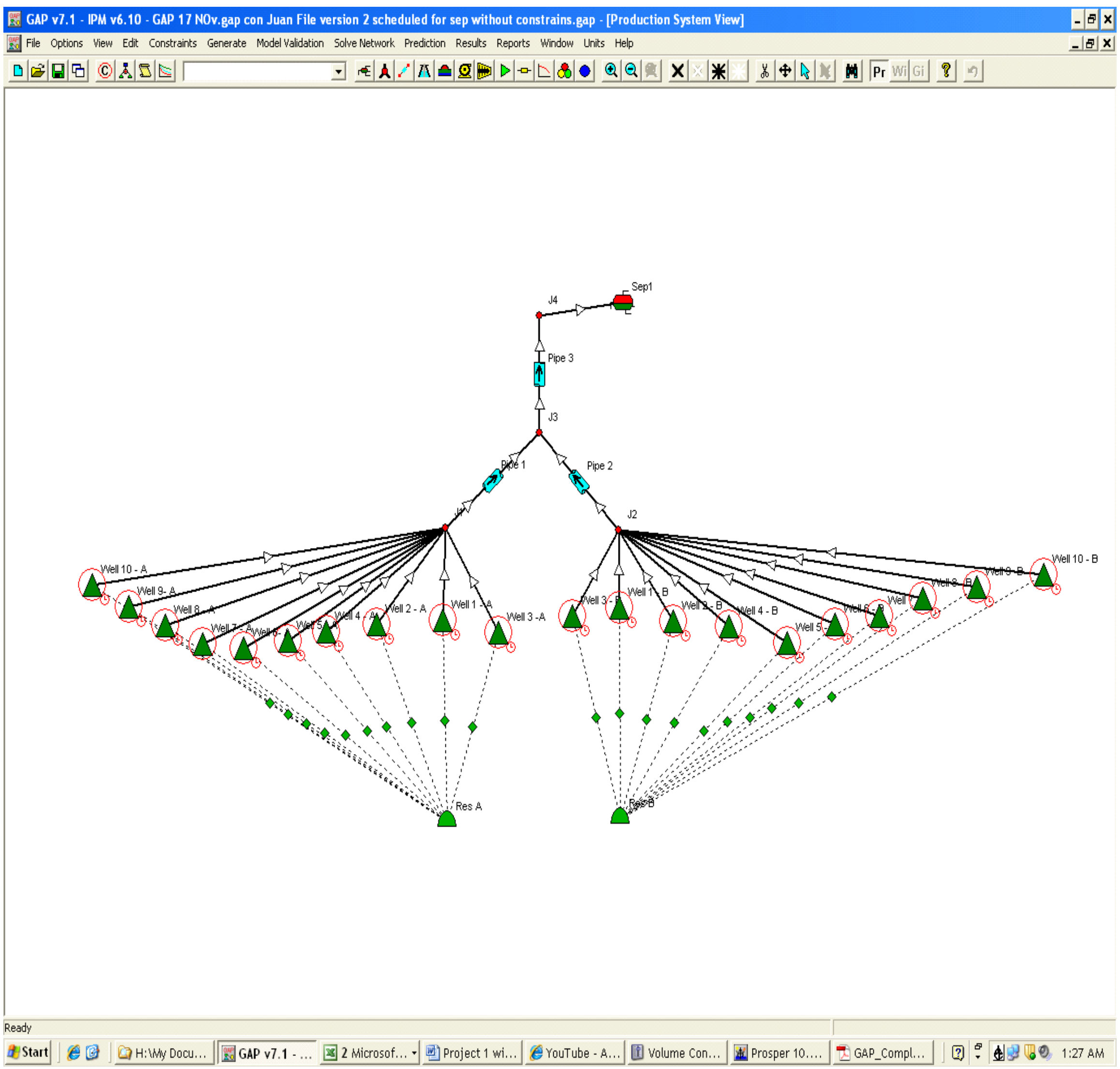

Figure 5.10 Optimization scheme for 10 well in reservoir A and 10 in reservoir B – scheduled

Table 5.3 Schedule for Wells in Reservoir A

Date	Event Type
1/1/2008	Start Well
1/1/2009	Stop Well
1/1/2010	Start Well
1/1/2011	Stop Well
1/1/2012	Start Well
1/1/2013	Stop Well
1/1/2014	Start Well
1/1/2015	Stop Well
1/1/2016	Start Well
1/1/2017	Stop Well

Table 5.4 Schedule for Wells in Reservoir B

Date	Event Type
1/1/2009	Start Well
1/1/2010	Stop Well
1/1/2011	Start Well
1/1/2012	Stop Well
1/1/2013	Start Well
1/1/2014	Stop Well
1/1/2015	Start Well
1/1/2016	Stop Well
1/1/2017	Start Well
1/1/2018	Stop Well

Table 5.5 Cumulative Production, Recovery Factor and Properties After 10 Years

Cumulative Oil Production (MMSTB)	Cumulative Water Production (MMSTB)	Cumulative Gas Production (MMscf)	Oil Recovery Factor (percent)	Gas Recovery Factor (percent)	Oil gravity (API)	Gas gravity (sp. gravity)
186.798	0	117258.6	18.14	34.85	32	0.62

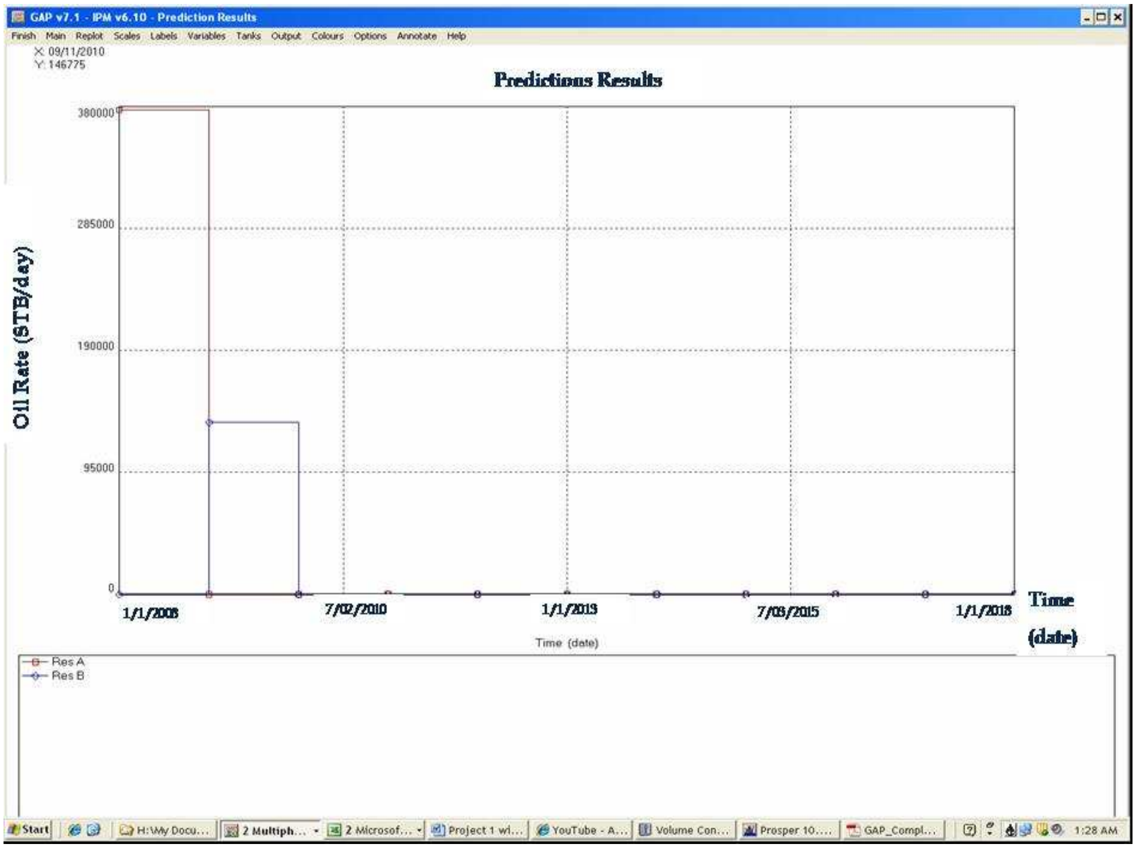

Figure 5.11 Oil rate behavior prediction within ten years for the reservoirs A & B (1/1/2008 to 1/1/2018)

5.2.6 Economic Analysis

To calculate the revenues for 30 options previously studied the following analysis was performed:

Assumptions:

- The money remains constant through the time.
- There is enough market to sell the maximum production of hydrocarbons.
- Taxes are not included in the calculations.
- Prices of separation equipment are not included.

Cost to produce oil ($/stb)	5	**Cost to produce gas ($/MMscf)**	300
Well in Res-1	$1,500,000.00	Oil Price($)	25
Well in Res-2	$1,000,000.00	Gas Price($)	2000
Total Well Cost ($)	$2,500,000.00		

Note: The oil/gas price data correspond to the year 2002, because the only data available related to the production and drilling cost was based on 2002 year. However, the current price of oil/gas is not going to affect our final results. Since, the increase in the petroleum prices favors our revenues.

The results showed that the option 30th, which corresponds to the scheduled production of 10 wells in Reservoir A and 10 wells in Reservoir B is the best optimization option. **Table 5.6** shows the economic analysis developed for the 30 options of hydrocarbon production systems; the best optimization alternative was highlighted.

Table 5.6 Economic Spreadsheet

	Oil Rate (STB/year)	Gas Rate (MMscf/day)	Cost to produce oil ($/stb)	Cost to produce gas ($/MMscf)	Cost to produce Hcs ($/MMscf)	Total Costs ($)	Total Oil Price ($)	Total Gas Price ($)	Total Hcs Price ($)	Revenue
OPTION 1	39812000.00	27071.92	199060000.00	8121576.00	207181576.00	208681576.00	995300000.00	54143840.00	1049443840.00	$840,762,264.00
OPTION 2	46624000.00	31582.99	233120000.00	9474896.70	242594896.70	245594896.70	1165600000.00	63165978.00	1228765978.00	$983,171,081.30
OPTION 3	51041000.00	35116.48	255205000.00	10534943.10	265739943.10	270239943.10	1276025000.00	70232954.00	1346257954.00	$1,076,018,010.90
OPTION 4	55895000.00	38009.43	279475000.00	11402829.90	290877829.90	296877829.90	1397375000.00	76018866.00	1473393866.00	$1,176,516,036.10
OPTION 5	20630000.00	32396.52	103150000.00	9718957.20	112868957.20	113868957.20	515750000.00	64793048.00	580543048.00	$466,674,090.80
OPTION 6	21703000.00	29873.76	108515000.00	8962127.40	117477127.40	119477127.40	542575000.00	59747516.00	602322516.00	$482,845,388.60
OPTION 7	24185000.00	41227.50	120925000.00	12368248.50	133293248.50	136293248.50	604625000.00	82454990.00	687079990.00	$550,786,741.50
OPTION 8	26689000.00	39274.60	133445000.00	11782380.30	145227380.30	149227380.30	667225000.00	78549202.00	745774202.00	$596,546,821.70
OPTION 9	60437000.00	59456.62	302185000.00	17836984.50	320021984.50	322521984.50	1510925000.00	118913230.00	1629838230.00	$1,307,316,245.50
OPTION 10	61500000.00	56892.73	307500000.00	17067817.50	324567817.50	328067817.50	1537500000.00	113785450.00	1651285450.00	$1,323,217,632.50
OPTION 11	63964000.00	68157.14	319820000.00	20447141.70	340267141.70	344767141.70	1599100000.00	136314278.00	1735414278.00	$1,390,647,136.30
OPTION 12	66423000.00	66049.74	332115000.00	19814922.60	351929922.60	357429922.60	1660575000.00	132099484.00	1792674484.00	$1,435,244,561.40
OPTION 13	67243000.00	63956.67	336215000.00	19187000.70	355402000.70	359402000.70	1681075000.00	127913338.00	1808988338.00	$1,449,586,337.30
OPTION 14	68299000.00	61369.85	341495000.00	18410956.20	359905956.20	364905956.20	1707475000.00	122739708.00	1830214708.00	$1,465,308,751.80
OPTION 15	70749000.00	72592.50	353745000.00	21777750.00	375522750.00	381522750.00	1768725000.00	145185000.00	1913910000.00	$1,532,387,250.00
OPTION 16	73135000.00	70345.29	365675000.00	21103586.10	386778586.10	393778586.10	1828375000.00	140690574.00	1969065574.00	$1,575,286,987.90
OPTION 17	71652000.00	67469.53	358260000.00	20240859.90	378500859.90	384000859.90	1791300000.00	134939066.00	1926239066.00	$1,542,238,206.10
OPTION 18	72663000.00	64747.08	363315000.00	19424124.60	382739124.60	389239124.60	1816575000.00	129494164.00	1946069164.00	$1,556,830,039.40
OPTION 19	75118000.00	75981.25	375590000.00	22794375.90	398384375.90	405884375.90	1877950000.00	151962506.00	2029912506.00	$1,624,028,130.10
OPTION 20	77476000.00	73784.53	387380000.00	22135357.80	409515357.80	418015357.80	1936900000.00	147569052.00	2084469052.00	$1,666,453,694.20
OPTION 21	76463000.00	70296.01	382315000.00	21088803.00	403403803.00	410403803.00	1911575000.00	140592020.00	2052167020.00	$1,641,763,217.00
OPTION 22	77440000.00	67515.68	387200000.00	20254703.40	407454703.40	415454703.40	1936000000.00	135031356.00	2071031356.00	$1,655,576,652.60
OPTION 23	79874000.00	78730.52	399370000.00	23619154.50	422989154.50	431989154.50	1996850000.00	157461030.00	2154311030.00	$1,722,321,875.50
OPTION 24	82185000.00	76486.14	410925000.00	22945841.40	433870841.40	443870841.40	2054625000.00	152972276.00	2207597276.00	$1,763,726,434.60
OPTION 25	109645000.00	94848.43	548225000.00	28454528.40	576679528.40	589679528.40	2741125000.00	189696856.00	2930821856.00	$2,341,142,327.60
OPTION 26	182380000.00	114972.75	911900000.00	34491824.40	946391824.40	971391824.40	4559500000.00	229945496.00	4789445496.00	$3,818,053,671.60
OPTION 27	137978000.00	93824.47	689890000.00	28147341.90	718037341.90	733037341.90	3449450000.00	187648946.00	3637098946.00	$2,904,061,604.10
OPTION 28	48955000.00	23498.29	244775000.00	7049486.40	251824486.40	261824486.40	1223875000.00	46996576.00	1270871576.00	$1,009,047,089.60
OPTION 29	160238000.00	111468.56	801190000.00	33440567.70	834630567.70	859630567.70	4005950000.00	222937118.00	4228887118.00	$3,369,256,550.30
OPTION 30	186798000.00	117258.56	933990000.00	35177567.70	969167567.70	994167567.70	4669950000.00	234517118.00	4904467118.00	**$3,910,299,550.30**

From the optimization analysis we can conclude and recommend:

- The analysis showed that the best option to optimize the system within 10 years of production life are the option 30th, which correspond to the scheduled production of 10 wells in Reservoir A and 10 wells in Reservoir B. The production is not sustained within 10 years of productivity life. However, based in the assumption that we made: "market is available for the maximum production", the options 30th is the one that give us maximum revenues.
- The best optimization option gives us profit of proximately 4 billons dollars over 10 years of hydrocarbon system life.
- The function schedule (GAP) allows shutting down the wells in order to recover its pressure, keeping the production for more time.
- Artificial lift techniques, such as, gas lift and pump systems can be incorporated into the simulation program. In this case, we produced a significant amount of gas. Therefore gas lift technique is the most suitable option.

This thesis comprises two main parts: the process simulation modeling and the availability analysis. Until this point, the process simulation modeling has been concluded with the economic evaluation in order to choose the best optimization solution.

The process simulation modeling includes: the reservoir modeling, well modeling and the network system modeling, which are going to enable to perform the first production forecast without includes any availability concepts.

Then, an availability model was created by Montecarlo simulation methodology, which involves the modeling of the probabilities of failure, the type of failure, the time to repair associated with each failure, and time of occurrence for a field system.

The availability model predicts the equipment downtime through production period as a function of the failure rate. The downtime is included in the process modeling in order to get the new production forecasting in an effective work time, reducing significantly the uncertainties due to the equipment failure on a multi-period planning of oil/gas production system.

The result of this analysis is a hydrocarbon production distribution, which is going to be used to accomplish a more certain production planning, having beneficial use in financial risk decisions. **The Figure 5.12** schematizes the methodology employed.

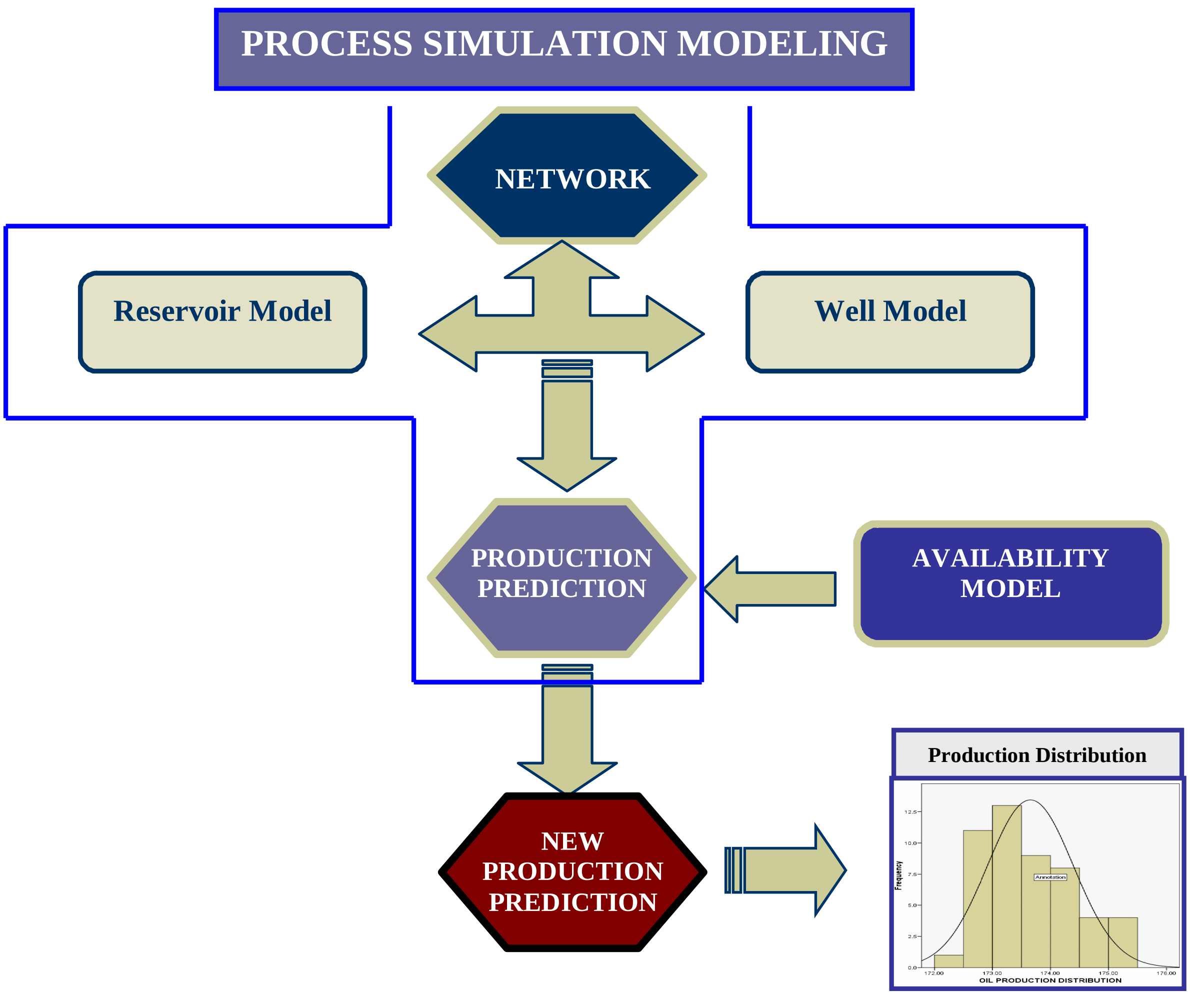

Figure 5.12 Methodology scheme

5.3 Availability Analysis

The availability software was running fifty times in order to reduce the uncertainty in the results. A total of one hundred nine failures from the principal subsea components were taking in account into the analysis.

5.3.1 Availability Model Results

The results that the software obtains predict the downtime for each one of the wells in the reservoir A and B, as well as, the exact time when the failure occurs (See appendix). However, for simplification purposes, we assume that all the failures reported in the 10 wells on the reservoir A are identical. At the same manner, it was assumed that the 10 wells on the reservoir B have the same downtime. The average results are shown in **Table 5.7**.

Table 5.7 Average Downtime for 10 Wells in Reservoirs A and B

	DOWNTIME (%)	
RUN	RESERVOIR A	RESERVOIR B
1	7.37	6.83
2	7.07	6.62
3	8.43	6.12
4	6.44	7.48
5	6.24	6.19
6	6.30	6.27
7	7.77	6.64
8	6.56	7.10
9	6.25	7.30
10	7.64	6.69
11	7.39	6.56
12	6.99	7.48
13	7.34	6.63
14	7.43	7.44
15	6.79	6.47
16	6.41	7.03
17	6.99	7.17
18	7.38	6.95
19	7.39	7.84
20	6.69	6.70
21	5.79	7.00
22	7.39	6.81
23	6.86	7.89
24	6.92	6.60
25	7.17	7.05

	DOWNTIME (%)	
RUN	RESERVOIR A	RESERVOIR B
26	6.89	6.65
27	6.42	6.85
28	6.85	7.30
29	7.06	7.40
30	7.58	6.48
31	7.47	7.39
32	7.17	6.81
33	6.06	6.73
34	7.34	6.98
35	7.59	5.97
36	7.80	6.40
37	6.83	7.79
38	7.73	6.46
39	7.58	6.94
40	6.84	6.80
41	8.06	6.34
42	6.80	7.39
43	6.45	6.32
44	7.14	8.44
45	6.57	7.03
46	7.23	6.85
47	7.10	7.17
48	7.23	7.17
49	7.52	6.33
50	7.80	7.30

5.3.2 Production Results

After the availability analysis was developed, we can include the downtime into the hydrocarbon process simulation modeling to get the new production values in an effective work time. **Tables 5.8** show the cumulative production that was obtained after including the availability model. The mean cumulative production is 173.654 millions of standard barrels (MMSTB) of oil with a standard deviation of 0.734 MMSTB.

Table 5.8 Cumulative Production

	CUMULATIVE PRODUCTION			CUMULATIVE PRODUCTION	
RUN	**OIL (MMSTB)**	**GAS (MMscf)**	**RUN**	**OIL (MMSTB)**	**GAS (MMscf)**
1	173.30	108743.33	**27**	174.60	109629.98
2	173.81	109074.02	**28**	173.78	109121.08
3	172.18	107915.17	**29**	173.45	108900.62
4	174.26	109463.58	**30**	173.18	108628.32
5	175.17	109953.53	**31**	172.88	108518.28
6	175.05	109878.49	**32**	173.58	108935.67
7	172.84	108412.56	**33**	175.15	109995.87
8	174.28	109440.04	**34**	173.41	108738.45
9	174.61	109684.03	**35**	172.91	108440.65
10	172.99	108522.81	**36**	173.57	109025.02
11	173.40	108787.84	**37**	173.57	109025.02
12	173.50	108947.55	**38**	172.98	108492.27
13	173.43	108818.35	**39**	172.95	108520.52
14	172.92	108544.09	**40**	174.04	109247.63
15	174.27	109371.88	**41**	172.58	108210.77
16	174.52	109597.18	**42**	173.81	109146.90
17	173.65	109020.19	**43**	174.81	109726.03
18	173.22	108705.83	**44**	172.83	108581.84
19	172.78	108487.89	**45**	174.30	109447.06
20	174.30	109411.81	**46**	173.48	108870.00
21	175.39	110185.93	**47**	173.50	108916.98
22	173.28	108729.26	**48**	173.32	108795.01
23	173.48	108973.44	**49**	173.33	108719.77
24	174.03	109219.44	**50**	172.52	108252.48
25	173.46	108879.43	**Mean**	**173.65**	**108997.80**
26	174.05	109235.87	**Std**	**0.73**	

These production values are used to find out the most probable range to produce oil. **Table 5.9** and **Figure 5.13** are the results from the oil production distribution, which shown the trend and the risk areas on the production forecast.

Table 5.9 Oil Production Distribution

Oil Production (MMSTB)	Number of cases	Cases (%)
172-172.5	1	2
172.5 - 173	11	22
173 - 173.5	13	26
173.5 - 174	9	18
174 - 174.5	8	16
174.5 -175	4	8
175 - 175.5	4	8
	50	**100**

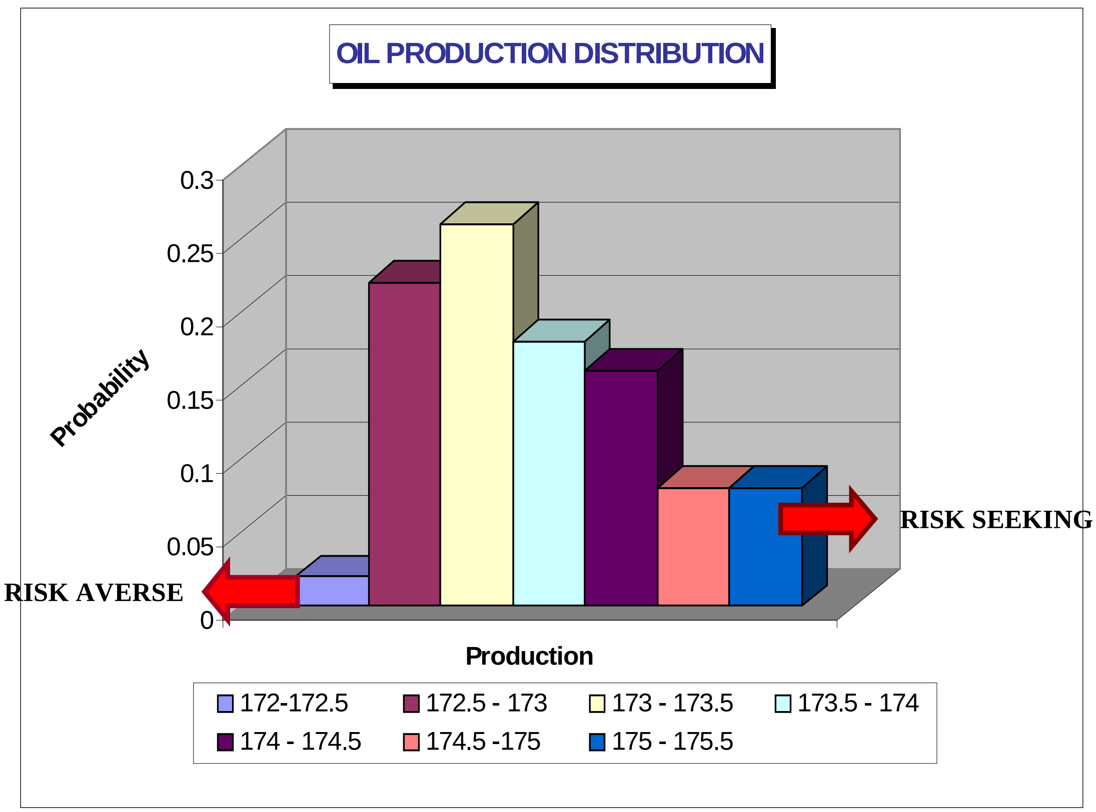

Figure 5.13 Distribution of oil production

CHAPTER VI

CONCLUSIONS AND FUTURE WORK

6.1 Conclusions

A dynamic availability program was performed successfully for a general case study of a hydrocarbon production system. The availability software can run for different configurations and scenarios, without the necessity of performing a tedious Fault Tree Analysis (FTA).

The availability model built reduces significantly the equipment uncertainties in the proposed system, predicting the probability of system failure through its lifetime. As well as, the type of failure, the time to repair and time of occurrence associated with each failure. Thus, this efficient approach will have beneficial use in making financial risk decisions.

I would like to clarify that the current analysis only takes in account the subsea equipment availability. However, there are other sources of uncertainty, such as, geological and financial uncertainties, which have to be included in order to perform an integral analysis. According with previous works, the geological uncertainties vary from 6% to 20 % [7,11,38], depending of the field case study. For instance, for new developments fields the uncertainty is higher than for the existing producing fields.

The case study on the planning of the oil/gas production systems proves that the proposed procedures have a significant effect in the production forecast. The integration of the availability concepts into the current process simulation technology of hydrocarbons field production is an effective solution to perform accurate production predictions. Therefore, it is highly recommend applying this approach in the real life cases to avoid very worrisome, but commons problems originated because of the lack of tools to measure the uncertainties in associated equipments. Using this simple but very useful availability approach, we can avoid huge financial losses due to wrong production hydrocarbon predictions.

From the work presented in this study we can conclude that:

- The availability model allows us to reduce effectively the uncertainties related to the equipment failure in the production prediction. It was found that the cumulative downtime for equipment subsea was around 7%. This result is similar to the total average downtime assumed in the field for petroleum experts, which is in a range of 10 to 30 percent for oil fields and from 5 to 10 percent for gas fields.
- The simulation modeling without taking in account the availability analysis showed that the best option to optimize the system was to drill 10 wells in each reservoir: A and B. The cumulative production was near to 186 MMSTB with a profit of proximately 4 billon dollars within 10 years of production life.
- It was proved that shutting down the wells; when its pressure decreases until some point which is unfeasibly to produce, allow us to recover the reservoir pressure. As a result, the oil production increase and productivity life is kept for a longer time.
- The new production results including the availability study show that the most probable range for the production forecast is 172.5 to 174.5 MMSTB, which differs significantly from the first result, where the availability was excluded.
- The production distribution presented a normal trend and will have a beneficial use in financial risk decisions, at different levels.
- The results obtained for the petroleum forecast after the availability analysis give us a degree of flexibility. Thus, the range in the production prediction that we plan to offer in the supply contract is going to depend on the manager behavior. For instance, a risk seeking person could plan to produce 175.5 MMSTB. On the

other hand, a risk averse individual could predict a production of only 172 MMSTB.

6.2 Future Work Recommended

- Expand the availability analysis to downstream equipment. Since that this analysis is only applicable to the subsea equipment on an offshore production field.
- The availability program could has an automated methodology using the open sever option into Petroleum Experts software. The results of the availability analysis can be used as input, using visual basic programming to automate the simulation, in stead of run multiple simulations manually.
- Use this approach to perform uncertainties analysis in other related areas, such as geological and financial disciplines.
- This technique also can be used for another kind of industries, if enough data is available to do the respective study.
- Perform a second approach of this research, where the downtime will be considered in the exact time when the failure occurs. This approach is going to give more precision on the results.
- As it already probed that the unavailability has a significant importance in the performance of a system. Therefore, develop a maintainability program to improve the availability of the hydrocarbons system will be an accomplishment for the overall project.

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APPENDIX

The program predict the type of failure, time of occurrence and time to repair for the 10 wells in reservoir A and 10 wells in reservoir B respectively. However, we show only one well (well 1) because of the huge amount of output data.

<u>RUN 1 en hours</u>

Well 1:

Fails 2 in day 1932 during 2 days.
Fails 2 in day 3127 during 2 days.
Fails 6 in day 3424 during 7 days.
Fails 7 in day 2353 during 7 days.
Fails 16 in day 1642 during 2 days.
Fails 19 in day 557 during 2 days.
Fails 22 in day 3467 during 36 days.
Fails 23 in day 1508 during 29 days.
Fails 23 in day 3448 during 29 days.
Fails 24 in day 2951 during 29 days.
Fails 25 in day 1345 during 76 days.
Fails 25 in day 1917 during 76 days.
Fails 25 in day 3051 during 76 days.
Fails 25 in day 3339 during 76 days.
Fails 26 in day 1005 during 76 days.
Fails 26 in day 3610 during 76 days.
Fails 27 in day 1803 during 76 days.
Fails 27 in day 3048 during 76 days.
Fails 27 in day 3162 during 76 days.
Fails 27 in day 3385 during 76 days.

Fails 27 in day 3596 during 76 days.

Fails 28 in day 377 during 76 days.

Fails 28 in day 1029 during 76 days.

Fails 28 in day 1678 during 76 days.

Fails 28 in day 2349 during 76 days.

Fails 28 in day 3415 during 76 days.

Fails 29 in day 2274 during 76 days.

Fails 29 in day 2889 during 76 days.

Fails 29 in day 3044 during 76 days.

Fails 29 in day 3189 during 76 days.

Fails 29 in day 3358 during 76 days.

Fails 30 in day 625 during 76 days.

Fails 30 in day 840 during 76 days.

Fails 30 in day 3243 during 76 days.

Fails 30 in day 3641 during 76 days.

Fails 31 in day 2400 during 76 days.

Fails 31 in day 3186 during 76 days.

Fails 31 in day 3636 during 76 days.

Fails 32 in day 1567 during 76 days.

Fails 32 in day 2255 during 76 days.

Fails 32 in day 2644 during 76 days.

Fails 32 in day 3589 during 76 days.

Fails 33 in day 2372 during 76 days.

Fails 33 in day 3424 during 76 days.

Fails 34 in day 2196 during 76 days.

Fails 34 in day 3341 during 76 days.

Fails 35 in day 1471 during 76 days.

Fails 35 in day 2482 during 76 days.

Fails 35 in day 3308 during 76 days.

Fails 36 in day 3247 during 76 days.

Fails 37 in day 240 during 76 days.

Fails 37 in day 566 during 76 days.

Fails 37 in day 2849 during 76 days.

Fails 38 in day 3422 during 40 days.

Fails 39 in day 2484 during 40 days.

Fails 39 in day 2918 during 40 days.

Fails 39 in day 3603 during 40 days.

Fails 40 in day 952 during 40 days.

Fails 40 in day 1300 during 40 days.

Fails 40 in day 2215 during 40 days.

Fails 40 in day 3541 during 40 days.

Fails 41 in day 963 during 40 days.

Fails 41 in day 3001 during 40 days.

Fails 41 in day 3496 during 40 days.

Fails 42 in day 416 during 40 days.

Fails 42 in day 3631 during 40 days.

Fails 43 in day 1470 during 40 days.

Fails 43 in day 3525 during 40 days.

Fails 45 in day 934 during 40 days.

Fails 45 in day 1904 during 40 days.

Fails 45 in day 1992 during 40 days.

Fails 45 in day 2725 during 40 days.

Fails 46 in day 996 during 40 days.

Fails 46 in day 2237 during 40 days.

Fails 46 in day 2371 during 40 days.

Fails 46 in day 3408 during 40 days.

Fails 47 in day 3271 during 36 days.

Fails 48 in day 3587 during 36 days.

Fails 49 in day 192 during 36 days.

Fails 49 in day 1972 during 36 days.

Fails 49 in day 3148 during 36 days.

Fails 49 in day 3629 during 36 days.

Fails 50 in day 1194 during 8 days.

Fails 50 in day 3464 during 8 days.

Fails 52 in day 660 during 7 days.

Fails 52 in day 1770 during 7 days.

Fails 52 in day 2010 during 7 days.

Fails 52 in day 2030 during 7 days.

Fails 52 in day 2293 during 7 days.

Fails 52 in day 3245 during 7 days.

Fails 52 in day 3610 during 7 days.

Fails 53 in day 301 during 6 days.

Fails 53 in day 530 during 6 days.

Fails 53 in day 1506 during 6 days.

Fails 54 in day 1873 during 7 days.

Fails 58 in day 1411 during 7 days.

Fails 59 in day 1854 during 7 days.

Fails 61 in day 317 during 7 days.

Fails 61 in day 342 during 7 days.

Fails 61 in day 2506 during 7 days.

Fails 61 in day 2829 during 7 days.

Fails 61 in day 3071 during 7 days.

Fails 61 in day 3272 during 7 days.

Fails 64 in day 3640 during 33 days.

Fails 67 in day 148 during 33 days.

Fails 69 in day 850 during 33 days.

Fails 70 in day 2128 during 33 days.

Fails 71 in day 1670 during 17 days.

Fails 71 in day 3580 during 17 days.

Fails 72 in day 2067 during 6 days.

Fails 72 in day 2178 during 6 days.

Fails 72 in day 2854 during 6 days.

Fails 72 in day 3364 during 6 days.

Fails 73 in day 3546 during 33 days.

Fails 75 in day 2883 during 35 days.

Fails 75 in day 3408 during 35 days.

Fails 75 in day 3547 during 35 days.

Fails 77 in day 1766 during 33 days.

Fails 77 in day 3016 during 33 days.

Fails 79 in day 3234 during 10 days.

Fails 83 in day 1816 during 7 days.

Fails 87 in day 3533 during 10 days.

Fails 88 in day 1858 during 12 days.

Fails 88 in day 2352 during 12 days.

Fails 88 in day 2816 during 12 days.

Fails 88 in day 3180 during 12 days.

Fails 88 in day 3382 during 12 days.

Fails 89 in day 2339 during 7 days.

Fails 89 in day 3458 during 7 days.

Fails 89 in day 3528 during 7 days.

Fails 90 in day 2934 during 7 days.

Fails 90 in day 3091 during 7 days.

Fails 90 in day 3476 during 7 days.

Fails 91 in day 2954 during 8 days.

Fails 91 in day 3394 during 8 days.

Fails 91 in day 3548 during 8 days.

Fails 91 in day 3641 during 8 days.

Fails 92 in day 1522 during 8 days.

Fails 92 in day 2587 during 8 days.

Fails 92 in day 2674 during 8 days.

Fails 92 in day 3118 during 8 days.

Fails 92 in day 3230 during 8 days.

Fails 92 in day 3295 during 8 days.

Fails 92 in day 3642 during 8 days.

Fails 93 in day 708 during 9 days.

Fails 94 in day 1924 during 9 days.

Fails 95 in day 1145 during 9 days.

Fails 95 in day 1946 during 9 days.

Fails 95 in day 3261 during 9 days.

Fails 96 in day 537 during 9 days.

Fails 96 in day 1996 during 9 days.

Fails 96 in day 2030 during 9 days.

Fails 96 in day 3283 during 9 days.

Fails 97 in day 1206 during 9 days.

Fails 97 in day 3584 during 9 days.

Fails 98 in day 2216 during 9 days.

Fails 98 in day 2802 during 9 days.

Fails 98 in day 3025 during 9 days.

Fails 98 in day 3487 during 9 days.

Fails 100 in day 3259 during 24 days.

Fails 101 in day 1690 during 24 days.

Fails 102 in day 2876 during 50 days.

Fails 104 in day 219 during 24 days.

Fails 104 in day 1108 during 24 days.

Fails 104 in day 2023 during 24 days.

Fails 104 in day 2508 during 24 days.

Fails 105 in day 2519 during 12 days.

Fails 105 in day 2801 during 12 days.

Fails 105 in day 3187 during 12 days.

Fails 106 in day 1298 during 11 days.

Fails 107 in day 677 during 12 days.

Fails 107 in day 3460 during 12 days.

Fails 108 in day 1054 during 11 days.

Fails 108 in day 2728 during 11 days.

Fails 110 in day 708 during 11 days.

Fails 110 in day 1074 during 11 days.

Fails 110 in day 2624 during 11 days.

Fails 110 in day 3604 during 11 days.

Fails 111 in day 2314 during 7 days.

Fails 111 in day 3315 during 7 days.

Fails 112 in day 1051 during 12 days.

Fails 112 in day 2933 during 12 days.

Fails 116 in day 2531 during 24 days.

Fails 116 in day 2787 during 24 days.

Fails 116 in day 3022 during 24 days.

Fails 116 in day 3261 during 24 days.

Fails 116 in day 3547 during 24 days.

Fails 119 in day 2865 during 12 days.

Fails 120 in day 2991 during 3 days.

Fails 120 in day 3533 during 3 days.

Fails 120 in day 3558 during 3 days.

Fails 120 in day 3582 during 3 days.

Fails 120 in day 3648 during 3 days.

Fails 121 in day 3064 during 21 days.

Fails 121 in day 3381 during 21 days.

Fails 121 in day 3536 during 21 days.

Fails 121 in day 3613 during 21 days.

Fails 122 in day 2758 during 24 days.

Fails 124 in day 1853 during 3 days.

Fails 125 in day 589 during 16 days.

Fails 125 in day 2035 during 16 days.

Fails 126 in day 2634 during 104 days.

Fails 127 in day 3436 during 8 days.

Fails 128 in day 665 during 43 days.

Fails 128 in day 2924 during 43 days.

Fails 128 in day 3260 during 43 days.

Fails 129 in day 681 during 24 days.

Fails 129 in day 2515 during 24 days.

Fails 129 in day 2966 during 24 days.

Fails 129 in day 3522 during 24 days.

Fails 129 in day 3635 during 24 days.

VITA

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