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Preface

'Alhamdulillah' is the first word I want to express to God who grants me this pleasant life, thus give me the chance to pursue my master degree as well as finishing this master thesis.

It has been challenging yet wonderful moment on these past 2 years, particularly starting from the September last year when I started to consider the topic for my master thesis. The beginning was the most burdensome time when there was no available project related to offshore oil & gas on the listed topics arranged by my department. It was a daring decision when I run after my own passion and determine the field development as my own proposed topic.

I sincerely would like to deliver a special gratitude to Prof. Jan Inge Dalane who always encourage me to grab this interesting topic. His supervising, knowledge, and discussion time contribute a lot on the completion of this project. The scope of this thesis itself is huge, and there was also time when I struggled to look for the available data. Delightedly, everything runs smoothly and under control because of his guidance. Moreover, it is an honor to have the opportunity to learn from one of the best field development expert in Norway.

Further, I do really want to appreciate the help and constant support from fellow colleagues. Thanks to Amrizal for the geological data and interpretation, Citra & Daisy for analyzing the reservoir condition, Budi & Nikka for the drilling part, as well as Madhan for sharing related to natural gas characteristics. Along with other friends I cannot mention one by one.

I also want to mention my dearest parents, Wahidin and Umi Lestari who always pray for me and support all of my decisions. Also to Iqbal Fathurahman, a brother who always care and never fails to cheer my day.

Last but not least, I dedicate this thesis to the 260 million Indonesian taxpayers who fund my study. Through LPDP-RI *(Lembaga Pengelola Dana Pendidikan – Republik Indonesia)* that manages the education endowment fund, currently the nation's young generations like me could achieve higher education in the best institutions all over the world. I truly intend to pay my debt of gratitude through delivering the excellent contribution to the growth of the nation.

Stavanger, 12th of June 2017

Amalia Handini Astari

Abstract

The vast amount of proven reserves of Masela gas block in Indonesia that reach 10.73 TCF is captivating in terms of development. The hydrocarbon is going to be produced through 18 production wells that are connected to 5 subsea manifolds in the water depth ranging from 300 m to 1,000 m and converted to LNG.

There are two main feasible development scenarios that are well known as offshore vs onshore concept. Offshore concept aims to build huge 500 x 82m FLNG with capacity of 7.5 MTPA, gas production up to 1,200 MMSCFD and 24,460 BOPD of condensate. With the defined capacity the size of FLNG on its completion will be marked as the most gigantic offshore vessel ever built. The other onshore concept that suggested the accumulated gas from subsea production system is connected to 330 x 65m FPSO then transported by pipeline to 9 MTPA onshore LNG Processing Plant in Maluku, and exported to customer from the region.

The engineering analysis is performed to evaluate the feasibility of FLNG to be implemented in Masela condition. The main challenge of FLNG Masela is its huge dimension that leads to safety issues. On onshore concept, the pipeline become the highlight of the study. The finest route is to lay 100 km pipeline to onshore Pulau Yamdena where is relatively save according to engineering evaluation as well as attractive in term of economic.

With certain assumptions, the economic model is built to compare both concept in business perspective. The cost of 7.5 MTPA FLNG reach 17.978 billion USD or expected about 2.4 billion USD/MTPA. On the other hand, onshore LNG Plant looks promising with cost of 1.165 billion USD/MTPA. The total cost for developing Masela block with onshore option in the range of 14.573 billion USD even 25% lower than the cost of FLNG itself. The capital expenditure as well as the price of LNG are highly affecting the economics value of both concepts.

The existence of Masela block in this region may lead to prosperity of this region or in contrast lead to larger gap in social strata of this province. Social analysis also conducted to gain broader point of view. More industries might be developed such as shipbuilding, fertilizer, also petrochemical industry as the multiplier effect of the existence of the block in the region.

Abbreviations

BMKG	Badan Meteorologi, Klimatologi, dan Geofisika Republik Indonesia (English: Meteorogical, Climatological, and Geophysical Agency of Republic of Indonesia)
BOPD	Barrels of Oil per Day
BPS	Badan Pusat Statistik Republik Indonesia (English: Statistic Institution of Republic of Indonesia)
FLNG	Floating Liquefied Natural Gas
FPSO	Floating Production Storage and Offloading
IRR	Internal Rate of Return
KESDM	Kementerian Energi dan Sumber Daya Mineral Republik Indonesia (English: Ministry of Energy and Natural Resources of Republic of Indonesia)
KEMENPERIN	Kementerian Perindustrian Republik Indonesia (English: Ministry of Industry of Republic of Indonesia)
KKS	Kontraktor Kontrak Kerja Sama (PSC Operator)
LNG	Liquefied Natural Gas
MMSCFD	Million Standard Cubic Feet per Day
MMSTB	Million Stock Tank Barrels
MTPA	Metric Tons per Annum
NPV	Net Present Value
POD	Plan of Development
PSC	Production Sharing Contract
SKK Migas	Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi (English: Special Task Force for Upstream Oil and Gas Business) Institution established by the Government of the Republic of Indonesia under Presidential Regulation to manage the upstream oil and gas business activities under a Cooperation Contract.
SURF	Subsea, Umbilical, Riser, and Flowline
TCF	Trillion Cubic Feet

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1 Introduction

1.1 Background

Abadi Field[1] that is part of Masela gas block is located in offshore Maluku Province, eastern territory of Republic of Indonesia. The huge amount of proven natural gas reserves on number 10.73 TCF (Trillion Cubic Feet) is three size larger than the remaining reserves of the nation's current largest operating natural gas block, Mahakam. PSC (Production Sharing Contract) is granted to INPEX and Shell as the official KKKS licensed operator for Masela. Since early 2000s Masela block has become the subject of discussion not simply just because of its giant reserves. The confirmed existing gas and condensate in the reservoirs marked the first discovery of hydrocarbon in the Arafura Sea and opened the new era of exploration on the Eastern Indonesia deep water.

In December 2010 when the proven reserves were ranging on 6-7 TCF, POD-1 (Plan of Development-1) was submitted by INPEX and Shell to develop the block with an FLNG (Floating Liquefied Natural Gas) with processing capacity up to 2.5 MTPA of LNG and 8,400 BOPD of condensate. Additional exploration drilling on 2013-2014 escalated proven volume reserves to the current state, thus INPEX and Shell submitted POD-2 in 2015. The essential mark on POD-2 is to expanse the FLNG capacity into 7.5 MTPA, with gas production up to 1,200 MMSCFD and 24,460 BOPD of condensate. With the defined capacity the size of FLNG was expanded into 500 meters length with 82 meters width and on its completion this will be marked as the most gigantic offshore vessel ever built.

The enormous capacity of the FLNG catch public interest, the other concept which is to develop the block by using an onshore LNG Plant came up. Now there are two main feasible development scenarios which are opposing each other that are well known with offshore vs onshore concept. The one that following INPEX and Shell proposed concept with subsea production and FLNG so the product can be directly exported to market. Or the other onshore concept that suggested the accumulated gas from subsea production system is connected to FPSO then transported by pipeline to onshore LNG Processing Plant in Maluku, and exported to customer from the region.

Development of Masela block necessitates an appropriate integrated assessment from extensive point of view. The proper studies should be conducted by considering technical, economic, and social aspects to examine the two recommended concepts and gain the finest solution for Masela. There is a soaring prominence to contemplate the development process as Masela in the future is anticipated to become the largest producing natural gas field to boost Indonesia's declining oil and gas sector.

[1] The gas field was named Abadi that means "eternal" in the Indonesian language due to its vast amount of gas reserves.

1.2 Objective and Scope of Work

The main objective of the thesis is to examine offshore FLNG concept as well as onshore LNG Plan concept in broad perspective based on technical, economic, and social aspects.

The scope of this thesis is evaluating both prospective concepts with the description as follows:

1. Describe the difference of the proposed offshore and onshore concepts.
2. Evaluate both concepts in term of technical/ engineering point of view (identify challenge for offshore FLNG and onshore pipeline, rough feasibility study for both FLNG and onshore pipeline to be implemented in Masela, determine the finest pipeline route for onshore LNG concept).
3. Set up and analyze economic model for both concepts in terms of NPV (Net Present Value), IRR (Internal Rate of Return) as well as its sensitivity parameters.
4. Review the offshore and onshore concepts based on social perspective through exploring its multiplier effects as well as its impact to the society.

The outcome of this thesis are the engineering, economic, and social evaluation result for the development of Masela.

1.3 Limitations

The thesis is limited to the rough concept evaluation within engineering, economy, and social boundary based on the available data. Moreover, the idea of the thesis is proposed by the author as an effort to apply the academic knowledge obtained from previous degree as well as from Offshore Technology Master Program at the Universitetet i Stavanger. Thus the accessibility to gain the accurate data is limited. Even though the Masela block and its present conditions are real, some of data listed on the thesis might be the certain assumption. The evaluation result, particularly the calculation on economic part, cannot be used as a reference for the real case. Further analysis with the right numbers should be conducted.

1.4 Structure of Thesis

The thesis is divided into 10 main chapters:

1. The thesis begins with an introduction that describes the background of study, objectives, scope of work, and its limitation.
2. The second chapter incorporates relevant fundamental theories that refer to academic literatures. The description of natural gas and condensate that represent Masela's reservoir are listed. The definition of commercial reserves also described on this chapter.
3. As the thesis examines the field development stages, thus the overview of processes and phases on typical field development also explained on Chapter 3.

4. The fourth section describes data of Masela block. The chapter starts with a brief history about the block, then geographical location, geology, as well as reservoir conditions. The condition of metocean and its projected market also listed on this section.
5. Chapter 5 answers the first scope of the thesis. This chapter describes building blocks for both offshore and onshore concepts also defines the difference of the proposed concepts.
6. The second point of scope of study answered by Chapter 6 and Chapter 7. Chapter 6 evaluates the FLNG by identifying the challenges that might occurs and feasibility assessment of FLNG implementation in Masela.
7. The main focus of seventh chapter is the pipeline that will be laid from FPSO to onshore Maluku. The feasibility of implementing pipeline concept in Arafura Sea is explained on this chapter. Then it follows by analysis to determine the most suitable pipeline route according to several driver parameters.
8. Economic models for both concepts are established on 8th Chapter. This chapter aims to give an idea about economic value as well as its sensitivity parameters.
9. The ninth chapter incorporates the description of social condition, demography, and the social impact analysis against the presence of exploitation activities in Masela.

The last chapter concludes the thesis and evaluation results for both offshore and onshore concept.

2 Fundamental Theories

2.1 Hydrocarbon Resources

Hydrocarbon defined as a natural organic compound consisting of hydrogen and carbon (Glossary, 2017b). There are different types of hydrocarbon stand on Earth, the most simple formations are methane [C1 or CH_4] and ethane [C2 or C_2H_6], and it can be exist on other highly complex molecules. Generally known that the molecules can have various kind of shapes, branching chains, rings, or other structures (IUPAC, 1979). Hydrocarbon can be exist on different phases depends on its conditions such as gasses (e.g. methane and propane), liquids (e.g. hexane and benzene), or solids (e.g. paraffin and naphthalene).

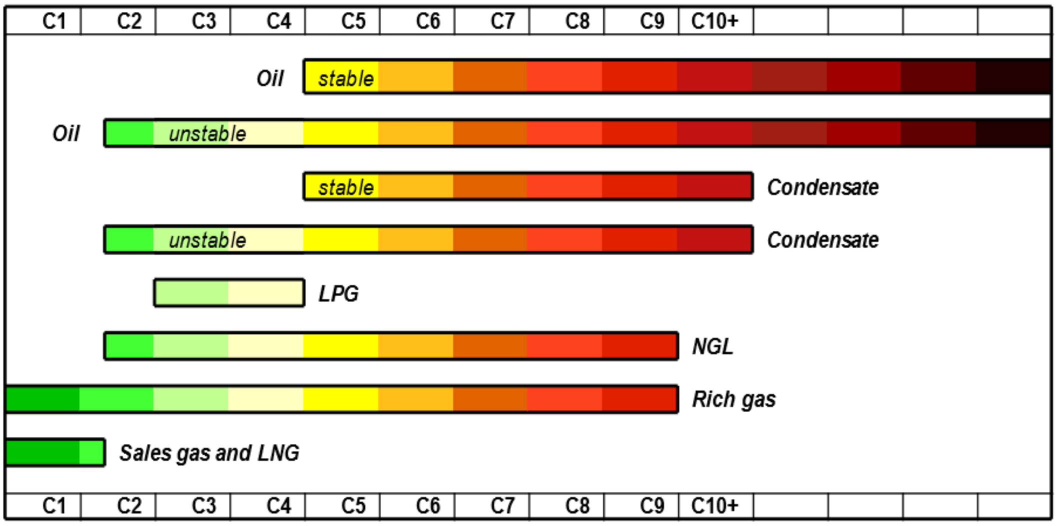


Figure 2.1 Hydrocarbons and Sales Product

Figure Source: OFF515 Offshore Field Development Lecture Note Chapter 04 by Odland (2014c)

Figure 2.1 above shows some properties of simple hydrocarbons, some definition below shows the general explanation for each products.

- The two most simple molecules, methane [C1] and ethane [C2], are classified as gas at ambient temperatures and need further pressure treatment to be liquefied. This is the LNG, the product of Masela.
    - On the other hand, molecules of propane [C3] appears as a liquid and can be easily liquefied.
    - Molecules of butane [C4] also can be easily liquefied and proven as safe fuel that commonly used as volatile fuel for small pocket lighters.
    - Pentane [C5] exists as a clear liquid within room temperature characterized with its odorless solvent of waxes that are widely used in chemistry and industry
    - In addition to [C5], hexane (6C) commonly used solvent too as a significant fraction of common gasoline

- Generally, ranging from hexane [C6] to decane [C10] are considered highly complex molecules as top components of gasoline, naphtha, jet fuel and specialized industrial solvent mixtures.

2.2 Natural Gas

Like any other hydrocarbon products, natural gas deposit can be found on the source rock deep of the Earth surface. Generally known, natural gas described as highly compressible and expansible naturally occurring mixture of hydrocarbon. Natural gas is widely used as a fuel and the raw material for chemicals and industry processes.

About 85% natural gas likely compounds as methane [CH_4], while the rest ranging from ethane [C_2H_6] to pentane [C_5H_{12}]. Natural gas also contains small amount of hydrocarbon gas liquids and nonhydrocarbon gases impurities such as carbon dioxide [CO_2], helium [He], nitrogen [N], or hydrogen sulphide [H_2S].

In general produced natural gas comes out with some mixtures amounts of ground water (contains no salts) vapor in equilibrium with the gas in the varying percentages. Those water can obstruct the production process as it leads to decreasing pressure and temperature in the flow lines.

There are two common categories of natural gas: wet gas and dry gas.

Wet gas

Wet gas, or also commonly mentioned as rich gas, is natural gas that contains significant compounds heavy carbons such as propane, butane and other liquid hydrocarbons that can be liquefied. The term of heavy carbons described as the hydrocarbon components which has heavier components than ethane (not water). Geologically, wet gas is term of a mixture of hydrocarbons withdrawn directly from a well contains liquid hydrocarbons (EIA, 2017).

Dry gas

Dry gas, or also commonly mentioned as lean gas, is natural gas that contains a few or no liquefiable liquid hydrocarbons (methane and ethane). This is the type of gas of Masela block, with high content of gas and no liquefiable liquid. This consumer-grade natural gas produced by separating methane, ethane, and other useful gases from the wet natural gas on the processing stage. Natural gas must be treated fulfilling commercial allowable standard concentration in terms of impurities such as water, carbon dioxide, etc. Then the dry gas distributed directly through pipelines or converted to liquefied gas.

2.3 Natural Gas Liquid (NGL)

Schlumberger’s Oilfield Glossary (2017d) describes NGL as component of natural gas in the form of liquid on the surface of its gas processing facility. NGL exists in the hydrocarbon molecules as propane, butane, hexane, and heptane but not as methane or ethane as the last two hydrocarbons require proper cooled down process to become liquid. In terms of value, NGL has high value on the market, thus they are extracted on the first processing stage and sold separately with the other natural gas products.

NGL is subdivided according to their vapor pressure[2] into:

Low Vapor Pressure - Condensate which is commodity of the Masela case, is liquid hydrocarbon which has low-density and high-API gravity (50-120 degrees) (Glossary, 2017a) that most likely arises associated with wet gas. Condensate is in the gaseous state under reservoir conditions and presence as a liquid when temperature or pressure is reduced below the dew point[3]. Condensate also widely known as natural gasoline due to its hydrocarbon components that occur on the gasoline boiling range. Condensate is mainly composed of propane, butane, pentane and heavier hydrocarbon fractions. Moreover, condensate is not only generated into the reservoir but also formed when liquid drops out, or condenses, from a gas stream in pipelines or surface facilities. Condensate a single-component system can behave as a gas, liquid, solid or a mixture of these relying upon its temperature and pressure as shown on **Figure 2.2** below.

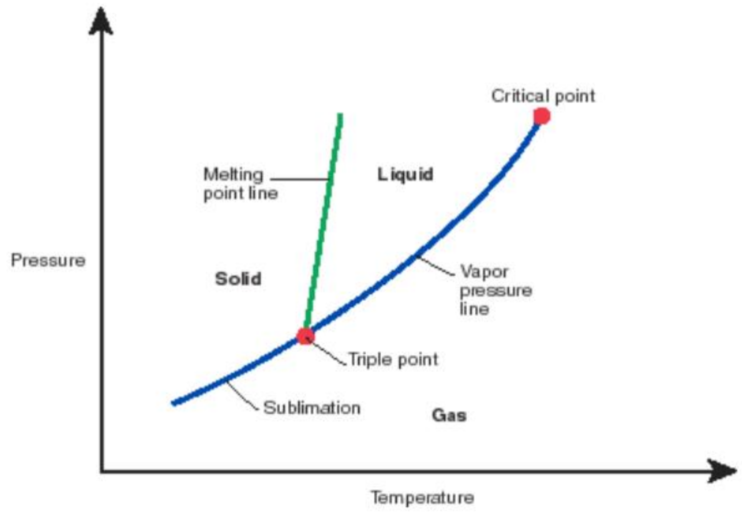


Figure 2.2 Condensate Behaviors Depending on Its Temperature and Pressure
Figure Source: Schlumberger Oilfield Glossary (2017a)

[2] The pressure exerted by a vapor escaping from a liquid. It quantifies the tendency of molecules to enter the gaseous phase. The vapor pressure of water increases as temperature increases and reaches one atmosphere pressure (760 mm Hg or 14.7 psia) at the boiling point (100°C or 212°F). The activity of an aqueous solution is the ratio of vapor pressures: $a_w = p/p_o$, where p = vapor pressure of a solution and p_o is vapor pressure of pure water. Since this is a ratio of vapor pressures, activity is not a strong function of temperature.

[3] The pressure at which the first condensate liquid comes out of solution in a gas condensate. Many gas condensate reservoirs are saturated at initial conditions, meaning that the dew point is equal to the initial reservoir pressure. Condensate dissolution is called retrograde condensation because this is counter to the behavior of pure substances, which vaporize when the pressure drops below the saturation pressure under isothermal (constant temperature) conditions.

Intermediate Vapor Pressure - Natural Gasoline (Naphtha) is a natural gas liquid which has intermediate vapor pressure between condensate and LPG. Natural gasoline that is mostly build up in terms of pentanes and heavier hydrocarbons is much more volatile and unstable compare to commercial gasoline. Naphtha is recovered at normal pressure, end-point, and temperature (Glossary, 2017e) like other specifications for natural gasoline.

High Vapor Pressure - LPG (Liquefied Petroleum Gas) is natural gas which has been liquefied at low temperatures and moderate pressures. The gas is retrieved from refinery gases or as a product of crude oil cracking process (Glossary, 2017c). Ranges of LPG, also well known as bottle gas, on the market are generally composed of propane and butane. LPG is widely used especially by industries and household customers as it is easy to convert the liquefied gas into gas on the atmospheric pressure.

2.4 Natural Gas Products

Natural gas has low density that makes it's not as simple as crude oil in terms of its storage and transportation process. Natural gas required cooling down process, compressing (EIA, 2017), and other phases in order to be readily used by consumes. As a result, natural gas comes to the market in various products due to its complex characteristics. These are common natural gas products on the market:

Piped Gas is natural gas transported via large-diameter and high-pressure pipeline from the processing plant to the customer. This product considered as simple transported product. However, this method is rather impractical for long-distance distribution. It is obligatory to keep the gas transported gas within certain temperature and pressure, on long distance pipeline the temperature of gas tends to heated up due to the friction of gas and pipeline.

LNG (Liquefied Natural Gas) is natural gas (mainly methane and ethane) that has been cooled and converted to liquid at extremely low temperature (-161^{o}C) or called cryogenic temperatures and within the pressure near the atmospheric pressure (1 bar). LNG is commonly used when the marketplace is far and pipeline can't reach that location. On the market destination, the LNG is regasified and transported into gas flow system to the customer.

CNG (compressed natural gas) is natural gas which is pressurized and stored in cylindrical or spherical tanks where the pressures is regulated up to 250 bar. The composition of CNG is the same as the piped gas, but in CNG some of water contains has been removed. CNG can also be stored in similar or greater energy density by storing it on the lower pressure tank called ANG (Adsorbed Natural Gas) which is made by assorted sponge-like materials.

Synthetic Fuel or Synfuel is any liquid fuel retrieved from coal, natural gas, biomass, or sometimes obtained from other solids through fermentation of bio-matter such as oil shale, tar sand, etc. There are several types of synfuels diverse based on its initial deriving hydrocarbon for example: CTL (Coal-to-liquids), GTL (Gas-to-liquids), or BTL (Biomass-to-liquids)

Methanol, widely familiar as methyl alcohol [CH_3OH], is the simplest form of alcohol identified as light, volatile, colorless, flammable, poisonous liquid with a distinctive odor. It is commonly produced from natural gas and suitable used as antifreeze, solvent and fuel.

2.5 Reserves Terminology

Reserves are the amount of hydrocarbon that claimed to be recoverable in terms of commercial perspective by using the existing technology. The estimated reserves clearly contains uncertainty on it leads by the reliability of the geology and reservoir data as well as the its interpretation (Odland, 2014c).

The level of uncertainty on the reservoir capacity may be divided into proven and unproven reserves. Then the unproven reserve is classified into probable and possible reserve. Thus the common reserves (shown on **Figure 2.3** below) are divided into:

- Proven reserves that also known as 1P
- Probable reserves that also known as 2P
- Possible reserves that also known as 3P

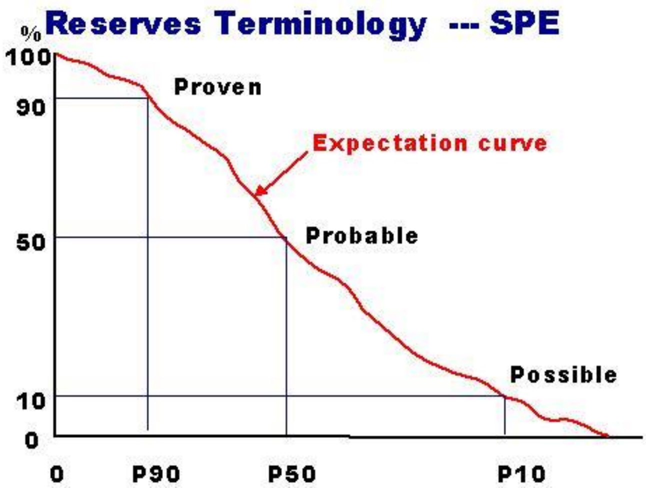


Figure 2.3 Reserves Terminology by SPE
Figure Source: Society of Petroleum Engineers (SPE, 2017)

Proven reserve is defined as P90 that means it involves 90% certainty of being produced. The level of uncertainty refers to the reasonable certainty of being recoverable in the current technology and economic circumstances.

The two unproven reserves are determined according to same geological and engineering data for the proven reserves (Odland, 2014c). However there are some issues related to the technical or economical perspective that create more uncertainties and lead those reserves to be classified as the unproven categories.

P50 is the other term for the probable reserve that claimed to has 50% recovery confidence. Then the less likely reserve is called the possible reserve. Then the possible reserve defined 10% chance to recover the reserves, or commonly called as P10.

2.6 Retrograde Gas-Condensate Reservoirs

The reservoir can be categorized according to its pressure and temperature properties. The retrograde gas-condensate reservoir which is the type of Masela reservoir is located on the middle part of the **Figure 2.4** below.

Retrograde gas-condensate reservoirs illustrates on the point B on the **Figure 2.4**. It presents when the pressure is sufficient to be above the boundary of the two-phase envelope and the temperature in between the critical temperature T_c and cricondentherm T_{cc} (Odland, 2014d). Only within those two point the condensate which has higher sales value can be produced. The fluid on the reservoir is in the single-phase gaseous state. When the pressure decreases, the produced fluid will turn into the single phase gas reservoirs, without condensate.

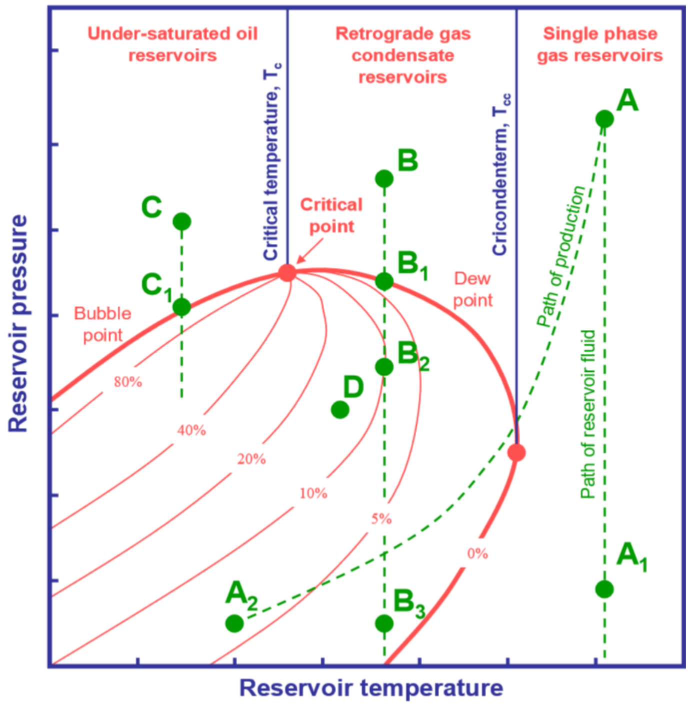


Figure 2.4 Phase Diagram of the Reservoir Fluids

Figure Source: OFF515 Offshore Field Development Lecture Note Chapter 06 by Odland (2014d)

As the reservoir contains both gas and condensate, thus should be any parameter to determine this ratio. Condensate-Gas Ratio (CGR) defines the ratio of condensate volume (liquid) to the produced gas. CGR is involves when the accumulation in the gas phase in the subsurface with the condensate (Odland, 2014d).

2.7 CO_2 Content

The purpose of the development is to gain as much profit as it can by commercializing the produced hydrocarbons. However there are some impurities that contained on the inlet oil & gas from reservoir and reduce the value of the product itself. Common impurities on the hydrocarbons for example are waxes, sulphur, H_2S, and CO_2

Gas fields in South East Asia generally contains high level of CO_2, so does Masela. The carbon dioxide is a corrosive substance that must be removed from the lifted gas in order to gain more value on the product itself. In Indonesia where Masela block is located, flaring is consider as an acceptable treatment to release the CO_2.

3 Project Development

The project is an integrated activity with the purposed objectives. The project is also defined as a unique set of activities (Gardiner, 2005) as one project different with another. Similar as any other project, developing an oil & gas field has a time constrains with its exploration at the beginning and the abandonment phase at the end of it. Each field development also particularly dissimilar with others in accordance to its field's characteristics.

The goals must be determined at the beginning of the development. The project development also involves extensive aspects on each phases. The scope and the subsequent phases are derived from that targets which at some extents reach to the detail level in order to optimize the achievement of the development itself.

3.1 Project Life Cycle

The project is the set of activities that presence for limited period over many years. This subchapter describes the typical framework of the project phases. The main steps of the project life cycle that are shown on **Figure 3.1** below includes: exploration, appraisal and planning, project execution, operation, and abandonment. The project development is part of the series of the project lifecycle that consist of appraisal and planning as well as the project execution.

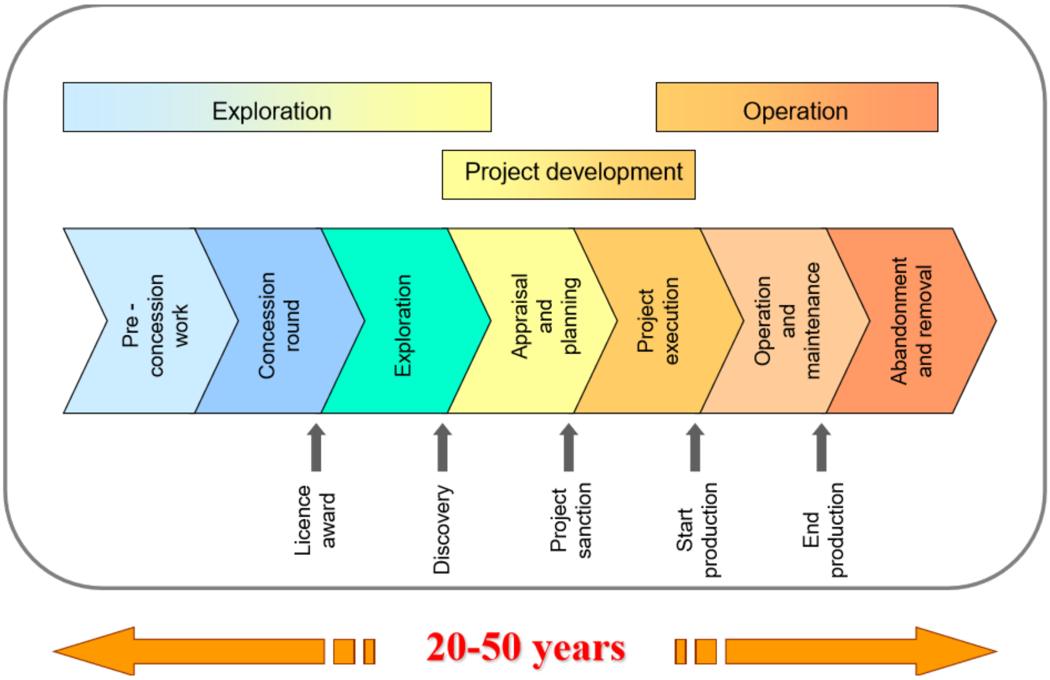


Figure 3.1 Typical Main Phases and Milestones on Oil & Gas Industry from Exploration, Development, to Operation
Figure Source: OFF515 Offshore Field Development Lecture Note Chapter 08 by Odland (2014e)

The beginning of the oil & gas project involves the license award that takes around 10 years until first start of production. After the license being granted, the operator starts the exploration then development. In addition, Purwanto et al. (2016) mentioned that statistically it took 5-12 years on developing gas fields in Indonesia.

On the oil & gas industry framework, the operator company is responsible for the massive development and its operation when discover a potential area. If the decided area is potentially profitable to be developed, the operator should start designing the front-end investment plan. The operator on this case is obligated to submit the Plan of Development (POD) to the authorized party to gain its approval. The authorities then evaluates the plan in consent of resources, impact, as well as acceptance of public interest.

The production period then started. Production is ranging from 10-50 years depends on the reservoir reserves. Some oil & gas fields may surpass the initial projected lifetime, for instance the case of ONWJ Block (Offshore North West Java) that operated by PERTAMINA. Thus it generally sums over many years of the whole project lifecycle from the exploration, development, as well as the operation phase. After the end of the production there is a responsibility from the operator to abandon the field accordance to standards and implemented regulations.

3.2 Planning Phase of Project Development

The project development phase is separated into two parts: project planning and project execution. The output of the planning period is the decision to execute the construction phase. The outcome of the construction phase is the start-up of the production. In the case of this thesis, the project development focus on the planning stage of Masela development.

The integrated planning at the beginning of the project is a crucial stage. Based on Gardiner (2005) that is the time when all the stakeholders convey their own purposes and negotiate with others. The aim of the project should accommodates the stakeholder’s urges. The planning phase then continue to get into detail into the technical details. At that phase the critical subject as well as the potential problems also been identified. Furthermore, more technical details such as analyzing the cost and risk will be followed when work progresses further (Odland, 2014e).

To control the decision phases, there are several structured steps with each decision gates (DG). Based on OFF515 Offshore Field Development Lecture Note, one of the possible execution model is shown on **Figure 3.2** below.

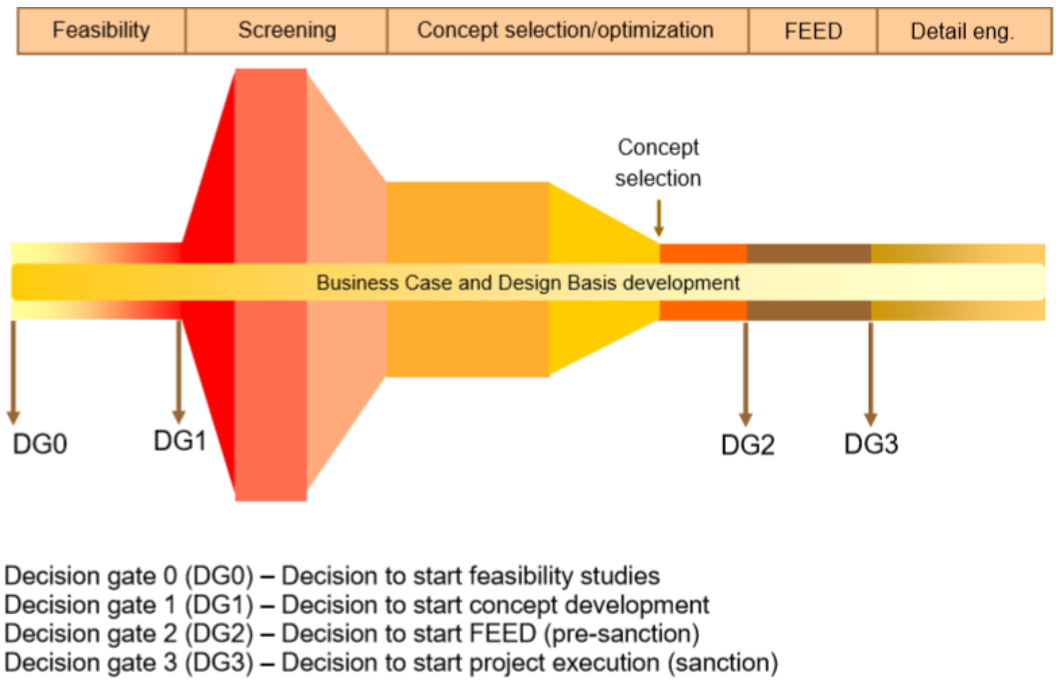


Figure 3.2 Structured Decision Points on the Planning Phase

Figure Source: OFF515 Offshore Field Development Lecture Note Chapter 08 by Odland (2014e)

On the planning phase, the feasibility, concept screening, concept selection, and pre-engineering phase are covered. The main purpose of this phase is to evaluate and determine the possible concepts in terms of technical feasibility, commercial scope, requirements, as well as the HSE within the limits of uncertainty (Odland, 2014e).

3.2.1 The Feasibility Phase

The feasibility phase aims to justify that the projected field is technically feasible and has economic opportunity to be developed. The output of this phase is the established document that is submitted for the DG 1. The authorized party at this point has responsibility to evaluate the feasible development which is technically accepted and profitable in accordance to the corporate's projects plans and budgets.

3.2.2 The Screening Phase

The screening phase follows after the DG 1. This purpose of the screening phase is to determine a list of the promising development concept. All relevant and feasible concepts will be established on this phase. Each concepts then be evaluated according to the requirements and expectations in order to judge most promising concepts to develop the selected field.

3.2.3 Concept Development and Selection Phase

The selected development concepts are developed on this phase. Further detail and specific evaluations are conducted here. Then at the end of this phase the most promising concept according to the determined criteria will be selected.

The outcome of this phase is the DG 2 that is the provisional project sanction authorized by the operator and authority. DG 2 responsible to approve the selected concept thus that concept is ready to be defined clearly.

3.2.4 Front End Engineering Development (FEED) Phase

On this FEED phase, the selected concept is develop and optimized on further details. Plan of Development (POD) is the product outcome of this step that contains the detail plan of project execution as well as its investment decision. The POD then submitted at the DG 3 to gain approval from the authority to continue as the basis project execution.

3.2.5 Detail Engineering

The last milestone on the planning phase is the detail engineering. This execution phase aims to design the detail engineering thus the concept will be ready to be executed.

3.3 Decision Criteria

The concept is selected accordance to the technical concept that included subsurface and well facilities as well as its business economic model. The concept is selected by comparing the promising concepts with the key driver criteria. The Net Present Value (NPV) is a powerful tool to evaluate the economic value of the project. Other than that, the other criteria also have to be considered to reflect the strategic issues and challenge. Those perspectives are:

- Technology perspective
- Value chain perspective
- Lifecycle perspective
- HSE perspective

3.4 Production Phases

Refer to Odland (2014d) the production phases can be categorized as three different types according to its reservoir production: primary, secondary, and tertiary recovery.

The primary recovery refers to the pressure depletion case which and employs the original pressure & temperature conditions of the reservoir. Some well stimulations that may contribute to increase and stabilize the plateau phase may also be implemented. For instance the well stimulation to improve the permeability of the well and the artificial lift (Odland, 2014d)

Further when the production rate is decreasing then it enters to the secondary recovery phase. The artificial lift is implemented on this phase by injecting water or gas to maintain the reservoir's pressure.

The tertiary recovery adopts the advanced recovery methods to increase the production rate such as chemical injection or any methods that may extract more hydrocarbons from the reservoir.

On this thesis the study is limited on the primary recovery phase only. This is due to the case that in Masela the primary phase has long plateau even without any artificial injection (will be shown on **Chapter 5.7.2**). Further recovery phases (secondary and tertiary) might be implemented after the end of plateau production.

3.5 Summary of Project Development

Oil & gas project development is an integrated work process that comprises many interdependencies with different disciplines. Including facilities, economic, social as well as legal aspects. This master thesis aims to evaluate the development of Masela block in approach of broad aspects. However its development will be limited only on the primary recovery production phase.

To elaborate that approach, the field development phase on this master thesis is limited only on the two stages: screening phase and development phase. All of them are part of the planning phase of the project development and the result of those is the defined development concept for further FEED of the field development.

4 Masela Block Description & Data

Offshore Indonesia is home to the Abadi gas field situated in the 3,221 km² Masela block in the Arafura Sea, Indonesia. The field lies in water depth ranging from 300 meters to 1,000 meters. INPEX Masela, a subsidiary of Japan-based oil and gas company INPEX, operates the field. INPEX earlier owned a 90% interest in the field but in July 2011 transferred 30% to Shell. Abadi is a large-scale project and INPEX invited Shell Upstream Overseas Services as a strategic partner to use its expertise in floating LNG technology. PT EMP Energi Indonesia owns the remaining 10%.

4.1 Brief History

In the beginning of its exploration on 1998, 100% total interest of Masela Block are owned by INPEX Masela, Ltd. through open bid. Production Sharing Contract (PSC) was granted on November 16th 1998 by Indonesian government for 30 years. On February and March on the year after, exploration was conducted by using 2D seismic marine vessel called Geco Rho (Offshore-Technology.com, 2017a). Hereinafter on December 2000, Abadi Gas Field was discovered through the first exploratory well drilled called Abadi-1 exploration well (INPEX, 2016) by using the Energy Searcher rig. While PGS Ramform Challenger marine vessel was used to performed 3D seismic survey on July to September 2001 (Offshore-Technology.com, 2017a). The confirmed existing gas and condensate in the reservoirs marked the first discovery of hydrocarbon in the Arafura Sea and opened the new era of exploration on the Eastern Indonesia deep water.

Thus INPEX as an operator drilled two appraisal wells called Abadi-2 and Abadi-3 on 2002 to measure the field reserves size. On May and June five years after, they subsequently drilled 4 more appraisal wells (Abadi-4, Abadi-5, Abadi-6, Abadi-7) and found significant amount of proven gas reserves (INPEX, 2016). Between 2000 and 2008 pre-FEED was carried out with this 6.9 TCF gas reserves.

Floating Liquefied Natural Gas (FLNG) was approved as a selected field development concept in the Plan of Development 1 (POD-1) by SKK Migas in December 2010. POD-1 respectively contains plan of FLNG concept development as well as Subsea, Umbilical, Riser, and Flowline (SURF) master plan design. POD-1 acquired the projected processing capacity of LNG is up to 2.5 MTPA and 8,400 BOPD of condensate.

In order to optimize the Abadi development gas field, in 2013-2014 three appraisal wells (Abadi-8, Abadi-9, Abadi-10) were drilled in the aim to expanding geology data and reservoir recoverable reserves (SKK-Migas, 2013). The result from those three wells unexpectedly added 4 more TCF proven volume reserves, marked Abadi field as the nation's third largest natural gas field by proven reserves. As the volume of reserved gas increasing, INPEX revised the previous POD, and resubmitted POD-2 on September 3rd 2015 to SKK Migas. The major mark on POD-2 is that it emphasizes to boost the FLNG capacity into 7.5 MTPA, with 1,200

MMSCFD gas production and 24,460 BOPD of condensate (INPEX, 2015, LNGWorldNews, 2015).

However the news of Abadi field development began to gain public attention, pros and cons about FLNG concept arise to the surface and has been becoming a national topic since then. On the beginning of 2016, many authorities' stakeholders from government institutions, expertise, and professional started to proposed different scheme of field development of Abadi field. Those many prospective building blocks then conned into the two most well-known concepts: offshore vs onshore. Offshore concept proposes to stay with existing INPEX plan with FLNG development, while onshore development suggests to build LNG Facility onshore. The two mentioned concepts (offshore and onshore) then will be analyzed further as the main topic on this master thesis.

4.2 Geographical Location

The Abadi gas field of Masela Block situated in Arafura Sea which is the farthest Southeast Sea in Indonesia, as well as stationed close to the border with neighboring countries, East Timor and Australia. Astronomically, Masela Block coordinates ranging from 08^0 05' 25.29" – 08^0 13' 58.94" South and 129^0 48' 11" – 129^0 56' 9.55" East (INPEX, 2016). Geographically, this block placed closed to Babar Sea on the North, Timor Sea on the South, also Arafura Sea in both East and West. The approximate area of this block is about 4,291 km², where located about 800km east of Kupang, Indonesia; and 400km north of Darwin, Australia. **Figure 4.1** below illustrates the location of Abadi Gas Field of Masela Block.

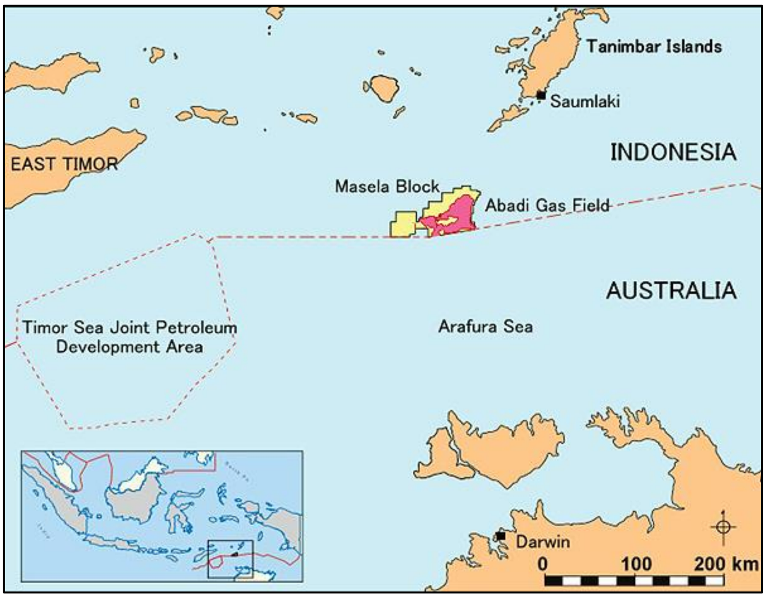


Figure 4.1 Geographical Location of Abadi Gas Field of Masela Block
Figure Source: Masela Block, Abadi Gas Field by Offshore-Technology.com (2017b)

4.3 Geology

Masela Block located on the *upper slope* of Australia continent, lies in water depth ranging from 300 m to 1,000 m, as seen on the **Figure 4.2** below. Abadi field which is estimated to contain 10 TCF natural gas reserves, geologically is from the Middle Jurassic Plover Formation (Nagura et al., 2003). Abadi reservoir plover formation approximately lie on 3,700 m to 3,900 m depths (Zushi et al., 2009), and also marked as the first hydrocarbon field from Middle Jurassic Plover Formation that was discovered in Indonesia. In terms of geology, Abadi field consists of relatively under formed Australian continental margin which is spread oud in Indonesia. Nagura et al. (2003) declared that this field has significant volume of accumulated gas column and its reservoir situated in the shallow marine, highly mature, quartzose sandstone environment.

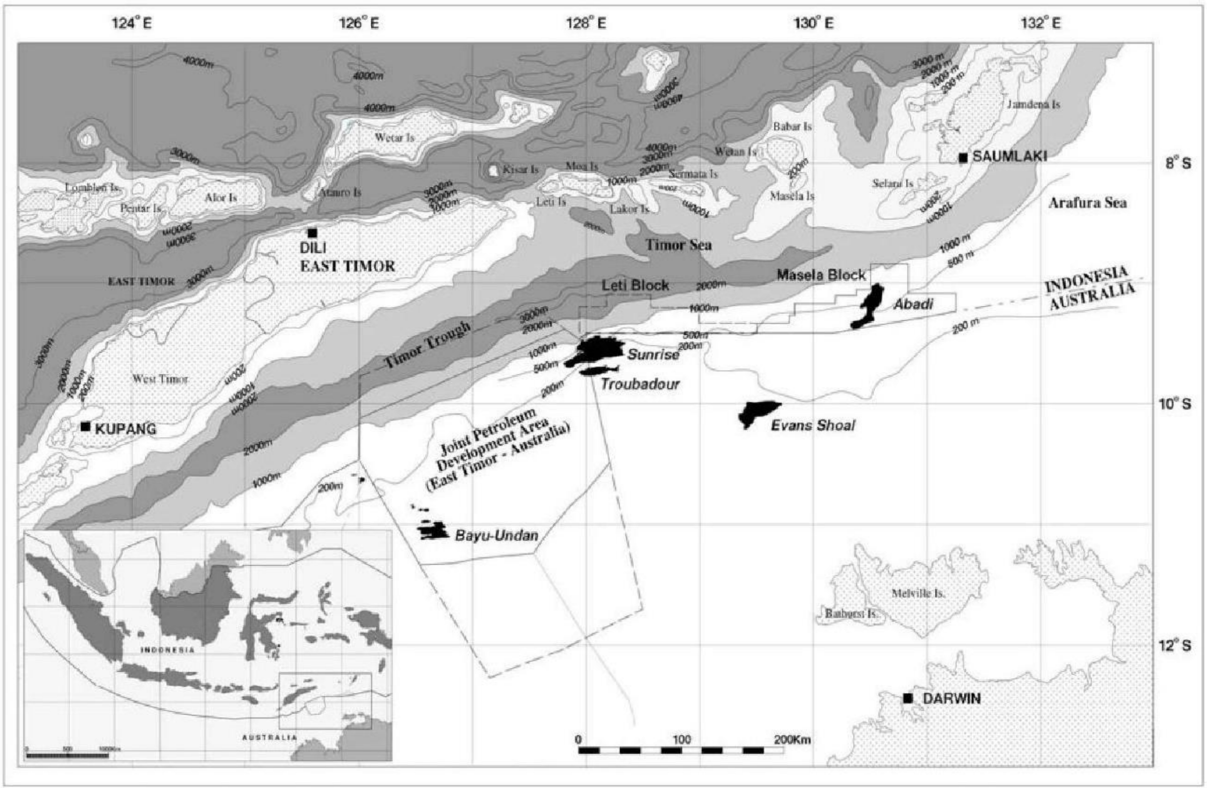


Figure 4.2 Location Map of the Abadi Gas Field
Figure Source: Map of Abadi Field by Nagura et al. (2003)

Source and Mitigation

The examination of source rock of the Abadi gas field conclude that the source rock foreseen to be laterally equivalent marine shales deposited contemporaneous with the Plover Formation (Nagura et al., 2003). Thermal maturity analysis diagnose that Abadi gas field has mature source rock in the Calderr-Malita Grabens, Masela Deep, and directly down-dip from Abadi Field towards the Timor Trough.

Inspection conducted by INPEX reported that the Grains containing Oil Inclusion (GOI) valued for Abadi field is less than 0.2% and discover no oil inclusion on quartz grains in the gas filled sandstone (Nagura et al., 2003). Based on Eadington et al (1996) that number express indication that there is no liquid hydrocarbon migration before the gas trap.

Trap and Seal

Based on INPEX studies, The Abadi Field structure is described as a paleo high that revived and adjusted by subsequent rifting both in the latest Jurassic or Cretaceous and in Neogene. The fault of the traps is generally divided into northern and southern block but postulated there is no fault compartmentalization conjugated on the field (Nagura et al., 2003). Nagura et al. (2003) also emphasize that the formation of primary side-seal had been developed along movement of southern block faults and east Plover reservoir, while the top seal is formulated by regional Euchaca Shoals Formation.

Reservoir Quality

According to INPEX reservoir studies the quality of the reservoir within quartzarenite sandstone of Plover Formation follows complex interaction of primary depositional controls setting and later diagenetic influences. In general the whole quality of reservoir is diverse from good to poor quality, while the excellent reservoir quality can be found in depths more than 3,400 meters.

4.4 Reservoir Description

The reservoir is comprised of a sandstone and mudstone sequence in the upper part of the Middle Jurassic Plover Formation. Reservoir target depths are approximately ranging from 3,700 to 3,900 meter below the mean sea level, with total size area 4.291,35 km^2 illustrates on **Figure 4.3** below. INPEX recent studies shows that gas column with common gas-water contact on the field extents more than 200 m in height. The area of accumulation enhances over a vast structural area closure which has size more than 1,000 km^2 and bounded by multiple conjugate faults. To conclude, the total gas in place proven reserves of the Abadi gas field estimated 10 TCF (approximately 242×10^{9}m^3) and 209 MMSTB of condensate (INPEX, 2015, ESDM, 2017).

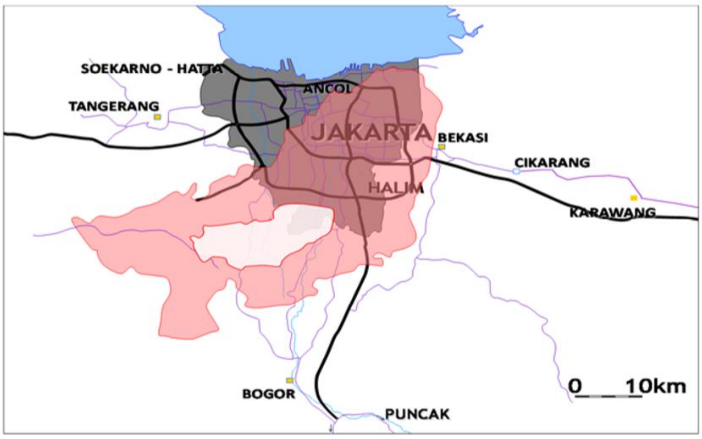


Figure 4.3 The Abadi Gas Field Compared to Size of Indonesia’s Capital Region Jakarta

Lean gas, also introduced as dry gas, with few liquefiable liquid hydrocarbons is the type of gas outspreaded in the field. According to Nagura et al. (2003) and Zushi et al. (2009), the lean gas on Abadi field contains generally 6-7% of CO2, while Offshore-Technology.com (2017a) claimed roughly 9.3% of CO2 on the total gas volume. The other hydrocarbon product contained on the field is that is small & waxy type condensate.

The development process will be executed in the northern portion of the field as mention on the **Section 4.3** above where the most of the proven reserves are accumulated. During the operational life cycle, the flow rates are projected on 60 MMSCFD per well with 18 directional production wells drilled from 5 subsea manifolds. Production rate is projected up to 1,200 MMSCFD of gas and 24,460 BOPD of condensate for the next 22-24 years. The calculation of production profile for both concepts later will be described on **Chapter 0** on page 37 below.

Table 4.1 The Gas Composition of Masela Reservoir
Data are cited from Yerido et al. (2016)

Composition	% Molarity
N_2	0.933
CO_2	9.291
C_1	81.49
C_2	4.288
C_3	1.512
i- C_4	0.296
n- C_4	0.143
i- C_5	0.187
n- C_5	0.157
C_6	0.230
C_7^+	1.474
H_2S	0.001
Total	100

The chemical components on Masela block is listed on **Table 4.1** above. On the table, it is mentioned that the content of carbon dioxide (CO_2) reach 9% of the reservoir. This high content is challenging on this case and may lead to corrosion on the facilities, as already mentioned on **Chapter 2.7** on page 10 above.

4.5 Climate & Metocean Condition

4.5.1 Climate

The climate of Indonesia is classified as tropical, so does Maluku. On dry season there is much less rainfall than on the wet season. According to Köppen-Geiger climate classification, the region classified as Aw level. Maluku province has annual average temperature in the number of 25.6 °C as shown on **Figure 4.4** below. Climate-Data (2017) defined that the annual precipitation on this province has an averages of 1420 mm.

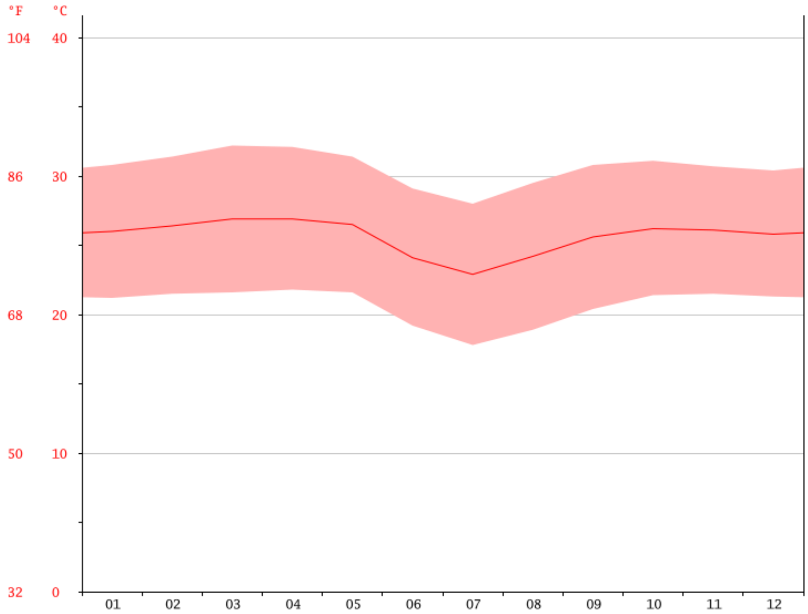


Figure 4.4 Annual Temperature of Maluku Province per Month

Figure Source: Climate-Data (2017)

4.5.2 Wave

Data from BMKG on **Figure 4.6** below shows that the significant wave height (100 years) around Masela on the range of 1.5-3.5 meters. According to BMKG, Masela surroundings considers as a rough sea in the Indonesia, but relatively benign for offshore operation if compared to the North Sea condition. The ocean waves tend to head from south-east to north-west.

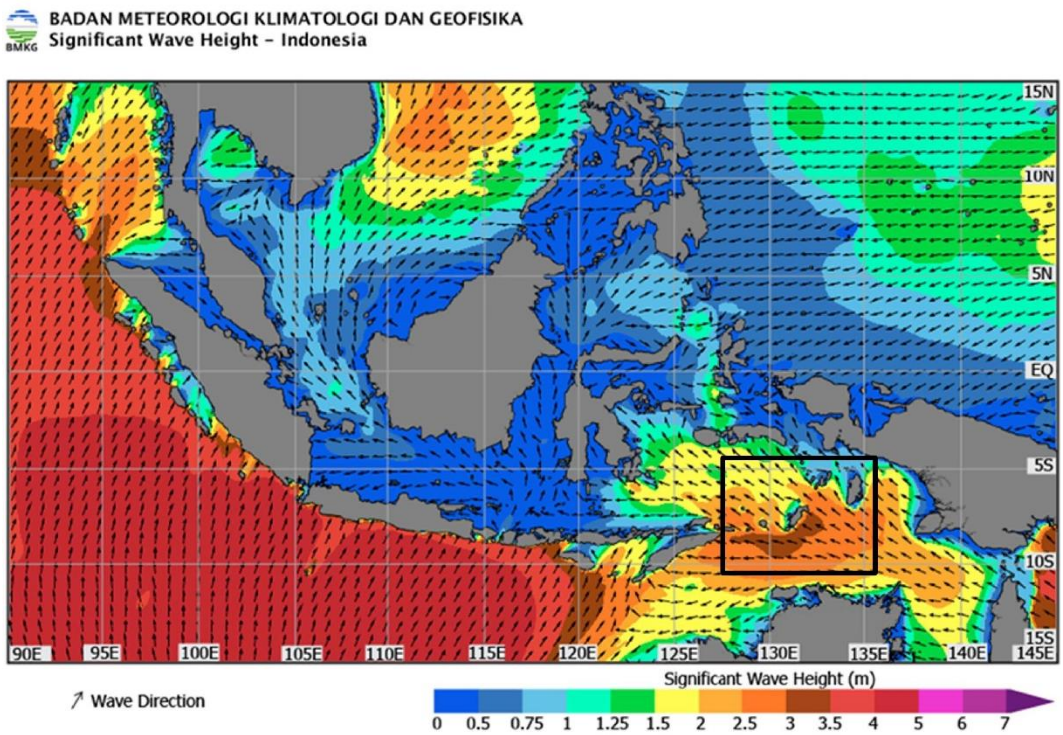


Figure 4.5 Significant Wave Height in Indonesia

Figure Source: Badan Meteorologi, Klimatologi, dan Geofisika Republik Indonesia (BMKG, 2017e)

4.5.3 Wind

Figure 4.6 below shows that the 100 years wind speed around Masela is forecasted to be around 10-30 knots or 5.2m/s – 15.6m/s. The condition is relatively calm and stable for offshore operation.

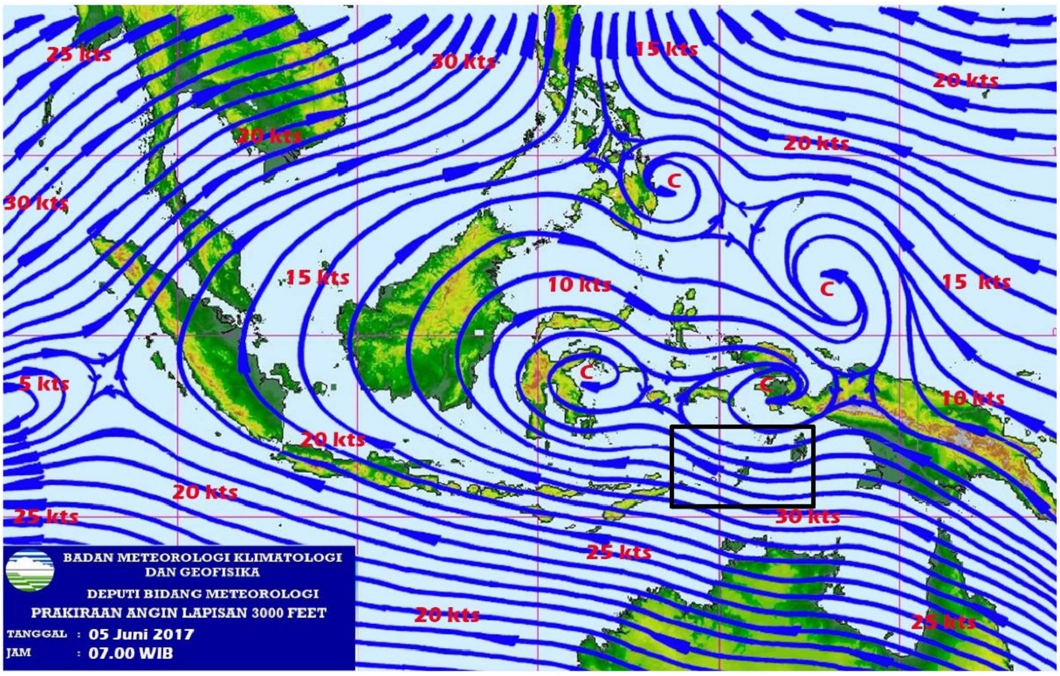


Figure 4.6 Wind Forecast in Indonesia

Figure Source: Badan Meteorologi, Klimatologi, dan Geofisika Republik Indonesia (BMKG, 2017c)

4.5.4 Sea Surface Temperature

The sea surface temperature in Indonesia generally is mild-warm temperature. The area of Masela block on **Figure 4.7** below states that its temperature is ranging from 27-29 ^{o}C.

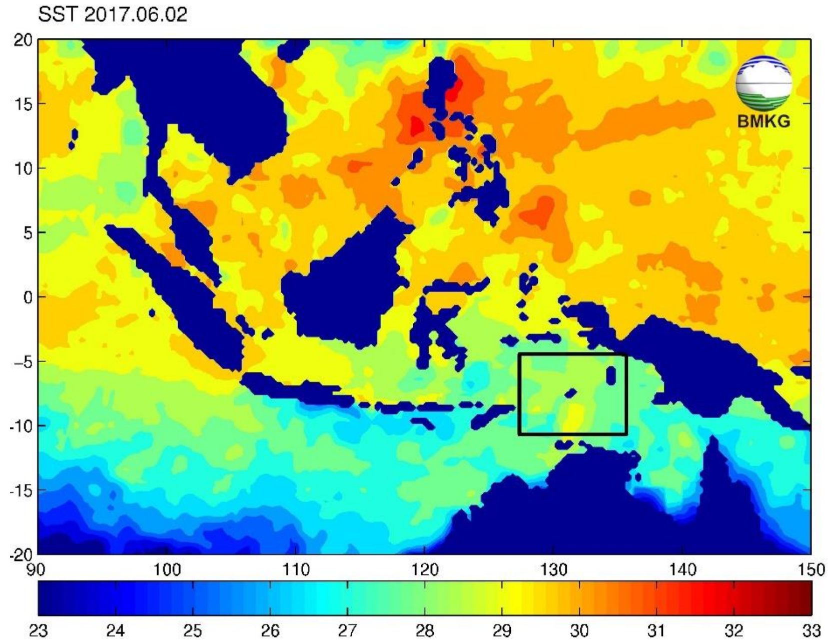


Figure 4.7 Sea Surface Temperature in Indonesia

Figure Source: Badan Meteorologi, Klimatologi, dan Geofisika Republik Indonesia (BMKG, 2017d)

4.5.5 Earthquake & Tsunami

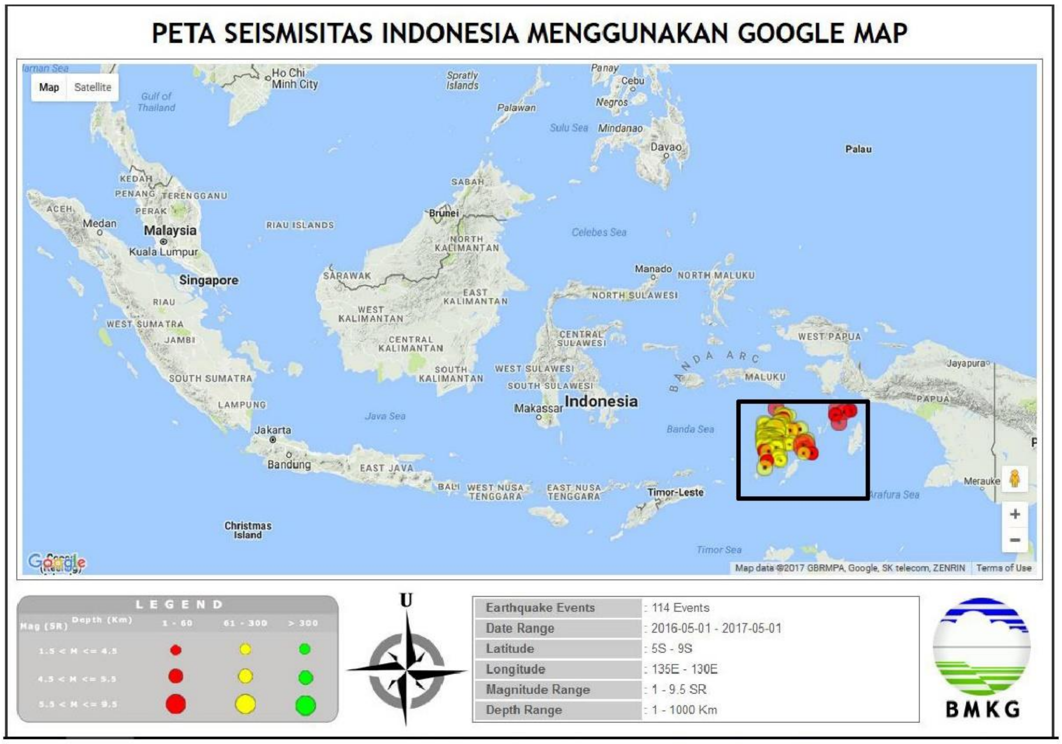


Figure 4.8 Seismic Activity Map from May 2016 to May 2017

Figure Source: Badan Meteorologi, Klimatologi, dan Geofisika Republik Indonesia (BMKG, 2017b)

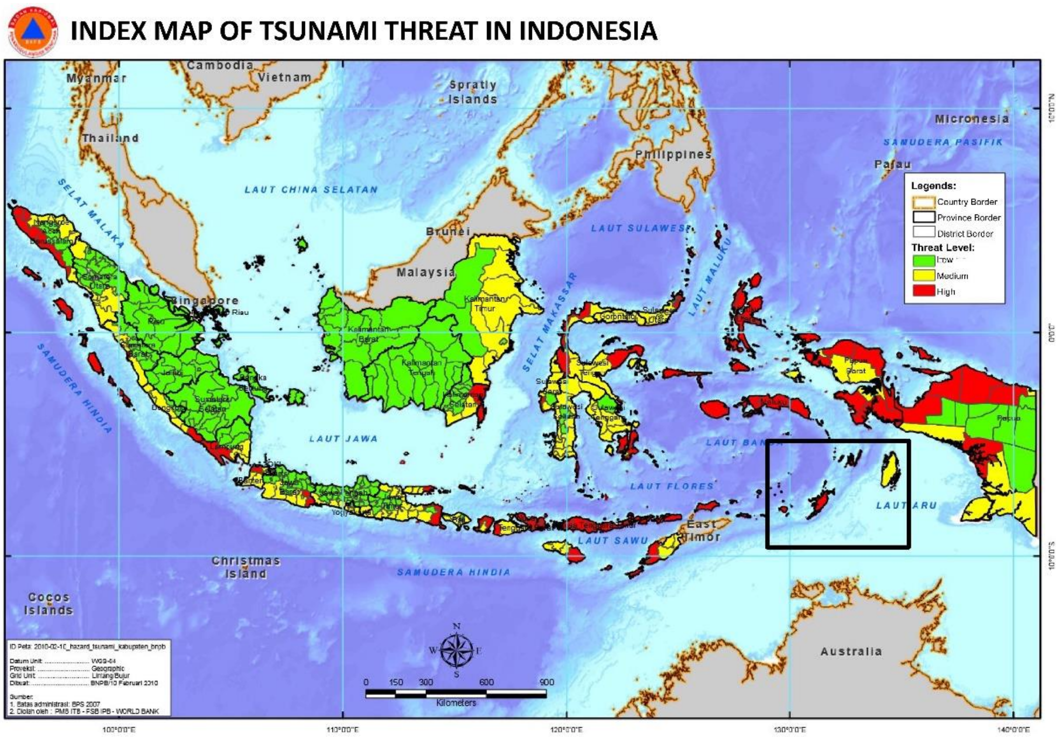


Figure 4.9 Index Map of Tsunami Threat in Indonesia

Figure Source: Badan Nasional Penganggulangan Bencana (BNPB, 2010)

Indonesia is part of the Pacific Ring of Fire, the region with massive numbers of volcanos and home of 75% of the world's active and dormant volcanoes (Igler, 2010). This phenomena leads the region vulnerable and has high potency of earthquake as well as tsunami. According to BMKG (2017a) there were 883 earthquakes that occurred from 01 January 2008 to 31 April 2017 on the range of 5-9 South Latitude and 135-130 East Longitude that are shown above.

Figure 4.8 above shows the seismic activity on the past year from May 2016 to 2017 that shows 114 earthquakes on Banda Sea. The red color indicates the earthquake occurred on the depth 1-60 km, the yellow color on depth 61-30 km, then earthquakes on depth more than 300 km shown on green circles. The map distribution on **Figure 4.8** might give the idea that the seismic activities are concentrated on the further north of Masela block, while the region where the block is located relatively save from earthquake. However, according to **Figure 4.9** above there is a high level of potency of tsunami on Masela closest onshore regions that should be considered on the field development process.

4.5.6 Gas & Condensate Market

The specific gas market for future Abadi gas and condensate product has not yet been decided as per March 2017. The negotiation still under process. However, Indonesia has long-term LNG buyers such as Japan, Korea, and China; which are now become the most probable costumers of Abadi field' products. Currently Indonesian government also in the middle of agreement with INPEX and Shell to own at least 30% of the production can be distributed on the local market.

5 Field Development Concept Comparison

5.1 LNG Process

Liquefied Natural Gas (LNG) is the way to transport gas to far marketplace where pipeline can't reach that location. The gas converted to liquid with cooling process at extremely low temperature (-161 ^oC) or called cryogenic temperatures and within the pressure near the atmospheric pressure (1 bar). The LNG production is following these steps:

5.1.1 Separation & Stabilization

The gas from the subsea facilities accumulated on the floating vessel (either FLNG or FPSO). This step aims to separate and recover the heavier hydrocarbon (condensate) which has higher economic value on the market. On Masela case, the reservoir contains high amount of condensate that will be extracted first on the floating vessel. At this early separation, the gas, condensate and water will be separated. The water also been removed at this early phase. The heavier hydrocarbons have been condensed during the chilling, and it can be stored on the floating vessel while waiting for its loading time.

5.1.2 Gas Treating

The purpose of gas treating or also refer as Acid Gas Removal Unit (AGRU) is to remove the impurities from the mined gas. On Masela case, high content of carbon dioxide (CO_2) must be removed to avoid blockage on the liquefaction section as well as the problem on the flow assurance. On the case of Masela, the carbon dioxide will be released to the air through flaring process which is still allowable according to Indonesian regulation.

The difference treatment process between offshore vs onshore concept begin on this step. On offshore concept, as all of the treatment will be conducted on the FLNG, the removal of carbon dioxide will be done on it. However, the onshore concept aims to take the carbon dioxide together with the produced gas via pipeline to the onshore LNG Plant. The high CO_2 contents has high potency to be utilized as raw material to any other industries such as petrochemical and fertilizer. Further explanation about this utilization is shown on **Chapter 9.5.1.1** on page 124 below.

Removal of H_2S also important as the common LNG specification requires very low level of hydrogen sulphide. Acid gasses used to purify the inlet gas. The consultant report from WorleyParsons (2013) mentioned that MDEA (methyldiethanolamine) or any other alkanolamines are the most used chemical solvent. Generally the gas treating process diminish CO2 to < 50 mol.ppm and H2S to < 5 mol.ppm (WorleyParsons, 2013)

5.1.3 Dehydration, Gas Conditioning

Another impurities that affect the quality of LNG is the water content. Water has been removed at the early separation phase. However, on this step the water content is cut down to the allowable level.

According to WorleyParsons (2013) the gas water content should be reduced to the level < 1 mol.ppm. To remove the water content, the gas from the gas treating process is dehydrated through the propane cooling process on the separator. Gas conditioning also remove other hydrocarbon impurities such as mercury and solids.

5.1.4 Liquefaction

Liquefaction is the main step of producing LNG. LNG liquefactions convert the gas into a cryogenic liquid. The cooling process of the stream occurs on the large temperature span. The heat is removed step by step in the ranging temperature as shown on **Figure 5.1** below. On the level temperature of -161°C, the methane gas as a main component on natural gas is converted to liquid.

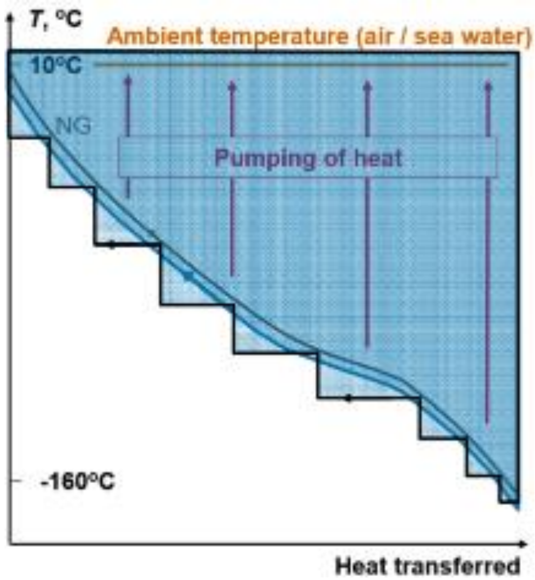


Figure 5.1 Natural Gas Cooling Process

Figure Source: Cooling Temperature Graph by Pettersen (2008)

5.1.5 Storage & Loading

The produced LNG stored in the storage tanks that have atmospheric pressure and then transported to the market.

The Masela development also following those five steps that already mentioned above for both its offshore and onshore concept. **Figure 5.2** below shows the LNG processing phases for the offshore concept. According to this figure, all of the steps are operated on the FLNG. However on the onshore concept that represented by **Figure 5.3** below the LNG processing are divided into two segments: the FPSO and onshore LNG Plant. FPSO in charge of inlet gas separation and condensate production, while the rest LNG production phases are conducted at the onshore LNG Plant.

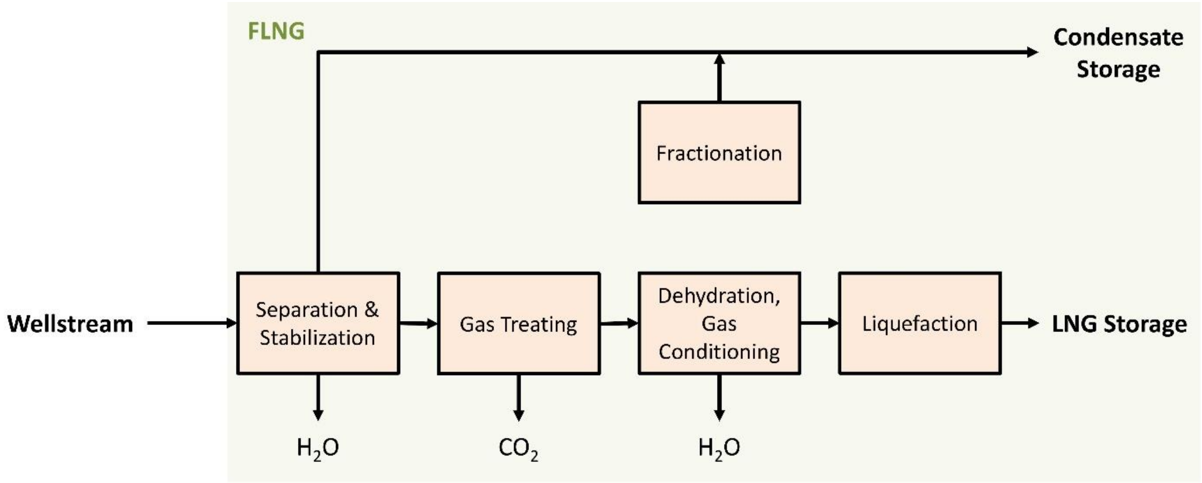


Figure 5.2 LNG Processing on Offshore Concept

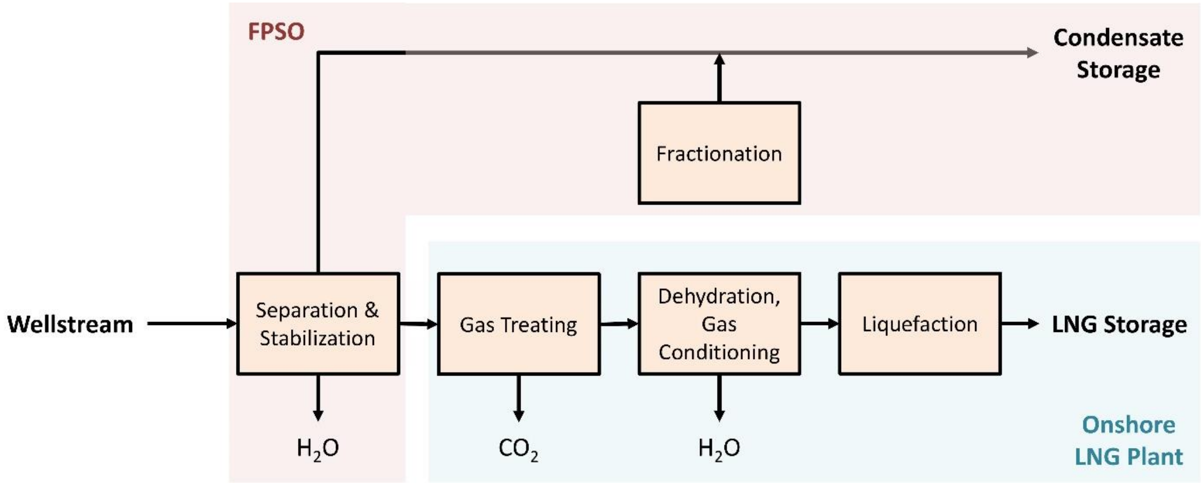


Figure 5.3 LNG Processing on Onshore Concept

5.2 Masela Building Blocks

The most essential part on field development is to design the configuration of the production facilities. The configuration of the field is based on the driven functional requirements with regard to technical and economic limitation. **Figure 5.4** below aims to give an illustrative comparison of the field configuration on both offshore and onshore concept within one picture. The left side of the picture explains the offshore concept, from the subsea facilities, FLNG, and logistic supply based. On the other right side, the onshore concept is illustrated. It includes subsea facility, FPSO, pipeline, as well as the onshore LNG Plant.

The **Figure 5.4** below represent the field configuration of offshore concept with its FLNG and logistic supply based. Also there is an FPSO, pipeline, and the onshore LNG Plant on the onshore concept. The production facilities for both offshore and onshore concept are summarized into three main categories as listed on **Table 5.1** below.

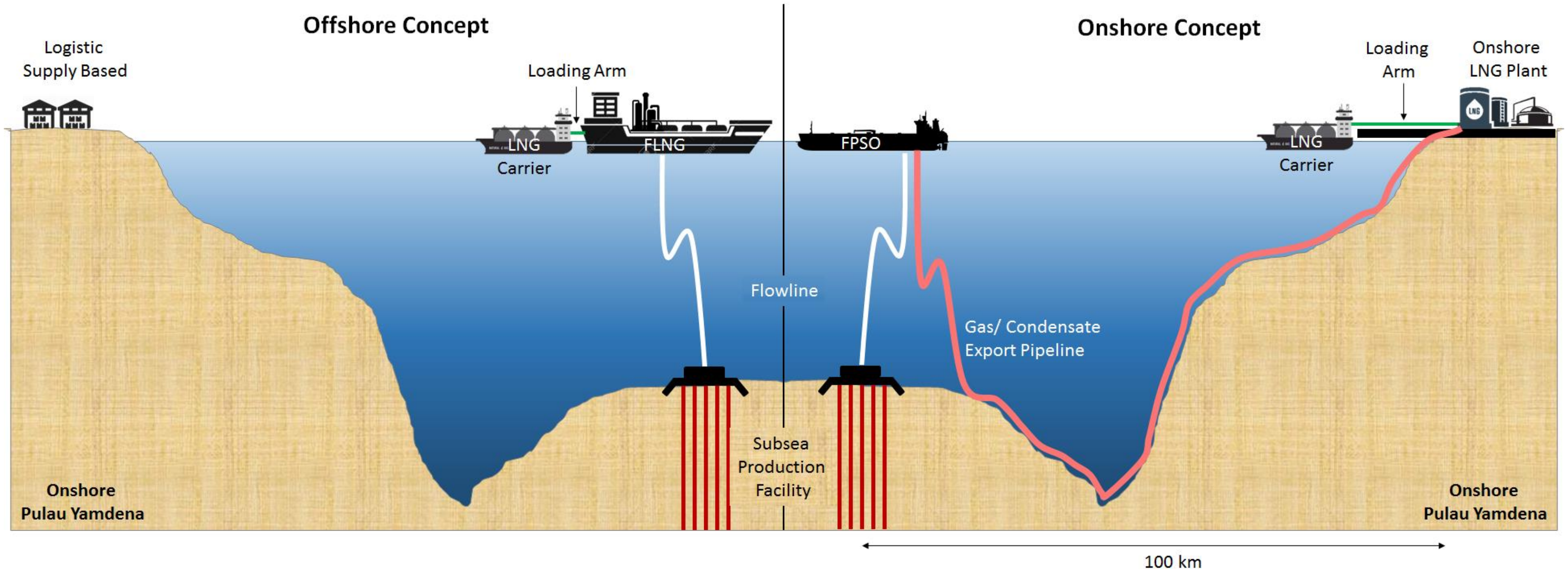


Figure 5.4 Illustrative Comparison of Offshore (Left Side) and Onshore Concept (Right Side) Development

Table 5.1 Configuration of Production Facilities

Category	Offshore Concept	Onshore Concept
Production Platform	FLNG & Logistic Supply Base	FPSO & Onshore LNG Plant
Well System	Subsea Facilities (SURF) - 18 production wells - 5 subsea manifolds - 5 flowlines & risers	
Export Facilities	LNG Carrier and Condensate Tanker	

5.3 SURF

Subsea Umbilical Riser Flowline (SURF) play important role in the production. Completed SURF generally are implemented in deep water field development with water depth ranging from 300 to 1000 meters such as Masela. On subsea configuration, the x-mas trees are placed on the sea bed or commonly referred as wet trees. The development of field using subsea aims the specialized nor expensive equipment that must be reliable and safe to be used, as well as economically feasible.

Gas and condensate that are the products from the production well heads will be transferred into the subsea manifold. The subsea manifold described as the metal equipment made up with pipes and valves to centralized the production and transfer it to the flowlines. Subsea flowlines refers as a vertical subsea pipelines that carrying gas and condensate from the manifold to the riser base. The subsea well configuration of Masela illustrates as on **Figure 5.5** below.

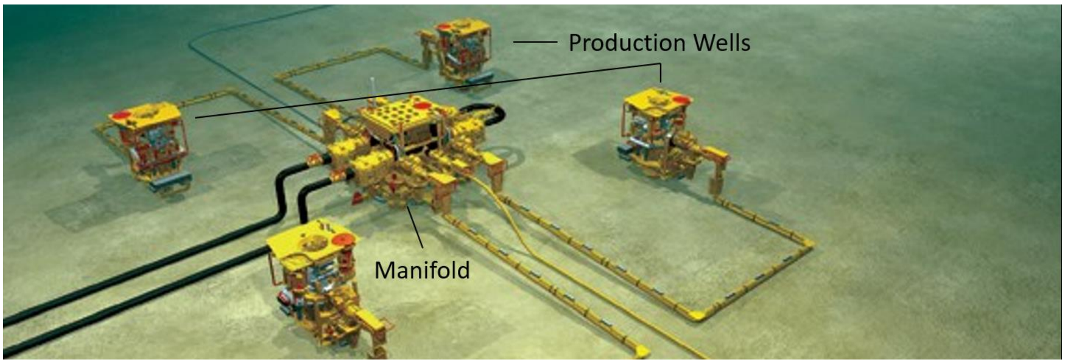


Figure 5.5 Well Configuration
Figure Source: Subsea Facilities by FMC (2007)

Figure 5.6 below also illustrates the subsea configuration on the general field development. Riser is the connector of subsea bottom facilities with the surface processing facilities. Additionally, as the wet tree wells are used, the production risers also considered as the extension of the flowlines. In the case of Masela which uses floating vessel (either FLNG or FPSO), the riser must be designed flexible enough to handle the high internal pressure and dynamic sea motions from waves, wind, current. For Masela, with water depth in the range of 300 – 1000 meters, the steel catenary risers or flexible pipe catenary risers should be used. On the case of benign water such as Masela, the steel catenary risers is possible to be implemented. However, most likely the flexible pipe catenary risers are used to compromise the depth of the water.

During the operational life cycle, the flow rates are projected on 60 MMSCFD per well (Kurniawan, 2013) with 18 directional production wells drilled from 5 subsea drilling centers (Manabe et al., 2009). The development focus on the north part of the block where the vast amount of gas are accumulated as illustrates on **Figure 5.7** below. The map shows the 18 well head productions that are connected to five manifolds and the projected location of the floating vessel. The clustering of the production wells distributed 3-4 wells per single subsea drilling center.

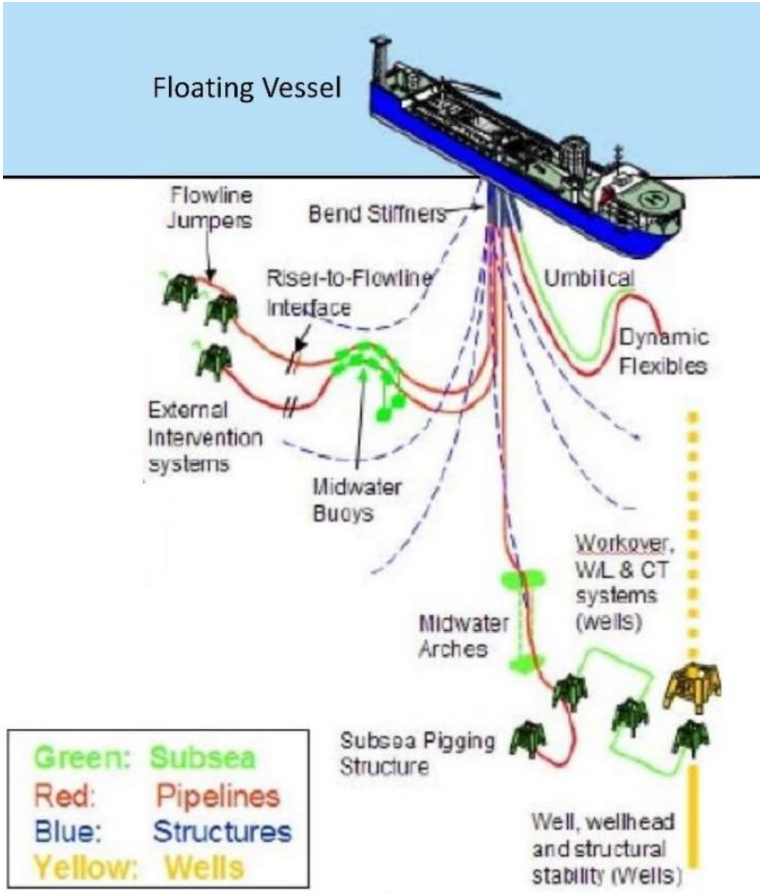


Figure 5.6 Subsea Configuration
Figure Source: Subsea Facilities by Ersdal and Selnes (2010)

The configuration and design of subsea facilities influenced by the dynamic behavior in flowing media. Flow back fluids is one of the most important factor to consider when designing the wells. Data from Kurniawan (2013) shows that Masela's solid materials subsists of sand, cement, fluid loss pill, and gun debris.

The main objective of the flow path is to be designed to deliver particulate materials to the floating vessel (FLNG on offshore concept or FPSO on onshore concept). The materials may flows if the minimum velocity of gas at the top of the riser is higher than the lifting critical velocity on reservoir (Kurniawan, 2013). Based on his analysis the 6000 µm diameter gun debris is the particulate with highest critical velocity. Also he mentioned on his report that the velocity of gas during flow back operation on the range of 60-180 MMSCFPD is sufficient to surpass the particles' critical velocity.

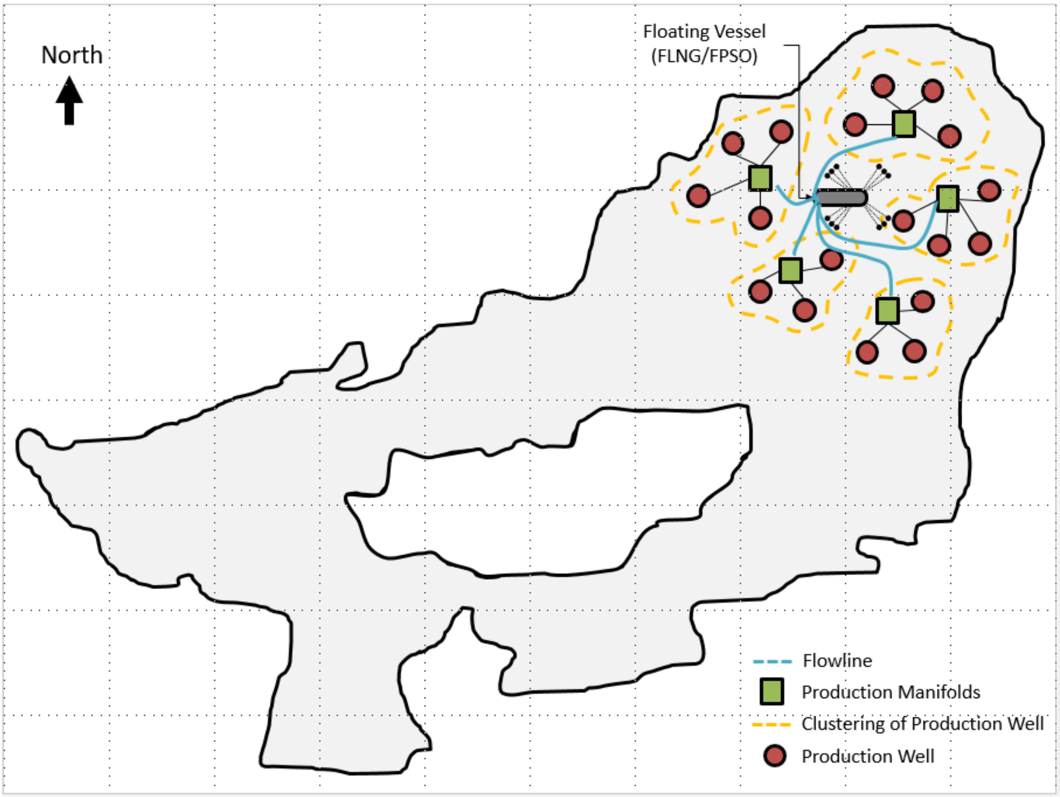


Figure 5.7 Reservoir Layout Sketch

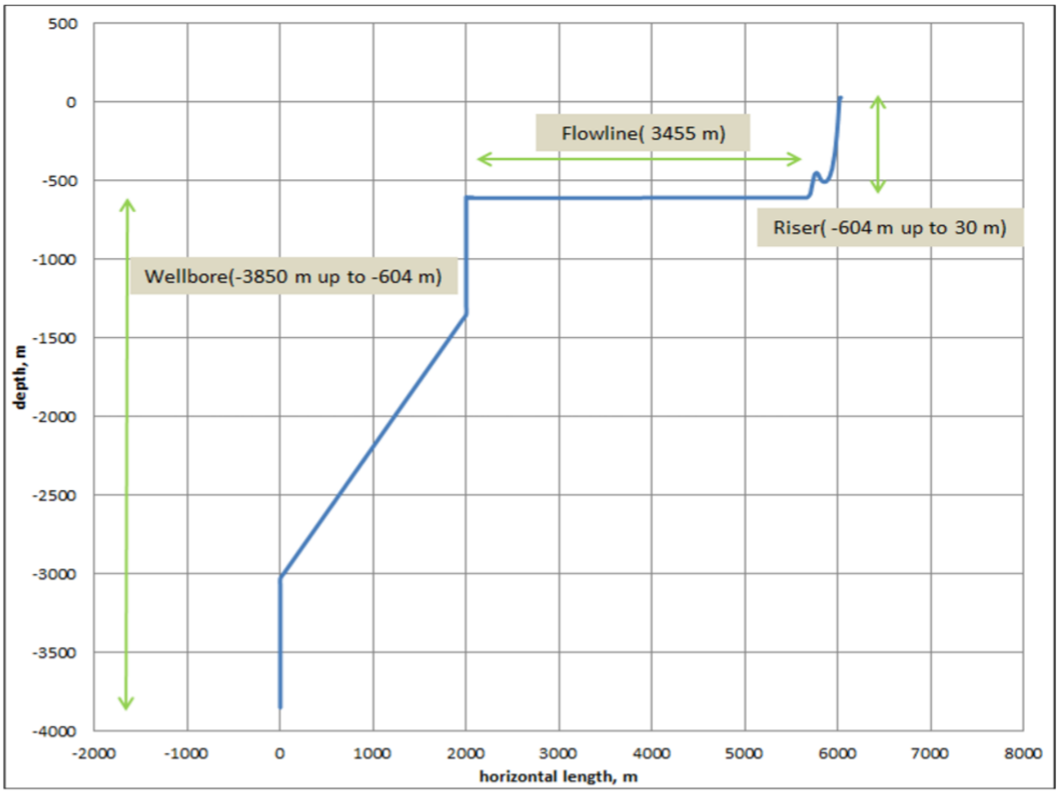


Figure 5.8 Flow Path of the Flow Back from Reservoir to Floating Vessel
Figure Source: Kurniawan (2013)

From those analysis, the designed flow path of Masela can transports the fluid from the wellbore to the topside of floating vessel which consists of both horizontal and vertical path. The analysis of Kurniawan (2013) resulted a flow path model of Masela that divided into 3 sections: wellbore, flowline, and flexible riser that shown on **Figure 5.8** above. The subsea facilities of Masela will have wellbore that planted from -3850 to -640 meters that connected to the well head. The 3455 meters of flowlines connects the well head production with the risers. Then 634 meters height risers transfer the gas to the floating vessel.

5.4 Offshore Concept

Offshore concept aims to transport the gas and condensate from the subsea facilities to the 500m x 82m Floating Liquefied Natural Gas (FLNG) with capacity of 7.5 LNG. All the gas and condensate processing from purification, separation, liquefaction, as well as loading process will be conducted on this vessel. To support all the offshore activities, the onshore logistic supply based also will be built onshore.

5.4.1 Floating Liquefied Natural Gas (FLNG)

FLNG is an FPSO LNG (Floating, Production, Storage, and Offloading System), where the vessel is built as an independent facility that can receive gas from subsurface, perform processing (processing, separation, and disbursing), storage, and off-loading in an offshore gas field. The value chain of FLNG itself consists of gas conditioning and liquefaction in ships operating in open seas, ship sending LNGs, and FSRUs on the market destination.

Masela performs complete LNG and condensate offshore processing facilities as FLNG illustrates on **Figure 5.9** below. The further analysis related to the FLNG concept, will be presented on **Chapter 6** on page 43 below about FLNG.

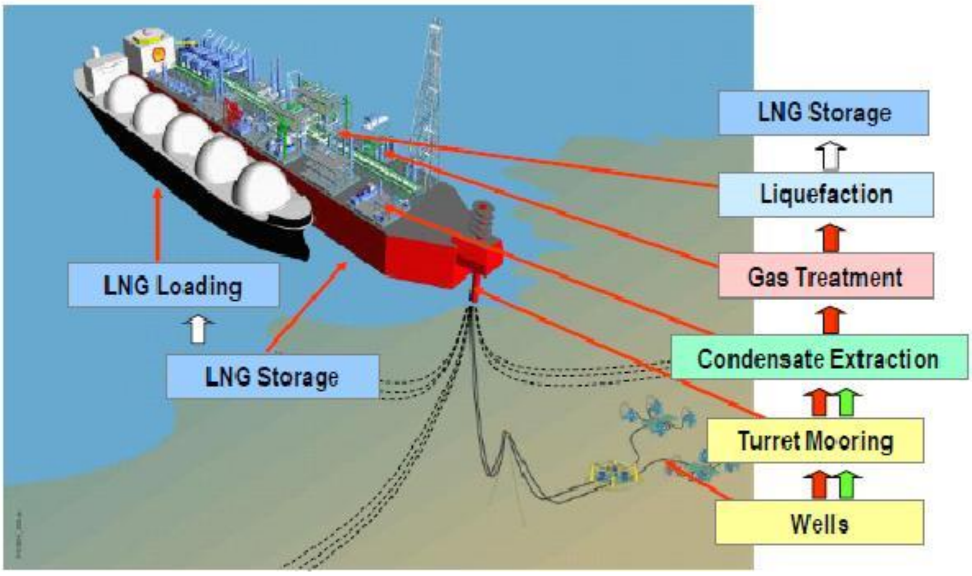


Figure 5.9 FLNG Masela Sketch Configuration
Figure Source: FLNG by 2B1Consulting (2012)

5.4.2 Onshore Logistic Supply Based

The offshore activities must be supported by the closest shore area. Supply based is necessary to transfer the logistic as well as the changing crew activity. As all the LNG and condensate productions conducted offshore, the onshore logistic based doesn't require wide area. Only necessary building that will present as illustrates on **Figure 5.10** below. Office and logistic based are the basic element to control the operation of the FLNG itself. Helipad as well as jetty also crucial for connecting offshore activities and the land.

Logistic supply for the production is built in the onshore area close to Masela block location. There are 3 proposed location for the logistic supply based. The chosen location depends on the pipeline route analysis that presented on **Chapter 7** below.

Figure 5.10 Integrated Onshore Logistic Supply Based
Figure Source: Onshore Supply Based taken by Low (2017)

5.5 Onshore Concept

The proposed onshore concept pursues the gas from subsea facilities to be produced at onshore LNG Plant. The raw gas planned to be transported to the 330m x 65m Floating Production Storage Offloading (FPSO) where the purification and separation will take place. Gas and condensate will be separated on FPSO, then the produced condensate will be loaded to the tanker directly to the market from offshore. The gas then be transported to the 9 MTPA capacity onshore LNG Plant via pipeline. The liquefaction and loading process to the market will be accomplished onshore.

5.5.1 Floating Production, Storage and Offloading (FPSO)

FPSO is a ship-shaped vessels are used to produce, storage, and offloads products. FPSO Masela on the onshore concept is categorized as simple FPSO without capability of complex gas processing. It will receives the raw gas from the subsea production facilities and separate the condensate and gas components. The gas will be transfers to the onshore LNG Plant through pipeline. While the condensate will be stabilized and extracted here. So in short, FPSO Masela will only produces the condensate and store it until its loading process to the tanker. Those explanation can be illustrates by **Figure 5.11** below.

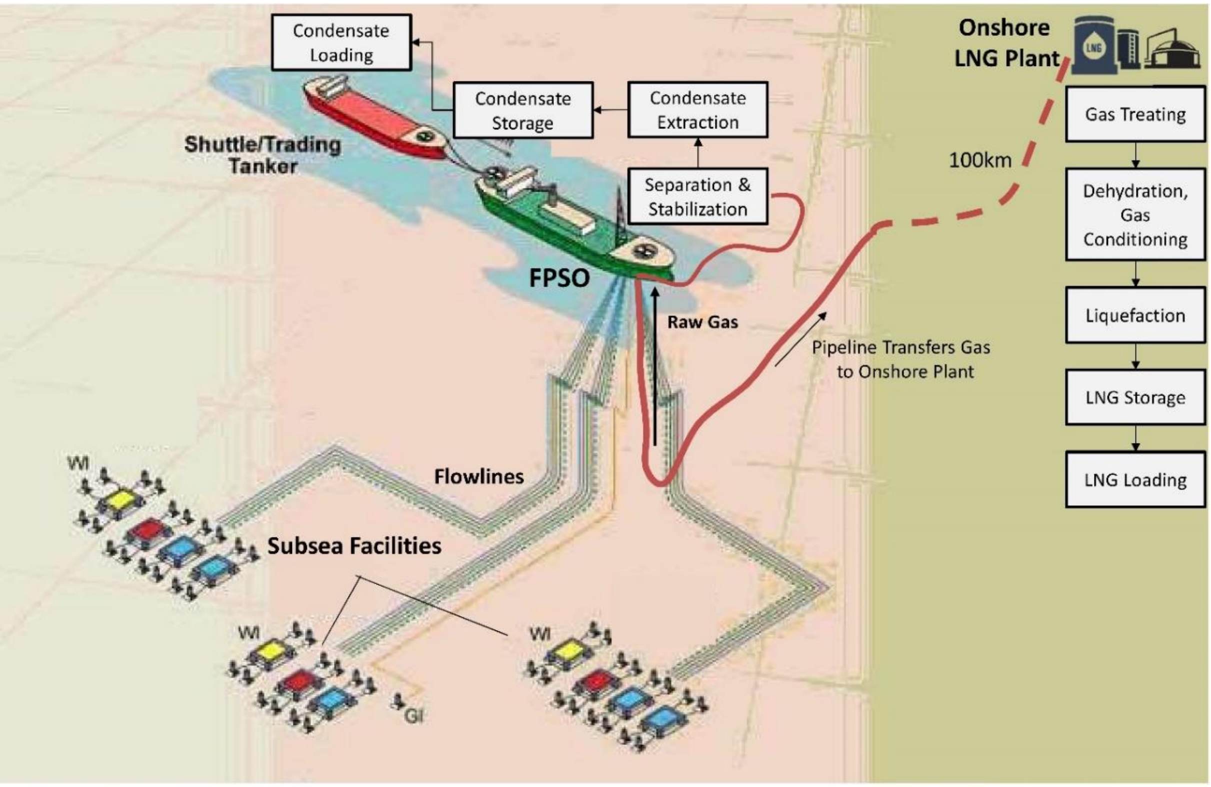


Figure 5.11 Masela FPSO Sketch Configuration
Original Figure from MercoPress (2013), then modified to give a sketch of FPSO Masela

Previous subchapter talked about FLNG as a vital part of offshore concept development. However, the onshore concept of Masela also requires a floating vessel: FPSO. Both FLNG and FPSO are the ship-shaped floating vessels that are used to produce hydrocarbon commodities. However, there's difference between those two. **Table 5.2** below specifically listed the difference of two floating vessels that are proposed on two different concept.

Table 5.2 FPSO and FLNG Comparison

Item	FPSO (Onshore Concept)	FLNG (Offshore Concept)
Product	Condensate	LNG, Condensate
Dimension of Vessel	330 m x 65 m	500 m x 82 m
Liquefaction System	-	Required
Tank Storage	Condensate	LNG, Condensate
Main Product Offloading	Condensate: Hose Offloading	LNG: Loading Arm
Refrigerant	-	Flammable Liquid Except N2 Expander cycle
Explosion Probability	Small	Large
Cryogenic Liquid Leak	-	Large

5.5.2 Export Pipeline

Pipelines are widely used to transport oil & gas from the wells to the processing area. It considers the most economical way to transport vast amount of hydrocarbons. To transport gas on long distance route (i.e. in the case of 600km pipeline to Pulau Aru), several compressor stations in gas lines are installed to maintain the pressure and temperature. As the product from Masela block is a gas and condensate with high CO_2 content, pipelines are constructed with carbon resistance allow which size is varying from 20 inches to over 60 inches in diameter. The further analysis related to pipeline is mentioned on Chapter 7 below.

5.5.3 Onshore LNG Plant

Masela onshore concept aims to build complete LNG facilities starting from gas processing, liquefaction, storage, to export jetty onshore. Masela onshore LNG Plant projected has a capacity up to 9 MTPA of LNG. **Figure 5.12** below illustrates the typical layout of onshore LNG Plant that also suitable to be implemented in Masela development. The estimated area as well as its development cost will be mentioned on **Chapter 8** Economic Analysis below.

On Masela proposed onshore development concept, the gas will be transported from FPSO to the onshore LNG Plant through the pipeline. The gas treatment, dehydrating, gas conditioning, and the liquefaction take place on this onshore facilities as shown on **Figure 5.12** below. The produced LNG is stored on the storage tank and loaded through jetty to the LNG Carrier.

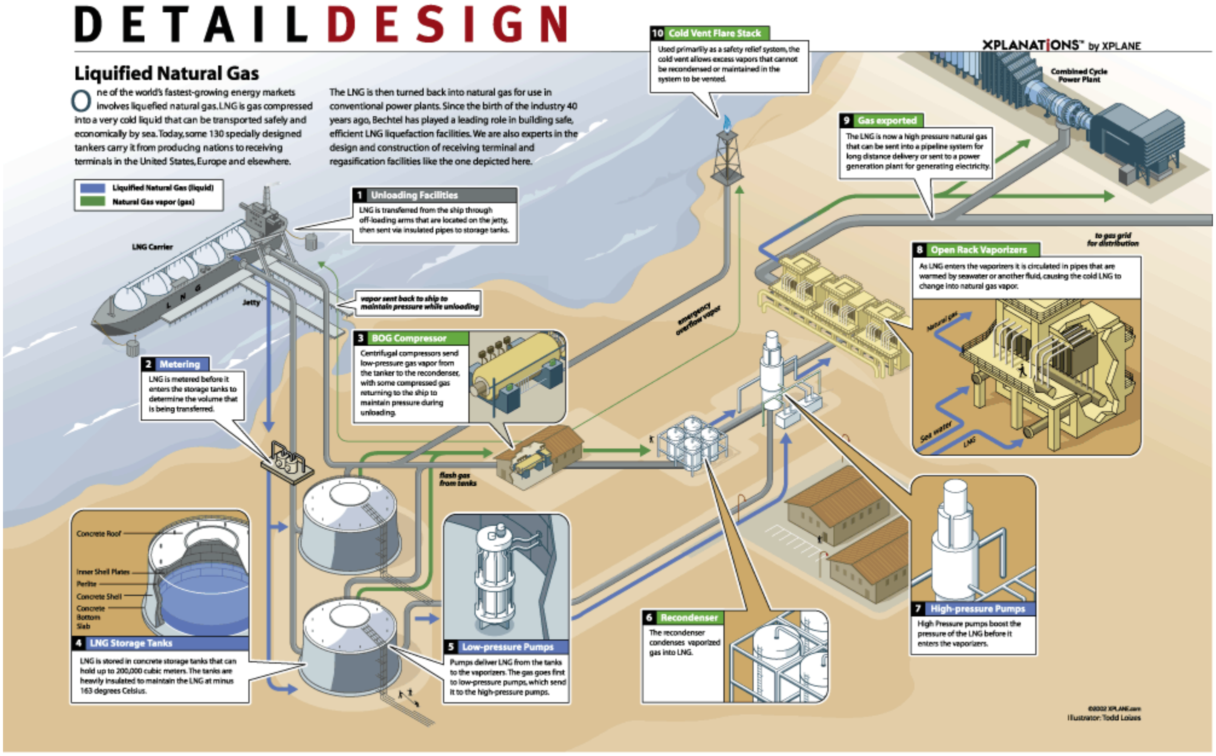


Figure 5.12 LNG Layout and Process

Figure Source: LNG Plant Layout by Loizes (2008)

As the current Masela's onshore surrounding currently considered as under-developed region, extensive infrastructure such as accommodation, new township, and airport must be build. The development may refer to the LNG Tangguh development that constructed all the LNG facilities as well as the subsequent supporting facilities such as airport and the accommodation camp that are shown on **Figure 5.13** below.

All the development cost of Masela region will be included on the CAPEX like in the case of LNG Tangguh development. The provided sum CAPEX that will be used as a benchmark on **Chapter 8** including these facilities. With the massive development like this, the huge number of area is needed. It also requires a lot of investment at the beginning of the development.

Figure 5.13 LNG Tangguh Supporting Facility: Babo Airport & Camp

Figure Source: (Ariyanti, 2017, Taruna, 2008)

Marine Facilities

Onshore LNG Plant requires support marine facilities, as illustrates on **Figure 5.14** typically consist of jetty and trestle linking to the shore. Building marine facilities mostly is relatively affordable, however its maintenance management might be considered as an expensive operation. Regular shoreline observations and dredging should be conduct to ensure that the bathymetry of the sailing line and the berthing area fulfil the requirement. The onshore nearby Masela is promising area, the bathymetry around the block is naturally considered as deep water, and thus it doesn't require extensive and regular dredging on its berthing area.

Figure 5.14 Marine Facilities

Figure Source: LNG Tangguh's Marine Facilities (BP, 2017)

5.6 LNG Carrier

It mentioned earlier that the natural gas converted into LNG to be transported in the long journey. So there is a requirement to transport the LNG with the specialized which able to keep maintain the temperature down to approximately -161^{o}C. Generally there are two types of LNG carriers that widely used, spherical and membrane tank. In addition, **Table 5.3** below listed the type of LNG carriers and its typical dimensions as well as its storage capacity.

Table 5.3 Typical LNG Carrier

Ship Type	Storage Capacity	Ship Dimensions Length x Breadth
Moss Sphere	127,000 m^3	272 m x 47.3 m
Membrane Tank	155,000 m^3	285 m x 43.4 m
Q-Flex	210,000 m^3	315 m x 50 m
Q-Max	260,000 m^3	345 m x 54 m

5.7 Production Profile

The production profile defined as the annual production volume that shows the overview sketch of the field production. On the early planning phase, the production profile should be established in order to understand the life span of the field as well as calculating its economic model. On this Masela development case, both offshore and onshore concept have different production capacity. FLNG undoubtedly has lower capacity with the number of 7.5 MTPA of LNG, while onshore LNG Plant may handle up to 9 MTPA of LNG liquefaction.

As mentioned on the earlier Chapter, the total recoverable volume of Masela block is 10.73 TCF of gas and 209 million barrel of condensate. **Section 5.3** above also mentioned that the gas will be drilled through 18 production wells that are connected through 5 manifolds. The production rate for each well is 60 MCF of gas and 1,359 barrel of condensate. Assuming that drilling and completion of production well takes 2 months each, thus **Table 5.4** below give a picture of the drilling schedule during the early production phase.

Table 5.4 Drilling Schedule

Production Well	18
Water Injector	0
Gas Injector	0
Total Number of Well	18

Year	Month	Well	Schedule
1	January February	1	P
	March April	2	P
	May June	3	P
	July August	4	P
	September October	5	P
	November December	6	P
2	January February	7	P
	March April	8	P
	May June	9	P
	July August	10	P
	September October	11	P
	November December	12	P
3	January February	13	P
	March April	14	P
	May June	15	P
	July August	16	P
	September October	17	P
	November December	18	P

Note:
P Production Well

The detail calculation is shown on **Appendix A** at the end of this thesis. The production profile of Masela block for each offshore and onshore concept is shown on **Figure 5.15** and **Figure 5.16** below for gas and condensate respectively. The production profile of gas will be different for both two concept as the platform capacities are different. However, the production profile for condensate is the same, as it is assume that the condensate production capacity of both FLNG and FPSO is the same.

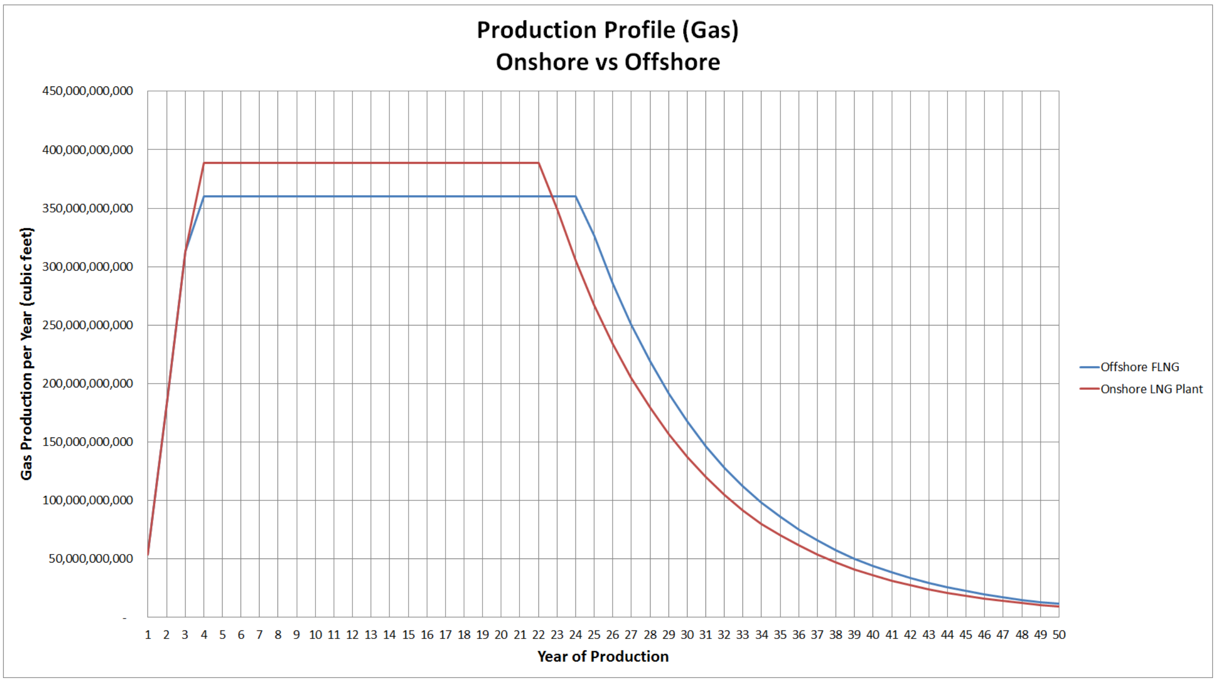


Figure 5.15 Production Profile (Gas)

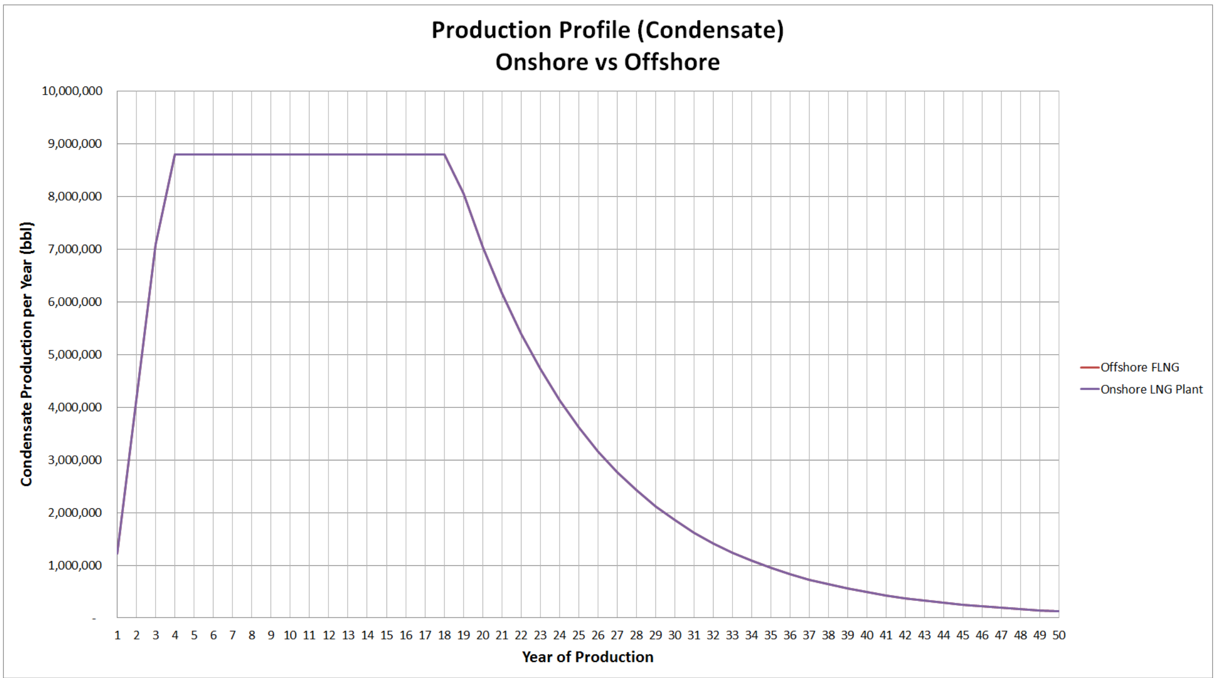


Figure 5.16 Production Profile (Condensate)

Generally, those production profile can be divided into three main phases: build-up, plateau, and production decline.

5.7.1 Production Build-Up

The beginning of the production is marked with low number of production as the drilling process still undergo. The main target of this phase is to install the production facilities as soon as possible to filling the production capacity. This is the aim to gain economically cash flow in an efficient way.

On Masela field development case for both onshore and offshore concepts require 3 years production build-up which is from Year 1-3. This also prevails for both gas and condensate production case as refer to **Figure 5.15** and **Figure 5.16** above.

5.7.2 Plateau Production

After the build-up phase, the production rate reaches its filling capacity. The equal number of production rate when the capacity utilization as its maximum during its production phase is called plateau. On this phase, the focus will be on the reservoir management that should maintain the pressure and temperature of reservoir in order to gain the production target. Any detention may lead to the deferred production.

According to **Figure 5.15** above, the gas plateau production of offshore concept will be long last for 20 years (Year 4-24) with up to 360 MCF production annually. For onshore concept, as the production facility has higher capacity, the plateau period slightly 2 years shorter when is from Year 4-22). However onshore annual production reaches the level of 388 MCF.

Despite there is a condensate-gas ratio (CGR) that present on the reservoir, it is assumed that the condensate production rate is the same for both concept. Condensate is relatively simple to be produced, easy to be stored, and has higher value on the market. Those factors lead the tendency to produce the condensate reserves as soon as possible to gain more revenue. In terms of reservoir management, is it possible to produce the condensate on that way. The geologist and reservoir engineers in charge have data related of the composition of each source rocks. To produce the certain amount of condensate, they might choose source rock with higher level of condensate to be produced first to another. With this assumption, on both concept the production rate of condensate is similar. The plateau period for condensate production onshore and offshore is 14 Years (Year 4-18) as shown on **Figure 5.16**.

5.7.3 Production Decline

A phase after the plateau production represents a declining production. To keep economic value of the exploitation, there should be any reservoir management efforts. Improved and enhanced recovery method should be implemented to utilize the remaining recoverable volume. However, the analysis on this thesis is limited only into the primary production. It is assumed that the production rate is based on the pressure depletion case without implementing any improved or enhanced recovery method.

On offshore case, the production will start to decrease at the beginning of Year 25 as shown on **Figure 5.15** above. Moreover according to the calculation on

Appendix A, the projected remaining recoverable gas reserves on that year will be 2.61 TCF. **Figure 5.15** above also shows that the declined production for onshore concept will start on the beginning of Year 23. At that time the remaining recoverable gas reserves is estimated to be 2.79 TCF. There is also 64.44 million barrel remaining condensate on the reservoir at the beginning of Year 19.

5.8 Masela Block' Schedule Estimation

5.8.1 Offshore Concept

The current revised POD that delivered to the Indonesian government is defined by using offshore FLNG. The previous POD with capacity of 4.5 MTPA was also defined by using the offshore FLNG. The study about this concept already familiar for both INPEX and government. If this option is accepted, the further engineering studies will continue from the existing POD and create detail engineering design from it. It will be expected to take 1-1.5 year to complete the detail engineering or it will be at the end of 2018. Construction may be start at the beginning of 2019 for 5 years until the end of 2023. So the beginning of production will be expected on 2024. According to production profile that had been shown before the offshore concept will have longer plateau for 20 years. Thus the production period is estimated from 2024 – 2048. The offshore schedule is shown on **Figure 5.17** below.

5.8.2 Onshore Concept

On the other hand, this onshore concept even though already been implemented in other regions this is the new concept for Masela field development. Detail area survey must be conducted and will take around 1 year. Both INPEX and government must be familiarize with this new concept. After this the further engineering studies will start from scrap again and detail engineering should be make as soon as possible. It will be expected to take 1-1.5 year to complete the detail engineering or it will be at the end of 2019. The other problem that may come up and will take long time is about the land acquisition (will further be analyzed on the **Chapter 9.5.1.2.1**.)

The land acquisition always become a major problem in any development in Indonesia. The conflict always rise between the local people and the developer. It may be takes at least one year to complete this phase, then the construction may be started after. The construction may be start at the beginning of 2021 for 5 years until the end of 2025. So the beginning of production will be expected on 2026. According to production profile that had been shown before the onshore concept will have plateau for 18 years. Thus the production period is estimated from 2026 – 2048. The onshore schedule is shown on **Figure 5.18** below.

Activity	Start Date	Duration (months)	Finish Date
DG-0			
Feasibility Study	Done		Done
DG1			
Conceptual Screening	01.07.2017	3	01.10.2017
DG-2			
Conceptual Studies	01.10.2017	3	01.01.2018
Pre-Sanction (DG-2)			
FEED	01.01.2018	12	01.01.2019
Sanction (DG-3)			
Development	01.01.2019	60	01.01.2024
Production Start (DG-4)			
Production Period	01.01.2024	288	01.01.2048

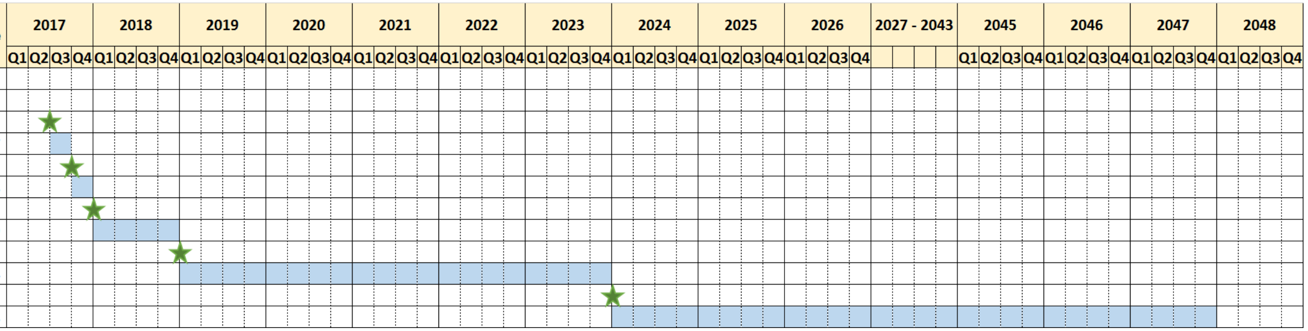


Figure 5.17 Projected Schedule of Offshore Concept

Activity	Start Date	Duration (months)	Finish Date
DG-0			
Feasibility Study	01.07.2017	6	01.01.2018
DG1			
Conceptual Screening	01.01.2018	12	01.01.2019
DG-2			
Conceptual Studies	01.01.2019	12	01.01.2020
Pre-Sanction (DG-2)			
FEED	01.01.2020	12	01.01.2021
Sanction (DG-3)			
Development	01.01.2021	60	01.01.2026
Production Start (DG-4)			
Production Period	01.01.2026	264	01.01.2048

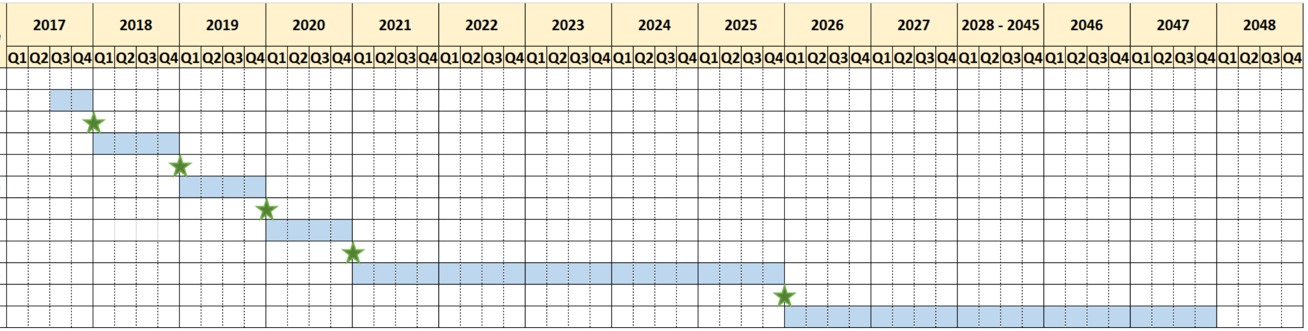


Figure 5.18 Projected Schedule of Onshore Concept

6 Floating Liquefied Natural Gas (FLNG)

6.1 FLNG in General

Floating Liquefied Natural Gas (FLNG) refers as a vessel operated in offshore location to produce, process, and store natural gas. This compact floating module moored above the offshore gas field and offers the several natural gas value chain stages to be conducted here; starting on recovery process from subsea wells, liquefaction, storage, into loading. **Figure 6.1** below illustrates this explanation. Generally, FLNG concept based on two well-established technology, LNG and FPSO. FLNG combines the function of FPSO, LNG Storage, and Processing Plant into one complex ship-shaped vessel. In short, the role of FLNG in the gas production as comparable as FPSO (Floating Production Storage Offloading) that are familiarly used in the oil production.

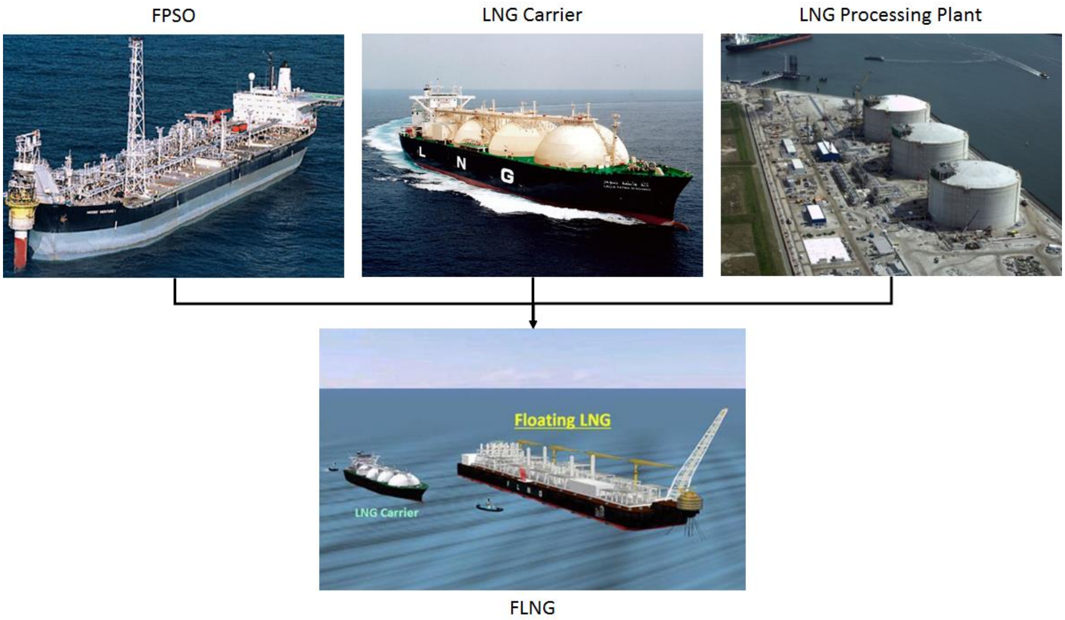


Figure 6.1 FLNG Combines Several LNG Value Chains within One Floating Vessel
Figure Source: FPSO (Rigzone, 2015), LNG Carrier (SafeShipping, 2016), LNG Processing Plant (Hydrocarbons-Technology, 2014)

There are two main areas on FLNG: Deck and Hull. Deck area generally used as onboard processing stage, shown on **Figure 6.2** below. Natural gas extracted and treated to remove impurities then chilled by using complex cooling system later it is converted to LNG at temperature -162°C. This cooling process shrinks the gas volume by 600 times to produce LNG (Shell, 2017a). Then the LNG from this processes stored in specialized tanks inside the hull of the FLNG before loaded to ocean-going LNG carriers and transported to the markets.

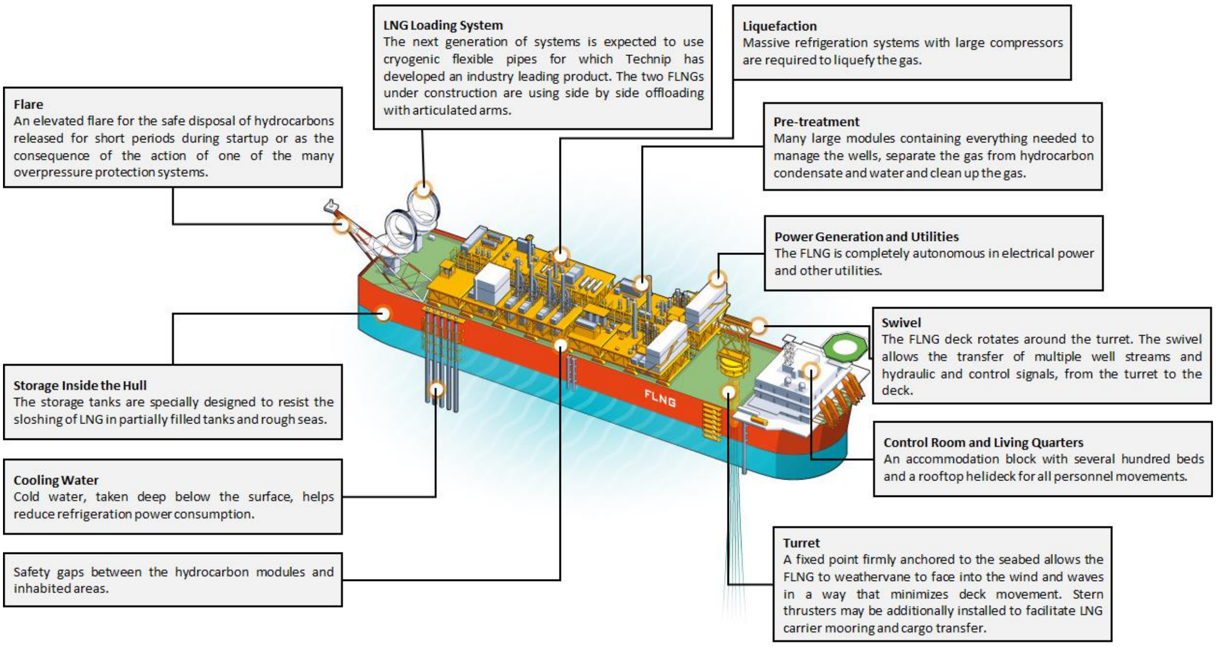


Figure 6.2 FLNG Deck Configuration

Figure Source: Technip (2016)

The compact modular architect of FLNG vessel has advantages because both the processing facilities and liquefaction facilities are on the same boat. As a consequence the developer can cut the budget of costly pipeline and complex production facilities.

The demand of LNG in increasing rapidly. Several studies proved that the offshore LNG development is potentially feasible and will be safely implemented. There is also the other parameter related to cost. In certain capacity points the development cost of offshore facilities may be lower than developing the onshore processing plant. The further example is explained on **Chapter 0.**

According to Sheffield (2005) in terms of technology there are several benefit to select the offshore options compared to the onshore one, which are:

- Development of the field which has remote location is solved through this offshore concept.
- Utilization and commercialization of associated gas products such as condensate and LNG. All of the facilities will be compacted in one vessel, so the process is more efficient and may commercialize other associated products.
- As the production facilities is build offshore, it can be relocated after the end of the lifetime production,
- It is also open the chance to develop the field which has limited reserve.

Moreover, there are also some key drivers that affect the development of offshore LNG production facilities (Sheffield, 2005):

- The demand of LNG. The market insists more LNG and it leads the suppliers to develop more fields that previously were not prospected.

- The resources of the reservoir. Vast amount of proven reserves that economically profitable may lead to the advanced level development by implementing new technologies such as FLNG.
- Availability of developers and investors. The eagerness from those two stakeholders determines the realization of the concept to the existing project.

Development of offshore LNG production facilities are competing with onshore land-based plant in terms of capital investment and its economical return. Most likely the proposed concept to develop 1-5 MTPA of LNG is by using land-based facilities because it is more captivating in terms of economic investment.

However there is a trend shifting to movement into offshore LNG (FLNG). That tendency is led by willingness to develop the remote gas field, security of supply, the onshore development cost which increasing, considering large environmental damage on the area, and the high demand of long-term gas supply (Sheffield, 2005)

FLNG option also beneficial in the place where the surrounded area is lack of infrastructure like Masela case. Commercialization of the gas is challenging because of the supporting facilities matter. Furthermore the cost of labor and raw materials also rise and make the onshore concept become more and more expensive compare to before. FLNG's modular design is the benefit in terms of cost reduction. Another advantage of this FLNG is to avoid the concern related security and opposition from local area that projected to come up on Masela.

The LNG on-board comprehensive facilities bundles a typical conventional onshore LNG processing plant into a part of its normal size. Its advanced concept building blocks significantly cuts the role of conventional pipeline that is commonly used to transport natural gas to the onshore LNG plants. This concept provides solution to develop remote gas fields, turn the stranded fields that previously were not economically and technologically possible into promising fields in the future. This is also in line with associated research about FLNG conducted by White and Longley (2009), Kanu et al. (2011), Dormer (2013) that support FLNG as a potential way to develop natural gas field. The floaters arrangement is also eminent in terms of flexibility for the small-medium fields with shorter development time.

All in all, the development of FLNG is claimed to significantly affect the global LNG CAPEX on 2019 (Sheffield, 2005). It will also triggers the development of offshore regasification vessel especially in developing countries. Douglas-Westwood (DW) projected that the economic growth drive the energy supply demand in Asia on 2013-2019, the region will focus on developing LNG and construct more liquefaction as well as regasification terminal.

6.2 Existing FLNG

History shows that the offshore FLNG concept has been raised into studies since the beginning of 1970s. However, Sheffield (2005) briefly reported that the extensive examination was conducted only by the mid-1990s. Comprehensive and large scale research of FLNG then conclude that this concept technically and economically feasible to be implemented. It takes about one decade to make developers dare to take the risk for turning the concept into existence.

Number of big-scale oil & gas companies are considering and conducting further studies to develop FLNG on their fields. Royal Dutch Shell leads in this expertise when they announced Shell's Prelude as the world first commercial FLNG project in 2011 (Shell, 2017a). **Figure 6.3** below shows that currently around 10 FLNG projects in different development stages are exist; ranging from possible, likely, to confirmed. Still, as per April 2017 PETRONAS FLNG Satu is the first and only commercial FLNG that is operating in the world.

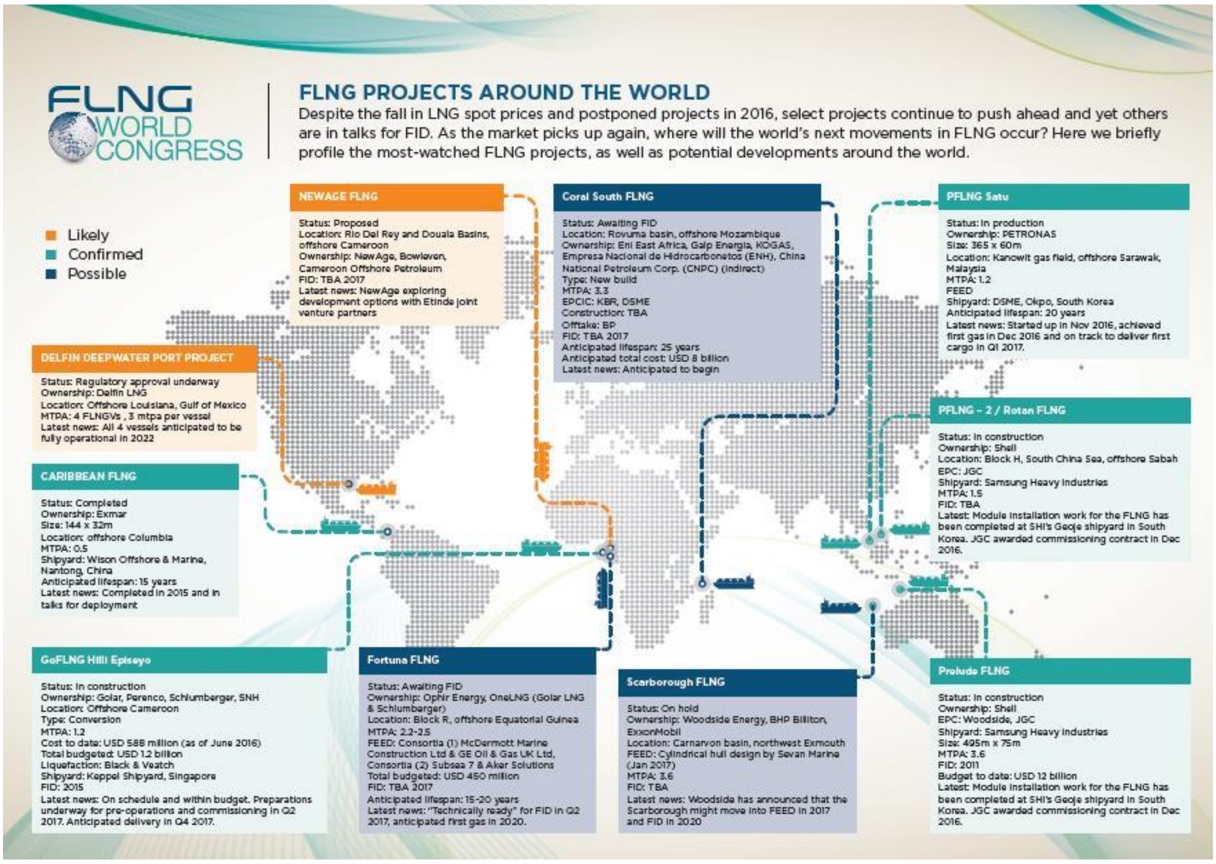


Figure 6.3 FLNG Projects around the World

Figure Source: Congress (2017)

On this slump oil price period, couple of FLNG projects are postponed or declined. Samsung Heavy Industry reported on April last year that its customer Royal Dutch Shell had cancelled three orders of FLNG for developing Australia's Browse Joint Venture (IHS, 2016). PETRONAS FLNG 2 also facing a problem. Despite being decided to keep running, the project will be delayed for the next two years (Zeng, 2016) for adjusting CAPEX-market downturn. These ongoing projects anticipate better market movement despite the struggling current condition of market.

Although developments in the FLNG sector have slowed down, a rebound in the demand for natural gas has the potential to create an environment in which these units are needed. Worldwide recognition that gas is the cleanest-burning hydrocarbon has sharpened the focus on gas development, which will have a place in a greener and more environmentally stringent world. The offshore industry understands the need to continue developing technology regardless of market conditions. The challenges that exist today will still be there when oil and gas prices inevitably rebound, and the technologies to address those challenges will be needed (Guttulsrod, 2016).

6.2.1 First Operating FLNG: PETRONAS FLNG Satu

The first and only operating FLNG in the world is owned by PETRONAS, a Malaysian national oil & gas company. It was named FLNG Satu on the ceremony 4 March 2016 with its strategic partners Daewoo Shipbuilding & Marine Engineering Co. Ltd (DSME) and Technip (PETRONAS, 2016c). FLNG Satu, shown on **Figure 6.4** below, is the floating vessel with design capacity up to 1.2MTPA of LNG for 20 years. On its early development stage, this FLNG designed without considering the specific installed location, later PETRONAS (2016c) decided to place the vessel in Kanowit gas field that located 180 kilometers offshore Sarawak, Malaysia.

Offshore Kanowit gas field well-known for its relatively shallow water ranging from 70 to 200 meters below mean sea level. The dimension of the vessel reaches 365 meters long with flare tower of 130metres height. PETRONAS (2016b) informed that 22 modular systems were installed, the total dry weight was measured around 132,000 tones that include the weight of both hull and topside.

Figure 6.4 First Operating FLNG in the World: PETRONAS FLNG Satu in Kanowit Gas Field, Malaysia
Figure Source: PETRONAS (2017a)

Official grown breaking project was started on June 2013. On April of the year after, the hull part was launched and 95% of the project was completed before the end of 2015 (PETRONAS, 2016b). Less than three years, the construction had been finished. It was on 14 May 2016 when the FLNG Satu sailed 2,120 nautical mile journey from DSME shipyard in Okpo, South Korea (PETRONAS, 2016b) to its home in Malaysia.

About 145 crews respectively are working everyday on the vessel, controlling the whole process of FLNG Satu starting from receiving natural gas process through a flexible subsea pipeline, then extracting process into LNG as well as storing stage on the hull. PETRONAS (2016a) marked the breakthrough on 14 November 2016 when FLNG Satu received its first ever gas milestone.

The first drop of LNG was extracted on 5 December 2016 (PETRONAS, 2016d) and was stored for about 4 months before loaded for the first time on 1 April, 2017 (PETRONAS, 2017b). The first fully loaded LNG transferred into LNG carrier Seri Camellia then transported to South Asian market.

The FLNG SATU success milestones unlock the FLNG infant concept into proven technology. It significantly proves the engineering concept of FLNG is feasible to be implemented. This also open the global LNG business and turn on more opportunities to develop remote and stranded fields that were unfeasible by conventional way in order to supply reliable LNG supply to the world market.

6.2.2 Largest FLNG: Shell Prelude FLNG (Under Development)

Despite PETRONAS FLNG Satu is the first and only existing FLNG Facility, Shell is actually the first operator that was signed the FLNG FID to develop offshore Western Australia block in May 2011. The 488 meters-long, 74meters-wide, and 44meters-depth Shell Prelude announced to be the floating LNG processing placed 200km offshore north-west Australia. With its capacity, it projected for field with 2-3 TCF proven reserves.

By April 2017 this FLNG is still under development, the construction has reached an advanced stage on the project (Shell, 2017a). Shell Prelude become the most-watched ongoing FLNG project as on its completion (shown on **Figure 6.5** below) and it will be the largest floating production facility in the universe. This floating facility four times longer by its length compared to soccer fields and its liquid storage tanks could fit water from 175 Olympic-sized swimming pools. Shell Prelude is projected to produce 5.3 MTPA (3.6 MTPA of LNG, 1.3 MTPA of condensate (equivalent to 35,000 b/d) and 0.4 MTPA of LPG) for its 20-25 years life span. This FLNG facility is also planned to be re-deployed to develop new gas fields after this location. Shell (2017a) reported that the estimated budget for the vessel is approximately in the range of 3-3.5 billion USD per MTPA.

Figure 6.5 Shell's Prelude on its Construction Site
Figure Source: Shell (2017b)

The first ground-breaking was carried out on 18 October 2012 with its strategic partner Technip and Samsung Heavy Industries. The construction of large module was conducted in Geoje Island Shipyard, South Korea, while some parts constructed elsewhere. All components then assembled in Samsung shipyard.

The massive structure is designed with high safety factor that able to withstand severe weather conditions, including category five cyclones and claimed to be able to withstand a 1-in-10,000-year storm. Safety barriers also implemented respectively on this vessel. Living quarter is located within maximum distance from the processing facilities. This is to minimize catastrophe for crew in the case of the gas leaking.

6.3 FLNG Masela

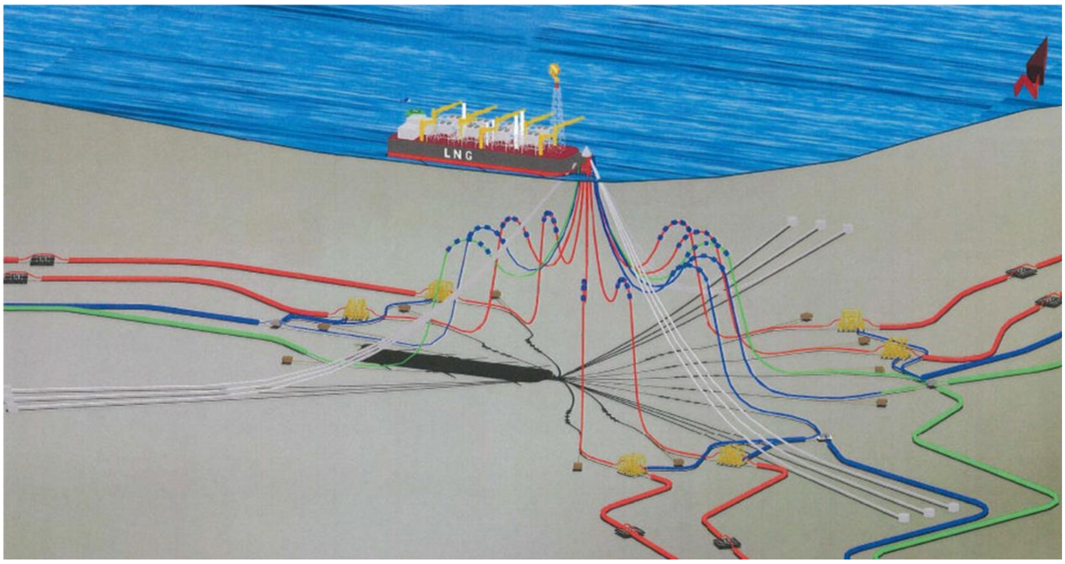


Figure 6.6 Design of FLNG Masela
Figure Source: Manabe et al. (2009)

The FLNG Masela will have a length of 500 m, a breadth of 82 m and a depth of 37.2 m (Wilde, 2010) as illustrates on **Figure 6.6** above. The production capacity is also designed for 7.5 MTPA. On its completion it will surpass the Prelude's dimension and become the largest floating vessel in the world. LNG will be offloaded to a shuttle tanker in a side-by-side mooring arrangement and condensate will be offloaded to shuttle tankers in a tandem arrangement.

FLNG creates longer plateau production period for Masela case. The vessel also provide the fast track delivery of LNG (White and Longley, 2009).

6.3.1 Topside/ Deck

The topside of FLNG is considered as the vital area that embrace the integrated processing facilities. The reservoir of Masela categorized as a dry gas, thus its processing facilities are little bit less complex than the wet gas. Wet gas needs NGL separator processing, while it is non-compliance for Masela case.

The topside design aims to be as flexible as possible to accommodate the gas processing requirement (Kanu et al., 2011). In case of Masela the complex process rely with the availability of topside design and process strategies that must be design to reduce downtown key of the production.

Figure 6.7 Integrated Processing Facilities on FLNG Masela
Figure Source: Chalis (2013)

Moreover, According to Manabe et al. (2009), the FLNG Masela will fully equipped with the processing facilities as well as its supporting area as shown on **Figure 6.7** above. The facilities include:

- Feed Gas Pre-treatment Process Facility
- Liquefaction Facility
- Condensate Processing facilities
- Water Process (MEG Reclamation, Produced Water Treatment)
- Utility System
- LNG & Condensate Storage
- LNG & Condensate Offloading Facilities
- Flare System
- Turret & Mooring
- Living Quarters

The essential issue that occur related to the topside is the layout arrangement. The layout must be designed to ensure the reliability of operation in the sensitive operation area where the vessel must withstand the motion to handle the sea wave. The layout also designed as compact as possible to keep the center of gravity as low for the stability. Integration of topsides with the hull will rely on a deck layout that meets operational and safety requirements design. The layout of the deck must also consider the safety aspect, create a barrier and distance between the hazardous zone and the living quarter. The topside layout is projected as **Figure 6.8** below.

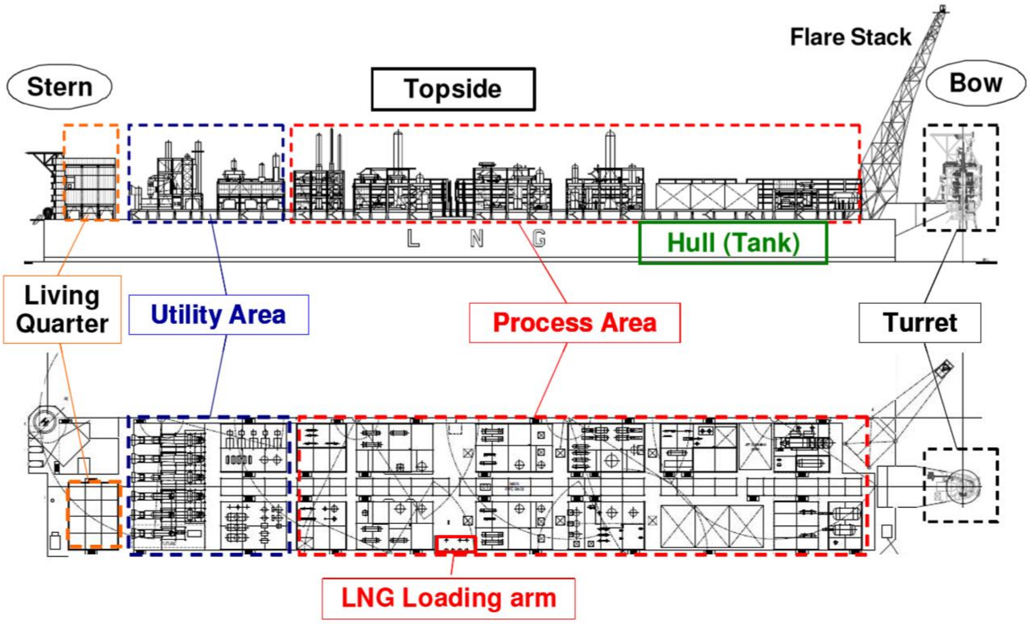


Figure 6.8 Topside Layout of FLNG Masela
Figure Source: Orimo (2012) and Manabe et al. (2009)

The main principle is to locate the living quarter on the opposite side of the turret area and the flare system. The processing area will be placed on the center. Then the non-hazardous utility area become a buffer zone in between the processing area and the living quarter.

According to Manabe et al. (2009) the turret must be placed closed to the bow as it has high pressure. Then living quarters must be located on the stern to obtain the maximum distance with the flare. The space allocated for the accommodation modules must be as compact as possible to safe the space. The number of personnel on board should also be limited to increase the safety operation. PETRONAS FLNG Satu has 158 crews on board (PETRONAS, 2016a) wile Shell's Prelude is expected to be operated by 220-240 crews (Shell, 2017b). It is relatively acceptable to estimate the crew of FLNG Masela will be in the range of 250-270 personnel.

6.3.2 Hull

The proposed design must be integrate the function of hull and topside. The hull has a function to counter the wave motion and ensure the stability of the vessel. So, the hull dimension significantly affect by the topside dimension. Shipyard availability also affect the design of the hull (Kanu et al., 2011).

Major space below the deck will be used as the LNG and condensate storage. The modules below the deck contains gas turret and ballasting equipment. Most likely the hull will be made from the steel with large rectangular structure as it is more effective and efficient in terms of stability, reliability, and cost (Sheffield, 2005). Based on analysis from Sheffield (2005) and Kanu et al. (2011), the membrane containments system must be implemented to handle the pressure loads from sloshing and reduce the liquid motion.

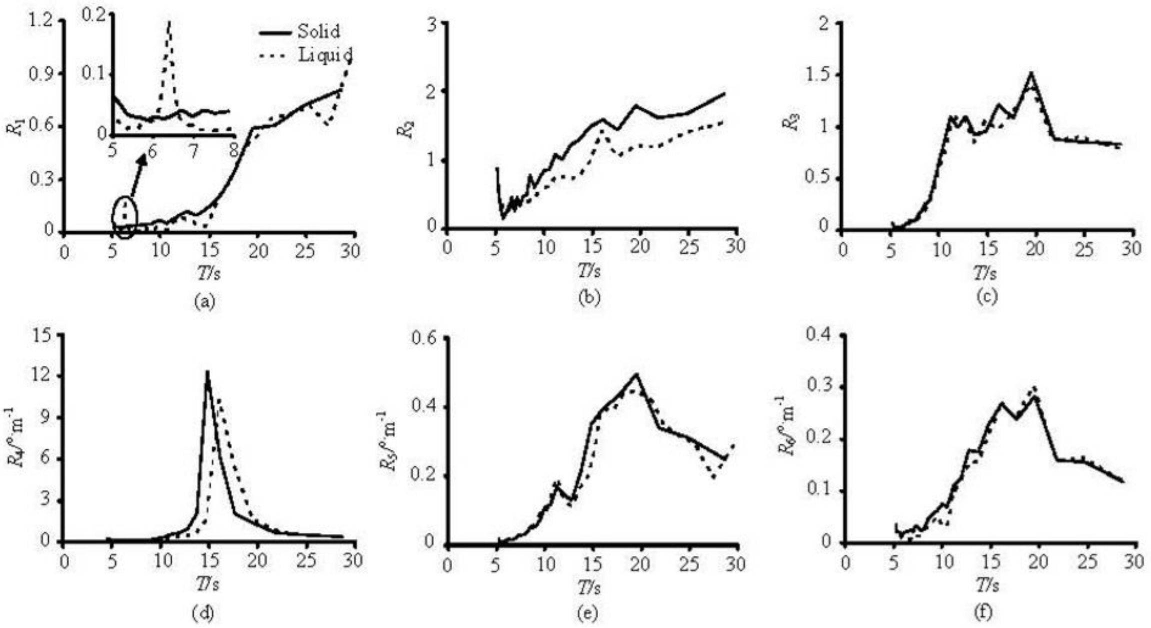


Figure 6.9 RAO Curves of the Six-Degree-of-Freedom Motions
The surge (a) and pitch (e) motions are measured in heading sea, the sway (b), heave (c) and roll (d) motions in beam seas, the yaw (f) motion. Figure Source: ZHAO et al. (2012)

On its operation, FLNG have to withstand the wave motion that cause sloshing on the partly filled tank. The model experiment by ZHAO et al. (2012) explained the response of the hull to the wave motion. **Figure 6.9** above shows the result of the experiment. The hull of FLNG unlikely affected by the surge, sway and yaw frequency motions. However the hull can mainly affected by the roll motion in response to the wave amplitude.

Figure 6.10 below shows the six degrees of freedom on the floating vessel, which in this case is the FLNG. The hull mainly might be affected by the roll motion (highlighted in yellow). Then the direction of the wave and wind that should be avoided is the one that facing the hull side that illustrates with the green arrows. Thus the arrangement of the FLNG on the location must be design to avoid facing the roll motion.

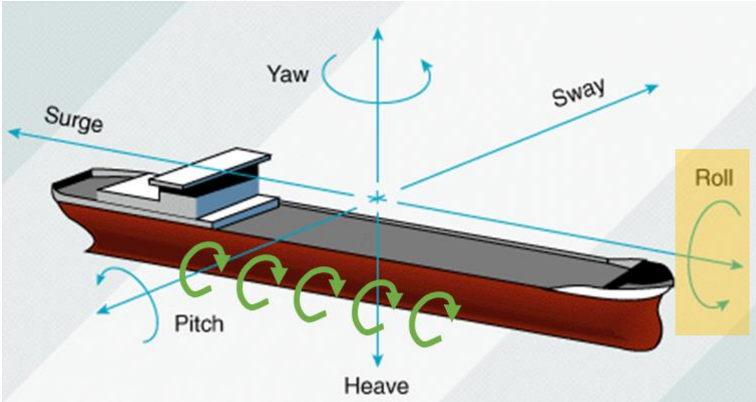


Figure 6.10 Six Degrees of Freedom in FLNG
Figure Source: Ships Stabilising Systems and Stabilisers (Mariner, 2017)

Refer to **Figure 4.5** on page 21 above, the significant wave height around Masela on the range of 1.-3.5 meters. The ocean waves tend to head from south-east to west. The condition relatively benign. Additionally according to study by Manabe et al. (2009) even on the tropical cyclone season from October to March the condition is relatively still stable. The benign wave condition is one of the consideration that the FLNG is acceptable in terms of design and operation of the hull.

The FLNG must be arranged like **Figure 6.11** below. The FLNG is arranged from west to the east to avoid the wave that can trigger the roll motion. The placement of bow also leads by the wind direction that flowing from east to the west. Bow area where the flare is located should be positioned on the west, then the living quarter at the stern corner.

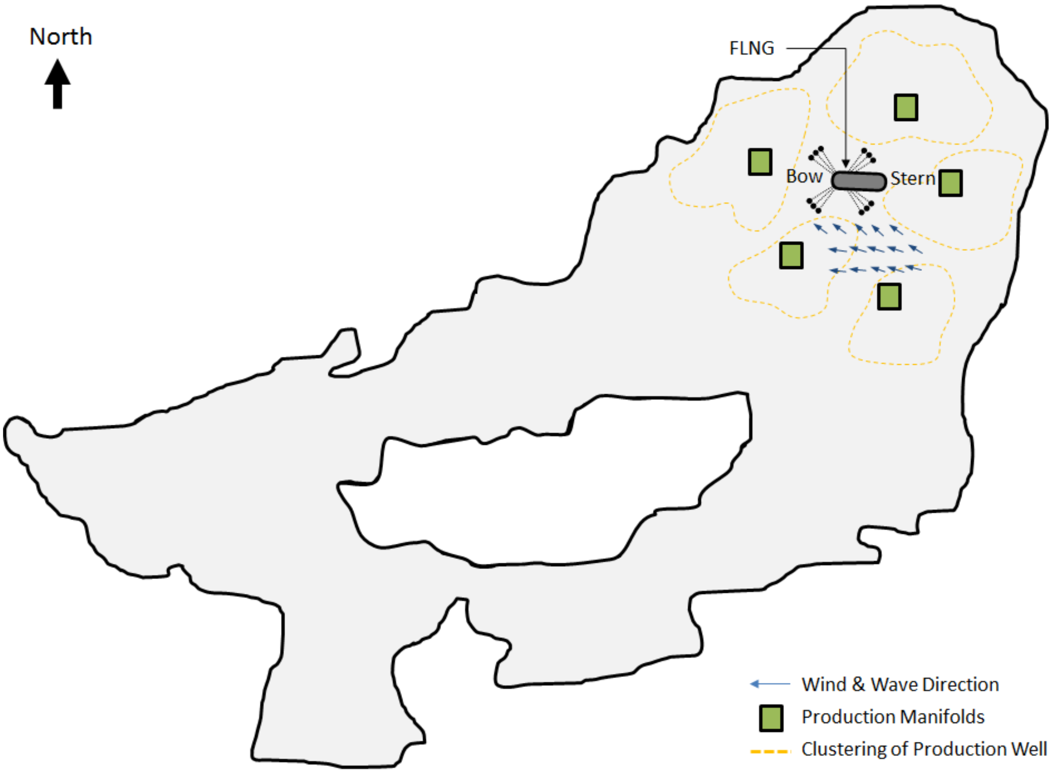


Figure 6.11 The Arrangement of FLNG

6.3.3 Safety

Safety evaluation is the most vital issue on FLNG Masela. Thus on the hazards are identified and listed on **Appendix D – Hazard Identification**. The listed events that corresponded on that Appendix are listed on **Table 6.1** below.

Table 6.1 Identified Hazards

No	Location	Event
1	Separator Area	Fracture or fatigue equipment on separation area
2	CO_2 Treatment Area	Damage on CO_2 absorber
3	Turbine Gas Unit	Explosion on Turbine Gas Unit
4	Generator	Fire & Explosion
5	Water Cooling Area	Fire & Explosion Water overflows
6	LNG Storage	Fire & Explosion
7	Flaring Area	Fire & Explosion Damage on Equipment
8	Loading Ship	LNG spill during offloading process

The analysis refer to the Recommended Practice DNV-RP-G101 (2010). The risk classification is refer to **Table 6.2** below in related to probability of failure (PoF) and consequences of failure (CoF). Probability of Failure (PoF) is an important part on risk analysis that its rate is different over the life cycle of the pump's component. It express the likelihood that an event might occur at a given time. Consequences of Failure (CoF) represent the accident outcome to the circumstances.

Table 6.2 Risk Classification Matrix

PoF Ranking	PoF Description		A	B	C	D	E
	Quantitative	Qualitative					
5	$> 10^{-2}$	Failure Expected	Yellow	Red	Red	Red	Red
4	10^{-3} to 10^{-2}	High	Yellow	Yellow	Red	Red	Red
3	10^{-4} to 10^{-3}	Medium	Green	Yellow	Yellow	Red	Red
2	10^{-5} to 10^{-4}	Low	Green	Green	Yellow	Yellow	Red
1	$< 10^{-5}$	Negligible	Green	Green	Green	Yellow	Yellow
CoF Types	Safety		No Injury	Slight/ Minor Injury	Major Injury	Single Fatality	Multiple Fatalities
	Environment		No Pollution	Slight/ Minor Effect	Local Effect	Major Effect	Massive Effect
	Business		No Downtime or Asset Damage	Slight/ Minor Damage	Local Damage	Major Damage	Extensive Damage
CoF Ranking			A	B	C	D	E

Source: DNV-RP-G101 (2010).

The risk distribution according to that classification is shown on **Figure 6.12** below. The highest risk is the explosion and fire on the LNG storage that contains flammable liquid. The other three events correspondingly noted by number 3,4,5 are located on the red zone which are risky. Thus it can be concluded from this sketch distribution that the major treat for FLNG Masela is the fire & explosion in the turbine, generator, water cooling, and LNG storage. Then from those four major area it might be concluded that the most possible major accident that will be occurred is the explosion.

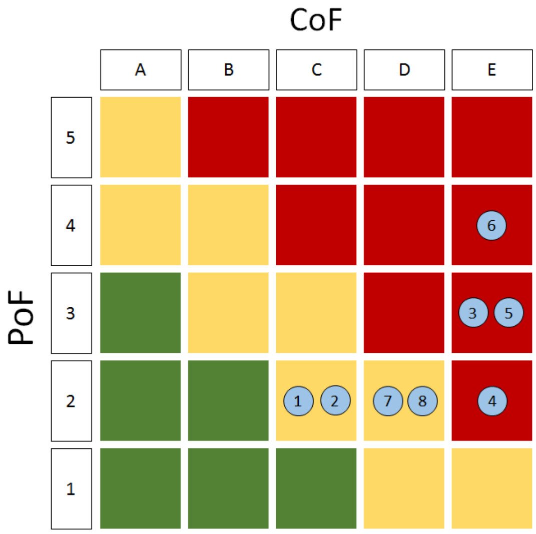


Figure 6.12 Hazard Distribution Sketch

The comprehensive study related to the explosion on the floating vessel was developed by Manabe et al. (2009). FLNG operates in the hazardous condition when all the process are integrated on the same place with limited barrier. Then the model of the explosion were established by Manabe et al. (2009).

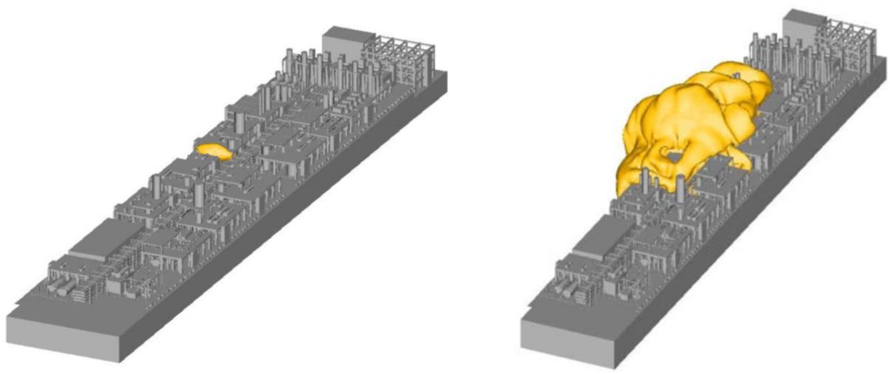


Figure 6.13 Explosion Simulation

(Left-side: Vapor Cloud of Leaked Mixed refrigerant at 1.3 sec after leak start, Right-side: The one at 3.0 sec after leak start)

Figure Source: Manabe et al. (2009)

Figure 6.13 above illustrates the explosion on the FLNG vessel with dimension 350 x 46 meter. The model was made with the scenario that the explosion occurred on the processing area in the normal operating weather (normal wind speed). One of the finding from that model is that the explosion overpressure on the processing area unlikely to harm the accommodation area where the gap (distance between explosion on the processing area and accommodation) is more than 100 meters.

The huge dimension of Masela has benefit according to that conclusion. The vessel has 500 meters length that will equipped all the processing facilities. The utilities area is projected to own 150 meters and can be treated as a buffer zone between the explosions to the living area.

The personnel on board will have sufficient time to evacuate in the case failure due to the explosion.

Explosion overpressure also projected not causing huge damage to the LNG tank, hull, and deck structure Manabe et al. (2009) because of its open area. Wide open area between the modules will also beneficial for FLNG Masela.

6.3.4 Offloading Operation

The most critical activities on the FLNG is the loading of LNG. The vulnerable condition of LNG that needs cryogenic temperature is the leading factor. To load massive number of LNG to the LNG Carrier, the special cryogenic hoses and piping must be used. Kanu et al. (2011) added that the loading arm requires steel pipework with specialty designed swivel joint.

The arrangement of offloading process for FLNG Masela had been decided by using side-by-side configuration for LNG. While loading condensate will use the tandem configuration as illustrates on **Figure 6.14** below.

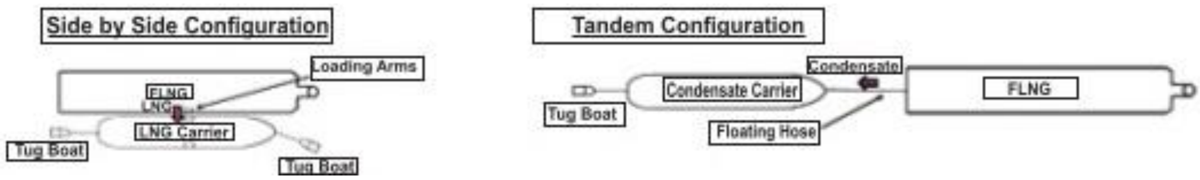


Figure 6.14 Offloading Configuration

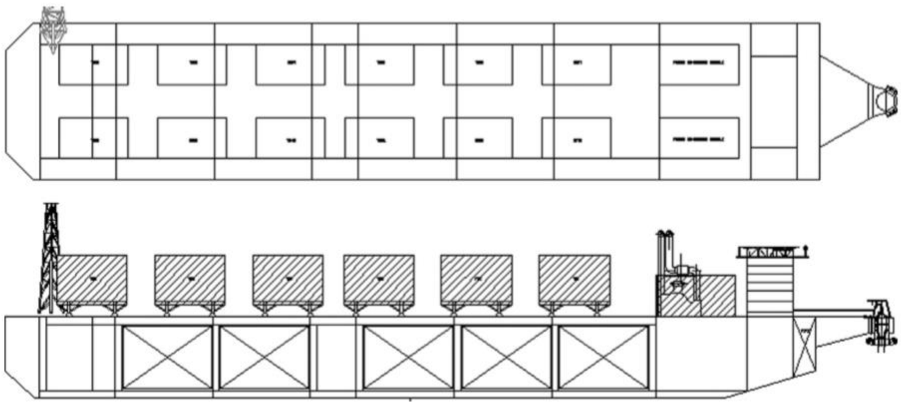


Figure 6.15 General Arrangement of the FLNG Vessel.
Figure Source: Zhao et al. (2014)

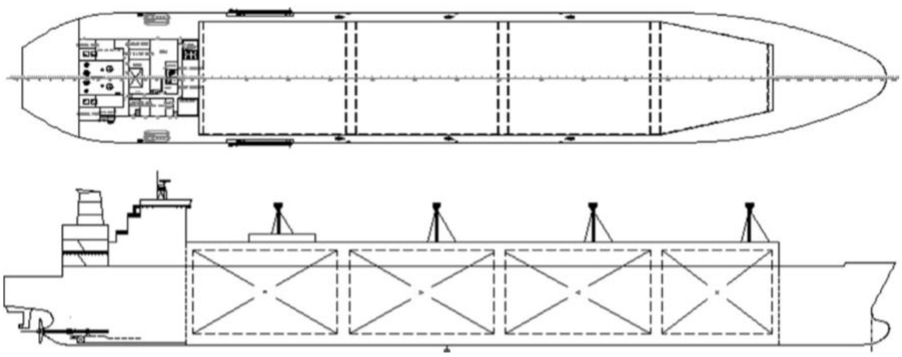


Figure 6.16 General Arrangement of the LNG Carrier
Figure Source: Zhao et al. (2014)

The first step of offloading is the maneuvering process when the LNG Carrier (**Figure 6.16**) approach the FLNG (**Figure 6.17**). The maneuvering process was evaluated by Manabe et al. (2009) using a FLNG model with size 350 x 46 meter. The relative motions of two floating vessels were modelled through the wave condition on the range of 1-10 meters. Their researched found that with proper heading control of the thruster FLNG, the relative motions are likely under the operational limit scale. **Figure 6.17** shows the approach movement of the LNG Carrier from the righto the left. Then it shown that the model of FLNG not even move. So, the rotating maneuver of LNG Carrier doesn't affect the stability of the FLNG as shown on **Figure 6.17** below.

The operating wave height of Masela ranging from 1.5-3.5 meters as shown on **Figure 4.5**. The model below was designed in more harsh condition than Masela. So, it can be concluded that the maneuvering operation is feasible for FLNG Masela and its LNG Carrier where the wave condition is relatively benign.

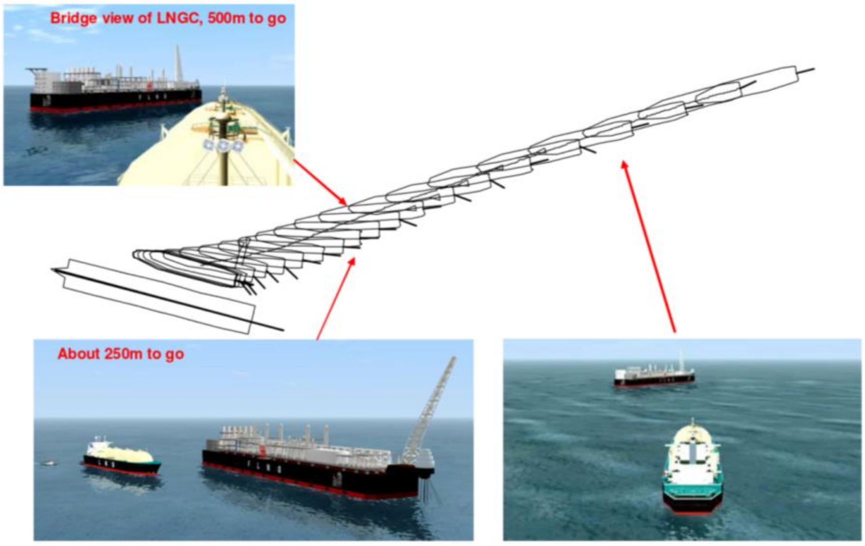


Figure 6.17 Maneuvering Simulation of LNG Carrier
Figure Source: Manabe et al. (2009)

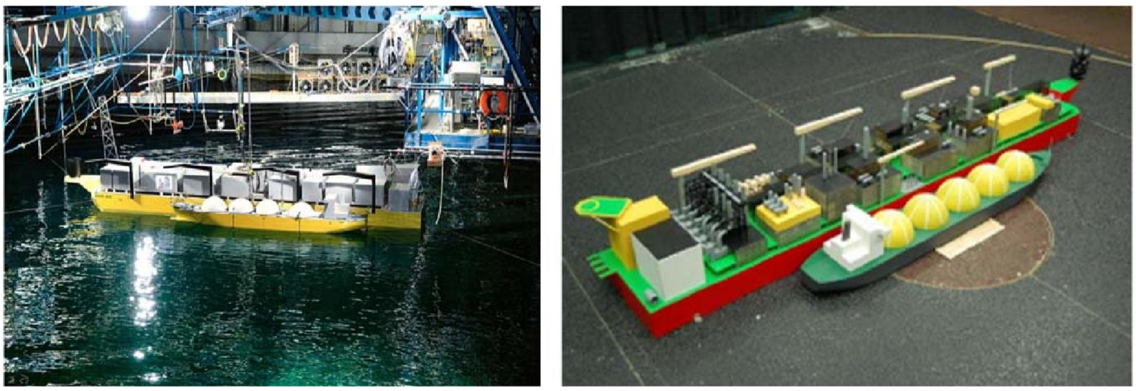


Figure 6.18 Schematic of LNG Offloading Model Tests
Figure Source Wadi (2015)

The offloading downtime analysis was performed by Wadi (2015) by using prototype on **Figure 6.18** above to determine its best schedule in terms of metocean parameters. The complete loading schedule for FLNG Masela is shown on **Figure 6.19** below. It takes 2 days for the offloading process.

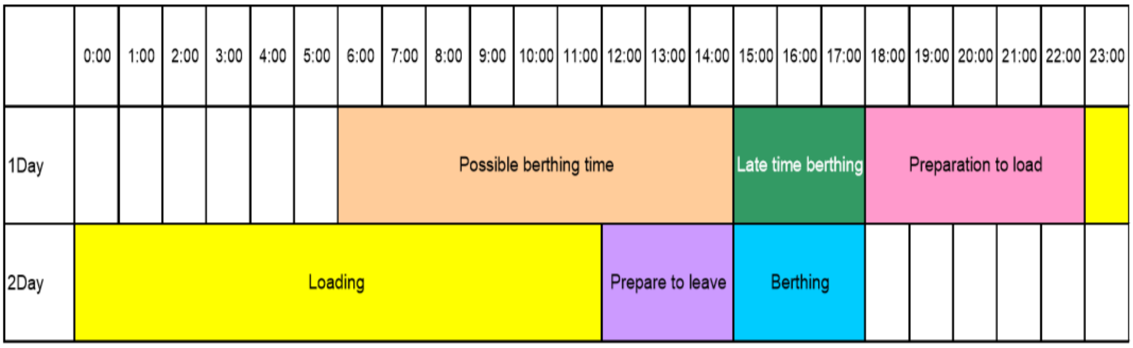


Figure 6.19 Typical Offloading Operations
Figure Source: Wadi (2015)

6.4 Operational Condition

The main objective of the FLNG Masela operation is to extract and deliver LNG in safe and efficient manner. Effective and efficient operation is mandatory to ensure the LNG is produced at the minimum cost.

One of the essential challenge of operating FLNG Masela is the limited support infrastructure on the surrounded area. The issues that may come up are related to the logistic supply, changing crew and regular maintenance.

The other issues is related to the schedule optimization related to the gas receiving, processing, storing, and loading process. The operation must address the time perfectly as all operations are integrated and interdepending with each other. One delay in certain operation become a risk and even may lead to failure to fulfilling the delivery contract (Sheffield, 2005).

FLNG has lower limited capacity. In the case of Masela the FLNG has a capacity of 7.5 MTPA of FLNG while the proposed onshore LNG Plant will be able to handle up to 9 MTPA. Smaller number of production capacity leads to lower feed gas volume rate requirement (Sheffield, 2005). FLNG Masela also purposes more production plateau for 20 years as mentioned on **Chapter 5.7.2** on page 40 above and lead to more optimum life of the field.

6.5 Legal Issues & Insurance

To successfully develop the Masela block with FLNG concept, the legal issues related to its construction and operation must be properly settled at the beginning phase. The FLNG is still a brand new technology that has not commonly implemented. The legal issue is a risk to the project and there should be a certain allocated time to resolve it. Feasibility studies in the matter of regulations and local standard should become an important subject on it.

The study of Sheffield (2005) mentioned at least three points that should be considered on FLNG development. In the context of FLNG Masela upstream legal regime, fiscal terms, as well as the local regulation should be taken as important topics. Those three segments affect the process of FLNG Masela's development.

The primary type of contract also needs a consideration. The contract should be decided either by using a single contract that covers all the structure all two divided the contract for the hull and the topside. Integration part must be completed when choosing two separate type of contract.

The stakeholder developer of Masela, in this case is KKKS (INPEX and Shell) must explain the technology specification of FLNG and its impact to the representative of government of Indonesia on oil & gas sector, which in this case is SKK Migas and Ministry of Energy & Natural Resource. Proper assessment should be conducted to evaluate this and to finally decide the legalization of FLNG Masela as part of offshore building block. Distinctive allocated time is needed as the country has never build and operate any offshore vessel with length more than 300 meters.

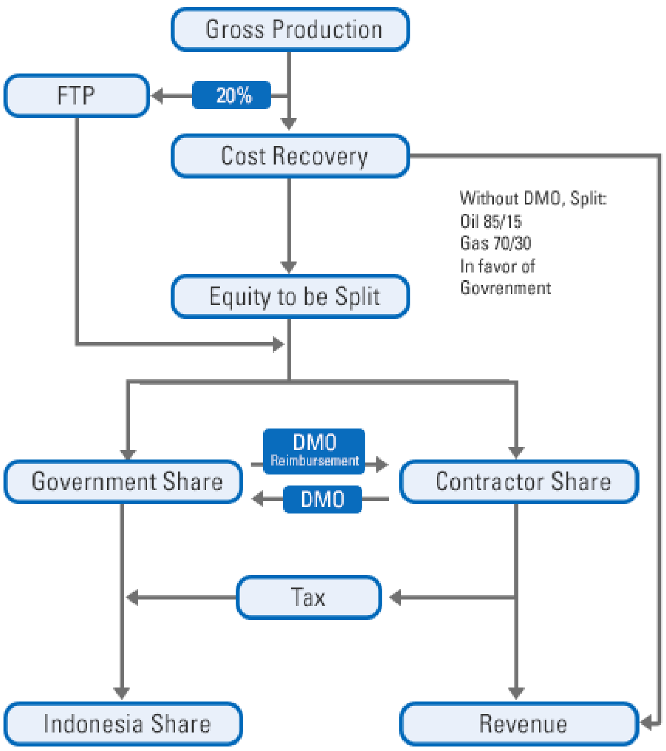


Figure 6.20 Indonesia's Upstream PSC Diagram
Figure Source: MedcoEnergi (2016)

The evaluation in terms of fiscal should also consider the Production Sharing Contract (PSC) scheme that is implemented on Indonesia's oil & gas upstream business. In PSC, all of tha capital expenditure will flow out since a cost recovery where operator may ask the cost reimbursement to the government as shown on **Figure 6.20** above. The large number of investment becomes another consideration as all funding and development cost as well as operating cost will be taken from the government budget which are the Indonesia taxpayer's money. The burden of the risk should be shared with insurance company as a third party.

Refer to Shell's Prelude history, it was not easy to find an insurance company that wants to cover the risk of its construction and operation. Finally Shell signed insurance paper with Lloyds as the insurance partner of the project (Lloyd's, 2014). It can be another challenge of Masela that the insurance contract is a risk according to technical and capacity perspective. Most of insurance companies unable to handle such a big risk on the critical operation for this massive size vessel. Moreover this technology is still infant and may contains larger risk than expected. It still possible, but proper management is an urgency to ensure the project is performed and delivered based on safety, quality, cost, and schedule principles. It might be recommended for FLNG Masela to use the same insurance company which handled Shell's Prelude insurance.

6.6 FLNG Masela Conclusion

At the beginning of field development there is process to identify and select feasible option. FLNG as a new technology concept to produce LNG is one of the feasible option to develop Masela block. FLNG Masela presents favorable opportunities to develop remote gas field with limited supporting facilities around.

The argument that mentioned this technology is unproven is no longer valid, as PETRONAS successfully operating its FLNG Satu on-stream without any meaningful obstacles. However, the main challenge of FLNG Masela is its giant dimension that on its completion will be surpass the current hugest constructed vessel and lead as the biggest offshore vessel ever built. The high risk related to safety, cost, and schedule are present on this massive construction.

In terms of technology constrain it is feasible to be implemented. The moderate sea condition is stable enough to handle the dynamic of the operating condition. The maneuvering operation is feasible for FLNG Masela and its LNG Carrier where the wave condition is relatively benign. The major treat accident that might occur is the explosion. The explosion model presented above also gave a picture of the safe operation on FLNG.

To develop long term and new born technology like FLNG requires stability in terms of fiscal regime and political. Indonesia's PSC with its cost recovery scheme might be attractive option according to operator's point of view. However based on government perspective it carrier high risk. Government may refer to Shell's Prelude that suitably become the most appropriate example for FLNG Masela. Moreover if the concept of FLNG Masela wants be applied but does not want to handle a big risk, the FLNG should be built with exactly same dimension like Prelude. Thus risk related to dimension may be reduced and safety level may increase as well.

When the technical consideration, operation, and legal issues are solved properly, the existence of FLNG Masela might offer an interesting alternative to develop the block. As the FLNG concept turning from concept to reality, the attention should be moved from technical to commercial area. The economic model for FLNG Masela development is explained on **Chapter 8** Economic Analysis on page 78 below.

7 Pipeline Analysis

The other option to develop Abadi gas field is to transport the gas from subsea facility into onshore LNG plant through long distance pipeline. After the condensate-gas separation process, the inlet gas pumped into the pipeline. Gas threatening, dehydration, gas conditioning, liquefaction, as well as its storage and loading process will be managed onshore. It is generally accepted that pipeline concept is mature design concept that widely implemented to transport gas from the field to processing facilities. This concept also proposed to be the other solution for Abadi field development in order to avoid higher risk when developing FLNG.

This chapter aims to analyze the feasibility of implementing pipeline concept on the Masela development. To begin with, there should be a clarity about definition of pipeline itself. The gas always be transported through steel rounded pipe, however not all of the pipelines can be precisely called pipeline. As an example the pipe which transports the raw gas from the subsea facilities to the topside facilities is called flowlines and riser. So, to make it clear the scope of pipeline analysis on this chapter is limited only for the pipeline that transport the gas from FPSO to the onshore LNG Plant, highlighted on **Figure 7.1** below.

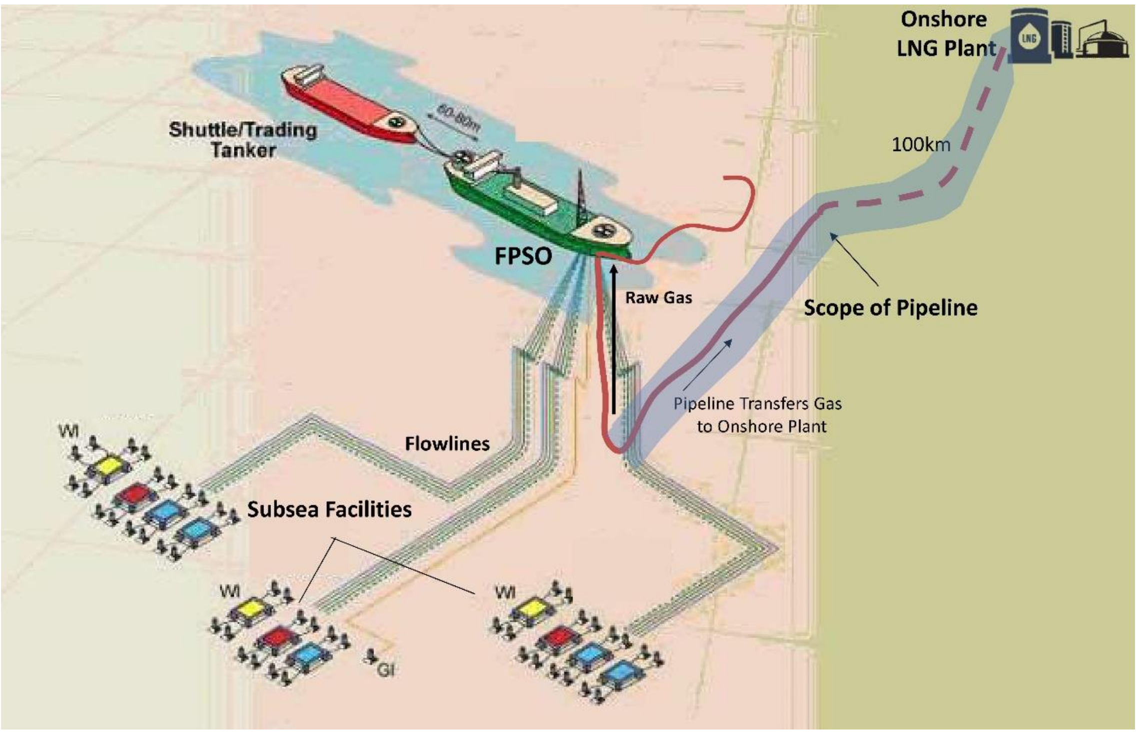


Figure 7.1 Scope of Pipeline on the Field Configuration
Modified Figure from

At glance, Masela pipeline concept is more promising way to develop this field. This is due to the fact that the country has been developing several gas-into-LNG blocks with pipeline and LNG plant such as LNG Tangguh in Papua. However, Masela onshore scheme cannot be undertaken in a simple way. Pipeline must be designed in regards to its location, geo-hazard, and feasibilities before making appropriate decision.

7.1 Pipeline Consideration

Pipelines will be routed to connect FPSO and the onshore LNG Plant. To evaluate the possible route, some considerations must be taken. Each terrain options may have its own issues, thus there consideration become the selection drivers when choosing the most feasible route.

7.1.1 Optimal Path Selection Criteria

Here are the optimal pipeline path criteria according to (Tawekal and Ilman, 2014).

- The shortest path, ideally a straight line. The shorter pipeline path will minimize the use of materials until the use of barge and/ or vessel laying. Implicitly, the shortest path selection will minimize the economic cost. In addition, the short path will reduce the effect of head loss due to friction fluid with the inner surface of the pipe, due to turns, and so forth.
- Ease of installation. In some conditions especially bathymetry conditions, the effect on the installation method is increasingly significant. Convenience in this case is the level of accuracy with a predetermined route selection. On the seabed hills, high accuracy is required to place pipes on predetermined routes. It also requires correction of both pre-lay and post-lay.
- The safest path. The level of path safety depends on the bathymetry condition. A relatively flat seafloor is the preferred route for a safe pipeline because it reduces the risk of free span and VIV (Vortex-Induced Vibration).

7.1.2 Design Issue

There are several design issues that should be considered when choosing the pipeline route. Inappropriate pipeline route will cause these certain design issues arise as problem.

Buckling is a state where the pipe is not round or deformed by large hydrostatic pressures at a certain depth. There are two types of buckling that is local and global.

Propagation buckling is the propagation of deformation of the shape on the cross section of the pipe that extends and propagates along the pipe. The energy that causes this propagation is the hydrostatic pressure. The principle of propagation buckling is the presence of pressure which can cause propagating buckle which is greater than the pressure required to prevent the occurrence of the buckle.

Rupture is a condition of pipe failure in withstanding working tension stress. Rupture occurs because the working voltage has reached the point of collapse on the strain voltage graph. Rupture on the pipeline can occur without the fluid inside.

Bursting is a condition of pipe failure in withstanding large internal pressure. The large internal pressure causes the pipe to reach the point of collapse and the fluid in which it bursts out through the collapsed part.

7.1.3 Flow Assurance

The issue of flow assurance recently gain attention relating in terms of technical production compounds. Flow assurance refers to the guarantee of the fluid journey from the reservoir to the proposed destination. There are several factors that affect the flow assurance on the pipeline such as temperature, pressure, and chemical components (Sloan et al., 2010). Several problems potentially occurred due to the flow assurance matter as illustrates on **Figure 7.2** below.

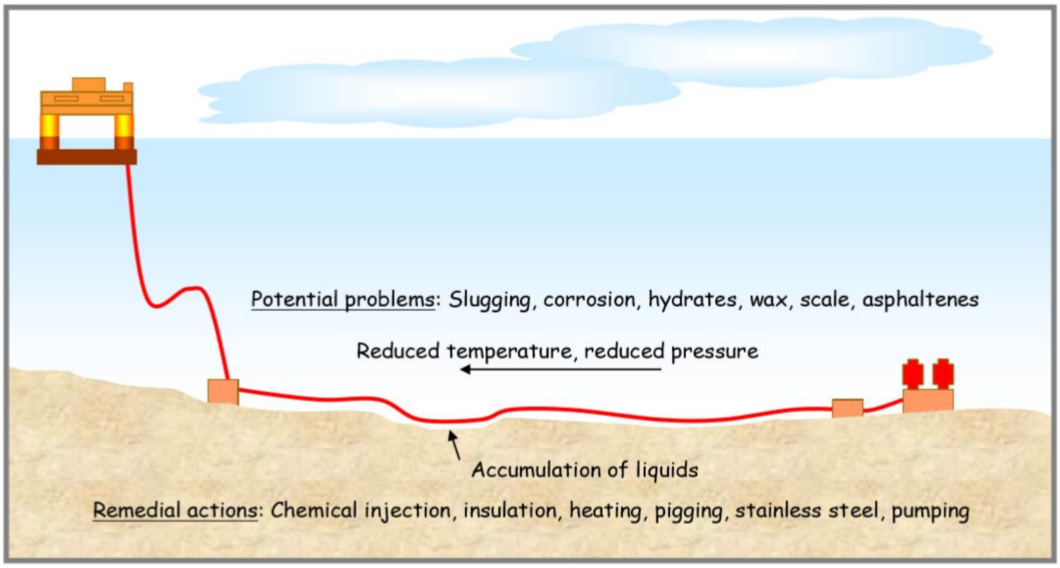


Figure 7.2 Potential Problems Related to Flow Assurance
Figure is taken from OFF515 Offshore Field Development Lecture Note by (Odland, 2014f)

In deep water production process flow assurance becomes the vital subject. Transferring fluids in deep water like Masela case is critical as the operating environment has high pressure as well as low temperature. Mishandling of this matter will interrupts the whole process as it might form solid blockage inside the pipe and cause the failure.

High concentration of CO_2 (that represent condition of Masela) on reservoir without proper treatment will worsen operating condition (Pruess, 2008, Sloan et al., 2010). Gas with rich carbon dioxide content will generate corrosions. Gas hydrates also is the other threat that accumulated on the lower elevation of the pipeline and might be occur in short period (Chapoy et al., 2015) and create blockage formation that should be avoided. It is an ice-like crystalline solid that formed from water and gas. Pipeline rupture and bursting may also occur on the worse condition.

One of the remedial action can be implement is by selecting the pipe material that suitable for flowing gas in deep water. The next section will explain the pipeline material selection for Masela.

7.1.4 Material Selection

The most common materials for pipeline are: carbon steel, high strength low alloy steel, and alloy steel.

Carbon steel is a commonly used and marketable type of steel. One category of steel material including carbon steel is A36 steel. Carbon content in carbon steel plays an important role and does not require the minimum requirements of other components. Carbon steel has a carbon percentage of up to 1.70% (Tawekal and Ilman, 2014). The higher the carbon content, the harder the steel but the harder it is to weld.

High strength low alloy steel (HSLA) is a steel with a mixture of other metals such as manganese, copper, nickel, niobium, nitrogen, vanadium, chromium, molybdenum, titanium, calcium, and zirconium. Copper, titanium, vanadium, and niobium are added to increase strength. This mixture improves its mechanical properties and causes the HSLA steel melting stress to be between 40 to 70 ksi (275 to 480 MPa) (Tawekal and Ilman, 2014). These additional components are also intended to prevent excessive corrosion of the steel. HSLA steel carbon content ranges from 0.5-0.25% in order to be formed and easy to weld.

Alloy steel or famously known as Corrosion Resistant Alloy (CRA) is a carbon steel with a mixture of other metals such as manganese, nickel, chromium, molybdenum, vanadium, silicon, and boron. Some minor metals such as aluminum, cobalt, copper, cerium, niobium, titanium, tungsten, lead, zinc, lead, and zirconium. Alloy steel can achieve a melting stress of 80 to 110 ksi (550 to 760 MPa). Alloy steel contains 0.1-0.3% carbon (Tawekal and Ilman, 2014) in order to limit the hardness of the microstructure of marten site which may be formed during heat treatment or welding, thereby reducing the cracking hazard.

Thus, for Masela which contains high level of CO_2 and operating on deep water area the most suitable material is by using Corrosion Resistant Alloy (CRA) pipeline. The alloy as a material will maintain the insulation and heating system inside the pipeline. Insulation layers are used to protect the pipeline against the inside-outside temperature difference. The insulation layer keep the gas temperature rate in the tolerable level to avoid intense expansion rate.

One of the specification of the CRA is the anti-corrosion coating. High level of CO_2 potentially corroborating rapidly. The salinity of the sea water also the major factor that lead to corrosion. Thus the corrosion coating should be used to protect the pipeline. The other coating that must be used is the weight coating that improve the stability of the pipe to stay on the seabed.

CRA also implemented on LNG Tangguh project which also its gas also has high content of CO_2. Moreover, LNG Tangguh project uses 24 inch diameter CRA pipeline. Further economic calculation on the **Chapter 8** will use unit cost as a benchmark. On the onshore concept development, the economic model mainly refer to existing and ongoing LNG Plant project which one of them is LNG Tangguh Train-3 Project. To simplify the further calculation, the author assuming that Masela onshore concept follows the LNG Tangguh's pipeline specification. So Masela will also use 24 inch diameter Corrosion Resistant Alloy (CRA) pipeline.

7.1.5 Radius Curvature

The seabed is dynamic, so there's no possibility to lay a straight pipeline on the sea. To avoid several hazards such as bathymetry difference, the path of pipeline slightly must be curved as illustrates on **Figure 7.3** below. The limitation of that bent radius is called the radius curvature. The radial path on the pipeline route must be designed higher than the calculated radius curvature.

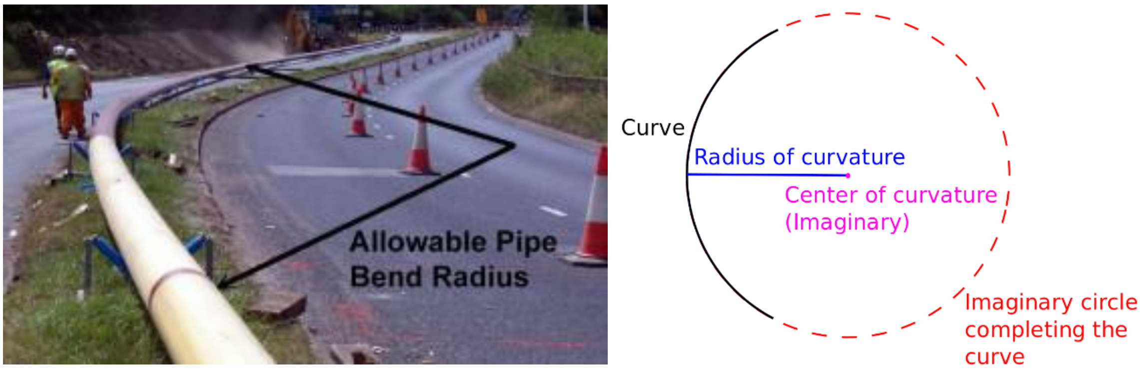


Figure 7.3 Illustration of Radius Curvature
Figure Source: NPC (2017)

Minimum Radius of Curvature, R_{min} – Bending Stress Equation

$$R_{min} = \frac{E.D}{2f.SYMS}$$

E = Modulus Young of Steel (200 GPA = 200,000 MPA)
D = Pipeline diameter (24 inch = 0.6096 meter)
f = safety factor (assumed to be 15%)
SYMS = *Specified Minimum Yield Strength*
(assumed use material API 5L X42, so SYMS is 42,000 psi = 290 MPA)

$$R_{min} = \frac{E.D}{2f.SYMS} = \frac{200{,}000 \text{ x } 0.6096}{2 \text{ x } 0.15 \text{ x } 290} = 1401.38 \text{ meter}$$

So the radius curvature of the Masela pipeline is 1401.38 meter. All of the curved pipeline segments must be designed larger than that.

7.1.6 Environmental Aspect

On its installation, pipeline requires dredging and laying off pipeline as far as hundreds kilometers. The construction of this will disturb the marine biodiversity on the region. Eastern part of Indonesia is well known for its beautiful coral reef and unique marine biotas, and their life will be disturbed by the existence of hundreds kilometers of pipeline around. During its 20 more year's operation, the environment will be disturbed as well.

In order to preserve the ecological value of the region, the operator must follow the environmental guidelines

7.2 Regional Study

Onshore concept needs to lay long distance pipeline to the shoreline area. According to those optimal path selection principles, there are four preliminary reasonable options where the LNG plant can be located. Those four preliminary options are defined according to the development feasibility such as the area, population, and distance from the field as defined on **Table 7.1** below.

Table 7.1 Comparison between Possible Locations

	Pulau Selaru	Pulau Yamdena	Pulau Babar	Pulau Aru
Area (Hectares)	35,400	328,000	63,170	642,800
Number of Villages	7	50	9	131
Population	13,085	34,725	6,795	88,739
Distance from FPSO (km)	85	90	120	500

Data Source: MediaIndonesia (2016) and Amelia (2017)

Moreover, **Figure 7.4** below shows that Pulau Babar, Pulau Selaru, Pulau Yamdena, and Pulau Aru are the possible options. The closest distance is to 8 5km Pulau Selaru or 90 km to Pulau Yamdena. But at a glance, refer to topography shown below, there are deep trench on the middle of the way between Masela block where the gas will be exploited and those two islands where LNG plant is projected.

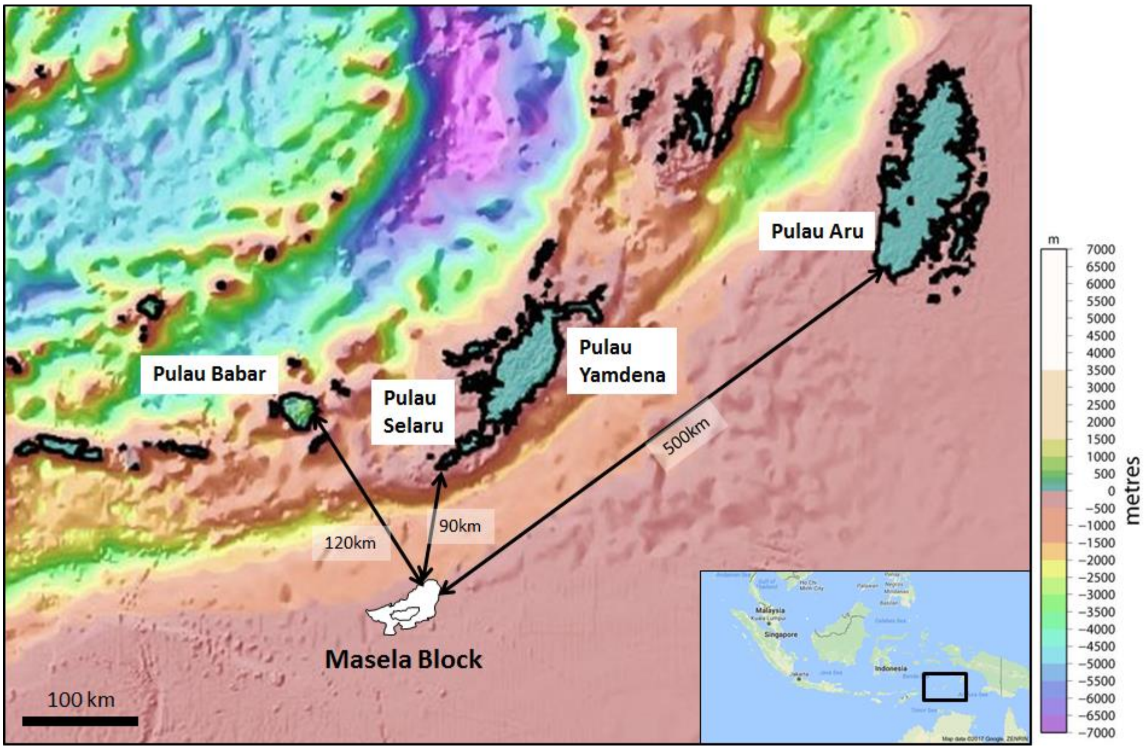


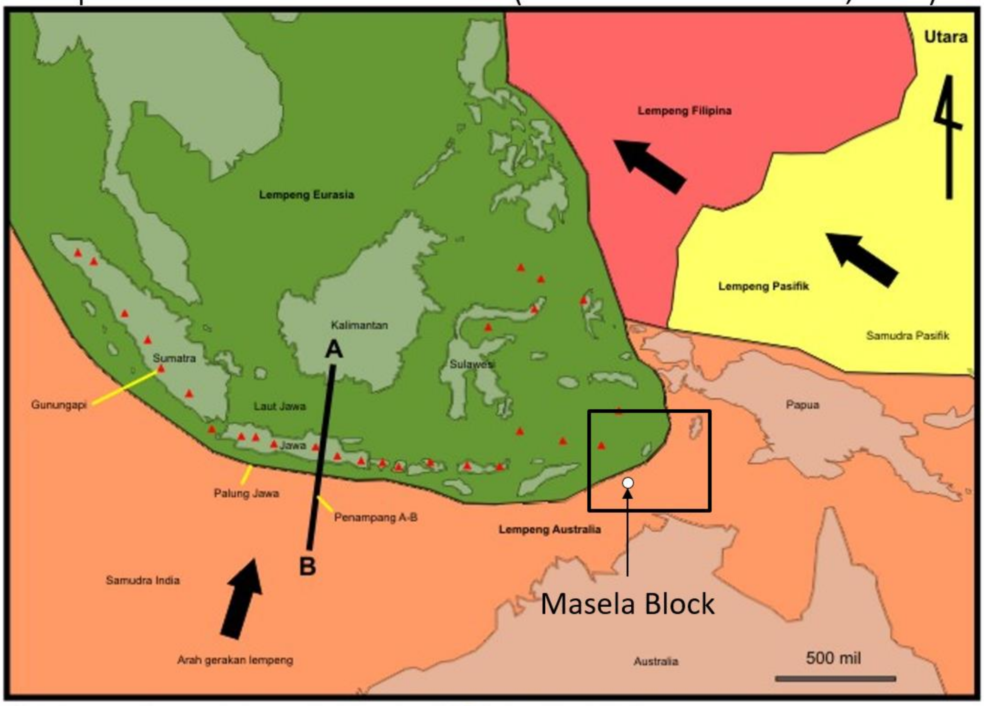
Figure 7.4 Possible Pipeline Route

The Topography Map is Taken from Geophysics (2017)

To evaluate each possible routes, general understanding about the regional condition is a compulsory. The location studies refer to **Chapter 4** which listed the data of Masela block.

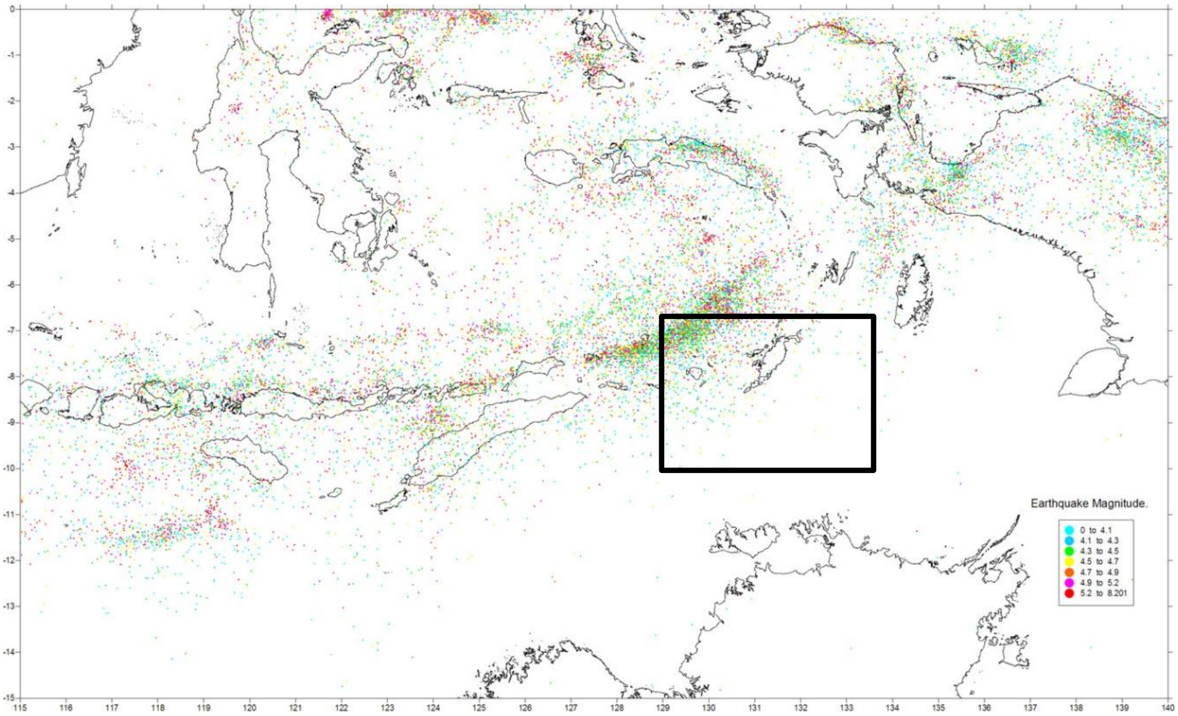
The location of Masela block not only in the border between two countries, but also on the two tectonic plates as shown on **Figure 7.5** below.

Map of Tectonic Plates in Indonesia (modified from Hamilton, 1979)



Source IKATAN AHLI GEOLOGI INDONESIA, 2006

Figure 7.5 The Location of Masela Block Close to the Asia and Australia Tectonic Plates



USGS/NEIC earthquake hypocentres: magnitudes colour coded.
PDE catalogue 1973 to April 2009.

Figure 7.6 Earthquakes Map Distribution

The border tectonic location leads to the intense tectonic activities close to the area. In addition, **Figure 7.6** above shows the earthquake activities on the region. The tectonic activities concentrated on the north-west part of Masela block and the possible islands. There are vast amount of earthquake that also happened on the area between the block and Pulau Babar.

Details earthquake data from 1973 – 2009 that were used to create **Figure 7.6** is not accessible for public. Then the earthquake distribution data according to its strength is unknown. It is just an estimation according to the presented colors that the strength of the earthquake close to Masela were generally less than 4.6 Magnitude in the last 40 years.

Earthquake data from the past 10 years are accessible for public through BMKG (2017a) website. Then refer to **Chapter 4.5.5** on this thesis, there were 883 earthquakes that occurred from 01 January 2008 to 31 April 2017 on the range of 5-9 South Latitude and 135-130 East Longitude (area with black square on the map). Its distribution is shortlisted on **Table 7.2** below.

Table 7.2 Earthquake Distributions

Occurrence		Frequency per Magnitude Scale			Total Number of Earthquake
from	to	1.5-4.5	4.6-5.5	5.6-9.5	
1-Jan-2008	31-Dec-2008	4	4	0	8
1-Jan-2009	31-Dec-2009	32	50	3	85
1-Jan-2010	31-Dec-2010	40	74	5	119
1-Jan-2011	31-Dec-2011	29	61	3	93
1-Jan-2012	31-Dec-2012	52	56	5	113
1-Jan-2013	31-Dec-2013	37	62	3	102
1-Jan-2014	31-Dec-2014	57	52	1	110
1-Jan-2015	31-Dec-2015	51	50	5	106
1-Jan-2016	31-Dec-2016	61	47	2	110
1-Jan-2017	31-Apr-2017	12	25	0	37
Total		375	481	27	883

Data Source: Badan Meteorologi Klimatologi dan Geofisika (BMKG, 2017a)

On the last 10 years, BMKG noted that there are 883 times earthquake occurred on the defined area ranging from 1-9 Magnitude up to 1000 km depth. In the average to high level of earthquake category from, there are 27 times earthquake from 2008-April 2017 with scale more than 5.6 Magnitude. However refer to **Figure 7.6** the high magnitude of earthquake (represent by magenta-red colors) only present at the north part of the area. Southern part of the area where the block is located is free from the high magnitude earthquake.

So, it can be concluded from both **Table 7.2** and **Figure 7.6** that the presences of high magnitude earthquake at the location of the block is relatively small. The earthquake activities also generally occurred on the further north of the block. Even though the general region is vulnerable, the development area can be concluded to be safe from huge catastrophe.

7.3 Pipeline Route Evaluation

7.3.1 Option 1: Lay 95km Pipeline to Pulau Selaru

The guidelines from earlier section about the optimal path selection will lead to consider the two closest islands: Pulau Selaru and Pulau Yamdena. Pulau Selaru is the closest onshore area to the Masela block with 85 km distance. Between Pulau Selaru and Masela Block there is trench which should be avoided. However detailed examination on the bathymetry, may conclude that there is actually small gap between the trenches that shown on **Figure 7.7** below.

Additionally, according to **Figure 4.5** the significant wave height on the surrounding of Pulau Selaru is in the range of 2-2.5 meters which is moderate. The wind speed around this island is on the level of 10 knots according to **Figure 4.6.** However the treat level of tsunami is consider high on this island based on data on **Figure 4.9**.

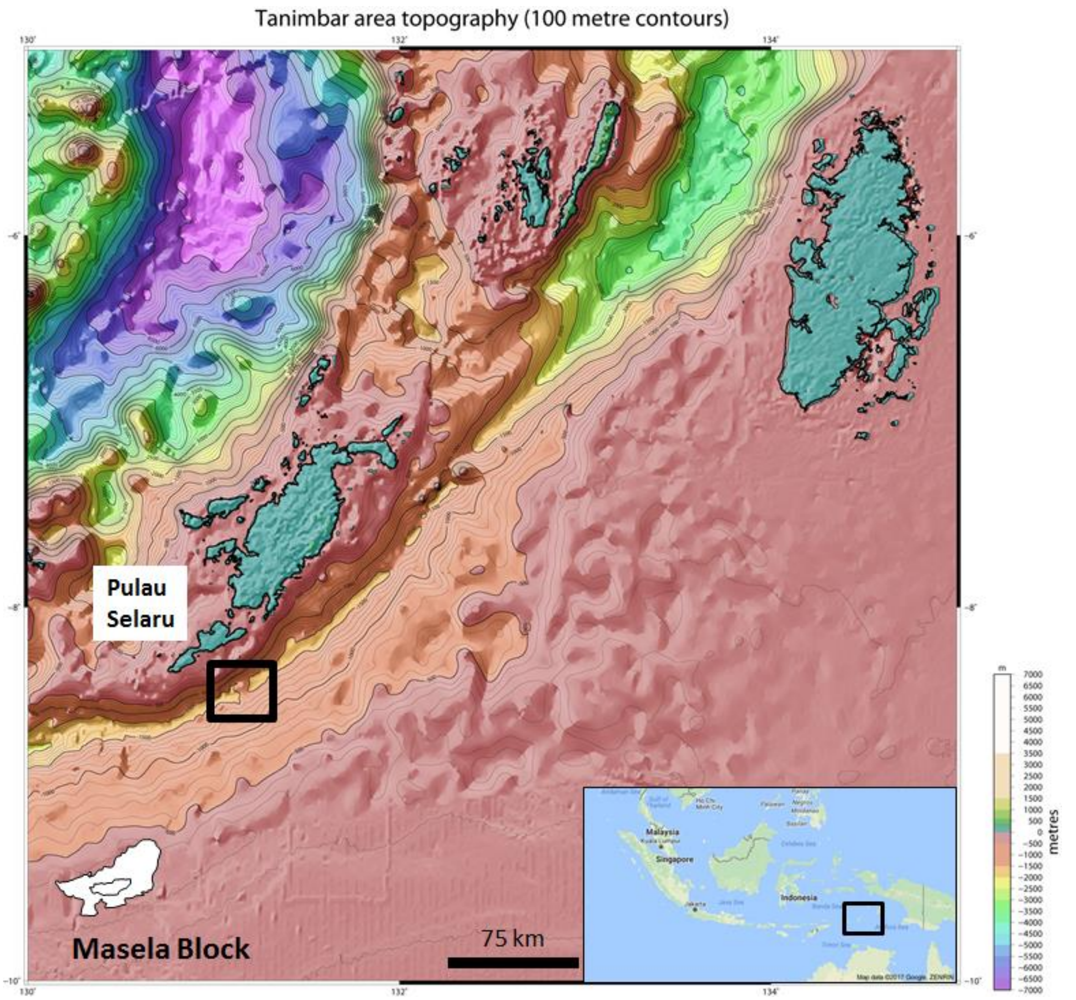


Figure 7.7 Gap between Trenches

Then the proposed route for the first option is to lay the pipeline through this gap to go to Pulau Selaru. This option still contain high risk as the pipeline will be laid from depth 500 to 1000 then back to 500 meter depth. However, by passing this small gap, the deeper trench which ranging between 1500-2000 meters near there can be avoided. The sketch of this option is shown on **Figure 7.8** below.

Direct distance from Masela Block to Pulau Selaru is 85 km, however on the **Figure 7.8** it shown that the pipeline will be laid on 95 km length. The proposed route is longer since there are small curve on the middle, not straight. Roughly, it can be seen that the curve has diameter around 120 km, so it is larger than the minimum radius curvature that calculated above. The route is safe according to this constrain.

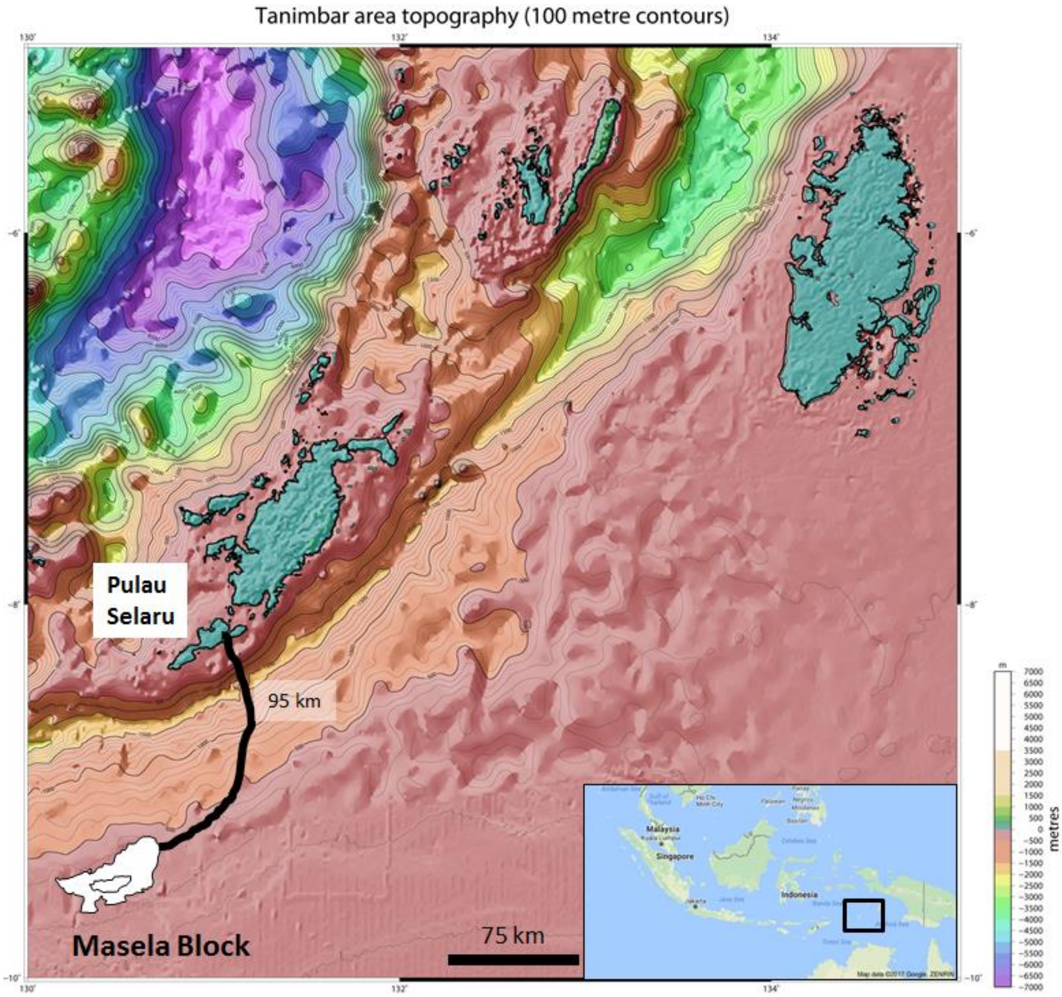


Figure 7.8 Pipeline Pulau Selaru

The bathymetry is changing rapidly meters by meters as illustrates on **Figure 7.9** below, the specific treatment for gas should be considered as mentioned on section flow assurance above. The pipeline will transport the gas which need specific pressure and temperature, by changing the depth consequently the pressure may be changed and disturb the process of transportation. Special requirement such as pressure monitoring and configuration should be implemented on the middle area when the pipeline depth slump into 1000 meters.

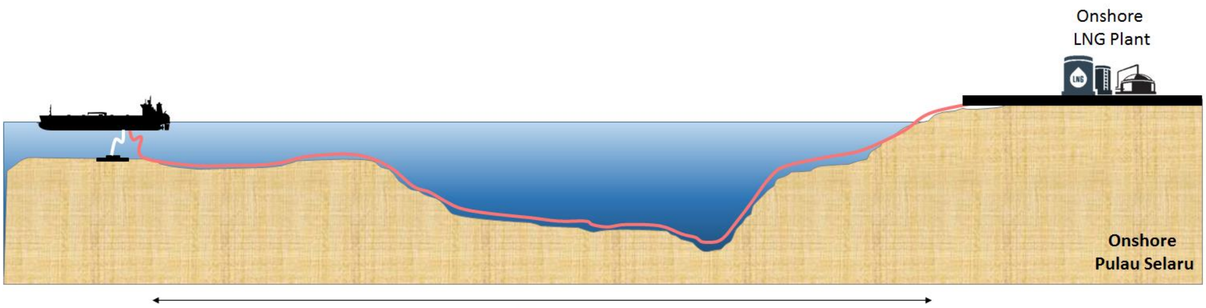


Figure 7.9 Cross Section Pipeline Pulau Selaru

<u>Rough Economic Model</u>

Detail economic model will be explained on **Chapter 8** Economic Analysis. However the economic estimation becomes one of the driver parameters to choose the pipeline route. Assumed that Z considered as the unit price of 1 km of 24 inch CRA pipeline. So the cost of pipeline to Pulau Selaru is 95Z.

7.3.2 Option 2: Lay 100km Pipeline to Pulau Yamdena

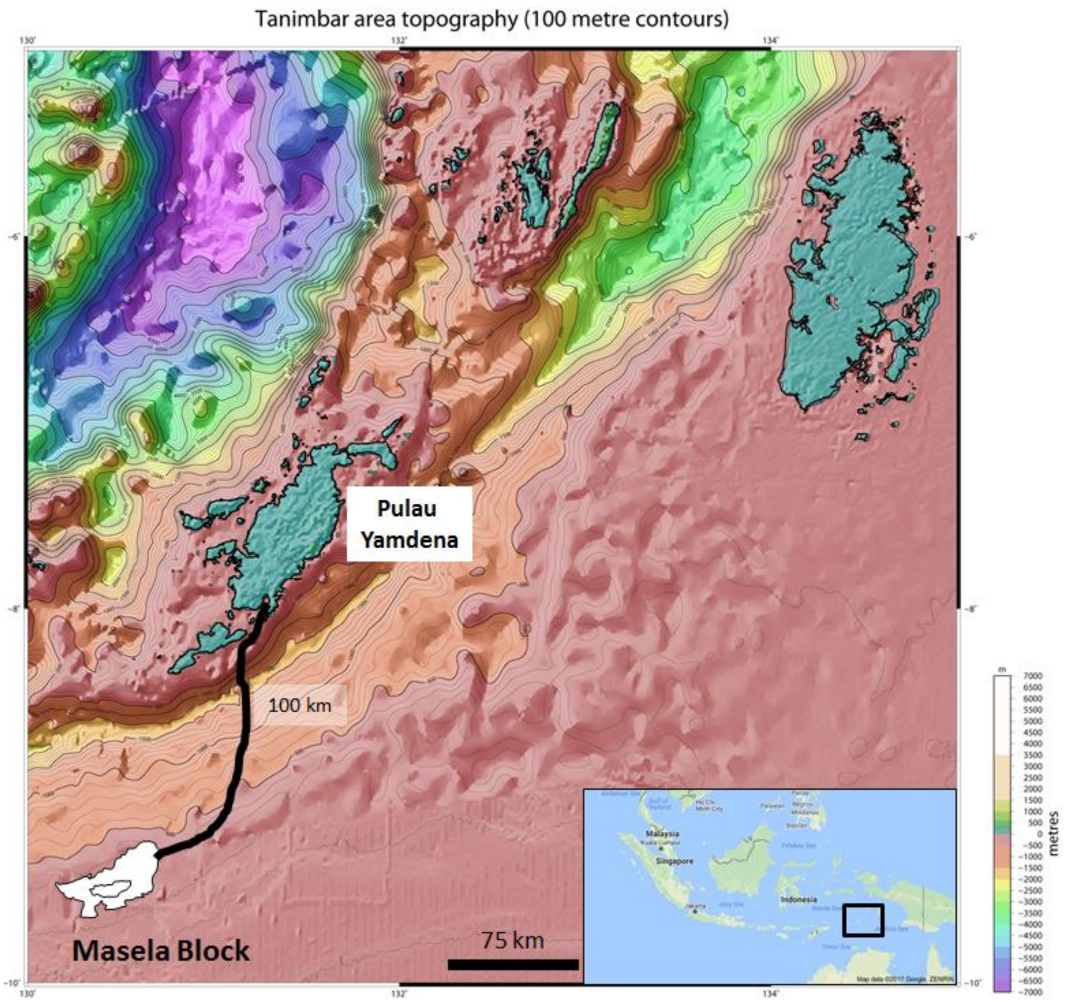


Figure 7.10 Pipeline Pulau Yamdena

Pulau Yamdena located 5 km from Pulau Selaru. The proposed second route is to add 5 more kilometres and build the onshore LNG Plant on the next island. The same path lays the pipeline through gap on **Figure 7.7** above to go to Pulau Yamdena. This option still contain high risk as the pipeline will be laid from depth 500 to 1000 then back to 500 meter depth. However, with the same reason the deeper trench which ranging between 1500-2000 meters near there can be avoided. The sketch of this option is shown on **Figure 7.10** above.

Additionally, according to **Figure 4.5** the significant wave height on the surrounding of Pulau Yamdena is in the range of 2-2.5 meters which is moderate. The wind speed around this island is on the level of 10 knots according to **Figure 4.6.** However the treat level of tsunami is consider high on this island based on data on **Figure 4.9**.

Direct distance from Masela Block to Pulau Yamdena is 95 km, however on the **Figure 7.10** it shown that the pipeline will be laid on 100 km length. The proposed route is longer since there are small curve on the middle, not straight. Roughly, it can be seen that the curve has diameter around 130 km, so it is larger than the minimum radius curvature that calculated above. The route is safe according to this constrain.

The bathymetry is changing rapidly meters by meters as illustrates on **Figure 7.11** below, the specific treatment for gas should be considered as mentioned on section flow assurance above. The pipeline will transport the gas which need specific pressure and temperature, by changing the depth consequently the pressure may be changed and disturb the process of transportation. Special requirement such as pressure monitoring and configuration should be implemented on the middle area when the pipeline depth slump into 1000 meters.

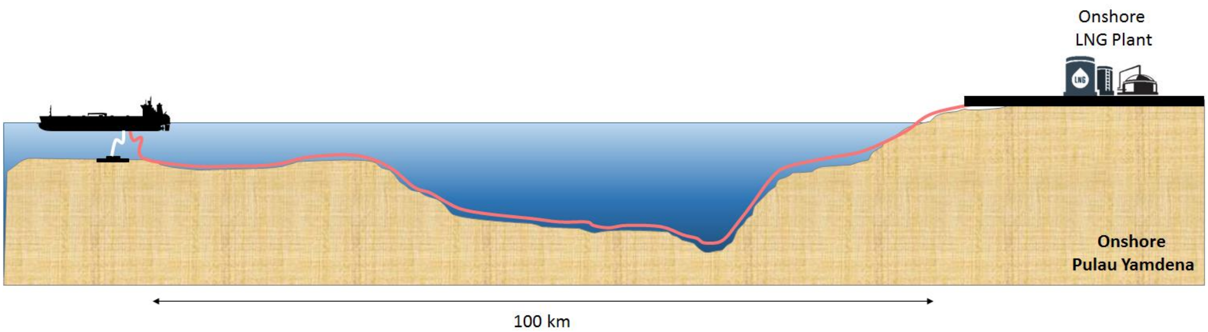


Figure 7.11 Cross Section Pipeline Pulau Yamdena

<u>Rough Economic Model</u>

Assumed that Z considered as the unit price of 1 km of 24 inch CRA pipeline. So the cost of pipeline to Pulau Selaru is 100Z.

7.3.3 Option 3: Lay 600km Pipeline to Pulau Aru

Based on the bathymetry shown on the beginning of this chapter, the 500 km distance to Pulau Aru relatively within the same depth ranging around 500 meter without any distinguished trench. The proposed route for this option is shown on **Figure 7.12** below.

Additionally, according to **Figure 4.5** the significant wave height on the surrounding of Pulau Yamdena is in the range of 1.25-1.5 meters which is calm sea. The wind speed around this island is on the level of 10 knots according to **Figure 4.6** and the treat level of tsunami is medium on this island based on data on **Figure 4.9**.

Direct distance from Masela Block to Pulau Aru is 500 km, however on the **Figure 7.12** it shown that the pipeline will be laid on 600 km length. The proposed route is longer since there are small curve on the middle, not straight. This is taken by following the main driver above to avoid the 1000 meters depth area and its bathymetry is stable from start to the end as shown on **Figure 7.13** below. Roughly, it can be seen that the curve has diameter around 50 km, so it is larger than the minimum radius curvature that calculated above. The route is safe according to this constrain.

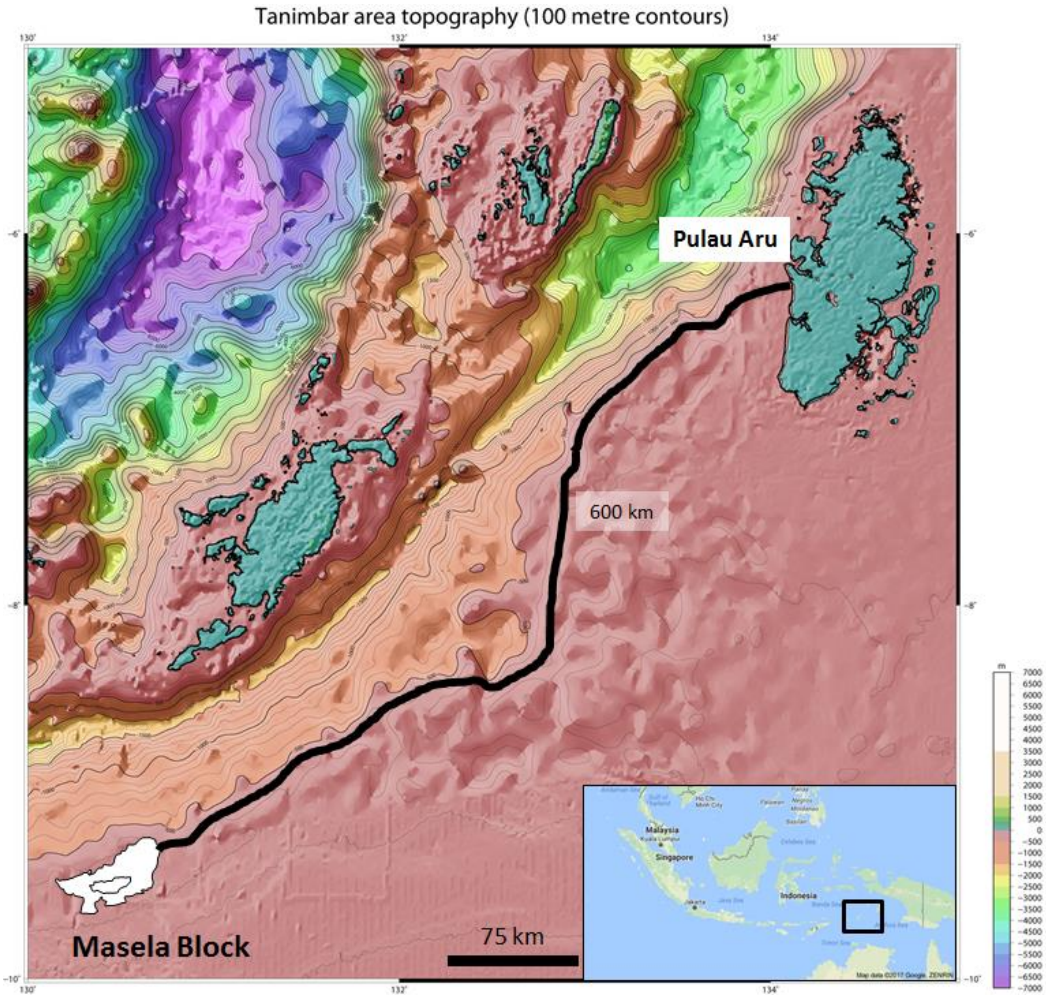


Figure 7.12 Pipeline Pulau Aru

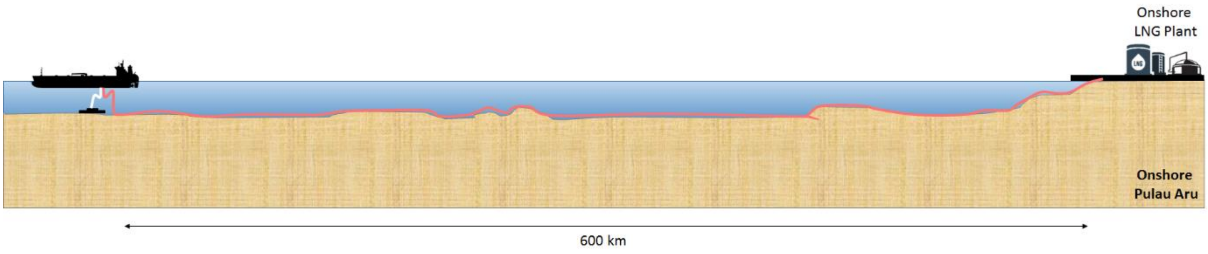


Figure 7.13 Cross Section Pipeline Pulau Aru

<u>Rough Economic Model</u>

Assumed that Z considered as the unit price of 1 km of 24 inch CRA pipeline. So the cost of pipeline to Pulau Aru is 600Z.

7.3.4 Option 4: Lay + Floating 120km Pipeline to Pulau Babar

Pulau Babar is the located relatively close to the Masela block with 120 km distance. However there is an unavoidable trench between Pulau Babar and Masela Block. On this route there are no small gap in between like the one we have on the second option, thus passing through trench is no longer avoidable. So, the last option which is to keep laying the pipeline to Pulau Babar that are located 120 km far, as shown on **Figure 7.14** below and proposed the floating pipeline on the bridging area shown on **Figure 7.15** below.

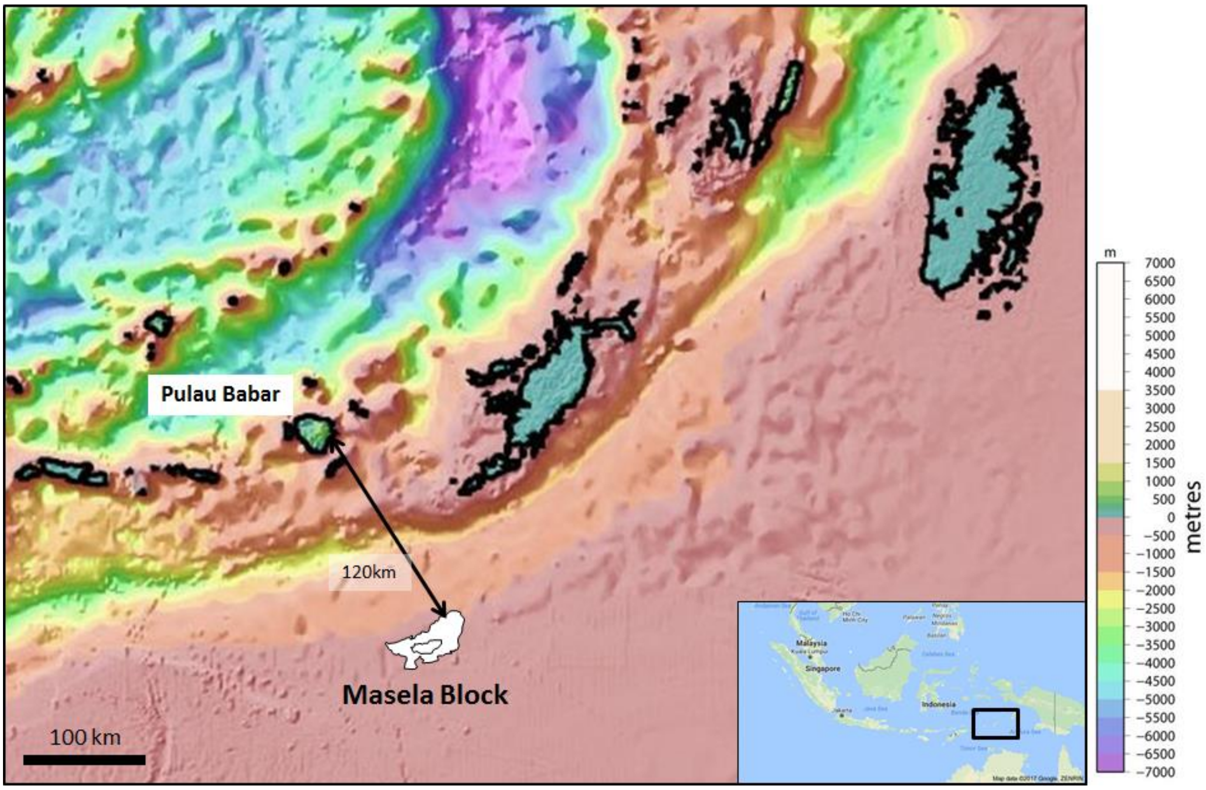


Figure 7.14 Pipeline Pulau Babar

Additionally, according to **Figure 4.5** the significant wave height on the surrounding of Pulau Babar is in the range of 2-2.5 meters which is moderate. The wind speed around this island is on the level of 10 knots according to **Figure 4.6.** However the treat level of tsunami is consider high on this island based on data on **Figure 4.9**.

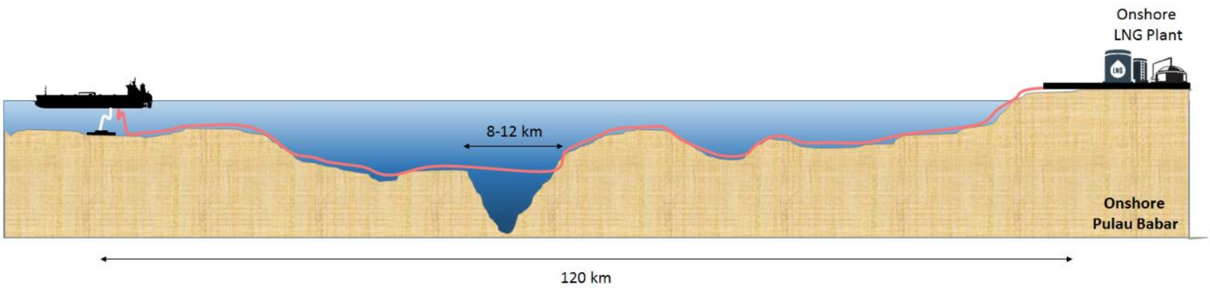


Figure 7.15 Cross Section Pipeline Pulau Babar

If this option is selected, need further research is needed to conquer the high level risk that occur by passing this 2000 meters depth trench. The common CRA pipeline cannot be laid immediately by using this method, as there's high risk that buckle may be occur on it. The proposed solution may be floating pipeline on the trench that illustrates on **Figure 7.15** above.

Floating gas pipeline never be implemented in any gas field in the globe. However there are floating pipeline that is used currently to transport water from Turkey to Cyprus. This method may be the solution for this option with further studies. The sketch of the proposed floating pipeline method is illustrates on **Figure 7.16** below.

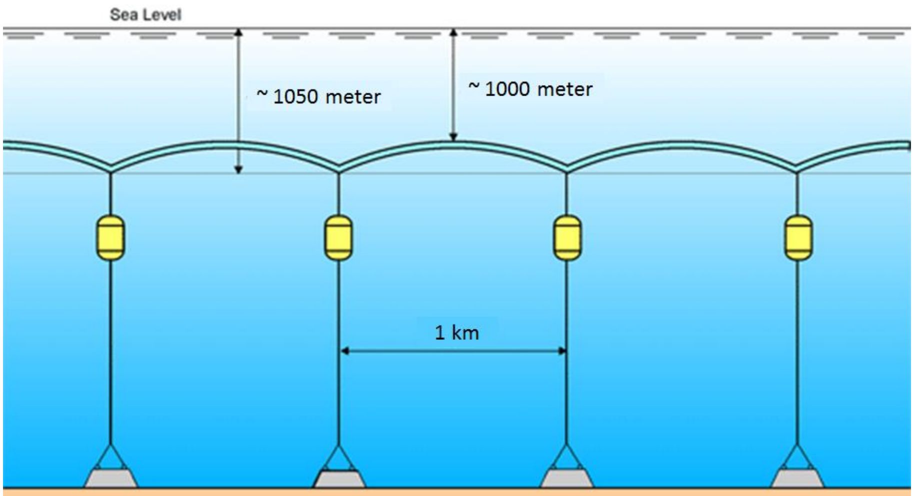


Figure 7.16 Proposed Floating Pipeline Solution
Modified Figure from DHI (2009)

Rough Economic Model

Assumed that Z considered as the unit price of 1 km of 24 inch CRA pipeline. Also assumed that the cost of the floating pipeline 20 times higher than the regular pipeline. So the cost of pipeline to Pulau Babar is:

Floating pipeline = 12km x 20 x Z = 240Z

Regular pipeline = (120km-12km) x Z = 108Z

The total cost is 348Z.

7.3.5 Chosen Option

Each terrain options may have its own issues, thus there consideration become the selection drivers when choosing the most feasible route. **Table 7.3** below shows the pipeline route options that can be implemented on Masela onshore concept development. Thus pugh matrix is used to compare each concept based on selected criteria.

Table 7.3 Pugh Matrix to Choose Pipeline Route

Criteria \ Route Option	Pulau Selaru	Pulau Yamdena	Pulau Aru	Pulau Babar
Distance	+++	+++	---	++
Earthquake Treat	0	0	+	-
Tsunami Treat	0	0	+	0
Flow Assurance Challenge	-	-	0	-
Onshore Area	-	+	++	-
Human Resource (Population)	0	+	++	-
Technology Challenge	0	0	0	--
Cost	++	++	--	-
∑+	5	7	6	2
∑-	2	1	5	5
∑0	4	3	2	1

+ positive
- negative
0 neutral

Based on evaluation on the table above, the number of positives are more in the Pulau Yamdena route compare to others. All in all, Pulau Yamdena was chosen as the most suitable location for the onshore LNG Plant location.

7.4 Conclusion

Onshore LNG plant have successfully utilized for many years. Its development be equipped with long distance pipeline. However, on Masela case there are some challenges on the pipeline concept to be implemented regarding its regional condition and the flow assurance. According to evaluation above, the most suitable onshore area is Pulau Yamdena where is located 100km from the Masela block.

Despite of the high potency of tsunami onshore Masela, there's not any single tsunami that happened on the region. The problem related to flow assurance due to its bathymetry and its chemical components might be solved by using 24inch diameter Corrosion Resistant Alloy (CRA) material.

8 Economic Analysis

8.1 General

8.1.1 Field Development Cost

In general, economical calculation for offshore field development associated with these five categories:

- Acquisition costs
- Exploration, appraisal and planning costs
- Capital expenditures – CAPEX
- Operating expenditures – OPEX
- Abandonment costs

However on this thesis, the calculation mentioned below are only related to the Capital Expenditure and Operational Expenditure. The acquisition phase had been done as well as the exploration cost. Then abandonment cost is estimated relatively small, thus it is being ignored and not included on this economic evaluation.

8.1.2 Capital Expenditure – CAPEX

CAPEX contains the cost from execution of the field development project based on the decided final investment. Generally it divided into two main segments Well CAPEX and Facilities CAPEX. Well CAPEX includes drilling and well completion. Facilities CAPEX includes production facilities cost related to engineering, procurement, construction, installation, and its completion. The large portion of the cost is distributed before the beginning of production. However some well CAPEX may be allocated after the start of production.

Another type of CAPEX that occurs on the production phase is called Operational CAPEX. This includes debottlenecking, facilities modification, IOR, etc.

8.1.3 Operating Expenditure - OPEX

OPEX contains the cost from start to the end of production. All cost comprise the production and its maintenance of facilities and wells, logistic, onshore support, transportation cost, and other cost related.

All in all, it is generally accepted that the cost of field development is driven by the oil & gas price itself. The cost of CAPEX and OPEX increase rapidly when oil & gas price increase over the period as happened on 2003-2008.

8.1.4 Unit Cost

Since the author has no sufficient field data (i.e. to calculate weight) related to Masela Block, thus the economic analysis performed on this chapter is through benchmarking process. Unit costs (e.g. costs per MTPA) are simple comparisons used for benchmarking on this preliminary economic model. The data that are available related Masela block that already mention on the previous **Chapters 4 and 5** are related to dimension and production capacity. Thus the time and cost in this chapter are measured by compare the defined number to unit cost.

When sufficient data is not available, like in this master thesis, unit cost is generally accepted to assess rough field development cost.

All the input numbers below are used by comparing through the similar existing or on going field development. But, to be noted that the unit cost comparison do not account the difference of design basis, reservoir size and complexity. Most likely, the unit cost of field development of large fields is less than the unit cost of small fields. However the range is diverse based on its location, design basis, water depth, and reservoir complexity. There are some cost estimations below that are significantly distinct from indicated unit cost, followed by important explanation on it. Some other assumption then implemented on this economic analysis.

8.1.5 Inflation & Deflation

The cost of field development increase through period. The reason is when the oil & gas price increase the general level of activity also increases. It normally leads to new development and new discoveries.

The amount of services and goods we earn from 1 US$ change time to time. In normal case, there is always an inflation that decreases the amount of services and goods we receive by time being year to year. Inflation generally also indicates the growth of economy over range of time. However it reduces the purchasing power of money (a loss of real value in the exchange of a unit in the economy). But in certain case there is also seldom exception called deflation, when the received amount of services and goods is increasing.

Both inflation and deflation are indicated by the inflation rate or deflation rate. The percent change in general price index over year. Inflation and deflation is the concern, then it is important to the reader that the calculated field development economic assessment below are indicated per period of January-May 2017.

8.1.6 Nominal Value vs Real Value

Nominal value is defined as the observed price, the actual amount gotten at the time of receipt.

Real value defined the purchasing power of money, the value in today's terms of the amount gotten at a different time (future or past). All calculation on this economic analysis is refer to real value instead, because it will be calculated with discounted rate with refer to the year 2017 when the economic analysis is performed. It will be shown that the worth of income will gradually decrease over years due to its discount rate.

8.1.7 Time Value of Money

The value of money will change by time being. Principally from financial perspective, the amount of money we own now is worth more than the same amount of money in the future. That's because through investment that money can earn some interest that increase the total owned money.

As the cost stream (investment and revenue) of the project takes long term period, the value of money itself will change gradually. There are several indicators show below that are widely used for evaluating the project investment. Those are used to express the present value of entire cash flow in the future.

By using this method, annual projected incomes in the future are discounted then summed together. Then the total present value of the entire income stream can be calculated.

8.1.7.1 Discount Rate

The interest rate change from time to time. The discount rate determines the interest used in the economic analysis that take into account the time value of money as well as its risk. Discount rate can also be recognized as an opportunity for the investor. It projected the interest rate is needed in order to gain certain return amount of money at the end of investment.

The discount rate have to be acknowledged when creating a cash flow of the project since all projected cost wanted to be comparable to the present value. So the determined discount rate is the vital point to analyze the cash flow properly. In the economic calculation of proven reserve oil & gas project, PV10 is commonly used to describe the discount rate (Investopedia, 2017, Kompas and Che, 2016). Thus in this economic calculation, 10% annual discounted rate is selected to get the present value.

8.1.7.2 Net Present Value (NPV)

The most important indicator to measure the economic value of field development project is by using NPV. Net Present Value (NPV) sum the total present value of the long-term stream cash flow; starting from the beginning of investment until the end of field lifetime. Project investment can be logically accepted when cash flow shows positive number, otherwise it should be avoided.

$$\mathrm{NPV} = \sum_{t=1}^{n} \frac{\mathrm{NCF_t}}{(1+r)^t} - \mathrm{NCF_0}$$

$\mathrm{NCF_0}$ = initial cash outlay on project

$\mathrm{NCF_t}$ = net cash flow generated by project at time t

n = life of the project

r = discounted rate

Based on OFF515 Offshore Field Development Lecture Note by Prof. Jonas Odland (2014b), it is highly accepted method as:

- NPV considers the time value of money on its calculation (discounted cash flow)
- NPV considers all relevant streams on the cash flow (CAPEX, OPEX, revenue, abandonment cost, etc)
- NPV shows the gained revenue for the project investment

- NPV unveils logical based for decision analysis process to either accept or reject the proposed project investment.

8.1.7.3 Internal Rate of Return (IRR)

Another indicator to evaluate the feasibility of the project investment is by using IRR. Internal Rate of Return (IRR) denotes the percentage discount rate which makes the NPV of the project life cycle is equal to zero. IRR helps the ranking of project investments. IRR is generally calculated based on real value instead of nominal value, some may address it as Real Rate of Return (RRoR) to emphasize that the rate is based on real value. Most likely in oil & gas field development to be attracted by the investors, the IRR should be higher than 10% or in other words the RRoR should be in positive number if the 10% discount rate is implemented.

8.1.7.4 Break-Even Price (BEP)

Break-Even Price (BEP) specifies the price which creates the NPV of the project life cycle is equal to zero. BEP shows the lowest product price that the project can tolerate. In Masela case: lowest tolerable gas price and condensate price that the project can be executed. The investment of the project will be accepted if the BEP is lower than the defined commodities' price on the market.

8.1.7.5 Other Criteria

8.1.7.5.1 Profitability Index (PI) or Present Worth Index (PWI)

PI or PWI evaluates the economic by divide the total discounted cash flow by the total discounted investment. When PI is positive it indicates that the investment is profitable, otherwise it's opposite.

$$\mathrm{PI} = \frac{\mathrm{PV}_{\text{Cash Inflows}}}{\mathrm{PV}_{\text{Cash Outflows}}}$$

PV = present value

8.1.7.5.2 Payback Time (Payout Time)

Payback time indicates the required waiting time for the investment to turn into profit. Payback time is pointed when the cumulative discounted cash flow is equal to zero. When the payback time is short (up to 5 years), the project is more attractive in term of investment. However, this simple criterion can't be used alone, it should be assess with other economic assessment such as NPV, IRR to judge the economic viability of a project.

8.1.7.5.3 Maximum Exposure

Maximum exposure indicates the maximum negative cumulative discounted (or undiscounted) cash flow of a project. Similar to payback time, this shows the liquidity of the investment.

8.1.7.5.4 Profit-to-Investment Ratio

Profit-to-investment ratio evaluates the profitability economic by divide the total undiscounted cash flow (without capital investment) by the total amount of investment itself.

This is another simple criteria, but to be considered, profit-to-investment ratio doesn't acknowledge the time value of money.

8.1.8 Contingency Plan

Through experiences, there are a lot of factors that leads the gap between the real expenses with the projected cost. The real expenses most likely are higher than the estimated cost due to some unavoidable risk or uncertain factors such as market price. Then contingency plan is introduced to take that investment risk at the beginning of the field development. However the contingency plan shouldn't be an excuse to not following the budget plan. The core value of it is to become the reserve money to patching up the shortage and make the project keep going. In high risk industry like oil and gas, 10% contingency plan is widely used (Peterson et al., 1993, Khamooshi and Cioffi, 2009)

8.2 Masela Block' Cost Estimation

8.2.1 Production Constrain and Assumptions

8.2.1.1 Production Constrains

There are several data related to production constrains that accessible for public through company website, online database, newspaper, etc. The production constrains for Masela Block are:

- There are 18 production wells that will be connected to 5 subsea manifolds, then transported through risers to the topside facility (mentioned on **Chapter 5.3**)
- Technical recoverable volume is 10.73 TCF and 209 million barrel of condensate (mentioned on **Chapter 4.4**).
- The gas production rate from any single well is ≤ 60 MMSCFD and 1,359 barrel per day of condensate (mentioned on **Chapter 4.4**).
- The economic calculation is analyzed from the beginning of development until the end of primary production that recognized as the plateau production (mentioned on **Chapter 2.5** and **5.7.2).** The reason is because Masela is a gas field, so the most important indicator is constant commodities supply to the customer that distinguish through its the production plateau.

8.2.1.2 Assumptions

- The production profile and economic calculation for both onshore and offshore concepts are based on pressure depletion scenario (limited only on the primary production stage), enhanced recovery method not implemented in this analysis.
- Drilling and completion of a production well takes two months.
- The total production rate must be lower than the capacity of production facility (assumption of 12.5% of technical recoverable volume of gas and condensate per year).
- Production could be done in the beginning of next year.
- One month is 30 days.

8.2.2 Commodities' Price

8.2.2.1 The Price of LNG

Unlike oil, the price of gas commodities are diverse according to the regional segments. Research from Paraskova (2016) mentioned that the different gas benchmark prices leaded by various factors such as pipeline, geography, geopolitics, supply, demand, as well as shipping cost.

Generally, the price of LNG is defined by the importing countries. Asia Pacific LNG importers have their own regional gas pricing benchmark. Shi and Variam (2016) mentioned on their reports that nowadays Singapore, Japan, and China are the leading hub benchmarking countries in Asia Pacific. EIA (2014) reported that through the listed Asian gas hubs, the Asia Pacific gas market will be more transparent for both exporters and importers, improve their transaction process, as well as raise the benefits to the involved parties. These also the reason for Masela's developer to offer Masela LNG to Asian market.

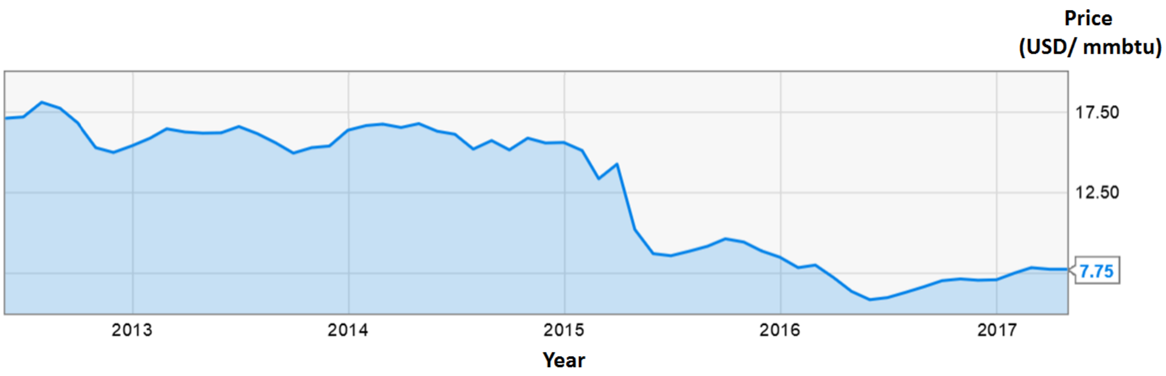
As mentioned on **Chapter 4.5.6 Gas & Condensate Market**, the buyer of Masela LNG and condensate has not been decided and still on the negotiation process. However, there is a high tendency that the customer will be both Japan and South Korea as those two countries are the long-term Indonesian LNG consumer and their demand of LNG will increase as predicted on **Table 8.1** below. Kompas and Che (2016) estimated that in 2020 Indonesian LNG will be 60% exported to Japan and Korea. Thus the determined LNG price that is used on this thesis is estimated from the Japan – Korea LNG Price.

Table 8.1 LNG Trade Flows In 2020 among Major Importers and Exporters

Importers	Exporters							Sum Import
	Australia	Indonesia	Malaysia	PNG	Qatar	Russia	US	
Japan	34.0	1.2	10.5	3.0	7.1	7.4	14.4	77.6
Korea	18.3	7.1	1.8	-	15.2	1.4	5.2	49.1
Taiwan	2.5	3.1	-	1.5	4.9	-	3.4	15.4
China	27.9	2.4	3.3	1.8	1.9	2.8	10.9	51.1
India	7.0	-	-	-	18.1	-	9.0	34.1
Others	2.3	-	-	-	3.3	-	5.1	10.7
Sum Export	92.0	13.8	15.6	6.3	50.5	11.5	48.0	237.9

Data Source: LNG Price by Kompas and Che (2016)

As the LNG will be transported to Japan and Korea, thus the Japan Korea Marker (JKM) is suitably used as the benchmark price. **Figure 8.1** below shown the JKM LNG Price from March 2013 to April 2017. In April 2017, LNG Price is on the level of 7.75 USD/ MMBTU, unchanged from the previous month. There is about 20% increase compare to the price on April last year. When the oil price slump in 2015-now, Bordoff and Losz (2016) agree that the price of LNG also declines. The current trend of LNG price is around 7-8 USD/MMBTU that are about 55% of the LNG Price on the past three years. On this economic analysis the commodities prices are assumed to be **constant** from the beginning to the end of production.



Data Source: World Bank

Figure 8.1 Japan Liquefied Natural Gas Import Price Chart
Figure Source: LNG Price Chart by YCharts (2017)

The future price of LNG is hard to predict, especially within the low oil price period like today. There is high demand of LNG from East Asian countries like Japan, South Korea, and China over the past decades. BP (2015) even forecasted that the international LNG market has been increasing 7.6% annually. LNG will also fulfill 26% global gas supplies by 2035 (BP, 2014). Those may be the driver factors to push the LNG price. However, the supply of LNG will also growth within the next decades. Several big gas field such as Sakhalin in Russia and Greater Sunrise in Australia which are now under construction will start their production in term of years. Even though the demand of LNG in Japan is generally increasing, there's also an inclination to rely more into their nuclear reactors. Slower economic growth in China and other East Asian countries may also responsible to the lower price of LNG in the future.

LNG price always fluctuates due to several reasons, still the economic analysis should be performed. This master thesis will use the current LNG Price that is 7.75 USD/ MMBTU as per April 2017 as the benchmark price as shown on **Figure 8.1** above. This number will be used to determine the production lifetime as well as the economic model.

8.2.2.2 The Price of Condensate

Theoretically, the price of condensate will be influenced by the value of goods that can be composed from it. So, in the market there is no consistent accepted benchmark price to determine the cost of every barrel of condensate (Pyziur, 2015). The same as LNG, the pricing is depends on each regions.

Generally, the price of Condensate highly influenced by the price of oil. **Figure 8.2** below shows that the trend of condensate price is follows the oil price pattern. So, the benchmarking process of condensate can be taken from the existing oil price.

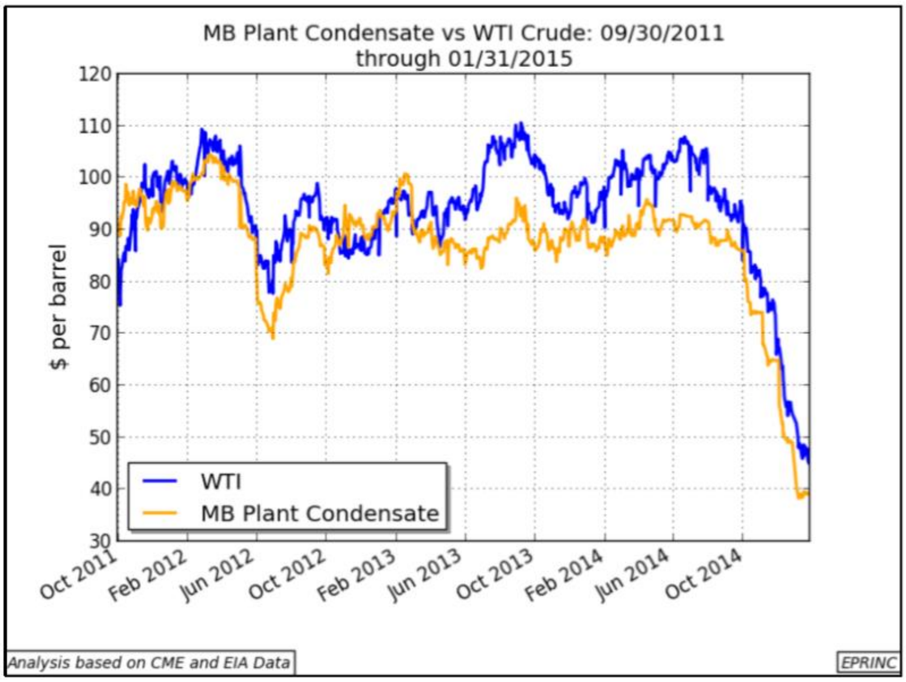


Figure 8.2 Crude Oil vs Condensate Price Chart
Figure Source: Cost Comparison by Pyziur (2015)

Based on Pyziur (2015) the condensate price from Middle East such as Qatar has two benchmarks. And in practice, the price of condensate that are transported to East Asian countries are in the range 5 USD above the Dubai crude oil. The condensate price also commonly determined up to 8 USD more than the Brent crude oil price (Pyziur, 2015).

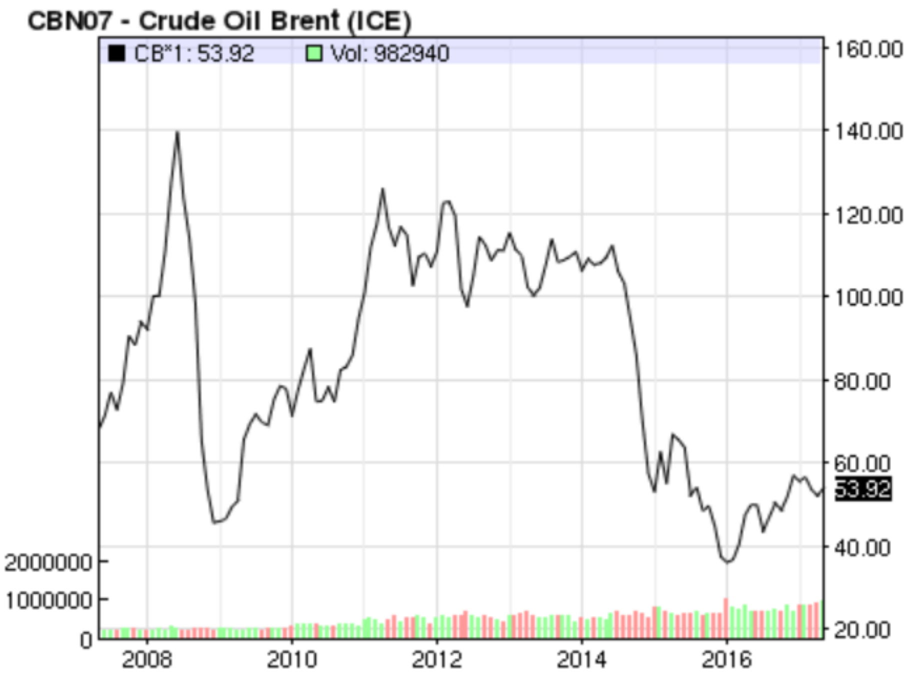


Figure 8.3 Brent Crude Oil Price
Figure Source: Oil Price taken from Nasdaq (2017)

The **Figure 8.3** above is the Brent crude oil chart for the past 10 years. There's significant in the recent three years that also influence the price of condensate. Same as the determined LNG price on the previous section, the price of condensate on this master thesis is also determined by benchmarking into current existing data. With the foreseen of condensate price ranging from 5 to 8 USD more than the Brent Crude Oil, thus the current projected condensate price is ranging from 58.92 to 61.92 USD. Then the average of 60 USD/ barrel of condensate apparently can be accepted as assumption on this master thesis.

8.2.3 CAPEX Well – Drilling & Completion

Capital expenditure related to drilling and completion of production wells. It was mentioned above that drilling and completion of a production well takes two months each, thus the schedule are divided by 2:1 based on the rule of thumb. It takes 40 days for drilling and the other 20 days for completion. Moreover, the rate listed below are based on several literature review, discussion with some drilling engineer colleagues and experts that experienced in drilling environment in Indonesia.

The Masela Block is located from 300 to 1,000 meter below MSL (984 to 3,281 feet) and its reservoir target depths are approximately extent from 3,700 to 3,900 meter below MSL. The cost per unit for estimating drilling rates are depends on the reservoir depths. The reservoir depths mentioned earlier are determined from MSL, however the reservoir depth that used commonly in terms of drilling is determined from seabed. On the other hand, there is another constrain that the reservoir is widely spread through various depth as mentioned on the previous paragraph. Thus the simple calculation below is used to get the average depth of the reservoir from seabed.

$$\text{Reservoir Average Depth:} \frac{(3700-300)+(3700-1000)+(3900-300)+(3900-1000)}{4} \text{meter}$$

$$\text{Reservoir Average Depth:} \frac{12{,}600}{4} \text{meter} = 3{,}150 \text{ meter} = 10{,}335 \text{ foot}$$

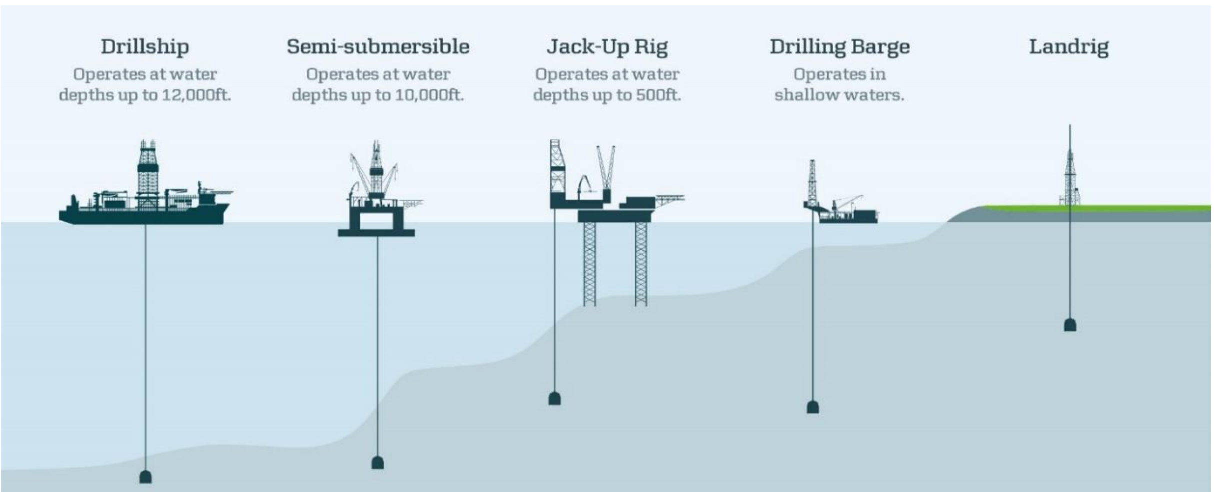


Figure 8.4 Different Types of Drilling Rigs Based on Its Operational Water Depth
Figure Source: Drilling Rigs (Maersk)

Specific type of drilling vessel is required to drill the well in the certain water depth as illustrates on **Figure 8.4** above. In Masela case, the feasible options are either semi-submersible or drillship.

Drilling and completion are the two most frontier phases on field development, and its breakdown calculation are shown on **Table 8.2** below then the cost breakdown for each sub categories also listed below. The total CAPEX Well is added with 10% contingency plan, as the number mentioned that are listed on **Chapter 8.2.3.1 Sub-category of Drilling** and **Chapter 8.2.3.2 Sub-category of Completion** below are estimated before including contingency plan.

Table 8.2 CAPEX Well Breakdown – Drilling & Completion

Expense Category	Unit Price				Unit Needs		Item Cost (thousand USD)	
	Price (thousand USD)		Unit					
Drilling								
Set Up Costs	USD	500	per Unit		1	Unit	USD	500
Rig Day	USD	300	per Day		40	Day	USD	12,000
Fluids, Chemicals, Transportation & Fuel	USD	1,500	per Unit		1	Unit	USD	1,500
Services & Rental Equipment	USD	1,500	per Unit		1	Unit	USD	1,500
Bits & Misc. Equipment	USD	50	per Bit		6	Bits	USD	300
Labor, Engineering & Overhead	USD	0.20	per Man Hour		48000	Man Hour	USD	9,600
Casing and Other Tangibles	USD	200	per Casing		1	Unit	USD	200
Contingencies 10% of Sub-total							USD	2,560
Sub-total for Drilling							**USD**	**28,160**
Completion								
Rig & Daywork	USD	300	per Day		20	Day	USD	6,000
Fluids, Chemicals, Transportation & Fuel	USD	2,000			1		USD	2,000
Services & Rental Equipment	USD	2,000			1		USD	2,000
Completion Equipment & Misc.	USD	6,500			1		USD	6,500
Contingencies 10% of Sub-total							USD	1,650
Sub-total for Completion							**USD**	**18,150**
Total Drilling and Completion Budget							**USD**	**46,310**

8.2.3.1 Sub-category of Drilling

8.2.3.1.1 Set-Up Cost

To start the drilling activity, the service company needs to set up their equipment. The operation starts from anchoring, cleaning the area, equipment installation, etc. The amount of 500 thousand USD apparently is a suitable price to complete the set up process.

8.2.3.1.2 Rig Day

The day-rate of semisubmersible and drillship are vary through its own capacity, capability, and availability. The cost of each vessel also influenced by the oil & gas price, the day-rate of drilling vessel on the era of peak oil price on 2012-2014 even doubled from current day-rates. Current day-rate of semisubmersible and drillship in in downturn. The history chart and current day-rate of semisubmersible and drillship are given by IHS (2017) and shown respectively on **Figure 8.5** and **Figure 8.6** below.

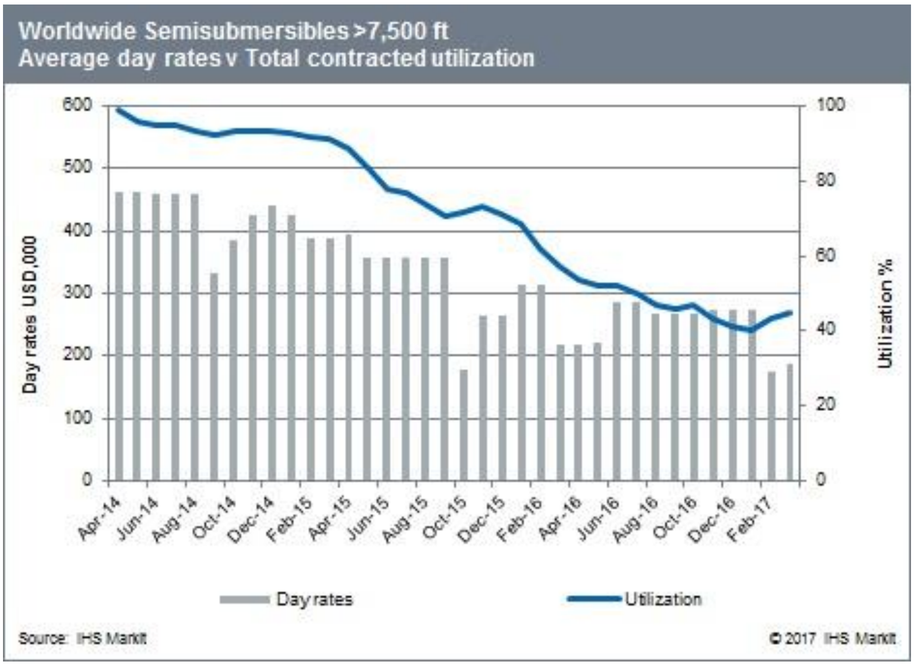


Figure 8.5 Semisubmersible Day Rates

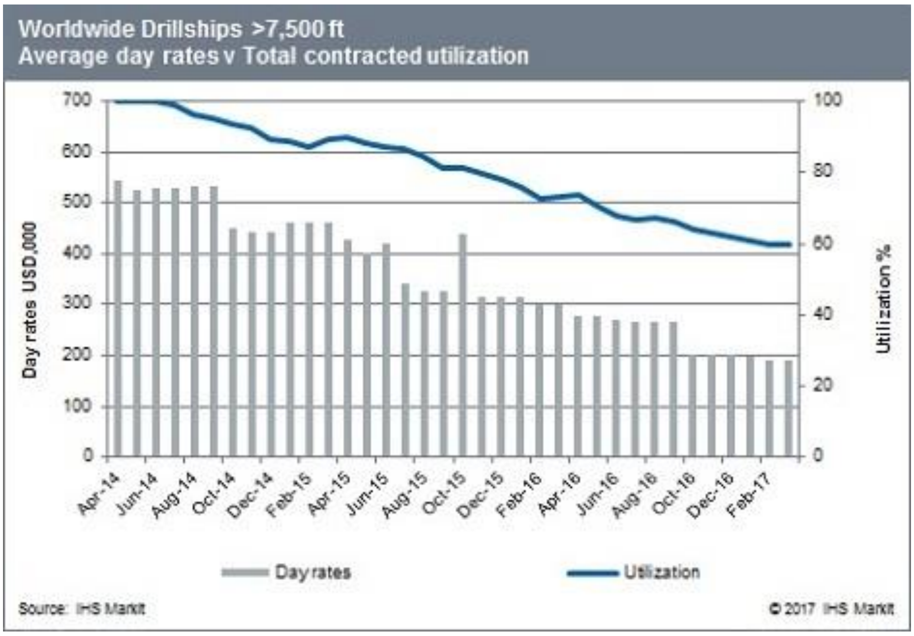


Figure 8.6 Drill Ships Day Rates

Based on **Figure 8.5** and **Figure 8.6**, the latest average day-rates of semisubmersible is ranging around 200-280 thousand USD, while for drillship is about 200 thousand USD. Additionally, recent news published on EnergyToday.com (2017) informed that the floater Actina that will be operated in midwater India has 111 thousand USD day-rates**.** From the same source, the rate of Deepwater Invictus in offshore Trinidad has 350 million USD day-rates. So, based on several data above, the day-rate for the drilling vessel is assumed as much as 300 thousand USD.

8.2.3.1.3 Fluids, Chemicals, Transportation & Fuel

The total cost of mud, chemical, and cementing fluids is assumed around 300 thousand USD per well. The remote location of Masela block is challenging for the rig transportation to that location. This also leads to high amount of cost of fuel that will be used during the transportation and logistics supply on the drilling phase. Thus the total estimation for fluids, chemicals, transportation & fuels is assumed to be 1.5 million USD.

8.2.3.1.4 Services & Rental Equipment

The other costly expense is services and rental equipment. To drill the reservoir with 3,000 meters like Masela case, the high quality and specific type of equipment are compulsory. Those equipment are not available in local services company, so it should be imported from abroad which also means that the cost will be higher. The amount of 1.5 million USD is suitable as assumption for this cost category.

8.2.3.1.5 Bits & Misc. Equipment

Drilling activity needs bits as its core cutting equipment to make holes and discard materials. This equipment is one of the most critical equipment during the drilling operation. There are two types of bits that are commonly used in the industry, Polycrystalline Diamond Compact (PDC) that is widely used in Indonesia and also Roller Cone Bit (Fjelde, 2012). The reservoir of Masela block is quartzone sandstone which according to Fjelde (2012) is categorized as medium high/ high formation. To drill this reservoir formation, the PDC is suitably implemented.

This drilling operation requires 6 bits from various size depends on the drilled holes diameter. On the common practice, the cost for each PDC bit is approximately ranging from 10-150 thousand USD (Rappold, 1995). Thus it can be estimated that 50 thousand USD per bit will be sufficient.

8.2.3.1.6 Labor, Engineering & Overhead

The second most expensive expense on drilling is the labor cost. Labor cost is calculated through the number of man-hour rate multiplied by the number of man-hour. Based on **Figure 8.7** below, the number of crew for operating semisubmersible is 80, while it requires around 90 personnel to operate drillship. On the calculation, 100 personnel is chosen as the estimation. The additional assumption is that the working hours are 8 hours per day for two months.

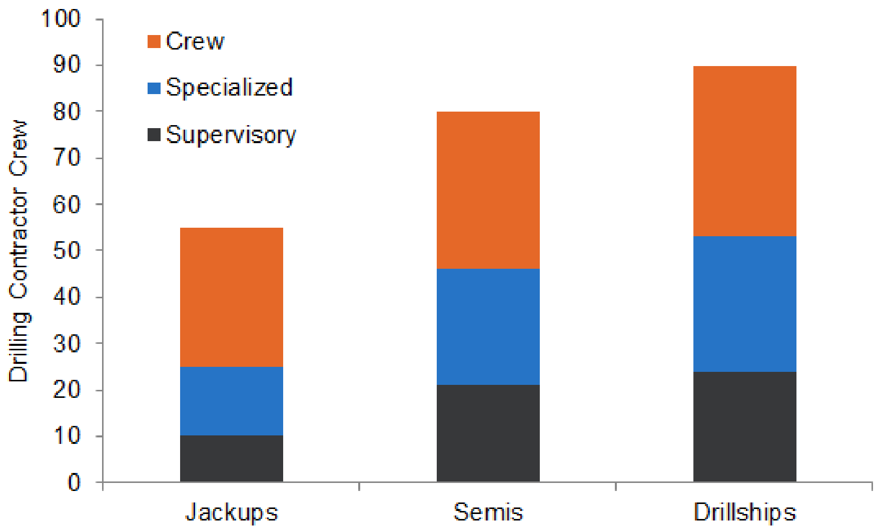


Figure 8.7 Typical Offshore Drilling Rig Crew Requirements
Source: Estimation Data from Oilpro.com (2016)

So, the calculated number of man-hour is:

$$\text{Manhour: } 100 \text{ personnel x } 60 \text{ days x } 8 \text{ hours} = 48{,}000 \text{ manhours}$$

Figure 8.8 below is the graphic that indicate man-hour rate based on OFF515 Offshore Field Development Course Lecture Note by Prof Jonas (Odland, 2014a). Drilling crews are categorized as an offshore labor that has man-hour rate around 235 USD. However the man-hour rate shown below are defined on 2010 when the price of oil & gas is relatively high. Refer to the graphic on **Figure 8.6** that shows the declining drilling ship for the current condition, it is also generally recognized that the man-hour rate is drop. The man-hour rate for drilling operation is assumed to be 200 USD/hour.

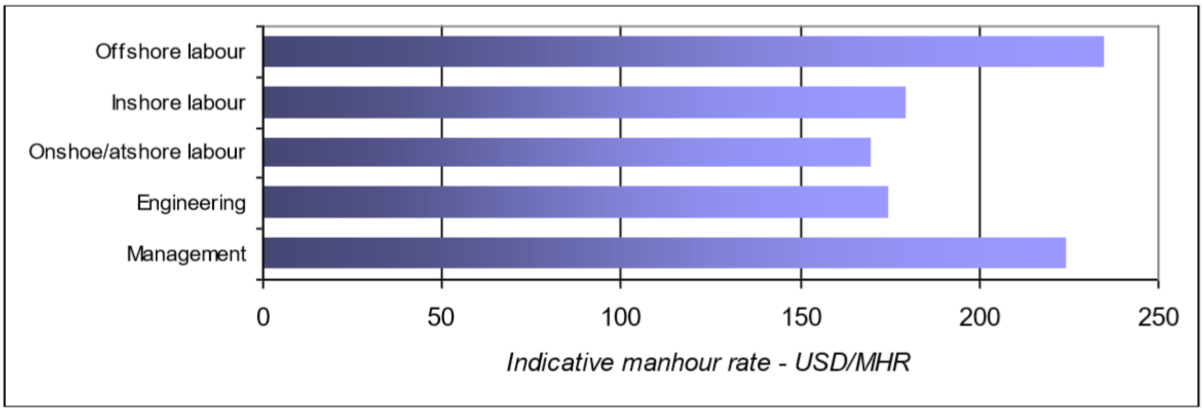


Figure 8.8 Graphic Man-hour Rate

8.2.3.1.7 Casing and Other Tangibles

Casing is the vital part of the production, it assures that the fluid will flow to the surface. The standard casing design includes the surface casing, intermediate casing, the production casing, as well as its well head. The high CO_2 contents on Masela reservoir requires the casings to have high CO_2 resistant and anti-corrosion specification. Thus the cost of each production well casing will be higher than other gas field. The amount of 200 thousand USD should be allocated for this part.

8.2.3.2 Sub-category of Completion

8.2.3.2.1 Fluids, Chemicals, Transportation & Fuel

After the drilling phase is completed, the operation continues to the completion phase. On the completion phase, well stimulating, fracturing, etc will be performed on the well to prepare the production phase. Thus the chemical and fluids used on this step are more complex. The amount of chemicals also higher in this phase compare to the previous phase. The total cost of mud, chemical, and cementing fluids on the earlier drilling phase is assumed to be 300 thousand USD per well. Since the fluids that are needed on the completion are much more, the assumption that it will take almost triple than the cost fluid in drilling phase should be logically accepted.

The cost of transportation and fuel will be the same 1,200 thousand USD as the location of the drillship will be the same. All in all, the cost of fluids, chemical, transportation, and fuel for the completion phase are assumed to be 2 million USD for every single well.

8.2.3.2.2 Services & Rental Equipment

On the completion phase, the well will be completed until it can be ready for production. Perforation and x-mas tree installation take place on this step. The production wells of Masela Block will use wet tree and connected to subsea facilities center. Deepwater operation require robot aids such as ROV (Remoted Operated Vehicle) because it beyond the human capacity. To set up those it requires more equipment and of course there's extra cost for that. It is assumed that the cost will be around 2 million USD.

8.2.3.2.3 Completion Equipment & Misc.

The budget for purchasing completion components such as x-mas tree will be included on this sub category. The x-mas tree is one of the most expensive component on the production well it is the most critical component on the well production as it control the subsurface condition. Senior drilling engineer Weeden (2012) wrote that the average cost for each x-mas tree is in the range of 5.5 million USD. The other 1 million USD is added on this sub categories for purchasing other proponent equipment. Thus the total estimation for completion equipment and miscellaneous is 6.5 million USD.

8.2.4 CAPEX Facility - SURF

On this case, the gas will be produced from 18 production wells that are connected to 5 manifolds then transported up into the floating vessel (FLNG or FPSO) to be processed. The cost of subsea facilities (Subsea, Umbilical, Risers, and Flowlines) are the same for both onshore and offshore concept. The capital expenditure for SURF facilities refers to recent project value. Based on Choi (2014) estimation, the cost per subsea center facility (1 manifold plus 4 production wells) is in the range of 100-250 million USD. The assumption of 200 million

USD for 1 manifold plus 4 production wells per cluster (refer to **Figure 5.7**on page 31 above) is relatively acceptable.

8.2.5 CAPEX Facility - Offshore Building Blocks

8.2.5.1 FLNG Cost

As already mentioned on **Chapter 6**, FLNG technology is still developing and there's only one operating FLNG as per May 2017. Thus the cost estimation relatively uncertain. PETRONAS (2016b) on its company website mentioned that the cost of The First FLNG Satu is up to 10 billion USD with capacity of 1.2 MTPA of LNG. However this cost is assessed cannot be used as a unit cost reference for each unit. The amount of 8.3 billion USD per MTPA is beyond the bounds of possibility for the cost of LNG development. Moreover, it's commonplace that the cost per unit for smaller vessel must be higher than the cost per unit in bigger vessel. During its construction phase, Petronas FLNG Satu which is the first operating FLNG in the world withstand its own risk and research development. The research budget also included in the total cost of 10 billion USD.

The unit price that can be used as a comparison benchmark for FLNG Masela is the cost of current massive ongoing Shell's Prelude project. In term of the dimension, FLNG Masela will be 'only' 12 meters longer, 6 meters wider, and 15 meters higher. The Prelude project also has been being constructed in the slump oil price, the condition also fit with the current and forecasted period when FLNG Masela on construction. The comparison between Prelude and FLNG Masela is shown on **Table 8.3** below.

Table 8.3 Comparison between FLNG Prelude and FLNG Masela

	Shell's Prelude		Masela's FLNG	
Capacity				
LNG Capacity	3.6	MTPA	7.5	MTPA
Condensate Capacity	1.3	MTPA (35,000 b/d)	0.91	MTPA (24,460 b/d)
LPG Capacity	0.4	MTPA	-	
Total Capacity	5.3	MTPA	8.41	MTPA
Dimension				
Length	488	m	500	m
Width	74	m	82	m
Height	105	m	120	m
Hull Depth	44	m	50	m
Deck Height	61	m	70	m
Hull & Deck Area	36,112	m2	41,000	m2
Hull Volume	1,588,928	m3	2,050,000	m3
Deck Volume	2,202,832	m3	2,870,000	m3
Projected Cost	12,600	mil. USD		

Prelude started to gain the public interest in 2011 when Shell introduced its own ever changing LNG development concept. The expert reported in BBC (2013) that Prelude will cost around 10.8 – 12.6 billion USD. Shell (2017a) then announced on 2014 that the cost may reach 3.5 billion USD/ MTPA. The most recent news from Royal Dutch Shell in March 2017 reported that the Prelude will be finished soon and the total cost will be 12.6 billion USD (Tay, 2017). So, the number of 12.6 billion USD for 3.6 MTPA of LNG is used on this master thesis as the benchmark unit price.

The study of Won et al. (2014) estimated that the cost proportion of FLNG construction as shown on **Figure 8.9** below. The data are gathered from various floating vessel such as FPSO and FSRU that had been constructed in South Korea shipyard (Hyundai Heavy Industry, Samsung Heavy Industry, etc). The biggest portion of the FLNG cost will be allocated to the gas treatment followed by the offloading utilities.

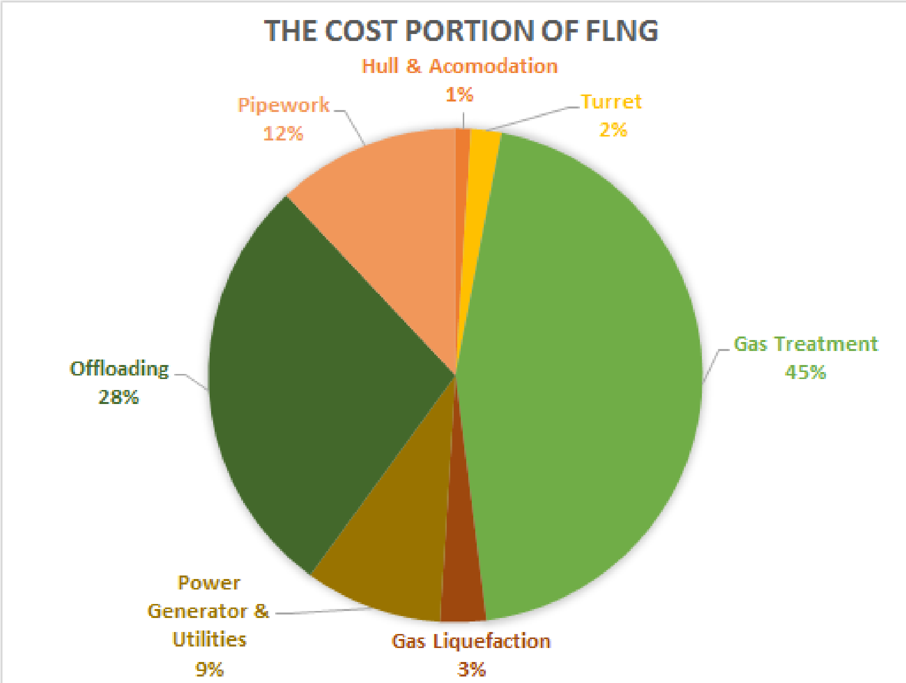


Figure 8.9 The Cost Proportion of FLNG by Won et al. (2014)

Refer to percentage on **Figure 8.9** above, the cost breakdown structure for Prelude is estimated on **Table 8.4** below. The unit price then known from divide the cost per stage by the capacity. Thus from those unit price, the cost of FLNG Masela can be estimated. **Table 8.4** below summarized the cost breakdown and total of FLNG Masela Cost. The detail calculation also follows after the table. The total 17,978 million USD is estimated to become the FLNG Masela price with the unit price in the range of 2.4 billion USD/MTPA

Table 8.4 FLNG Masela Cost Refer to Prelude Unit Cost

Unit Stages	Cost Portion	Prelude Cost per Stage		Prelude Unit Price		Masela Cost per Stage	
		Cost	Unit	Cost	Unit	Cost	Unit
Hull & Accommodation	1%	126.00	mil.USD	79.30	USD/ m3	162.56	mil. USD
Turret	2%	252.00	mil.USD	252.00	mil.USD/ Unit	252.00	mil. USD
Gas Treatment	45%						mil. USD
LNG Treatment		3,851.32	mil.USD	1,069.81	mil.USD/ MTPA LNG	8,023.58	mil. USD
Condensate Treatment		1,390.75	mil.USD	1,069.81	mil.USD/ MTPA Condens	973.53	mil. USD
LPG Treatment		427.92	mil.USD	1,069.81	mil.USD/ MTPA LPG	-	
Gas Liquefaction	3%	378.00	mil.USD	94.50	mil. USD/ MTPA	708.75	mil. USD
Power Generator & Utilities	9%	1,134.00	mil.USD	514.79	USD/ m3	1,477.45	mil. USD
Offloading	28%	3,528.00	mil.USD	3,528.00	mil.USD/ Unit	4,410.00	mil. USD
Pipework	12%	1,512.00	mil.USD	686.39	USD/ m3	1,969.94	mil. USD
Total	100%	12,600.00	mil.USD			17,977.82	mil. USD
Cost per MTPA of LNG		3,500.00	mil. USD			2,397.04	mil. USD

8.2.5.1.1 Cost per Material Volume

The unit price of hull & accommodation, power generator & utilities, and the pipework can be measured by cost per volume. The hull volume and deck volume are calculated by:

$$\text{Volume of Hull} = \text{length x width x hull depth}$$

$$\text{Hull Volume of Prelude FLNG} = 488\text{m x }78\text{m x }44\text{m} = 1{,}588{,}928\text{ m}^3$$

$$\text{Hull Volume of FLNG Masela} = 500\text{m x }82\text{m x }50\text{m} = 2{,}050{,}000\text{ m}^3$$

$$\text{Volume of Deck} = \text{length x width x deck height}$$

$$\text{Deck Volume of Prelude FLNG} = 488\text{m x }78\text{m x }61\text{m} = 2{,}202{,}832\text{ m}^3$$

$$\text{Deck Volume of FLNG Masela} = 500\text{m x }82\text{m x }70\text{m} = 2{,}870{,}000\text{ m}^3$$

Cost for Hull & Accommodation

The hull & accommodation will make up to 1% of the total cost. The cost of 126 million USD covered the Prelude's hull & accommodation with 1,589,928 m^3 hull volume. The unit price of hull & accommodation is:

$$\text{Unit Price for Hull \& Accommodation} = \frac{126\text{ million USD}}{1{,}588{,}928\text{ m}^3} = 79.30\ {}^{\text{USD}}/_{\text{m}^3}$$

Then, the cost for hull & accommodation of FLNG Masela is:

$$\text{Cost for Hull \& Accommodation} = 2{,}050{,}000\text{ m}^3\text{ x }79.30\ {}^{\text{USD}}/_{\text{m}^3} = 162.56\text{ million USD}$$

Cost for Turret

There's a tendency that the design of FLNG Masela will be similar with Prelude design. Then one turret will be used at FLNG Masela. Then the cost for FLNG Masela can be assumed same as Prelude FLNG that is 252 million USD.

Cost for Power Generator & Utilities

The power generator and utilities will make up to 9% of the total FLNG construction cost. The cost of 1,134 million USD covered the Prelude's power and utilities with 2,202,832 m^3 deck volume. The unit price of power generator & utilities is:

$$\text{Unit Price for Power Generator \& Utilities} = \frac{1{,}134\text{ million USD}}{2{,}202{,}832\text{ m}^3} = 514.79\ {}^{\text{USD}}/_{\text{m}^3}$$

Then, the cost for power generator & utilities of FLNG Masela is:

$$\text{Cost for Power Generator \& Utilities} = 2{,}870{,}000\text{ m}^3\text{ x }514.79\ {}^{\text{USD}}/_{\text{m}^3}$$
$$= 1{,}287.49\text{ million USD}$$

Cost for Offloading

The offloading unit stages will be the second highest proportion and make up to 28% of the total FLNG construction cost. The cost of 3,528 million USD covered the Prelude's offloading to transfer 3.6 MTPA of LNG, 1.3 MTPA of condensate (35,000 barrel/day equivalent), and 0.4 MTPA of LPG. There's a tendency that the arrangement of offloading equipment FLNG Masela will be similar with Prelude design, the dimension might slightly different but will not be significant. Then the cost for FLNG Masela can be assumed same to be 25% higher than Prelude FLNG that can be calculated as:

$$\text{Cost for Offloading} = 125\% \text{ x } 3{,}528 \text{ million USD} = 4{,}410 \text{ million USD}$$

Cost for Pipework

The pipework will make up to 12% of the total FLNG construction cost. The cost of 1,512 million USD covered the Prelude's pipework area with 2,202,832 m^3 deck volume. The unit price of pipework is:

$$\text{Unit Price for Pipework} = \frac{1{,}512 \text{ million USD}}{2{,}202{,}832 \text{ m}^3} = 686.39 \ {}^{\text{USD}}/_{\text{m}^3}$$

Then, the cost for pipework of FLNG Masela is:

$$\text{Cost for Power Generator \& Utilities} = 2{,}870{,}000 \text{ m}^3 \text{ x } 686.39 \ {}^{\text{USD}}/_{\text{m}^3}$$
$$= 1{,}287.49 \text{ million USD}$$

8.2.5.1.2 Cost per MTPA

Several unit stages (gas treatment, gas liquefaction, and offloading) can't be decided through the cost per volume since there's no any explanation or the specification of equipment that will be used. So, for these three unit stages, the rough estimation based on cost per MTPA apparently can be used.

Cost for Gas Treatment

The gas treatment unit stages will be the highest proportion and make up to 45% of the total FLNG construction cost. The cost of 5,670 million USD covered the Prelude's gas treatment area to process 3.6 MTPA of LNG, 1.3 MTPA of condensate (35,000 barrel/day equivalent), and 0.4 MTPA of LPG. The gas treatment stages will process those three products, so the total capacity of the Prelude for this calculation is 5.3 MTPA instead of 3.6 MTPA of LNG. The unit price of gas treatment is:

$$\text{Unit Price for Gas Treatment} = \frac{5{,}670 \text{ million USD}}{5.3 \text{ MTPA}} = 1{,}069.81 \ {}^{\text{million USD}}/_{\text{MTPA}}$$

Then, the cost for gas treatment of FLNG Masela is:

$$\text{Cost for Gas Treatment (LNG)} = 7.5 \text{ MTPA x } 1{,}069.81 \ {}^{\text{million USD}}/_{\text{MTPA}}$$
$$= 8{,}023.58 \text{ million USD}$$

$$\text{Cost for Gas Treatment (Condensate)} = 0.91 \text{ MTPA x } 1{,}069.81 \ {}^{\text{million USD}}/_{\text{MTPA}}$$
$$= 973.53 \text{ million USD}$$

Cost for Gas Liquefaction

The gas liquefaction unit stages make up to 3% of the total FLNG construction cost. The cost of 378 million USD covered the Prelude's gas treatment area to liquefy 3.6 MTPA of LNG and 0.4 MTPA of LPG. The gas liquefaction stages will process those two products, so the liquefaction capacity of the Prelude for this calculation is 4 MTPA liquid instead of 3.6 MTPA of LNG. The unit price of gas liquefaction is:

$$\text{Unit Price for Gas Liquefaction} = \frac{378 \text{ million USD}}{4 \text{ MTPA}} = 94.50 \,{}^{\text{million USD}}/_{\text{MTPA}}$$

Then, the cost for gas treatment of FLNG Masela is:

$$\text{Cost for Gas Liquefaction} = 7.5 \text{ MTPA x } 94.50 \,{}^{\text{million USD}}/_{\text{MTPA}} = 708.75 \text{ million USD}$$

8.2.5.2 Logistic Supply Based

The offshore activities must be supported by the closest shore area. Supply based is necessary to transfer the logistic as well as the changing crew activity. According to the fellow engineer college who had experience in the field stated that it requires around 40-50 hectares (400,000 – 500,000 m^2) of area to build the onshore logistic supply based. Assume that the cost for each hectare will cost 5 million USD, so the cost for logistic supply based is:

$$\text{Cost for Logistic Supply Based} = 50 \text{ hectares x } 5 \text{ million USD} = 250 \text{ million USD}$$

8.2.6 CAPEX Facility - Onshore Building Blocks

8.2.6.1 FPSO Cost

The dimension of Masela FPSO as mentioned on **Chapter 5.5.1** earlier is 330 m length and 65 m width. The most recent FPSO contract was awarded to Daewoo Ship and Marine Engineering (DSME), South Korea. For a single FPSO with dimension 300 m x 50 m the contract valued ranging from 800 million USD to 1.2 billion USD (DSME, 2017). The purpose of Masela's FPSO only to separate the gas and condensate and remove the water also load condensate to the tanker, it's relatively not a complex system on the vessel. So, it can be roughly estimated that the cost of FPSO Masela is approximately 1.5 billion USD.

8.2.6.2 Gas Export Pipeline

Gas export pipeline is the main focus discussion on the onshore option as mentioned earlier on **Chapter 0**. The previous chapter also concluded that 100 km pipeline through Pulau Yamdena is the most suitable option in term of engineering perspective. Masela gas export pipeline uses 24 inch diameter pipeline.

Pipeline engineer of PHE ONWJ[4] informed that commonly for 24 inch diameter pipeline around 1 million USD is needed for each kilometer in ONWJ block. The gas export pipeline cost estimation on this master thesis refer to this price as a benchmark.

Masela pipeline will be laid 500 – 1500 meters below MSL, determined pressure and temperature material is required. The pipeline also needs to be buried 2 meters under seabed and rock dumping on the top of it. Offshore spread will be needed, and during the installation the hyperbaric diving also necessary. Moreover, Masela gas reservoir contains high level of CO_2 so the CRA (Corrosion Resistant Alloy) will be used in this field development. The cost of CRA pipeline (with same diameter and in the same depth) is normally within range 1.3 to 2 times higher than the general carbon steel. Thus, through this benchmarking process, the amount of 1.5 million USD/ kilometers is relatively reasonable for Masela export pipeline.

8.2.6.3 Onshore LNG Plant

As already mentioned on **Chapter 5.5.3**, Onshore LNG Plant is a mature technology that has been implemented in many regions in the world. Indonesia itself at least has five existing LNG Plants as shown on **Figure 8.10** below. There are many source and several existing projects that can be a certain benchmark to estimate the cost. The most recent finished LNG onshore plant in Indonesia is Donggi-Senoro LNG Plant that cost 2.8 billion USD for 2 MTPA capacity. The cost of 1.4 billion USD per MTPA may be a rough benchmark for the calculation. This also in line with the chart published by Oxford (2014), that estimated the development cost of LNG may be around 1.3 billion USD per MTPA on **Figure 8.11** below.

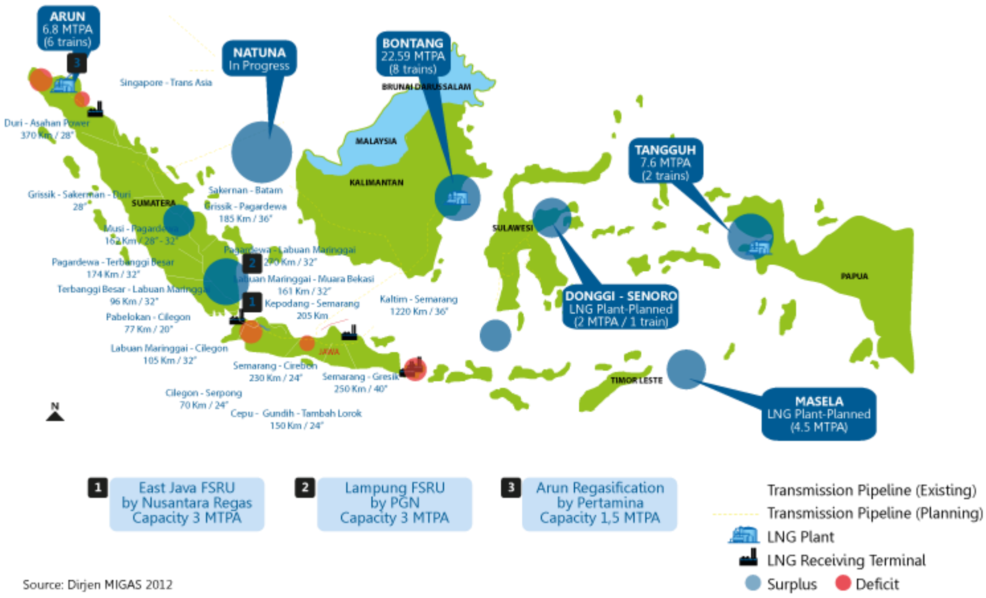
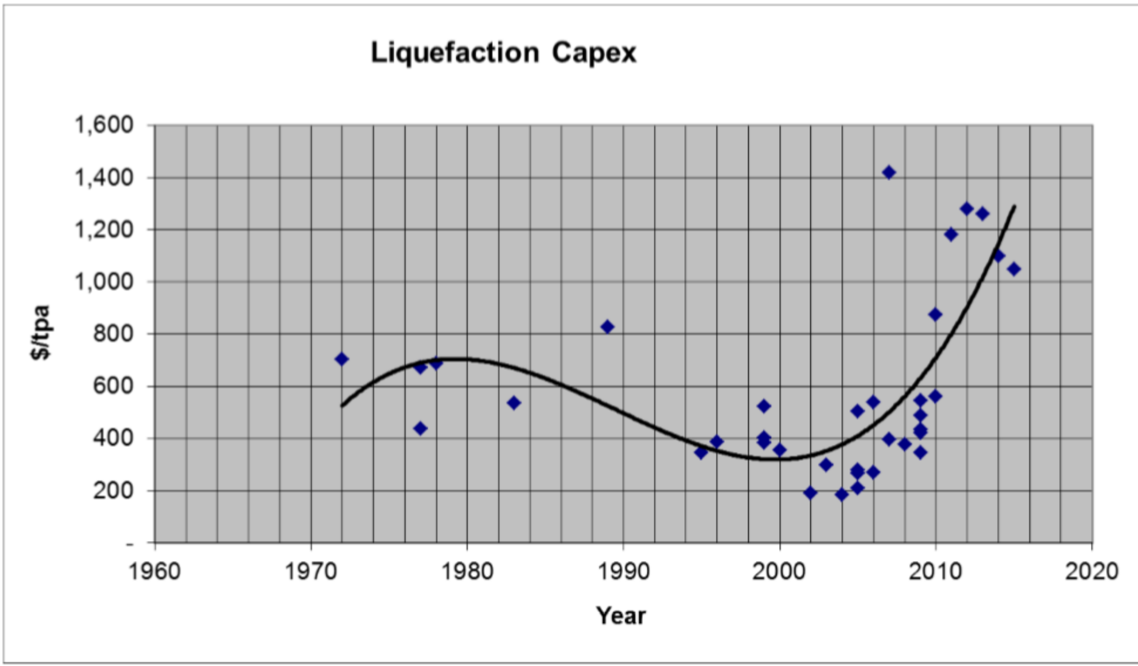


Figure 8.10 LNG Plant in Indonesia

[4] PHE ONWJ (Pertamina Hulu Energi – Offshore North West Java), Pertamina's subsidiary unit that handle offshore North West java block.

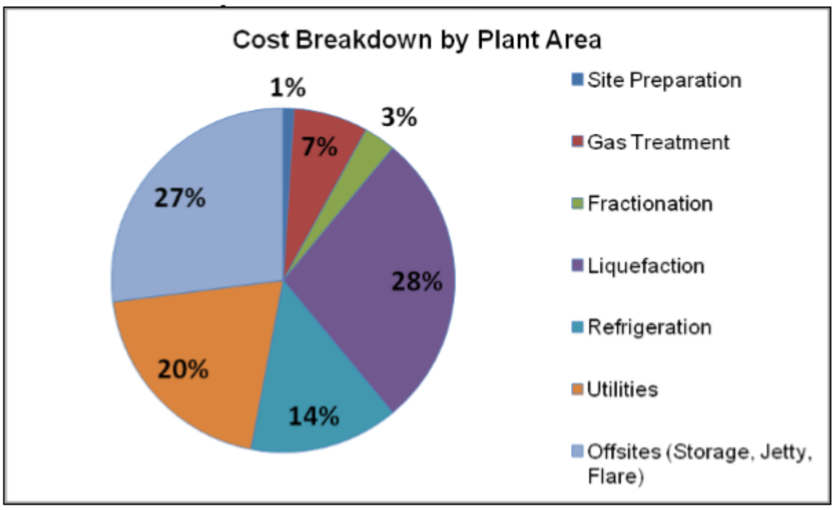


Source: Wood Mackenzie

Figure 8.11 Liquefaction CAPEX per MTPA Capacity

The country also has one ongoing LNG development projects on the eastern part of the region which is BP's Tangguh Train 3. The unit price that can be used as a comparison benchmark for Masela Onshore LNG Plant is the cost of current ongoing LNG Tangguh Train 3. LNG Tangguh Train 3 will build the facility for 3.8 MTPA of LNG to make the total capacity of LNG Tangguh up to 11.4 MTPA.

The study from Oxford (2014) estimated that the cost proportion of Onshore LNG Plant construction as shown on **Figure 8.12** below. The data are gathered from various finished and ongoing projects such as Itchys, Donggi, Gorgon, etc. The biggest portion of the Onshore LNG Plant cost will be allocated to the refrigeration followed by the liquefaction utilities.



Source: Published Data from Various Projects

Figure 8.12 The Cost Proportion of Onshore LNG Plant by Oxford (2014)

Refer to percentage on **Figure 8.12** above the cost breakdown structure for BP's Tangguh Train 3 is estimated on **Table 8.5** below. The recent news from BP said that they expect the cost of LNG Tangguh Train 3 will be on 8 billion USD (all in, included two new offshore platform and subsea facility). The cost of two platforms is estimated in 1.5 billion USD while 13 subsea production well heads and other subsea facilities cost up to 1 billion USD. So, the cost of LNG Plant itself in the range of 5.5 billion USD for 3.8 MTPA of FLNG.

The unit price then known from divide the cost per stage by the capacity. Thus from those unit price, the cost of Masela Onshore LNG Plant can be estimated. **Table 8.5** below summarized the cost breakdown and total of Masela Onshore LNG Plant Cost. The detail calculation also follows after the table. The total 10,498 million USD is estimated to become the Masela Onshore LNG Plant price with the unit price in the range of 1.17 billion USD/MTPA

Table 8.5 Masela Oshore LNG Plant Cost Refer to LNG Tangguh Unit Cost

	BP's LNG Tangguh Train 3		Masela's Onshore LNG Plant	
LNG Capacity	3.8	MTPA	9	MTPA
Area	1100	Hectares	800	Hectares
Projected Cost	5,500	mil. USD		

Plant Area	Cost Portion	LNG Tangguh Cost per Area Plant		LNG Tangguh Unit Price		Masela Cost per Stage	
		Cost	Unit	Cost	Unit	Cost	Unit
Site Preparation	1%	55.00	mil.USD	0.05	mil. USD/ hectares	40.000	mil. USD
Gas Treatment	7%	385.00	mil.USD	101.32	mil. USD/ MTPA	911.842	mil. USD
Fractionation	3%	165.00	mil.USD	43.42	mil. USD/ MTPA	390.789	mil. USD
Liquefaction	28%	1,540.00	mil.USD	405.26	mil. USD/ MTPA	3,647.368	mil. USD
Refrigeration	14%	770.00	mil.USD	202.63	mil. USD/ MTPA	1,823.684	mil. USD
Utilities	20%	1,100.00	mil.USD	289.47	mil. USD/ MTPA	2,605.263	mil. USD
Offsite (Storage, Jetty, Flare)	27%	1,485.00	mil.USD	1.35	mil. USD/ hectares	1,080.000	mil. USD
Total	100%	5,500.00	mil.USD			10,498.947	mil. USD
Cost per MTPA of LNG		1,447.37	mil. USD			1,166.550	mil. USD

8.2.6.3.1 Cost per Area

The unit price of site preparation and offsite facilities (storage, jetty, flare) can be measured by cost per area. According to INPEX and independent consultant, the development of Masela onshore LNG Plant will approximately requires 600-800 hectares of area. On the other hand, BP'LNG Tangguh Plant with capacity total 11.4 MTPA now is occupying 3,500 hectares of area (BP, 2017). So, with the simple calculation, Tangguh Train 3 with its 3.8 MTPA capacity takes 1/3 the area or around 1,100 hectares.

<u>Cost for Site Preparation</u>

The site preparation will make up to 1% of the total cost. The cost of 55 million USD covered the LNG Tangguh Train 3's site preparation with 1,100 hectares area. The unit price of site preparation is:

$$\text{Unit Price for Site Preparation} = \frac{55 \text{ million USD}}{1{,}100 \text{ hectares}} = 0.05 \ {}^{\text{mil. USD}}/_{\text{hectares}}$$

Then, the cost for Site Preparation of Masela Onshore LNG Plant is:

$$\text{Cost for Site Preparation} = 800 \text{ hectares x } 0.05 \ {}^{\text{mil. USD}}/_{\text{hectares}} = 40 \text{ million USD}$$

Cost for Offsite Facilities (Storage, Jetty, Flare)

The site offsite facilities (storage, jetty, flare) will make up to 27% of the total cost. The cost of 1,485 million USD covered the LNG Tangguh Train 3's offsite facilities (storage, jetty, flare) with 1,100 hectares area. The unit price of offsite facilities is:

$$\text{Unit Price for Offsite Facilities} = \frac{1{,}485 \text{ million USD}}{1{,}100 \text{ hectares}} = 1.35 \ {}^{\text{mil. USD}}/_{\text{hectares}}$$

Then, the cost for offsite facilities of Masela Onshore LNG Plant is:

$$\text{Cost for Offsite Facilities} = 800 \text{ hectares x } 1.35 \ {}^{\text{mil. USD}}/_{\text{hectares}} = 1{,}080 \text{ million USD}$$

8.2.6.3.2 Cost per MTPA

Several unit stages (gas treatment, fractionation, liquefaction, refrigeration, and utilities) can't be decided through the cost per area since there's no any explanation or the specification of equipment that will be used. So, for these five plant areas, the rough estimation based on cost per MTPA apparently can be used.

Cost for Gas Treatment

The gas treatment plant area make up to 7% of the total Onshore LNG Plant construction cost. The cost of 385 million USD covered the LNG Tangguh Train 3's gas treatment plant area to process 3.8 MTPA of LNG. The unit price of gas treatment is:

$$\text{Unit Price for Gas Treatment} = \frac{385 \text{ million USD}}{3.8 \text{ MTPA}} = 101.32 \ {}^{\text{million USD}}/_{\text{MTPA}}$$

Then, the cost for gas treatment of Masela Onshore LNG Plant is:

$$\text{Cost for Gas Treatment} = 9 \text{ MTPA x } 101.32 \ {}^{\text{million USD}}/_{\text{MTPA}} = 911.842 \text{ million USD}$$

Cost for Fractionation

The fractionation plant area make up to 3% of the total Onshore LNG Plant construction cost. The cost of 165 million USD covered the LNG Tangguh Train 3's fractionation plant area to process 3.8 MTPA of LNG. The unit price of fractionation is:

$$\text{Unit Price for Gas Treatment} = \frac{165 \text{ million USD}}{3.8 \text{ MTPA}} = 43.42 \ {}^{\text{million USD}}/_{\text{MTPA}}$$

Then, the cost for fractionation of Masela Onshore LNG Plant is:

$$\text{Cost for Fractionation} = 9 \text{ MTPA x } 43.42 \ {}^{\text{million USD}}/_{\text{MTPA}} = 390.789 \text{ million USD}$$

Cost for Liquefaction

The liquefaction plant area will be the highest proportion and make up to 28% of the total Onshore LNG Plant construction cost. The cost of 1,540 million USD covered the LNG Tangguh Train 3's liquefaction plant area to process 3.8 MTPA of LNG. The unit price of liquefaction is:

$$\text{Unit Price for Liquefaction} = \frac{1{,}540 \text{ million USD}}{3.8 \text{ MTPA}} = 405.26 \ {}^{\text{million USD}}/_{\text{MTPA}}$$

Then, the cost for liquefaction of Masela Onshore LNG Plant is:

$$\text{Cost for Liquefaction} = 9 \text{ MTPA x } 405.26 \ {}^{\text{million USD}}/_{\text{MTPA}} = 3{,}647.36 \text{ million USD}$$

Cost for Refrigeration

The refrigeration plant area make up to 14% of the total Onshore LNG Plant construction cost. The cost of 770 million USD covered the LNG Tangguh Train 3's refrigeration plant area to process 3.8 MTPA of LNG. The unit price of refrigeration is:

$$\text{Unit Price for Refrigeration} = \frac{770 \text{ million USD}}{3.8 \text{ MTPA}} = 202.63 \ {}^{\text{million USD}}/_{\text{MTPA}}$$

Then, the cost for refrigeration of Masela Onshore LNG Plant is:

$$\text{Cost for Refrigeration} = 9 \text{ MTPA x } 202.63 \ {}^{\text{million USD}}/_{\text{MTPA}} = 1{,}823.68 \text{ million USD}$$

Cost for Utilities

The utilities plant make up to 20% of the total Onshore LNG Plant construction cost. The cost of 1,100 million USD covered the LNG Tangguh Train 3's utilities plant area to process 3.8 MTPA of LNG. The unit price of utilities is:

$$\text{Unit Price for Utilities} = \frac{1{,}100 \text{ million USD}}{3.8 \text{ MTPA}} = 289.47 \ {}^{\text{million USD}}/_{\text{MTPA}}$$

Then, the cost for utilities of Masela Onshore LNG Plant is:

$$\text{Cost for Utilities} = 9 \text{ MTPA x } 289.47 \ {}^{\text{million USD}}/_{\text{MTPA}} = 2{,}605.26 \text{ million USD}$$

8.2.7 CAPEX Facility – LNG Carrier

The LNG commodity that are produced either in offshore or onshore, will be transported via LNG carrier to the customers. Chen (2014) argued that a standard LNG Carrier can cost around 200 million USD. Dalian Shipbuilding also reported to get four new building LNG Carriers that cost 230 million USD each (Goh, 2014). Refer to these numbers, the assumption of 300 million USD per LNG Carrier is relatively acceptable.

As a large field, at least Masela needs 2 LNG carriers to transport its LNG to the consumer, as illustrated on **Figure 8.13**below . So, the CAPEX for LNG Carrier is 2 x 300 million USD = 600 million USD.

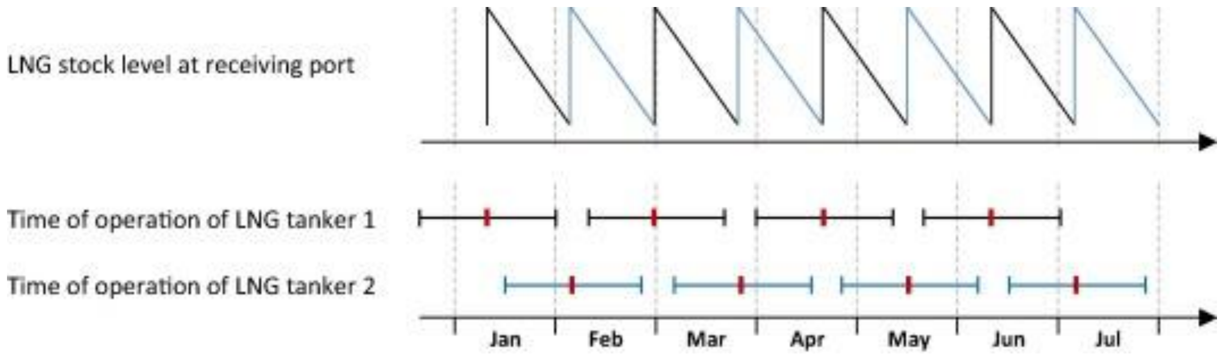


Figure 8.13 LNG Carrier Illustrated Schedule

Figure Source: LNG Carrier Design Basis by Koza et al. (2017)

8.2.8 OPEX – Offshore Option

Operating cost divided into two main categories:

- Fixed Annual Cost
- Cost that depends on the produced LNG

The fixed cost is the base cost that will be flow out annually, whether the plant producing LNG or not. The other cost is depends on the amount of produced LNG.

8.2.8.1 Fixed Annual Operating Cost

To be noted that the only existing FLNG, PETRONAS FLNG Satu, has been operating less than a year (mentioned on **Chapter 6.2.1** above). Thus the existing data for annual operating cost of FLNG is remaining unknown. However, the operating cost of huge offshore vessel such as FPSO and FSRU are known. So, the annual operating cost of FLNG Masela is assumed in the range of 20 million USD per year refer to the operating cost of large FSRU and FPSO.

8.2.8.2 LNG Producing & Transportation Cost

Other than the fixed annual cost, the cost of operating and transportation cost for offshore FLNG are referred to report (2008, Bordoff and Losz, 2016):

- Liquefaction cost 1.2 USD/ MCF with range +/- 0.20 USD
- Shipping cost 0.7 USD/ MCF with range +/- 0.30 USD depends on the distance refer to **Table 8.6** below.

8.2.9 OPEX – Onshore Option

8.2.9.1 Fixed Annual Operating Cost

The annual operating cost of Masela Onshore LNG Plant assumed from the existing LNG plant + FPSO that is 10 million USD per year.

8.2.9.2 LNG Producing & Transportation Cost

Other than the fixed annual cost, the cost of operating and transportation cost for onshore LNG plant are referred to report (2008, Bordoff and Losz, 2016):

- Liquefaction cost 1.1 USD/ MCF with range +/- 0.20 USD

- Shipping cost 0.7 USD/ MCF with range +/- 0.30 USD depends on the distance refer to **Table 8.6** below.

Table 8.6 Transport Cost

	Cost Range ($/MMBtu)	Europe	Asia
Fixed Capacity / Tolling Fee	**2.25 – 3.5**	Sunk Cost	Sunk Cost
Henry Hub + 15% Surcharge	**2.0 – 4.0**	Variable	Variable
Transport Costs			
Vessel Charter Cost	**0.2 – 0.6**	Sunk for Some	Sunk for Some
Fuel Cost*	**0.2 – 1.8**	Variable	Variable
Canal Tolls	**0.2**	N/A	Variable
Port / Insurance / Other	**<0.1**	Variable	Variable
Regasification Cost	**0.3 – 0.4**	Variable	N/A
Est. Total Cost Range	**5.0 – 10.6**		

** Fuel cost includes the cost of the boil-off gas (BOG) and the marine fuel that LNG carriers use for propulsion.*

Data Source: Estimation by Bordoff and Losz (2016)

8.2.10 OPEX - Condensate Operating & Transportation Cost

For both onshore and offshore option, condensate will be extracted offshore, either in FPSO or in FLNG. So can be concluded that condensate operating and transportation cost will be the same for both options.

Senior reservoir engineer Spackman (2016) on GLJ Petroleum consultant report was estimated that the condensate transportation cost from South East Asia to East Asian on the range of 5 CAD/ barrel when the condensate price is 56.40 CAD/ barrel or equivalent as 3.6 USD/ barrel when the condensate price is 42 USD/ barrel. He also mentioned that the offshore operating cost for condensate is on the range of 1.3 – 1.5 USD/ barrel. So, can be assumed that the price of condensate operating & transportation cost is 5 USD/ barrel.

8.3 CAPEX Comparison

All in all, **Table 8.7** below sums all the expenditures that estimated earlier. CAPEX well and subsea production facilities will be the same for both options. The cost of 7.5 MTPA LNG is 17.977 billion USD or about 2.4 billion USD/MTPA is expected. On the other hand, onshore LNG Plant looks promising with cost of 1.165 billion USD/MTPA. The total cost for developing Masela block with onshore option even 25% lower than the cost of FLNG itself.

Table 8.7 CAPEX Comparison between Offshore and Onshore Concept

Expenditure Category	Unit Price		Unit Needs		Offshore Concept FLNG	Onshore Concept FPSO + LNG Plant
	Price	Unit				
CAPEX						
CAPEX WELL						
Drilling & Completion	USD 46,310,000	per Well	18	Wells	USD 833,580,000	USD 833,580,000
Sum CAPEX Well					USD 833,580,000	USD 833,580,000
CAPEX FACILITIES						
Production Facility: Subsea SURF	USD 200,000,000	per SURF	5	SURF	USD 1,000,000,000	USD 1,000,000,000
Processing Facilities						
FLNG Capacity 7.5 MTPA LNG	USD 2,397,040,000	per MTPA	7.5	MTPA	USD 17,977,800,000	N.A.
Logistic Supply Based	USD 5,000,000	per Hectare	50	Hectare	USD 250,000,000	
FPSO	USD 1,500,000,000	per Unit	1	Unit	N.A.	USD 1,500,000,000
Pipeline	USD 1,500,000	per km	100	km		USD 150,000,000
Onshore LNG Processing Plant	USD 1,165,500,000	per MTPA	9	MTPA		USD 10,489,500,000
Transport Facilities: LNG Carrier	USD 300,000,000	per Unit	2	Unit	USD 600,000,000	USD 600,000,000
SUM CAPEX FACILITIES					USD 19,827,800,000	USD 13,739,500,000
TOTAL CAPEX					USD 20,661,380,000	USD 14,573,080,000
OPEX						
Fixed Annual Operating Cost						
Offshore FLNG	USD 20,000,000	per Year			USD 200,000,000	N.A.
Onshore LNG Plant	USD 10,000,000	per Year			N.A.	USD 100,000,000
LNG & Condensate Production Cost						
Offshore FLNG	USD 1.20	USD/MCF				
Onshore LNG Plant	USD 1.10	USD/MCF				
Transportation Cost						
LNG Transportation	USD 0.70	USD/MCF				
Condensate Transportation	USD 5.50	USD/bbl				
TOTAL OPEX						

To be noted that the contingency plan has been included on each sub expenditure categories on **Table 8.7**, so there's no additional contingency plan at the end of the calculation. In the case of CAPEX Well when the total expenditure was calculated in refer to each elements, the 10% contingency plan was added at the calculation (take a look at **Table 8.2**). However, the estimated budget of the other on CAPEX Facilities (**Chapter 8.2.4** to **8.2.7**) were referred to the data from existing projects. Those data listed already contains 10% contingency plan.

The total CAPEX significantly influenced by the capacity of LNG Plant. Smaller the capacity leads to cheaper the total CAPEX itself. **Table 8.8** below shows the comparison CAPEX Price accordance to the capacity for each onshore and offshore concept. **Figure 8.14** below then illustrates the comparison on both concept on the same chart.

Table 8.8 Total CAPEX per MTPA Capacity

Offshore FLNG		Onshore LNG Plant	
FLNG Capacity	**Changed CAPEX (mil.USD)**	**LNG Plant Capacity**	**Changed CAPEX (mil.USD)**
7.5	**20,661.38**	**9.0**	**14,573.08**
0.5	3,882.10	0.5	4666.330
1.0	5,080.62	1.0	5249.080
1.5	6,279.14	1.5	5831.830
2.0	7,477.66	2.0	6414.580
2.5	8,676.18	2.5	6997.330
3.0	9,874.70	3.0	7580.080
3.5	11,073.22	3.5	8162.830
4.0	12,271.74	4.0	8745.580
4.5	13,470.26	4.5	9328.330
5.0	14,668.78	5.0	9911.080
5.5	15,867.30	5.5	10493.830
6.0	17,065.82	6.0	11076.580
6.5	18,264.34	6.5	11659.330
7.0	19,462.86	7.0	12242.080
7.5	20,661.38	7.5	12824.830
8.0	21,859.90	8.0	13407.580
8.5	23,058.42	8.5	13990.330
9.0	24,256.94	9.0	14573.080
9.5	25,455.46	9.5	15155.830
10.0	26,653.98	10.0	15738.580
10.5	27,852.50	10.5	16321.330
11.0	29,051.02	11.0	16904.080
11.5	30,249.54	11.5	17486.830
12.0	31,448.06	12.0	18069.580
12.5	32,646.58	12.5	18652.330
13.0	33,845.10	13.0	19235.080
13.5	35,043.62	13.5	19817.830
14.0	36,242.14	14.0	20400.580
14.5	37,440.66	14.5	20983.330
15.0	38,639.18	15.0	21566.080

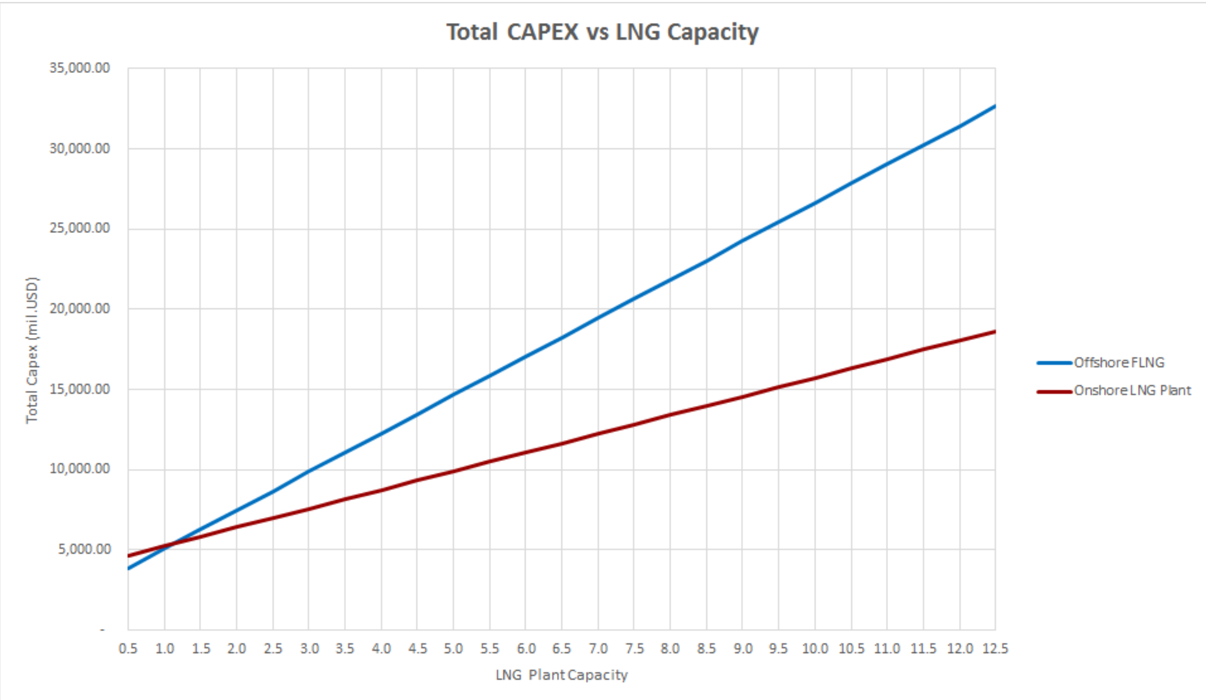


Figure 8.14 Comparison of Total CAPEX and LNG Capacity for both Concepts

Figure 8.14 above illustrates the total CAPEX changes accordance to the LNG capacity. On the Masela case, for LNG Plant less than 1.2 MTPA it has been shown that offshore concept has lower total investment. However for capacity more than 1.2 MTPA, onshore LNG Plant concept is more promising. In the case of Masela block with development of 7.5-9MTPA of LNG, onshore LNG Plant is more attractive for the investment. Those numbers relatively small and not comparable for the offshore concept.

The offshore concept with 7.5 MTPA capacity of FLNG will be cheaper in the case when the total CAPEX of the offshore concept is reduced 25% from the base CAPEX and the cost of onshore LNG Plant increase 25% as shown on **Table 8.9** below.

Table 8.9 Total CAPEX per MTPA Capacity with Price Adjustment

Offshore FLNG (Reduce 25% Cost)		Onshore LNG Plant (Increase 25% Cost)	
FLNG Capacity	Changed CAPEX (mil.USD)	LNG Plant Capacity	Changed CAPEX (mil.USD)
7.5	15,496.04	9.0	18,216.35
0.5	2,911.58	0.5	5832.913
1.0	3,810.47	1.0	6561.350
1.5	4,709.36	1.5	7289.788
2.0	5,608.25	2.0	8018.225
2.5	6,507.14	2.5	8746.663
3.0	7,406.03	3.0	9475.100
3.5	8,304.92	3.5	10203.538
4.0	9,203.81	4.0	10931.975
4.5	10,102.70	4.5	11660.413
5.0	11,001.59	5.0	12388.850
5.5	11,900.48	5.5	13117.288
6.0	12,799.37	6.0	13845.725
6.5	13,698.26	6.5	14574.163
7.0	14,597.15	7.0	15302.600
7.5	15,496.04	7.5	16031.038
8.0	16,394.93	8.0	16759.475
8.5	17,293.82	8.5	17487.913
9.0	18,192.71	9.0	18216.350
9.5	19,091.60	9.5	18944.788
10.0	19,990.49	10.0	19673.225
10.5	20,889.38	10.5	20401.663
11.0	21,788.27	11.0	21130.100
11.5	22,687.16	11.5	21858.538
12.0	23,586.05	12.0	22586.975
12.5	24,484.94	12.5	23315.413
13.0	25,383.83	13.0	24043.850
13.5	26,282.72	13.5	24772.288
14.0	27,181.61	14.0	25500.725
14.5	28,080.50	14.5	26229.163
15.0	28,979.39	15.0	26957.600

Then **Figure 8.15** below illustrates the total CAPEX changes accordance to the LNG capacity with adjusted price. With the total cost of offshore concept being reduced by 25% and the cost of onshore concept is escalated by 25%, FLNG Masela with capacity of 7.5 MTPA is cheaper. The break-even price is on the level of 9 MTPA capacity of LNG.

Thus the explanation of economic model analysis are presented on the next section.

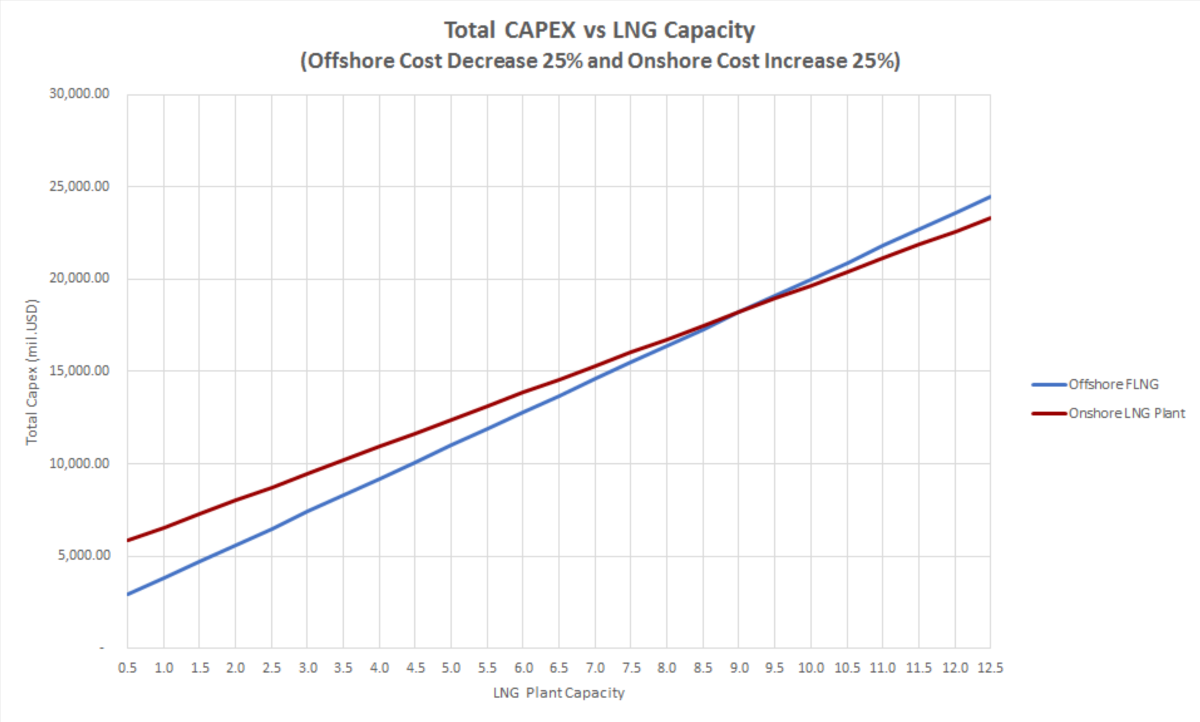


Figure 8.15 Comparison of Total CAPEX and LNG Capacity for both Concepts with Price Adjustment

8.4 Pre-tax Economic Model Analysis

The data from previous **Table 8.7** above then used to analyze the economical aspect of each concept. Production year for both concept are different and following the schedules that have been decided earlier on **Chapter 5.8**. The economic analysis also following the production profile mentioned on **Chapter 0**. The CAPEX facilities costs can be assumed to be distributed by: 5% in year 1, 15% in year 2, 20% in year 3, 50% in year 4, and 10% in year 5 respectively for both concept following the typical S-curve of the project as shown on **Figure 8.16** below.

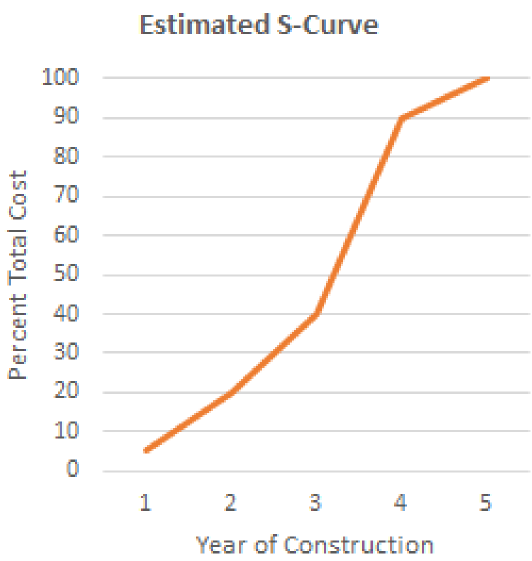


Figure 8.16 Cost Distribution of CAPEX Facilities

The cost of CAPEX well can be distributed equally for those 3 years as the number of drilled production wells will be the same each year.

Figure 8.17 below shows that offshore concept with the calculated facilities cost when the LNG price is 7.75 USD/MMBTU and condensate is 60 USD/barrel is not a promising concept. Detail calculation on **Appendix B – Economic Model** mentioned that the investment will create 2.3 billion USD loss. The IRR is -1% (with 10% discounted rate) and there's no payback period on its lifetime production. The breakeven price that is suitable for this FLNG concept is on 8.60 USD/MMBTU

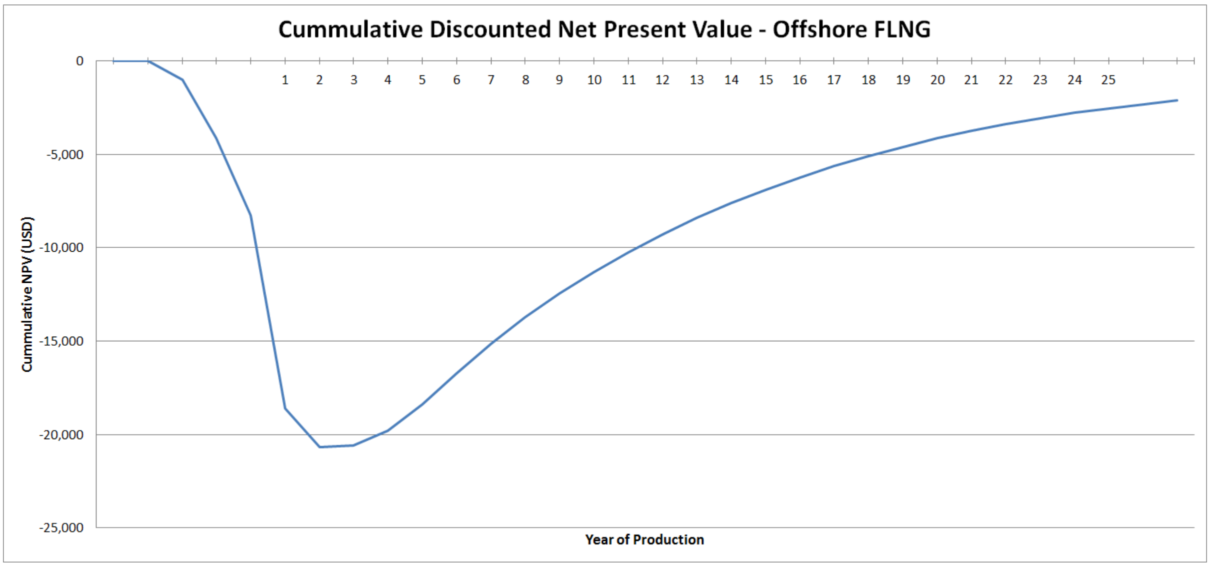


Figure 8.17 Economic Model for Offshore FLNG Concept

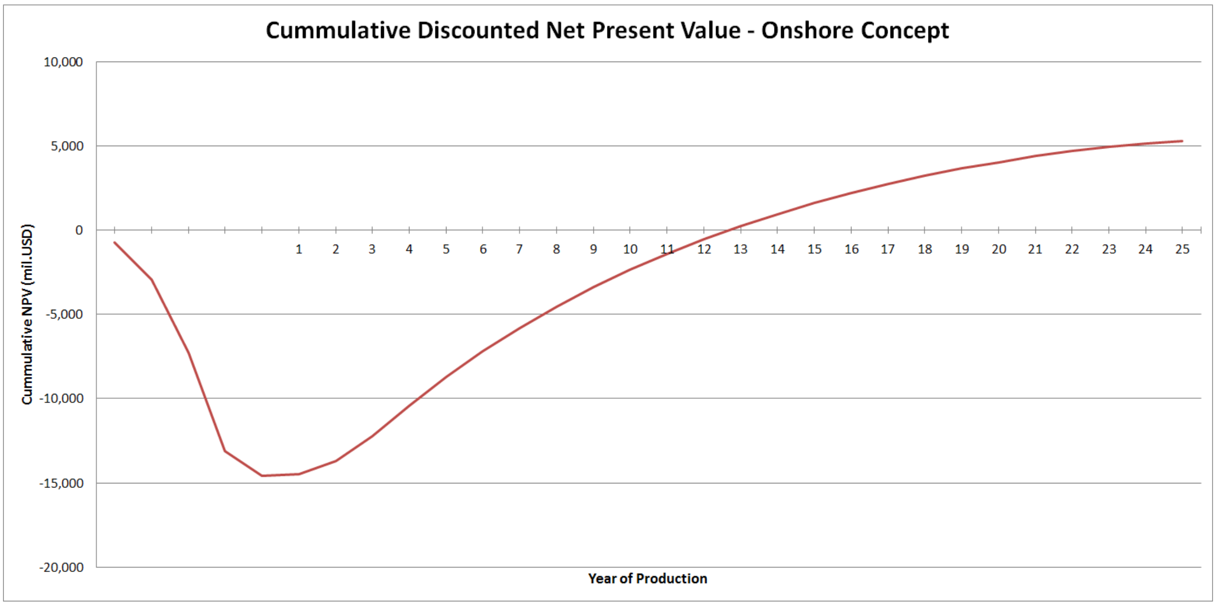


Figure 8.18 Economic Model for Onshore LNG Concept

On the other hand **Figure 8.18** above shows that onshore concept with the calculated facilities cost when the LNG price is 7.75 USD/MMBTU and condensate is 60 USD/barrel is a promising concept. Detail calculation on **Appendix B – Economic Model** mentioned that the investment will create NPV 4.7 billion USD. The IRR is 3% (with 10% discounted rate) and the payback period is 12.8 years. The breakeven price for this onshore LNG concept is on 6.08 USD/MMBTU.

So, the **Table 8.10** below summarized the economic parameter for both offshore and onshore concept.

Table 8.10 Economic Comparison between Offshore and Onshore Concept

Parameter	Offshore FLNG Concept	Onshore LNG Plant Concept
NPV	-2.311 billion USD	4.686,47 billion USD
IRR (with 10% discounted rate)	-1%	3%
Payback Period	Never	12.8 Years
LNG Break Even Price	8.60 USD/MMBTU	6.08 USD/MMBTU

8.5 Sensitivity Analysis

There is always risk in all activities and decision that we take, especially when the data is limited and a lot of assumptions are used. Even though detail assessment has been conducted for calculating economic value, there is always uncertainty. In oil and gas sector, there is significant factor that affect NPV of the project that is the commodities price and CAPEX that affect IRR. So in general, the economic assessment should be conducted regularly to balance the uncertainty risk itself.

Generally, the sensitivity analysis on this section refers to Bratvold and Begg (2010). NPV and IRR are agreed to be the most important parameter on the economic evaluation as mentioned earlier on this chapter. The sensitivity models are created to show the impact of certain variables on the NPV and IRR for each offshore and onshore concept respectively. This sensitivity analysis is conducted with these certain assumptions:

- The number of reserves is the same as projected
- The production rate is the same as projected
- The changed driver parameters assumed in related to LNG only. The price of condensate as well as its transportation cost are defined the same.

The decided driver parameters on this sensitivity analysis are:

- CAPEX Facilities +/- 50% from based cost
- LNG Operating Cost +/- 50% from based cost
- LNG Transportation Cost +/- 50% from based cost
- LNG Price +/- 50% from based cost
- Discount Rate +/- 50% from based rate

8.5.1 Offshore Concept

8.5.1.1 Sensitivity Analysis towards NPV

Sensitivity analysis towards Net Present Value of the offshore concept's economic model based on five changed parameters as shown on **Table 8.12** below. Detail analysis are attached on **Appendix C – Sensitivity Analysis** and summarized through **Table 8.11** below, and the result of the sensitivity analysis are shown on the tornado chart in **Figure 8.19** below. Spider diagram of this sensitivity analysis also shown in **Figure 8.20** below to shows the direction of the parameter drivers into offshore concept's NPV.

Table 8.11 Sensitivity Scenarios - Offshore Concept towards NPV

CAPEX Facilities

Change	CAPEX Scenario	Changed NPV (mil.USD)
Based	**20,661**	**-2311.01**
-50%	10,331	8019.37
-40%	12,397	5953.37
-30%	14,463	3887.37
-20%	16,529	1821.37
-10%	18,595	-244.63
0%	20,661	-2311.01
10%	22,728	-4377.63
20%	24,794	-6443.63
30%	26,860	-8509.63
40%	28,926	-10575.63
50%	30,992	-12641.63

LNG Operating Cost

Change	Operating Cost Scenario	Changed NPV (mil.USD)
Based	**1.20**	**-2311.01**
-50%	0.60	-644.95
-40%	0.72	-978.17
-30%	0.84	-1311.38
-20%	0.96	-1644.59
-10%	1.08	-1977.80
0%	1.20	-2311.01
10%	1.32	-2644.22
20%	1.44	-2977.43
30%	1.56	-3310.64
40%	1.68	-3643.85
50%	1.80	-3977.06

LNG Transportation Cost

Change	LNG Transport Cost	Changed NPV (mil.USD)
Based	**0.70**	**-2311.01**
-50%	0.35	-1339.14
-40%	0.42	-1533.52
-30%	0.49	-1727.89
-20%	0.56	-1922.26
-10%	0.63	-2116.63
0%	0.70	-2311.01
10%	0.77	-2505.38
20%	0.84	-2699.75
30%	0.91	-2894.13
40%	0.98	-3088.50
50%	1.07	-3338.41

LNG Price

Change	LNG Price Scenario	Changed NPV (mil.USD)
Based	**7.75**	**-2311.01**
-50%	3.88	-12774.53
-40%	4.65	-10692.64
-30%	5.43	-8583.71
-20%	6.20	-6501.82
-10%	6.98	-4392.90
0%	7.75	-2311.01
10%	8.53	-202.08
20%	9.30	1879.81
30%	10.08	3988.74
40%	10.85	6070.63
50%	11.63	8179.56

Discount Rate

Change	Discount Rate Scenario	Changed NPV (mil.USD)
Based	**10%**	**-2311.01**
-50%	5%	9189.14
-40%	6%	6199.86
-30%	7%	3614.07
-20%	8%	1367.41
-10%	9%	-593.05
0%	10%	-2311.01
10%	11%	-3822.64
20%	12%	-5158.06
30%	13%	-6342.39
40%	14%	-7396.66
50%	15%	-8338.58

Table 8.12 Parameters on Sensitivity Analysis of Offshore Concept's NPV

Assumptions	Change	Rank	Negative	Positive
CAPEX Facilities	+/- 50%	3	-12641.63	8019.37
LNG Price	+/- 50%	1	-12774.53	8179.56
Discount Rate	+/- 50%	2	-8338.58	9189.14
LNG Operating Cost	+/- 50%	4	-3977.06	-644.95
LNG Transportation Cost	+/- 50%	5	-3338.41	-1339.14

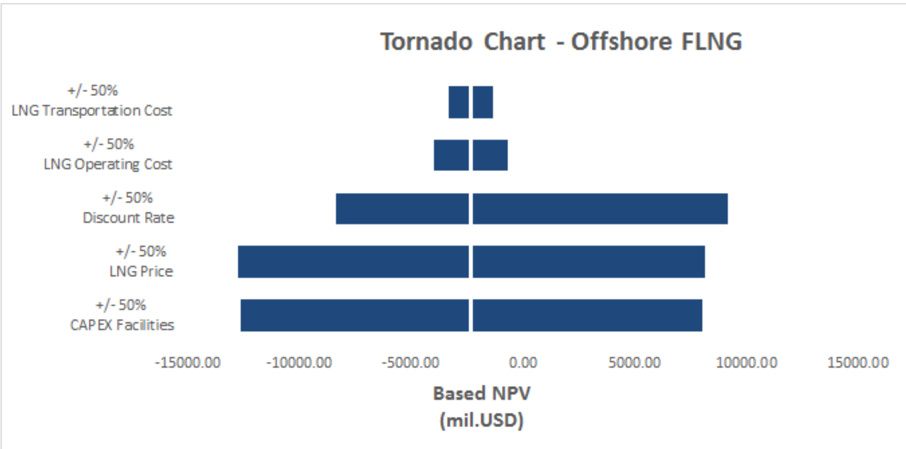


Figure 8.19 Tornado Chart to Identify Uncertainty Drivers on Offshore Concept's NPV

Tornado chart above shows changes on the NPV from the based estimation calculated on the previous section due to some parameters. On this offshore concept, the NPV significantly affected by the CAPEX Facilities as well as LNG Price. The discount rate also become a high driver parameters. In contrast, the change on LNG Transportation cost and LNG operating cost only create small deviation on NPV.

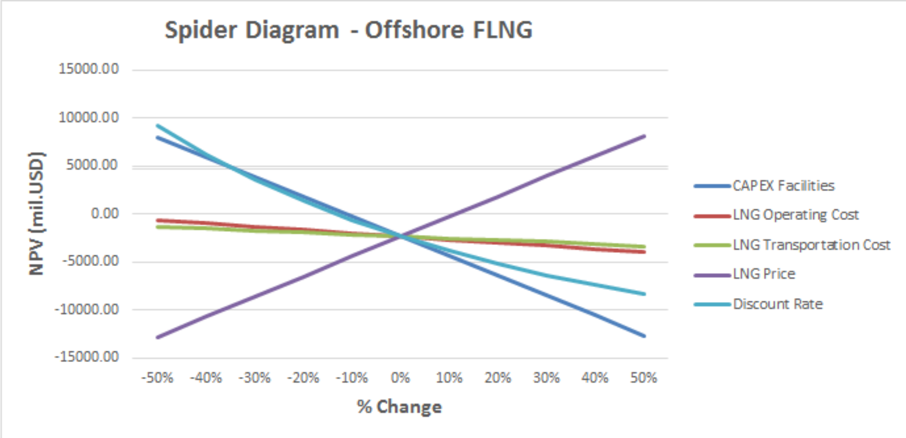


Figure 8.20 Spider Diagram to Show Direction of Sensitivity Drivers on Offshore Concept's NPV

Spider diagram above shows the direction of the driver parameters towards the NPV. The line slopes of CAPEX Facilities, Discount Rate, and LNG Price are steep. The steep line illustrates that those three drivers are more sensitive to the NPV compare to flat lines on LNG Operating Cost and LNG Transportation Cost. Thus CAPEX Facilities, LNG Price, as well as discount rate are consider as the sensitive parameters. In compliance with the Tornado chart shown on earlier **Figure 8.19** above, any changes on CAPEX Facilities cost, LNG Price and the discount rate will significantly affect the NPV.

On the same figure, the purple line that shows LNG Price inclines from negative NPV on the left to positive on the right. This means that when the price of LNG is reduced from the based price, the NPV will be lower than the projected value. And when the price of LNG rises, more profit may be obtained and NPV will increase positively from the projected value. On the opposite, the other four driver parameters are leaning from positive NPV on the right to negative on the left. Lower the CAPEX facilities cost, operating cost, and the discount factor are beneficial on the project as the NPV will rise.

8.5.1.2 Sensitivity Analysis towards IRR

Sensitivity analysis towards Internal Rate of Return of the offshore concept's economic model based on five changed parameters as shown on **Table 8.14** below. Detail analysis are attached on **Appendix C – Sensitivity Analysis** and summarized through **Table 8.13** below, and the result of the sensitivity analysis are shown on the tornado chart in **Figure 8.21** below. Spider diagram of this sensitivity analysis also shown in **Figure 8.22** below to shows the direction of the parameter drivers into offshore concept's IRR.

Table 8.13 Sensitivity Scenarios - Offshore Concept towards NPV

CAPEX Facilities		
Change	CAPEX Scenario	Changed IRR
Based	**20,661**	**-1%**
-50%	10,331	6%
-40%	12,397	4%
-30%	14,463	2%
-20%	16,529	1%
-10%	18,595	0%
0%	20,661	-1%
10%	22,728	-2%
20%	24,794	-3%
30%	26,860	-3%
40%	28,926	-4%
50%	30,992	-4%

LNG Operating Cost		
Change	Operating Cost Scenario	Changed IRR
Based	**1.20**	**-1%**
-50%	0.60	0%
-40%	0.72	0%
-30%	0.84	-1%
-20%	0.96	-1%
-10%	1.08	-1%
0%	1.20	-1%
10%	1.32	-1%
20%	1.44	-1%
30%	1.56	-2%
40%	1.68	-2%
50%	1.80	-2%

LNG Transportation Cost		
Change	LNG Transport Cost	Changed IRR
Based	**0.70**	**-1%**
-50%	0.35	-1%
-40%	0.42	-1%
-30%	0.49	-1%
-20%	0.56	-1%
-10%	0.63	-1%
0%	0.70	-1%
10%	0.77	-1%
20%	0.84	-1%
30%	0.91	-1%
40%	0.98	-1%
50%	1.07	-2%

LNG Price		
Change	LNG Price Scenario	Changed IRR
Based	**7.75**	**-1%**
-50%	3.88	-7%
-40%	4.65	-6%
-30%	5.43	-4%
-20%	6.20	-3%
-10%	6.98	-2%
0%	7.75	-1%
10%	8.53	0%
20%	9.30	1%
30%	10.08	2%
40%	10.85	2%
50%	11.63	3%

Discount Rate		
Change	Discount Rate Scenario	Changed IRR
Based	**10%**	**-1%**
-50%	5%	3%
-40%	6%	2%
-30%	7%	1%
-20%	8%	1%
-10%	9%	0%
0%	10%	-1%
10%	11%	-2%
20%	12%	-3%
30%	13%	-3%
40%	14%	-4%
50%	15%	-5%

Table 8.14 Parameters on Sensitivity Analysis of Offshore Concept's IRR

Assumptions	Change	Rank	Negative	Positive
CAPEX Facilities	+/- 50%	1	-4%	6%
LNG Price	+/- 50%	2	-7%	3%
Discount Rate	+/- 50%	3	-5%	3%
LNG Operating Cost	+/- 50%	4	-2%	0%
LNG Transportation Cost	+/- 50%	5	-2%	-1%

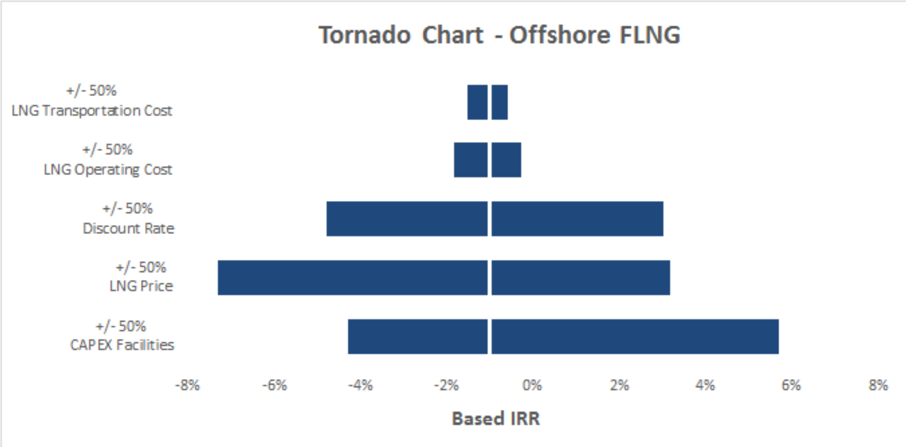


Figure 8.21 Tornado Chart to Identify Uncertainty Drivers on Offshore Concept's IRR

Tornado chart above shows changes on the IRR from the based estimation calculated on the previous section due to some parameters. On this offshore concept, the IRR significantly affected by the CAPEX Facilities as well as LNG Price. The discount rate also become a high driver parameters. In contrast, the change on LNG Transportation cost and LNG operating cost only create small deviation on IRR.

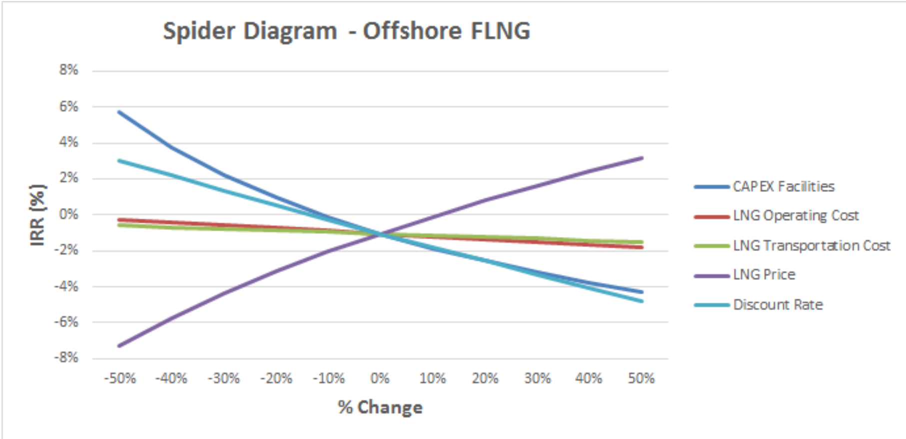


Figure 8.22 Spider Diagram to Show Direction of Sensitivity Drivers on Offshore Concept's IRR

Spider diagram above shows the direction of the driver parameters towards the IRR. The line slopes of CAPEX Facilities, Discount Rate, and LNG Price are steep. The steep line illustrates that those three drivers are more sensitive to the IRR compare to flat lines on LNG Operating Cost and LNG Transportation Cost. Thus CAPEX Facilities, LNG Price, as well as discount rate are consider as the sensitive parameters. In compliance with the Tornado chart shown on earlier **Figure 8.21** above, any changes on CAPEX Facilities cost, LNG Price and the discount rate will significantly affect the IRR.

On the same figure, the purple line that shows LNG Price inclines from negative IRR on the left to positive on the right. This means that when the price of LNG is reduced from the based price, the IRR will be lower than the projected rate. And when the price of LNG rises, the rate of return on the investment will be higher and IRR will increase positively from the projected value. On the opposite, the other four driver parameters are leaning from positive IRR on the right to negative on the left. Lower the CAPEX facilities cost, operating cost, and the discount factor are beneficial on the project's investment as the IRR will rise.

8.5.2 Onshore Concept

8.5.2.1 Sensitivity Analysis towards NPV

Sensitivity analysis towards Net Present Value of the onshore concept's economic model based on five changed parameters as shown on **Table 8.16** below. Detail analysis are attached on **Appendix C – Sensitivity Analysis** and summarized through **Table 8.15** below, and the result of the sensitivity analysis are shown on the tornado chart in **Figure 8.23** below. Spider diagram of this sensitivity analysis also shown in **Figure 8.24** below to shows the direction of the parameter drivers into onshore concept's NPV.

Table 8.15 Sensitivity Scenarios - Onshore Concept towards NPV

CAPEX Facilities		
Change	CAPEX Scenario	Changed NPV
Based	14,573	4686.47
-50%	7,287	11973.01
-40%	8,744	10515.70
-30%	10,201	9058.39
-20%	11,658	7601.08
-10%	13,116	6143.78
0%	14,573	4686.47
10%	16,030	3229.16
20%	17,488	1771.85
30%	18,945	314.54
40%	20,402	-1142.76
50%	21,860	-2600.07

LNG Operating Cost		
Change	Operating Cost Scenario	Changed NPV
Based	1.10	4686.47
-50%	0.55	6270.26
-40%	0.66	5953.50
-30%	0.77	5636.74
-20%	0.88	5319.99
-10%	0.99	5003.23
0%	1.10	4686.47
10%	1.21	4369.71
20%	1.32	4052.95
30%	1.43	3736.19
40%	1.54	3419.43
50%	1.65	3102.67

LNG Transportation Cost		
Change	LNG Transport Cost	Changed NPV
Based	0.70	4686.47
-50%	0.35	5694.34
-40%	0.42	5492.76
-30%	0.49	5291.19
-20%	0.56	5089.62
-10%	0.63	4888.04
0%	0.70	4686.47
10%	0.77	4484.89
20%	0.84	4283.32
30%	0.91	4081.75
40%	0.98	3880.17
50%	1.07	3621.01

LNG Price		
Change	LNG Price Scenario	Changed NPV
Based	7.75	4686.47
-50%	3.88	-6164.70
-40%	4.65	-4005.68
-30%	5.43	-1818.62
-20%	6.20	340.39
-10%	6.98	2527.45
0%	7.75	4686.47
10%	8.53	6873.53
20%	9.30	9032.54
30%	10.08	11219.60
40%	10.85	13378.62
50%	11.63	15565.67

Discount Rate		
Change	Discount Rate Scenario	Changed NPV
Based	10%	4686.47
-50%	5%	16115.29
-40%	6%	13185.22
-30%	7%	10629.01
-20%	8%	8390.41
-10%	9%	6422.59
0%	10%	4686.47
10%	11%	3149.27
20%	12%	1783.46
30%	13%	565.80
40%	14%	-523.35
50%	15%	-1500.68

Table 8.16 Parameters on Sensitivity Analysis of Onshore Concept's NPV

Assumptions	Change	Rank	Negative	Positive
LNG Price	+/- 50%	1	-6164.70	15565.67
Discount Rate	+/- 50%	2	-1500.68	16115.29
CAPEX Facilities	+/- 50%	3	-2600.07	11973.01
LNG Operating Cost	+/- 50%	4	3102.67	6270.26
LNG Transportation Cost	+/- 50%	5	3621.01	5694.34

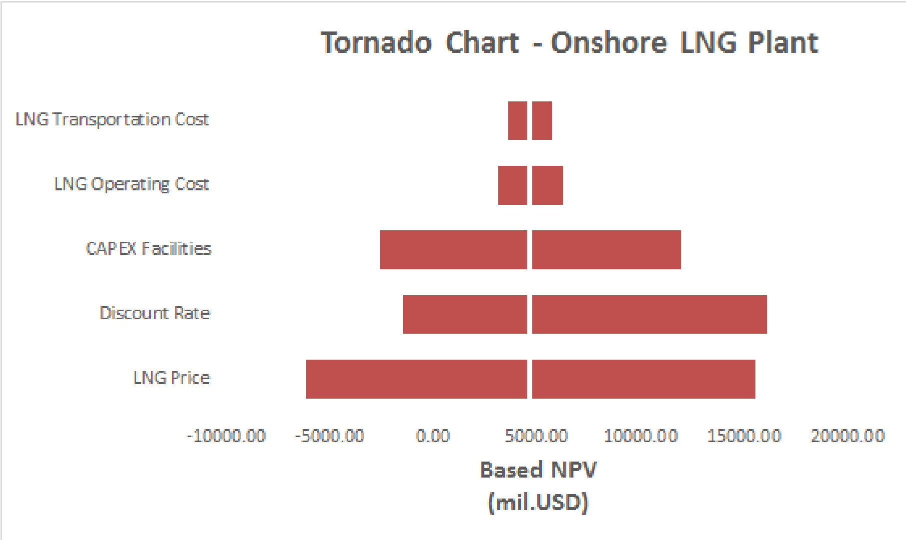


Figure 8.23 Tornado Chart to Identify Uncertainty Drivers on Onshore Concept's NPV

Tornado chart above shows changes on the NPV from the based estimation calculated on the previous section due to some parameters. On this onshore concept, the NPV significantly affected by the CAPEX Facilities as well as LNG Price. The discount rate also become a high driver parameters. In contrast, the change on LNG Transportation cost and LNG operating cost only create small deviation on NPV.

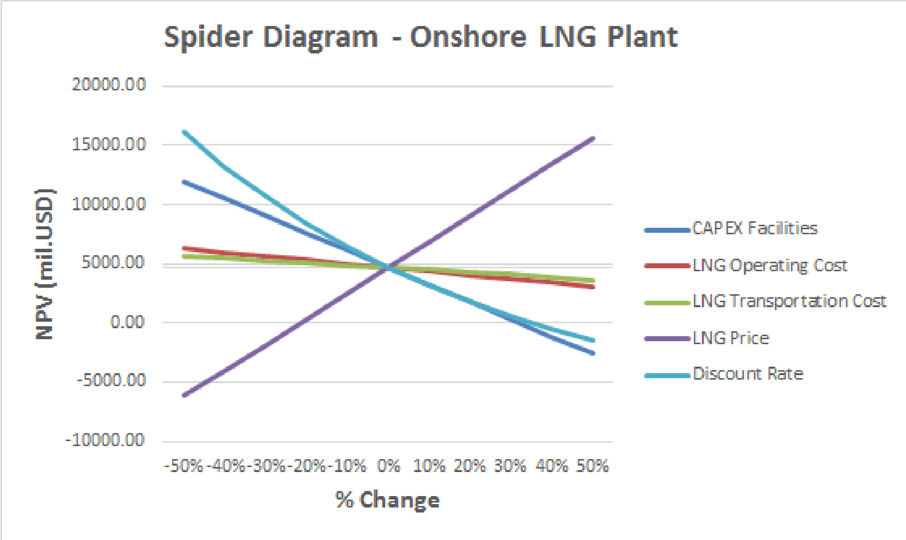


Figure 8.24 Spider Diagram to Show Direction of Sensitivity Drivers on Onshore Concept's NPV

Spider diagram above shows the direction of the driver parameters towards the NPV. The line slopes of CAPEX Facilities and Discount Rate. The steep line illustrates that those three drivers are more sensitive to the NPV compare to flat lines on LNG Operating Cost and LNG Transportation Cost. Thus CAPEX Facilities and LNG Price are consider as the sensitive parameters. In compliance with the Tornado chart shown on earlier **Figure 8.23** above, any changes on CAPEX Facilities cost and LNG Price will significantly affect the NPV.

On the same figure, the purple line that shows LNG Price inclines from negative NPV on the left to positive on the right. This means that when the price of LNG is reduced from the based price, the NPV will be lower than the projected value. And when the price of LNG rises, more profit may be obtained and NPV will increase positively from the projected value. On the opposite, the other four driver parameters are leaning from positive NPV on the right to negative on the left. Lower the CAPEX facilities cost, operating cost, and the discount factor are beneficial on the project as the NPV will rise.

8.5.2.2 Sensitivity Analysis towards IRR

Sensitivity analysis towards Internal Rate of Return of the onshore concept's economic model based on five changed parameters as shown on **Table 8.18** below. Detail analysis are attached on **Appendix C – Sensitivity Analysis** and summarized through **Table 8.17** below, and the result of the sensitivity analysis are shown on the tornado chart in **Figure 8.25** below. Spider diagram of this sensitivity analysis also shown in **Figure 8.26** below to shows the direction of the parameter drivers into onshore concept's IRR.

Table 8.17 Sensitivity Scenarios - Onshore Concept towards IRR

CAPEX Facilities		
Change	CAPEX Scenario	Changed IRR
Based	14,573	3%
-50%	7,287	10%
-40%	8,744	8%
-30%	10,201	6%
-20%	11,658	5%
-10%	13,116	4%
0%	14,573	3%
10%	16,030	2%
20%	17,488	1%
30%	18,945	0%
40%	20,402	-1%
50%	21,860	-1%

LNG Operating Cost		
Change	Operating Cost Scenario	Changed IRR
Based	1.10	3%
-50%	0.55	3%
-40%	0.66	3%
-30%	0.77	3%
-20%	0.88	3%
-10%	0.99	3%
0%	1.10	3%
10%	1.21	2%
20%	1.32	2%
30%	1.43	2%
40%	1.54	2%
50%	1.65	2%

LNG Transportation Cost		
Change	LNG Transport Cost	Changed IRR
Based	0.70	3%
-50%	0.35	3%
-40%	0.42	3%
-30%	0.49	3%
-20%	0.56	3%
-10%	0.63	3%
0%	0.70	3%
10%	0.77	3%
20%	0.84	2%
30%	0.91	2%
40%	0.98	2%
50%	1.07	2%

LNG Price		
Change	LNG Price Scenario	Changed IRR
Based	7.75	3%
-50%	3.88	-5%
-40%	4.65	-3%
-30%	5.43	-1%
-20%	6.20	0%
-10%	6.98	1%
0%	7.75	3%
10%	8.53	4%
20%	9.30	5%
30%	10.08	6%
40%	10.85	7%
50%	11.63	8%

Discount Rate		
Change	Discount Rate Scenario	Changed IRR
Based	10%	3%
-50%	5%	7%
-40%	6%	6%
-30%	7%	5%
-20%	8%	4%
-10%	9%	3%
0%	10%	3%
10%	11%	2%
20%	12%	1%
30%	13%	0%
40%	14%	0%
50%	15%	-1%

Table 8.18 Parameters on Sensitivity Analysis of Onshore Concept's IRR

Assumptions	Change	Rank	Negative	Positive
LNG Price	+/- 50%	1	-5%	8%
CAPEX Facilities	+/- 50%	2	-1%	10%
Discount Rate	+/- 50%	3	-1%	7%
LNG Operating Cost	+/- 50%	4	2%	3%
LNG Transportation Cost	+/- 50%	5	2%	3%

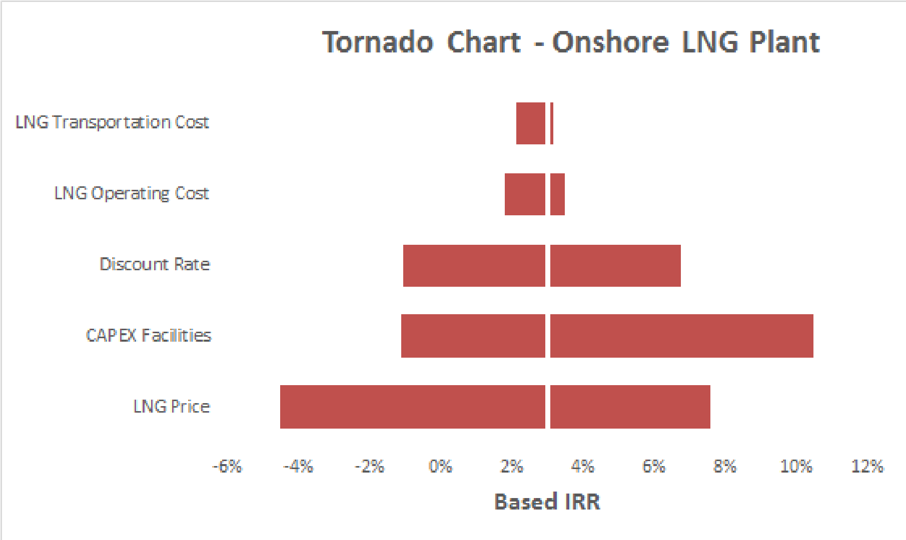


Figure 8.25 Tornado Chart to Identify Uncertainty Drivers on Onshore Concept's IRR

Tornado chart above shows changes on the IRR from the based estimation calculated on the previous section due to some parameters. On this onshore concept, the IRR significantly affected by the CAPEX Facilities as well as LNG Price. The discount rate also become a high driver parameters. In contrast, the change on LNG Transportation cost and LNG operating cost only create small deviation on IRR.

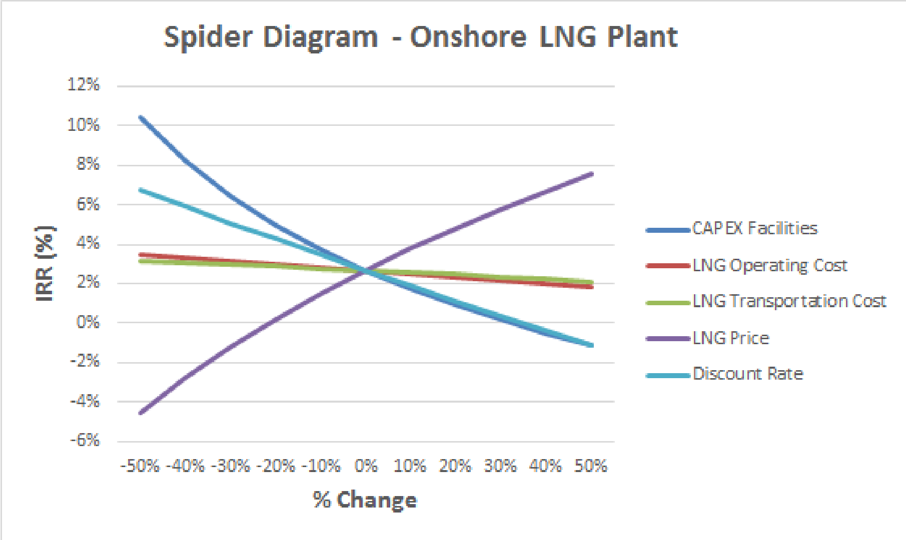


Figure 8.26 Spider Diagram to Show Direction of Sensitivity Drivers on Onshore Concept's IRR

Spider diagram above shows the direction of the driver parameters towards the IRR. The line slopes of CAPEX Facilities and LNG Price are steep. The steep line illustrates that those three drivers are more sensitive to the IRR compare to flat lines on LNG Operating Cost and LNG Transportation Cost. Thus CAPEX Facilities and LNG Price are consider as the sensitive parameters. In compliance with the Tornado Chart shown on earlier **Figure 8.25** above, any changes on CAPEX Facilities cost and LNG Price will significantly affect the IRR.

On the same figure, the purple line that shows LNG Price inclines from negative IRR on the left to positive on the right. This means that when the price of LNG is reduced from the based price, the IRR will be lower than the projected rate. And when the price of LNG rises, the rate of return on the investment will be higher and IRR will increase positively from the projected value. On the opposite, the other four driver parameters are leaning from positive IRR on the right to negative on the left. Lower the CAPEX facilities cost, operating cost, and the discount factor are beneficial on the project's investment as the IRR will rise.

8.5.3 Sensitivity Analysis Conclusion

For both offshore and onshore concept the cost of CAPEX Facilities and LNG Price significantly affect the NPV and IRR. Both CAPEX Facilities and LNG Price are sensitive parameters for the Masela economic model. Bigger NPV will be gained by reducing the CAPEX Facilities cost as well as the discount rate and the LNG Price should be larger than the current estimated price.

The discount rate factor is uncommonly affect this significant changes on the sensitivity analysis. However all calculations that are attached on **Appendix C – Sensitivity Analysis** shows that any small changes (1%) on discount rate significantly affect the NPV. This can be analyzed as the calculated cost of development takes large amount of money, while the current LNG Price condition is on slump. Thus the discount rate affect the economic model of the Masela block development.

9 Social Analysis

9.1 Brief History

Maluku (English: Moluccas) is one of the territory in East part of Indonesia that was highly recognized as Spice Islands. Maluku is one of the oldest existing province in Indonesian history. The evidence had been recorded in clay tablets found in Persian, Mesopotamia, and Egypt. It was written that "there is a very rich land far east, is the land of heaven, with plenty natural resources such as cloves, gold, and pearls" (Gorlinski, 2017), that mentioned land is nothing else than Maluku islands where nutmeg, cloves, and pearls were the main traded commodities. The excellent quality goods from this domain then blew nobility of the islands all over the world.

Europeans heard the prestige of the islands thus started their journey into Maluku. The beginning of long history conflicts was arising in 1512 when Portuguese settled themselves there (Gorlinski, 2017, Sejarawan, 2014). Portuguese initially established the friendly trading relationship with reigning sultans of Ternate and Tidore. However over time, Portuguese implemented a monopoly system which strangled people and lead to severe battles. Sejarawan (2014) mentioned that the earliest bloodshed broken out between Portuguese and local rulers in 1570, the five year war ended with departure of Portuguese from Maluku islands.

Thirty years after, Spanish, English, Dutch respectively arrived and forced their power into the area. The immerse value of spices in Europe made English and Dutch confronted each other to dominated Maluku. Dutch gained victory and has ruled the country for three centuries. Maluku then became the biggest money bag of Dutch-East-Indies (The name of Indonesia when were part of Dutch colonies) government until the World War II.

In short period, this region fell into Japan' grip from 1942 to 1945. After Indonesia had declared their independence on 17th of August 1945, Maluku joins the new republic. However Dutch endeavored to reauthorized their control in East part of Indonesia until decisively granted the independence of Indonesia in December 1949.

The land of Maluku never been in peace even after the independence. Ethnic separatism emerges to surface, and RMS (*Republik Maluku Selatan*, English: Republic of South Moluccas) formed not even one year after the granted independence (Hartati, 2010, Gorlinski, 2017) to pursue the segregation with the nation. There were couple of contentions between the newborn central government and the sovereign activists, however RMS attempts always been demolished. Activities of RMS no longer can be detected but their ideologies still can be felt its existence.

The other bloody conflict then came out from 1999-2002, it was part of series rooted from the injustice and marginal strife as the result of central government policy. The feud worsened when religion issues dragged into the case (Waileruny, 2010). High tension and civil war occurred around that time between two main religions group: Christian and Islam. According to report about 500,000 people were demised on the war until the end of 2002.

Fifteen years after the grisly warfare, the province has been recovered and start their new live. Through multiple hostilities that were presented, current Maluku is completely different with what European had heard couple of centuries ago. The dignity of the famous Spice Islands anyhow now is overcast. The development has been and always be the nation priority, however the social data that will be presented below still showing the contraries from the goals itself. Hence the existence of Masela Block on this province may be a glimpse of hope from the people to make Maluku as glorious as past time.

9.2 Maluku Province in General

After 62 years join the Republic of Indonesia, currently Maluku territories are divided into two provinces. The first province, Maluku Province includes the middle and southern extent of the islands. While northern part of Maluku stand with the other province called Maluku Islands Province. Maluku Province where Masela Block is located in present time is split into nine regencies (*kabupaten*) and the two cities (*kota*) (Maluku, 2017). The province is one of 34 provinces in Indonesia, shown on **Figure 9.1** below.

The Gross Domestic Product (GDP) of Maluku reached 6.70 percent in 2014. The extensive goods produced on the region are rice, coconut, copra, and spices. Oil and gas industry still on frontier line commodities nowadays. The presence of Masela block on this region twists its economic drift, now they focus on evolving natural gas as their main asset.

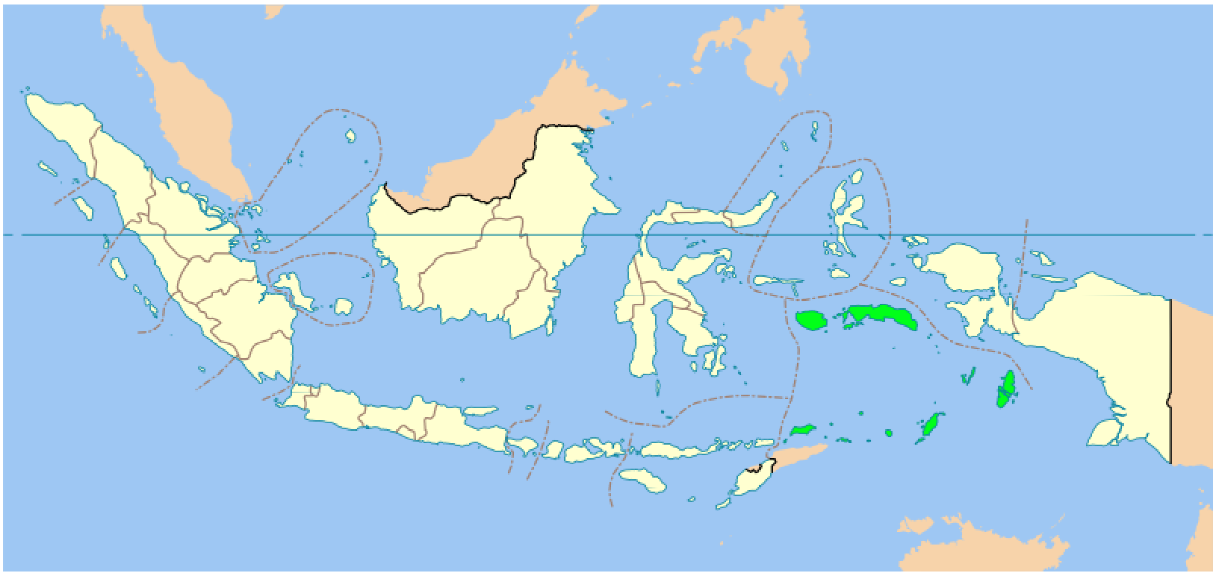


Figure 9.1 Maluku Province is highlighted in Green within Indonesia Map

9.3 Demography

Indonesia is well known for its diverse as well as the multiethnic population. Huat (2014) emphasized that around 300 ethnics residing in the same country while multiculturalism become part of national ideology. One of the ethnicity is Melanesia Pacific that dominates Maluku Province. Most likely they have darker skin, curly hair, as well as larger and stronger bone skeletons, also have more athletic body profile than any other races in Indonesia. In terms of appearance they have more similarities with residents of Pacific's countries such as Fiji and Tonga than any other ethnics in western Indonesia.

According to census conducted by BPS (2017), the population of Maluku province recorded on December 2016 as many as 1.715.548 people as shown on **Table 9.1** below. Those numbers represent less than 1% of total population of the country. While the distribution for each age group is illustrated by **Figure 9.2** below. On the same province, the population growth rate in 2010-2015 is about 1.85%. However, currently the life expectancy of residence of Maluku Province only around 65.4 years, the third lowest province in term of life expectancy in Indonesia.

Table 9.1 Maluku Demography

Regency/ City	Number of Population			Gender Ratio	Dependency Ratio	Percentage of Elderly Population
	Men	Women	Total			
Maluku Tenggara Barat	55,819	55,264	111,083	101.00	68.24	7.42
Maluku Tenggara	48,674	50,412	99,086	96.55	69.11	8.97
Maluku Tengah	187,037	183,490	370,527	101.93	60.09	7.72
Buru	67,609	64,164	131,773	105.37	63.23	5.79
Kepulauan Aru	48,025	44,553	92,578	107.79	61.87	5.04
Seram Bagian Barat	86,511	83,512	170,023	103.59	70.84	6.61
Seram Bagian Timur	55,990	54,034	110,024	103.62	65.31	5.60
Maluku Barat Daya	36,484	36,020	72,504	101.29	71.42	9.37
Buru Selatan	30,899	29,428	60,327	105.00	75.66	5.01
Kota Ambon	213,630	214,304	427,934	99.69	44.10	6.13
Kota Tuai	34,490	35,199	69,689	97.99	61.36	5.53
MALUKU	**865,168**	**850,380**	**1,715,548**	**101.74**	**59.31**	**6.72**

Data Source: Statistic Report of Maluku Province (BPS, 2017)

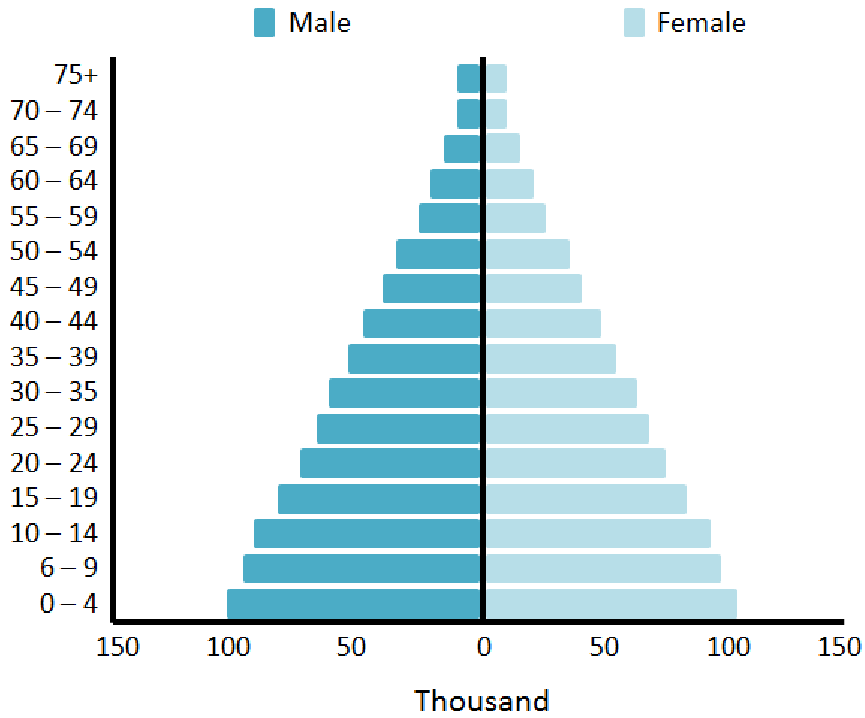


Figure 9.2 Population Pyramid of Maluku Province 2010-2035
Data Source: Statistic Report of Maluku Province (BPS, 2017)

The Population pyramid in Indonesia in general and specifically in Maluku Province as shown illustrates expansive type, which majority of the population is within young range age. Dependency ratio compares the population of non-productive population (people between 0-14 years old and more than 64 years old) and the number of productive population (15-64 years old). **Table 9.1** above and **Figure 9.2** above respectively also shows that the dependency ratio of the province is 59.31, means that every 100 productive people bear 59-60 non-productive people. Generally, the trend of dependency ratio in Indonesia is declining but Maluku categorizes as top three provinces with highest dependency ratio in the nation.

The expansive type population pyramid is like double-edged knife, it can be a potency or the source of problem for the region itself. If it can be well utilized, the large number of workforce will generate more earnings and bring more prosperity. In contrast, the high number of workforce without proper training and education will just carry more homework to society.

In fact, currently 49% of the citizen of Maluku pursue their education only until middle school or lower as listed on **Table 9.2** below.

Most likely local people stop their education early and start to struggle in agriculture, fishery, and forestry sector. People tend to work early rather than continue their education as the province has high unemployment rate. From those large number of residents, BPS (2017) registered that in 2016 there are 7.05% of those unemployed. That unemployment rate is rank 27th among 34 provinces in Indonesia.

Table 9.2 Level of Education in Maluku Province

Education Level	2015		2016	
	February	August	February	August
Middle School and Lower	347,749	360,686	346,632	343,770
High School/ Equivalent	238,242	207,867	233,713	246,595
College and Higher Education	77,027	86,210	101,828	100,421
TOTAL	**663,261**	**655,063**	**682,173**	**690,786**

Data Source: Statistic Report of Maluku Province (BPS, 2017)

Limited access to higher education may be one of the root of the problem. The government of Maluku Province stated that there are only 5 national universities and 19 private universities (Maluku, 2017), and only 2 study program that have an "A" accredited from BAN-PT (2015)[5]. Without favorable attention on this aspect, the combination between massive number of labor force and its low education level may lead to catastrophe in the next 20-30 years.

Maluku province is not the only province with these kind of limitations. Those conditions generally occurred in other outermost territories as well. Even though there are the foremost face of Indonesia, their conditions are far from decent. Limitations and backwardness are always become two predicates that perfectly describe the face of the islands in the border region. Most likely they have low income, low level education, and higher unemployment rate compare to other provinces. The previous descriptions conclude that their condition is far from decent and government has to take actions.

9.4 Geopolitic

Islands around Masela block are couple of 92 Indonesia's outermost islands (Ririmasse, 2013). Despite of its massive economic worth as mentioned on previous chapters, this region also salvaging strategic value in terms of geopolitics location. This is due to the fact that this block is located in the border between Indonesia, Australia and East Timor. Further, this is also one of the outermost point of Asia continent which directly facing the other continent: Australia. So, it is necessary to take a look at Masela's potencies and challenges in terms of geopolitics point of view.

Indonesia directly shares borders with nine countries. Masela and the other 22 islands are neighbor of Australia. While the others share the line with Malaysia, India, East Timor, Palau, Singapore, Vietnam, and Papua New Guinea. There are several tensions have happened between Indonesia and the listed boarding countries related to its territories.

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[5] BAN-PT *(Badan Akreditasi Nasional – Perguruan Tinggi,* English: National Accreditation Institution for Higher Education). A national institution that evaluates higher institutions and their study programs. Accreditation level range from A (very good) to E (unsatisfied).

Border clash is not a recent topic come up in the nation geopolitics affair. Ririmasse (2013) claimed that the characteristics of waters around the region that full of vast landscape of the islands naturally pushes legitimacy over the uninhabited islands. The configuration of those small islands are complex even though there's an international rule that arrange it. As a result there's no doubt that the outer boundary of each countries on the region overlapping with others and lead to strife.

A matter of border management in the country always be a vital issues since it involves the other indispensable subject such as politics, defenses, and economics. Government of Indonesia issued president regulation (*Peraturan Presiden*) Perpres No.78 in 2005 about governance of outermost islands which hold strategic position and economic development.

Perpres No.78 in 2005 highly suitable to be implemented in Masela block condition. The major point on this regulation is the acceleration of development and the importance of local content on every activities. Being one of the furthermost region in the country, Masela should be the pioneer to succeed of outer regions in the future. All in all, there is an urgency to accelerate the development of the border islands, no exception of Masela. Then Masela field development should be the gate of regional development to answer discrepancy issues, economic stimulation, as well as boosting the development index.

Strengthen the power of Maluku province by developing Masela block to gain prosperity of the local will have enormous impact to the geopolitics of eastern Indonesia.

9.5 Sosio-technology Impact

Exploring the potential of regional resources is a top priority of Indonesia development. It is to increase the regional income with injustice and independence of each region. So as a result, it increase the prosperity of the region itself. Maluku Province already faced a discrepancy on the past, and it must be avoided in the future to strengthen the region itself.

Oil and gas industry highly recognized as industry with high capital, high risk, and high technology. Without hesitation, it also requires high quality people to manage the assets of that industry. INPEX as the main operator will bring its massive number of personnel to build and operate Masela block. In other word, within couple of years, huge number of other ethnics as well as other nationalities will move to Maluku Province. Those people will not only bring their experience and knowledge, but also new cultures and new lifestyle to the province. Those will affect the residence of Maluku positively or negatively.

The existence of Masela block in this region may lead to prosperity of this region and to eastern part of Indonesia in general, on in contrast it also may lead to bigger gap in social strata of this province and lead to social pathology. Social pathology defined as the individual failure to adapt with new social order and inability of social institutions take action to develop their personality (Blackmar and Bilin, 1923 cited in Kartono 2003). As mentioned earlier that this region relatively vulnerable for Indonesia, its development should consider this aspect in order to gain as much benefit as the proposed, especially for the people of Maluku.

Exploitation in Masela region will positively and negatively affect Maluku society. There are at least four social community aspects that will be changed according to Siregar (2015) survey and analysis.

- Produced economic capital (e.g. asset and resource)
- Human Capital (e.g. education, knowledge, expertise, etc)
- Social capital (e.g. norm)
- Natural Capital (e.g. environmental effect, etc)

Those four aspects were summarized on **Table 9.3** below and then the explanation follow.

Table 9.3 Comparison of Socio-technology Impact Analysis for both Offshore and Onshore Concept

Aspects	Offshore FLNG Concept	Onshore LNG Plant Concept
Produced Economic Capital	Stimulate Shipbuilding Industry	Stimulate Fertilizer and Petrochemical Industry
Human Capital	Increase Human Capital Level	Increase Massive Human Capital Level
Social Capital	Low Interaction between Local and Newcomers. Well Perceived Local Culture and Norm.	High Interaction between Local and Newcomers. Potency of Local Culture and Norm Erosion.
Natural Capital	Low Potency to Harm Marine Ecology	High Potency to Harm Marine Ecology

9.5.1 Produced Economic Capital

Previously on **Chapter** 8 in page 78 the economic model was evaluated. The NPV of 4.7 billion USD is expected for the onshore concept, while the offshore concept is not profitable for investment. Those NPVs are the direct benefit of the exploitation activity. However, for any exploitation there's always any multiplier effects that occur due to the activity itself. The other sector such as transportation, hospitality, and other services will be developed along with the lapse of the gas production. This sub-chapter discusses the produced economic capital that may be occur on both offshore and onshore concept.

9.5.1.1 Offshore Concept

Masela's offshore concept mainly requires FLNG and onshore supply based. On this concept development, the steps of production and liquefaction will be done offshore. Nothing transported onshore as the condensate and LNG will be directly distributed from offshore FLNG to the market. In addition, this concept also requires 50 hectares onshore to build the logistic supply based.

9.5.1.1.1 Onshore Supply Based Effect

The existence of onshore supply based will enliven Maluku region, especially Kabupaten Maluku Tenggara Barat (MTB) the regencies where the block is located. Logistic for operation will be transported from this supply based. Changing crew also one of the important activity that will be conducted here. Supporting industry such as transportation, hospitality, and other services may also be develop even though will not be as impactful as building complete onshore LNG Plant on it.

9.5.1.1.2 FLNG Effect

To build huge 500 m x 82 m FLNG it needs a shipyard with bigger capacity than the projected dimension. International top shipyards company such as Samsung Heavy Industry in South Korea which is now constructing Shell's Prelude has capacity up to 640 m x 97.5 m x 13 m (Samsung, 2017). With that capacity, the projected FLNG Masela dimension able to be constructed there.

However, Masela has been considered as a national issues. The trace of the project are followed by the citizen and there is an eagerness to construct the vessel in domestic shipyard. It is also supported by the recent decision from SKK Migas to build the ship, platform, and topside of oil & gas field development in Indonesia instead. SKK Migas aims to increase the national economic development by switching on the domestic maritime companies.

There should not be any hesitation whether local personnel can operate it or not. The capability of domestic shipyard keep improving years to years. The recent FSRU 200 m x 46 m project that was built by PT. Saipem Indonesia in Karimun on the last year (Agustinus, 2016) prove that the domestic shipyard can compete with international competitors. This achievement lead SKK Migas as a regulator to announce the obligation for upstream oil & gas to use local product starting on December 2016. With this new obligation, the FLNG Masela should to be built in the domestic shipyard.

Indonesia domestic shipyards are capable enough to compete in ship manufacture industry and other maritime sector. However, again, the main challenge of FLNG Masela is its dimension. The maximum capacity of the existing shipyard is 300 m length shipyard owned by PT Anggrek Hitam at Karimun, Kepulauan Riau (AnggrekHitam, 2015) which is not sizable enough to build up FLNG Masela.

Indonesia as the largest archipelago country on Earth as well as located in one of busiest sea crossing lines actually has large potency on its maritime industry. But the maritime sector currently not fully developed. The dimension of largest domestic shipyard even half of the world class shipyard such as Samsung Heavy Industry. Moreover, the contribution of shipbuilding sector reported only 0.034% of total GDP (Windyandari, 2008) which is insignificant. Windyandari (2008) also emphasized that even the bicycle industry which doesn't require any complex technology is able to contribute to 0.023% of total GDP. There must be a massive effort to boost the shipbuilding industry.

The existence of FLNG Masela going to be a chance and trigger to build massive shipyard in Indonesia. Building a new shipyard is in line with President Joko Widodo's mission to make Indonesia a world maritime axis. The biggest challenge is to increase the role of Indonesian shipyards in international market. The market share of Indonesia's shipbuilding industry contributes only 0.3% world's market or practically not a substantial market player.

If the government decide to implement offshore FLNG concept, the country will build and own its largest shipyard and become the trigger to build another shipyards in the future. Then after FLNG Masela completed, the shipyard itself may take international orders and compete with other world class shipyards. Constructing the FLNG needs advance knowledge and technology, people will absorb a lot of new knowledge and it will be useful to build another vessel in the future. When the shipbuilding industry is developed, the economy of a country will go forward as well. To boost economic in eastern Indonesia and shorten the economic gap between west-east Indonesia, the new shipyard can even be built in Maluku or Papua.

Currently there are around 250 shipyards spread out in Indonesia (KEMENPERIN, 2017). As many as 37% of shipyards are located in Java island, 26% in Sumatra, 26% in Kalimantan (Borneo), while only the rest of 12% located in eastern part of Indonesia (Windyandari, 2008). Deep water bathymetry as well as stable area in Maluku and Papua are relatively suitable to build a ship. Even more, the ancestors of the Maluku' people are people who were famous for their greatness to build ships and wade through oceans. It may become the other motivation for the local people to contribute as well as gain benefit from the existence of Masela block on their region.

The new shipyard may become the indirect prompt to accelerate economic development in eastern part of Indonesia that proposed on President Joko Widodo's Nawacita[6]. As a comparison, Indonesia's closest neighbor Singapore mark its shipbuilding industry as the dominant sector to supply the country income. Maritime and Port Authority of Singapore (MPA, 2017) reported that the maritime industry contributing up to 7% to Singapore GDP and open work opportunity for over 170,000 personnel. Maluku's young population as shown earlier can be absorbed on this sector as well.

9.5.1.2 Onshore Concept

Masela's onshore concept mainly requires Onshore LNG Plant, FPSO, and pipeline. On this concept development, the gas and condensate will be purified on FPSO. Condensate will be transported directly from offshore FPSO to the market, while the gas will be transported through pipeline to the onshore LNG plant. Liquefaction process then conducted onshore and the produced LNG will be loaded from port to the market. As major activities are performed onshore, this concept requires around 800 hectares to accommodate those facilities.

[6] Nawacita refers to 9 priority programs of the current president, one of them is to strengthen the border area.

9.5.1.2.1 Onshore LNG Plant Effect

In contrast with the offshore concept, major exploitation activities will be conducted onshore. Starting on its construction phase, the LNG plant will directly impact the economic and development of the region. The area around 800 hectares are proposed to quarter the production facilities as well as its supporting amenities.

The development of onshore LNG Plant will generate the industrial zone on the region. LNG Plant itself will be a core of the economic mobility, while its precincts become the supporting zone. Residential area will automatically developed. More people will emigrate on the area and drum up the region economic and social. When people start to reside, the other sector will flourish as well. Market, shopping center, transportation, even tourism may come up to remark people demands. All in all, the whole region will straightly access the benefit from the existence of Masela exploitation as illustrated on **Figure 9.3** below.

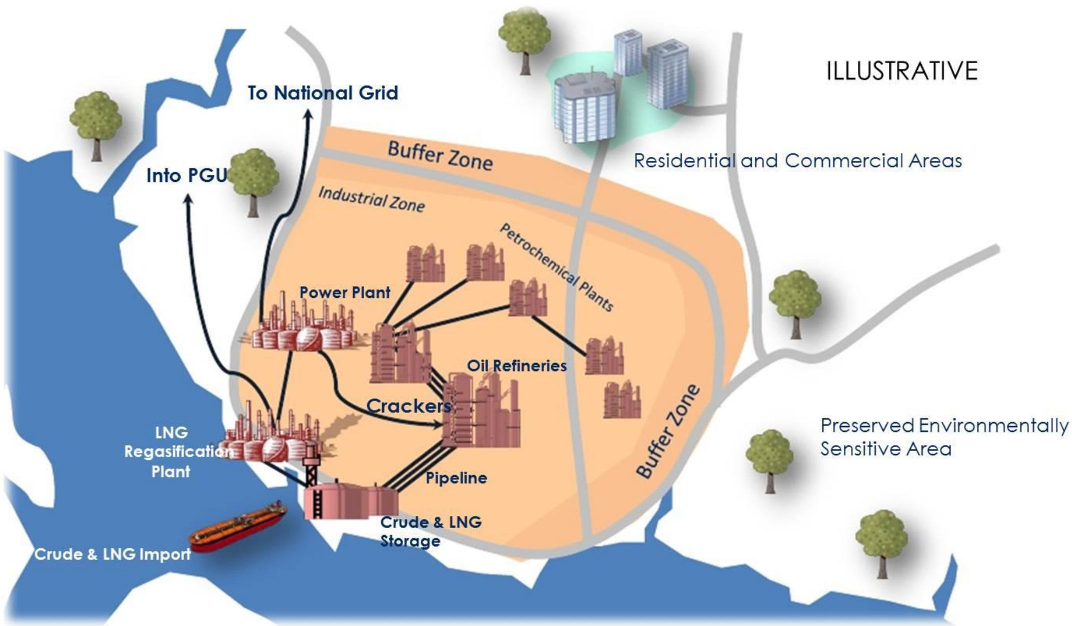

Figure 9.3 Multiplier Effect Illustration
Figure Source: Malaysia LNG Development Plan (MTBC, 2016)

The future portrait of Masela in the next 20 years (if the LNG Plant located onshore) is most likely will be similar with Bontang, East Kalimantan. Bontang is the home for LNG Badak, the current nation's largest LNG plant with capacity up to 22 MTPA of LNG (BadakLNG, 2017). Nowadays, oil & gas industry dominates 84.80% regional income (BPS, 2015) while the economic in general growth above the aggregate. Data from BPS (2015) also mentioned that the supporting sector such as electricity, transportation, construction and agriculture, forestry, and fishing sector growing 3-13% each year. The total poor population in Bontang also drop from 7.87% in 2007 to 5.16% in 2013 (BPS, 2015).

Starting from 1970s when LNG Badak established, the city of Bontang quickly transformed as a modern city with various amenities. Beside of its seaport which has important role of the region, Bontang local airport also establish to support LNG Badak activity. To support oil &

gas exploitation activities in East Kalimantan Province (LNG Badak, oil & gas block in Mahakam, etc), the huge Sepinggan airport was established in Balikpapan and recently nominated as the 6th best airport in Indonesia. International-standard hotels and shopping centers sprouts around the region that makes Bontang can be aligned with other cities in Indonesia.

The growth of Bontang not only because of LNG Badak. Several years after the establishment of LNG Badak, PT Pupuk Kalimantan Timur was inaugurated in 1977 (PupukKaltim, 2017) as a fertilizer and urea industry. Currently the company produces up to 2.98 million tons of Urea and 1.85 million tons of ammonia per year. The natural gas from Mahakam and CO_2 impurities from separation process of LNG are main raw materials to produce urea and ammonia, as shown on **Figure 9.4** below.

Other than the gas and LNG itself, the derived products from oil & gas become another agenda on developing Masela block. There's another concern to increase capacity of fertilizer and petrochemical industry in order to strengthen the competitiveness of Indonesian agriculture in the world market. The onshore concept transports natural gas via pipeline to onshore LNG Plant. By using this concept development, the gas will be accumulated and stored onshore. Then it becomes easier to earn the raw material and initiate the derived industries from natural gas such as fertilizer industry as explained above.

Agriculture is one of the dominant sector that contribute to Indonesia's GDP. On the last five years, agriculture contributes 13-15% to national GDP (BPS, 2016, Suryowati, 2014) and employed up to 41% the nation's work force (Investment, 2017). Moreover, it was also mentioned earlier on this chapter that the main commodities of Maluku Province are agriculture products such as copra.

The agriculture industry closely related to the availability of land and fertilizer supply. However, the current data from BPS shows that Indonesia can't fulfil its demand of fertilizer and highly depend on import. Local fertilizer companies such as Pupuk Kujang and Pupuk Kaltim unable to increase their capacity as its competitiveness of the local product still lower than the imported one. This is due to the high price of natural gas as a raw material that leads the industries face difficulty to grow (Somantri and Thahir, 2016).

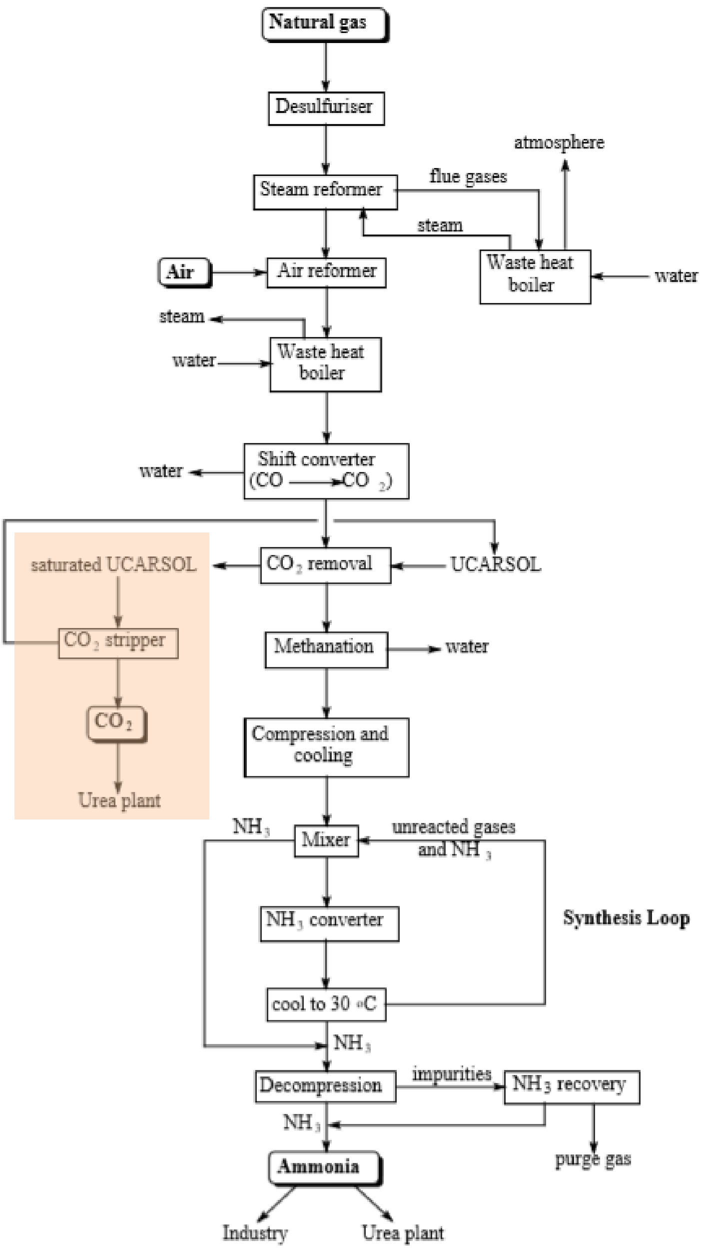

Figure 9.4 Schematic Diagram to Show Urea and Ammonia Synthesis Process
Figure Source: Urea & Fertilizer (Copplestone and Kirk)

The main commodities of eastern part of Indonesia (Maluku and Papua) are dominated by agricultural products. However, there's not even one of big fertilizer company exist there. The closest one is Pupuk Kaltim that located in Kalimantan, middle part of Indonesia. The high cost of fertilizer's transportation is also another problem of developing agriculture sector. There is discourse to grow agricultural sector in order to following President's Nawacita as explained by Somantri and Thahir (2016) on their journal.

The agricultural product should be develop and encouraged to be able to compete with the other local product as well as global market by reducing the cost of fertilizer. Building fertilizer factory in the Masela industry region may be the solution to improve the agricultural as well as the petrochemical industry development in eastern part of Indonesia. There beneficial multiplier industries only can occur if the development of Masela block is handled onshore.

However, the other challenge will occur on the onshore concept as it requires huge production area. The main challenge of exploration and the beginning of exploitation in Indonesia is the acceptance of local people (Siregar, 2015). Land acquisition always be one of the biggest challenge when developing one field in Indonesia. There are some parties that can accept the government instruction and willing to sell their land to KKKS. However the major side doesn't want to proceed the transaction.

As mentioned on earlier passage, that Maluku people (and Indonesian in general) value the ancestral heritage as an important matter. The land that they own now is inheritance of their ancestors that supposed to be kept and maintained for their generations, not for sale. The head of Village Adaut[7] proposes the solution to leasing the land to KKKS instead of selling it. Villagers wish to keep own that land. Local people doesn't want to lose their valuable land. It is to avoid the case that in one day indigenous people will be displaced and have no shelter and livelihood (Papilaya, 2014). So INPEX as KKKS, rent that lands instead of buy that and all the common facilities (such as training center) should be shared between the operator and the local community.

Literally it's still possible to develop petrochemical and fertilizer industry when using offshore concept. However, it will be inefficient and even may increase the cost of production itself. In offshore concept, the gas will be modified into LNG then transported. Then the LNG receiving terminal as well as its regasification unit should be built in Maluku Province. The LNG converted again into gas as a supply material for petrochemical and fertilizer industry. There are double steps which are not necessary and can be removed by using the onshore concept.

The existence of Masela block in Maluku is an asset for the Maluku region itself to become well developed province like other oil & gas region in Indonesia. Direct multiplier effect will be perceived more by the local community if the LNG plant established onshore. Those direct improvements will be relatively small for the local people if the exploitation facilities are established offshore.

9.5.1.2.2 FPSO Effect

The existing largest shipyard in Indonesia not even big enough to construct the proposed Masela FPSO with 330m x 65m. The same solution which is to build a new shipyard in Maluku may also be used. However, most likely to occur on this case there will not be a new shipyard, instead adding the capacity of the existing one. Shipyard of PT PAL only 30 meters shorter than the proposed FPSO dimension. With some modifications and additions of equipment, the dock will be ready for constructing Masela FPSO.

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[7] Village that Located on the Proposed Onshore LNG Plant Location

9.5.1.2.3 Pipeline Effect

Tingkat Kandungan Dalam Negeri (TKDN), local content for supporting oil & gas industry decreases from 63% in 2010 into 54% in 2014 as illustrates on **Figure 9.5** below. ESDM claimed that this is due to the fact that recent oil & gas investments are dominated offshore which the local equipment itself are limited.

Figure 9.5 Local Content in Oil & Gas Sector in Indonesia
Figure Source: Local Content (KataData, 2016)

The amount of 91% onshore drilling equipment are supplied by local industry. About 80% of onshore pipeline are produced in the country. While only 40% floating offshore facilities were built in the country. The onshore concept with its pipeline will increase the local participation on the oil & gas industry.

9.5.2 Human Capital

Exploration and production need a lot of experts. However As mentioned earlier, that Maluku Province has one of the lowest education level in Indonesia. Moreover report on 2011, stated that about 19.65% of locals never been into the formal education (Worldbank). Education crisis should be the main development focus.

Education discrepancy must be solved since it has an impact on the backwardness of the locals to get the job opportunities in his own region. INPEX employees generally have higher level education than local people and it may spark the conflict in between. The education level in the region should be improved by building couple of new universities, especially related to oil & gas sector, so they can compete with the emigrant.

New Universities and higher institutions related to oil & gas sectors should be the vital aspect, thus the locals will be ready to face the transition period to oil & gas production. Training institutions in the service sector should be built to empower people especially local youth to increase their capability. STT Migas[8] in Balikpapan can be a good example. The presence of this higher education empowered the local youth to pursue their higher education and improve their standard of living.

Pusdiklat Cepu as well as Mahakam Training Center were established as the training center for keep improving their personnel on the recent technologies. On its production state, the similar training center will also be established. In the future Maluku's educational standard may also rise.

Table 9.4 below may give the idea about education level in Bontang, the region where LNG Badak located. 48.71% of the jobseekers in 2014 are graduated from higher institution or universities, the other 39% were graduated from high schools, and only small amount of 12% that graduated from middle schools or elementary schools. High level education of jobseekers on this regions may be a sign that the education level as well as its economic has been develop.

Table 9.4 Number of Jobseekers and Labor on Demand by Education Level

Education Level	Men	Women	Total
Jobseeker			
Elementary School	288	110	398
Middle School	455	211	666
High School	2,362	644	3,006
College Diploma I-III	1,337	331	1,668
University and higher	1,612	576	2,188
Job Availability			
Elementary School	44	2	46
Middle School	34	1	35
High School	645	87	732
College Diploma I-III	322	44	366
University and higher	552	56	608

Data Source: Social and Manpower Regional Office, Bontang (BPS, 2015)

The effect of increased human capital especially in education will be perceived on both offshore and onshore concept. However, onshore concept that requires more area and automatically increases the interaction between local and new comers creates more opportunity for locals as has happened in Bontang.

9.5.3 Social Capital

Local people may get a job, new knowledge, experience as well as open their mind against the outside area. On the other side, norm and local value will be eroded. Globalization, slow or fast will affect the structure of the society.

[8] STT Migas: *Sekolah Tinggi Teknik Minyak dan Gas* (English: Oil and Gas Technology College)

Onshore concept limits the interaction between local people and INPEX personnel. The norm and local value projected to be indwell there for years. However this may also leads to problem because to local will only heard about the offshore exploitation activity without even witnessed the activity itself. This may become a concern issue about social gap between newcomer and local people.

In contrast, onshore concept will lead massive interaction between INPEX personnel and the local. The norm and local value will be exposed, new culture as well as new lifestyle undoubtedly will tuck into their life. There's important task for both local and central government to play a role in supporting cultural preservation whether the LNG plant built onshore or offshore. These norms can't be changed easily and should be perceived as local value. However when those values are eroded, its challenging task to rebuild it in the society.

Absolutely there will be some changes on social life of Maluku local people during the exploitation stage of Masela block. Both options have benefits as well as risky harmful effect to the society. Good local value and norms should be perceived but people should also be ready to accept the broader point of view. All in all, the LNG production in Maluku should become a trigger to increase the social level of the local as well as engaging the newcomer and local people on the society.

9.5.4 Natural Capital

On this era, awareness towards environmental and social issues in oil & gas industry significantly boost. Those topics become global concern as more people can access the information quickly on the news. Production without proper consideration about environment may lead to environmental damage. Most likely government and locals still not aware about this natural aspect. However, natural capital is a critical aspect, especially if we talk further about sustainability. A sustainability on the natural resource exploitation is required as the production takes 20-50 years. Savitz and Weber (2006) added the environmental sustainability also improves the company activity by supporting its economic and non-economic aspects.

On Masela case, the connection between Maluku's people and its land and sea like a religio-magic relationship (Siregar, 2015). They perceive their nature really well and ready to block anyone who wants to destroy it. This may be a major problem for INPEX if they cannot guarantee to perform the production in safety and environmentally friendly way.

Laying 100km pipeline no doubt will disturb the harmony of existence marine ecology. There will be a huge number of coral reef that will be discard on the pipeline route. However operating huge FLNG also has a potency to disturb the marine ecology. Massive number of seawater will be used to the cooling process when converting gas into LNG. Both options have their own impact to the environment. Further environmental analysis should be performed in order to perceive the business in a sustainable manner.

10 Conclusion

1. The vast amount of 10.73 TCF of gas located on offshore Masela going to be produced through 18 production wells that are connected to 5 subsea manifolds in the water depth ranging from 300 m to 1,000 m.

   Offshore concept aims to transport the gas and condensate from the subsea facilities to the 500 m x 82 m Floating Liquefied Natural Gas (FLNG) with capacity of 7.5 MTPA of LNG. All the gas and condensate processing from separation, stabilization, gas treating, dehydration, gas conditioning, liquefaction, as well as loading process will be conducted on this vessel. Additionally, to support all the offshore activities a logistic supply based will also be built on the closest island.

   In contrast, the proposed onshore concept pursues the gas from subsea facilities to be produced at onshore LNG Plant. The raw gas planned to be transported to the 330m x 65m Floating Production Storage Offloading (FPSO) where the separation and stabilization will take place. Gas and condensate will be separated on FPSO, then the produced condensate will be loaded to the tanker and directly been delivered from the offshore vessel to the market. The gas then be transported to the 9 MTPA capacity onshore LNG Plant via pipeline. The gas treating, dehydration, conditioning, liquefaction and loading process to the market will be accomplished onshore.

2. The most essential building block of the offshore concept is the FLNG while the most challenging subject of the onshore concept is its pipeline.

   Opinion about FLNG as an unproven technology can be neglected by the recent presence of Petronas FLNG Satu which is remarkably become the first operated FLNG in the world. However, the most crucial question of FLNG Masela is its dimension that projected to be bigger than the current giant-under-construction-FLNG: Shell's Prelude. The immerse dimension of FLNG Masela owns higher risk compare to the existing vessel. However, according to literature study and evaluation on **Chapter 6,** there will be no significant technical problem on constructing and operating FLNG Masela.

   The pipeline and onshore LNG Plant are mature concept that widely used in oil & gas industry. However, the vulnerable location of Masela in terms of bathymetry, earthquake, and tsunami potency become the threats for the pipeline concept to be implemented. Regardless of those challenges, the study on the **Chapter 7** concludes that the pipeline feasible to be carried out on the region. Large number of earthquakes on the past 10 years occurred on the further north of the block and predicted not affecting the pipeline route. Despite of the high potency of tsunami onshore Masela, there's not any single tsunami that happened on the region. The problem related to flow assurance due to its bathymetry and high CO_2 content might be reduced by using 24inch diameter Corrosion Resistant Alloy (CRA) on its pipeline material.

The finest route according to the analysis on **Chapter 7** is to lay 100 km pipeline to onshore Pulau Yamdena. Onshore Pulau Yamdena was chosen as it is relatively save according to engineering evaluation as well as attractive in term of economic.

3. CAPEX well and subsea production facilities are the same for both options. The cost of 7.5 MTPA FLNG is 17.978 billion USD or expected about 2.4 billion USD/MTPA. The total CAPEX for offshore option reach 20.661 billion USD. On the other hand, onshore LNG Plant looks promising with cost of 1.165 billion USD/MTPA. The total cost for developing Masela block with onshore option in the range of 14.573 billion USD even 25% lower than the cost of FLNG itself.

   On the Masela case, the implementation of offshore concept with capacity less than 1.2 MTPA has lower total investment. However for capacity more than 1 MTPA, onshore LNG Plant concept is more profitable. In the case of Masela block with development of 7.5-9 MTPA of LNG, onshore LNG Plant is more captivating for the investment. FLNG Masela with capacity of 7.5 MTPA will be cheaper when the total CAPEX of offshore concept being reduced by 25% and the budget estimated for the onshore concept is rising 25%.

   Offshore concept with the calculated facilities cost when the LNG price is 7.75 USD/MMBTU and condensate is 60 USD/barrel is not a promising concept. Calculation on **Chapter 8** shows that the investment will create 3.5 billion USD loss. The IRR is -1% (with 10% discounted rate, or similar as 9% without 10% discount rate) and there's no payback period on its lifetime production. The breakeven price that is suitable for this FLNG concept is on the level of 8.60 USD/MMBTU of LNG.

   On the other hand onshore concept within the same commodities prices looks worthwhile as the investment will gain NPV 4.7 billion USD. The IRR is 3% (with 10% discounted rate) and the payback period is 12.8 years. The breakeven price for this onshore LNG concept is on 6.08 USD/MMBTU of LNG.

   For both offshore and onshore concept the cost of CAPEX Facilities and LNG Price significantly affect the NPV and IRR. Both CAPEX Facilities and LNG Price are sensitive parameters for the Masela economic model. Bigger NPV will be gained by reducing the CAPEX Facilities cost as well as the discount rate and the LNG Price should be larger than the current estimated price.

4. The existence of Masela block in this region may lead to prosperity of this region and to eastern part of Indonesia in general, or in contrast it also may lead to larger gap in social strata of this province and lead to social pathology that was evaluated on **Chapter 9.**

   Offshore concept projected to create multiplier effect through stimulating the shipbuilding industry. The human capital level will also increase. However the low interaction between local and the newcomer (operator's worker) may cause social gap problem but keep the local culture and norm to be well perceived. In terms of environmental perspective, the offshore concept has lower potency to harm the marine ecology.

Fertilizer industry and petrochemical industry are projected to be the multiplier effect from the existence of onshore LNG Plant. As the production takes place onshore and close to the local household, massive human capital level will be increased significantly. The high level interaction between local and newcomers definitely will occur. The cultural transfer and interaction surely will be mixed, thus there is a potency of erosion of local culture as well as its norm. Onshore option that proposed to lay 100 km pipeline exactly will disturb the condition of marine ecology. Suitable action must be conduct to preserve the natural biodiversity

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Appendix A – Production Profile

A.1 Production Profile Calculation – Offshore Concept

Production Profile of Offshore Concept

Technical Recoverable Volume	10,730,000,000,000	Cubic Feet of Gas	Input
	209,000,000	Barrel of condensate	Assumption
Gas Production Rate (per Well)	60,000,000	Cubic Feet of Gas per day	Calculation Result
Condensate Production Rate	24,460	Barrel of condensate per day	
Condensate Production Rate (per Well)	1,359	Barrel of condensate per day	
Total Production Rate	12.50%	of remaining recoverable volume	
Platform Capacity	7.50	MMTPA of LNG	
	360,211,627,050	Cubic Feet of Gas	
	8,927,900	Barrel of condensate	
Operating Cost	2.5	USD/MCF	
	0.0025	USD/cubic feer	
Gas Price	7.75	USD/mmbtu	
	0.00800	USD/cubic feer	
Condensate Price	60	USD/bbl	

Year	Month	Number of Production Wells	Gas Production						Cummulative Production	Remaining Recoverable Volumes	Condensate Production					Cummulative Production	Revenue Gas	Revenue Condensate	Total Revenue	Operating Cost	Net Cash Flow	Cummulative NCF
			Remaining Recoverable Volumes	Constraint 01		Constraint 02	Constraint 03	Production per Year			Constraint 01		Constraint 02	Constraint 03	Production per Year							
				Production Rate per Month	Production Rate per Year	Total Production Rate per Year	FLNG Capacity				Production Rate per Month	Production Rate per Year	Total Production Rate per Year	FLNG Capacity								
			(cubic feet)	(cubic feet)	(cubic feet)	(cubic feet)	(cubic feet)	(cubic feet)	(cubic feet)	(bbl)	(bbl)	(bbl)	(bbl)	(bbl)	(bbl)	(bbl)	USD	USD	USD	USD	USD	USD
1	January	0	10,730,000,000,000	-	54,000,000,000	1,341,250,000,000	360,211,627,050	54,000,000,000	54,000,000,000	209,000,000	-	1,223,000	26,125,000	8,927,900	1,223,000	1,223,000	431,892,000	73,380,000	505,272,000	135,000,000	370,272,000	370,272,000
	February	0		-							-											
	March	1		1,800,000,000							40,766.7											
	April	1		1,800,000,000							40,766.7											
	May	2		3,600,000,000							81,533.3											
	June	2		3,600,000,000							81,533.3											
	July	3		5,400,000,000							122,300.0											
	August	3		5,400,000,000							122,300.0											
	September	4		7,200,000,000							163,066.7											
	October	4		7,200,000,000							163,066.7											
	November	5		9,000,000,000							203,833.3											
	December	5		9,000,000,000							203,833.3											
2	January	6	10,676,000,000,000	10,800,000,000	183,600,000,000	1,334,500,000,000	360,211,627,050	183,600,000,000	237,600,000,000	207,777,000	244,600.0	4,158,200	25,972,125	8,927,900	4,158,200	5,381,200	1,468,432,800	249,492,000	1,717,924,800	459,000,000	1,258,924,800	1,629,196,800
	February	6		10,800,000,000							244,600.0											
	March	7		12,600,000,000							285,366.7											
	April	7		12,600,000,000							285,366.7											
	May	8		14,400,000,000							326,133.3											
	June	8		14,400,000,000							326,133.3											
	July	9		16,200,000,000							366,900.0											
	August	9		16,200,000,000							366,900.0											
	September	10		18,000,000,000							407,666.7											
	October	10		18,000,000,000							407,666.7											
	November	11		19,800,000,000							448,433.3											
	December	11		19,800,000,000							448,433.3											
3	January	12	10,492,400,000,000	21,600,000,000	313,200,000,000	1,311,550,000,000	360,211,627,050	313,200,000,000	550,800,000,000	203,618,800	489,200.0	7,093,400	25,452,350	8,927,900	7,093,400	12,474,600	2,504,973,600	425,604,000	2,930,577,600	783,000,000	2,147,577,600	3,776,774,400
	February	12		21,600,000,000							489,200.0											
	March	13		23,400,000,000							529,966.7											
	April	13		23,400,000,000							529,966.7											
	May	14		25,200,000,000							570,733.3											
	June	14		25,200,000,000							570,733.3											
	July	15		27,000,000,000							611,500.0											
	August	15		27,000,000,000							611,500.0											
	September	16		28,800,000,000							652,266.7											
	October	16		28,800,000,000							652,266.7											
	November	17		30,600,000,000							693,033.3											
	December	17		30,600,000,000							693,033.3											
4	January-December	18	10,179,200,000,000	32,400,000,000	388,800,000,000	1,272,400,000,000	360,211,627,050	360,211,627,050	911,011,627,050	196,525,400	733,800.0	8,805,600	24,565,675	8,927,900	8,805,600	21,280,200	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	6,285,553,926
5	January-December	18	9,818,988,372,950	32,400,000,000	388,800,000,000	1,227,373,546,619	360,211,627,050	360,211,627,050	1,271,223,254,100	187,719,800	733,800.0	8,805,600	23,464,975	8,927,900	8,805,600	30,085,800	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	8,794,333,451
6	January-December	18	9,458,776,745,900	32,400,000,000	388,800,000,000	1,182,347,093,238	360,211,627,050	360,211,627,050	1,631,434,881,150	178,914,200	733,800.0	8,805,600	22,364,275	8,927,900	8,805,600	38,891,400	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	11,303,112,977
7	January-December	18	9,098,565,118,850	32,400,000,000	388,800,000,000	1,137,320,639,856	360,211,627,050	360,211,627,050	1,991,646,508,200	170,108,600	733,800.0	8,805,600	21,263,575	8,927,900	8,805,600	47,697,000	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	13,811,892,502
8	January-December	18	8,738,353,491,800	32,400,000,000	388,800,000,000	1,092,294,186,475	360,211,627,050	360,211,627,050	2,351,858,135,250	161,303,000	733,800.0	8,805,600	20,162,875	8,927,900	8,805,600	56,502,600	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	16,320,672,028
9	January-December	18	8,378,141,864,750	32,400,000,000	388,800,000,000	1,047,267,733,094	360,211,627,050	360,211,627,050	2,712,069,762,300	152,497,400	733,800.0	8,805,600	19,062,175	8,927,900	8,805,600	65,308,200	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	18,829,451,553
10	January-December	18	8,017,930,237,700	32,400,000,000	388,800,000,000	1,002,241,279,713	360,211,627,050	360,211,627,050	3,072,281,389,350	143,691,800	733,800.0	8,805,600	17,961,475	8,927,900	8,805,600	74,113,800	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	21,338,231,079
11	January-December	18	7,657,718,610,650	32,400,000,000	388,800,000,000	957,214,826,331	360,211,627,050	360,211,627,050	3,432,493,016,400	134,886,200	733,800.0	8,805,600	16,860,775	8,927,900	8,805,600	82,919,400	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	23,847,010,604
12	January-December	18	7,297,506,983,600	32,400,000,000	388,800,000,000	912,188,372,950	360,211,627,050	360,211,627,050	3,792,704,643,450	126,080,600	733,800.0	8,805,600	15,760,075	8,927,900	8,805,600	91,725,000	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	26,355,790,130
13	January-December	18	6,937,295,356,550	32,400,000,000	388,800,000,000	867,161,919,569	360,211,627,050	360,211,627,050	4,152,916,270,500	117,275,000	733,800.0	8,805,600	14,659,375	8,927,900	8,805,600	100,530,600	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	28,864,569,655
14	January-December	18	6,577,083,729,500	32,400,000,000	388,800,000,000	822,135,466,188	360,211,627,050	360,211,627,050	4,513,127,897,550	108,469,400	733,800.0	8,805,600	13,558,675	8,927,900	8,805,600	109,336,200	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	31,373,349,181
15	January-December	18	6,216,872,102,450	32,400,000,000	388,800,000,000	777,109,012,806	360,211,627,050	360,211,627,050	4,873,339,524,600	99,663,800	733,800.0	8,805,600	12,457,975	8,927,900	8,805,600	118,141,800	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	33,882,128,706
16	January-December	18	5,856,660,475,400	32,400,000,000	388,800,000,000	732,082,559,425	360,211,627,050	360,211,627,050	5,233,551,151,650	90,858,200	733,800.0	8,805,600	11,357,275	8,927,900	8,805,600	126,947,400	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	36,390,908,232
17	January-December	18	5,496,448,848,350	32,400,000,000	388,800,000,000	687,056,106,044	360,211,627,050	360,211,627,050	5,593,762,778,700	82,052,600	733,800.0	8,805,600	10,256,575	8,927,900	8,805,600	135,753,000	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	38,899,687,757
18	January-December	18	5,136,237,221,300	32,400,000,000	388,800,000,000	642,029,652,663	360,211,627,050	360,211,627,050	5,953,974,405,750	73,247,000	733,800.0	8,805,600	9,155,875	8,927,900	8,805,600	144,558,600	2,880,972,593	528,336,000	3,409,308,593	900,529,068	2,508,779,526	41,408,467,283
19	January-December	18	4,776,025,594,250	32,400,000,000	388,800,000,000	597,003,199,281	360,211,627,050	360,211,627,050	6,314,186,032,800	64,441,400	733,800.0	8,805,600	8,055,175	8,927,900	8,055,175	152,613,775	2,880,972,593	483,310,500	3,364,283,093	900,529,068	2,463,754,026	43,872,221,308
20	January-December	18	4,415,813,967,200	32,400,000,000	388,800,000,000	551,976,745,900	360,211,627,050	360,211,627,050	6,674,397,659,850	56,386,225	733,800.0	8,805,600	7,048,278	8,927,900	7,048,278	159,662,053	2,880,972,593	422,896,688	3,303,869,281	900,529,068	2,403,340,213	46,275,561,521
21	January-December	18	4,055,602,340,150	32,400,000,000	388,800,000,000	506,950,292,519	360,211,627,050	360,211,627,050	7,034,609,286,900	49,337,947	733,800.0	8,805,600	6,167,243	8,927,900	6,167,243	165,829,296	2,880,972,593	370,034,602	3,251,007,195	900,529,068	2,350,478,127	48,626,039,648
22	January-December	18	3,695,390,713,100	32,400,000,000	388,800,000,000	461,923,839,138	360,211,627,050	360,211,627,050	7,394,820,913,950	43,170,704	733,800.0	8,805,600	5,396,338	8,927,900	5,396,338	171,225,634	2,880,972,593	323,780,276	3,204,752,870	900,529,068	2,304,223,802	50,930,263,450
23	January-December	18	3,335,179,086,050	32,400,000,000	388,800,000,000	416,897,385,756	360,211,627,050	360,211,627,050	7,755,032,541,000	37,774,366	733,800.0	8,805,600	4,721,796	8,927,900	4,721,796	175,947,430	2,880,972,593	283,307,742	3,164,280,335	900,529,068	2,263,751,267	53,194,014,718
24	January-December	18	2,974,967,459,000	32,400,000,000	388,800,000,000	371,870,932,375	360,211,627,050	360,211,627,050	8,115,244,168,050	33,052,570	733,800.0	8,805,600	4,131,571	8,927,900	4,131,571	180,079,001	2,880,972,593	247,894,274	3,128,866,867	900,529,068	2,228,337,800	55,422,352,517
25	January-December	18	2,614,755,831,950	32,400,000,000	388,800,000,000	326,844,478,994	360,211,627,050	326,844,478,994	8,442,088,647,044	28,920,999	733,800.0	8,805,600	3,615,125	8,927,900	3,615,125	183,694,126	2,614,102,143	216,907,490	2,831,009,633	817,111,197	2,013,898,435	57,436,250,953
26	January-December	18	2,287,911,352,956	32,400,000,000	388,800,000,000	285,988,919,120	360,211,627,050	285,988,919,120	8,728,077,566,163	25,305,874	733,800.0	8,805,600	3,163,234	8,927,900	3,163,234	186,857,360	2,287,339,375	189,794,054	2,477,133,429	714,972,298	1,762,161,131	59,198,412,084
27	January-December	18	2,001,922,433,837	32,400,000,000	388,800,000,000	250,240,304,230	360,211,627,050	250,240,304,230	8,978,317,870,393	22,142,640	733,800.0	8,805,600	2,767,830	8,927,900	2,767,830	189,625,190	2,001,421,953	166,069,797	2,167,491,750	625,600,761	1,541,890,990	60,740,303,073
28	January-December	18	1,751,682,129,607	32,400,000,000	388,800,000,000	218,960,266,201	360,211,627,050	218,960,266,201	9,197,278,136,594	19,374,810	733,800.0	8,805,600	2,421,851	8,927,900	2,421,851	192,047,042	1,751,244,209	145,311,072	1,896,555,281	547,400,666	1,349,154,616	62,089,457,689
29	January-December	18	1,532,721,863,406	32,400,000,000	388,800,000,000	191,590,232,926	360,211,627,050	191,590,232,926	9,388,868,369,520	16,952,958	733,800.0	8,805,600	2,119,120	8,927,900	2,119,120	194,166,161	1,532,338,683	127,147,188	1,659,485,871	478,975,582	1,180,510,289	63,269,967,978
30	January-December	18	1,341,131,630,480	32,400,000,000	388,800,000,000	167,641,453,810	360,211,627,050	167,641,453,810	9,556,509,823,330	14,833,839	733,800.0	8,805,600	1,854,230	8,927,900	1,854,230	196,020,391	1,340,796,348	111,253,790	1,452,050,137	419,103,635	1,032,946,503	64,302,914,481
31	January-December	18	1,173,490,176,670	32,400,000,000	388,800,000,000	146,686,272,084	360,211,627,050	146,686,272,084	9,703,196,095,413	12,979,609	733,800.0	8,805,600	1,622,451	8,927,900	1,622,451	197,642,842	1,173,196,804	97,347,066	1,270,543,870	366,715,680	903,828,190	65,206,742,671
32	January-December	18	1,026,803,904,587	32,400,000,000	388,800,000,000	128,350,488,073	360,211,627,050	128,350,488,073	9,831,546,583,487	11,357,158	733,800.0	8,805,600	1,419,645	8,927,900	1,419,645	199,062,487	1,026,547,204	85,178,683	1,111,725,886	320,876,220	790,849,666	65,997,592,337
33	January-December	18	898,453,416,513	32,400,000,000	388,800,000,000	112,306,677,064	360,211,627,050	112,306,677,064	9,943,853,260,551	9,937,513	733,800.0	8,805,600	1,242,189	8,927,900	1,242,189	200,304,676	898,228,803	74,531,347	972,760,151	280,766,693	691,993,458	66,689,585,795
34	January-December	18	786,146,739,449	32,400,000,000	388,800,000,000	98,268,342,431	360,211,627,050	98,268,342,431	10,042,121,602,982	8,695,324	733,800.0	8,805,600	1,086,915	8,927,900	1,086,915	201,391,592	785,950,203	65,214,929	851,165,132	245,670,856	605,494,276	67,295,080,070
35	January-December	18	687,878,397,018	32,400,000,000	388,800,000,000	85,984,799,627	360,211,627,050	85,984,799,627	10,128,106,402,609	7,608,408	733,800.0	8,805,600	951,051	8,927,900	951,051	202,342,643	687,706,427	57,063,063	744,769,490	214,961,999	529,807,491	67,824,887,562
36	January-December	18	601,893,597,391	32,400,000,000	388,800,000,000	75,236,699,674	360,211,627,050	75,236,699,674	10,203,343,102,283	6,657,357	733,800.0	8,805,600	832,170	8,927,900	832,170	203,174,812	601,743,124	49,930,180	651,673,304	188,091,749	463,581,555	68,288,469,116
37	January-December	18	526,656,897,717	32,400,000,000	388,800,000,000	65,832,112,215	360,211,627,050	65,832,112,215	10,269,175,214,498	5,825,188	733,800.0	8,805,600	728,148	8,927,900	728,148	203,902,961	526,525,233	43,688,908	570,214,141	164,580,281	405,633,860	68,694,102,977
38	January-December	18	460,824,785,502	32,400,000,000	388,800,000,000	57,603,098,188	360,211,627,050	57,603,098,188	10,326,778,312,686	5,097,039	733,800.0	8,805,600	637,130	8,927,900	637,130	204,540,091	460,709,579	38,227,794	498,937,373	144,007,745	354,929,628	69,049,032,605
39	January-December	18	403,221,687,314	32,400,000,000	388,800,000,000	50,402,710,914	360,211,627,050	50,402,710,914	10,377,181,023,600	4,459,909	733,800.0	8,805,600	557,489	8,927,900	557,489	205,097,579	403,120,882	33,449,320	436,570,202	126,006,777	310,563,424	69,359,596,029
40	January-December	18	352,818,976,400	32,400,000,000	388,800,000,000	44,102,372,050	360,211,627,050	44,102,372,050	10,421,283,395,650	3,902,421	733,800.0	8,805,600	487,803	8,927,900	487,803	205,585,382	352,730,772	29,268,155	381,998,926	110,255,930	271,742,996	69,631,339,025
41	January-December	18	308,716,604,350	32,400,000,000	388,800,000,000	38,589,575,544	360,211,627,050	38,589,575,544	10,459,872,971,194	3,414,618	733,800.0	8,805,600	426,827	8,927,900	426,827	206,012,209	308,639,425	25,609,635	334,249,061	96,473,939	237,775,122	69,869,114,147
42	January-December	18	270,127,028,806	32,400,000,000	388,800,000,000	33,765,878,601	360,211,627,050	33,765,878,601	10,493,638,849,794	2,987,791	733,800.0	8,805,600	373,474	8,927,900	373,474	206,385,683	270,059,497	22,408,431	292,467,928	84,414,697	208,053,232	70,077,167,379
43	January-December	18	236,361,150,206	32,400,000,000	388,800,000,000	29,545,143,776	360,211,627,050	29,545,143,776	10,523,183,993,570	2,614,317	733,800.0	8,805,600	326,790	8,927,900	326,790	206,712,473	236,302,060	19,607,377	255,909,437	73,862,859	182,046,578	70,259,213,957
44	January-December	18	206,816,006,430	32,400,000,000	388,800,000,000	25,852,000,804	360,211,627,050	25,852,000,804	10,549,035,994,374	2,287,527	733,800.0	8,805,600	285,941	8,927,900	285,941	206,998,414	206,764,302	17,156,455	223,920,757	64,630,002	159,290,755	70,418,504,712
45	January-December	18	180,964,005,626	32,400,000,000	388,800,000,000	22,620,500,703	360,211,627,050	22,620,500,703	10,571,656,495,077	2,001,586	733,800.0	8,805,600	250,198	8,927,900	250,198	207,248,612	180,918,765	15,011,898	195,930,663	56,551,252	139,379,411	70,557,884,123
46	January-December	18	158,343,504,923	32,400,000,000	388,800,000,000	19,792,938,115	360,211,627,050	19,792,938,115	10,591,449,433,193	1,751,388	733,800.0	8,805,600	218,924	8,927,900	218,924	207,467,535	158,303,919	13,135,411	171,439,330	49,482,345	121,956,985	70,679,841,108
47	January-December	18	138,550,566,808	32,400,000,000	388,800,000,000	17,318,820,851	360,211,627,050	17,318,820,851	10,608,768,254,043	1,532,465	733,800.0	8,805,600	191,558	8,927,900	191,558	207,659,093	138,515,929	11,493,485	150,009,414	43,297,052	106,712,362	70,786,553,469
48	January-December	18	121,231,745,957	32,400,000,000	388,800,000,000	15,153,968,245	360,211,627,050	15,153,968,245	10,623,922,222,288	1,340,907	733,800.0	8,805,600	167,613	8,927,900	167,613	207,826,707	121,201,438	10,056,799	131,258,237	37,884,921	93,373,316	70,879,926,785
49	January-December	18	106,077,777,712	32,400,000,000	388,800,000,000	13,259,722,214	360,211,627,050	13,259,722,214	10,637,181,944,502	1,173,293	733,800.0	8,805,600	146,662	8,927,900	146,662	207,973,368	106,051,258	8,799,699	114,850,957	33,149,306	81,701,652	70,961,628,437
50	January-December	18	92,818,055,498	32,400,000,000	388,800,000,000	11,602,256,937	360,211,627,050	11,602,256,937	10,648,784,201,439	1,026,632	733,800.0	8,805,600	128,329	8,927,900	128,329	208,101,697	92,794,851	7,699,737	100,494,588	29,005,642	71,488,945	71,033,117,383

A.1 Production Profile Calculation – Onshore Concept

Production Profile of Onshore Concept

Technical Recoverable Volume	10,730,000,000,000	Cubic Feet of Gas
	209,000,000	Barrel of condensate
Gas Production Rate (per Well)	60,000,000	Cubic Feet of Gas per day
Condensate Production Rate	24,460	Barrel of condensate per day
Condensate Production Rate (per Well)	1,359	Barrel of condensate per day
Total Production Rate	12.50%	of remaining recoverable volume
Platform Capacity	9.00	MMTPA of LNG
	432,253,952,460	Cubic Feet of Gas
	8,927,900	Barrel of condensate
Operating Cost	2.5	USD/MCF
	0.0025	USD/cubic feer
Gas Price	7.75	USD/mmbtu
	0.00800	USD/cubic feer
Condensate Price	60	USD/bbl

Input
Assumption
Calculation Result

Gas Production

Year	Month	Number of Production Wells	Remaining Recoverable Volumes (cubic feet)	Constraint 01: Production Rate per Month (cubic feet)	Constraint 01: Production Rate per Year (cubic feet)	Constraint 02: Total Production Rate per Year (cubic feet)	Constraint 03: FLNG Capacity (cubic feet)	Production per Year (cubic feet)	Cummulative Production (cubic feet)
1	January	0	10,730,000,000,000	-	54,000,000,000	1,341,250,000,000	432,253,952,460	54,000,000,000	54,000,000,000
	February	0		-					
	March	1		1,800,000,000					
	April	1		1,800,000,000					
	May	2		3,600,000,000					
	June	2		3,600,000,000					
	July	3		5,400,000,000					
	August	3		5,400,000,000					
	September	4		7,200,000,000					
	October	4		7,200,000,000					
	November	5		9,000,000,000					
	December	5		9,000,000,000					
2	January	6	10,676,000,000,000	10,800,000,000	183,600,000,000	1,334,500,000,000	432,253,952,460	183,600,000,000	237,600,000,000
	February	6		10,800,000,000					
	March	7		12,600,000,000					
	April	7		12,600,000,000					
	May	8		14,400,000,000					
	June	8		14,400,000,000					
	July	9		16,200,000,000					
	August	9		16,200,000,000					
	September	10		18,000,000,000					
	October	10		18,000,000,000					
	November	11		19,800,000,000					
	December	11		19,800,000,000					
3	January	12	10,492,400,000,000	21,600,000,000	313,200,000,000	1,311,550,000,000	432,253,952,460	313,200,000,000	550,800,000,000
	February	12		21,600,000,000					
	March	13		23,400,000,000					
	April	13		23,400,000,000					
	May	14		25,200,000,000					
	June	14		25,200,000,000					
	July	15		27,000,000,000					
	August	15		27,000,000,000					
	September	16		28,800,000,000					
	October	16		28,800,000,000					
	November	17		30,600,000,000					
	December	17		30,600,000,000					
4	January-December	18	10,179,200,000,000	32,400,000,000	388,800,000,000	1,272,400,000,000	432,253,952,460	388,800,000,000	939,600,000,000
5	January-December	18	9,790,400,000,000	32,400,000,000	388,800,000,000	1,223,800,000,000	432,253,952,460	388,800,000,000	1,328,400,000,000
6	January-December	18	9,401,600,000,000	32,400,000,000	388,800,000,000	1,175,200,000,000	432,253,952,460	388,800,000,000	1,717,200,000,000
7	January-December	18	9,012,800,000,000	32,400,000,000	388,800,000,000	1,126,600,000,000	432,253,952,460	388,800,000,000	2,106,000,000,000
8	January-December	18	8,624,000,000,000	32,400,000,000	388,800,000,000	1,078,000,000,000	432,253,952,460	388,800,000,000	2,494,800,000,000
9	January-December	18	8,235,200,000,000	32,400,000,000	388,800,000,000	1,029,400,000,000	432,253,952,460	388,800,000,000	2,883,600,000,000
10	January-December	18	7,846,400,000,000	32,400,000,000	388,800,000,000	980,800,000,000	432,253,952,460	388,800,000,000	3,272,400,000,000
11	January-December	18	7,457,600,000,000	32,400,000,000	388,800,000,000	932,200,000,000	432,253,952,460	388,800,000,000	3,661,200,000,000
12	January-December	18	7,068,800,000,000	32,400,000,000	388,800,000,000	883,600,000,000	432,253,952,460	388,800,000,000	4,050,000,000,000
13	January-December	18	6,680,000,000,000	32,400,000,000	388,800,000,000	835,000,000,000	432,253,952,460	388,800,000,000	4,438,800,000,000
14	January-December	18	6,291,200,000,000	32,400,000,000	388,800,000,000	786,400,000,000	432,253,952,460	388,800,000,000	4,827,600,000,000
15	January-December	18	5,902,400,000,000	32,400,000,000	388,800,000,000	737,800,000,000	432,253,952,460	388,800,000,000	5,216,400,000,000
16	January-December	18	5,513,600,000,000	32,400,000,000	388,800,000,000	689,200,000,000	432,253,952,460	388,800,000,000	5,605,200,000,000
17	January-December	18	5,124,800,000,000	32,400,000,000	388,800,000,000	640,600,000,000	432,253,952,460	388,800,000,000	5,994,000,000,000
18	January-December	18	4,736,000,000,000	32,400,000,000	388,800,000,000	592,000,000,000	432,253,952,460	388,800,000,000	6,382,800,000,000
19	January-December	18	4,347,200,000,000	32,400,000,000	388,800,000,000	543,400,000,000	432,253,952,460	388,800,000,000	6,771,600,000,000
20	January-December	18	3,958,400,000,000	32,400,000,000	388,800,000,000	494,800,000,000	432,253,952,460	388,800,000,000	7,160,400,000,000
21	January-December	18	3,569,600,000,000	32,400,000,000	388,800,000,000	446,200,000,000	432,253,952,460	388,800,000,000	7,549,200,000,000
22	January-December	18	3,180,800,000,000	32,400,000,000	388,800,000,000	397,600,000,000	432,253,952,460	388,800,000,000	7,938,000,000,000
23	January-December	18	2,792,000,000,000	32,400,000,000	388,800,000,000	349,000,000,000	432,253,952,460	349,000,000,000	8,287,000,000,000
24	January-December	18	2,443,000,000,000	32,400,000,000	388,800,000,000	305,375,000,000	432,253,952,460	305,375,000,000	8,592,375,000,000
25	January-December	18	2,137,625,000,000	32,400,000,000	388,800,000,000	267,203,125,000	432,253,952,460	267,203,125,000	8,859,578,125,000
26	January-December	18	1,870,421,875,000	32,400,000,000	388,800,000,000	233,802,734,375	432,253,952,460	233,802,734,375	9,093,380,859,375
27	January-December	18	1,636,619,140,625	32,400,000,000	388,800,000,000	204,577,392,578	432,253,952,460	204,577,392,578	9,297,958,251,953
28	January-December	18	1,432,041,748,047	32,400,000,000	388,800,000,000	179,005,218,506	432,253,952,460	179,005,218,506	9,476,963,470,459
29	January-December	18	1,253,036,529,541	32,400,000,000	388,800,000,000	156,629,566,193	432,253,952,460	156,629,566,193	9,633,593,036,652
30	January-December	18	1,096,406,963,348	32,400,000,000	388,800,000,000	137,050,870,419	432,253,952,460	137,050,870,419	9,770,643,907,070
31	January-December	18	959,356,092,930	32,400,000,000	388,800,000,000	119,919,511,616	432,253,952,460	119,919,511,616	9,890,563,418,686
32	January-December	18	839,436,581,314	32,400,000,000	388,800,000,000	104,929,572,664	432,253,952,460	104,929,572,664	9,995,492,991,351
33	January-December	18	734,507,008,649	32,400,000,000	388,800,000,000	91,813,376,081	432,253,952,460	91,813,376,081	10,087,306,367,432
34	January-December	18	642,693,632,568	32,400,000,000	388,800,000,000	80,336,704,071	432,253,952,460	80,336,704,071	10,167,643,071,503
35	January-December	18	562,356,928,497	32,400,000,000	388,800,000,000	70,294,616,062	432,253,952,460	70,294,616,062	10,237,937,687,565
36	January-December	18	492,062,312,435	32,400,000,000	388,800,000,000	61,507,789,054	432,253,952,460	61,507,789,054	10,299,445,476,619
37	January-December	18	430,554,523,381	32,400,000,000	388,800,000,000	53,819,315,423	432,253,952,460	53,819,315,423	10,353,264,792,042
38	January-December	18	376,735,207,958	32,400,000,000	388,800,000,000	47,091,900,995	432,253,952,460	47,091,900,995	10,400,356,693,037
39	January-December	18	329,643,306,963	32,400,000,000	388,800,000,000	41,205,413,370	432,253,952,460	41,205,413,370	10,441,562,106,407
40	January-December	18	288,437,893,593	32,400,000,000	388,800,000,000	36,054,736,699	432,253,952,460	36,054,736,699	10,477,616,843,106
41	January-December	18	252,383,156,894	32,400,000,000	388,800,000,000	31,547,894,612	432,253,952,460	31,547,894,612	10,509,164,737,718
42	January-December	18	220,835,262,282	32,400,000,000	388,800,000,000	27,604,407,785	432,253,952,460	27,604,407,785	10,536,769,145,503
43	January-December	18	193,230,854,497	32,400,000,000	388,800,000,000	24,153,856,812	432,253,952,460	24,153,856,812	10,560,923,002,315
44	January-December	18	169,076,997,685	32,400,000,000	388,800,000,000	21,134,624,711	432,253,952,460	21,134,624,711	10,582,057,627,026
45	January-December	18	147,942,372,974	32,400,000,000	388,800,000,000	18,492,796,622	432,253,952,460	18,492,796,622	10,600,550,423,648
46	January-December	18	129,449,576,352	32,400,000,000	388,800,000,000	16,181,197,044	432,253,952,460	16,181,197,044	10,616,731,620,692
47	January-December	18	113,268,379,308	32,400,000,000	388,800,000,000	14,158,547,414	432,253,952,460	14,158,547,414	10,630,890,168,105
48	January-December	18	99,109,831,895	32,400,000,000	388,800,000,000	12,388,728,987	432,253,952,460	12,388,728,987	10,643,278,897,092
49	January-December	18	86,721,102,908	32,400,000,000	388,800,000,000	10,840,137,863	432,253,952,460	10,840,137,863	10,654,119,034,956
50	January-December	18	75,880,965,044	32,400,000,000	388,800,000,000	9,485,120,631	432,253,952,460	9,485,120,631	10,663,604,155,586

Condensate Production

Year	Month	Remaining Recoverable Volumes (bbl)	Constraint 01: Production Rate per Month (bbl)	Constraint 01: Production Rate per Year (bbl)	Constraint 02: Total Production Rate per Year (bbl)	Constraint 03: FLNG Capacity (bbl)	Production per Year (bbl)	Cummulative Production (bbl)	Revenue Gas USD	Revenue Condensate USD	Total Revenue USD	Operating Cost USD	Net Cash Flow USD	Cummulative NCF USD
1	January	209,000,000	-	1,223,000	26,125,000	8,927,900	1,223,000	1,223,000	431,892,000	73,380,000	505,272,000	135,000,000	370,272,000	370,272,000
	February		-											
	March		40,766.7											
	April		40,766.7											
	May		81,533.3											
	June		81,533.3											
	July		122,300.0											
	August		122,300.0											
	September		163,066.7											
	October		163,066.7											
	November		203,833.3											
	December		203,833.3											
2	January	207,777,000	244,600.0	4,158,200	25,972,125	8,927,900	4,158,200	5,381,200	1,468,432,800	249,492,000	1,717,924,800	459,000,000	1,258,924,800	1,629,196,800
	February		244,600.0											
	March		285,366.7											
	April		285,366.7											
	May		326,133.3											
	June		326,133.3											
	July		366,900.0											
	August		366,900.0											
	September		407,666.7											
	October		407,666.7											
	November		448,433.3											
	December		448,433.3											
3	January	203,618,800	489,200.0	7,093,400	25,452,350	8,927,900	7,093,400	12,474,600	2,504,973,600	425,604,000	2,930,577,600	783,000,000	2,147,577,600	3,776,774,400
	February		489,200.0											
	March		529,966.7											
	April		529,966.7											
	May		570,733.3											
	June		570,733.3											
	July		611,500.0											
	August		611,500.0											
	September		652,266.7											
	October		652,266.7											
	November		693,033.3											
	December		693,033.3											
4	January-December	196,525,400	733,800.0	8,805,600	24,565,675	8,927,900	8,805,600	21,280,200	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	6,442,732,800
5	January-December	187,719,800	733,800.0	8,805,600	23,464,975	8,927,900	8,805,600	30,085,800	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	9,108,691,200
6	January-December	178,914,200	733,800.0	8,805,600	22,364,275	8,927,900	8,805,600	38,891,400	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	11,774,649,600
7	January-December	170,108,600	733,800.0	8,805,600	21,263,575	8,927,900	8,805,600	47,697,000	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	14,440,608,000
8	January-December	161,303,000	733,800.0	8,805,600	20,162,875	8,927,900	8,805,600	56,502,600	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	17,106,566,400
9	January-December	152,497,400	733,800.0	8,805,600	19,062,175	8,927,900	8,805,600	65,308,200	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	19,772,524,800
10	January-December	143,691,800	733,800.0	8,805,600	17,961,475	8,927,900	8,805,600	74,113,800	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	22,438,483,200
11	January-December	134,886,200	733,800.0	8,805,600	16,860,775	8,927,900	8,805,600	82,919,400	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	25,104,441,600
12	January-December	126,080,600	733,800.0	8,805,600	15,760,075	8,927,900	8,805,600	91,725,000	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	27,770,400,000
13	January-December	117,275,000	733,800.0	8,805,600	14,659,375	8,927,900	8,805,600	100,530,600	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	30,436,358,400
14	January-December	108,469,400	733,800.0	8,805,600	13,558,675	8,927,900	8,805,600	109,336,200	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	33,102,316,800
15	January-December	99,663,800	733,800.0	8,805,600	12,457,975	8,927,900	8,805,600	118,141,800	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	35,768,275,200
16	January-December	90,858,200	733,800.0	8,805,600	11,357,275	8,927,900	8,805,600	126,947,400	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	38,434,233,600
17	January-December	82,052,600	733,800.0	8,805,600	10,256,575	8,927,900	8,805,600	135,753,000	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	41,100,192,000
18	January-December	73,247,000	733,800.0	8,805,600	9,155,875	8,927,900	8,805,600	144,558,600	3,109,622,400	528,336,000	3,637,958,400	972,000,000	2,665,958,400	43,766,150,400
19	January-December	64,441,400	733,800.0	8,805,600	8,055,175	8,927,900	8,055,175	152,613,775	3,109,622,400	483,310,500	3,592,932,900	972,000,000	2,620,932,900	46,387,083,300
20	January-December	56,386,225	733,800.0	8,805,600	7,048,278	8,927,900	7,048,278	159,662,053	3,109,622,400	422,896,688	3,532,519,088	972,000,000	2,560,519,088	48,947,602,388
21	January-December	49,337,947	733,800.0	8,805,600	6,167,243	8,927,900	6,167,243	165,829,296	3,109,622,400	370,034,602	3,479,657,002	972,000,000	2,507,657,002	51,455,259,389
22	January-December	43,170,704	733,800.0	8,805,600	5,396,338	8,927,900	5,396,338	171,225,634	3,109,622,400	323,780,276	3,433,402,676	972,000,000	2,461,402,676	53,916,662,065
23	January-December	37,774,366	733,800.0	8,805,600	4,721,796	8,927,900	4,721,796	175,947,430	2,791,302,000	283,307,742	3,074,609,742	872,500,000	2,202,109,742	56,118,771,807
24	January-December	33,052,570	733,800.0	8,805,600	4,131,571	8,927,900	4,131,571	180,079,001	2,442,389,250	247,894,274	2,690,283,524	763,437,500	1,926,846,024	58,045,617,831
25	January-December	28,920,999	733,800.0	8,805,600	3,615,125	8,927,900	3,615,125	183,694,126	2,137,090,594	216,907,490	2,353,998,084	668,007,813	1,685,990,271	59,731,608,102
26	January-December	25,305,874	733,800.0	8,805,600	3,163,234	8,927,900	3,163,234	186,857,360	1,869,954,270	189,794,054	2,059,748,323	584,506,836	1,475,241,487	61,206,849,590
27	January-December	22,142,640	733,800.0	8,805,600	2,767,830	8,927,900	2,767,830	189,625,190	1,636,209,986	166,069,797	1,802,279,783	511,443,481	1,290,836,301	62,497,685,891
28	January-December	19,374,810	733,800.0	8,805,600	2,421,851	8,927,900	2,421,851	192,047,042	1,431,683,738	145,311,072	1,576,994,810	447,513,046	1,129,481,764	63,627,167,655
29	January-December	16,952,958	733,800.0	8,805,600	2,119,120	8,927,900	2,119,120	194,166,161	1,252,723,270	127,147,188	1,379,870,459	391,573,915	988,296,543	64,615,464,198
30	January-December	14,833,839	733,800.0	8,805,600	1,854,230	8,927,900	1,854,230	196,020,391	1,096,132,862	111,253,790	1,207,386,651	342,627,176	864,759,475	65,480,223,673
31	January-December	12,979,609	733,800.0	8,805,600	1,622,451	8,927,900	1,622,451	197,642,842	959,116,254	97,347,066	1,056,463,320	299,798,779	756,664,541	66,236,888,214
32	January-December	11,357,158	733,800.0	8,805,600	1,419,645	8,927,900	1,419,645	199,062,487	839,226,722	85,178,683	924,405,405	262,323,932	662,081,473	66,898,969,687
33	January-December	9,937,513	733,800.0	8,805,600	1,242,189	8,927,900	1,242,189	200,304,676	734,323,382	74,531,347	808,854,729	229,533,440	579,321,289	67,478,290,976
34	January-December	8,695,324	733,800.0	8,805,600	1,086,915	8,927,900	1,086,915	201,391,592	642,532,959	65,214,929	707,747,888	200,841,760	506,906,128	67,985,197,104
35	January-December	7,608,408	733,800.0	8,805,600	951,051	8,927,900	951,051	202,342,643	562,216,339	57,063,063	619,279,402	175,736,540	443,542,862	68,428,739,966
36	January-December	6,657,357	733,800.0	8,805,600	832,170	8,927,900	832,170	203,174,812	491,939,297	49,930,180	541,869,477	153,769,473	388,100,004	68,816,839,970
37	January-December	5,825,188	733,800.0	8,805,600	728,148	8,927,900	728,148	203,902,961	430,446,885	43,688,908	474,135,792	134,548,289	339,587,504	69,156,427,474
38	January-December	5,097,039	733,800.0	8,805,600	637,130	8,927,900	637,130	204,540,091	376,641,024	38,227,794	414,868,818	117,729,752	297,139,066	69,453,566,540
39	January-December	4,459,909	733,800.0	8,805,600	557,489	8,927,900	557,489	205,097,579	329,560,896	33,449,320	363,010,216	103,013,533	259,996,683	69,713,563,222
40	January-December	3,902,421	733,800.0	8,805,600	487,803	8,927,900	487,803	205,585,382	288,365,784	29,268,155	317,633,939	90,136,842	227,497,097	69,941,060,320
41	January-December	3,414,618	733,800.0	8,805,600	426,827	8,927,900	426,827	206,012,209	252,320,061	25,609,635	277,929,697	78,869,737	199,059,960	70,140,120,280
42	January-December	2,987,791	733,800.0	8,805,600	373,474	8,927,900	373,474	206,385,683	220,780,053	22,408,431	243,188,485	69,011,019	174,177,465	70,314,297,745
43	January-December	2,614,317	733,800.0	8,805,600	326,790	8,927,900	326,790	206,712,473	193,182,547	19,607,377	212,789,924	60,384,642	152,405,282	70,466,703,027
44	January-December	2,287,527	733,800.0	8,805,600	285,941	8,927,900	285,941	206,998,414	169,034,728	17,156,455	186,191,183	52,836,562	133,354,622	70,600,057,648
45	January-December	2,001,586	733,800.0	8,805,600	250,198	8,927,900	250,198	207,248,612	147,905,387	15,011,898	162,917,286	46,231,992	116,685,294	70,716,742,942
46	January-December	1,751,388	733,800.0	8,805,600	218,924	8,927,900	218,924	207,467,535	129,417,214	13,135,411	142,552,625	40,452,993	102,099,632	70,818,842,574
47	January-December	1,532,465	733,800.0	8,805,600	191,558	8,927,900	191,558	207,659,093	113,240,062	11,493,485	124,733,547	35,396,369	89,337,178	70,908,179,753
48	January-December	1,340,907	733,800.0	8,805,600	167,613	8,927,900	167,613	207,826,707	99,085,054	10,056,799	109,141,853	30,971,822	78,170,031	70,986,349,784
49	January-December	1,173,293	733,800.0	8,805,600	146,662	8,927,900	146,662	207,973,368	86,699,423	8,799,699	95,499,122	27,100,345	68,398,777	71,054,748,561
50	January-December	1,026,632	733,800.0	8,805,600	128,329	8,927,900	128,329	208,101,697	75,861,995	7,699,737	83,561,731	23,712,802	59,848,930	71,114,597,491

Appendix B – Economic Model

B.1 Economic Model Calculation – Offshore Concept

Pre-tax Net Present Value of the Offshore Concept Based on 10% Discount Rate

CAPEX Well	834	mil.USD
CAPEX Facilities	20,661	mil.USD
Annual Operating Cost	20	mil.USD
Operating Cost	1.2	USD/MCF
	0.0012	USD/cubic feer
LNG Transportation Cost	0.70	USD/MCF
	0.0007	USD/cubic feer
Condensate Transportation Cost	5.50	USD/ bbl
LNG Price	7.75	USD/mmbtu
	0.00755	USD/cubic feet
Condensate Price	60	USD/bbl
Discount Rate	10%	

Input
Assumption
Calculation Result

Production Year	Year	Production		Outcome Cost					Income		Net Cash Flow	Cummulative NPV	Discount Factor	Discounted Present Value	Cummulative Discounted Present Value
		Production of Gas	Production of Condensate	CAPEX Facilities	CAPEX Well	Annual Operation	Tariff for LNG Transport	Tariff for Condensate Transport	LNG Production	Condensate Production					
		MCF	bbl	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD		mil.USD	mil.USD
	2017										0	0			0
	2018										0	0			0
	2019			1,033							(1,033)	(1,033)		(1,033)	(1,033)
	2020			3,099							(3,099)	(4,132.28)		(3,099)	(4,132)
	2021			4,132							(4,132)	(8,264.55)		(4,132)	(8,265)
	2022			10,331							(10,331)	(18,595.24)		(10,331)	(18,595)
	2023			2,066							(2,066)	(20,661.38)		(2,066)	(20,661)
1	2024	54,000	1,223,000		278	85	38	6.73	407	73	74	(20,587.69)	0.909	66.99	(20,594)
2	2025	183,600	4,158,200		278	240	129	22.87	1,385	249	965	(19,622.28)	0.826	797.86	(19,797)
3	2026	313,200	7,093,400		278	396	219	39.01	2,363	426	1,857	(17,765.14)	0.751	1,395.29	(18,401)
4	2027	360,212	8,805,600			452	252	48.43	2,718	528	2,494	(15,271.39)	0.683	1,703.27	(16,698)
5	2028	360,212	8,805,600			452	252	48.43	2,718	528	2,494	(12,777.64)	0.621	1,548.42	(15,150)
6	2029	360,212	8,805,600			452	252	48.43	2,718	528	2,494	(10,283.89)	0.564	1,407.66	(13,742)
7	2030	360,212	8,805,600			452	252	48.43	2,718	528	2,494	(7,790.14)	0.513	1,279.69	(12,462)
8	2031	360,212	8,805,600			452	252	48.43	2,718	528	2,494	(5,296.39)	0.467	1,163.35	(11,299)
9	2032	360,212	8,805,600			452	252	48.43	2,718	528	2,494	(2,802.64)	0.424	1,057.59	(10,241)
10	2033	360,212	8,805,600			452	252	48.43	2,718	528	2,494	(308.89)	0.386	961.45	(9,280)
11	2034	360,212	8,805,600			452	252	48.43	2,718	528	2,494	2,184.87	0.350	874.04	(8,406)
12	2035	360,212	8,805,600			452	252	48.43	2,718	528	2,494	4,678.62	0.319	794.59	(7,611)
13	2036	360,212	8,805,600			452	252	48.43	2,718	528	2,494	7,172.37	0.290	722.35	(6,889)
14	2037	360,212	8,805,600			452	252	48.43	2,718	528	2,494	9,666.12	0.263	656.68	(6,232)
15	2038	360,212	8,805,600			452	252	48.43	2,718	528	2,494	12,159.87	0.239	596.98	(5,635)
16	2039	360,212	8,805,600			452	252	48.43	2,718	528	2,494	14,653.62	0.218	542.71	(5,092)
17	2040	360,212	8,805,600			452	252	48.43	2,718	528	2,494	17,147.37	0.198	493.38	(4,599)
18	2041	360,212	8,805,600			452	252	48.43	2,718	528	2,494	19,641.12	0.180	448.52	(4,151)
19	2042	360,212	8,055,175			452	252	44.30	2,718	483	2,453	22,093.97	0.164	401.06	(3,749)
20	2043	360,212	7,048,278			452	252	38.77	2,718	423	2,398	24,491.95	0.149	356.44	(3,393)
21	2044	360,212	6,167,243			452	252	33.92	2,718	370	2,350	26,841.91	0.135	317.55	(3,075)
22	2045	360,212	5,396,338			452	252	29.68	2,718	324	2,308	29,149.85	0.123	283.52	(2,792)
23	2046	360,212	4,721,796			452	252	25.97	2,718	283	2,271	31,421.04	0.112	253.64	(2,538)
24	2047	360,212	4,131,571			452	252	22.72	2,718	248	2,239	33,660.05	0.102	227.32	(2,311)
25	2048	326,844	3,615,125			412	229	19.88	2,466	217	2,022	35,682.52	0.092	186.67	(2,124)

NPV	**(2,311)**	**mil.USD**
IRR	**-1%**	
Payback Period	**Never**	
Break Even Price	**8.60**	**USD/mmbtu**

B.1 Economic Model Calculation – Onshore Concept

Pre-tax Net Present Value of the Onshore Concept Based on 10% Discount Rate

CAPEX Well	834	mil.USD
CAPEX Facilities	14,573	mil.USD
Annual Operating Cost	10	mil.USD
Operating Cost	1.1	USD/MCF
	0.0011	USD/cubic feer
LNG Transportation Cost	0.70	USD/MCF
	0.0007	USD/cubic feer
Condensate Transportation Cost	5.50	USD/ bbl
LNG Price	7.75	USD/mmbtu
	0.00755	USD/cubic feet
Condensate Price	60	USD/bbl
Discount Rate	10%	

Input
Assumption
Calculation Result

Production Year	Year	Production: Production of Gas	Production: Production of Condensate	Outcome Cost: CAPEX Facilities	Outcome Cost: CAPEX Well	Outcome Cost: Annual Operation	Outcome Cost: Tariff for LNG Transport	Outcome Cost: Tariff for Condensate Transport	Income: LNG Production	Income: Condensate Production	Net Cash Flow	Cummulative NPV	Discount Factor	Discounted Present Value	Cummulative Discounted Present Value
		MCF	bbl	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD	mil.USD		mil.USD	mil.USD
	2017										0	0		0	0
	2018										0	0		0	0
	2019										0	0		0	0
	2020										0	0		0	0
	2021			729							(729)	(728.65)		(729)	(729)
	2022			2,186							(2,186)	(2,914.62)		(2,186)	(2,915)
	2023			4,372							(4,372)	(7,286.54)		(4,372)	(7,287)
	2024			5,829							(5,829)	(13,115.77)		(5,829)	(13,116)
	2025			1,457							(1,457)	(14,573.08)		(1,457)	(14,573)
1	2026	54,000	1,223,000		278	69	38	6.73	407	73	89	(14,483.99)	0.909	80.99	(14,492)
2	2027	183,600	4,158,200		278	212	129	22.87	1,385	249	994	(13,490.22)	0.826	821.30	(13,671)
3	2028	313,200	7,093,400		278	355	219	39.01	2,363	426	1,898	(11,591.76)	0.751	1,426.34	(12,244)
4	2029	388,800	8,805,600			438	272	48.43	2,934	528	2,704	(8,887.71)	0.683	1,846.90	(10,398)
5	2030	388,800	8,805,600			438	272	48.43	2,934	528	2,704	(6,183.66)	0.621	1,679.00	(8,719)
6	2031	388,800	8,805,600			438	272	48.43	2,934	528	2,704	(3,479.62)	0.564	1,526.36	(7,192)
7	2032	388,800	8,805,600			438	272	48.43	2,934	528	2,704	(775.57)	0.513	1,387.60	(5,805)
8	2033	388,800	8,805,600			438	272	48.43	2,934	528	2,704	1,928.48	0.467	1,261.46	(4,543)
9	2034	388,800	8,805,600			438	272	48.43	2,934	528	2,704	4,632.53	0.424	1,146.78	(3,396)
10	2035	388,800	8,805,600			438	272	48.43	2,934	528	2,704	7,336.57	0.386	1,042.53	(2,354)
11	2036	388,800	8,805,600			438	272	48.43	2,934	528	2,704	10,040.62	0.350	947.75	(1,406)
12	2037	388,800	8,805,600			438	272	48.43	2,934	528	2,704	12,744.67	0.319	861.59	(544)
13	2038	388,800	8,805,600			438	272	48.43	2,934	528	2,704	15,448.72	0.290	783.27	239
14	2039	388,800	8,805,600			438	272	48.43	2,934	528	2,704	18,152.77	0.263	712.06	951
15	2040	388,800	8,805,600			438	272	48.43	2,934	528	2,704	20,856.81	0.239	647.33	1,598
16	2041	388,800	8,805,600			438	272	48.43	2,934	528	2,704	23,560.86	0.218	588.48	2,187
17	2042	388,800	8,805,600			438	272	48.43	2,934	528	2,704	26,264.91	0.198	534.98	2,722
18	2043	388,800	8,805,600			438	272	48.43	2,934	528	2,704	28,968.96	0.180	486.35	3,208
19	2044	388,800	8,055,175			438	272	44.30	2,934	483	2,663	31,632.11	0.164	435.45	3,643
20	2045	388,800	7,048,278			438	272	38.77	2,934	423	2,608	34,240.38	0.149	387.70	4,031
21	2046	388,800	6,167,243			438	272	33.92	2,934	370	2,560	36,800.64	0.135	345.97	4,377
22	2047	388,800	5,396,338			438	272	29.68	2,934	324	2,518	39,318.88	0.123	309.36	4,686
23	2048	349,000	4,721,796			394	244	25.97	2,634	283	2,253	41,571.66	0.112	251.59	4,938
24	2049	305,375	4,131,571			346	214	22.72	2,304	248	1,970	43,541.59	0.102	200.00	5,138
25	2050	267,203	3,615,125			304	187	19.88	2,016	217	1,722	45,264.03	0.092	158.97	5,297

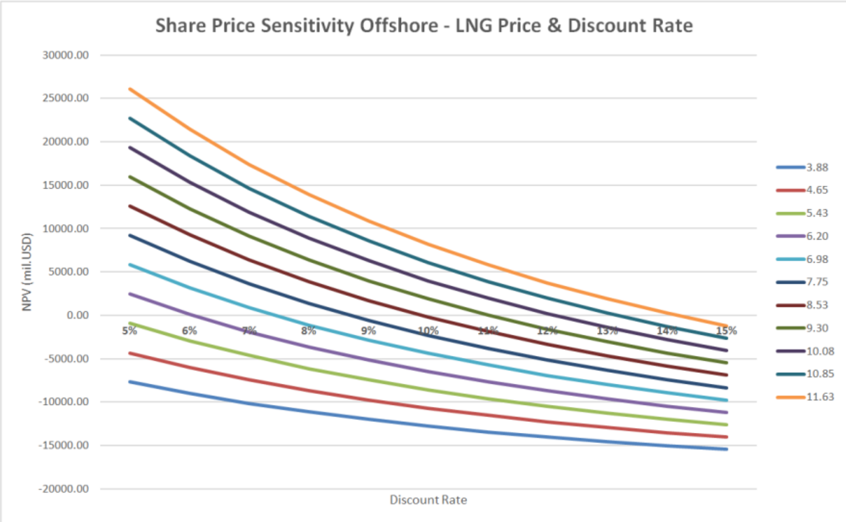
NPV	**4686.47**	**mil.USD**
IRR	**3%**	
Payback Period	**12.8**	**Years**
reak Even Price (LNG)	**6.08**	**USD/mmbtu**

Appendix C – Sensitivity Analysis

C.1 Sensitivity Analysis – Offshore Concept – NPV

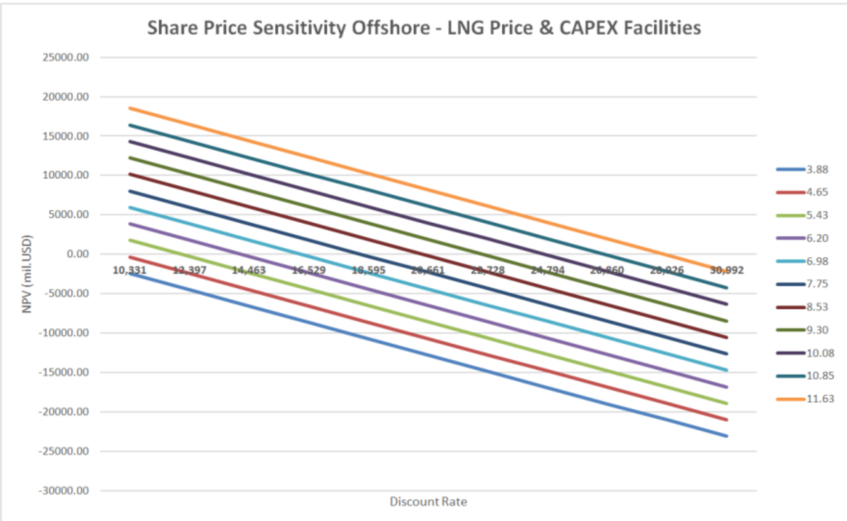
Share Price Sensitivity (NPV) (LNG Price & Discount Rate)

Discount Rate	LNG Price (USD/mmbtu) 3.88	4.65	5.43	6.20	6.98	7.75	8.53	9.30	10.08	10.85	11.63
5%	-7685.11	-4327.70	-926.69	2430.72	5831.73	9189.14	12590.15	15947.56	19348.57	22705.98	26106.99
6%	-9006.00	-5980.55	-2915.80	109.66	3174.40	6199.86	9264.60	12290.06	15354.81	18380.26	21445.01
7%	-10149.77	-7411.22	-4637.12	-1898.58	875.53	3614.07	6388.18	9126.72	11900.82	14639.36	17413.47
8%	-11144.40	-8654.97	-6133.21	-3643.78	-1122.02	1367.41	3889.17	6378.60	8900.36	11389.79	13911.55
9%	-12012.96	-9740.78	-7439.10	-5166.92	-2865.23	-593.05	1708.63	3980.81	6282.50	8554.67	10856.36
10%	-12774.53	-10692.64	-8583.71	-6501.82	-4392.90	-2311.01	-202.08	1879.81	3988.74	6070.63	8179.56
11%	-13444.94	-11530.42	-9591.05	-7676.53	-5737.16	-3822.64	-1883.27	31.25	1970.62	3885.14	5824.51
12%	-14037.37	-12270.68	-10481.06	-8714.37	-6924.75	-5158.06	-3368.44	-1601.75	187.87	1954.56	3744.18
13%	-14562.84	-12927.25	-11270.41	-9634.82	-7977.98	-6342.39	-4685.55	-3049.96	-1393.12	242.48	1899.31
14%	-15030.62	-13511.72	-11973.09	-10454.19	-8915.56	-7396.66	-5858.03	-4339.13	-2800.50	-1281.60	257.03
15%	-15448.50	-14033.86	-12600.85	-11186.22	-9753.21	-8338.58	-6905.57	-5490.93	-4057.92	-2643.29	-1210.28



Share Price Sensitivity (NPV) (LNG Price & Discount Rate)

CAPEX Facilities (mil.USD)	LNG Price (USD/mmbtu) 3.88	4.65	5.43	6.20	6.98	7.75	8.53	9.30	10.08	10.85	11.63
10,331	-2444.15	-362.26	1746.67	3828.56	5937.48	8019.37	10128.30	12210.19	14319.12	16401.01	18509.94
12,397	-4510.15	-2428.26	-319.33	1762.56	3871.48	5953.37	8062.30	10144.19	12253.12	14335.01	16443.94
14,463	-6576.15	-4494.26	-2385.33	-303.44	1805.48	3887.37	5996.30	8078.19	10187.12	12269.01	14377.94
16,529	-8642.15	-6560.26	-4451.33	-2369.44	-260.52	1821.37	3930.30	6012.19	8121.12	10203.01	12311.94
18,595	-10708.15	-8626.26	-6517.33	-4435.44	-2326.52	-244.63	1864.30	3946.19	6055.12	8137.01	10245.94
20,661	-12774.15	-10692.26	-8583.33	-6501.44	-4392.52	-2310.63	-201.70	1880.19	3989.12	6071.01	8179.94
22,728	-14841.15	-12759.26	-10650.33	-8568.44	-6459.52	-4377.63	-2268.70	-186.81	1922.12	4004.01	6112.94
24,794	-16907.15	-14825.26	-12716.33	-10634.44	-8525.52	-6443.63	-4334.70	-2252.81	-143.88	1938.01	4046.94
26,860	-18973.15	-16891.26	-14782.33	-12700.44	-10591.52	-8509.63	-6400.70	-4318.81	-2209.88	-127.99	1980.94
28,926	-21039.15	-18957.26	-16848.33	-14766.44	-12657.52	-10575.63	-8466.70	-6384.81	-4275.88	-2193.99	-85.06
30,992	-23105.15	-21023.26	-18914.33	-16832.44	-14723.52	-12641.63	-10532.70	-8450.81	-6341.88	-4259.99	-2151.06



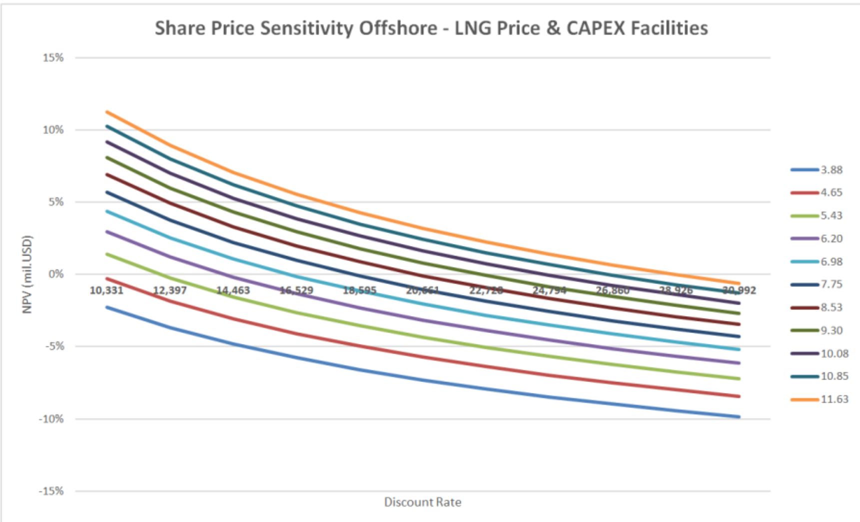
C.2 Sensitivity Analysis – Offshore Concept – IRR

Share Price Sensitivity (IRR) (LNG Price & Discount Rate)

Discount Rate	LNG Price (USD/mmbtu) 3.88	4.65	5.43	6.20	6.98	7.75	8.53	9.30	10.08	10.85	11.63
5%	-3%	-2%	0%	1%	2%	3%	4%	5%	6%	7%	7%
6%	-4%	-3%	-1%	0%	1%	2%	3%	4%	5%	6%	6%
7%	-5%	-3%	-2%	-1%	0%	1%	2%	3%	4%	5%	6%
8%	-6%	-4%	-3%	-2%	0%	1%	2%	2%	3%	4%	5%
9%	-7%	-5%	-4%	-2%	-1%	0%	1%	2%	2%	3%	4%
10%	-7%	-6%	-4%	-3%	-2%	-1%	0%	1%	2%	2%	3%
11%	-8%	-6%	-5%	-4%	-3%	-2%	-1%	0%	1%	2%	2%
12%	-9%	-7%	-6%	-5%	-4%	-3%	-2%	-1%	0%	1%	2%
13%	-9%	-8%	-7%	-5%	-4%	-3%	-2%	-2%	-1%	0%	1%
14%	-10%	-9%	-7%	-6%	-5%	-4%	-3%	-2%	-1%	-1%	0%
15%	-11%	-9%	-8%	-7%	-6%	-5%	-4%	-3%	-2%	-1%	-1%

Share Price Sensitivity (IRR) (LNG Price & Discount Rate)

CAPEX Facilities (mil.USD)	LNG Price (USD/mmbtu) 3.88	4.65	5.43	6.20	6.98	7.75	8.53	9.30	10.08	10.85	11.63
10,331	-2%	0%	1%	3%	4%	6%	7%	8%	9%	10%	11%
12,397	-4%	-2%	0%	1%	3%	4%	5%	6%	7%	8%	9%
14,463	-5%	-3%	-2%	0%	1%	2%	3%	4%	5%	6%	7%
16,529	-6%	-4%	-3%	-1%	0%	1%	2%	3%	4%	5%	6%
18,595	-7%	-5%	-4%	-2%	-1%	0%	1%	2%	3%	3%	4%
20,661	-7%	-6%	-4%	-3%	-2%	-1%	0%	1%	2%	2%	3%
22,728	-8%	-6%	-5%	-4%	-3%	-2%	-1%	0%	1%	2%	2%
24,794	-8%	-7%	-6%	-5%	-4%	-3%	-2%	-1%	0%	1%	1%
26,860	-9%	-8%	-6%	-5%	-4%	-3%	-2%	-2%	-1%	0%	1%
28,926	-9%	-8%	-7%	-6%	-5%	-4%	-3%	-2%	-1%	-1%	0%
30,992	-10%	-8%	-7%	-6%	-5%	-4%	-3%	-3%	-2%	-1%	-1%



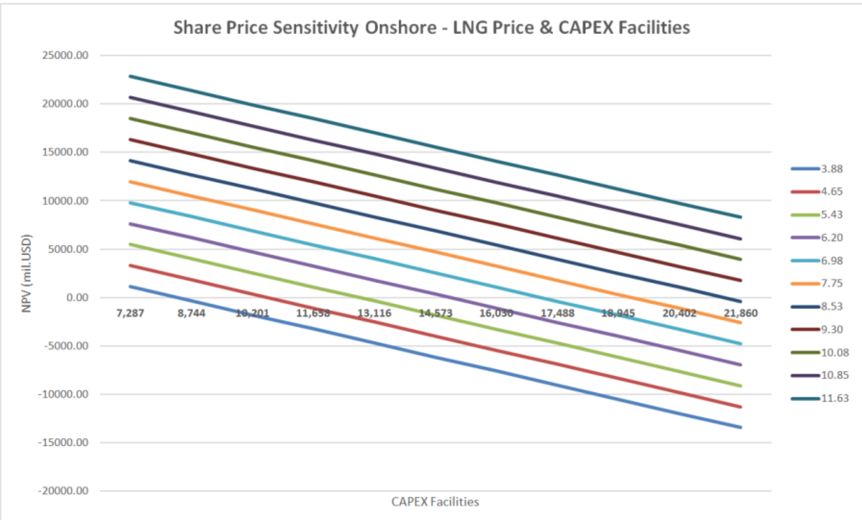
C.3 Sensitivity Analysis – Onshore Concept – NPV

Share Price Sensitivity (NPV) (LNG Price & Discount Rate)

Discount Rate	LNG Price (USD/mmbtu) 3.88	4.65	5.43	6.20	6.98	7.75	8.53	9.30	10.08	10.85	11.63
5%	-1020.82	2388.69	5842.48	9251.99	12705.78	16115.29	19569.08	22978.59	26432.38	29841.89	33295.68
6%	-2339.30	749.56	3878.53	6967.39	10096.37	13185.22	16314.20	19403.06	22532.03	25620.89	28749.86
7%	-3489.79	-680.62	2165.03	4974.19	7819.84	10629.01	13474.66	16283.83	19129.48	21938.64	24784.29
8%	-4497.45	-1933.20	664.35	3228.60	5826.16	8390.41	10987.96	13552.21	16149.76	18714.01	21311.56
9%	-5383.24	-3034.28	-654.81	1694.16	4073.63	6422.59	8802.06	11151.03	13530.50	15879.46	18258.93
10%	-6164.70	-4005.68	-1818.62	340.39	2527.45	4686.47	6873.53	9032.54	11219.60	13378.62	15565.67
11%	-6856.52	-4865.70	-2849.03	-858.22	1158.46	3149.27	5165.94	7156.76	9173.43	11164.24	13180.91
12%	-7471.06	-5629.72	-3764.47	-1923.13	-57.88	1783.46	3648.71	5490.05	7355.30	9196.64	11061.89
13%	-8018.77	-6310.73	-4580.50	-2872.46	-1142.24	565.80	2296.02	4004.07	5734.29	7442.33	9172.55
14%	-8508.48	-6919.71	-5310.30	-3721.53	-2112.12	-523.35	1086.05	2674.83	4284.23	5873.00	7482.41
15%	-8947.69	-7465.99	-5965.04	-4483.33	-2982.39	-1500.68	0.27	1481.97	2982.92	4464.63	5965.58

Share Price Sensitivity (NPV) (LNG Price & CAPEX Facilities)

CAPEX Facilities (mil.USD)	LNG Price (USD/mmbtu) 3.88	4.65	5.43	6.20	6.98	7.75	8.53	9.30	10.08	10.85	11.63
7,287	1121.84	3280.86	5467.92	7626.93	9813.99	11973.01	14160.07	16319.08	18506.14	20665.16	22852.21
8,744	-335.47	1823.55	4010.61	6169.63	8356.68	10515.70	12702.76	14861.77	17048.83	19207.85	21394.91
10,201	-1792.78	366.24	2553.30	4712.32	6899.37	9058.39	11245.45	13404.47	15591.52	17750.54	19937.60
11,658	-3250.08	-1091.07	1095.99	3255.01	5442.07	7601.08	9788.14	11947.16	14134.22	16293.23	18480.29
13,116	-4707.39	-2548.37	-361.32	1797.70	3984.76	6143.78	8330.83	10489.85	12676.91	14835.93	17022.98
14,573	-6164.70	-4005.68	-1818.62	340.39	2527.45	4686.47	6873.53	9032.54	11219.60	13378.62	15565.67
16,030	-7622.01	-5462.99	-3275.93	-1116.91	1070.14	3229.16	5416.22	7575.23	9762.29	11921.31	14108.37
17,488	-9079.32	-6920.30	-4733.24	-2574.22	-387.17	1771.85	3958.91	6117.93	8304.98	10464.00	12651.06
18,945	-10536.62	-8377.61	-6190.55	-4031.53	-1844.47	314.54	2501.60	4660.62	6847.68	9006.69	11193.75
20,402	-11993.93	-9834.91	-7647.86	-5488.84	-3301.78	-1142.76	1044.29	3203.31	5390.37	7549.39	9736.44
21,860	-13451.24	-11292.22	-9105.16	-6946.15	-4759.09	-2600.07	-413.01	1746.00	3933.06	6092.08	8279.13



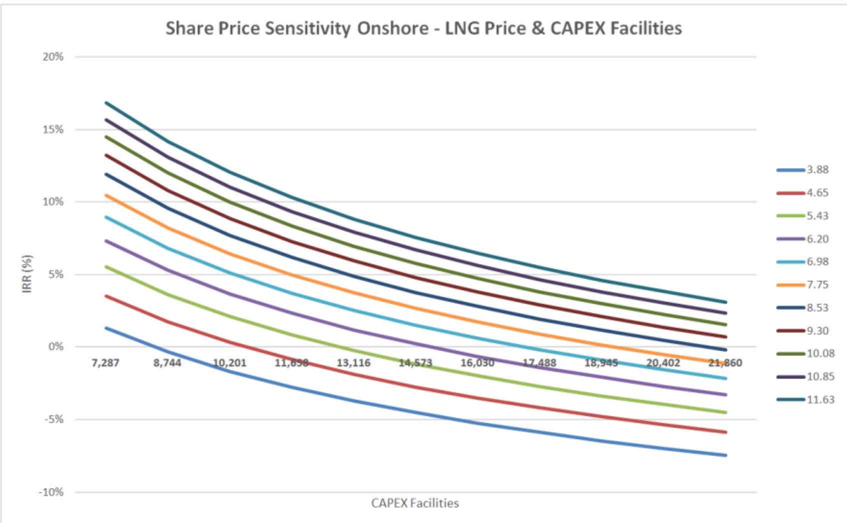
C.3 Sensitivity Analysis – Onshore Concept – IRR

Share Price Sensitivity (IRR) (LNG Price & Discount Rate)

	LNG Price (USD/mmbtu)										
Discount Rate	3.88	4.65	5.43	6.20	6.98	7.75	8.53	9.30	10.08	10.85	11.63
5%	-1%	1%	3%	4%	6%	7%	8%	9%	10%	11%	12%
6%	-1%	0%	2%	3%	5%	6%	7%	8%	9%	10%	11%
7%	-2%	0%	1%	3%	4%	5%	6%	7%	8%	9%	10%
8%	-3%	-1%	0%	2%	3%	4%	5%	6%	7%	8%	9%
9%	-4%	-2%	0%	1%	2%	3%	5%	6%	7%	7%	8%
10%	-5%	-3%	-1%	0%	1%	3%	4%	5%	6%	7%	8%
11%	-5%	-4%	-2%	-1%	1%	2%	3%	4%	5%	6%	7%
12%	-6%	-4%	-3%	-1%	0%	1%	2%	3%	4%	5%	6%
13%	-7%	-5%	-3%	-2%	-1%	0%	1%	2%	3%	4%	5%
14%	-7%	-6%	-4%	-3%	-2%	0%	1%	2%	3%	4%	4%
15%	-8%	-6%	-5%	-4%	-2%	-1%	0%	1%	2%	3%	4%

Share Price Sensitivity (IRR) (LNG Price & CAPEX Facilities)

	LNG Price (USD/mmbtu)										
CAPEX Facilities (mil.USD)	3.88	4.65	5.43	6.20	6.98	7.75	8.53	9.30	10.08	10.85	11.63
7,287	1%	4%	6%	7%	9%	10%	12%	13%	14%	16%	17%
8,744	0%	2%	4%	5%	7%	8%	10%	11%	12%	13%	14%
10,201	-2%	0%	2%	4%	5%	6%	8%	9%	10%	11%	12%
11,658	-3%	-1%	1%	2%	4%	5%	6%	7%	8%	9%	10%
13,116	-4%	-2%	0%	1%	3%	4%	5%	6%	7%	8%	9%
14,573	-5%	-3%	-1%	0%	1%	3%	4%	5%	6%	7%	8%
16,030	-5%	-4%	-2%	-1%	1%	2%	3%	4%	5%	6%	6%
17,488	-6%	-4%	-3%	-1%	0%	1%	2%	3%	4%	5%	5%
18,945	-6%	-5%	-3%	-2%	-1%	0%	1%	2%	3%	4%	5%
20,402	-7%	-5%	-4%	-3%	-2%	-1%	0%	1%	2%	3%	4%
21,860	-7%	-6%	-4%	-3%	-2%	-1%	0%	1%	2%	2%	3%



Appendix D – Hazard Identification

No	Location	Event	Cause	Consequence	PoF	CoF	Risk Reducing Measure
1	Separator Area	Fracture or fatigue equipment on separation area	Lack of proper maintenance	- Lower LNG quality - Damage on Equipment	2	C	Periodic inspection, condition monitoring, preventive maintenance, calibration
2	CO_2 Treatment Area	Damage on CO_2 absorber	Pressure and temperature is higher than standard.	- Explosion on absorber - Lower LNG quality - Contaminants can cause damage to other equipment	2	C	Periodic inspection, condition monitoring, preventive maintenance, calibration
3	Turbine Gas Unit	Explosion on Turbine Gas Unit	Failure of turbine and rotor blades	Fatal injury Shutdown on production	3	E	Periodic inspection, condition monitoring, preventive maintenance, calibration
4	Generator	Fire Explosion	Short Circuit	Fatal injury Shutdown on production	2	E	Isolation, protection, periodic inspection
5	Water Cooling Area	Fire Explosion Water overflows	Pressure and temperature and higher than standard.	Fatal injury Shutdown on production	3	E	periodic inspection, condition monitoring, preventive maintenance, install valve protection
6	LNG Storage	Fire Explosion	Pressure Tank regulator is not working properly. Pressure is higher than standard.	Fatal injury Shutdown on production Loss of production	4	E	periodic inspection, condition monitoring, preventive maintenance
7	Flaring Area	Fire Explosion Damage on Equipment	Flare location too close to process equipment - Processing area too close to accommodation	Severe injury Stop production	2	D	Arrangement of flares away from processes and accommodation Arrangement of flares consider the factor of wind direction
8	Loading Ship	LNG spill during offloading process	- Human error - Harsh weather (wave, wind)	Environmental pollution Loss of production	2	D	- Proper training for crews - Follow standard operational procedure