Master Thesis

Optimizing Spacing and Fracture Dimensions for Horizontal Wells in a Tight Carbonate Formation with the Help of Numerical Simulation

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Danksagung / Acknowledgement

Writing this thesis has been a challenging, exciting and outmost educational process which has given me the opportunity to do the practical work of a reservoir simulation engineer.

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Lastly, I would like to take the opportunity to thank my family and fiance. Their unconditional support and love have guided me through each and every step along the way.

Kurzfassung

Es ist heutzutage weithin akzeptiert, dass die Förderung von Kohlenwasserstoffen aus geringpermeablen Lagerstätten vor allem aus geeigneten Hydraulic Fracturing Stimulationen resultiert. Die Herausforderungen, die bei der Bestimmung des optimalen Abstandes von stimulierten Horizontalbohrungen bei Feldesentwicklungen zu beachten sind, müssen angemessen berücksichtigt werden. Trotz der vielfältigen Publikationen von analytischen und numerischen Studien gibt es bisher nur begrenztes Verständnis bezüglich der Leistungsmerkmale sowie der Konnektivität der Lagerstätte zwischen solchen Bohrungen.

Diese Diplomarbeit behandelt die numerische Simulation für ein geringpermeables Karbonatfeld im rumänischen Sektor des Schwarzen Meeres. Mit Hilfe einer statistischen Versuchsplanung werden die Ergebnisse von durchgeführten Interferenztests auf ihre Sensitivitäten in Bezug auf die Abmessungen der Fractures, die Lagerstätteneigenschaften und die Distanz zwischen den Bohrungen untersucht und dokumentiert. Die Verwendung von Antwortflächen-Modellen unterstreicht die Bedeutung der relevanten Sensitivitätsparameter.

Für diese Arbeit werden Softwarepakete von Schlumberger (Petrel, Eclipse) verwendet, um die Vielfalt der Produktionsparameter für das geringpermeable Karbonat-System zu untersuchen und zu interpretieren. Der praktische Teil ist in zwei Unterkapitel unterteilt. Zunächst wird die Implementierung neuer Pilot-Horizontalbohrungen und ihrer jeweiligen Komplettierungen untersucht, um das Modell anzupassen, indem die lokale Gitterverfeinerung innerhalb eines Sektormodells verwendet wird. Danach werden Proxy-Modelle für das finale ökonomische Modell konstruiert, um die optimalen Lagerstätten- und Komplettierungsmerkmale für einen maximalen Ausbeutegrad zu erhalten.

Keywords: Karbonat ; Hydraulic Fracturing ; Numerische Simulation ; Proxy-Modelle

Abstract

It is commonly acceptable today that the development of hydrocarbons from low-permeability reservoirs benefits mostly from suitable hydraulic fracturing. Adequate consideration must be given to the challenges met in the determination of the optimum spacing of fractured horizontal wells during field applications. Despite the multiple publications of analytical and numerical studies, there is limited consensus regarding the performance characteristics and the connectivity of the reservoir between such wells.

This thesis presents a numerical simulation for a tight carbonate field located in the Romanian sector of the Black Sea. By the use of a Design of Experiments, sensitivities of the results related to the fracture dimensions, reservoir properties and well spacing are observed from the simulation runs and documented. Using response surface models based on the final analysis can demonstrate the importance of the relative sensitivity parameters.

For this work, software packages from Schlumberger (Petrel, Eclipse) are used to investigate and interpret the variety of production features pertinent to the tight oil carbonate system. The case study is subdivided in two parts. Initially, the creation of new pilot horizontal wells and their respective completion was needed to match the model, by use of local grid refinement within a sector model. From there, history matching and forecasting scenarios for the up-scaled geological model are needed for flow behaviour and interference observation. Afterwards, proxy models are constructed in regards to a final economical model to showcase the optimum reservoir and completion characteristics needed for the highest recovery efficiency.

Keywords: design of experiments, hydraulic fracturing, numerical simulation, tight carbonate

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Abbreviations

BBL / BOE	Blue Barrels / Barrels of Oil Equivalent
BHA	Bottomhole Assembly
CRS	Custom Coordinate Reference
DOE	Design of Experiments
DLS	Dog Leg Severity
DPI	Discounted Profitability Index
ESP	Electrical Submersible Pump
ETRS89	European-Terrestrial-Reference-System ’89
FRAC/ FRACCING	Fracture / Fracturing
HC	Hydrocarbons
HM	History Match
IRR	Internal Rate of Return
KB	Kelly Bushing
KOP	Kick-Off Point
LGR	Local Grid Refinement
LWD	Logging While Drilling
MAXINC	Maximum Inclination
MD	Measured Depth
MDT	Modular Formation Dynamics Tester
MSL	Mean Sea Level
NFA	No Further Action
NPV	Net Present Value
NTG	Net To Gross ratio
PC	Capillary Pressure
PFS	Surface Facility Platform
PHI – K	Porosity – Permeability relationship
PVT	Pressure-Volume-Temperature Diagram
RF	Recovery Factor
RS	Solution Ratio
SCAL	Special Core Analysis
SLB	Schlumberger
STOIIP	Stock Tank Oil Initially In Place
SW	Water Saturation
T/D	Time / Depth
TDMD	True Depth – Measured Depth
TVDSS	True Vertical Depth Subsea
TWTAuto	Two Way Time – automatic travel
VSP	Vertical Seismic Profile
WACC	Weighted Average Cost of Capital
Z	Depth

Table of content

1 Introduction

1.1 Description of the topic

This thesis has been conducted under the sponsorship and supervision of the OMV and the Montan Leoben University of Austria. The original material (presentations, reports, data sets) that had been offered to me with the intent of guiding in the creation of the thesis had to be renamed and altered under strict company regulations, yet the results still denote the real nature of the field.

When hoping to produce from tight reservoirs, the feasibility of well stimulation via hydraulic fracturing requires in-depth investigation. It is imperative therefore to have a proper understanding of the stress state, rock mechanics, reservoir properties and the geological and operational constraints.

The case study domain is a tight oil carbonate field in the offshore region of Romania, with varying Pc entry from J-function and maximum depth of irreducible HC saturation. The PVT samples were deemed as unrepresentative, but reliable SCAL measurements are available. It had been shown in the past that multiple extended reach horizontal wells were characterized by interference between the fracture stages and flow of liquids would often travel between same-well stages or from one neighboring well to the other.

Consequently, there are two main reasons for this study:

- *Understanding the impact of fracture dimensions and well spacing* – The field license depicts multiple rock types and wedges and my contribution relates to the understanding of the western sector of this field. Prediction of the reservoir and well performance requires numerical simulation, capable of solving more complex problems of optimization. Forecasting is needed for various development scenarios, then economics are calculated from optimizing the spacing and hydraulic fracture properties.

- *Successful field (sector) development* – remaining field potential can be assessed by the use of numerical simulation as well. The production prognosis is not easy to determine through analytical methods, as the flow is dominated by infinite-acting rather than boundary-dominated regimes.

  The current crude oil price is a major constraint and is less likely to lead to a convenient field optimization.

  The technical input however depends on the project's ultimate goal. For an increase in the short-term production, well spacing based on the fracture system is utilized. If the goal is to obtain a higher ultimate recovery, then the spacing should be considered based on the matrix flow network.

1.2 Objectives

Numerical simulation can represent the effects of original matrix permeability, well placement and well stimulation on the flow regime in the tight oil system. The focus is the understanding of the well productivity, reserve estimation and evaluation of economical analysis.

Ergo I base the scope of work on the following objectives:

(1) Analysis of the available field data, specifically the parameters that affect the behaviour of the fractures and liquid flux.
(2) Upscaling of the geological model, then cutting a portion of the field in order to obtain a sector model followed by subsequent local grid refinement (LGR) of the well fractures.
(3) History matching and field development through goal-orientated workflows.
(4) Creation of a surface response model / proxy model based on the results obtained from the simulation runs.
(5) Building and updating an economical model to support the final field development plan.

1.3 Thesis Outline

This thesis is split into six chapters.

Chapter 1 (“*Introduction”*) offers the reader a brief explanation of the problem statement and outlines how the study is organized.

Chapter 2 (“*Literature Review”*) wraps up the literature review and the concepts necessary to understand the published study.

Chapter 3 (“*Field Case Study”*) presents the field application synopsis and the methodology used to solve the problem, while including high-level feasibility scenarios for possible further exploitation.

Chapter 4 (“*Results and Discussion”*) summarizes the important results of the overall investigation and puts into perspective the target of the dissertation.

Chapter 5 (“*Conclusions and Recommendations”*) debates the study results into conclusions and endows recommendations for future work.

Lastly, Chapter 6 (“*References”*) entails the original articles, notes, quotations that were used to enrich the quality of the essay.

2 Literature Review

The aim of literature review is to briefly define the porous media and fluid characterization. Specific reservoir storage and fluid transport mechanisms are reviewed, such as the fractured media, microscale flow and reservoir geomechanics. The physico-chemical aspects of models governing fluid flux in porous media are introduced. These comprise of Darcy's equation and more complex flux mechanisms for multiphase flow. Also this chapter entails brief explanations of analytical and numerical methods and the differences associated with them. For the final review, my project requires pre-phase investments, therefore, several tools (numerical simulation, stochastic techniques) were applied to observe the feasibility analysis. This method can mitigate some of the risks associated with offshore tight reservoir development and uphold higher success of the project.

The investigated field is located offshore, holding conventional hydrocarbons in unconventional reservoirs. Unlike the conventional reservoirs where the hydrocarbons are trapped by overlying rock formations with low permeability, unconventional reservoirs are characterized by low permeability themselves and not always require cap rocks as sealing or trapping features.

Geological characterization and reservoir performance data are required for developing reliable dynamic models. In reservoir simulation, an increased challenge with tight reservoirs is placed upon quantifying the fracture dimensions like fracture porosity, permeability, connectivity, length, spacing, aperture and orientation. For a better investigation, the state and development of the fracture regime combined with cores, logs and production history can successfully lead to prime reservoir simulation results. These output sets of data, in conjunction with the geostatistical methods can be used to generate a meticulous sensitivity analysis of the relationship between the fracture dimensions, reservoir data and fluid flow.

The techniques used to forecast and optimize a field do not stop with the statistical methods, which only infer the possibilities of future outcomes depending on the generated models. The Fiscal Terms and economical state regulations have to be studied as well, in order to decisively construct a Development Scenario that aims to ascertain whether the project is economically feasible.

2.1 Tight Reservoirs

In order to understand how tight reservoirs fair against conventional reservoirs, it is essential to know the proper classification of hydrocarbon resources, depicted in the figure below.

Railsback's *Petroleum Geoscience and Subsurface Geology*

Categories of hydrocarbon accumulations and sources

Category	Hydrocarbon source or process	Prominent examples	Description	Challenges or concerns
Conventional	**Conventional petroleum**	Fields in Middle East and North Sea	Liquid and gaseous hydrocarbons in porous and permeable sedimentary rocks	Seeming scarcity or depth of undiscovered large accumulations
Unconventional petroleum – Conventional hydrocarbons in unconventional reservoirs – Sources dependent on fracking	**Tight oil**	Bakken Formation (Williston Basin, North Dakota); Eagle Ford Shale (Texas)	Liquid and gaseous hydrocarbons liberated from impermeable sedimentary rocks by hydraulic fracturing("fracking")	Cost of fracturing process; air pollution from fracking engines; disposal of wastewater from fracturing; potential contamination of groundwater resources.
Unconventional petroleum – Conventional hydrocarbons in unconventional reservoirs – Sources dependent on fracking	**Shale gas** (Conceptually a subset of tight gas, but usually treated as a separate category)	Marcellus Shale (Appalachian Basin); Barnett Shale (Texas)	Gaseous hydrocarbons (largely methane but locally "wet") liberated from shale (an impermeable sedimentary rock) by hydraulic fracturing	Cost of fracturing process; air pollution from fracking engines; disposal of wastewater from fracturing; potential contamination of groundwater resources.
Unconventional petroleum – Conventional hydrocarbons in unconventional reservoirs – Sources dependent on fracking	**Tight gas**	Austin Chalk (Texas-Louisiana); Niobrara Chalk (Colorado etc.)	Gaseous hydrocarbons (largely methane but locally "wet") liberated from impermeable rocks by hydraulic fracturing ("fracking")	Cost of fracturing process; air pollution from fracking engines; disposal of wastewater from fracturing; potential contamination of groundwater resources.
Unconventional petroleum – Conventional hydrocarbons in unconventional reservoirs	**Coalbed methane**	Powder River Basin (Wyoming)	Methane adsorbed on maceral and fracture surfaces in coal	Drawdown of aquifers; disposal of associated water.
Unconventional petroleum – Unconventional hydrocarbons – Unconventional hydrocarbons in conventional reservoirs	**Tar sands; heavy oil; bitumen; oil sands**	Athabasca (Canada) and Orinoco (Venezuela) sands	Viscous dense petroleum in shallowly buried porous and permeable sands and sandstones	Where mined, economic and environmental costs of mining; great energy required for heating tar to liquid state; water sources and wastewater.
Unconventional petroleum – Unconventional hydrocarbons	**Oil Shale**	Green River Shale (Colorado, and with lesser certainty Utah and Wyoming	Hydrocarbons generated by heating kerogen (pre-petroleum organic matter) in shallowly buried impermeable sedimentary rocks, typically shales.	Economic and environmental costs of mining; energy required for pyrolysis of kerogen; sources of water; impact on air quality.
Unconventional petroleum – Unconventional hydrocarbons	**Coal gasification; coal liquefaction**	"Town gas" of late 1800s to mid 1900s; modern Shanxi Jincheng plant in China; present proposed plants in U.S. etc.	Indirect synthesis of fuels via chemical reaction of coal with steam and O_2, generating H_2, CO, CO_2 and, after further reaction, methane or liquid hydrocarbons	Economic and environmental costs of mining of coal; complexity of chemical processing; water sources and waste water; generation of CO_2, a greenhouse gas.
Unconventional petroleum – Unconventional hydrocarbons	**Methane hydrates; gas hydrates**	Ignik Sikumi gas hydrate field trial (Alaska)	Small hydrocarbon molecules trapped in H_2O frameworks in permafrost or in seafloor sediments and fractures	Uncertainty as to the extent and concentration of deposits, and as to economically viable recovery technologies.

Sources include Keith et al. (2003), Bartis et al. (2005); Meyer et al. (2007), Toman et al. (2008), Collett et al. (2009), U.S. Geological Survey (2009, 2010), Bjørlykke (2010), Energy Information Administration (2010), and National Energy Technology Laboratory (2012). This table was improved by the comments of Dr. David S. Ortiz of the RAND Corporation.

LBR 6/2012 PetroleumCon&Unconventional01.odg

Figure 1: Classification of Hydrocarbon Resources (Georgia, 2012)

There is a clear distinction between the conventional petroleum saturated reservoirs and unconventional petroleum saturated reservoirs (tight reservoirs and unconventional HC-bearing reservoirs). Generally conventional petroleum reservoirs contain hydrocarbon either in liquid or gaseous form in porous medium consisting essentially of sedimentary rocks with adequate porosity and permeability to provide sufficient storage and flow capacity for the fluids to be produced by conventional techniques even under economical conditions. On the other hand, unconventional petroleum reserves are either conventional hydrocarbon reserves in non-conventional porous media, meaning that either the flow capacity or the storage capacity severely limits the production scheme, or such reservoirs that contain hydrocarbon found in a state that significantly differs from the conventional conditions, e.g. highly viscous and dense petroleum and hydrocarbon generated via kerogen heating.

Tight oil, which is the focus of this study, belongs to the family of conventional hydrocarbons in unconventional reservoirs. Tight reservoirs are defined by the following (Georgia, 2012):

- the pore sizes are in micro-Darcy scale;
- the source of hydrocarbons consists of a mother rock from which they migrate until are trapped in the current residing formation;
- stimulation is highly necessary in order for the production to be economical;

– hydraulic fracturing treatment covers a significant part of the overall well costs;
– horizontal wells with multiple fraccing stages may lead to an increase in production;
– the transient flow periods in tight reservoirs may last for many months.

While these tight reservoirs are generally configured with low values of effective permeabilities, developing them could hold even more shortcomings than expected. They are prone to high degrees of damage mechanisms during drilling and well completion, as well as workover and special operations. Low permeability petroleum fields usually have an average pore throat radius very small which would create extraordinary amounts of capillary pressure energy suction. The problem then reflects very high critical water saturation values from imbibed liquid trapped in the capillary pores. Another damage is considered to be the phase trapping when there is an invasion of the liquid and the water saturation is increased around the wellbore. (FAIRHURST, November 2007).

Other than the water distribution in the field, gas distribution differs from the general trend found within conventional plays as well. Due to the different rock properties, rock-fracture interactions and pressure changes, the Gas In Place is determined by the free, adsorbed and the dissolved amount of gas. The free gas is found in both the rock and fracture matrices. The adsorbed gas is the gas which sticks to the organic matter, minerals within the matrix and the fractures. The dissolved gas resides within the reservoir liquids or inside the bitumen due to the saturation pressure being lower than the reservoir pressure.

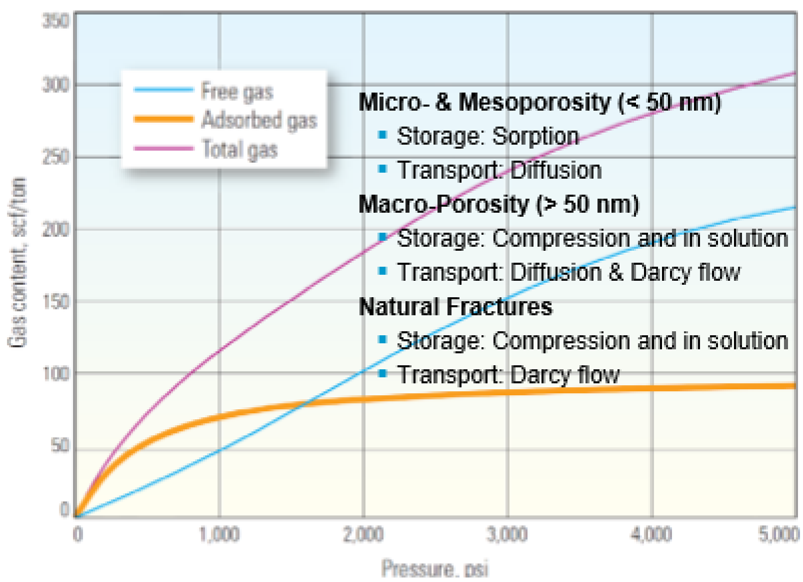


Figure 2: Types of gas residing within a tight trap (Coasne, 2016)

While the free and the dissolved gas are relatively easy to determine from cores, logs or production tests, the adsorbates require a more delicate approach and extremely representative core material. Gas adsorption can also be described either via graphical interpretation (Figure 3) or via mathematical formula.

Gas adsorption can be determined from the Langmuir isotherm, which refers to a rock's matrix ability to adsorb gas at any given temperature. The Langmuir isotherm formula is the following:

$$V = \frac{V_L * p}{p_L + p} \tag{2.1}$$

Where V (scf/ton) is the amount of gas adsorbed at pressure p (psi), while V_L (scf/ton) and p_L (psi) are the Langmuir volume and pressure for a certain gas component. V_L is seen as the maximum adsorption capacity for any given temperature and p_L is a pressure for which the adsorbed quantity of gas is equal to half of V_L.

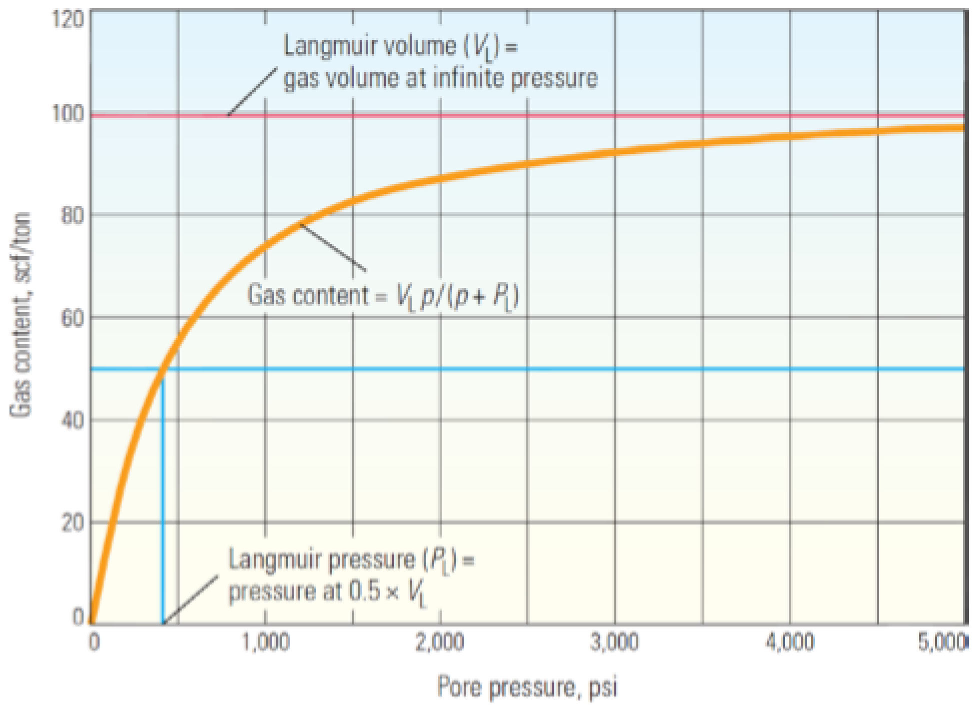


Figure 3: Gas Adsorption Isotherm – graphical interpretation (Coasne, 2016)

For the amount of stored gas, the kerogen content, kerogen type, gas composition, temperature and reservoir pressure are key factors which directly impact all three gas types.

As Langmuir isotherm will measure the total possible gas adsorbed to the organic matter (kerogen), a proper way to estimate the gas adsorption capacity from a rock sample is through either one of the following methods:

- Mercury Porosimetry (measuring the pore throats, would yield lower values than N_2);
- Nitrogen Porosimetry (measuring the pore sizes, depends on the injection pressure).

Due to fluctuations in the mineralogy and lithology, the solutions to fluid dynamics problems in tight reservoirs are explained by different flow mechanisms. Flux in underground geobodies involves mostly convection (diffusion and advection) of the volumetric phases: (Amin GHAREHBAGHI, 2016)

- Advection flux represents the motion of the fluid with a net mean flow. Here, the viscous flow is applied, which relates to the mean free path being small in comparison with the pore scale. The pressure drops are determined mainly by molecular collision. One can differentiate between two types of flow behavior:
  - Darcy Flow: the viscosity of the fluid only depends on the pressure and temperature conditions and is independent of the internal shearing within the fluid.
  - Non-Darcy Flow: such fluids exhibit viscosity that is a strong function of shear rate – meaning that the viscosity of the fluid is either increasing or decreases by increasing shear rate.
- Diffusion flux represents the transport of the fluid with a more chaotic / random behavior. Two separate types of diffusion come into play:
  - Fickian diffusion
  - Knudsen diffusion.

As mentioned, in ultra-low permeability layers the flow transitions from macroscopic regimes (Darcy and Non-Darcy) to microscopic regimes (diffusive and dispersive flow).

A study based on the field's frequency of pore size distribution (Figure 4) determined that the reservoir varies in between 0.1 miliDarcy to 0.1 microDarcy. According to this scale, the flow regime used further in this thesis for simulation purposes has been adjusted to mainly laminar flow (creep flow), which translates into variations of the Darcy's Law.

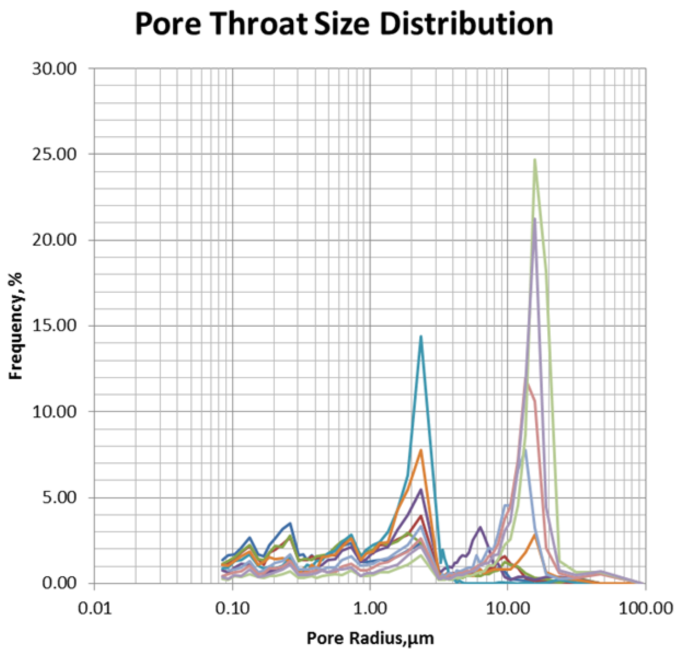


Figure 4: Frequency of the pore sizes of producers from the field's sector of interest

The viscous flow can be Darcy flow or Non-Darcy flow. For low Reynolds numbers (for values much lower than 1 in cases of generally slow, inertia less fluid flow, also known as *creeping* flow), the flow is laminar and Darcy's law can properly describe the flux. The laminar flow (Darcy) equation (Hagoort, 1988) is:

$$v = -\frac{K}{\mu}\nabla p \tag{2.2}$$

At high Reynolds numbers such as during essentially fast, turbulating flow, the Darcy equation is no longer applicable and the Forchheimer's equation is employed (Hagoort, 1988) which considers inertia as well over the conditions applicable to the Darcy equation:

$$-\frac{dp}{dx} = \frac{\mu}{k}v_x + \rho\beta v_x^2 \tag{2.3}$$

For the above equations, p refers to pressure, v represents the flux, k and μ are permeability and viscosity. β is known as the Forchheimer (non-Darcy) coefficient.

Although not part of the prospect of this report, I will review the basic microscopic flow regime characteristics that may be encountered in a tight reservoir.

Equations that describe the microscopic or pore-flow are variations of Navier-Stokes (creeping flow) and of the mass conservation law. (White, 2006)

The equation for Stokes flow, applicable generally for compressible Newtonian fluids:

$$\rho\left(\frac{\partial u}{\partial t} + u\cdot\nabla u\right) = -\nabla p + \nabla\cdot\left(\mu(\nabla u + (\nabla u)^T) - \frac{2}{3}\,\mu(\nabla\cdot u)I\right) + F \tag{2.4}$$

(1) (2) (3) (4)

for which u is the fluid velocity, p is the fluid pressure, ρ is the fluid density and μ is the fluid dynamic viscosity. Different terms correspond to inertial forces (1), pressure forces (2), viscous forces (3) and external forces on the fluid (4).

Navier-Stokes equation is known to govern the fluid flow in microscale. For dynamic modeling, the Navier-Stokes equations are always solved together with the continuity equation, which is known as the conservation of mass:

$$\frac{\partial p}{\partial t} + \nabla\cdot(\rho\, u) = 0 \tag{2.5}$$

Fickian diffusion (pure molecular diffusion) is determined by differences in concentration gradients for which the mean free path of particles is much lower than those of the pores (Figure 5 – left)

Knudsen diffusion follows principles similar to the Fickian diffusion, but the mean free path of particles is much longer than the pore scale (Figure 5 – middle). Collisions of the particles with the walls happen rather frequently. Knudsen diffusion is known to be common for pore sizes that do not exceed 50 nm in range.

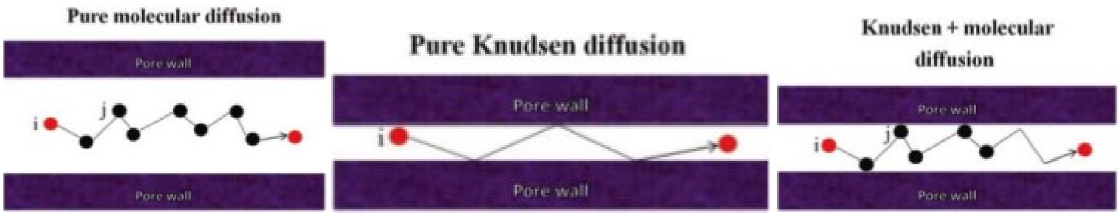


Figure 5: Diffusion Mechanisms (Suwanwarangkul R, 2006)

Knudsen number is a very useful mathematical approach to describe flow regimes. It is dimensionless, defined as the ratio between the molecular mean free path length and a physical characteristic length:

$$k_n = \frac{\lambda}{\mathrm{d}_P} \tag{2.6}$$

Where λ is known as the mean free path length and d_P as the pore diameter.

Slip flow (also known as the Klinkenberg effect) takes place when gas molecules experience slipping at rock surfaces. The equation is the following:

$$K_a = k_\infty \left(1 + \frac{b_K}{p}\right) \tag{2.7}$$

With K_a as apparent permeability, k_∞ as absolute liquid permeability, b_K is the Klinkenberg correction factor and p is the reservoir pressure.

The following figure offers a broad view of the different flow regimes described from the Knudsen number values: the viscous flow regime at Kn<0.001, slip flow regimes for 0.001<Kn<0.1, transition flow regime when 0.1<Kn<10 and Knudsen diffusion (free molecular flow) for values of Kn>10. In the scope of this work, the field of interest is on the continuum scale in the viscous flow regime with Kn<0.001.

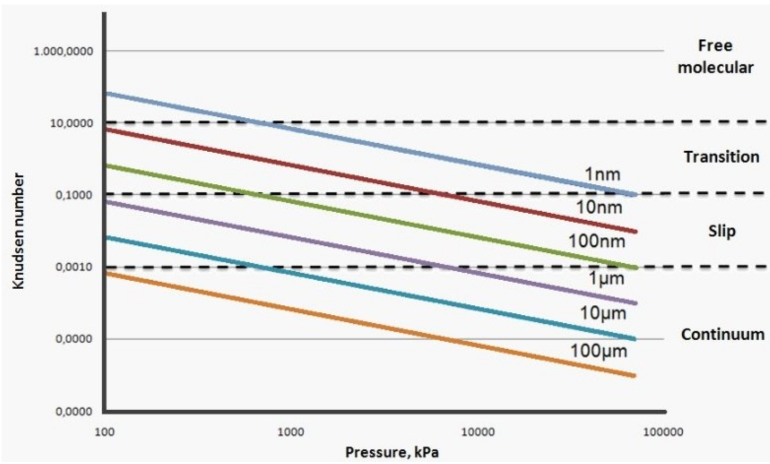


Figure 6: Knudsen number as a function of pressure (constant 360 K) for different pore sizes (Martin, 2016)

2.2 Geomechanics and Consideration of Hydraulic Fracturing

From a geomechanical point of view, a fracture represents the area in which a loss of cohesion has occurred, thus resulting in the rupture of the material. Normally, a fracture represents a discontinuity in the geological units, leading to the tearing of the layers within the geological blocks.

The geological environment has an essential role in the formation and development of fractured reservoirs. There are specifically two fractured reservoir categories of importance (Golf-Racht, 1982):

- Naturally Fractured Reservoirs – fractures have a coherent orientation and regularity, this relation referring to the local characteristics of the structure;
- Artificially Fractured Reservoirs – fractures not attributed to the structure, which include irregular ruptures which show no coherence in orientation.

Fractures can occur in deposits formed by loose rocks with low permeability, which had been affected by various tectonic events that led to the formation of large and very extended fracks, called macro-fractures. However, if the rock is not brittle and has large intergranular porosity, the cracks developed have a limited extension and a rather small opening, so-called micro-fractures or simply, fractures.

A volume of rock under field conditions is in a state of tension caused by geostatic pressure, confining pressure, pressure of fluids present in the pores and sometimes the pressure associated with tectonic forces. In Figure 7, a typical representation of the forces acting on the rock in the three planes is realized. The three vectors indicate the maximum, intermediate and least principal stress: σ1 - the lithostatic pressure; σ2, σ3 - both can be compressive or tensile forces.

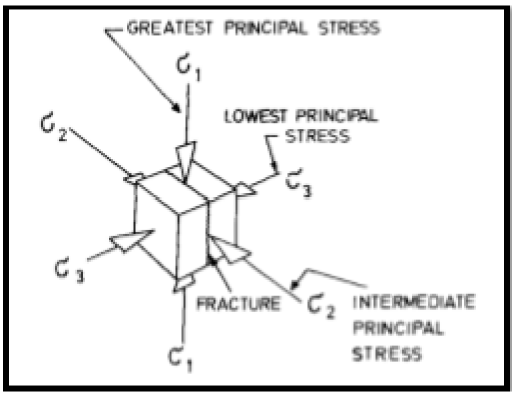


Figure 7: Principal stresses and the fracture planes (Golf-Racht, 1982)

Characterization of fractured fields is in fact much more complex than conventional ones due to spatial variations in crack characteristics. The description of these types of reservoirs begins with the study of simple fractures with a basic characterization, and then the system of fractures that characterize the area of interest must be examined. Parameters of a single fracture refer to intrinsic characteristics, such as its opening, size, nature, and orientation. (Golf-Racht, 1982)

Before we discuss any relevant fracture properties, it should be noted that the field itself does not have any natural fractures due to a rather low to moderate normal fault stress regime. However, all the wells relevant to the study have been hydraulically fractured for the sake of project feasibility resulting in an artificial (induced) fracture system in the vicinity of these wells.

Parameters of a fractured system are defined by the fracture arrangement (geometry). The orientation and number of fractures present in the rock matrix is directly proportional to the distribution and density of the fracks (when the density of the fracks is mainly related to the lithology of the area, a particular parameter, called frack intensity, is introduced). Some of these fracture parameters are discussed below (opening, size, nature, orientation). Out of all of them, the most pertinent for the study are the *fracture size* and *fracture orientation*, which were intensely studied in order for the completion jobs to be accurately simulated. (Wayne Narr, 2006)

Fracture Opening

The opening of cracks (or their width) is actually the distance between the fractured walls and depends on the depth of the layer in which it occurs, the pore pressure and the rock type, with a width variation between 10-400 microns. It also depends on the petro-physico-lithological characteristics of the rock, the nature of rock stress (pressure) and the sedimentary basin. Due to the absence of confinement pressure and pore pressure under laboratory conditions, the width of the frack will be slightly different in the two media (subsurface and surface conditions).

The induced fracture must be of a width large enough to allow the deposition of the proppant and, at the same time, allow for an uninhibited flow of pore fluid after the cracking treatment has been completed. If the proppant is pumped when the crack does not have a fairly large width, it will lead to premature deposition of proppant material and the formation of sand bridges.

Fracture Size

Between the fracture length and the layer thickness there is an inter-dependence relationship so that the frack size can be classified in the following way:

- Minor fracks - Have a smaller length than the net thickness of a single layer;
- Medium fracks - Cross through multiple layers;
- Major fracks - They have a large extension, of tens or hundreds of meters.

The larger the injected fluid volume over time, the larger the crack will be. However, it is necessary to optimize the fracture correctly because uncontrolled propagation in the direction of minimal resistance of the rock can lead to fracture grow in the gas cap or the area of the aquifer, which is not desirable in terms of well productivity.

Fracture Nature

It mainly takes into account the state of fractures and these parameters:

- Fracture Opening – Whether the fracture is open, closed or united;
- Fracture Filling - If the fracture is filled with various minerals;
- Closure - If the fracture is homogeneously closed or filled with diffused filler debris;
- Fissure walls – Depending whether they are rough or smooth.

Fracture Orientation

This parameter is very important because it refers to the connectivity of the unique fractures to the environment. The orientation plane is defined by 2 angles:

- Azimuth angle of the fracture;
- Inclination angle of the fracture.

Hydraulic Fracturing

Hydraulic fracturing stands for the well stimulation method that creates artificial fractures in the reservoir by using hydraulic pressure (Figure 8). The fractures steadily grow in length, height, width by continuously pumping at high-pressure rates the hydraulic fluid mixed with proppants. The propping agents are meant to sustain the openings of the fractures in a way that promotes flow connection between wells and the reservoir. (Golf-Racht, 1982)

The process is simple enough, as the hydraulic pressure overtakes the formation strength, cracks in the rock are created. Due to the heterogeneities encountered, the fracturing fluid could be lost and as a result, the pump rate has to be maintained high enough for the fractures to propagate further inside the reservoir and increase the stimulated rock volume. The proppant is strikingly resistant and keeps the fractures open, enhancing both porosity and absolute permeability leading to high fracture conductivity. Once the proppant volume is in place, the pumping stops and the well is shut-in to allow the matrix elasto-plastic deformation to stabilize. Soon after, a clean-up follows and the production may begin. The fractures are eligible for the new production enhancement.

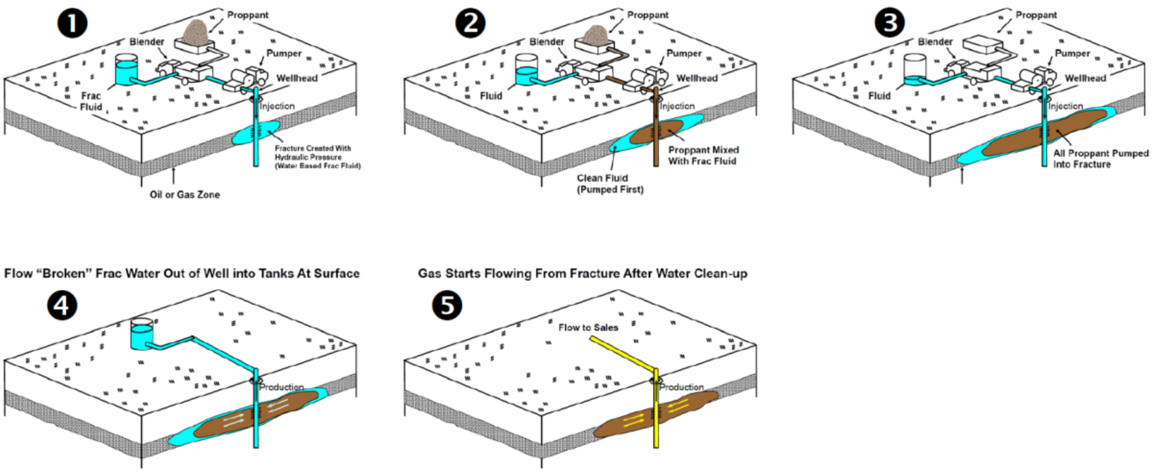


Figure 8: Hydraulic Fracturing Operation (Georgia, 2012)

For the horizontal wells drilled towards the direction of least principal stress (minimum horizontal stress), the cracks align perpendicular to the wellbore. Multiple fracture stages along the horizontal section could in theory promote higher ultimate recovery, but the costs in doing so limit the stage number. (Golf-Racht, 1982)

There are a few vital factors to consider when planning such stimulations. First, there is the in-situ stress regime that highly impacts tensile fractures and breakouts. Also, the location and orientation of the main principal stresses as well as the propagation direction requires delicate consideration for proper effectiveness. Lastly, the junctions created by the fractures are needed for a complex grid of pathways governing the flow as desired. (Golf-Racht, 1982)

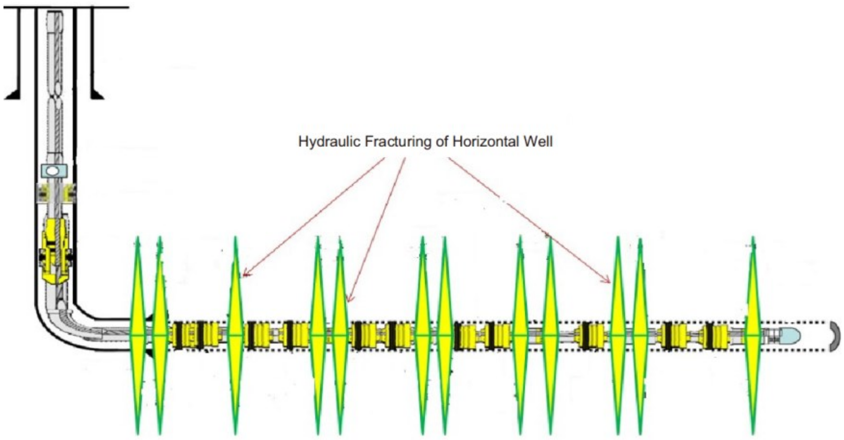


Figure 9: Hydraulic Fracturing - wellbore example (Anon., 2016)

For proper completion, the fracking fluid requires to adhere to specific physico-chemical traits: must be chemically compatible with the underground rocks and fluids, has to keep the proppants in suspension after delivering them into the fractures, requires good transport capacity and easy flush out. (Golf-Racht, 1982)

The fracturing fluid contains approximately 90% water, 9.5% sand and the other 0.5% are chemical additives or common household items (Sodium Chloride, Ethylene Glycol, Borate salts, Sodium Carbonate, Potassium Carbonate, Guar Gum, Isopropanol). This fluid can be of three main types:

– Water based: slick water, HC-based fluid, liquid CO2, methanol-based fluids;
– Water-soluble polymers based: polysaccharides, synthetic polymers, guar;
– Oil based: sodium / aluminum carboxylates, aluminum phosphate.

The usage of additives plays a vital role in the fraccing expertise. *Gelling agents* and *Cross-linkers* are needed to increase the fluid viscosity, while *Breakers* will reduce it. Then there are *clay* and *gel Stabilizers*, *Surfactants*, *Friction Reducers* and even *Biocides* that destroy the remnant bacteria in the injected water.

Hydraulic Fracture Fluids

The role of fracturing fluids is to transmit the required fracturing pressure to the layer needed to be stimulated and to transport the chemical agents into the fractures. By its properties, a cracking fluid must meet the following conditions: (Golf-Racht, 1982)

- good stability to temperature and pressure variations;
- viscosity suitable for carrying the material necessary for holding the open cracks;
- not reacting with minerals in the rocks or with the fluids that saturate these rocks;
- not forming emulsions in the layers;
- possibility to be removed from the layer upon finishing the completion operations.

The most important properties of a fracture fluid are viscosity and filtration. The disadvantage of such fluids is that they require large pumping pressures, because pipe pressure losses are high. More viscous fluids are difficult to remove from the formation, requiring large pressure drops between the layer and the well.

A high filtration fluid favors the deposition of the support material (proppant) even at the fracture entrance. In terms of composition, the cracking fluids can be:

- neutral (water and oil in the form of emulsions or gels)
- acidic (obtained by gelling or emulsifying organic or inorganic acids), normally used for acidic cracking treatments.

Fracture fluids are classified into four categories based on fluid composition:

- Hydrocarbon based
    - viscous oil products (refined oils);
    - lighter petroleum products (diesel oil or lampant);
    - crude oil: simple and thickened;
- Water based
    - gelled water;
    - cross-linked gels;
    - acid solutions for acid cracking;

- Foam based (liquid-gas dispersions)
    - Nitrogen based (N2);
    - carbon dioxide based(CO2);
- Alcohol based

Out of these, the ones mostly implemented in the offshore area for the case study are the neutral crosslinked gels and acid fracturing solutions. In the tight oil reservoir studied in the scope of this thesis, acid fracturing was employed on the new wells, and proppant was chosen as the fracture agent in the already existing wells.

Acid fracturing differs from propped fracturing as it does not need proppant, and fractures remain opened on the Etched Fracture Relief. Applicable for inhomogeneous carbonates like the reservoirs that will be discussed further in the next chapter, acid fracturing was considered to be a proper candidate.

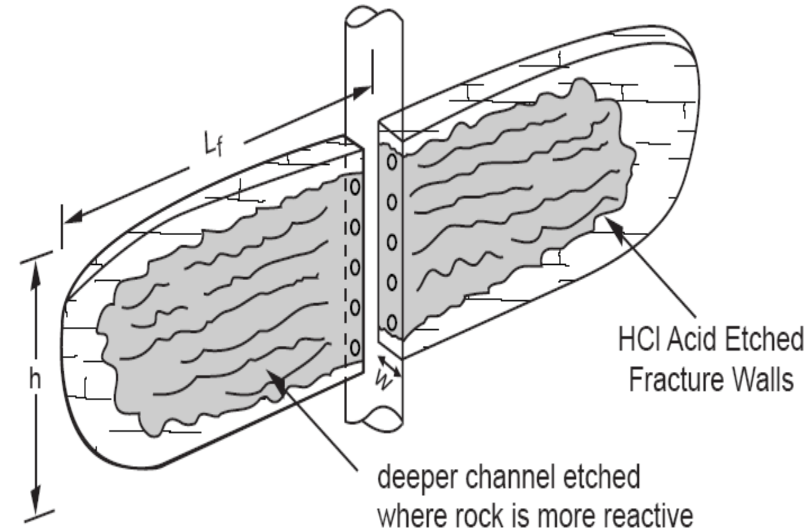


Figure 10: Classic representation of acid - induced fractures in carbonate rocks (Dragomir, 2010)

When acid solubility is higher than 75%, the acid fracturing is considered an option. However, if it is any lower, the propped fracturing will be relevant instead. It's also extremely important that the design engineer of such stimulation jobs understands whether the formation rocks exposed to the acid will release large amounts of fines or not. If the answer is yes, then propped fracturing is the only solution. (Dragomir, 2010)

There are various advantages and disadvantages when designing an acid fracturing job in carbonates: (Dragomir, 2010)

- Advantages
    - Conductivity created by etched fracture is almost infinite;
    - It involves no screenout risk;
    - Rate of success in appropriate conditions is very high;
    - No proppant flow-back problems.

- Disadvantages
  - Highly dependent on rock proprieties;
  - At high temperature is very unlikely to obtain long etched fractures;
  - In most of the cases fractured wells have high starting rate but higher decline comparing with propped fracturing;
  - It needs more severe protective measures;
  - Fluids used are very corrosive;
  - Amount of fluid used offshore are limited by acid amount that can be transported.

Hydraulic Fracturing Proppants

One of the most important steps in designing a fracture operation is the correct choice of the support material. The proppant is used to prevent new crack closure and thus allow fluids to flow from the rock pores. Its purpose is to maximize the conductivity of the induced cracks. The type of material and particle size used have a great influence on the conductivity of the fractures and the penetration of this material inside them. The most used are:

- Sands
- Sands covered with resin
- Intermediate mechanical support materials - heat-treated ceramics
- Synthesized bauxite
- Zirconium-based support materials

Sand was the first support material used in fracking operations. It is mainly used in wells with small shut-off pressures ranging from 150 to 400 bar. Sands are divided into two groups:

1. Excellent sand (premium). This sand complies with API standards, has a density of approximately 2650 kg / m3;
2. Standard sand. This sand is darker, cheaper and more usable.

The resin coated sands have a density of 2550 kg / m3 and a much higher mechanical resistance than conventional sand due to the resin that helps distribute the pressure on a much larger granule surface. When granules are crushed, resin coating helps encapsulate crushed portions and prevents them from migrating and clogging the flow channels, thus preventing permeability reduction.

Intermediate Mechanical Resistance Support Materials (ISPs) are thermally treated ceramic support materials, having a density of 2700 ÷ 3300 kg / m3 and are generally used in wells with closing pressures between 420 bar (when the sand gets destruct) and 700-845 bar (when the intermediate mechanical support gets crushed).

Synthesized Bauxite and Zirconium support materials have a density of 3400 kg / m3 and even higher and are only used for wells with very high closing pressures because they are very expensive.

There are also different advantages and disadvantages when designing a propped fracturing job in carbonates: (Dragomir, 2010)

- Advantages
  - Create conductive fractures not depending by rock solubility;
  - Create longer conductive fractures;
  - Needs less lab research;
  - Fluids are less corrosive.

- Disadvantages
  - Tough carbonates induce big tortuosity;
  - Multiple fracture which are competing for space is a very common phenomenon because they already created;
  - Rock matrix is not very porous and so not very compressible. In many cases is just pure rock;
  - In tough carbonates, screen-out rate is very high.

Proppant Size and Distribution

For the fracture design, it is necessary to consider the size of the proppant granules, this dimension depending on the degree of stress, the conductivity of the formation and the required frack width. The particle size and concentration of the proppant influences its placement within the fracture in several ways:

- Larger particles will be placed in the area near the wellbore due to their higher deposition rate;
- Larger proppant granules lead to easier formation of sand bridges;
- The higher the proppant concentration, the higher the apparent viscosity of the slurry, which increases the width of the fracture and reduces its length;
- Smaller particle sizes are transported over a greater distance, thus increasing the chance of keeping open the crack tip by depositing these particles in that area.

The proppant with the smallest size (80/100) maximizes the crack length and the effectively stimulated volume. In the case of the largest grain (20/40 of a mesh sand), it forms sandbanks in the immediate vicinity of the well, but maximizes average conductivity. The most granular proppant would be the most appropriate choice if it could be transported far enough because it would increase the crack height, and consequently its conductivity.

The choice of supporting materials must be made according to the size of the rock particles in the formation to be treated/stimulated. If the productive formation contains a large percentage of clay minerals and fine particles, which have a strong migration in the support material package, then it is recommended that small-sized support materials resist the invasion of the fine material in the layer. Larger particle sizes of support materials can cause problems in larger depth wells due to high crush susceptibility and placement problems.

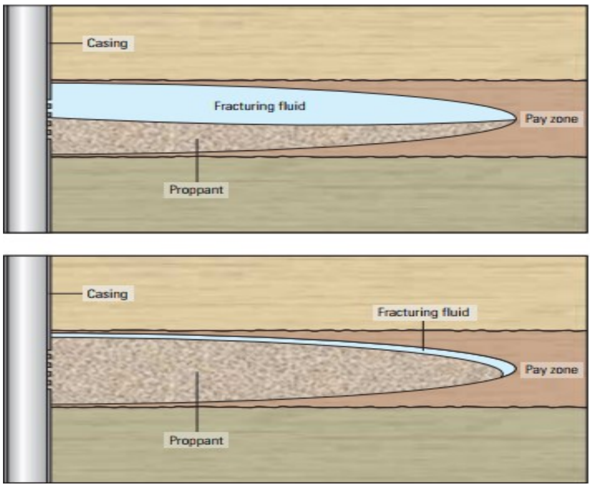


Figure 11: Effect of proppant settling velocity – examples Top and Bottom (Bivins, 2005)

Top Figure: High settling velocities cause proppant to concentrate at the frac bottom before it closes.

Bottom Figure: Low settling velocities promote complete and uniform distribution of the proppant throughout the fracture.

Proppant Form Characteristics

The shape of the proppant granules refers to two characteristics:

- Sphericity of the granule
- Circularity of the granule

Circularity of the granule is a measure of the smoothness of the granule surface. It is recommended that the sand should have a minimum circularity of 0.6, while the ceramic granules should have a minimum value of 0.7.

Sphericity of the granule refers to the way the granule resembles a sphere. The higher the pressure, the higher the granularity of the proppant, the greater the crack-induced permeability. The lower the proppant granularity, the lower the permeability. Always an engineer must bear in mind the pressure, as the angular granule like proppant is crushed at high pressures, generating fine grains which will reduce the conductivity of the crack. The rounding of the support material granules is a property that appreciates the relative sharpness of the corners of the granules or their curvature.

Resistance to crushing

The proppant should be chosen so that the granules do not crush under the action of the natural closing forces. The traditional method of calculating the closing forces is the difference between the minimum horizontal stress and the pressure in the wellbore at the beginning of the production. There have been noted multiple conclusions by Schlumberger and other research-orientated companies:

- As the reservoir pressure drops, the forces on the proppant decrease;
- As the pressure difference occurs, the pressure in the wellbore and the forces on the proppant granules will increase;
- The pressure in the fracture is even greater as its length is greater;
- When a hydraulic crack is created, the in situ pressure must be high enough that it can initiate and propagate the crack. If the support material is not sufficiently resistant to this crack closing pressure, it can be crushed and by increasing the percentage of fine material in the support package the crack permeability is greatly reduced.

Fracture Conductivity

As it had been already mentioned above, crack conductivity is a measure of proppant performance, but it also depends on the width of the crack, the distribution and proppant concentration. The width of the post-stimulation crack is controlled by the size of the proppant used, while its concentration is determined by the spacing, a parameter not readily controllable. The efficiency of crack conductivity is determined by the following:

- The production and migration of fine proppant grains;
- Proppant's inverse (reverse) flow;
- Propagation of the proppant in the rock matrix;
- Multiphase flow;
- Considerations on non-Darcy flow.

Reverse Flow of the Proppant

The higher the pumping speed of the fluid, the greater the likelihood that the proppant will flow back into the well and form sand bridges, thereby reducing productivity, abrasion of well equipment and shut-off of the well for eventual repairs. It would also reduce the conductivity of the fracture and the reservoir.

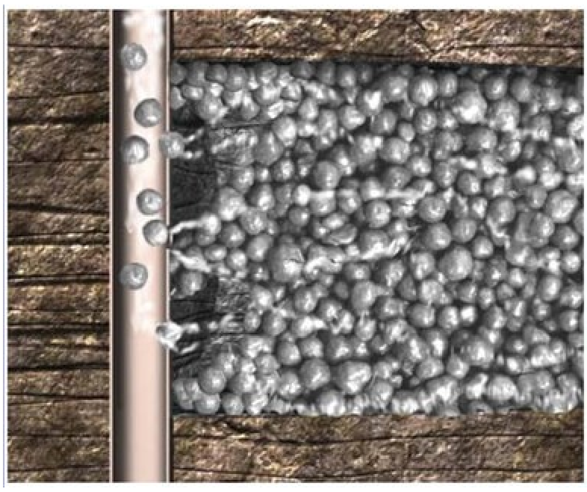


Figure 12: Proppant Flowback from the fracture into the wellbore (Terracina, 2010)

2.3 Modelling of Hydraulic Fractures

Fractured reservoirs are classified based on the basic rock properties of the matrix and fractures (Nelson, 2001) as follows:

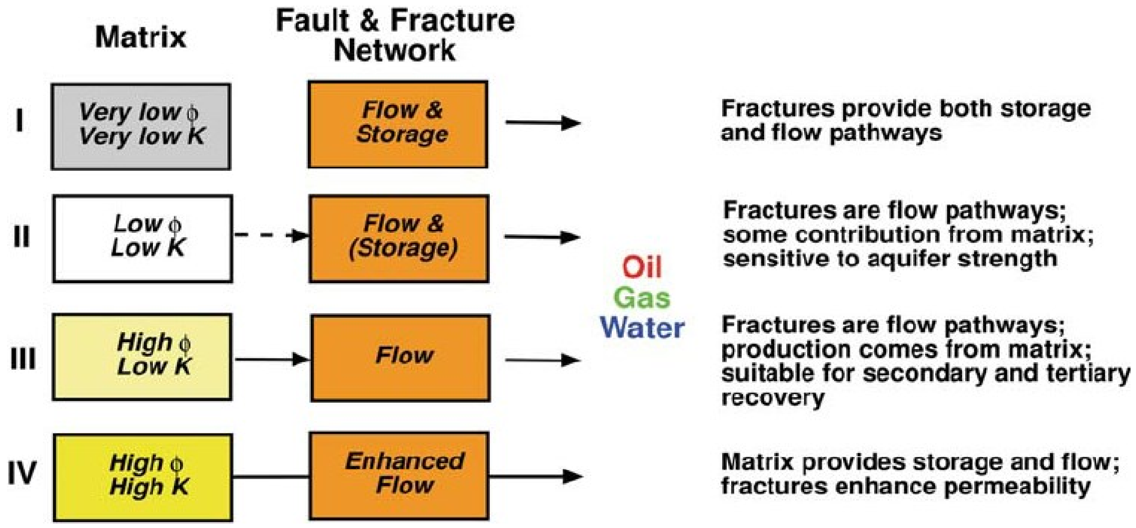


Figure 13: Schematic outline of common subdivision of fractured reservoir types based primarily on matrix character (Nelson, 2001)

Adequate processing of the mechanical rock deformation, fluid flow within the matrix-fractures network and the fraccing development have to be implicitly considered. However, the modelling of such fractures will be established based on the realistic model of the true geometry. The geometrical fracture arrangement, properties and newly developed flow paths will have to be stored in the models to represent the authentic circumstances of the producible reservoir.

In order to model hydraulically fractured reservoir one of the following methods are usually chosen: (Sacramento, 2013)

- Local Grid Refinement (LGR);
- Equivalent Effective Wellbore Radius (negative skin);
- Conductive Fractures (Eclipse E100 / E300);
- Upscaling the results of fine scale simulations;

Local Grid Refinement

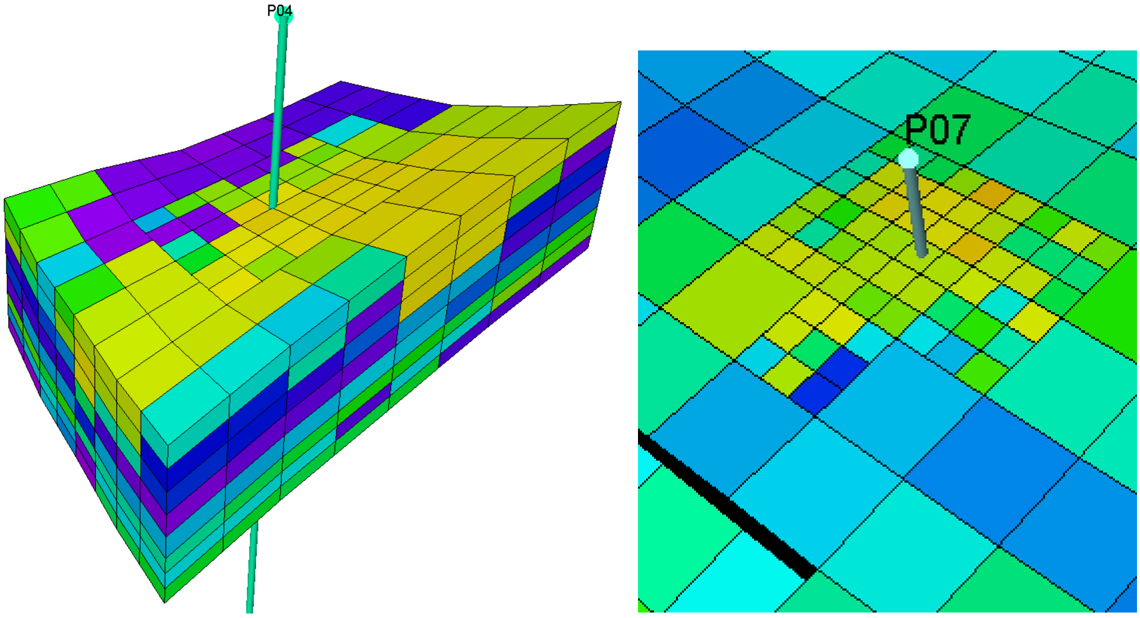


Figure 14: Display View (Side view and Top view) of a LGR modeling around a well (SCHLUMBERGER, 2010)

The LGR technique is employed to refine the cell geometry either around the wells or fractures in order to depict the fluid movement, pressure and saturation more accurate. Furthermore, one may apply additional data to the refined zone, which exclude the need to define complex models capturing all the relevant processes. By only locally attaching increased amount of dataset, it is possible to keep the model simple in the regions which are more out of scope due more stabilized conditions. As a downside, the simulation run time can get quite lengthy and maybe even inefficient, depending on the refinement and the reservoir conditions.

Equivalent Effective Wellbore Radius

In petroleum engineering, the skin factor is a numerical value strongly dependent on the horizontal flow capacity, utilized in the calculation of the Darcy Law to predict pressure and permeability changes.

By adjusting the skin (lowering the skin in this case), productivity of the well is increased in order to match the appropriate stimulation effectiveness. This deceptive maneuver is highly preferred when there is little data on the stresses of the rock columns or only analogue production data of longer periods of time. Figure 15 presents the pressure conditioned modified by the introduction of skin effects in the near wellbore region.

While boosting the simulation time, it is constrained by the effective wellbore radius demanding to be smaller than the pressure equivalent radius of the grid cell. In short, there will be only one grid block governing the induced fracture regime.

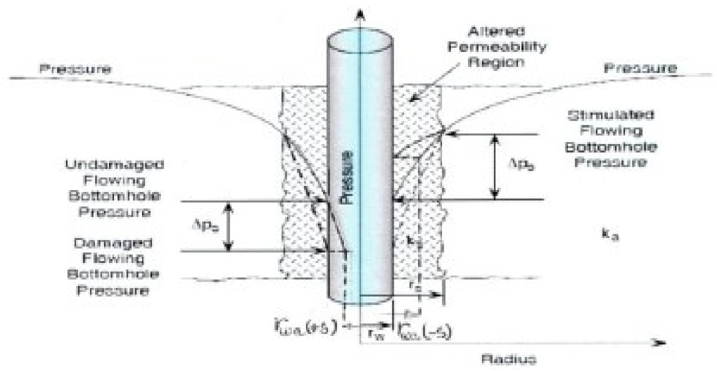


Figure 15: Representation of the skin factor (Sacramento, 2013)

Conductive Fractures

One way to accurately represent the different flow behavior in the matrix system and in the fracture network in a numerical simulator, a Dual Continuum model can be established, meaning that matrix behavior and fracture behavior are characterized each by a set of static data (e.g. matrix porosity vs. fracture porosity, matrix permeability vs. fracture permeability). In such models, conservation equations are solved separately for the fracture and the matrix system as well. However, employing such models increases simulation run time significantly.

Without thoroughly including the simulator properties of Dual Continuum features in the model, there are ways to integrate the effects of fracture conductivity into a single medium model by changing the grid properties. Averaging techniques are used soon after increasing the porosity and permeability of the fractures. Permeabilities are flow-averaged instead of being upstream weighted (as is the case in usual reservoir simulations) using the Darcy Law, while the porosities are increased by proportional volume averaging methods.

This method is effective for large fractures which need more grid blocks to be altered, since short fractures overlap with the rock voidage induced by fraccing.

Upscaling the results of fine scale simulations

In most simulation-enabled petroleum softwares (Petrel, Eclipse) there are built-in options that remodel the productivity index and transmissibilities of the well and near-wellbore area on the coarse grid to establish a prominent replica of the finer scaled model.

The hydraulic fracturing is considered at that point in time when the connections intercepted by the three dimensions of the fracture and the near-wellbore transmissibility multipliers are modified by automatic deduction processes using a patented SLB correlation.

Regularly, the geological models consist of unstructured grids capable of conforming to the subsurface structures and tectonics. The grids are meant to honor the faults exactly. Upgridding and upscaling may or may not preserve the grid structure types used when building the static model. Even so, the coarser flow model needs to be consistent with the observed geological features and also reflect the real flow dynamics.

2.4 Mathematical Solutions for Fractured Wells

The field development in this project work requires a large variance of input values and calculations will be handled by a numerical simulator. There are clear distinctions between the analytical and numerical approaches to solving a problem.

While the analytical approach uses exact theorems and lemmas to offer exact solutions, numerical methods use determined algorithms which offer approximate solutions, within a reasonable tolerance.

As these two approaches are both required to cross check information and results, they serve different purposes. For complex high order partial differential equations, analytical methods sometimes fail to find the solutions and are limited by their inability to coherently break down highly non-linear equations, but they are useful to validate the numerical method. They provide a good high level control on the mechanisms and physical effects. They can be a good estimate for a model that requires understanding of its behavior or circumstances. That may also threaten the results by oversimplifying the solver. Numerical methods work best with iterations by time step control of the solver and can solve complex problems that relate to physics, mechanics or geometry. (Ganzer, 2016)

2.4.1 Analytical Solutions

Out of all the methods described in literature that apply to the up-growth of analytical research on fractured reservoirs, the real basis for analytical applications relates to a proper understanding of the Laplace domain. The flow rate and time have to be transformed in dimensionless time, and the explicit analytical formulas for the rates develop a basic dependency on the dimensionless fracture conductivity. (BROUSSARD, 2013)

Usually, the reservoir in this case is divided into two major volumes of different boundaries. The one closest to the wellbore is stimulated and benefits from a power-law equation bridging together the matrix permeability and the radial distance from the fractures. The outer region remains unstimulated, following the basic input physical laws (standard flow).

What is worth mentioning is that the dimensionless parameters like pressure and rate are solved for implicitly with the Laplace Transform equation, but then are numerically inverted into the real domain at different radius intervals in the reservoir (at the expense of negligible divergences, small deviation errors). Frequently, unstructured grids are used even for the dynamic configurations of complex fractures.

Few major objectives are therefore met when using unstructured grids: preservation of near-wellbore region geology, simulation of relevant flow and transport processes, investigation and analysis of the limits imposed by the resulting flow behaviour and comparison against the standard simulation results.

2.4.2 Numerical Solutions

The practical everyday approach of solving the issues introduced by fracture networks resides within the numerical reservoir modelling. It has been proven to be exceptionally effective for handling simultaneous complex system effects of fracture conductivity, reservoir boundaries, multi-phase and non-Darcy flow effects. (Ganzer, 2016)

While the analytical methods are fast, they assume infinitely large fractures. The numerical solvers can get very tedious, yet they can honour the reservoir and fracture connectivity.

The simulation model layouts are fully three dimensional representations, which should justify the geological and engineering characteristics determined by the initial, current and future changes underground. Initially these must match the static models and the critical properties that affect the induced fractures.

As the tensile failures develop in the rock packages, their basic properties are altered automatically. The single porosity model changes to a double porosity type, as the system becomes a Dual Continuum system. The permeability itself is employed in the realms of cubic law equations as a function of the fracture aperture, width, roughness.

The "transfer functions" help encapsulate fractures in the simulation models using a dual-porosity approach. For this, the key elements required as input are the fracture permeability, the matrix properties and the transfer function selected depending on the case.

Even though the solutions obtained from discretizing have a small order of errors, an even bigger concern may arise from the lack of proper boundary condition understanding. Not knowing how to treat the solutions in the grid boundaries as the time evolution progress would jeopardize the coarse model. There are two types of conditions normally presented in reservoir simulation to describe Darcy velocity or boundary pressure. These are the Dirichlet boundary conditions, when the values of the relevant parameters are enforced at the boundaries of the grid, and Von Neumann type conditions, when the derivative values of the relevant factors remain fixed. (Ganzer, 2016)

Overall, the main reasons for having a simulation of the fractures within the reservoir is because the fluid flow, HC recovery mechanisms, fluids distribution and well test results are different from single-porosity reservoirs. Also the input data holds a larger variety of parameters.

2.5 General Information about Experimental Designs

In petroleum engineering disciplines, data scarcity, invalid or unrepresentative data can lead to a variety of uncertainties. Numerical reservoir solvers are very tedious and when multiple simulation runs are needed to quantify and understand reservoir uncertainty, there is little chance of having a good sensitivity analysis of this sort in time. That is due to business decisions being drastically rushed due to monetary value and since simulations can take too long time to prove their effectiveness, new approaches have been considered.

Being a probabilistic approach (stochastic), the Experimental Design is a very common method used in field development planning, especially in the early field life cycle. It is good for assessing development plan alternatives and estimating recoverable petroleum resources, including the uncertainties that follow them. During an Experimental Design, several parameters are varied simultaneously (unlike the Spider Diagram – economical tool graph in which only one parameter is varied at a time), in a series of experimental runs based on predefined patterns.

The procedure for this stochastic method starts by identifying the relevant input parameters (for the project, these will be the fracture half length, matrix permeability, well spacing) and their impact- Recovery Factor. Then, the settings for each input parameter is specified (method of analysis and dependencies) in a series of experimental runs (simulation). The target is to obtain the maximum information from a minimum number of runs. From there, a ranking of the input parameters by impact is made and response surfaces are generated.

The experimental design offers a recipe for the simulation runs. The results of the experimental designs are polynomial approximations and are constructed under the condition that the deviation between the true function (reservoir simulator) and the polynomial approximation is minimized (regression analysis).

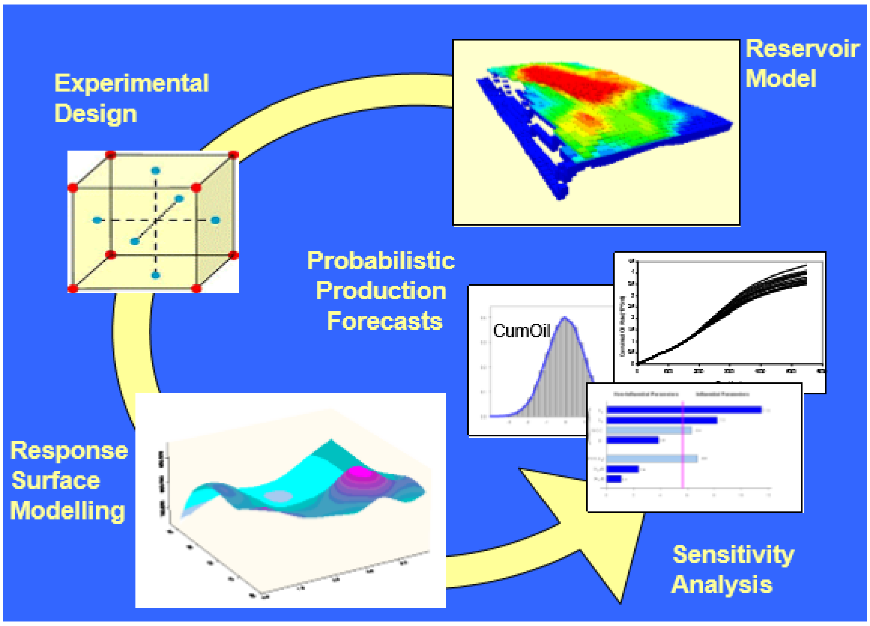


Figure 16: Modeling approach using Experimental Design (Akeem O. Arinkoola, 2015)

Monte Carlo simulations and Proxy Models are substituting the iterative simulation process with the latter being proven as most time and cost efficient. Uncertainty and risk analysis, history matching and development optimization are all readily available when these analytical algorithms are implemented. Proxy models are more time efficient than the Monte Carlo approach, which are limited to the number of parameter capacity. In regards to costs, uncertainty screening utilizing experimental designs however have the consequence of underperformance and is such needed to be compared against other capable methodologies. (Akeem O. Arinkoola, 2015)

In this thesis, the major reason to employ an experimental design is to use a reduced number of parameter values to create relationships between them, while in turn reducing the time needed to analyse uncertainties.

Apart from using a numerical simulator to determine the forecasted productions and depletion strategies, the thesis required the use of combining the numerical solutions from the black oil simulator with analytical-based models, which were obtained from iterative computational scenarios within the DOE. The statistical tool which performed the solving of the linear and nonlinear equations in order to generate the experimental design is called MiniTab 18 (Minitab, 2017).

The statistical model (DOE surface model) was done through a process that could be described as both linear and non-linear. There are discrete steps in which the economical performance of the reservoir depends on the step before it. That makes the process locally linear when looking at small steps, but nonlinear when looking at the process as a whole. This simply means that a linear relationship is correct for small differences but a nonlinear equation for larger differences is highly recommended.

2.6 Fiscal Terms

In order to analyze a project economically, a petroleum engineer would have to build an economical model of the venture. It is a development cashflow-oriented model which normally comes after the predictions have been established. The parameters of the model are based on the information gathered from various departments, so the accuracy of the obtained information varies considerably. The most probable outcome of the venture is defined as the *base case*. The thesis will present at the end of Chapter 3 an economical scenario built upon the base case model.

To appreciate the effect of possible variations in the base case model, a set of sensitivities are defined, evaluated and analyzed. These will be the different Hydrocarbon price assumptions, alternative reserve estimations, changes in capital (CAPEX) and/or operational (OPEX) expenditures. Studying these sensitivities will reveal the project's vulnerability and worthiness. The term CAPEX refers to the one-time costs that occur at the beginning of a project. Examples would be assets with lifetime that surpass an year(platforms, facilities, wells). The term OPEX denotes costs which occur periodically and are necessary for day to day operations (such as well maintenance, insurance). (Economical, 2017)

Whenever petroleum related projects are concerned, the starting point of the investment analysis lies with the responsibility of knowing what cashflow will be ultimately generated. Investors choose to spend money today (cash outflow), while expecting to harvest more of it in the future (cash inflow). Simply put, the inflow represents the revenues obtained while the outflow are the expenditures of the project.

Revenues are the payments received and they come in many forms: gross revenues from the sale of hydrocarbons or equipment, payments from farming out projects, incentives and others. The expenditures are CAPEX, OPEX and the money retrieved by the government (royalty, taxes). The government take (share of money) could extend further than the normally agreed royalties and taxes. A royalty is a percentage of the gross revenues from the sale of hydrocarbons and is payable from the start of production. A tax is a percentage of the taxable income, calculated by subtracting fiscal costs from revenues.

Fiscal costs are the sum of royalty, OPEX and fiscal depreciation of the assets. Depreciation is not on its own an element of the cash flow, but its role is in the calculation of taxes. Since depreciation reduces the taxable income, a fast depreciation leads to lower taxes in the early years of a project.

Net cash flow (NPV) represents the full amount of money which flows in or out of the treasury during a certain period (usually it is done per year or per month). The term discounting is leisurely used here, which is the process of converting a future value to a present value. Normally, when a project starts, the investments made require a certain period of time until they have been paid out. The length of time required for total cash expenses to be recovered through the profit generated by the project is called the Breakeven (Payout time).

An internal rate of return (IRR) is a company's earning power, a discount rate which would make the NPV reach 0. The hurdle rate is also an economical term that refers to the minimum acceptable rate of return on a project. In order for the project to be profitable, the hurdle rate must be lower or at most equal to the IRR.

The Weighted Average Cost of Capital (WACC) is another fiscal term important for operating companies. It detailed terms, it is the average of the interest rate of the company's loans and shareholder expectation of the rate of return for the equity capital of the company.

Figure 17 illustrates the cash flow indicators for a typical project's lifetime. The losses observed from the start of the project make the exploitation of a hydrocarbon field a high risk – high reward investment. The techniques needed to limit the risk can be quite costly and are needed to predict and optimize production. They involve the basin analysis, laboratory analysis, field prospection (Seismic) and a continuous reservoir model that is updated with every new piece of information collected during its life cycle.

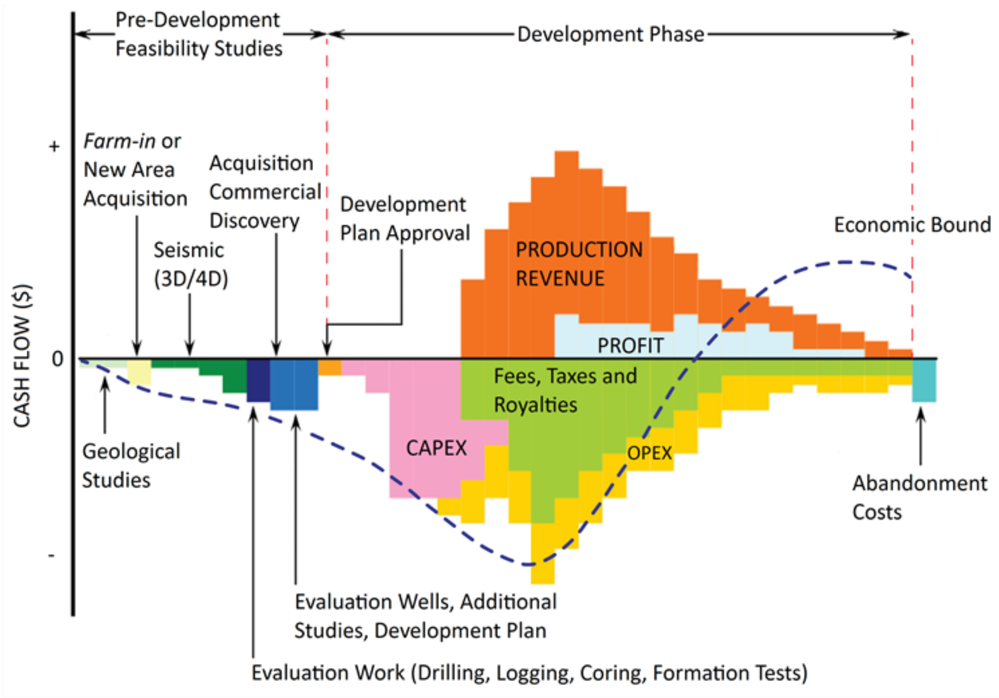


Figure 17: A typical cashflow diagram for an Exploration and Production project (Economical, 2017)

Some petroleum economics formulas are given below to summarize the terms discussed thus far.

$$Taxable\ Income = Revenues - Fiscal\ Costs \tag{2.8}$$

$$Fiscal\ Costs = Royalty + Opex + Fiscal\ Depreciation \tag{2.9}$$

$$Cashflow = Revenues - Expenditure \tag{2.10}$$

$$Return\ on\ Investment = \frac{\sum Net\ Cashflow}{Investment} \tag{2.11}$$

$$Depreciation = \frac{Cost\ Price\ of\ the\ Asset - Salvage\ value\ of\ the\ Asset}{Useful\ life\ of\ the\ Asset} \tag{2.12}$$

Very important for the project is the sensitivity analysis, observed to be the perfect process of establishing how economics of a project are affected by deviations from the base case assumptions. Complementary to it is the Spider Diagram, which is a chart showing the sensitivity of a project's NPV to variations in one parameter at a time.

In the example below, it is seen that the NPV reaches the value of $4 Million, when each of the three variables (Capex, Opex, Oil price) have the pre-determined value (100%). However it is sufficient for just one parameter to be modified by altering it's percentage (± 10,20 %) for the entire project net present value worth to be modified. In the example, a 2% decrease in the oil price is enough to make the project submarginal, as the NPV reaches 0. Such altering makes easier to distinguish between negative, marginal, positive and excellent projects.

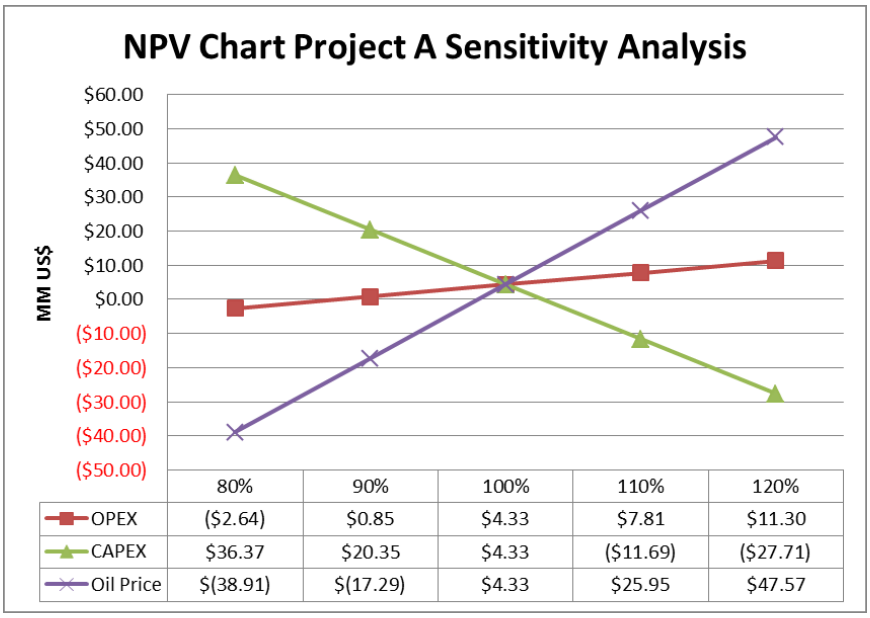


Figure 18: Spider Diagram – NPV sensitivity analysis for changes in Capex, Opex, Oil price (Economical, 2017)

3 Field Case Study

3.1 Overview of the field data

The Romanian offshore is undoubtedly the most explored area of the entire Black Sea. The Black Sea Continental Platform defines the prolongation under the sea waters of the neighbouring geological units, forming a fairly small seashore area with varying width across the Black Sea region, thus delimiting a deeper area. The continental shelf area has a width of 130-150 km and extends towards the continental slope at 130 meters deep under water. From a geostrategic point of view, the Black Sea continental platform represents an extension of the Dobrogean units: the South - Dobrogean Platform, the Central Massif - Dobrogean and the Northern Structogen - Dobrogean, as well as the lowered northern area, covered by the Danube Delta formations.

In the overall structure of the sedimentary blanket, several structural floors separated by stratigraphic discord were highlighted.

The data obtained through boreholes and seismics allow to highlight a structural floor within the Oligocene - Quaternar structural interval, with at least two sub - floors - Oligocene and Miocene superior - Quaternary and consists of very thick monoclinic deposits (Over 6000 m thick, rarely affected by faults).

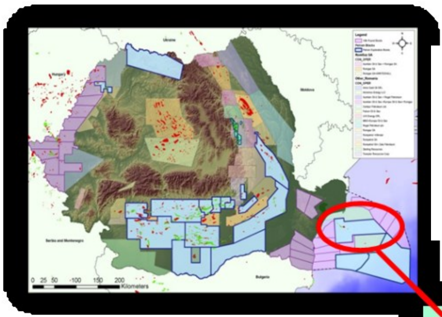
Also, through the data obtained from the drilling, a structural floor belonging to the Eocene and one belonging to the Albian could be highlighted. Within the structures Odette and Odile, Albian has a slight form of synclinal, locally bordered by faults, the Eocene being monoclinally disposed. Post - drilling information also indicates the presence of highly tectonic neocomian (Lowest Cretaceous stage) deposits within the Odette & Odile structures. These deposits are located on top of the Jurassic medium of the Odette structure and are transgressively and discordantly covered by Albian.

The Black Sea Basin truly became sketched in the Late Jurassic, when the first depressional structures appeared. The sedimentation process was known to happen in several stages:

- Extensional stage (Jurassic, Neocomian, Barremian-Early Albian)
  It took place during the Neojurasic - Eo-Cretaceous, when the Sea Basin gradually widened, due to the occurrence of distensive faults, which led to the formation of asymmetrical structures such as graben / horst.
- Post-extentional stage (Primary Cretaceous, Late Eocene)
  This stage took place during Neocretaceous - Eocene and is characterized by a period of tectonic relaxation, the area of the hill entering a moderate period of subsidence, as the Cretaceous and Eocene formations were formed.
- Inversion stage (Oligocene)

It is a compressive stage that reactivated already-existing distensive faults, giving them a reverse fault character. For this reason, the deposits are characterized by progressive stratigraphic effilites, which give a false stratigraphic discord. This stage is represented by the formation of the Oligocene period.

- Post-inversion stage (Sarmatian, Pontian, Pliocene - Quaternary)
  The accumulations of this period are characterized by a somewhat straight horizontal position and a very large spread, covering the whole area of the shelf and corresponding to the Medieval-Upper Miocene, Pliocene and Quaternary.



- **LOCATION**
  - **In the romanian sector of the Black Sea shelf**
  - **75 km N-E of Constanta city**
  - **Northern flank of Histria Depression**
  - **In an area with water depth of 50m**

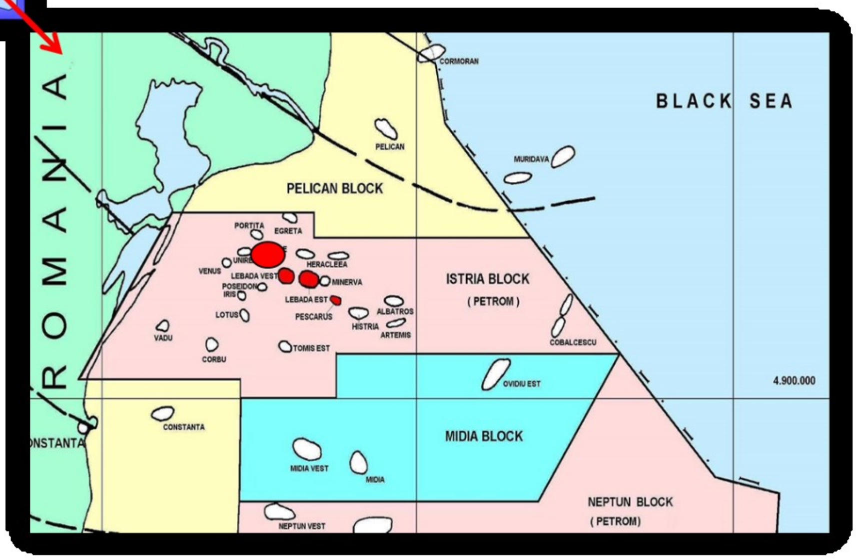


Figure 19: Location Map of the Field of Interest

FIELD DESCRIPTION

The structure is located in the Continental Black Sea platform, approximately 75 km NE from Constanta, in a depth of water up to 50 m, being situated on the NE flank of the Histria Depression and representing an extension under the waters of the Babadag Basin. The major continental faults Peceneaga - Camena and Sf. Gheorghe are also extended in the marine domain, delimiting the prolongations of the North Dobrogean Orogen, Central Dobrogean and the Scitic Platform.

In 1969, the Black Sea started to be researched through geophysical prospecting and the drilling of the first wells started in 1976. With the well 81 and well 817 between 1984 and 1985, the first oil accumulations in the offshore area of Romania were discovered, belonging to the formations of Albian, Cretaceous and Eocene. Continental Platform Research continued with the first 3D seismic drilling operations, with a large number of drilled wells, which led to a more detailed picture of the oil and gas fields in the shallow water area of the Black Sea. In order to get a new image and information, a new seismic research campaign was raised in 2005, totaling 625 km^2.

The Odile and Odette oil and gas fields, situated in shallow waters offshore Romania are geological 'twin' anticline structures, separated by a saddle area. The East (Odile) field was discovered in 1980 and produced first oil in 1987, whilst the West (Odette) field was found in 1984 and only started production 1993. The oil is generally light, with in-situ viscosities 0.6-0.9 cP.

The 3 reservoir horizons are:

- The fair-to-good quality Early Albian sand / sandy limestone oil reservoirs at about 2300 m TVDSS. Both reservoirs are in a mature stage of depletion and producing under water injection.
- The tight Primary Cretaceous series (<1mD) oil reservoirs, with substantial in place oil resources, currently the focus of horizontal multi-stage frac technology application. No clear oil water contact has been established yet and the saddle area between East and West remains prospective, despite increasing water saturations with depth.
- The Late Eocene reservoirs overlying the Primary Cretaceous which are of different character, with a relatively low permeability marly limestone gas reservoir in the East and a complex, heterogeneous quartzitic sandstone oil reservoir in the West. The latter reservoir was produced under depletion drive yielding a relatively low oil recovery efficiency.

ODETTE FIELD / RESERVOIR DESCRIPTION

The Odette West field, the twin of Odile (1980) was discovered in 1984. Developed by 2 wellhead jackets with treatment facilities, on stream 1993, this field has been producing from the same intervals as the East field, all oil reservoirs with gas caps. A total 42 wells have been drilled, of which 24 are currently in use (producing/injecting). As is the case with the East field, end-of-facilities-life is 2019 (PFS6 platform end-of-life is even 2015), with measures to extend facilities life to 2030 underway. Modern 3D seismic was acquired in 2005, which should help more reliable reservoir model re-building for re-development study and design.

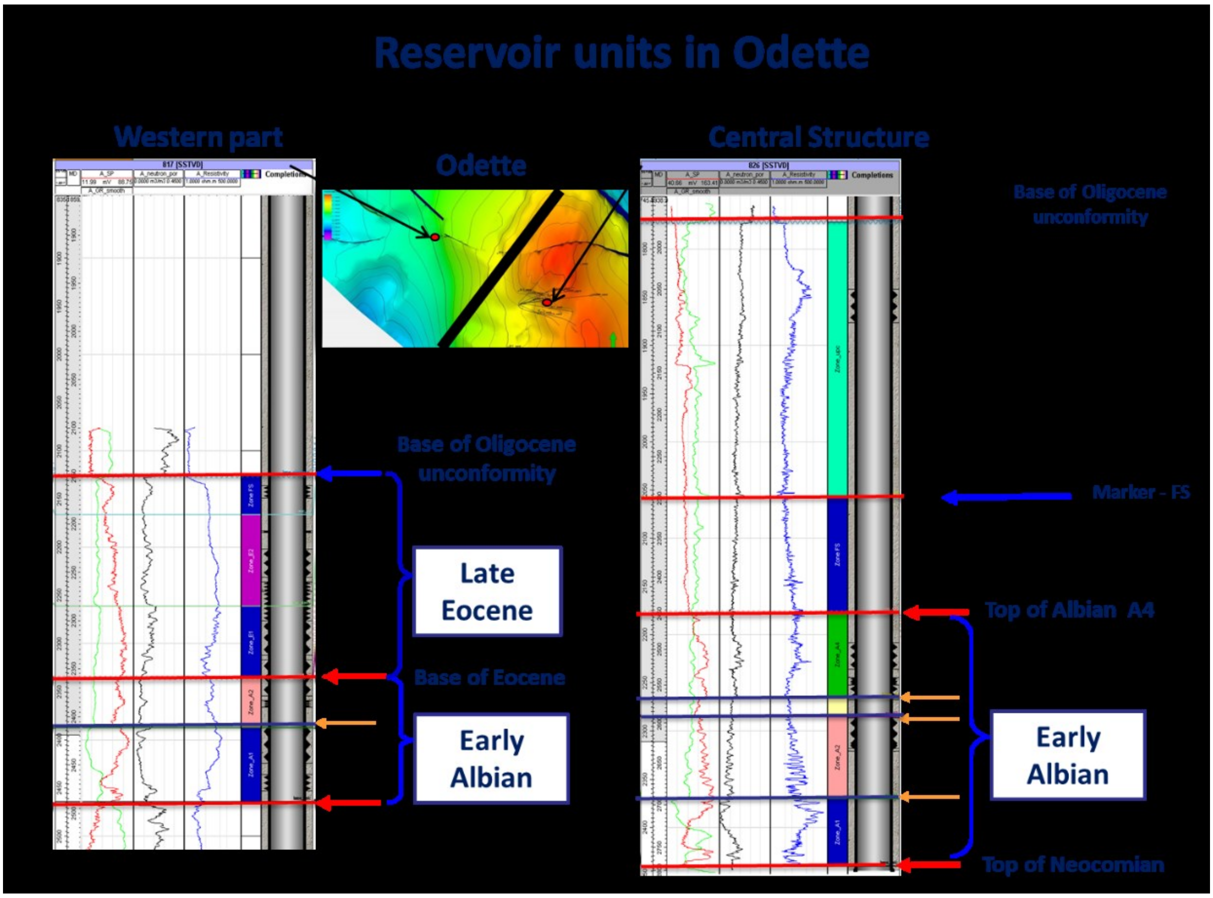


Figure 20: Formations encountered by wells drilled into the Odette field

Given that the main interest is represented by the Primary Cretaceous reservoir, as OMV is looking into a feasible new horizontal well to be drilled and fracked in this horizon, I will be offering information partaking the reservoir properties.

There exist three PVT reports for the Primary Cretaceous:

- Two downhole samples (one above and one slightly below the saturation pressure);
- One surface recombination sample (with lab results simulated).

Table 1: Primary Cretaceous – List of Reservoir Properties

No.	Specification	Primary Cretaceous
1	Depth (m, TVDSS)	1800 - 1900
2	Initial Pressure (at)	275
3	Temperature (^{o}C (K))	86 (359)
4	Bubblepoint Pressure (atm)	215
5	Initial Solution Gas Oil Ratio (Smc/mc)	120
6	Oil Formation Volume Factor: at initial conditions	1.31
8	Viscosity (cP): at bubblepoint pressure	0.5
9	Viscosity (cP): at standard conditions	35 - 48
10	Specific Oil Gravity: at standard conditions (kg/mc)	865
11	Gas Formation Volume Factor: at initial conditions	0.00633
13	Salinity (ppm)	14000-30000
14	Average Porosity (%)	18
15	Average Absolute Permeability, 10^{-15} m^2 (mD)	0.45
16	Irreducible Water Saturation (%)	40
17	Net Thickness (m)	70

3.2 Methodology

For the Odette field, the following methodology has been applied in order to ensure a proper simulation schedule:

- Analysis of the field data (Sub chapter 3.2.1);
- Upscaling and Sector Modelling of the area of interest (Sub chapter 3.2.2);
- Setting up Workflows for History Matching and Prediction (Sub chapter 3.2.3);
- Sensitivity Analysis – Infill well alternatives (Sub chapter 3.2.4).

3.2.1 Analysis of Odette

The field started producing in May, 1987 followed immediately after by a water injection process in November, same year. There are 3 main reservoirs:

- Early Albian (oil reservoir with gas cap);
- Primary Cretaceous – main interest (oil reservoir);
- Late Eocene (condensate reservoir).

A total number of 51 wells have been drilled, out of which:

- 14 wells for vertical exploration (P&A wells);
- 37 wells for development.

The production system consists of the following methods : Natural Flow, Gas Lift and ESP. The surface facilities consist of a main Central Production Platform and four wellhead support jackets.

Primary Cretaceous consists of sandy limestone and calcareous sandstones with poor reservoir properties (medium porosity and very low permeability – less than 1 mD).

Rock-Fluid properties are based on :

- Lab data of 182 cores (over 4200 plugs analyzed) and wire line logging;
- PVT data.

Sealing is offered by the Eocene marls and the trap is both structural-stratigraphic and lithological. This reservoir is undersaturated with the main drive mechanism being Depletion Drive. So far, Water Injection is not applied here.

The main risks and uncertainties for the Primary Cretaceous are the following:

• Geophysics:

- base Oligocene unconformity due to undershooting;
- faults definition;
- T/D conversion – velocity model;
- internal architecture - calibration log- seismic;
- western reservoir closure / boundary;
- well ties to sonic – no VSP acquired initially (only check shots).

• Geology / Static modelling:

- gross and net thickness;
- porosity and permeability distribution;
- water saturation distribution in the western side of the structure, towards Odette field.

• Reservoir engineering:

- actual reservoir pressure;
- forecasting assumption for fractured wells;
- geomechanical and stress models.

• Drilling / Well engineering: availability of slots for infill drilling.

• Facilities / Operational: life of the platform and the end of pipeline life.

3.2.2 Upscaling and Sector Modelling

The static modelling aims to provide a static, geological description for the reservoirs, while assuming equilibrium conditions in place. Main aspects were the requirement of having a proper understanding of the depositional environment and the rock typing.

In order to satisfy the orthogonality criteria of cells for flow simulation (cells need to have close to orthogonal angles), a new grid with a simple horizontal geometry of 100x100 meters was generated with vertical pillars.

As such, the fine scale geological model was thereafter upscaled in this coarse grid both for geometry and properties. This ensures a good respect of orthogonality criteria. However, only the major faults where preserved through this process. The vertical number of cell was also reduced, while trying to keep resolution as high as could reasonably be simulated.

Name	Color	Top horizon	Base horizon	Zone division		
Zone 1		BaseOligocen	TOP EOCENE	Proportional	Number of layers	1
Zone 2		TOP EOCENE	BASE EOCENE	Proportional	Number of layers	50
Zone Eoc		BASE EOCENE	Base Eocene East	Proportional	Number of layers	1
Zone Ma		Base Eocene East	TopCp	Proportional	Number of layers	1
Zone Cp		TopCp	TopSt_Co_Tu	Proportional	Number of layers	1
Zone St_		TopSt_Co_Tu	TopCm	Proportional	Number of layers	12
Zone Cm		TopCm	BaseCm_poros	Proportional	Number of layers	10
Zone Bas		BaseCm_poros	TopVr	Proportional	Number of layers	15
Zone Vr		TopVr	BaseVr	Proportional	Number of layers	6
Zone Bas		BaseVr	TopA4	Proportional	Number of layers	1
Zone A4		TopA4	TopA3	Proportional	Number of layers	24
Zone A3		TopA3	TopA2	Proportional	Number of layers	40
Zone A2		TopA2	TopA1	Proportional	Number of layers	10
Zone A1		TopA1	Top Neocomian	Proportional	Number of layers	2

Figure 21: Upscaling the grid – vertical resolution

Due to the lack of proper information regarding the rock types, upscaling while considering the rock properties have been approximated to fit the base case simulation runs.

For porosity, the variogram shows quite weak control on the anisotropy. The variogram was tuned to reflect concepts more than experimental data. The resulting single variogram used for all stratigraphic units was 5000x5000x40 (Figure 22).

The regression curve fits only a minor portion of the data and were taken to correspond mainly to the wells which were considered as reference to the upcoming infill well planned to be drilled and forecasted.

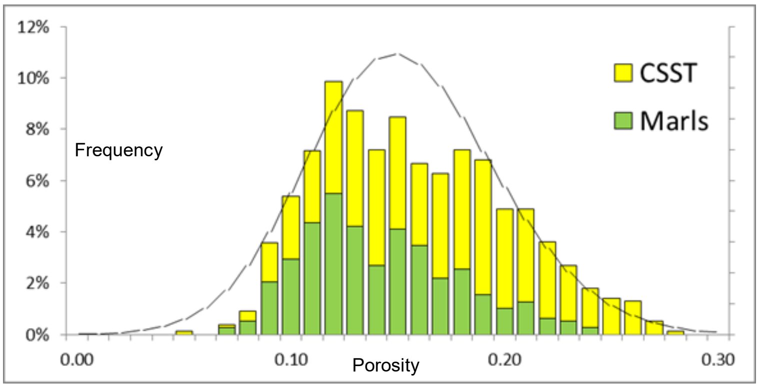


Figure 22: Porosity-variogram of calcareous sandstones and marls

Permeability was analysed similarly to porosity. The issues with rock typing however remains and as such, I determined them by stratigraphic zoning. The general porosity-permeability cross-plot here depicts a high variance for the permeability values for each porosity class, despite the existing linear trend (Figure 23).

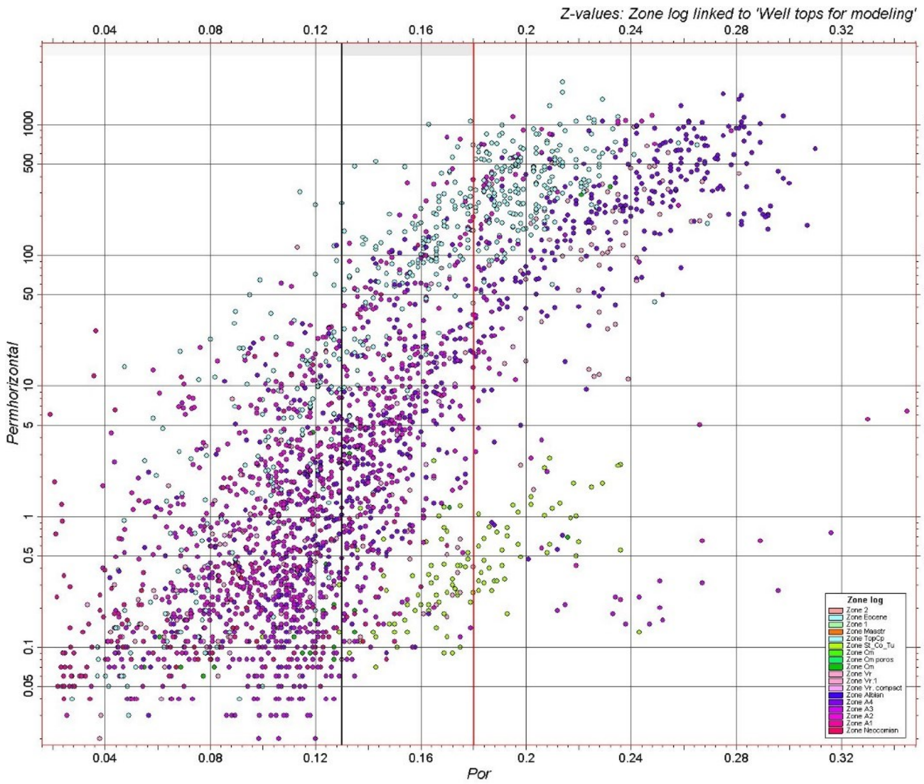


Figure 23: General PHI-K cross-plot from sidewall core samples (Albian – purple, Eocene - light blue and Primary Cretaceous - light green)

In order to minimize the impact of not having rock types interpretations, permeabilities were analysed per stratigraphic zone and per porosity class. From the figure above, there are clear problems in trying to establish a proper function to be added in Petrel's development strategy. The best way to clear irrelevant data is to only consider the main producible layer, in the area where the well will be drilled.

For the Primary Cretaceous (the primary producing target), a new cross-plot of porosity-permeability values was obtained by clearing the noisy data. (Figure 24)

The observed trend can fit into a linear function of the least square methods and be used as input for further property modelling processes. With effective porosities of 12 to 16%, the permeabilities seem to go only as high as 0.5 mD, which remains a rather pessimistic realization, given that most other producing wells of interest have shown greater values. Therefore, the range is extended to accommodate higher values of rock permeability.

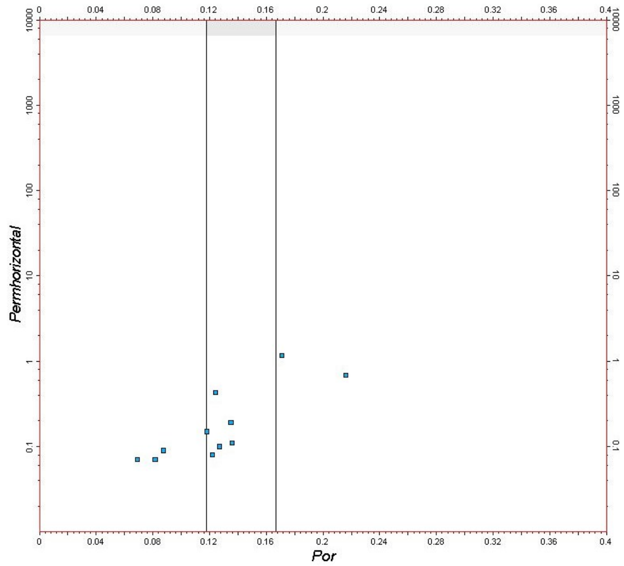


Figure 24: Cross-plot of porosity versus permeability for Primary Cretaceous core plugs

Water saturation upscaling was considered to be attributed to a single saturation height function and was further initialized for different free water levels:

$$SW = 1.0569 \times h^{(-1.334\, x\, PHIE\, +\, 0.08339)} - 0.23348 \qquad (3.1)$$

Where SW is the water saturation, h represents the block height and PHIE is the effective porosity value.

Since this saturation is dependant of height and porosity, some relatively good match can be observed between modelled saturation and saturation calculated from log data (Figure 25). However, it is important to keep in mind the uncertainties in the calculation of water saturation from the logs.

Uncertainties appear from the lack of proper reservoir monitoring in recent years, lack of well testing analysis and the fact that almost 80% of the recorded logs are of low quality, due to them being very old and imprecise. However, the entry of the initial water saturation distribution for most dynamic models should be avoided. It may be really good for geological models, but for reservoir engineering it should be internally calculated from the capillary-gravity equilibrium state, depending on the rock - fluid property distributions and the initial contacts of the existing fluids. The initial water saturation distribution should not be mentioned in a reservoir simulator, otherwise reservoir rock characterization is not possible due to changes in capillary pressure, wettability, etc. during the history matching.

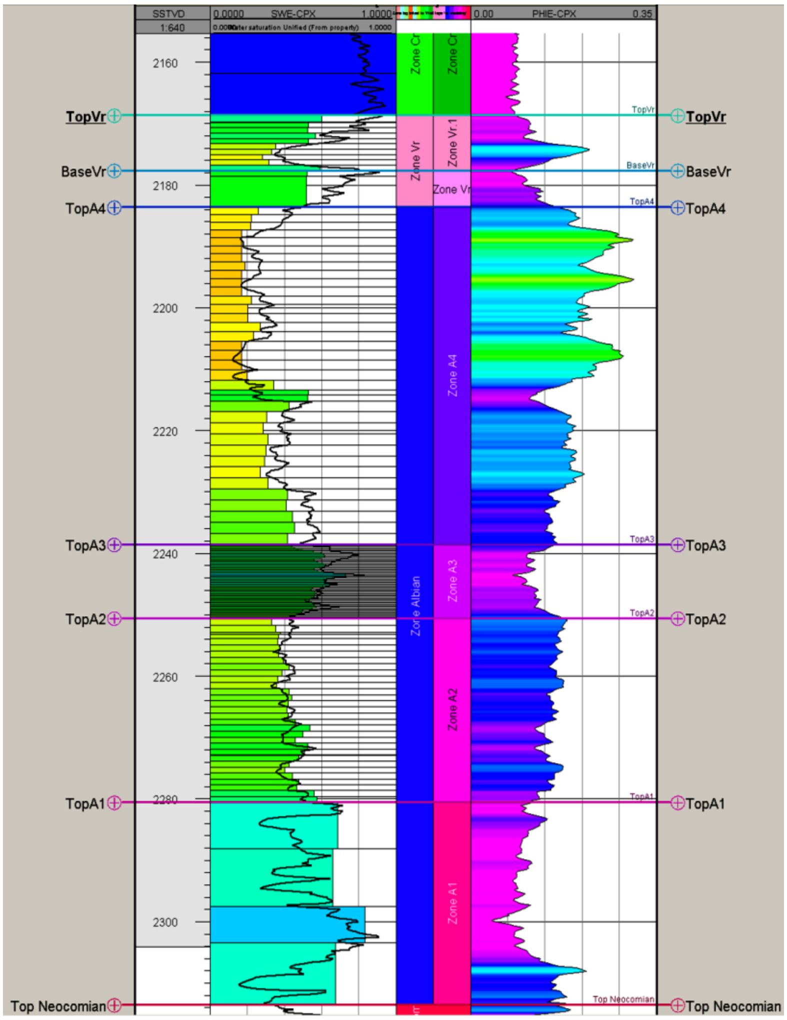


Figure 25: Example of a good profile for the calculated Water Saturation from saturation-height function with log water Saturation at well *Hope*

Modelling uncertainties for the Odette field are mostly of two types:

• Uncertainty on Gross Rock Volume from lack of control on Free Water Level, and from uncertainties on time to depth conversion (reduced quality of sonic data, strong lateral due to unconformities).

• Uncertainties on rock-types and their associated parameters:

- No rock types established at wells from logs or full cores;
- No possibility to constrain permeability distribution to rock-type distribution;
- Lack of understanding of reservoir vertical and horizontal connectivity;
- Lack of control on irreducible water saturations;
- Lack of control on Net to Gross (NTG).

Those shortcomings prevent any realistic estimation of volumetric ranges and put some doubt on the possibility to achieve reliable forecasting of production.

Within the Appendices, Appendix 1 shows the upscaled geomodel. It is a cut section of the whole field which defines the Primary Cretaceous reservoir, but since the interest lies in the west region, the sector model will be turned on only for the Odette field and not for Odile.

Figures 26 and 27 represent the sector model which is characterized by its rock properties. For figure 26, the porosity map shows that most values are within the 0.14-0.18 % interval and doesn't contradict with the static model values.

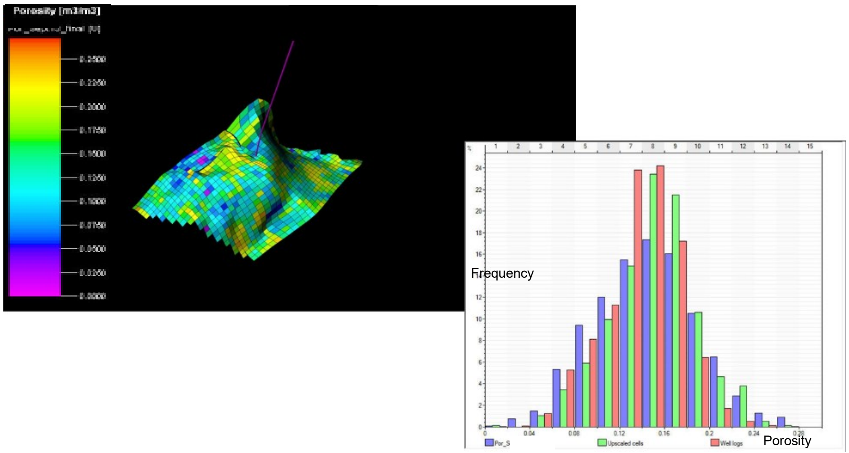


Figure 26: Sector Model – Porosity populated map & Porosity Distribution map

Figure 27 confirms the validity of the multiple rock types and demonstrates the usefulness of the sector modeling. It also gives very optimistic results, placing the higher distributive occurance of permeability values in the 0.7 – 1.3 mDarcy interval. These values are amongst the highest in whole Odette and as such it is hoped for a new well to be drilled in the portion where these high value spikes were encountered.

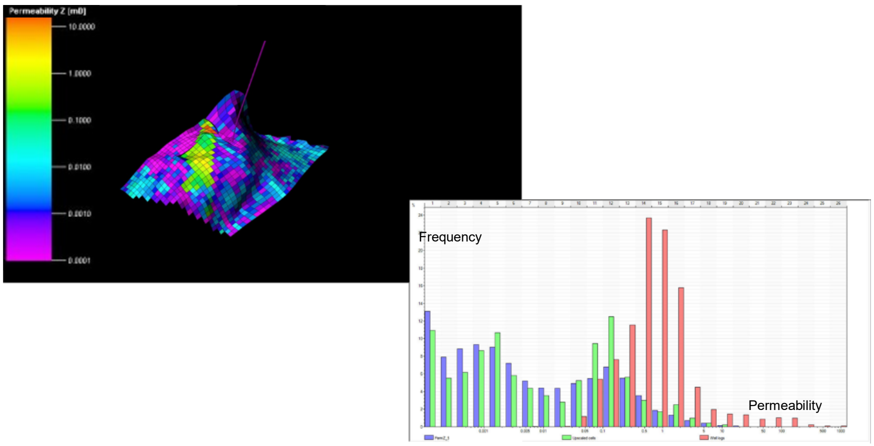


Figure 27: Sector Model – Permeability populated map & Permeability Distribution map

3.2.3 History Matching and Prediction

The sector model has its boundary conditions set in a way to either honour the bottomhole pressure or the flow rates.

It is in the reservoir engineer's interest to select a sector model large enough to ensure that the model will not be dominated by the input boundary conditions.

In this study flux boundary conditions are used.

For the initialization, the NTG is chosen to be equal to 1.

The relative permeability curves are prone to mixed wet rock, with almost free capillary gas migration through the fractures (corresponding to a Corey exponent – curvature of the relative permeability of ng = 1 – validated by history matching). The sample was a tight carbonate with porosity of 15.4% and permeability of 0.26 mD.

The simulation identified two sets of relative permeabilities:

- Good rock: no = 3.5 (from core), nw = 3, kro = 0.8, krwr = 0.35;
- Tight rock: nw = 4.5 (from core), following a trend of concave down.

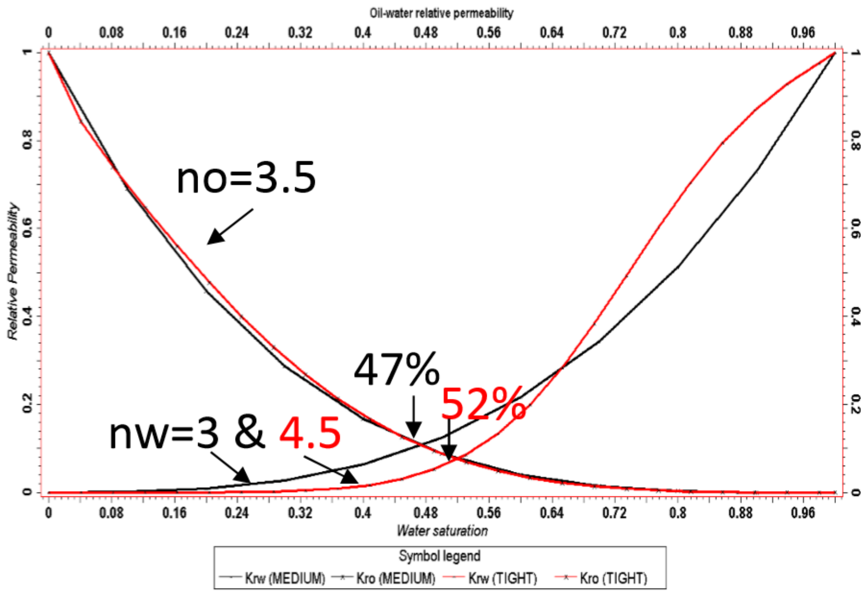


Figure 28: Oil - Water Relative Permeability curves

These relative permeability curves here show that the system leads towards a strong oil-wet rock system, which naturally has a negative impact on the recovery factor. Water flows more freely and there will be higher residual oil saturation than in the case of a water-wet system.

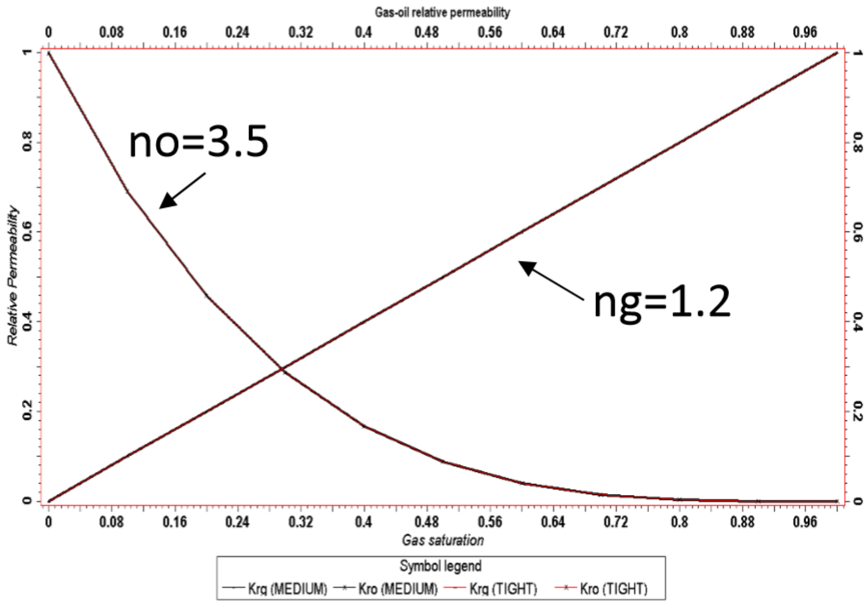


Figure 29: Gas - Oil Relative Permeability curves

Critical gas saturation (Sgc) is the saturation below which the gas phase remains disconnected and will not flow. As permeability decreases, connected pore throat sizes develop into progressively smaller sized. Due to strong oil wettability, any oil in such tiny connecting pores will substantially interfere with gas flow; hence, a higher gas saturation is needed to establish a connective path for it.

The active model domain is shown in 2D (Figure 30) and in 3D (Figure 31) perspective, that was used in the history matching and further prediction cases. All defined wells reached the Cretaceous target and have all been declared to have very reasonable permeability values around 0.5 mD.

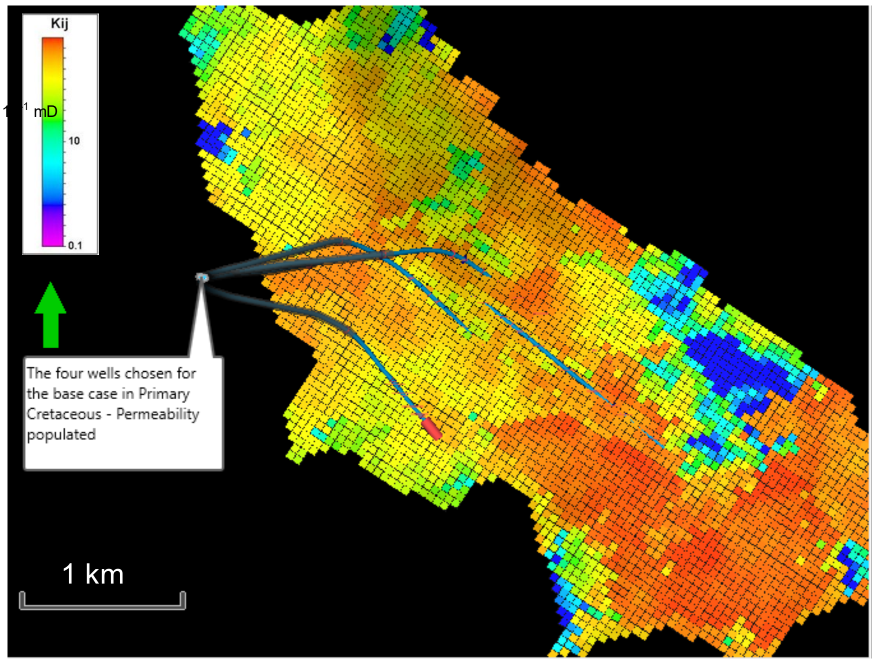


Figure 30: 2D Permeability Distribution Map of the Primary Cretaceous

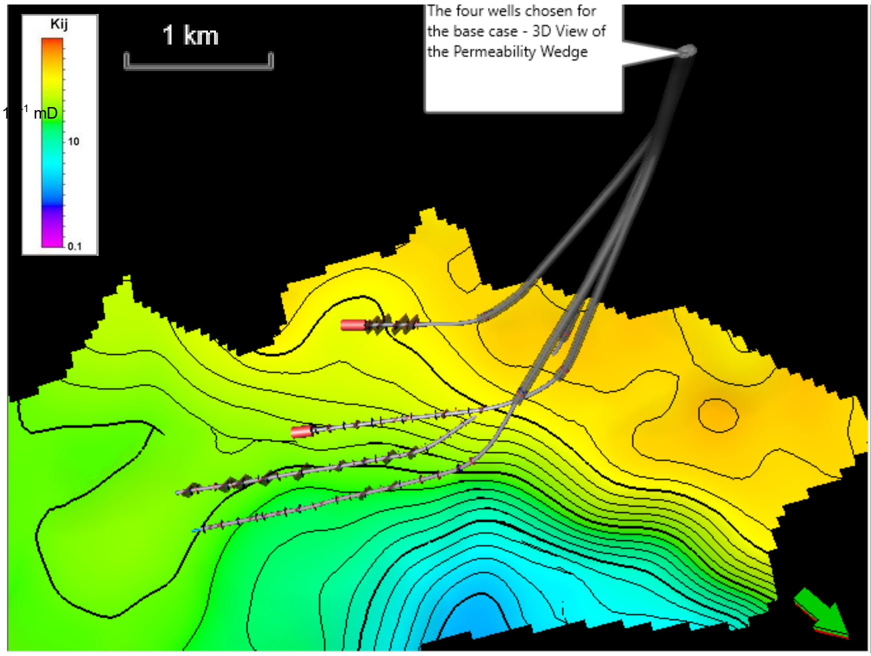


Figure 31: 3D Permeability Distribution Map of the Primary Cretaceous

The newly customized model requires two main cases as basis for all the future simulation experiments to support the final decision. The History Matching is the first tool for the development strategies and it only accounts for the material balance of the active wells. However, the Prediction case is based upon a newly added well called Swan Base Case, placed after further considerations at the epicentre of the likely well path design options. More about the well creation and completion options will be discussed at a later stage.

The main focus before having to implement the cases were placed upon the LGR and Sector Modelling criteria (including boundary conditions), defining the fracturing in Petrel by using the Eclipse exported keywords and the creation and alteration of the extended reach horizontal wells. Once that has been established, there are a few data input requirements. Firstly it is to assurance of proper PVT data for the black oil model. Secondly, the rock physics must honour the data that is been used for the four producers. Then, a production and development strategy is implemented.

First calibration is done by history matching. Its purpose is in achieving a reasonable agreement between simulated and observed historical behavior. The model will be later on used for predictions. The main history match parameters offer a feedback loop every time the simulations are run. The loops will tell us if the geological or simulation model are missing pieces of information pertinent to the nature of the reservoir and thus can improve one another.

Main geological data necessary for History Matching:

- Porosity
- Initial Water Saturation
- Fluid Contact Level (also needed for HCIIP calculations);
- Permeability.

Main Historical Production data:

- Rates – water rate, oil rate, gas rate;
- Pressures – initial reservoir pressure, drawdown pressure.

Required dynamic data:

- Relative Permeability, Fault / Fracture transmissibility;
- PVT data, Aquifer data.

The images accompanying the setup processes for Odette's development strategy will be found in the Appendices section, as Appendix 1, Appendix 2 and Appendix 3. Once a proper history match simulation has been saved, it can be implemented into a restart case which would take the output and use it as input for further prediction. Basically, all the historical records are memorized by the case and used as a reference, saving up time and avoiding computational (large memory requirements) and stability problems (time step length changes, convergence issues).

During the simulation case export, it has been shown that there are over 50 superimposed fractured zones between the current producers and the upcoming proposed well. Given the eclipse print file, the newly added well will be rather characterized by interference between the stages (flowback), as well as interference between itself and the other wells.

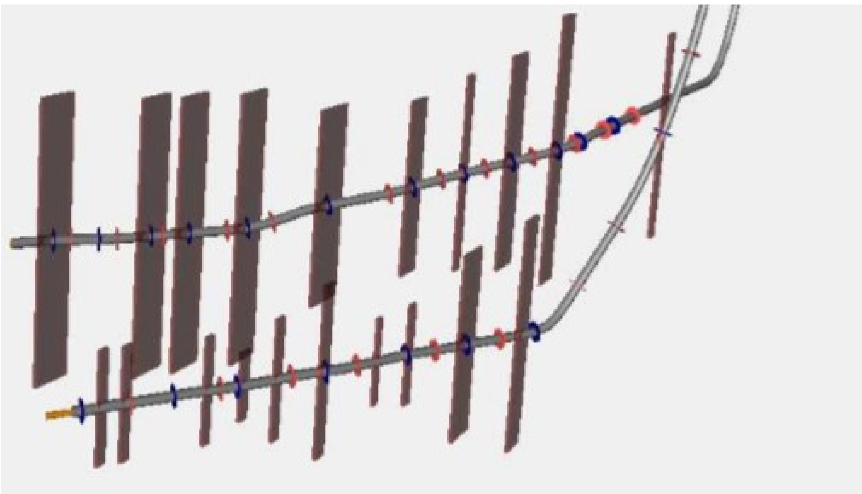


Figure 32: Fractured stages interference

3.2.4 Sensitivity Analysis – Design Case Options

Given the scope of this thesis, field development is viable if both the well spacing and the fracture dimensions alike are correlated in a way such that the Recovery Factor is maximized while the Capex / Opex is lowered to a minimum.

For the addition of new infill wells, it is required to develop a drilling strategy program within Petrel, taking into account the likely geological uncertainties given by the platitude of layers surrounding the trap. One of the main uncertainties is triggered by the entry point of the reservoir, which lays in a vertical window of approximately 10 meters. However, the degree of the dipping bed towards the structural flanks is well represented by the sector model.

In order to minimize the risk of drilling out of the target formation, the proposed well trajectories will be adjusted based on the 3D geo-cellular model, with the entry points of the horizontal Primary Cretaceous layer found in the vicinity of the offset producing wells (Figure 33).

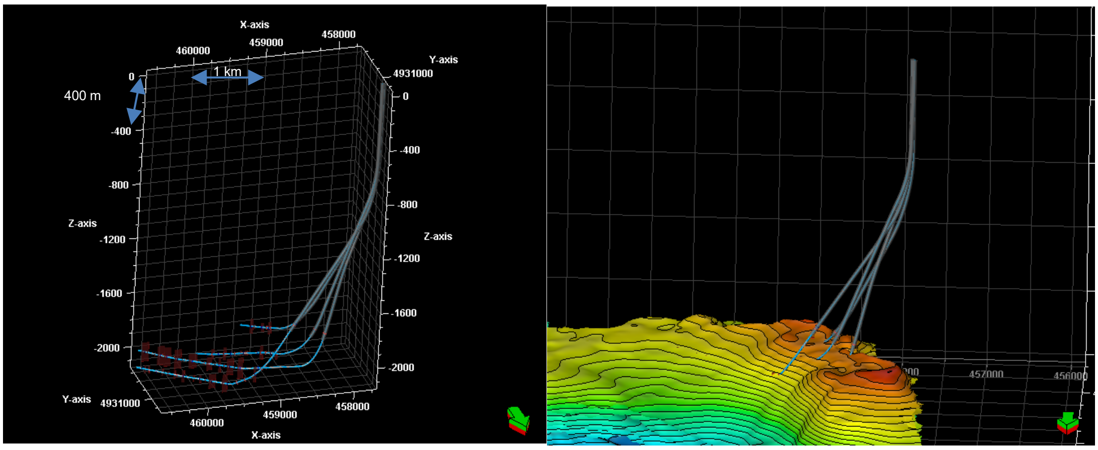


Figure 33: Visualization of the existing active wells

Once the drilling survey plan and the anti-collision report of the new proposed wells have been commended, a quick report attached below will give the well attributes. Separately, I have inserted a table which shows the mild differences in the geolocation of the new infill well alternatives.

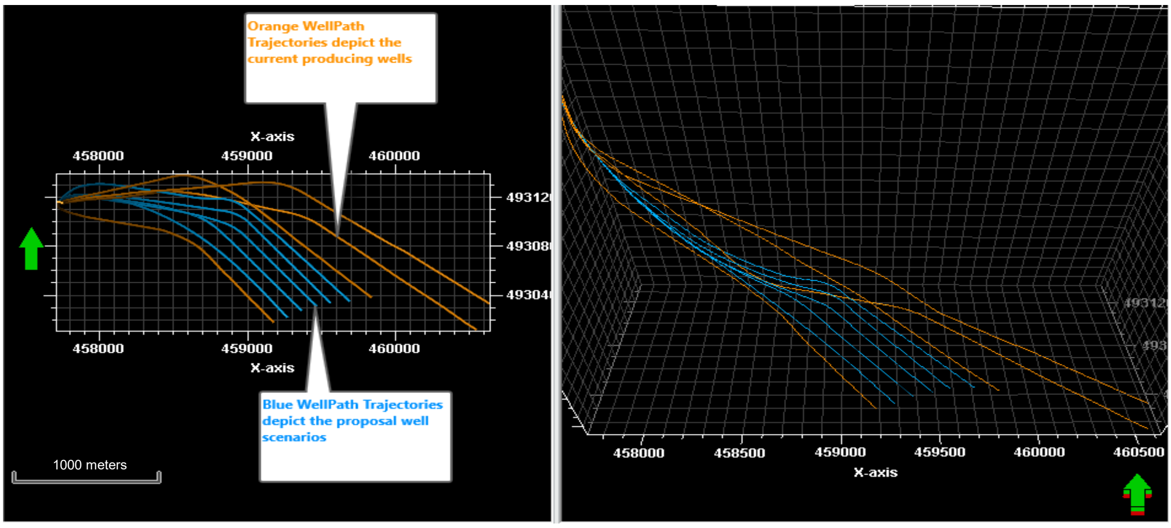


Figure 34: Visualization of the producers and the proposal alternatives

The proposal well is going to be located within the drainage radius of well #1 and well #2. The spacing between the viable well trajectories for the proposal is in between 100 to 120 meters from each other. Between the wells #1 and #2, there is a gap of 690 meters, hence the viability of planning 5 different path trajectories (Swan 1-4 and Swan Base Case) becomes a good idea in order to test the well spacing impact on the project economics.

These tables will determine the survey outlook for the drilling process done in the software package. As observed, the total measured depth of the swan wells (alternatives) can differ up to 440 meters, which are incurring costs of almost 5% of the drilling costs.

Table 2: Geolocation report for the sector model simulation wells

Well ID	Well datum (KB)	TD (TVDSS)	TD (MD)
Well # 1	32.7 m	1909.2 m	3037 m
Well # 2	38.1 m	2027.3 m	3700 m
Well # 3	39.2 m	2094.9 m	4420 m
Well # 4	38.7 m	2030.5 m	4558.6 m
Swan v1	23.7 m	1912.2 m	3210 m
Swan v2	23.7 m	1923.9 m	3300 m
Swan Base Case	23.7 m	1929.8 m	3350 m
Swan v3	23.7 m	1934.1 m	3460 m
Swan v4	23.7 m	1943.4 m	3650 m

Table 3: Drilling report example for the proposal well

Well Attributes: Swan Base Case			
Attribute	**Value**	**Attribute**	**Value**
Name	***Swan Base Case***	UWI	
WellHeadX	***457730.42 m***	WellHeadY	***4931162.55 m***
TD / TVDSS	***1929.76 m***	TDMD	***3350.00 m***
Cost	***NaN***	Z	***23.66 m***
MaxInc	***88.00 deg***	TWTAuto	***NaN***
Longitude	***29°28'4.7862"E***	Latitude	***44°31'57.1851"N***
Reference Level	***KB [23.66]***	Project Name	***Odette_sim_model.pet***
MSL	***0.00 m***	CRS	***ETRS89 / TM 30 NE***
DLS (max)	***4º***	Version	***2015.5***

The main characteristic of the reservoir is the low permeability in the range of 0.1 to 2 mD. In order to increase both the production and the drainage radius, the well needs to be stimulated by multistage hydraulic fracturing.

Based on field experience, no sand production is expected for the proposal well. Also, the erosion to carbon steel tubulars is low to non-existing due to the sufficiently low flow velocities. The main issue will be the scale, as Calcium Carbonate scale has been shown to exist in all previous wells to some degree. As such, injection of scale inhibitors via the same downhole chemical injection valve will provide adequate protection, if it is deemed required.

The Swan Base Case scenario is represented by the central mid trajectory of the 5 likely well paths and was considered to be the most optimum in terms of maximizing the un-swept oil production. Its objective is to accelerate and appraise the Primary Cretaceous reservoir production between Well #1 and Well #2.

It will exit through the 7" production casing at a planned depth = 1900m MD. At kick-off, the inclination will be 35° with 265° azimuth. The well will then build and turn with DLS < 3°/30m to reach planned TD at 3350m MD with 88° inclination and 213.61° azimuth.

The hole section will track the Primary Cretaceous reservoir by use of a rotary steerable + LWD BHA. The well will be completed with a 4-½" multi stage fracture lower completion which utilises hydraulically set packers for zone isolation (4-½" frac stage ports are provisionally planned). The liner will not be cemented. Corresponding multi-stage fracture stimulation will then be conducted before the well is put on production.

The upper completion is run and stung into the liner top packer with a snap latch seal assembly which aids in space out calculations rather than fix the upper completion in place. The seal assembly is 20ft long to accommodate tubing movement during the stimulation job.

Jewelry below the tubing hanger consists of subsurface safety valve, sliding sleeve, permanent pressure/temperature gauge, chemical injection mandrel and snap latch seal assembly.

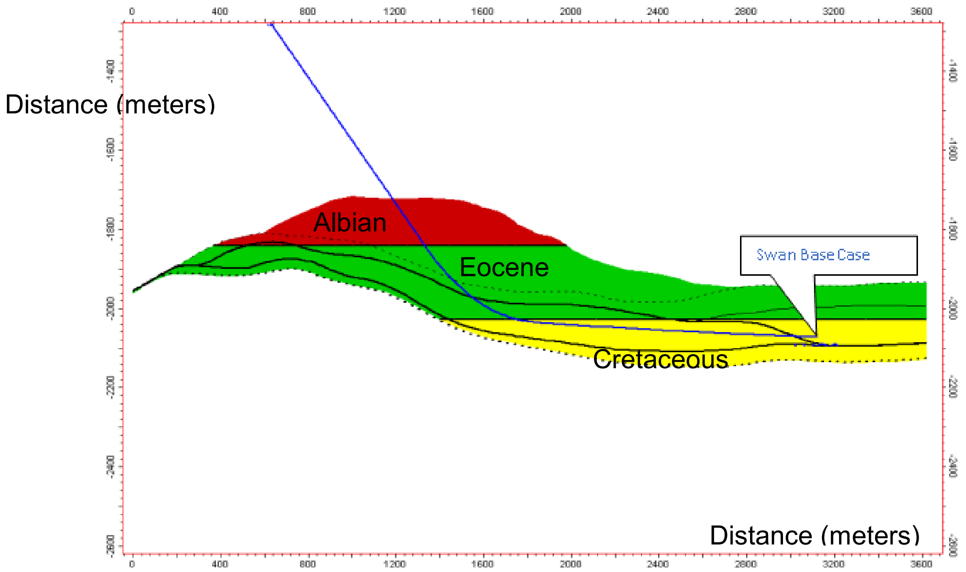


Figure 35: Cross-Section representation for the Swan Base Case well in Primary Cretaceous

The Fracture dimensions for the proposed well will have the following values:

- X_F of 80 meters;
- H_F of 50 meters;
- K_F of 5 Darcy;
- W_F of 0.15 in.

Well name		Categ	Type	Name	Start date	Top from	To off m	Bottom from	B m
Swan Base Case		Borehole	Borehole	Borehole	01/01/2018	Start of well trajectory	0.00	End of well trajectory	0.00
Swan Base Case		Casing	Casing string	7 in	01/01/2018	Start of well trajectory	0.00	Well datum	1900.00
Swan Base Case		Casing	Casing part	7 in:1	01/01/2018	Start of well trajectory	0.00	Well datum	1900.00
Swan Base Case		Tubing	Tubing string	4.5 in	01/01/2018	Start of well trajectory	0.00	Well datum	3350.00
Swan Base Case		Tubing	Tubing part	4.5 in:1	01/01/2018	Start of well trajectory	0.00	Well datum	3350.00
Swan Base Case		Devices	Packer	Top Packer	01/01/2018	Well datum	1675.00	Well datum	1678.00
Swan Base Case		Devices	Packer	Packer 1	01/01/2018	Well datum	3111.10	Well datum	3114.10
Swan Base Case		Devices	Packer	Packer 2	01/01/2018	Well datum	2925.30	Well datum	2928.30
Swan Base Case		Devices	Packer	Packer 3	01/01/2018	Well datum	2820.00	Well datum	2823.00
Swan Base Case		Devices	Packer	Packer 4	01/01/2018	Well datum	2632.50	Well datum	2635.50
Swan Base Case		Devices	Packer	Packer 5	01/01/2018	Well datum	2486.10	Well datum	2489.10
Swan Base Case		Devices	Packer	Packer 6	01/01/2018	Well datum	2325.90	Well datum	2328.90
Swan Base Case		Devices	Packer	Packer 7	01/01/2018	Well datum	2176.00	Well datum	2179.00
Swan Base Case		Devices	Sliding sleeve	Sliding sleeve 1	01/01/2018	Well datum	2957.40	Well datum	2959.40
Swan Base Case		Devices	Sliding sleeve	Sliding sleeve 2	01/01/2018	Well datum	2852.10	Well datum	2854.10
Swan Base Case		Devices	Sliding sleeve	Sliding sleeve 3	01/01/2018	Well datum	2787.90	Well datum	2789.90
Swan Base Case		Devices	Sliding sleeve	Sliding sleeve 4	01/01/2018	Well datum	2545.60	Well datum	2547.60
Swan Base Case		Devices	Sliding sleeve	Sliding sleeve 5	01/01/2018	Well datum	2385.50	Well datum	2387.50
Swan Base Case		Devices	Sliding sleeve	Sliding sleeve 6	01/01/2018	Well datum	2211.80	Well datum	2213.80
Swan Base Case		Workovers	Hydr Frac	Hydr Frac 1	01/01/2018	Well datum	3138.00	Well datum	3138.00
Swan Base Case		Workovers	Hydr Frac	Hydr Frac 2	01/01/2018	Well datum	2957.00	Well datum	2957.00
Swan Base Case		Workovers	Hydr Frac	Hydr Frac 3	01/01/2018	Well datum	2852.00	Well datum	2852.00
Swan Base Case		Workovers	Hydr Frac	Hydr Frac 4	01/01/2018	Well datum	2788.00	Well datum	2788.00
Swan Base Case		Workovers	Hydr Frac	Hydr Frac 5	01/01/2018	Well datum	2546.00	Well datum	2546.00
Swan Base Case		Workovers	Hydr Frac	Hydr Frac 6	01/01/2018	Well datum	2385.00	Well datum	2385.00

Name	Value	Unit
Bottom offset	2385.00	m
Bottom SSTVD	1837.64	m
Top from	Well datum	
Top MD	2385.00	m
Top offset	2385.00	m
Top SSTVD	1837.64	m
General		
Category	Workovers	
Completion length		m
End date		
Name	Hydr Frac 6	
Start date	01/01/2018 00:00:00	
Type	Hydr Frac	
UWI		
Well folder	Wells\SIM	
Well name	Swan Base Case	
Validation		
Validity	Valid	
Workover		
Fracture height	50.00	m
Fracture length	80.00	m
Fracture orientation	45.00	deg
Fracture permeability	5000.0000	mD
Fracture width	0.15000	in
Use Fracture Correlatic	✓	

Figure 36: Completion Program Summary: Swan Base Case example

The reservoir is being exploited under depletion drive: oil (with pore and connate water) expansion down to the bubble point pressure and solution gas drive below bubble point pressure, with some contribution from the adjacent gas cap expansion. The observed rapid production decline is consistent with reduced relative oil permeability and a loss of reservoir drive energy in the well drainage areas. Bottom hole pressure measurement results are sparse and difficult to interpret. The current cumulative production is 2.86 MMbbls (488,000 m^3) since the production start of this sector model occurred in 2013. This related to a 3% of the reported Stock Tank Oil Initially In Place, whilst gas recovery stands at 12% of Gas Initially In Place. Remaining proven reserves are presently booked.

3.3 Experimental Design

The Design of Experiments (DOE) is needed as a powerful statistical method for conducting experiments when the sample data points are not enough to make economical decisions. The investigation of the well placement and fracture dimensions on the production forecast sums up a total of 125 different simulation cases (Eclipse runs). Running sector model simulations however require approximately 130 minutes per run.

The dynamic model workflow assumes a history match of the four producers until the year 2017. As the work load (lengthy process of running the history match alongside forecast) is needed to be mediated, a restart case has been created (Prediction – restart type). With it, the improvements that optimize the project's load define how the time-step information data is kept and further runs will have both the historical data and a NFA prediction already defined. This Prediction case is meant to have the Swan Base Case well put in production from the very first day of 2018, with an end date of 31st December 2030.

The values obtained from the standard scenario Eclipse run for the base case well are observed below. The Swan Base Case well adds an increment to the total sector model production by 113700 m^3 (RF is 7.02%). The total recoverable reserve of Odette's sector model field stands at over 1.6 million m^3.

The oil reserve totals 1.619MM m^3 - Swan Base Case cumulative is 0.1137 MM m^3

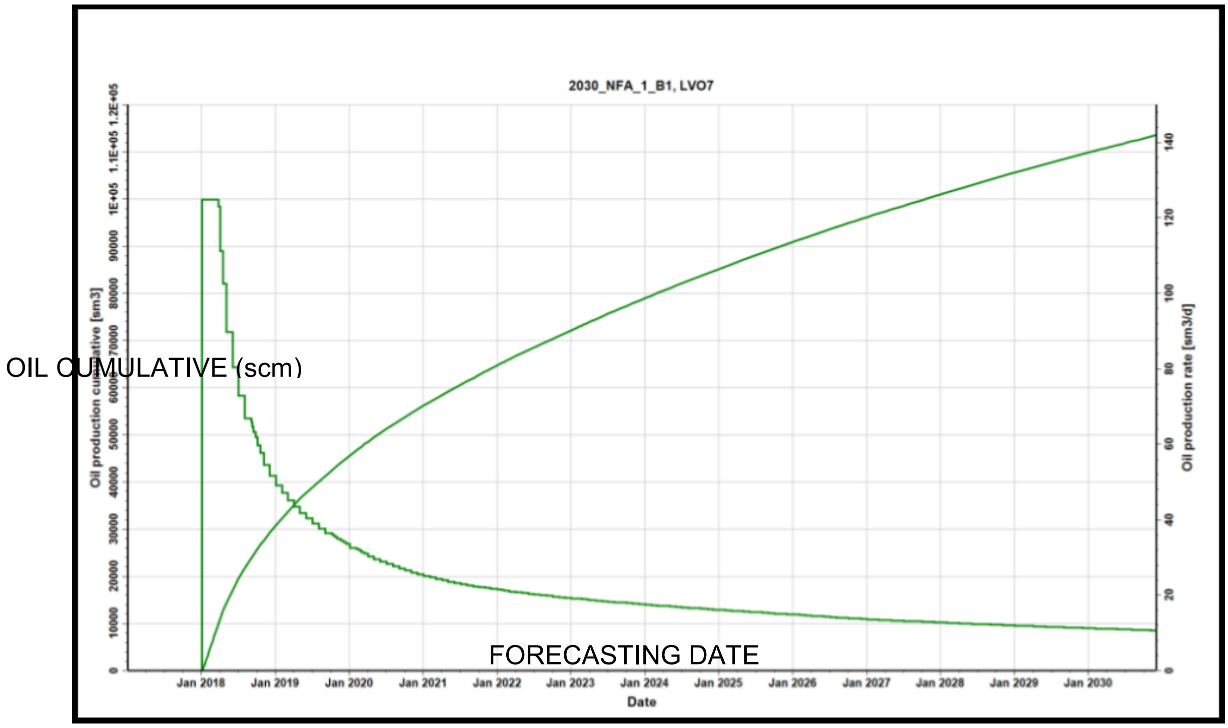


Figure 37: Forecast for the NFA simulation run – Swan Base Case

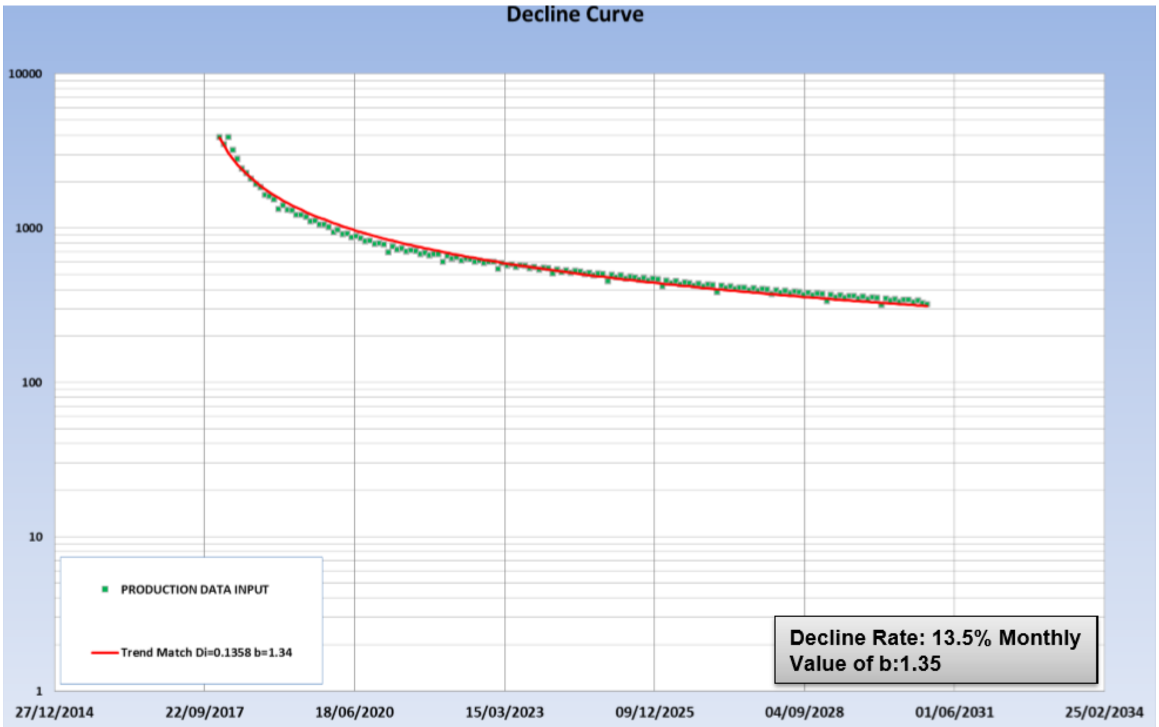


Figure 38: Decline Rate Analysis of the Swan Base Case scenario

DOE is needed to provide a comparison of all scenarios run on this sector dynamic model for all various factors (Field Level Increment, Well Individual Increment, Increment based on surrounding wells).

In constructing the DOE, a Response Surface Design needs to be established. The following parameters are considered as (continuous) factors implemented for the Central Composite Design (DOE template used): fracture half-length, matrix permeability, well distance from closest offset producer. For the well distance, the 5 proposal well trajectories are considered (Swan v1, Swan v2, Swan v3, Swan v4 and Swan Base Case).

Table 4: Response Surface Design – Continuous Factors and Limiting Sampling interval

Parameters \ Factors	X_F	K_m	Well Distance
Lower Limits	40 m	0.05 mD	100 m
Upper Limits	120 m	1 mD	500 m
Swan Base Case	80 m	0.5 mD	300 m

The distribution of the input values is calculated by sampling each of these parameters for a specified number of iterations. Every single iteration yields a fixed set of input parameters and determines a predictive pattern of the outcomes while considering the behaviour of the set model. From the simulated iterations (results), the outcomes develop a distinct distribution that outline the system's behaviour (2D / 3D). Uncertainty is still seen as a decisive (overriding) factor for all the results.

The experimental design is done within the freeware software called Minitab, a user-friendly interface software meant to guide students in their project work. The Response Surface Model of choice required to fine-tweak the continuous parameters and construct a cube out of 1024 runs that continuously modified the three parameters (factors). Their impact on the Recovery Factor has been registered and analysed both analytically and graphically.

The DOE data sets have taken into account three different qualitative information:

- the 5 different well spacing trajectories of the Swan wells, due to simulation runs in Eclipse;
- History Matching and Prediction of NFA with Swan Base Case running until 2030;
- 8 varied matrix permeabilities and 6 different fracture half length values, all within 30% variance of the base case model.

I chose to keep the Base Case Swan - fracture parameters and matrix permeability values - unscathed so that they would be seen as a reference in further variance changes of the newly obtained data.

Once it was put together what the experimental design looks like, the responses had to be specified. The responses are the measurements of all the terms from the eclipse simulation runs, adjusted based on the higher order terms of the response surface design. This helps in estimating the noise values, particularly to estimate the standard error of the factors estimates, which is seen in the interaction plots below (Figure 39).

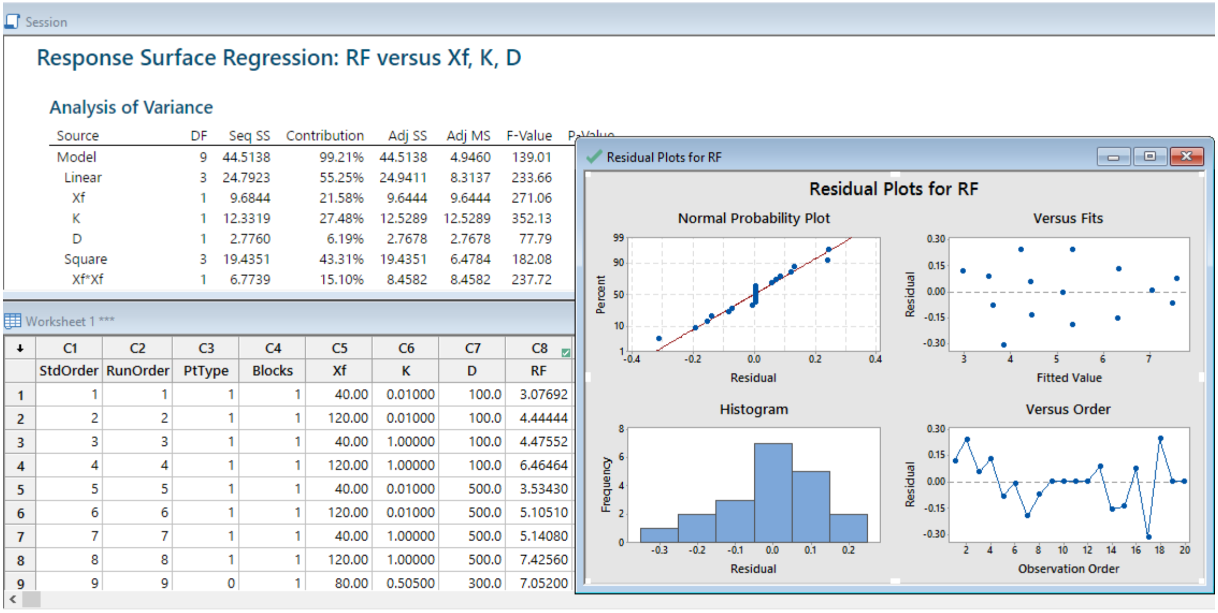


Figure 39: Proxy Model plots without noisy data

There is a three level hierarchy for the complexity of the DOE polynomials. Only a linear model (2D) shows a response surface as a flat plain, oriented in the multidimensional space (most basic model). Adding one more level of complexity (3D surfaces) would describe the change in height of the system which is the value of its response.

As the DOE model I have created is based on quadratic terms (3D model terms), the changes from left to right axes as well as the height changes offer a drastic increase of the response. This comes from the fact that the three modelled continuous factors have to honour the recovery factors observed when certain patterns (variance in values) in X_F, K_m and Spacing were implemented during the Eclipse simulation runs. There are a few observations worth noting:

- Statistically speaking, it would seem that the higher the fracture half-length value is, the better the recovery factor. Higher fissures in the reservoir would lead to higher drainage areas as the stimulated rock volume is increased.
- An increase in the matrix permeability does lead to higher Recovery, but it seems that the gain in cumulative volumes is halted before the highest matrix permeability is reached. While the stimulated rock volume from fracturing is increased, it would seem

that a maximum of 0.7 mD is enough to reach the same end Cumulative. This can be attributed to an acceleration in the production profile, without having an impact on the recovery factor itself.

- Due to the fact that the spacing between the wells is limited, the maximum distance for the production target is 600 meters, which is the spacing of the two existing producers perforations (Well #1 and Well #2). It would appear that the optimum distance is reached closely to the middle of the two producers.

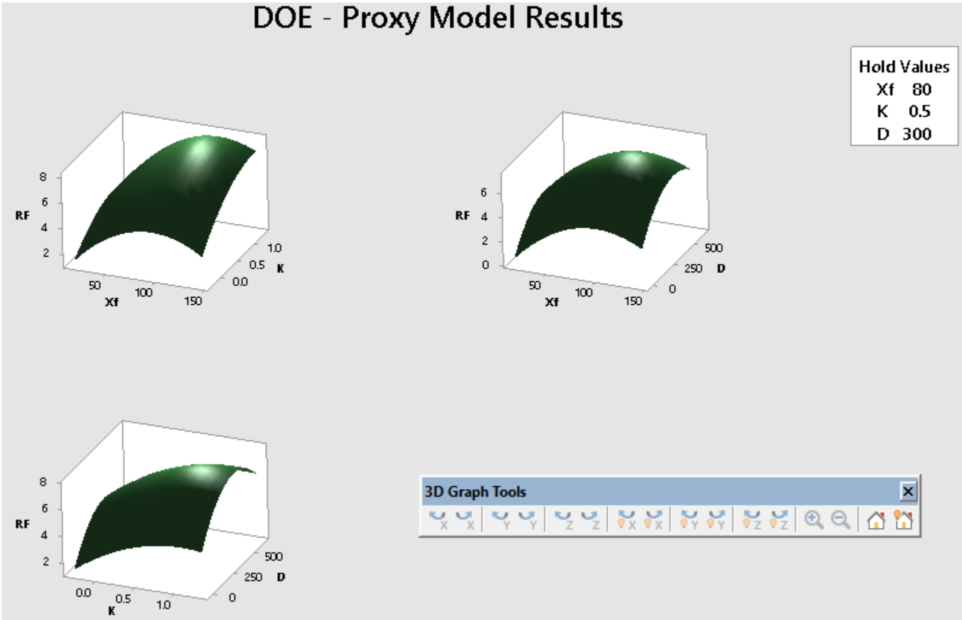
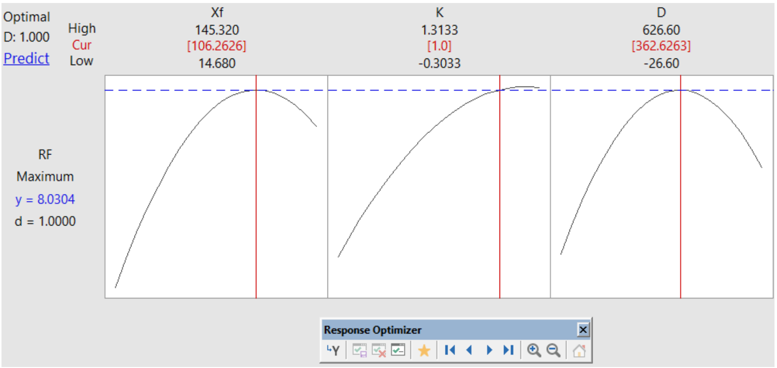


Figure 40: Robustness performance screening

There is a process under the Minitab DOE response optimization which allows to set a target as the end result.



Multiple Response Prediction

Variable	Setting
Xf	106.263
K	1
D	362.626

Response	Fit	SE Fit	95% CI	95% PI
RF	8.0304	0.0983	(7.8113, 8.2495)	(7.5565, 8.5044)

Figure 41: Response Optimization for the highest RF as target of the DOE

For maximizing the Recovery Factor, it would appear that drilling a proposal well in the sweet spot region of the reservoir, where the matrix permeability is 1mD, while adjusting the fracturing design to pump enough slurry at a pressure which will result in 106 meters fracture half length is best. The spacing would be at the mid-region between the current producers, at a distance of 362 meters away from the first producer. Therefore, the maximum viable RF under these ideal conditions would be 8.03%.

The Eclipse simulation run is showing as base case a Recovery Factor of 7.02%, compared to the ideal case where the maximum viable value of the recovery is 8.03%. However, the other well trajectories offer less incremental oil when the matrix permeability and the fracture half length reach the above ideal values.

The following table (Table 5) will summarize the values befitting the simulation runs and the statistical observations.

Table 5: Fracture Dimensions and Well Spacing – Incremental Recovery Factor optimization

Attribute	Unit Name	Swan v1			Swan v2			Swan Base Case			Swan v3			Swan v4		
Scenario	-	P10	P50	P90	P10	P50	P90	P10	P50	P90	P10	P50	P90	P10	P50	P90
X_F	*[m]*	120	100	80	120	100	80	120	100	80	120	100	80	120	100	80
K_m	*[mD]*	1	0.75	0.5	1	0.75	0.5	1	0.75	0.5	1	0.75	0.5	1	0.75	0.5
Final Cumulative	*[m3]*	110500	103190	96645	119600	111688	104604	130000	121400	113700	122200	114116	106878	114400	106832	100056
Recovery Factor	*[%]*	6.825	6.374	5.97	7.387	6.899	6.461	8.03	7.498	7.023	7.548	7.049	6.601	7.066	6.599	6.18

Given that the impact of the well spacing on the well construction and completion costs is negligible, a single economical scenario has been considered for the proposed well.

Swan Well	P10 Cost (€)	P50 Cost (€)	P90 Cost (€)
Planning and Preparation	1700000	2000000	2500000
Well Construction	9500000	10500000	13850000
Completion	3850000	4250000	4850000
Total Project	**15050000**	**16750000**	**21200000**

Swan Well	P10 Time (days)	P50 Time (days)	P90 Time (days)
Planning and Preparation	5	7	10
Well Construction	44	49	57
Completion	7	10	13
Total Project	**56**	**66**	**80**

Figure 42: Cost & Time estimation for the Swan Well (Proposed well)

3.4 Petroleum Economics: Development Scenario

Within the Exploration and Production industry, energy companies seek to maximize the efficiency and revenues of their assets. In this subchapter, the development scenario takes Net Present Value (NPV) as the goal objective, since the profit attractiveness represents a crucial factor. The NPV is the difference between the present value of cash inflows and the present value of cash outflows. It is used in capital budgeting, to analyze the profitability of an investment or project. (Economical, 2017)

Therefore, calculating the NPV was done by taking into account the discount rate, the investment and the total annual revenue after the deduction of taxes, opex and royalties. These additional Key Performance Indicators (KPI) such as taxes, royalties, operational and capital costs are applied to seize how much influence the altering behavior of a system has on estimating the value of the project.

In order to determine if a successful field re-development can be advantageous to the company, a conservative approach in calculating the economics was taken. Both the costs needed to further finance the project and the cumulative production are subject to changes in the initial planning. The entire revenue directly depends on the estimations of cumulative hydrocarbon production. Therefore, the P90 case for the Recovery Factor and the well costs have been considered (Table 5 & Figure 42), in which the lowest likely production and highest incurring costs are used.

The final result is an insight regarding the parameter-based model combined with optimum economical assumptions.

The discount rates used were the following: WACC rate of 9%, Hurdle rate of 12%.

The benchmark crude oil served as reference is Brent and assumes a stress scenario starting from \$55 / bbl. The upper margin of its value is reached in 2020, when it is assumed to reach \$75 / bbl. The commodity price assumption was taken from Petrom's general forecast trend, in which every year there is an incremental in the oil price of \$10 / bbl.

Following next is a table (Table 6) summarizing the important parameters used in the economical model.

Table 6: Summary Table for the Economical results

Specifications	**Unit**	**MTP**
Period of analysis	-	2018 - 2030
Operating expenses	EUR	20,688,539
Abandonment expenditures OMV Petrom	EUR	3,244,250
Investment	EUR	23,747,500
Oil production	T	193,363
Gas production	E3m3	100,549
NPV @ 9%	EUR	7,660,778
NPV @ 12%	EUR	5,832,214
IRR	%	51.5
Payout time @ 9%	Years	2.64
DPI @ 9%	-	0.53
DPI @ 12%	-	0.5

While the most conservative approach was considered in order to increase the reliability of the outcome, it would seem that the project remains feasible by a large margin. It would take at least 32 months for the project's expected financial return to reach a neutral net income.

The capital budget and operating expenses for the forecasted years take into account the financial securities and risk allowances. Having reached a positive income of at least 5.8 Million Euro, there are few unpredictable factors that could turn this project into a negative one.

The Capital Expenditure costs are plotted as a function of the average Hydrocarbon daily production, as shown in the Figure 43. The figure shows that the high incurring costs take place at the same time as the beginning of the production increase. The reason for such an increase in the production of a tight reservoir is due to the simulation data. The software will also account for the time length of the fracturing procedure, initial stage interflow and material balance reconnection from the sector model to the whole field.

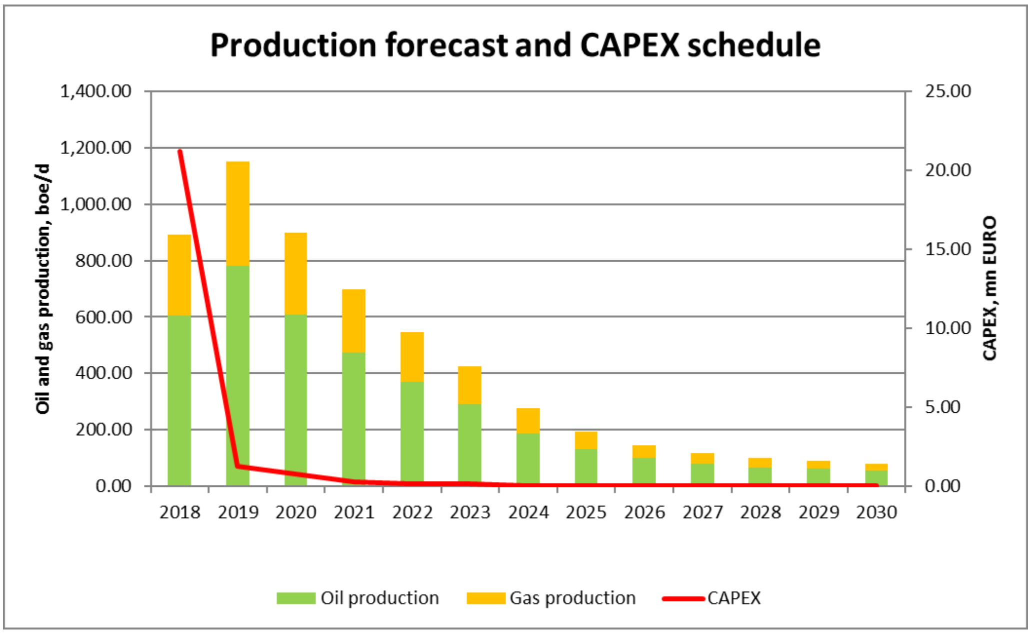


Figure 43: Hydrocarbon Production Forecast versus Capex schedule

In the figure above, the average daily production per year is considered. Now for a better outlook on estimating the value obtained from the sale of Hydrocarbons, CAPEX is plotted against the NPV. With OMV's internal discount rate of 12%, the following trend is observed (Figure 44).

What makes the illustrated graph interesting is the stabilization of both the cash flow, 4 to 5 years before the end of the production limit. With only a few years left to exploit the sector, NPV changes relevant to internal and external affairs may require an overview. The sliding scales (term often used in petroleum economics) should be highly considered for a flexible government take. For example, by having royalties directly dependant on the annual production cumulative, the project would improve greatly.

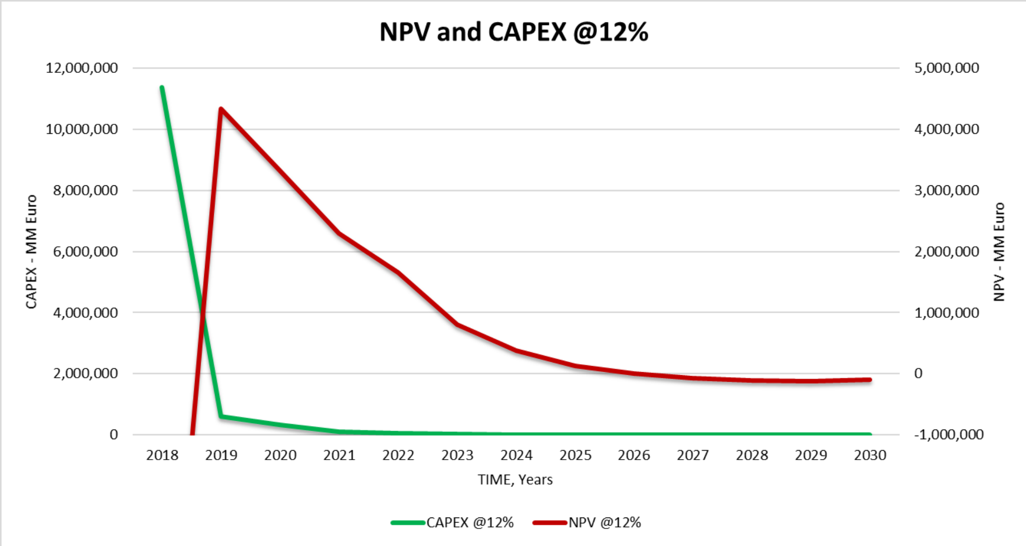


Figure 44: NPV versus CAPEX schedule

As the study's value is based on the impact of the optimum allocation decision, the conservative approach can be declared satisfactory. In practice, the majority of all economical planning parameters are a function of the producing rates and commodity prices.

On the basis of the deterrance of the commodities values, the future outlook may look challenging. With the Brent's marker value at only $50/bbl, the problem of having a negative project arises. A comparison of the standard price forecast is observed below, in the Figure 45, respectively Figure 46.

With the stress scenario, the project will have to be stopped 3 years earlier than the expected decomissioning of the offshore platform.

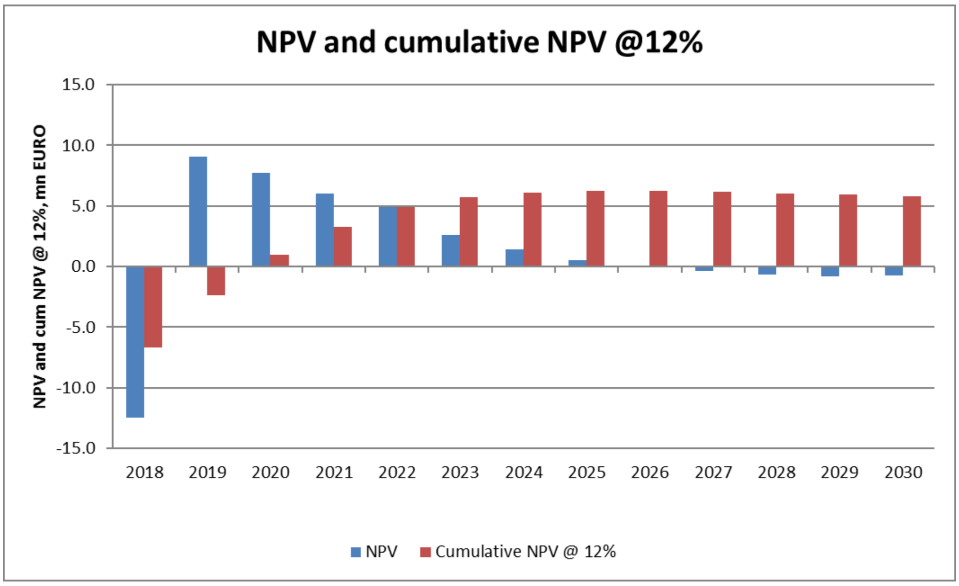


Figure 45: NPV versus the discounted NPV @ 12% (normal oil price forecast)

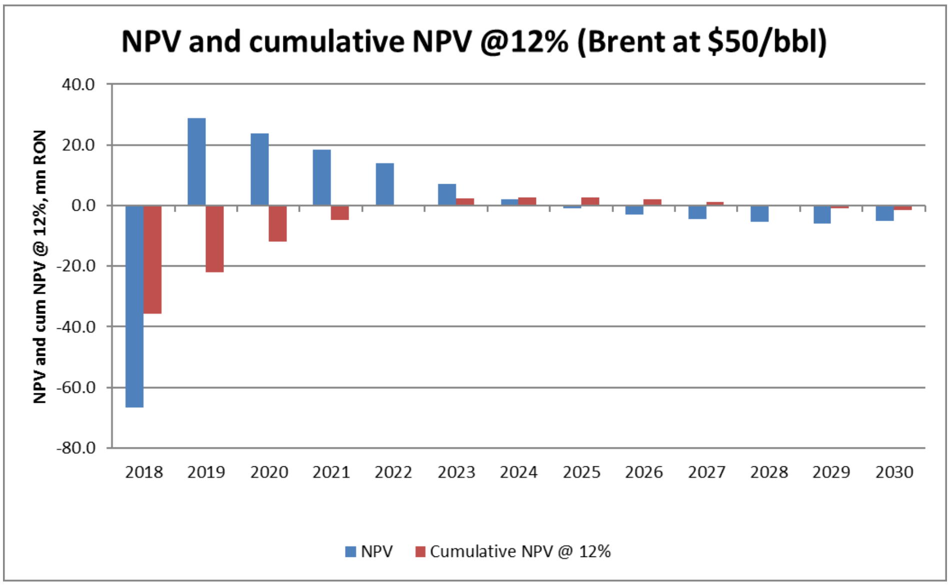


Figure 46: NPV versus the discounted NPV @ 12% (Stress scenario of $50/bbl)

In the end, the economical sensitivity of the project has been performed for the base case oil price starting at $55/bbl. The remaining analysis factors that have the highest degree of uncertainty are the cumulative production and the investment costs. The annual revenue for each of the three probability scenarios is seen in Figure 47. As a reminder, the scenarios consist of the following data:

- P90 Scenario: Swan well costs total 21.2 MM Euro, with an expected oil RF of 7.203%;
- P50 Scenario: The well costs reach 16.75 MM Euro, with an expected oil RF of 7.498%;
- P10 Scenario: Only 15.05 MM Euro are needed, with an expected oil RF of 9.03%.

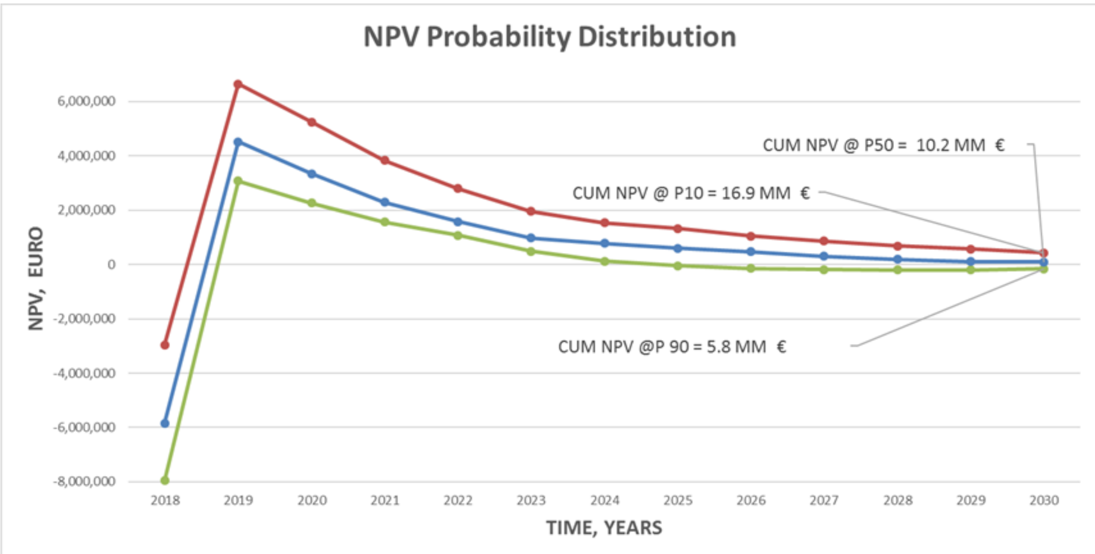


Figure 47: NPV Probability distribution for the simulated Swan well scenarios

As shown in Figure 47, the project is positive when accounting for current economical considerations. Given the sensitivity of the CAPEX/OPEX incurred costs as well as the branded oil and gas prices, there are a few factors which need to be considered. The project could become negative, at a NPV @ 12% only in the case that one the following turns true:

- Oil production decreases by 37.1%;
- Oil Price decreases by 36.54%;
- Capex increases by 51.85%.

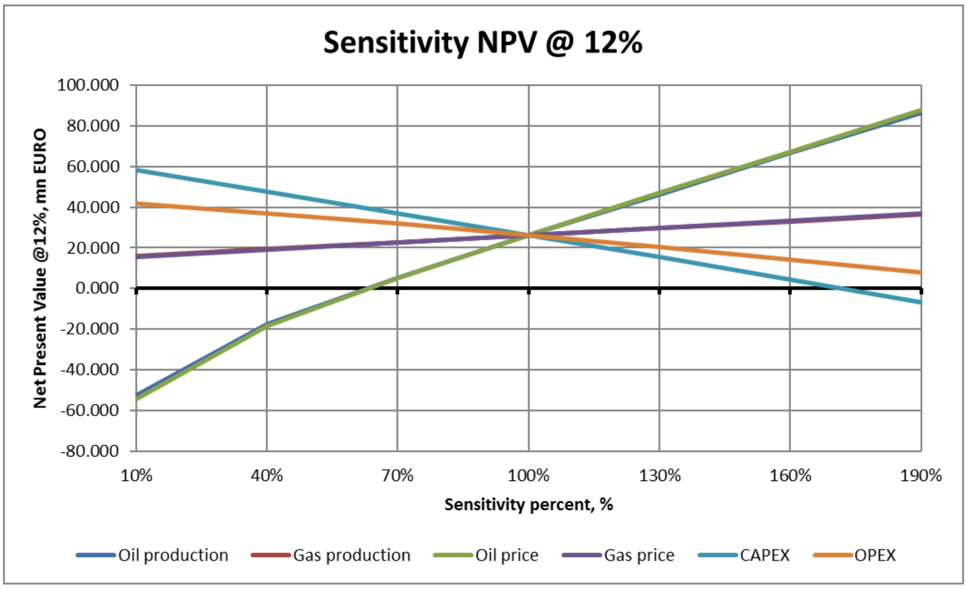


Figure 48: Spider Diagram for the tweaking of the NPV @ 12%

4 Results and Discussion

This study has the purpose to provide a superior understanding of the OMV's tight carbonate reservoir, Odette. A comprehensive optimization approach has been adopted based on the Recovery Factor and NPV maximization. The sector model, while only describing a portion of the whole Odette reservoir, is by no means disconnected from the material balance calculations which helps accurately determine the recoverable oil.

Building a numerical model adequate in capturing major geomechanical and petrophysical aspects of Odette was crucial for studying the effects of varying parameters on flow behavior.

The methodology based on statistical simulation was employed due to its proven efficiency and steady control on the sensitivity of every decisive factor. The design factors used for the optimum response surface model were the following:

- The fracture half length - taken from real field data and simulation;
- The matrix permeability - which varies greatly in the portion of the reservoir where a new infill well is planned to be drilled;
- Well spacing – constrained by the limited portion between two of the active producers and the simulated drainage radius.

One main conclusion of the results was that the Recovery Factor is sensitive to all of the above design elements. The Well Spacing however impacts the least, which is most likely due to the fixed stimulated rock volume that a newly completed infill well has access to.

There is also an effect in the NPV treatment from the economical considerations. The early annual revenues clearly subsidize more than the ones found at later years. The flow transient period of this tight reservoir is lengthier than one would expect for normal reservoirs and the precise estimation of it before the pseudo-steady state develops might lead to improved cost-effective development scenarios.

Limitations of the proxy model come from not considering the induced fractures interaction, anisotropy of the rock properties and the stress field patterns.

In the case of permeabilities with values close to 1 mD, it has been shown that the fracturing operations do not necessarily contribute with additional production, but only accelerate the production, shortening the well's effective time.

Following the assumption of proper well completion and fracture stimulation in place, the well Swan may achieve a very good result.

The relationship of the fracture dimensions (fracture half length specifically) and the well spacing has proven to be vital in trying to optimize the field development.

5 Conclusions and Recommendations

5.1 Conclusions

The main and most capital intensive re-development opportunity in these fields is the tight Primary Cretaceous oil reservoir. If the recovery efficiency anticipated for Odette (10.6% of STOIIP) could be achieved, there would be an incentive of some 1.131 MMbbls.

The analyzed field is a source at the conventional and unconventional boundary, with a variation in effective permeability between 0 and 2 mD, the most frequent being around 0.4 - 0.7 mD. The hydraulic fracturing operations have been successfully applied, contributing considerably to production and implicitly to the increase of the final recovery factor, thus allowing efficient and economical exploitation of the Odette. In the case of small permeabilities, it is very important to consider efficient design and optimization of the fraccing process by increasing the exposure of the productive area to the whole reservoir, as well as by increasing the pore volume. All rock geomechanics interventions need to be carried out in optimal conditions, both in terms of efficiency and safety and environment.

The current development approach will be by up-hole re-completion of the wells (as these will reach their economic limit) which may offer opportunities for horizontal drainage in combination with multi-stage frac stimulation.

It is understood that considerable study effort has been spent for some time and is presently ongoing and it goes without saying that success is not guaranteed. Field results show, that modern propped frac stimulation offers the best chance to expand economic Primary Cretaceous development, because of the improved connectivity to reservoir layers that would otherwise remain unconnected. The possibility, that economic development could be provided by un-fracced horizontal wells placed in the main reservoir cannot be ruled out, but this would connect only half the currently estimated STOIIP or even less, according to the Experimental Design results. Ultimately it is important to get across the message that calculation results are very sensitive to detailed reservoir architecture and parameters.

Some of the issues to be addressed are:

- Acquisition of further data, are crucial for ongoing and future study effort, such as reservoir pressures, vertical well logging (including regional stress direction data to inform fracture orientation), PVT (to inform understanding of compositional variation), petrophysical and reservoir parameters by means of special core analysis etc.
- Including more core data in order to improve reservoir characterization.
- Detailed reservoir process study, possibly using prototype simulation models (subject to representative reservoir and field data) in order to improve understanding of:
    - Optimal spacing and orientation of wells;
    - Optimal spacing of hydraulic fractures.

5.2 Future Work

On the basis of scouting calculations, it is plausible that in the Primary Cretaceous un-fracced (but 'properly' stimulated) multiple lateral wells can yield comparable initial production potential to one multi-stage fracced leg. However, (multiple) legs with fracs are expected to have higher production potentials and achieve higher ultimate recovery than un-fracced legs. With respect to Primary Cretaceous, it is recommended to investigate the 'value of information' of a long duration production test of un-fracced horizontal well (to be fracced at a later stage).

Despite there being potential application opportunities for horizontal and multi-lateral wells, there is no shortcut to their optimal placement. This remains ultimately a field / reservoir development issue that can only be decided on the basis of integrated reservoir study, ideally involving static and dynamic modeling and simulation. Such study being crucially dependent on high quality field data, it was noted that the extraordinary wealth of core material offers unique opportunities in this respect. In order to have a very good control on the shear fracture propagation, it is recommended that during the intervention, microseismic mapping tests are also carried out.

In order to gain a better understanding of the production of each crack port, the evolution of the fluids that flow into the wellbore and their unwanted effect (water, gas), the use of tracer technology is recommended. These tracer chemicals are injected down the annulus along with the completion equipment and are specially designed to determine any modification of a molecular composition of a fluid test. Their purpose is to provide a response to the contribution of each fracturing stage, which will lead to an improvement in future fracturing operations, well location, and the length of the drain.

It is impetuous to also be able to determine how major the impact of the interference between the wells put in production or the well stages. Crossflow dominated regions occur within the reservoir and may or may not lead to a successful improvement in the production of the oil.

Considering the above recommendations, the applicability is yet to be tested, and I hope that the continuous improvement of the field redevelopment teams in OMV will aim to accomplish an enhanced and successful production level.

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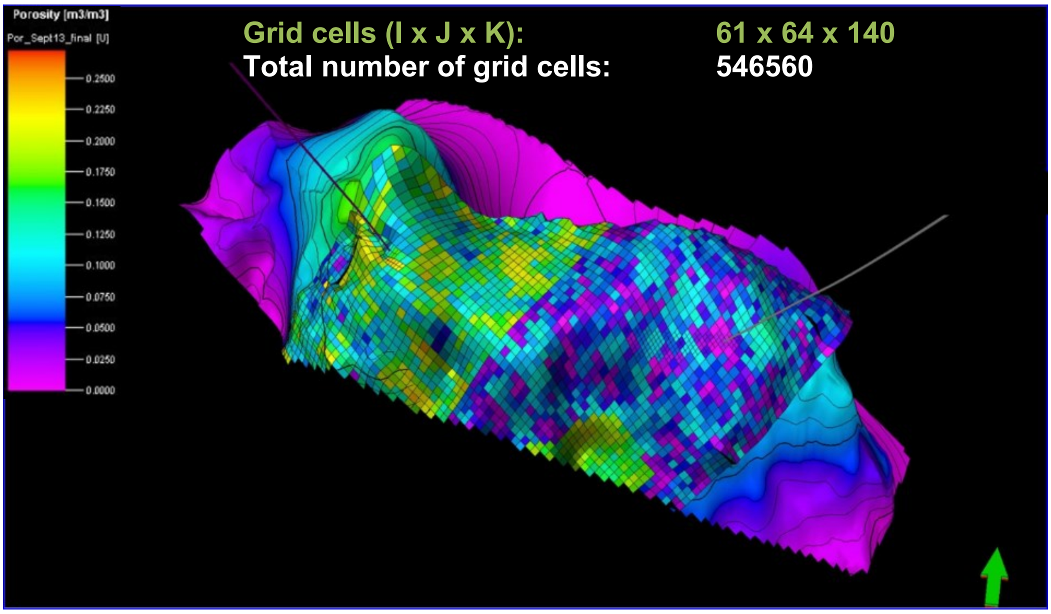
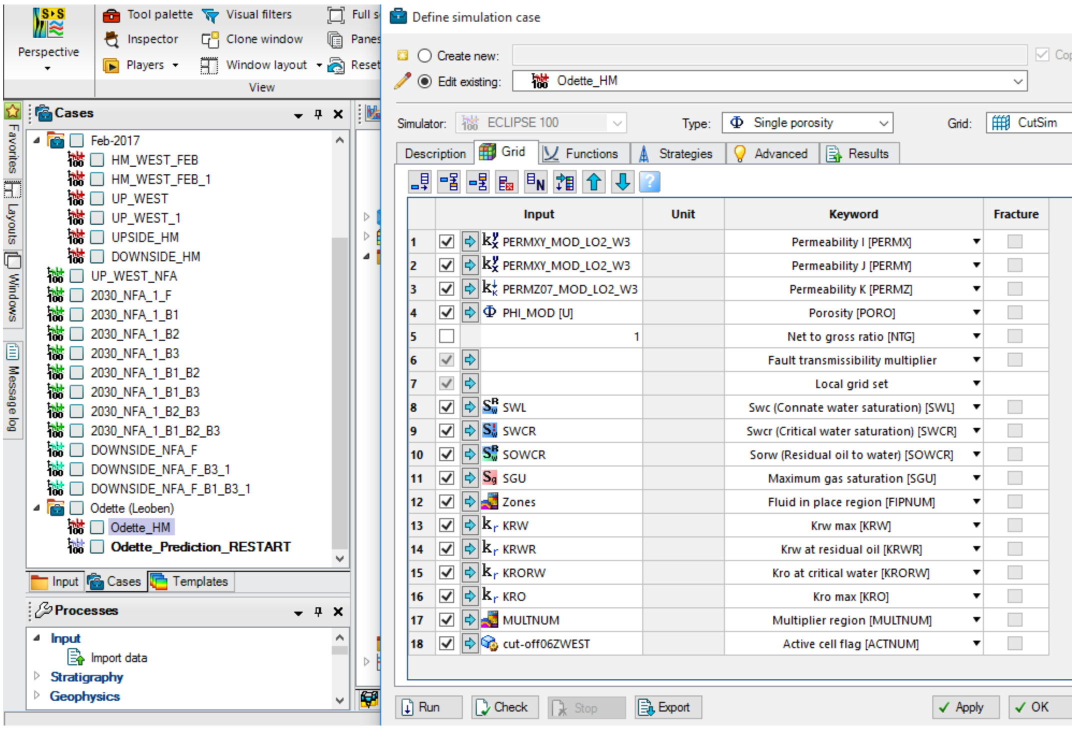
Appendix 1



Odette's Primary Cretaceous Dynamic Model

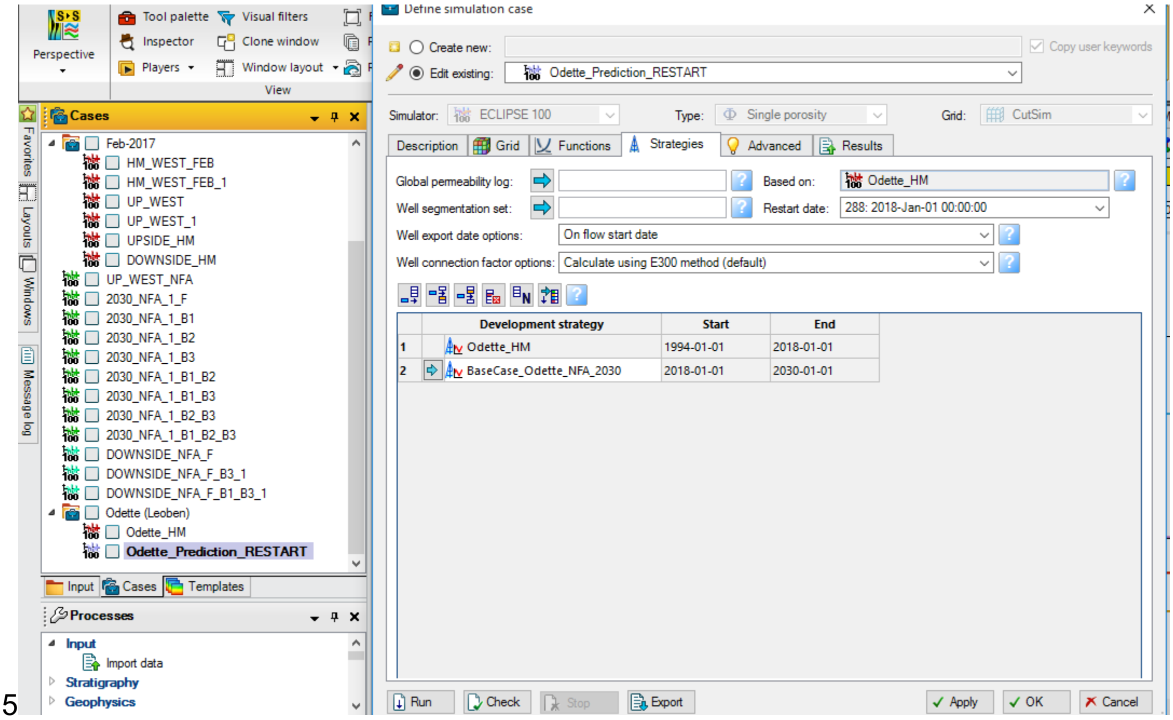
Appendix 2



Grid setup – Odette's HM simulation case

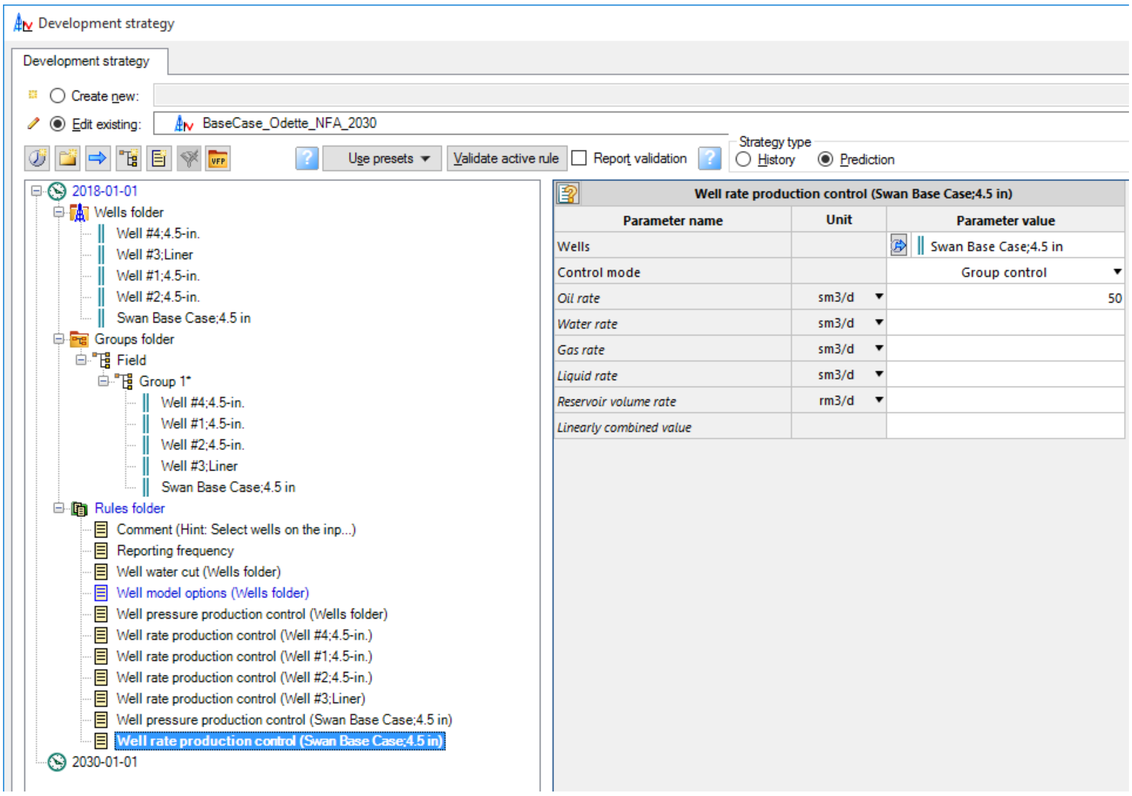
Appendix 3

5



Prediction restart case

Appendix 4



Development strategy – Future Prediction