NATURAL GAS INFRASTRUCTURE IN INDONESIA

MODELLING OPTIONS FROM DOMESTIC SUPPLY & EXPORT

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Natural Gas Infrastructure in Indonesia: Modelling options from domestic supply and export

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Preface

This report is the result of six months of research. It is written as a thesis to attain a master degree in System Engineering, Policy Analysis and Management (SEPAM) at Delft University of Technology. It was started with my ambition to raise a topic of discussion about energy sector in Southeast Asia and particularly, in Indonesia. During my preliminary research, I found that there was a cross-border gas pipelines master plan, called Trans-ASEAN Gas Pipelines (TAGP), proposed by the ASEAN Council on Petroleum (ASCOPE). Besides gas pipelines, the region also actively develops LNG infrastructure to facilitate LNG export and import trades. These aroused my curiosity about the projects, especially to know whether these two gas infrastructure master plans (i.e. TAGP and LNG infrastructure) could facilitate the regional (within Southeast Asia) and international gas trades in the future. At the end (which was actually the start of this research), I decided to focus on the development of gas infrastructure and gas market in Southeast Asia.

I would like to express my deepest gratitude to my God, Jesus Christ, for all His grace, favor, and blessings upon my life. When a lot of things in this world are uncertain, I know that His love and promises are always certain. To my family, Papa and Mama, and also my brothers, thank you for your endless love, support, and prayers. To Andrian Chandra, thank you for your love, patience and support for the last two years.

I would also thank my graduation committee, Prof. Weijnen, Dr. Correljé, and Dr. de Vries, for their time to review my work with all comments and feedbacks that were really constructive and helpful. I did enjoy all meetings with them. They encouraged me to think outside of my simple model and be dare to cover broader issues so that I could present a profound analysis. Last but not least, to my best friends in SEPAM program (Denise, Yae Jin, Yi Wen, Dong Zhe, and Michael), and Indonesian friends from PPI Delft, for sharing the ups and downs. Thanks a lot guys!

This report is aimed to give a better understanding of the Southeast Asian gas market, and in particular, to help the Indonesian government in developing its gas sector. Finally, I hope the readers will enjoy reading this report.

Delft, June 2015

Yuliana
Summary

Gas producing countries in Southeast Asia, i.e. Indonesia, Malaysia, and Brunei have been known as major LNG exporters to the Northeast Asian countries such as Japan, South Korea, China, and Taiwan. Within the Southeast Asian region, natural gas is traded and transported via gas pipelines. Several cross-border gas pipelines have been constructed to deliver gas from countries with more gas supplies or reserves to countries that are short of gas supplies. Among the ASEAN policy makers, the plan to expand the gas pipeline connections is known as Trans-ASEAN gas pipeline or TAGP. Currently 12 gas pipeline connections have been in operation and according to the TAGP master plan from the ASCOPE (ASEAN Council on Petroleum), there are four possible routes for new gas pipeline connections from East Natuna, e.g. to Java (Indonesia), Kerteh (Malaysia), Erawan (Thailand), and Vietnam.

Besides gas pipelines, there are also several LNG infrastructures built throughout the region. LNG liquefaction plants are mainly located in the three LNG exporting countries. Meanwhile, the LNG regasification terminals can be found not only in the gas consuming countries or countries with no gas reserves, but also in the gas producing countries, especially Indonesia and Malaysia. This is due to their geography of scattered islands which makes transporting gas via pipelines less favorable. In this case, the regasification capacities are mainly used to handle domestic gas supplies from distant supply sites. Several liquefaction and regasification facilities are proposed to be built in the upcoming years as reported by the IEA and ERIA.

After being major LNG exporters for the last four decades, the gas producing countries are confronted with depleting gas resources. The whole region is facing a similar trend of increasing domestic gas consumption and a decline in domestic gas production that creates a problem of security of gas supply. As mentioned before, several projects to expand the natural gas infrastructures in Southeast Asia have been proposed. However, uncertainties such as the amount of proven gas reserves, future growth of domestic natural gas demand, gas pricing mechanism, and changes in national energy or gas policy have caused a stagnation, especially for the TAGP project. Nowadays, the ASEAN policy makers are doubtful whether or not to proceed with the TAGP project, especially the Indonesian government who owns the East Natuna gas field. Policy makers in each ASEAN member state also have to decide whether to support the TAGP project or focus on the development of their own LNG projects.

In the Indonesian case, particularly, the government will face a dilemma between allocation of natural gas for domestic needs and allocation for exports. Allocating more natural gas for domestic needs will reduce the government income. However, it is expected that the benefits from domestic allocation, e.g. industrial and city gas development, could offset the revenue losses from export.

This leads to the following research question:

What infrastructure investment strategy should be pursued by the Indonesian government to facilitate domestic gas supply and maximize profit from gas sales?
A model-based approach is used to answer this research question, combining the use of gas network model on the basis of linear programming and options valuation models with simple ‘adjusted’ discounted cash-flow (DCF) and real options techniques to value the infrastructure options. ‘Adjusted’ because the DCF follows the cost structure (e.g. cost recovery mechanism, profit sharing, tax) of each production sharing contract (PSC) in each particular gas project.

Two scenarios are developed in the gas network model, the Business-as-Usual (BAU) and the Reference scenario. In the BAU scenario, according to estimates from the BPPT, gas production in Indonesia will decline after 2017 with a rate of 4.14% from 2018 to 2023 and 3.80% from 2023 to 2045 while the domestic gas consumption is assumed to grow at 2.20% per annum. In this scenario, Indonesia could not extend any long term gas export contracts. In the Reference scenario, on the other hand, the Indonesian gas production will grow constantly at 0.50% per annum. The domestic consumption in this Reference scenario is assumed to be 2.70% per annum. In the Reference scenario, it is possible for Indonesia to export its gas and this could affect the future plans of gas network expansion in its neighboring countries, especially Singapore and Thailand because Indonesia could be their potential supplier. The growth of natural gas production and consumption in other countries is based on projections by the IEA.

The results of the gas network model show that the current plans are hardly sufficient to meet natural gas demand especially in Indonesia, Thailand, and Singapore, and therefore, need to be revised. Indonesia in particular, according to the BAU Scenario, will need to expand its regasification capacity by 5.45 bcm in 2035 and 31.30 bcm in 2045. This is mainly due to its declining gas production and growing gas consumption. In this scenario, Indonesia cannot export its gas anymore and all gas production from East Natuna will be needed to meet Indonesian domestic gas demand. Therefore, there will be only one gas pipeline connection, i.e. from East Natuna to Java (or other demand centers in Indonesia).

In the Reference Scenario,

- Indonesia could still export pipelined gas or LNG, given that its production will grow 0.5% per annum. New regasification capacity is not needed at least until 2044. However, this amount has not included the capacities used to manage domestic LNG supplies. In practice, additional regasification capacities might be needed especially when the domestic demands start to grow.

- Indonesia could export its gas production from East Natuna to Thailand either in the form of LNG or pipelined gas. When the trend of the Indonesian gas production is uncertain, an onshore LNG plant in East Natuna could become an option. When the production trend shows as such in the Reference scenario, the gas pipeline from East Natuna to Erawan, Thailand could be built.

- Indonesia and Singapore might agree to extend the existing pipelined gas supplies or build a gas pipeline extension to connect East Natuna gas field to the West Natuna-Singapore gas pipeline. This could support the Singaporean goal to become an Asian gas hub as there will be an alternative of gas supplies (outside LNG). Singapore could also defer the expansion of its regasification terminal up to 2040.
Several policy recommendations are addressed to the Indonesian government as follows:

**Upstream related (Production Sharing Contract)**
- Establish criteria for negotiable PSC variables such as profit sharing, tax holiday, and contract duration in a more transparent way.
- Review the minimum domestic market obligation. The government especially will have to increase the minimum DMO if the production declines as such in the BAU scenario. Another option is by giving a restricted condition, i.e. export is allowed after domestic demand has been fulfilled.
- Reduce CAPEX volatility by enforcing local content requirements, e.g. labors and materials in the PSC to develop other economic sectors. However, the government should put more effort in order to ensure the compliance and quality of the materials’ composition and labors’ expertise to the International standards that are widely accepted.

**Export/import contracts**
The government should conduct a study to better anticipate the impact of new pricing mechanism, i.e. hybrid pricing or hub pricing, to its existing institutions setting, especially export and import contracts. Based on the results of the options valuation, the onshore LNG plants in Abadi and East Natuna are not economically viable to be built when the gas selling prices follow the low gas price scenario. To reduce the gas price volatility, Indonesia could use following pricing mechanisms for its export contracts if they will be signed within the upcoming five to ten years:
- JCC pricing with price floor and price ceiling
- Fixed price (could be with n% escalation every t years) to ensure the new projects will be break-even with additional profit margin
For import contracts, Indonesia could use the hybrid model (mixed JCC and HH index), especially if the sources of LNG supply come from the US. Otherwise, the same pricing mechanisms as in the export contracts could be used.

**Downstream related**
- Give minimum or no subsidy for domestic gas price to prevent heavy burden in the future as in the case of the oil subsidy. The subsidies could be allocated to other incentives that could grow the domestic gas market and increase natural gas utilization in Indonesia.
- Focus on developing downstream gas infrastructures. The government should put off the plan to liberalize national gas market in order to create a conducive business climate for the state-owned companies to build the infrastructures. The government could maintain the status quo for the upcoming 2 to 3 years. If the realization is less than expected or the state-owned companies do not have sufficient resources (e.g. financial, human or expertise) to realize the plan, then the government could push on with the liberalization, given that the multi-national companies (or foreign investors) will help to build the infrastructures and transfer the ownership to the state after t years, depending on the agreement.
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<tbody>
<tr>
<td>BAU</td>
<td>Business-as-Usual (Scenario)</td>
</tr>
<tr>
<td>BCM</td>
<td>Billion cubic meter</td>
</tr>
<tr>
<td>CIF</td>
<td>Cost, Insurance, Freight</td>
</tr>
<tr>
<td>DCF</td>
<td>Discounted Cash Flow</td>
</tr>
<tr>
<td>DMO</td>
<td>Domestic Market Obligation</td>
</tr>
<tr>
<td>FEED</td>
<td>Front-end engineering design</td>
</tr>
<tr>
<td>FTP</td>
<td>First Tranche Petroleum</td>
</tr>
<tr>
<td>GSA</td>
<td>Gas Sales Agreement</td>
</tr>
<tr>
<td>JCC</td>
<td>Japan Crude Cocktail</td>
</tr>
<tr>
<td>MCF</td>
<td>Million cubic feet</td>
</tr>
<tr>
<td>MMBtu</td>
<td>Million Metric British thermal units</td>
</tr>
<tr>
<td>MMcfd</td>
<td>Million cubic feet per day</td>
</tr>
<tr>
<td>MTPA</td>
<td>Million tons per annum</td>
</tr>
<tr>
<td>PSC</td>
<td>Production Sharing Contract</td>
</tr>
<tr>
<td>REF</td>
<td>Reference (Scenario)</td>
</tr>
<tr>
<td>ROA</td>
<td>Real Options Analysis</td>
</tr>
<tr>
<td>ROW</td>
<td>Right of Way</td>
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<tr>
<td>TCF</td>
<td>Trillion cubic feet</td>
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1 Introduction

1.1 BACKGROUND

1.1.1 Gas Infrastructures in Southeast Asia

Countries in Southeast Asia through a regional cooperation called ASEAN (Association of South East Asia Nations) have established cooperation in various sectors including energy. In 1975, the Organization of Petroleum Exporting Countries (OPEC) convinced ASEAN to create a petroleum council (also known as ASEAN Council on Petroleum - ASCOPE) that manages dedicated programs towards promoting and coordinating energy research, and addressing energy-related problems (Sovacool, 2009). One of the plans put forward by the ASCOPE is Trans-ASEAN Gas Pipeline (TAGP) to connect gas infrastructure within Southeast Asia. The first cross-border gas pipeline in the ASEAN region was commissioned in 1991 to export gas from Malaysia to Singapore (Roberts & Cull, 2003). Since then, several cross-border gas pipelines have been constructed and new likely TAGP connections are proposed to be built to increase the interconnection capacity within the ASEAN. Figure 1.1 shows the master plan of the TAGP project. Further expansion of the TAGP will depend on the ability to develop East Natuna gas field in Indonesia, which is estimated to contain 46 trillion cubic feet (tcf) of gas reserves (ACE, 2013).

![Figure 1.1 Map of Trans-ASEAN Gas Pipeline](source: ASCOPE from ACE (2013))

Pipelined natural gas (PNG) is a preferable option when transporting large volumes of natural gas over relatively short distances. Offshore pipelining (sub-sea and deep-sea pipelining) is usually more costly than onshore pipelining, mainly due to its locations that are more difficult to reach and consequently, more effort and expertise (i.e. technologies) are required to construct and install the pipelines. In
some regions, such as Japan, however, the right of way (ROW)¹ for onshore pipelining is difficult and costly to acquire (Jensen, 2011). This could lead to higher costs for onshore pipelining than offshore pipelining. When transporting natural gas via pipelines is unfeasible, LNG could become an option. Generally, LNG is chosen when the location between the production site and market is distant (e.g. over 2000 kilometers) or the production site is located in a political unstable region (Dijkema & Praet, 2014).

Some authors argue that investments in LNG offer a much lower degree of specificity than pipelines (Dorigoni, Graziano, & Pontoni, 2010). Even though the investments in LNG infrastructure are usually based on long-term contracts, the buyers might opt to other more convenient suppliers when the contracts are expired. Meanwhile, in the pipeline cases, the physical assets cannot be moved (Kumar et al., 2011). The pipelines also encounter problems when are faced with different gas quality and different pressure or flow rate at each cross-border grid (Kumar et al., 2011; Sovacool, 2009).

According to a report from the ASEAN Center of Energy (ACE, 2013), the Southeast Asian region will face depletion of available indigenous piped gas resources with a widening supply-demand gap around 10.7 billion square cubic feet per day in 2030. Increasing domestic gas demand and inability of domestic (or regional) gas production to meet the demand have led some Southeast Asian countries to develop LNG regasification terminals. In addition, there are also some projects to expand LNG liquefaction plants (e.g. Tangguh LNG in Indonesia and Malaysian LNG – MLNG Bintulu) and build floating LNG facilities in Indonesia and Malaysia. Figure 1.2 shows the existing and planned LNG infrastructures in Southeast Asia.

Figure 1.2 LNG infrastructures in Southeast Asia
Source: IEA and ERIA (2013)

¹ Right of way is the legal right that should be acquired by one party to pass along a specific route (in this case to construct and operate gas pipelines) through grounds or property owned by other parties.
1.1.2 Energy Policy

For the last decades, the notion of 3A objectives of the energy policy (Availability, Affordability, and Acceptability) has been widely used including in the ASEAN energy cooperation (ACE, 2013). In his energy policy needs pyramid, Frei (2004) uses terms ‘security of supply’, ‘cost efficiency’, and ‘social acceptability’ that have similar meanings with availability, affordability, and acceptability (or sustainability). In the pyramid, Frei (2004) adds two goals: access to commercial energy and natural resources efficiency. The efficiency of natural resources can be grouped together with social acceptability to measure the sustainability. He adopts the Maslow’s hierarchy of needs and puts the energy policy goals in a pyramid as shown in figure 1.3.

As can be seen in figure 1.3, the two lowest goals in the pyramid are not debatable because energy should be seen as a basic need for people and thus, it is the responsibility of the government to provide means (i.e. infrastructures) to fulfill the need. This leads to an interesting dynamic in the ASEAN whether each member state has the same policy goals’ orientation or not and at which level. Singapore for example, is known as the most developed country in Southeast Asia. The electrification rate in Singapore is 100% while in Indonesia, it is 94% at urban areas and 56% at rural areas (IEA, 2012). This might lead to a different focus of energy policy at each country. Indonesia will have to focus more on access to energy for its citizens, while Singapore, should maintain the security of supply and increase the cost efficiency.

![Energy policy needs pyramid](Frei, 2004)

In the Indonesian case, particularly, the government will face a dilemma between allocation of natural gas for domestic needs and allocation for exports. Allocating more natural gas for domestic needs will reduce the government income. In 2014, oil and gas sector contributed 19.58% of the total income earned by the Indonesian government (CNN-Indonesia, 2015; Ministry-of-Finance, 2014). On the other hand, allocating more natural gas for domestic needs will support the growth of industrial sectors (e.g. chemical, fertilizer), increase electrification rate through new gas fired power plants, and reduce dependence on oil (as fuel substitution for transportation sector). Some studies (LKI, 2013; Tjandranegara, 2012) were conducted to measure the trade-offs, revealed in a more positive contribution for the whole economy if the natural gas is allocated for domestic needs.
1.2 RESEARCH PROBLEM

1.2.1 Uncertainties in Southeast Asian gas market

All decisions about investments are difficult because there are always uncertainties that involve future technology developments, the market in the future, particularly in the distant future, as well as returns in the future (Heuvelhof, 2008). Some major uncertainties in and around the Southeast Asian gas market have been identified as follows:

**Regional proven reserves**

Currently, the TAGP project is waiting for the development of East Natuna gas field. Sovacool (2009) states that, “The amount of natural gas reserves, naturally, serves as the bedrock for any decision to build a pipeline”. The estimates of gas reserves available in each Southeast Asian country are questionable since different surveyors might give different numbers. For instance, British Petroleum’s (BP) Statistical Review reports that Thailand has 12.5 tcf of gas, while the U.S. Energy Information Administration (EIA) gives estimation twice as large as 22.9 tcf (Sovacool, 2009). The significant differences among the estimates cause more uncertainties for both policy makers and also gas investors because the value of the gas field will depend on the amount of its reserves. Investors or gas companies want to know the value of the gas field before they invest. Policy makers or regulators also want to know the value of the gas fields in their territory so that they could gain revenues as much as possible through the contract agreements.

**Unconventional gas resource**

The findings of shale gas in the U.S. has led many countries such as China, Australia, Canada, and also Indonesia to develop shale gas within their territory. However, in the Indonesian case, it is still uncertain. The first possible shale gas resource has been tendered in 2013 and the government still has to wait for coming years to see the progress. Another gas source, coal-bed methane (CBM) also can be found in Indonesia. Currently, it is still under development. If all unconventional gas resources could be developed, Indonesia in particular could be the center (or the main supplier) for the gas market in Southeast Asia. However, it is less likely to happen at least in the next 20 years or until the applications of both technologies (CBM and shale gas) are proven to be successful in Indonesia. According to an estimate from the Indonesian Center of Energy Resources Development Technology (BPPT, 2014), the contribution of the unconventional gas resource in Indonesia is expected to be 0.2 bcf in 2016 and 74 bcf (approximately 2.1 bcm) in 2035.

**Growth in regional gas demand**

EIA scenario predicts that in the Non-OECD countries, gas demand will grow 2.2% annually from 2013 to 2040 (EIA, 2013c). However, in the Asian Development Bank (ADB) scenario, it is estimated that the growth in Asia Pacific region (both OECD and non-OECD) will be 3.9% per annum through 2035 (ADB, 2013) which is almost twice the EIA scenario. This difference causes an uncertainty since the EIA also states that the Non-OECD countries will have higher growth compared to the OECD countries.

**Changes in national policy orientation or regional market reform**

Some national regulations might change. For instance, the government of Indonesia has considered not to extend the long-term contracts for LNG export in line with its aim to promote gas utilization domestically (Thompson, 2006). Indonesia, Malaysia, and Thailand are in the process to deregulate
their gas markets and bring more competition (Wu, 2011). However, it is still uncertain when it will be achieved and the impacts for the gas markets during the transition phase.

Oil-linked gas pricing and international gas trade
Changes in the oil price can change the gas price since most of the long-term gas contracts still use oil indexation. Any changes that are made regarding the gas pricing mechanism will affect the market and thus, affect investment decisions because the potential revenues are changed based on the price change.

The development of LNG has made it possible to deliver gas from the U.S. market to the Asian market. The findings of shale gas in the U.S. cause significant changes for the international gas trade because the gas price in the U.S. are much lower nowadays. These lead the Southeast Asian countries, e.g. Singapore and Indonesia to buy LNG from the U.S. (Gronholt-Pedersen, 2014; Gronholt-Pedersen & Tan, 2014). Major LNG importers, e.g. Japan and South Korea could also diversify their LNG supplies and thus reduce their dependency on the supplies from the Southeast Asian LNG exporters. Australia and Papua New Guinea are planning (EIA, 2013c; Wood, 2012) to explore their gas resources and could be dominant suppliers for the Asian gas market in the future.

1.2.2 Knowledge Gaps
The way the uncertainties could affect the future gas supply and demand within Southeast Asian region have not been discussed extensively in the literatures. The impact of different energy (gas) policies’ objectives to the gas projects (gas pipeline and LNG) in Southeast Asia is unknown. Therefore, the future gas market in Southeast Asian, either via pipedline gas or LNG, is still blurred.

1.2.3 Problem Definition
Several projects to expand the natural gas infrastructures in Southeast Asia have been proposed (ACE, 2013). However, the uncertainties in the Southeast Asian gas market have caused a stagnation, especially for the TAGP project. Nowadays, the ASEAN policy makers are doubtful whether or not to proceed with the TAGP project, especially the Indonesian government who owns the East Natuna gas field. Policy makers in each of the Member States also have to decide whether to support the TAGP project or focus on the development of their own LNG projects. High sunk cost of the investment in gas infrastructure, dominant trade agreements with long-term contracts and increasing use of flexible destination clause in long term LNG contracts make the policy makers really need to consider the long-term investment strategy carefully.

1.2.4 Scope
This research will focus on the two lowest policy goals in Frei’s energy policy needs pyramid, i.e. providing access to natural gas and securing natural gas supply. Two master plans of gas infrastructure expansion, i.e. TAGP and ASEAN LNG facilities will be evaluated to see whether the current proposed plans are sufficient to manage gas supplies needed in each ASEAN member state.

In particular, this research will raise a case study from the perspective of the Indonesian government. This is due to the fact that the East Natuna gas field, which is the main source for the completion of TAGP is located within the territory of Indonesia.
1.3 SOCIAL AND SCIENTIFIC RELEVANCE

In 2009, natural gas had 11.1% share of final energy consumption in Asia and the Pacific, and was projected to increase at 3.9% per year (ADB, 2013). No matter what the growth percentage is, all literatures agree that natural gas will be the fastest-growing fuel among other fossil fuels (ADB, 2013; EIA, 2013c; IEA & ERIA, 2013). Southeast Asian countries, such as Indonesia, Malaysia, and Brunei are known as major LNG exporters, especially to Northeast Asian countries such as Japan, South Korea, China, and Taiwan. Meanwhile, other countries who have less (or no) gas reserves, are in urgency to build a reliable gas infrastructure to meet their demands, e.g. Singapore and Thailand. The gas exporting countries also have declared that they will reduce the amount of exported gas or even not extending the long term contracts. Therefore, any investment decisions that are made regarding gas infrastructure in Southeast Asia will bring significant effect for the development of gas market domestically, within the region, and globally.

From scientific point of view, this research contributes to the understanding of the current gas market in Southeast Asia and its future development. The gas market and its network of gas infrastructures will be represented in a model. The model itself will contribute to the real-world application of its domain, i.e. gas network modeling and valuation model. The results could be a reference, not only for the policy makers, but also for researchers and academics to come up with different approaches or criticize the findings.

1.4 RESEARCH OBJECTIVES AND QUESTIONS

The objective of this study is twofold. Its first objective is to understand the current condition of gas markets in Southeast Asia. The second objective is to evaluate the long-term investment strategy for the gas infrastructure, especially in Indonesia, and figure out if any better options might be available and feasible to achieve the policy goals of providing access to natural gas for domestic market and maximizing profit from domestic gas production.

The main research question in this research is:

*What infrastructure investment strategy should be pursued by the Indonesian government to facilitate domestic gas supply and maximize profit from gas sales?*

Following sub-questions are formulated to answer the main research question:

1. What does the future gas supply and demand in Southeast Asia look like?
2. What are the main infrastructure options for matching gas supply and demand in the Indonesian case?
3. What options should be selected to achieve the Indonesian gas policy goals?

1.5 RESEARCH METHOD

A model-based approach will be used in this research. When the model could represent the current condition, it is expected that the model could also represent the future condition. There will be two models built in this research. The first model is a gas network model that represents the gas infrastructures in the Southeast Asian countries. The use of this model is to measure additional
capacity requirement of each gas infrastructure in the future with different scenarios. The output of this model will become the input for the second model, the options valuation model. As indicated by the name, the use of this model is to value each gas infrastructure option. Both models will be built by following a system perspective (Sage & Armstrong, 2000, p. 49) and taking into account the actor, institutions, economic, and technical aspects of the system. Figure 1.4 illustrates the research method used in this research. The way to answer each sub-question will be discussed in more detail in the next paragraphs.

Sub-Question 1: What does the future gas supply and demand in Southeast Asia look like?
To answer this question, a gas network model will be built. The model will represent the gas infrastructures in Southeast Asia. Therefore, information such as natural gas value chain and existing gas infrastructures is needed to build the conceptual design of the model. Furthermore, other information such as existing gas sales agreement, contract duration, pricing mechanism, capacity of the infrastructures, and national energy policy is also needed as inputs and constraints of the model. Afterwards, the model will enter the development phase. In this phase, the conceptual design will be translated into programming codes. The model itself will be built in MATLAB 2014b. When the model has been able to be run, the model should be verified and validated. After that, the model could be developed further through experimental design by changing the values of the parameters or changing the assumptions. In this phase, the uncertainties could be explored in the form of several scenarios. The main output of the model is capacity used and additional capacity requirement of each gas infrastructure.
**Sub-Question 2: What are the main infrastructure options for matching gas supply and demand in the Indonesian case?**

This question will be answered as a part of the definition phase of the second model, the options valuation model. Based on the results of the previous model, the author could know additional capacity requirement of each gas infrastructure. Afterwards, the author will delve into the existing plan of the new (or expansion) gas infrastructures. The definition phase of the second model is slightly different with the first model because for the second model, the author will develop infrastructure options to meet the design requirements which are related to capacity, time, and profit. To develop the infrastructure options, technical and cost information of gas pipeline and LNG facilities are essential. Shareholder analysis, especially their power (represent by their share percentage) and interests is also needed because each gas project will be funded and executed by different group of shareholders. The case of the East Natuna TAGP will essentially need this actor analysis because the project has been postponed for a long time and the composition of the shareholders in the consortium has also changed several times. This analysis could help the Indonesian government in managing the project, especially during the PSC negotiations.

**Sub-Question 3: What options should be selected to achieve the Indonesian gas policy goals?**

To answer this question, the author needs to go through the development and deployment phases of the second model. Each project will be valued individually, and thus there will be several options valuation models. However, all of the models will share same foundation. The differences will be on the cost structure (depending on the production sharing contract - PSC at each gas field), input, and constraints of the model. There will be two options valuation techniques used in this research. First is discounted cash flow that will be adjusted to the cost structure of the PSC, while the second will follow real options approach. Any options selected should be able to support the country, in this case Indonesia, to achieve security of gas supply and maintain the profit from the gas sector. Sensitivity analysis and Monte Carlo Simulation will be performed to observe the performance (indicated by NPV) of the infrastructure options in the uncertain environment which is indicated by different parameter settings.

**1.6 STRUCTURE**

Chapter 2 presents the current gas market condition in Southeast Asia. Historical records of the gas production and consumption will also be showed and could be used to estimate the future growth of both domestic gas supply and demand. In chapter 2, the structure of the common Production Sharing Contract (PSC) will also be discussed, together with the gas pricing mechanism that is used in the Gas Sales Agreement (GSA) or buyer-seller contract. Chapter 3 provides technology and cost information of gas pipeline and LNG infrastructures. Chapter 4 will summarize the literature review of gas network models that have been built at the European level or global (world) level. There will also be a review of the option valuation techniques, especially those that are used in this research, i.e. discounted cash flow (DCF) method and real options valuation (or analysis) method (ROV or ROA can be used interchangeably).

Chapter 5 will explain steps to build the model, started with a conceptual design and followed by model development, model verification, and model validation. Chapter 6 presents scenario planning and also the results after the model being run in each scenario. Chapter 6 also includes a brief analysis
of the future gas network expansion in each Southeast Asian country according to the results of the gas network model.

In chapter 7, each proposed gas project in Indonesia will be discussed, followed by alternative options to develop the projects. This chapter will be dominated by technical and cost analysis of each infrastructure option. Afterwards, each infrastructure option will be valued in chapter 8, based on DCF and ROV techniques. In chapter 9, synthesis of the results and findings from earlier chapters will be presented, followed by discussion in chapter 10. Final conclusions of the research and recommendations for the Indonesian government can be found in chapter 11. The author’s reflection can be found at the end of the report. Figure 1.5 summarizes the structure of the report.

Figure 1.5 Structure of the report
Southeast Asian Gas Market

This chapter will present a general overview of natural gas production and consumption by each Southeast Asian country followed by a discussion of intra (within Southeast Asia) and inter-regional gas trades (mainly with Northeast Asian countries). Gas market regime in the Southeast Asia, including key actors, degree of market opening, structure of production sharing contract (PSC), and gas pricing mechanisms will also be presented in this chapter. Existing and proposed natural gas infrastructures in the region will be presented afterwards. The information presented in this chapter is needed to better understand the current condition of the Southeast Asian gas market.

2.1 GENERAL OVERVIEW

Natural gas is the fastest-growing fossil fuel in the world, expected to increase from 113.0 tcf in 2010 to 185.0 tcf in 2040 (EIA, 2013c). The British Petroleum’s scenario predicts that natural gas will grow 2.0% annually, followed by coal with 1.2%, and oil 0.8% (BP, 2013). Natural gas is often considered to be the “bridging fuel” to a sustainable energy system (Kumar et al., 2011). It is more environmentally attractive because of its lower carbon intensity compared to coal and oil. As in Ratner (2010), natural gas combustion emits about two-thirds less carbon dioxide than coal and one-quarter less than oil when consumed in a typical electric power plant. It also emits less particulate matter, sulfur dioxide, and nitrogen oxides than coal or oil (Ratner, 2010). In addition, it has stronger competitive position among other energy sources because of its abundant resources (especially after the development of unconventional gas resources) and robust production and distribution technologies (EIA, 2013c).

Indonesia, Malaysia and Myanmar are expected to be the main contributors of natural gas production in Southeast Asia (IEA & ERIA, 2013). The IEA (2013) also estimates that a cumulative investment of USD 705 billion is needed for fossil fuel-supply infrastructure over 2013-2035, and nearly two-thirds are going to gas exploration and production, LNG infrastructure and pipelines. It also states that private-foreign investments and expertise will be important to develop the energy sector as many of state-owned energy companies are still limited by the availability of capital and technical capacity.

2.1.1 Natural Gas Proven Reserves

At the end of 2012, Southeast Asia accounted for 3.5% of the total world gas reserves (IEA & ERIA, 2013). The EIA defines ‘proven reserves’ as volumes of natural gas that are based on geological and engineering data and could be reasonably recovered in future years from known reservoirs under existing economic and operating conditions. Figure 2.1 shows the historical record of the amount of proven gas reserves in Southeast Asia from 1980 to 2013. The majority of the gas reserves are located in Indonesia and Malaysia. At the end of 2013, Indonesia had 52% share of the total gas reserves in Southeast Asia, while Malaysia owned around 20%. The rest amount of these gas reserves will depend on the rate of production in each country. The amount also could increase if there are new findings of gas reserves. According to data from the EIA, Philippines also has gas reserves. However, the amount is relatively small (-/+ 0.1 tcm) and it is all used for its domestic needs without any export activities. Other Southeast Asian countries, i.e. Laos, Cambodia, and Singapore do not have any gas reserves. Singapore relies on imported gas to fulfil its domestic consumption. Laos and Cambodia, meanwhile,
do not have any import activities and rely on other sources of energy, e.g. hydro, coal. Therefore, in the next discussion, without any intention to exclude particular countries, the focus will be given on the countries who have significant activities along the natural gas value chain.

![Proven gas resources in Southeast Asia](Data Source: BP Statistics, 2014)

The gas reserves in Indonesia spread throughout the region as shown in figure 2.2. According to the General Directorate of Oil and Gas, Ministry of Energy and Mineral Resources of Indonesia (2012), in 2012, the country had 103.35 tcf proven reserves and 47.35 potential resources. Natuna holds the majority of the reserves. It is also the biggest gas field in Southeast Asia. Currently, the West Natuna gas field has been well developed and is used to export gas to Singapore and Malaysia via subsea pipelines (Offshore-Technology). It is estimated that the East Natuna has more gas reserves than the West Natuna. However, according to the feasibility study by ExxonMobil, the natural gas from East Natuna contains 71% CO₂, which make it too difficult and expensive to be developed. In 2007, the Indonesian government decided to terminate its contract with Exxon, leaving Pertamina (the Indonesian state-owned oil and gas company) in charge (Offshore-Technology).

In Malaysia, natural gas proven reserves can be found in the east cost of Peninsular Malaysia (38%), offshore Sarawak (48%), and offshore Sabah (14%). Approximately 50% of these producing fields are solely operated by Petronas's subsidiary, Petronas Carigali (GasMalaysia). In Myanmar, the major exploration projects are from Yadana, Yetagun, Zawtika (blok M9) and Shwe gas fields. There are also some smaller onshore exploration projects. Gas from Yadana, Yetagun, and Zawtika are exported to Thailand (some small shares are used for domestic consumption) while gas from Shwe is exported to
China (ElevenMyanmar, 2014). Thailand gas reserves are shown in figure 2.3, at joint development areas (JDA), together with Malaysia, e.g. Arthit, Bongkot, and Pailin.

Figure 2.2 Natural gas reserves in Indonesia as of January 2012 (tcf)
Source: DitjenMigas

Figure 2.3 Gas fields in Myanmar, Thailand, and Vietnam (Intellasia, 2011)
Vietnam’s two biggest gas fields, Lan Do and Lan Tay, are located at block 06.1 in Nam Con Son basin (Offshore-Technology). The blocks were discovered in 1992-1993 and account for 30% of natural gas production in Vietnam (Offshore-Technology). The estimated recoverable reserves of these fields are about 170 bcm. There is also a smaller gas field, called Su Tu Rang, which is located at Cuu Long basin and contains 20 bcm of gas reserve (Offshore-Technology). In 2012, Gazprom Group and PetroVietnam signed the Agreement on Gazprom’s involvement in joint development projects for licensed blocks 05.2 and 05.3 offshore Vietnam (Gazprom, 2013). As reported by Gazprom (2013), the blocks are located in the southeastern part of the Vietnamese shelf and two gas and condensate fields – Moc Tinh and Hai Thach – were discovered within the blocks. The expected recoverable reserves of these fields are up to 35.9 bcm of gas and 15.2 million tons of gas condensate (Gazprom, 2013). Figure 2.4 shows the gas fields in the Southern Vietnam.

![Figure 2.4 Gas fields in Southern Vietnam (Offshoreenergytoday, 2012)](image)

The amount of proven gas reverses vary among data released by different organization, e.g. BP Statistics, EIA, or IEA. Table 2.1 shows the gas proven reserves in 2013. There is a significant difference for the amount of proven gas reserves in Malaysia, which is more than double. However, the historical record from the EIA shows no decline for the Malaysian gas proven reserves from 2008 to 2013. On the other side, the historical record from BP statistic shows that the amount of Malaysian gas proven reserves decreased from 2.38 tcm in 2008 to 1.13 tcm in 2009 without any clear explanation for the main reason. The amounts of proven reserves showed by the IEA look like the rounded up version of the EIA data.
Table 2.1 Proven reserves based on BP and EIA publication

<table>
<thead>
<tr>
<th>Country</th>
<th>BP (tcm)</th>
<th>EIA (tcm)</th>
<th>Difference BP and EIA (tcm)</th>
<th>IEA (tcm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thailand</td>
<td>0.2849</td>
<td>0.2849</td>
<td>3.36269E-06</td>
<td>0.3</td>
</tr>
<tr>
<td>Vietnam</td>
<td>0.6171</td>
<td>0.6995</td>
<td>0.082394403</td>
<td>0.7</td>
</tr>
<tr>
<td>Malaysia</td>
<td>1.0914</td>
<td>2.3506</td>
<td>1.259114554</td>
<td>2.4</td>
</tr>
<tr>
<td>Indonesia</td>
<td>2.9265</td>
<td>3.0699</td>
<td>0.14341665</td>
<td>3.1</td>
</tr>
<tr>
<td>Brunei</td>
<td>0.2880</td>
<td>0.3908</td>
<td>0.102816012</td>
<td>0.4</td>
</tr>
<tr>
<td>Myanmar</td>
<td>0.2832</td>
<td>0.2832</td>
<td>3.15053E-05</td>
<td>0.5</td>
</tr>
<tr>
<td>Philippines (excl.)</td>
<td>0.0986</td>
<td>0.0986</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>5.5897</td>
<td>7.1774</td>
<td>1.587701502</td>
<td>7.5</td>
</tr>
</tbody>
</table>

Hereafter, the proven reserves used in the model for this research will be based on the EIA and IEA data. The amount of Myanmar’s proven reserves needs to be adjusted to 511.50 bcm, taking into account the findings block M9 (Offshore-Technology) and Shwe gas fields (estimated to contain 127 to 218 bcm of gas).

2.1.2 Natural Gas Production and Consumption

Production of natural gas in Southeast Asia has been started since 1960s, pioneered by Brunei, Indonesia, and Malaysia. These countries are also known as gas exporters (LNG), mainly to the Northeast Asian countries such as Japan and South Korea. Figure 2.5 shows the production trend of natural gas in Southeast Asia.

![Production per Country](image-url)

*Figure 2.5 Natural gas production in Southeast Asia (1980 – 2013)*

Data Source: BP Statistics, 2014
The highest volume of natural gas production comes from Indonesia, followed by Malaysia and Thailand. The production volumes of these three countries show an increasing growth trend, although since 2010, the production volume of Indonesia has been decreasing. The main cause of the decreasing was the depletion of Arun gas field (Neraca, 2012). Thailand, although included in the top three gas producers, is also known as a gas importer, both from pipelines (from Myanmar) and LNG. This is due to its gas consumptions that are much higher than its productions. The graph in figure 2.5 shows that the production levels of Brunei are relatively stable. Myanmar started its production in 1974, however, the production volumes were much lower compared with Indonesia, Malaysia, and Thailand. The significant rise could be seen around 2000, probably after the agreement to export pipelined gas to Thailand. In the coming years, the production probably would increase since Myanmar will also export its gas to China via pipelines. In Vietnam, up to this time, all productions are used for domestic needs. Vietnam has shown a serious commitment to develop its gas fields, indicated by its cooperation with various multi-national gas companies. Therefore, it might be possible that Vietnam could surpass Myanmar’s and Brunei’s gas production in the future.

Historical data (BP, 2014c) shows that Indonesia has started the consumption of natural gas since 1965. At that time, the amount of consumption was around 0.5 billion cubic meter (bcm). It probably was only used for oil lifting. Malaysia followed afterwards in 1971 with consumption amount of 0.1 bcm. A decade later, in 1981, Thailand started to use natural gas as much as 0.3 bcm and increased to 1.3 bcm a year after. Vietnam started to consume in 1991, followed by Singapore in 1992. Economic and demographic growth in these regions have led to a significant growth of energy consumption. Based on the Business as Usual (BAU) scenario from ASEAN Energy Outlook, the natural gas will grow 3.2% per annum (IEEJ, 2011). The growth is led by industrial sectors and power generation plants that use natural gas as fuel (EIA, 2013c).

The graphical growth of natural gas consumption in these countries can be seen in figure 2.6. Due to the limitation of data available, only consumptions from year 2001 to 2013 are presented in the figure. Thailand has the highest volume of gas consumption, followed by Indonesia and Malaysia. In Thailand, natural gas accounted for more than 31% of the national energy consumption, while in Indonesia, it was 17%, and Malaysia 36% (EIA, 2013a). The total share of Indonesian and Thailand’s gas consumptions are higher than Malaysia’s due to the amount of the populations that are much bigger, and consequently, will have more energy demands. In this (consumption) activity, there is a new ‘player’, i.e. Singapore, who has a significant portion because its consumption is more than Vietnam, Myanmar, and Brunei. This is interesting because Singapore does not have any gas resources, and therefore, it has to rely on imported gas to fulfil the domestic demand.

The comparison of production and consumption level of each country is presented in figure 2.7 (only for the year 2013). The graph clearly shows that for countries who are known as gas exporters, their consumption levels are less than half of their production, except for Indonesia who is slightly higher. Countries who produce less than their consumption, undoubtedly will import from other countries. Some of the excess production from the gas producers in this region are moved to their neighbors.
Figure 2.6 Natural gas consumption in Southeast Asia (2001-2013)
Data Source: BP and EIA Statistics

Figure 2.7 Production and consumption in 2013
Data Source: BP and EIA Statistics
Table 2.2 summarizes the average growth of production and consumption in each country from 2005 to 2013. This short period is selected to adjust fluctuation or significant inclination that happened before 2005 in both natural gas production and consumption profiles.

<table>
<thead>
<tr>
<th>Country</th>
<th>Production growth (%)</th>
<th>Consumption growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Indonesia</td>
<td>0,19</td>
<td>2,19</td>
</tr>
<tr>
<td>Malaysia</td>
<td>2,88</td>
<td>4,04</td>
</tr>
<tr>
<td>Brunei</td>
<td>0,06</td>
<td>4,02</td>
</tr>
<tr>
<td>Thailand</td>
<td>7,30</td>
<td>6,47</td>
</tr>
<tr>
<td>Myanmar</td>
<td>3,10</td>
<td>6,57</td>
</tr>
<tr>
<td>Vietnam</td>
<td>5,59</td>
<td>5,59</td>
</tr>
<tr>
<td>Singapore</td>
<td>-</td>
<td>9,16</td>
</tr>
</tbody>
</table>

The production growth in Indonesia and Brunei was relatively stable, less than 0.2%. The highest growth was owned by Thailand. This might due to the joined exploration and production with Myanmar and Malaysia. For the consumption, the highest growth was owned by Singapore. This could be explained by development of industrial and business clusters in Singapore during that period (Wong, Ho, & Singh, 2010). Singapore had successfully attracted foreign direct investment from multinational companies to build their headquarters, distribution office, or plants which led to higher demand for natural gas, either for electricity, heating or as feedstock for chemical plants. IEA and ERIA (2013) predict the natural gas demand growth from 2011 to 2035 in Indonesia, Malaysia, and Thailand, to be 3.0%, 1.50%, and 2.10% respectively. Another report from IEEJ (2013) predicts the consumption growth from 2010 to 2035 in Indonesia, Malaysia, Thailand, Vietnam, and Singapore to be 3.0%, 3.20%, 4.70%, 3.10%, and 2.60% respectively. In terms of natural gas production, IEA and ERIA (2013) predict the growth will be as follows: Indonesia 2.30%, Malaysia 0.60%, Brunei 0.50%, Thailand -5.50%, Myanmar 2.60%, and Vietnam 1.30%.

Conclusions

The estimated growth for natural gas production and consumption either based on historical data from the EIA or BP Statistics, or from analysis of the IEA and ERIA (2013) and the IEEJ (2013) shows no convergence except for Indonesian gas consumption in which the IEA, ERIA, and IEEJ agree that the growth through 2035 will be 3.0%. Different estimates regarding the growth in production and consumption could be translated into scenarios. However, if possible, gathering information (i.e. production and consumption growth) from reports published by each individual country would give more valuable insights because each country might have a better projection since it has more information and know the domestic condition better than the international agencies.
2.2 GAS MARKET REGIMES

2.2.1 Actors and Degree of Market Opening

In a liberalized gas market, several players are involved along the value chain, i.e. from exploration, production, trading, to transmission and distribution. In a traditional market, the activities are still dominated by the state-owned company with its subsidiaries. Figure 2.8 shows the degree of gas market opening in Southeast Asia. The dash circles represent the countries that are in transition and are expected to be in that level in the coming years.

Currently, Singapore who owns no gas reserves is the one who leads the gas market liberalization. To support the vision to become an Asian gas hub, Singapore has invested in LNG terminal (through Singapore LNG Corporation – SLNG) and hired British Gas (BG) as LNG aggregator. Malaysia still adopts monopoly, in which it is less open, even for exploration and production. However, Malaysia is trying to have a little change and become more open as it also wants to become a gas hub in Southeast Asia, otherwise it will be left farther behind Singapore. Indonesia and Thailand have de-regulated their gas markets, however, there are still some gaps between the ‘new’ regulations and the current practices (Wu, 2011), i.e. the current practices are still based on vertical integration although new regulations for liberalization have been ratified (or proposed). Thailand will face depleting gas reserves in the next five years, and afterwards, they will have a similar position as Singapore, i.e. no or very low gas production and high gas consumption. This will push Thailand to liberalize its gas market in a faster pace, especially if Singapore could prove its success in terms of cost efficiency and high security of gas supply after the gas market liberalization.
In Indonesia, the ratification of the ‘new regulation’ has been postponed which lead to uncertainty in the market. For that reason, investors tend to wait and see before making any decisions. This could be seen from a delay in several new gas projects. The willingness to do unbundling also draw a pro and contra among the actors in the value chain. Multinational companies or smaller private companies will favor unbundling as they will have higher chances to enter the market and use the current transmission or distribution pipeline networks. On the other hand, the state-owned companies tend to refute the unbundling as they will have to put additional cost (in which they claim to be very high and not profitable). Based on an interview with a senior official of PGN, third party access and unbundling could slow down the network expansion plan. The reason is that, now, the companies (i.e. PGN and Pertamina) become less guaranteed that their investments for the infrastructure would be profitable since they also need to compete at the downstream level. Table 2.3 summarizes state-owned and multi-national gas companies that involve in the gas projects in Southeast Asia.

Table 2.3 Gas companies that operate in Southeast Asia

<table>
<thead>
<tr>
<th>Gas fields in (country)</th>
<th>National Oil&amp; Gas Companies (NOGCs)</th>
<th>Multinational Gas (and oil) Companies operate in the country</th>
<th>Transmission</th>
<th>Distribution (domestic market)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Indonesia</td>
<td>Pertamina, PGN</td>
<td>Conoco, Inpex, Texaco, Premier Oil, Gulf Resources, ExxonMobil, Caltex, Total, UNOCAL, Hess, Vico, Arco, Shell</td>
<td>Pertagas (Pertamina)</td>
<td>PGN</td>
</tr>
<tr>
<td>Malaysia</td>
<td>Petronas</td>
<td>Esso (ExxonMobil), Shell, ConocoPhillips</td>
<td>Petronas</td>
<td>Gas Malaysia Sdn Bhd (GMSB)</td>
</tr>
<tr>
<td>Brunei</td>
<td>BSP, JEJV</td>
<td>Shell</td>
<td>BSP, BLNG, BST</td>
<td>BSM</td>
</tr>
<tr>
<td>Myanmar</td>
<td>MOGE</td>
<td>Total, Premier Oil, PTTEP, Petronas, Nippon Oil, UNOCAL, Hess, CNOOC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Thailand</td>
<td>PTTEP</td>
<td>UNOCAL, Total, Shell, Esso</td>
<td>PTT</td>
<td>PTT</td>
</tr>
<tr>
<td>Singapore</td>
<td>PowerGas, SLNG</td>
<td>PowerGas, SLNG</td>
<td>PowerGas</td>
<td></td>
</tr>
</tbody>
</table>

Source: Various sources

In the traditional gas market, the roles of the state-owned companies are very dominant along the value chain. Countries such as Indonesia, Thailand, Myanmar, and Vietnam appear to be more open compared with Brunei and Malaysia, as there are more multinational gas companies operating the gas fields in those countries. The similarity among these countries is that both the transmission and distribution networks are owned and operated by the state-owned company. However, unlike in Singapore where the state-owned companies only manage the infrastructures, the state-owned gas companies in other Southeast Asian countries are also actively involved in the markets (i.e. buying and selling gas).

2.2.2 Production Sharing Contract (PSC)
The common scheme that is used by most of the countries related to gas production activities is called production sharing contract (PSC), in which the host country gives permission or rights for the gas
companies (state-owned, multinationals or joint ventures) to do exploration and production activities in particular blocks or gas fields. The rights are awarded through competitive bidding or bilateral (direct) negotiation (WorldBank, 2014). Later, the contract winners will be called as contractor. The contractor could ask other companies to join (for example in the form of consortium or establish a joint venture) and share the costs and profits. In practice, the consortium could appoint one of the members or another company to act as the operator of the gas field. Usually, the PSC scheme has several terms and conditions, depending on the agreement between the parties. One of the main condition is the amount of gas that should be kept as domestic reserves or to be sold at the domestic market. Each country might have different terms and conditions of PSC. This section will only cover the Indonesian PSC. PSC structures of other Southeast Asian gas producing countries can be found in a report by APEC (2010).

Indonesian PSC

There are five key components of the Indonesian PSC, consists of first tranche petroleum (FTP), cost recovery, profit sharing, income tax, and domestic market obligation (DMO)².

- FTP is derived from the gross revenues of the gas sales and is shared between the government and the contractor. The percentage of the FTP itself is currently 20% of the gross revenue. The shares of the FTP between the government and the contractor is usually as same as the profit sharing.
- After cut by the FTP, the contractor is allowed to gain cost recovery from the rest of the revenue. In Indonesia, there is no cost recovery ceiling, and thus, the contractor could take 100% of the rest revenue to recover the cost.
- The profit sharing (before tax) in most PSC scheme in Indonesia is 70% for the government and 30% for the contractor. The precise percentage for gas fields located at conventional areas is 62.50% and 71.43% for the gas fields located at frontier areas. When the cost recovery period has ended, the profit sharing is 80% of the gross revenue and the part of the contractor is subjected to the tax.
- The current income tax rate in the Indonesian PSC is 44%. In some PSCs, tax holidays for several years were given by the government as an incentive for the contractor.
- Based on 2002 conventional model contract, DMO gas price is at market rates. The amount of DMO has been changed from previously at most 25% to a minimum of 25% (based on an interview with the upstream regulator)

2.2.3 Regional Gas Trade

Indonesia, Malaysia, Myanmar, and Brunei are known as gas exporters (both pipeline and LNG) to Northeast Asian countries, i.e. Japan, South Korea, Taiwan, and China. However, at the same time, other countries in Southeast Asia are also known as gas importers, e.g. Singapore and Thailand. Data of gas export and import trades from the year 2000 to 2013 have been collected from BP Statistics. Figure 2.9 shows the trade movements via pipeline and LNG intra-regional (within Southeast Asia) and inter-regional (with Northeast Asia countries) during 2013.

² DMO is minimum allocation of natural gas from one particular gas field or working area (could be several gas fields) to domestic (national) market
The solid lines represent gas trade movements via pipelines, while the dotted lines represent gas trade movements in LNG. The heavier lines represent more amount of gas traded. The total amount of gas pipeline movements in 2013 were 18.9 bcm, while the LNG trades were 67.9 bcm. As can be seen from the figure, most of the gas from Southeast Asia went to Northeast Asia countries, dominantly to Japan and South Korea. Only small shares of the gas went out of these two regions.

Figure 2.10 and 2.11 show the historical gas export trades in period 2001 to 2013 from Brunei, Malaysia and Indonesia. The amount of gas exported by Brunei were relatively stable as can be seen from the graph. However, for the last two years, the exported gas to Japan declined while exported gas to South Korea and other places (probably to spot market) increased. For Malaysia, the exported gas (LNG) to Japan and China have increased since 2009. The exported LNG to South Korea reached the peak during 2007-2009 and got stable afterwards. The exported LNG to Taiwan and pipelined gas to Singapore were relatively stable.

The exported LNG from Indonesia to Japan has declined after reached its peak in 2003. This might due to the contract expiration and diversification of gas supplies by the Japanese customers. As reported by Morikawa (2012), the largest amount of long-term LNG import contract by Japan came from Malaysia (15.41 MT), followed by Australia (13.26 MT), Brunei (6.01 MT), Qatar (6.00 MT), Indonesia (5.83 MT), Russia, UAE, Oman, and other countries from the spot market. There are also changes in gas supplier composition for the Korean gas market. Based on Korea International Trade Association (KITA), in 2000, 43% of the LNG imports came from Indonesia, 21% from Qatar, 17% from Malaysia, 11% from Oman, 6% from Brunei and the rest 2% from other countries. In 2012, however, the supply from Indonesia accounted only for 21% while Qatar increased its share to 28%. Malaysia contributed 11%, Oman 12%, and the rest 28% were shared by Brunei, Australia, Russia, Egypt, Yemen, and Nigeria, ranged from 2% to 7%, and other countries accounted for 4% (Huh, 2013).
As shown in figure 2.11, the amount of Indonesian gas exported to Singapore increased after 2005 due to new pipeline connection that was constructed in 2003 (see table 2.5). The amount of gas pipeline exported to Malaysia was also relatively stable. The amount of gas sold to other countries were relatively small. This indicated that Indonesia were less active in the spot trading.

2.2.4 Gas Pricing in Southeast Asia
The gas trades in the Asian gas market, i.e. Southeast Asia and Northeast Asia, are dominated by bilateral long-term contracts. For the gas traded via pipelines, based on an interview conducted with the upstream regulator (SKK Migas) in Indonesia, the price is flat with an escalation of 3 to 4% for each three years, while for the LNG, the price refers to Japan Crude Cocktail (JCC) index and could be renegotiated. Hashimoto and Koyama (2012) use natural gas pipeline data from the IEA in period 1971 to 2012 and find that the trend increased by 2.8% during that period. While for the LNG, the price growth is 6.6% during 1990 to 2000, and 7.9% during 2000 – 2011.
As in Huh (2013), the common LNG pricing formula is:

\[ P = C + S \times JCC \]

Where:

- \( P \): LNG price in $/MMBtu
- \( C \): a constant which is a pass-through of known transport costs in $/MMBtu
- \( S \): gas/oil parity factor (slope of the S-Curve)
- \( JCC \): Japanese Crude Cocktail index in $/Bbl

The \( S \) value indicates how closely LNG prices move to oil prices and the value could be different for each contract for it is a main subject of negotiation. As summarized by Huh (2013),

“The Internal Revenue Service (IRS) defines an average heating value of one barrel of crude oil is 5.8MMBtu, thus, the conversion factor for converting $/Bbl to $/MMBtu would be 1/5.8 = 0.172. This coefficient is known as the 'Full Oil Parity' where price of LNG rise perfectly parallel to that of oil prices. This slope is used as a reference to compare how LNG prices move relevant to crude oil prices. If \( S > 0.172 \), LNG prices will rise or fall at a faster pace, and if \( S < 0.172 \), it will be the opposite.”

According to Huh (2013), the variables that are discussed during the negotiation of LNG contracts are the slope (\( S \)), the constant (\( C \)), the two pivot points, and the moderated slopes (i.e. the slopes of the curve once it passes the pivot points) as illustrated in figure 2.12. The reduced slope and the S-curve slope will set the floor and ceiling of the LNG prices in order to protect both buyers and sellers from the swings of oil prices.

![S-Curve](Image)

Figure 2.12 Illustration of LNG price setting (Huh, 2013)

Table 2.4 shows the recapitulation of imported LNG prices by Korea from various countries in period 2000 to 2012. Even imported from the same region, i.e. from Indonesia and Malaysia, the prices are quite different. The average LNG price to Korea during 2000 to 2012 from Indonesia is higher than from Malaysia. However, compared with the LNG price from the Middle East (e.g. Qatar and Oman), for the last four years (2009 to 2012), the Indonesian LNG prices are lower. Table 2.4 also shows a significant price growth at full oil parity that is almost four times between 2000 and 2012. There was a significant decreasing in 2009 that was caused by the global economic crisis. The close correlation with the oil price will cause the gas price becomes vulnerable to the economic and geopolitical crisis.

In Indonesian LNG contracts, the prices might be set based on Indonesian Crude Price (ICP) which is determined by the Indonesian government periodically according to the movement in the crude price
at the selected international market (Deloitte, 2013). This ICP is the basis to calculate the gross revenue, cost recovery, contractors’ share, and taxable income as in the PSC structure. As reported by Platts (2014), the Indonesian Government is still assessing the possibility of using Brent crude assessments as the basis for the ICP formula plus an alpha that represents the transportation costs, crude quality and spot prices. According to one government official, this might be done only next year due to the lower production of Indonesian crude oil grades (Platts, 2014).

According to Jensen (2011), one of the most challenging issues affecting many Asian governments is subsidy pricing. In Brunei, the gas price is relatively low because the consumption is much less than the production and its total population is much lower compared to other Southeast Asian countries, including Singapore. In Malaysia and Vietnam, the gas prices for consumers are fully subsidized, while in Indonesia and Thailand, the prices are partly subsidized by the government (Xin, 2013). When the governments give subsidy, it means the prices are less than or below the market price. In Singapore, the gas price is more cost-reflective or market based.

<table>
<thead>
<tr>
<th>Year</th>
<th>Qatar</th>
<th>Indonesia</th>
<th>Malaysia</th>
<th>Oman</th>
<th>Russia</th>
<th>Australia</th>
<th>Avg Price</th>
<th>Full Oil Parity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>6.4</td>
<td>6.7</td>
<td>6.0</td>
<td>6.7</td>
<td>0.0</td>
<td>0.0</td>
<td>6.5</td>
<td>4.95</td>
</tr>
<tr>
<td>2001</td>
<td>6.8</td>
<td>6.1</td>
<td>6.8</td>
<td>6.6</td>
<td>0.0</td>
<td>0.0</td>
<td>6.9</td>
<td>4.31</td>
</tr>
<tr>
<td>2002</td>
<td>5.8</td>
<td>5.7</td>
<td>5.9</td>
<td>5.7</td>
<td>0.0</td>
<td>0.0</td>
<td>4.9</td>
<td>4.30</td>
</tr>
<tr>
<td>2003</td>
<td>6.7</td>
<td>6.9</td>
<td>6.3</td>
<td>6.6</td>
<td>0.0</td>
<td>0.0</td>
<td>6.4</td>
<td>5.04</td>
</tr>
<tr>
<td>2004</td>
<td>7.5</td>
<td>8.7</td>
<td>6.7</td>
<td>7.4</td>
<td>0.0</td>
<td>0.0</td>
<td>6.2</td>
<td>6.31</td>
</tr>
<tr>
<td>2005</td>
<td>10.1</td>
<td>11.8</td>
<td>7.2</td>
<td>10.3</td>
<td>0.0</td>
<td>0.0</td>
<td>8.8</td>
<td>8.89</td>
</tr>
<tr>
<td>2006</td>
<td>13.2</td>
<td>14.1</td>
<td>8.3</td>
<td>13.8</td>
<td>0.0</td>
<td>0.0</td>
<td>7.4</td>
<td>12.1</td>
</tr>
<tr>
<td>2007</td>
<td>13.7</td>
<td>15.5</td>
<td>8.8</td>
<td>14.3</td>
<td>0.0</td>
<td>0.0</td>
<td>7.3</td>
<td>12.5</td>
</tr>
<tr>
<td>2008</td>
<td>20.8</td>
<td>21.4</td>
<td>11.9</td>
<td>21.6</td>
<td>0.0</td>
<td>0.0</td>
<td>9.4</td>
<td>18.7</td>
</tr>
<tr>
<td>2009</td>
<td>16.3</td>
<td>11.5</td>
<td>10.3</td>
<td>15.6</td>
<td>0.0</td>
<td>8.7</td>
<td>9.7</td>
<td>12.5</td>
</tr>
<tr>
<td>2010</td>
<td>16.7</td>
<td>13.1</td>
<td>11.1</td>
<td>16.2</td>
<td>0.0</td>
<td>7.0</td>
<td>11.0</td>
<td>13.3</td>
</tr>
<tr>
<td>2011</td>
<td>21.0</td>
<td>16.9</td>
<td>12.7</td>
<td>20.8</td>
<td>0.0</td>
<td>9.3</td>
<td>14.7</td>
<td>16.6</td>
</tr>
<tr>
<td>2012</td>
<td>23.8</td>
<td>18.1</td>
<td>14.3</td>
<td>24.2</td>
<td>9.9</td>
<td>18.5</td>
<td>19.2</td>
<td>19.63</td>
</tr>
</tbody>
</table>

Source: KITA, Petroleum Association of Japan

Conclusions

The issue of liberalized gas market is less applicable in this research because in practice, there is only Singapore who has liberalized its gas market while in other Southeast Asian countries, the common practices are still based on the traditional approach, i.e. vertical integration and market opening at production or upstream development. In terms of regional gas market, up to 2013, it was dominated by intra-regional trades and inter-regional trades with the Northeast Asian countries. However, in the coming years, wider scope of trades (internationally) could be expected as several countries have secured long-term contracts with the U.S. or European suppliers. The Northeast Asian countries also become less dependent on gas supplies from the Southeast Asian as they have started to diversify their gas supplies, indicated by less percentage in 2012 than in early 2000. As there is no Southeast Asian gas hub pricing, the common pricing scheme in the Southeast Asian gas market is based on JCC index, with varied constant and slope values, depending on the gas sales agreements.
2.3 GAS INFRASTRUCTURES

This section contains some information regarding the existing gas pipelines and LNG infrastructures in Southeast Asia together with the future plans to expand or build new facilities which can be found in table 2.5 to 2.9. This information will be used as inputs and constraints in the model development.

Table 2.5 Existing LNG liquefaction facilities in Southeast Asia (IEA & ERIA, 2013)

<table>
<thead>
<tr>
<th>Country</th>
<th>Project (Location)</th>
<th>Capacity mtpa</th>
<th>Capacity Bcm/y</th>
<th>Status</th>
<th>Start</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brunei</td>
<td>Brunei LNG</td>
<td>7.2</td>
<td>9.8</td>
<td>Operating</td>
<td>1972</td>
</tr>
<tr>
<td>Indonesia</td>
<td>Bontang (East Kalimantan)</td>
<td>21.6</td>
<td>29.4</td>
<td>Operating</td>
<td>1978</td>
</tr>
<tr>
<td></td>
<td>Arun* (Aceh)</td>
<td>4.8</td>
<td>6.4</td>
<td>Operating</td>
<td>1978</td>
</tr>
<tr>
<td></td>
<td>Tangguh LNG (Papua)</td>
<td>7.6</td>
<td>10.3</td>
<td>Operating</td>
<td>2009</td>
</tr>
<tr>
<td></td>
<td>Donggi-Senoro (Sulawesi)</td>
<td>2.0</td>
<td>2.7</td>
<td>Construction</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Sengkang (South Sulawesi)</td>
<td>2.0</td>
<td>2.7</td>
<td>Construction</td>
<td>2014</td>
</tr>
<tr>
<td>Malaysia</td>
<td>MLNG I, II, III (Bintulu)</td>
<td>24.2</td>
<td>32.9</td>
<td>Operating</td>
<td>1983</td>
</tr>
<tr>
<td></td>
<td>~ expansion</td>
<td>3.6</td>
<td>4.9</td>
<td>Construction</td>
<td>2015</td>
</tr>
<tr>
<td></td>
<td>Kanowit FLNG (Sarawak)</td>
<td>1.2</td>
<td>1.6</td>
<td>Construction</td>
<td>2015</td>
</tr>
</tbody>
</table>

*The Arun LNG terminal is being converted from a liquefaction unit to a regasification unit

Table 2.6 Existing LNG regasification facilities in Southeast Asia (IEA & ERIA, 2013)

<table>
<thead>
<tr>
<th>Country</th>
<th>Project (Location)</th>
<th>Capacity mtpa</th>
<th>Capacity Bcm/y</th>
<th>Status</th>
<th>Start</th>
</tr>
</thead>
<tbody>
<tr>
<td>Indonesia</td>
<td>West Java FSRU</td>
<td>3.7</td>
<td>5.2</td>
<td>Operating</td>
<td>2012</td>
</tr>
<tr>
<td></td>
<td>Lampung FSRU</td>
<td>2.0</td>
<td>2.8</td>
<td>Construction</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Arun (Aceh)</td>
<td>1.5</td>
<td>2.1</td>
<td>Construction</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Banten FSRU</td>
<td>3.0</td>
<td>4.1</td>
<td>Construction</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Central Java FSRU</td>
<td>3.0</td>
<td>4.1</td>
<td>Construction</td>
<td>2014</td>
</tr>
<tr>
<td>Malaysia</td>
<td>Lekas (Malacca)</td>
<td>3.8</td>
<td>5.2</td>
<td>Operating</td>
<td>2013</td>
</tr>
<tr>
<td>Singapore</td>
<td>Jurong Island</td>
<td>3.5</td>
<td>4.7</td>
<td>Operating</td>
<td>2013</td>
</tr>
<tr>
<td></td>
<td>~ expansion</td>
<td>5.3</td>
<td>7.1</td>
<td>Construction</td>
<td>2014</td>
</tr>
<tr>
<td>Thailand</td>
<td>Ma Ta Phut</td>
<td>5.0</td>
<td>6.9</td>
<td>Operating</td>
<td>2011</td>
</tr>
</tbody>
</table>

Table 2.7 Planned LNG liquefaction and regasification facilities in Southeast Asia (IEA & ERIA, 2013)

<table>
<thead>
<tr>
<th>Country</th>
<th>Project (Location)</th>
<th>Capacity mtpa</th>
<th>Capacity Bcm/y</th>
<th>Status</th>
<th>Start</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquefaction Facilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indonesia</td>
<td>~ expansion LNG Tangguh</td>
<td>3.8</td>
<td>5.2</td>
<td>Planned</td>
<td>2018</td>
</tr>
<tr>
<td></td>
<td>Abadi FLNG (Arafura Sea)</td>
<td>2.5</td>
<td>3.4</td>
<td>Planned</td>
<td>2016</td>
</tr>
<tr>
<td>Malaysia</td>
<td>Rotan FLNG (Sabah)</td>
<td>1.5</td>
<td>2.0</td>
<td>Planned</td>
<td>2016</td>
</tr>
</tbody>
</table>

| Regasification Facilities |
| Malaysia | Lahad Datu (Sabah) | 0.8           | 1.1           | Planned | 2016 |
|         | Pengerang (Johor) | 3.8           | 5.2           | Planned | 2017 |
| Thailand | ~ expansion Ma Ta Phut | 5.0             | 6.9           | Planned | 2017 |
| Vietnam | Thi Vai            | 1.0           | 1.4           | Planned | 2016 |
|         | Bin Thuan          | 3.0           | 4.1           | Planned | 2018 |
### Table 2.8 Existing cross-border gas pipelines in Southeast Asia

<table>
<thead>
<tr>
<th>No.</th>
<th>In operation since</th>
<th>From (Country, Location)</th>
<th>To (Country, Location)</th>
<th>Length (km)</th>
<th>Other Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>1991</td>
<td>Malaysia (Segamat - Peninsular)</td>
<td>Singapore</td>
<td>5</td>
<td>24 inch; 155MMCFD (max. 250MMCFD), a part of Peninsular gas pipelines project; 20 years (until 2011)</td>
</tr>
<tr>
<td>2.</td>
<td>1999</td>
<td>Myanmar (Yadana)</td>
<td>Thailand</td>
<td>410</td>
<td>36 inch; 200MMCFD (max. 500MMCFD) (since 2010, additional pipeline to Yangon, Myanmar with a capacity of 150MMCFD); reserves 5.3 tcf; 30 years (until 2025)</td>
</tr>
<tr>
<td>3.</td>
<td>2000</td>
<td>Myanmar (Yetagun)</td>
<td>Thailand</td>
<td>277</td>
<td>24 inch; 260 MMCFD (max. 300MMCFD); reserves 3.2 tcf; 30 years (until 2027)</td>
</tr>
<tr>
<td>4.</td>
<td>2001</td>
<td>Indonesia (West Natuna)</td>
<td>Singapore (Jurong)</td>
<td>654</td>
<td>28 inch; 325MMCFD; 22 years (until 2023)</td>
</tr>
<tr>
<td>5.</td>
<td>2001</td>
<td>Indonesia (West Natuna)</td>
<td>Malaysia (Duyong)</td>
<td>96</td>
<td>22 inch; 250 MMCFD (max.300 MMCFD); 20 years; (until 2021)</td>
</tr>
<tr>
<td>6.</td>
<td>2002</td>
<td>CAA*</td>
<td>Malaysia</td>
<td>170</td>
<td>24 inch; 270 MMCFD</td>
</tr>
<tr>
<td>7.</td>
<td>2003</td>
<td>Indonesia (South Sumatra)</td>
<td>Singapore</td>
<td>468</td>
<td>28 inch; 350 mmmscf; 20 years (until 2023)</td>
</tr>
<tr>
<td>8.</td>
<td>2007</td>
<td>CAA*</td>
<td>Vietnam</td>
<td>330</td>
<td>18 inch, 120 MMcfd</td>
</tr>
<tr>
<td>9.</td>
<td>2005</td>
<td>JDA**</td>
<td>Thailand</td>
<td></td>
<td>390 MMCFD, 35 years (5 years exploration, 5 years retention, 5 years development, 20 years production) 55km-28inch + 277km-34inch, max 1,020mmmscf</td>
</tr>
<tr>
<td>10.</td>
<td>2006/2007</td>
<td>Malaysia</td>
<td>Singapore</td>
<td>4</td>
<td>115 MMCFD, 18 years (until 2025)</td>
</tr>
<tr>
<td>11.</td>
<td>2009</td>
<td>JDA**</td>
<td>Malaysia</td>
<td>96.5</td>
<td>36 inch onshore, max. 750MMSCFD</td>
</tr>
<tr>
<td>12.</td>
<td>2013</td>
<td>M9</td>
<td>Thailand</td>
<td>300</td>
<td>230km offshore and 70km onshore; 28 inch; max.300MMSCFD; reserves 1.8-2.5tcf</td>
</tr>
</tbody>
</table>

Data from various sources

*CAA is Commercial Arrangement Area between Malaysia and Vietnam
**JDA is Joint Development Area between Malaysia and Thailand
Figure 2.13 shows the total volume of traded pipelined gas between Indonesia and Malaysia (pipeline 1), Indonesia and Singapore (pipeline 2), Malaysia and Singapore (pipeline 3), and Myanmar and Thailand (pipeline 4). BP Statistics started to record pipelined gas movement from Indonesia to Malaysia since 2008. However, according to ACE (2013), the pipelined gas from Indonesia to Malaysia has been in operation since 2001. Since there is no information available regarding the exact amount transported during 2001 to 2007, the author could not include the pipelined gas trades between Indonesia and Malaysia during those periods. The volume transported at gas pipeline 1 is relatively lower compared to other gas pipeline routes. This might be due to the position of the two countries as gas producer (and also gas exporter), and thus, Malaysia in fact, does not really need gas supply from Indonesia, except for supply diversification reason, or economic reason, i.e. it might be cheaper for the Peninsular or western region of Malaysia to get gas supply from Indonesian pipeline compared to LNG shipping from the eastern Malaysia (near the Indonesian Borneo and Brunei territory).

![Volume of gas pipeline trade](image)

*Figure 2.13 Aggregated volume of pipelined gas traded within Southeast Asia*

<table>
<thead>
<tr>
<th>No.</th>
<th>From</th>
<th>To</th>
<th>Length (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>East Natuna (Indonesia)</td>
<td>JDA-Erawan (Thailand)</td>
<td>1500</td>
</tr>
<tr>
<td>2.</td>
<td>East Natuna (Indonesia)</td>
<td>Kerteh (Malaysia)</td>
<td>600</td>
</tr>
<tr>
<td>3.</td>
<td>East Natuna (Indonesia)</td>
<td>Jawa (Indonesia)</td>
<td>1400</td>
</tr>
<tr>
<td>4.</td>
<td>East Natuna (Indonesia)</td>
<td>Vietnam</td>
<td>900</td>
</tr>
</tbody>
</table>

*Table 2.9 Planned cross-border gas pipelines in Southeast Asia (ACE, 2013)*
3 Gas Pipeline and LNG Infrastructure

This chapter presents technical and economic aspects of gas pipeline and LNG facilities. Understanding of these aspects is important especially to develop alternatives of options to manage the new (proposed) gas projects and to value the options. This chapter will cover most of the activities in the natural gas value chain (except upstream activities) that are related to the use of gas pipeline and LNG technologies. As a side note, not all information provided in this chapter will be used in the model or in the analysis. The author will only pick some relevant information based on the project requirements in chapter 7.

3.1 PIPELINED GAS: TECHNICAL AND ECONOMIC PERSPECTIVES

Natural gas pipeline system can be classified into three major subsystem: gathering system, transmission pipeline system, and distribution system (EIA; Prieto, Correlje, & Ascri, 2012). The gathering system consists of small diameter pipelines (6 – 16 inch) that transport natural gas from the wellhead to the natural gas processing plant or to an interconnection with a larger mainline pipeline. The mainline pipeline has wider diameter (20 – 42 inch) to transport natural gas from producing areas to market areas, covers much longer distances than the gathering system pipeline. Smaller diameter pipelines are also used to distribute gas from local distribution company to end users. The general scheme of the natural gas transmission path can be seen in figure 3.1.

Figure 3.1 Natural gas transmission path (EIA)
3.1.1 Gas Transmission Systems

A pipeline transmission system consists of several main physical components: pipelines, valves, compressor stations, metering stations, city gate stations, pig launching/receiving facilities and storage facilities (Dijkema & Praet, 2014). These physical components also can be found in the pipeline distribution systems. Briefly, the function and characteristics of each component are as follows; summarized from Dijkema (2014), Dijkema and Praet (2014), Correlje (2014), Prieto et al. (2012), and Nasr and Connor (2014).

- **Pipelines**: The diameter could be up to 60 inch with pressure up to 200bar. The construction cost for pipelines from steel with inner and outer coating is between € 1.5 to 2 million per kilometer. In terms of economics of scale: 48 inch pipeline has (approximately) six times capacity of a 24 inch pipeline but only (approximately) two times the cost; the longer the pipe, the lower the capacity, but the extra length has a marginally reducing effect; the pressure drop per unit of length increases with distance, hence beyond a certain distance compression become necessary and economic.

- **Compressor stations**: Compressors are used to increase the flow capacity in the system between two points. They increase pressure to help overcome flow-related pressure losses but they also increase flow capacity by making the gas denser. The number of compressors that are installed at each compressor station impacts the availability, reliability, fuel consumption, and the pipeline capacity.

- **Metering stations**: These stations allow pipeline and local distribution companies to monitor, manage, and account for the natural gas in their pipes. Essentially, these metering stations measure the flow of gas along the pipeline, allowing pipeline companies to track natural gas as it flows along the pipeline.

- **City gate stations**: They are also called town borders or tap stations with a basic function to meter the gas and reduce the pressure from the pipeline to the distribution system.

- **Valves**: They work like gateways and are used to allow or stop the flow of the natural gas.

- **Pig launching/receiving facilities**: They allow the pipeline to accommodate a high-resolution internal inspection tool. The pigs are used to clean the inside of the pipeline and to monitor its internal and external condition. Launchers and receivers enable the pigs to be inserted into or removed from the pipeline.

According to the EIA, the principal requirement of the natural gas transmission system is its capability to meet the peak demand of its shippers who have contracts for firm service. Thus, the transmission pipelines need to be combined with other facilities such as natural gas storage sites and LNG facilities located in the market areas. These facilities play a vital role to maintain the reliability of gas supply to meet the consumers’ demand (Prieto et al., 2012).

In designing a pipeline system, there are several degrees-of-freedoms, such as pipeline routing, number of parallel pipelines, operating and maximum pressure, number and location of compressor stations, and number, size, and location of the storage (Dijkema, 2014). The EIA proposes several options for creating additional pipeline capacity, such as:

- Building an entirely new pipeline
- Converting an oil or product pipeline to a natural gas pipeline
- Adding a parallel pipeline along a segment of pipeline, called looping
• Installing a lateral or extension off the existing mainline
• Upgrading and expanding facilities, such as compressor stations, along an existing route. This option is usually the quickest, least expensive, and has the least environmental impacts.

There are several key threats or risks to the transmission pipeline during its operating life, such as third-party interference, corrosion, ground movement, flooding, internal/external stress corrosion cracking, fatigue and human error (Nasr & Connor, 2014). These can cause technical failures that might result in leakage as happened in the pipeline transmission from West Natuna (Indonesia) to Jurong (Singapore) that caused a black-out in nearly half of Singapore in 2002 and 2004 (Reuters, 2004).

3.1.2 Gas Distribution Systems
Gas distribution systems consist of smaller pipeline diameter with much smaller pressure (mbar). As have been mentioned before, the physical components of gas distribution systems are similar with the transmission systems. In general, the distribution activities start from the city gate stations. The network operators of gas distribution systems could be the same (and also different) with those who own the transmission systems, depending on the regime adopted in one particular country. Another scheme is through local distribution companies (LDCs). Usually, they are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area (Prieto et al., 2012). The network operators and also LDCs could be owned by private investors or local governments.

Nasr and Connor (2014) state that the planning and design of gas distribution systems is an iterative process in which there is no single absolute solution. The ideal design would be minimizing cost while at the same time retaining sufficient flexibility to allow for future changes in the pattern of gas consumption. Distribution costs typically make up about half on natural gas costs for households and small groups of consumers because of the diversity in wide geographic area coverage (Prieto et al., 2012). According to Nasr and Connor (2014), the systems should be designed to meet the maximum demands placed upon them. In the absence of information on diversity, it should be assumed that the maximum flow will occur at the peak of the system design flow rate. In cases where there are high risks of interruptible supplies, special consideration should be given, i.e. the maximum system demand may not occur under the peak conditions with interruptible supplies off, but rather at the point just prior to interruption when firm demands will be at a lower level (Nasr & Connor, 2014). Thus, under these conditions, the higher demand level should be used as a basis for the system design flow rate.

Southeast Asia is located near the equator, and consequently, the climate is mainly tropical hot and humid for the whole year with the exception for Northern Vietnam and Myanmar Himalayas that have a sub-tropical climate (i.e. they have a cold winter with snow). This causes less fluctuation in natural gas demand along the year, unlike regions who have extreme summer and winter season. Figure 3.2 shows the generalized natural gas pipeline capacity design from the EIA. The heating and non-heating season is not applicable in this research. But still, the picture can give us a better understanding of the transmission and distribution pipeline systems.
3.1.3 Cost Structure of Pipeline Systems

According to Dijkema and Praet (2014), the investment for transmission pipelines is largely determined by the costs that are related to the pipeline subsystem and those that are related to the costs of the compressor subsystem. The physical characteristics of the pipeline (e.g. material, length, diameter, and coating) could vary the cost of the pipeline.

Cornot-Gandolphe et al. (2003) state that the key determinants of pipeline construction costs are diameter, operating pressures, distance and terrain. Other factors, including climate, labor costs, the degree of competition among contracting companies, safety regulations, population density and rights of way, may cause construction costs to vary significantly from one region to another. Schoots et al. (2011) collect data of pipeline construction with various diameters, from 1960s to 2008, and conclude that pipeline construction costs have not decreased over recent decades, or at least the possible reductions in the total costs have been out-shadowed by the variability in the costs of key input, e.g. costs of labor and fluctuating market prices for the material, such as steel. The authors admit the difficulties in comparing pipeline construction costs between different projects, as a result of the influence of terrain and location of the project. They use ‘terrain factor’ and ‘location factor’ as shown in table 3.1 and 3.2 to adjust the calculation.
As shown in table 3.1, the cost differs due to technical difficulties associated with the accessibility of the location to construct the pipeline networks. The terrain factor means, for 50% mountainous land, the cost would be 1.5 times 700kUS$/km (at year 2000). Countries or regions also influence the pipeline construction costs. These could be due to wage differences or right-of-way costs for the legal and permitting issues.

Another important determinant of pipeline cost is its coating (inner or outer) to prevent corrosion. Webster (2010) states that the cost structure of pipeline transmission consists of 38% cost of capital, 10% failures, 52% operations and maintenance, while 80% of the operations and maintenances are due to corrosion. The main cause of corrosion is CO₂ in the gas.

Rui, Metz, Reynolds, Chen, and Zhou (2011) analyze historical data of 412 pipelines (only onshore pipelines and exclude compressor station costs) recorded between 1992 and 2008 in the oil and gas journal which was adjusted to 2008 dollar values. They find the shares of pipeline cost components on average is 31% material, 40% labor, 23% miscellaneous, and 7% ROW. The costs distribution through year 1992 to 2008 can be seen in figure 3.3.
Rui et al. (2011) address three factors that could affect the difference of pipeline construction cost. These factors are development stage of technology, geographic and environmental condition, and market situation. From the technological perspective, onshore pipeline construction is in a more mature state compared to offshore pipeline or LNG, and thus, has less learning effect in the future. However, the U.S. Department of Energy (DOE) has funded several projects to develop advanced technologies. It is expected that these technologies could create significant cost reduction in the future. Geographic and environmental condition also affect the construction cost. For example, in some cold regions, pipelines need to be insulated or built above the ground. In populated regions, thicker pipeline wall also has to be selected to mitigate societal and environmental risk (Sanderson, Ohm, & Jacobs, 1999). According to Parker (2004), a pipeline through a rural area without special environmental concerns can cost five times less than a pipeline of the same length and diameter through a dense urban area. Rui et al. (2011) also argue that potential demand will cause increasing current unit cost of pipelines, and therefore, expected demand of pipelines will indirectly influence learning rate of pipelines.

Table 3.3 shows an example of the way to calculate offshore pipeline construction costs. The cost variables are divided into two: direct costs that are associated directly with the pipeline and indirect costs that are related to management, supervision, and insurance.
Table 3.3 Pipeline costing rules of thumb (ECCO, 2011)

<table>
<thead>
<tr>
<th>Direct Cost</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering</td>
<td>0.4 million$ + 6$/m</td>
</tr>
<tr>
<td>Line pipe</td>
<td>1.3$/kg</td>
</tr>
<tr>
<td>Corrosion coating</td>
<td>9 √D $/m</td>
</tr>
<tr>
<td>Weight coating</td>
<td>7 √D $/m</td>
</tr>
<tr>
<td>Other material cost</td>
<td>1.2 √D $/m</td>
</tr>
<tr>
<td>Tie-in or riser cost (each)</td>
<td>0.26 √D million$</td>
</tr>
<tr>
<td>Installation cost</td>
<td>0.6 √D million$ + 60 √D $/m</td>
</tr>
<tr>
<td>Trenching and dumping cost</td>
<td>0.4 √D million$ + 16 √D $/m</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>Factor 1.1 to 1.3</td>
</tr>
<tr>
<td>Shore approach/ landfall</td>
<td>2 – 10 million$ (depend on the case)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Indirect cost</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Management &amp; supervision</td>
<td>5% of direct cost</td>
</tr>
<tr>
<td>Insurance</td>
<td>2% of direct and indirect cost</td>
</tr>
</tbody>
</table>

Note: D = diameter (inch); w = weight (kg)

3.2 LNG: TECHNICAL AND ECONOMIC PERSPECTIVES

Activities in an LNG value chain consist of liquefaction of the natural gas (upstream level), LNG shipping, storage, and regasification at midstream to downstream level. After regasification, the natural gas could either be distributed directly to the large consumers such as industrial plants or power generations or through the local distribution companies that will distribute the natural gas via smaller distribution pipelines to the end customers. Currently, the biggest LNG market is in Asia, dominated by countries from Northeast Asia as LNG importers, e.g. Japan, South Korea, China, and Taiwan; and countries from Southeast Asia as their major suppliers (LNG exporters), e.g. Indonesia, Malaysia, and Brunei. The main reason for LNG market development in Asia is its geography that is scattered (with a lot of small islands) which caused gas transportation via pipeline is less advantageous.

Following characteristics should be present so that LNG could be a viable option versus pipelined gas (Natgas):

- The gas market is more than 2,000 km from the field.
- The gas field contains at least 3 tcf to 5 tcf of recoverable gas.
- Gas production costs are, ideally, less than $5/MMBtu, delivered to the liquefaction plant.
- The gas contains minimal other impurities, such as CO2 or sulphur.
- A marine port where a liquefaction plant could be built is relatively close to the field.
- The political situation in the country supports large-scale, long-term investments.
- The market price in the importing country is sufficiently high to support the entire chain and provide a competitive return to the gas exporting company and host country.
- A pipeline alternative would require crossing uninvolved third-party countries and the buyer is concerned about security of supply.
An LNG facility producing 1 million tons per year (million tons per annum, or mtpa) of LNG requires 48.7 bcf (1.38 bcm) of natural gas per year, equivalent to 133 MMcfd (million cubic feet per day). This facility would require recoverable reserves of approximately 1 tcf over a 20-year life. Similarly, a 4-mtpa LNG train would consume an equivalent of 534 MMcfd, in other words, requiring reserves of 4 tcf over 20 years (Natgas). In this research, the units conversion will follow energy conversion table published by the Energy Markets International, Ltd. Shearer, Nissen, and Townsend (2003) compare the benefits and risks of gas pipeline and LNG as shown in table 3.4.

**Table 3.4 Benefits and risks comparison of gas pipeline and LNG** (Shearer et al., 2003)

<table>
<thead>
<tr>
<th>Benefits</th>
<th>LNG</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Lower commodity price (avoid LNG conversion costs)</td>
<td>- Reduced buyer country capital exposure (not underwriting the entire supply chain)</td>
</tr>
<tr>
<td>- Aggregate capital costs are lower</td>
<td>- Limit cross border issues</td>
</tr>
<tr>
<td>- Better for short distances to small markets</td>
<td>- Volumes can be matched to market evolution more closely</td>
</tr>
<tr>
<td>- The only option for inland markets</td>
<td>- More supplier options</td>
</tr>
<tr>
<td><strong>Risks</strong></td>
<td></td>
</tr>
<tr>
<td>- Single supplier risk</td>
<td>- Higher commodity fuel price</td>
</tr>
<tr>
<td>- Market overestimation may leave larger stranded assets</td>
<td>- May require more infrastructure on buyer’s part</td>
</tr>
<tr>
<td>- Multi-country exposure on cross-border pipelines</td>
<td>- Works best for near-coastal markets</td>
</tr>
</tbody>
</table>

Some countries that have a large share of imported pipelined gas could see LNG as a means to diversify the gas supply. However, it is not solely a matter of choice as geographical location might become a restriction to import or export natural gas with one of the two technologies. For example, countries that are surrounded by land territories of other countries might not be able to export or import LNG because there is no access to the sea transportation, and thus, gas pipeline is the only viable option.

### 3.2.1 Liquefaction Plants

At upstream level, the gas should be refrigerated at liquefaction facilities. The liquefaction process not only change the form from gas to liquid, but also reduce the volume of gaseous gas by approximately 600 times, i.e. 1m³ of LNG = 600 m³ of natural gas. An LNG plant comprises of feeding gas pipeline reception facilities, one or more ‘LNG trains’, fractionation, product storage and loading, refrigerant storage, utilities (e.g. power, heating medium, fuel gas, water, nitrogen, etc.), and general facilities such as plant buildings and infrastructure (Morgan & White, 2012). The LNG trains consist of gas pre-treatment (i.e. impurities removal), NGL removal, liquefaction unit (to condense the natural gas), and end flash that would auto-refrigerate LNG, remove nitrogen (nitrogen is used to refrigerate the natural gas) and recompress end flash gas for use as fuel gas (Morgan & White, 2012). Morgan and White (2012) summarize the options for liquefaction plants as shown in table 3.5.
Table 3.5 Size range of liquefaction plants (Morgan & White, 2012)

<table>
<thead>
<tr>
<th>Options</th>
<th>LNG Train Capacity Range (mtpa)</th>
<th>Typical Liquefaction Technology</th>
<th>Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mini LNG</td>
<td>&lt; 0.1</td>
<td>Nitrogen expander</td>
<td>Peak shaving plants, vehicle fuel, ship boil off gas liquefaction</td>
</tr>
<tr>
<td>Mid-Scale</td>
<td>0.2 to 1.5</td>
<td>Single mixed refrigerant</td>
<td>For domestic consumption, transport by road or rail</td>
</tr>
<tr>
<td>Base Load</td>
<td>3 to 5 (could be larger, e.g. 8 mtpa in Qatar)</td>
<td>Propane pre-cooled mixed refrigerant, dual mixed refrigerant, pure component cascade</td>
<td>Overseas export by ship</td>
</tr>
</tbody>
</table>

When the location of the gas field is stranded, an onshore liquefaction plant is not an option. The technology has developed and resulted in floating liquefaction natural gas (FLNG) that has similar functions with an onshore liquefaction plant. Currently, there are three FLNG under construction, in Malaysia, Colombia, and Australia. Gordon (2013) identifies three risks related to the development of FLNG. Firstly, FLNG is an unproven technology. Therefore, any issues with the start-up of the first units in service could significantly affect the spread of the technology in the future. Secondly is the commodity prices. It relates to the uncertainty of shale gas export from the U.S. If the U.S. regulators allow large-scale export of shale gas, then FLNG could become less attractive. And lastly is any delays, postponement or cancellation of current projects that could be caused by resource constraints, technical challenges, and high CAPEX involved.

3.2.2 LNG shipping

Specially designed refrigerated ships are usually used to transport the LNG to the consumers. The ships operate at low atmospheric pressure, transporting the LNG in individual insulated tanks (Natgas). There are two dominant types of LNG tanker fleet: spherical ship tanks and membrane ship tanks (Dijkema & Praet, 2014). Number of ships are determined by ship capacity and distance to import terminal (Morgan & White, 2012). According to Morgan and White (2012), conventional ships have capacity in range of 130,000 to 145,000 m³, and the largest LNG carriers is Q-Max type, which has a maximum capacity of 266,000 m³.

LNG shipping is the key driver for LNG competitiveness as both LNG regasification and liquefaction are suffering an unexpected cost increase (Dorigoni, Mazzei, Pontoni, & Sileo, 2008). Although the raw materials prices for the ship construction also increase, the economies of scale help decreasing the overall construction costs (Dorigoni et al., 2008). Dorigoni et al. (2008) collect the data of world’s LNG shipping and find that three main LNG routes are from Malaysia, Indonesia, and Australia, all of them are to Japan. Based on the number of tankers, route Malaysia – Japan uses 18 tankers (each with a capacity of 1.9 mcm), both Indonesia – Japan and Australia - Japan use 17 tankers. Tankers from Indonesia to Japan, each has a capacity of 2.0 mcm while from Australia to Japan is 2.3 mcm.

Several units are commonly used in the LNG trade. As summarized from Natgas, produced gas is measured in volume (cubic meters or cubic feet), but once it is converted into LNG, it is measured in
mass units, usually tons or million tons. Million tons should technically be abbreviated MMT. However, the LNG industry uses MT to represent million tons. LNG ship sizes are specified in cargo volume (typically, thousands of cubic meters), and once the LNG has been reconverted to gas, it is sold by energy units in millions of British thermal units (MMBtu).

In traditional contractual practices, LNG tankers were dedicated exclusively to specific trades indicated by a common practice to build new tankers for new supply contracts (Dorigoni et al., 2008). This lack of contractual flexibility made the LNG traders could not minimize the transportation costs. In recent practices, Dorigoni et al. (2008) state that flexibility has been a new trend in LNG contracting, not only in supply contracts but also in shipping contracts. This leads to a gradual elimination of destination restriction terms, in which each tanker might be associated with multiple destinations and LNG buyers are allowed to divert their own surplus on the short-term market (Dorigoni et al., 2008).

Currently, there are two types of LNG shipping contracts. In a destination ex-ship (DES) contract, suppliers will incur all shipping costs. The other one is a freight on board (FOB) contract, in which the supplier only pays the transportation cost until the port of shipment and the rest will be covered by the buyer.

3.2.3 Storage and Regasification

LNG Storage is an important part of the LNG value-chain and is present at both the liquefaction and regasification facilities. The storage and regasification terminal can be either an onshore terminal, comprising a dedicated jetty regasification unit (JRU) that makes use of a moored floating storage unit alongside to hold the LNG buffer stock, or a floating storage regasification unit (FSRU) on-board a ship (Strande & Johnson, 2013). As defined by Strande and Johnson (2013), FSRU is an LNG carrier converted by the addition of on-board storage and regasification facilities.

The main components of FSRU are (Bulte, 2013): LNG transfer system (offloading system), storage tanks (in ship), boil-off gas (BOG) handling system, LNG pumping system, vaporization equipment, delivery facility (connected to the subsea pipeline or via high-pressure loading arms fixed on a jetty), and auxiliary systems. According to Bulte (2013), there are three possible means of LNG vaporization:

- Open Loop Seawater: pumping warm seawater across the vaporizer and discharging cooled seawater
- Closed Loop Water: pumping fresh water through a closed circuit in which the water is warmed in the FSRU boilers and cooled across the LNG vaporizer
- Closed Loop Steam: using steam produced in the FSRU boilers to vaporize the LNG and returning the condensate back to the boilers in a closed loop

Compared to onshore import terminals, FSRUs present a strong economic case because they can typically be built in half the time – around two years – and at half the cost in some instances (Strande & Johnson, 2013).
3.2.4 Cost Structure of LNG Systems

As in the pipeline case, each infrastructure requirement in the LNG value chain is capital intensive and the investment is usually front-end loaded so that revenue does not begin to flow until the project is complete (Jensen, 2003).

Cost Structure of LNG Liquefaction Plants

Songhurst (2014) collects various LNG liquefaction projects and finds the cost breakdown based on plant area and category as shown in figure 3.4.

Figure 3.4 LNG liquefaction plant cost breakdown (Songhurst, 2014)

As indicated in the figure, construction costs typically represent 30% of the total project cost. Addition marine offsite facilities can increase the costs significantly. The cost of construction is primarily driven by plant location and is a combination of construction man hours, labor costs, and productivity. For the equipment, the main costs are the cryogenic heat exchangers, refrigeration compressors and drivers, power plant, and LNG storage tanks (Songhurst, 2014). As noted by Songhurst (2014), the owner’s costs include the costs of the owner’s project team and support services from the planning stage to handover to the operations department. The costs also include cost of all specialist contractors and consultants for activities such as feasibility studies, drawing up commercial contracts for the purchase of the feed gas and the sale of LNG, working with the project financiers (banks) and the government organizations and other regulatory bodies for permitting. Songhurst (2014) compares the cost for complete facility and only liquefaction based on the location, as shown in table 3.6.

Table 3.6 Liquefaction plant metric cost (Songhurst, 2014)

<table>
<thead>
<tr>
<th>Complete Facility</th>
<th>High</th>
<th>High High</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(US$ 1000-1200 /tpa)</td>
<td>(US$ 1400-1800 /tpa)</td>
</tr>
<tr>
<td>Liquefaction Only</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td></td>
<td>(US$ 600-800 /tpa)</td>
<td>(US$ 1000-1200 /tpa)</td>
</tr>
<tr>
<td>Normal Cost</td>
<td>High Cost</td>
<td></td>
</tr>
</tbody>
</table>

LOCATION

Morgan and White (2012) also try to breakdown the CAPEX of LNG liquefaction, as follows: pretreatment 6%, liquefaction 50%, utilities 16%, LNG storage 18%, and loading facilities 10%, with annual operating expenditures as much as 3% of the CAPEX.
The overall schedule for major liquefaction projects is 10 years (Songhurst, 2014), from initial planning of evaluation (1 year), feasibility studies (2 years), appraisal and optimization (2 years), to development (5 years). The development activities include front end engineering design (FEED) and bidding for 2 years, and engineering-procurement-construction (EPC) for 4 years. For modular floating liquefaction unit, the construction

**LNG Shipping Cost**

The LNG shipping costs could be classified into four (or five) components (IEA, 2014):

- **The daily rates for tanker.** As of July 2014, the shipping rate was less than half of its peak at USD 65,000 per day for a tanker carrying 130,000 cubic meters (the equivalent of 3,000,000 million British thermal units). This is due to the large expansion of the tanker fleet and narrowing of the west/east arbitrage window.

- **The fuel cost** is a key component of the total shipping cost. It is very dependent on fuel prices.

- **The small losses resulting from boil-off** is the evaporation loss during the shipping. On a round trip, the evaporated volume amounts to about 0.2% per 1000 km of distance shipped.

- **The costs for berthing at the ports.** It is estimated to be on average USD 200,000 per port per day.

- **Other costs.** These costs depend on the chosen shipping route. An example is given to Singapore as the destination of LNG shipping. From the Northwest Australian projects, the distance is only 1,700 NM and it costs USD 0.7/MMBtu. Shipping from East African LNG is almost twice as expensive and from the North American west coast, LNG would cost approximately three times the price. The U.S. Gulf and East Coast projects, as well as Yamal LNG, could arrive in Singapore at a shipping cost range of USD 3.3 to 3.9/MMBtu (IEA, 2014).

**Total Cost**

Total CAPEX allocation of the LNG supply chain can be estimated as follows:

<table>
<thead>
<tr>
<th>Table 3.7 CAPEX allocation of the LNG supply chain</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Morgan and White (2012)</strong></td>
</tr>
<tr>
<td>Upstream Development</td>
</tr>
<tr>
<td>LNG Plant</td>
</tr>
<tr>
<td>LNG Shipping</td>
</tr>
<tr>
<td>Receiving &amp; Regasification Terminal</td>
</tr>
</tbody>
</table>
A Review of Gas Infrastructure Models and Option Valuation Techniques

In this chapter, a review of gas infrastructure models at European and global level will be presented. This is due to the unavailability of gas infrastructure models for Southeast Asia and even Asia. The review is expected to give some insights to develop a gas infrastructure model for Southeast Asia. This chapter will also include various option valuation techniques, i.e. discounted cash flow and real options valuation that will be used to value the options of proposed gas projects in the region.

4.1 SELECTED STUDIES OF GAS INFRASTRUCTURE MODEL

Several gas infrastructure models have been built either at the European level, e.g. EUGAS (Perner & Seeliger, 2004), GASTALE (Boots, Rijkers, & Hobbs, 2003), TIGER (Lochner, 2007), InTraGas (Neumann, Viehrig, & Weigt, 2009) or at a larger scale (global), e.g. World Gas Trade Model from the Baker Institute (Hartley & Medlock, 2005). To the extent of the author’s knowledge, there has not been any gas infrastructure models built for Asia. At this section, a brief review of each model, the way it works, important assumptions, inputs, and outputs of the model will be discussed.

4.1.1 EUGAS Model

Perner and Seeliger (2004) develop a model, called EUGAS, to analyze the future European natural gas supply. The model is based on a long-term, dynamic, and inter-regional optimization model with an aim to optimize the natural gas supplies at minimum costs. The model provides forecasts until year 2030 (from 2005), divided to several periods, where each period has five years duration. The main parameters in the model are European gas demand, supply costs, and gas reserves. The model includes natural gas infrastructures such as gas pipelines, liquefaction plants, and regasification terminals. Together, the infrastructures form a transportation network that is modelled as a system of interlinked nodes, also called ‘hubs and spokes’. One of the key parameters is gas supply cost that comprises of capacity and operating costs of gas production and transportation. The EUGAS model uses a discount rate of 10% for both production and transportation. According to Perner and Seeliger (2004), different discount rates could be applied because of different risk exposures for production and transportation activities.

In EUGAS model, natural gas demand and availability of resources are given exogenously. Production costs include investment costs and operating costs, differ for each producing area. The model does not only include European gas producers, e.g. the Netherlands, Norway, the U.K., but also non-European exporting countries, e.g. Algeria, Egypt, and Libya. The production costs at each producing area have specific cost ranges from the lowest cost level to the highest cost level (in USD/MMBtu).

Construction costs of the pipelines are based on diameter of the pipelines, derived from pipeline cost data in the U.S. and Canada from the Oil and Gas Journal. For onshore pipelines, it is estimated at USD 1,200 per km x mm. For offshore pipelines, the investment costs are estimated to be 50% above the
onshore pipelines. The economic lifetime of the pipelines is assumed to be 30 years with internal rate of return on capital is 10%.

For LNG liquefaction, the investment costs are estimated to be USD 240 per ton per annum, while for LNG regasification, it is estimated to be USD 80 per 1000 cubic meter per annum. For the LNG tankers, the price is USD 175 million per tanker with a standard capacity of 135,000 m$^3$. The economic lifetime of all LNG facilities is assumed to be 20 years with 10% internal rate of return on capital (Note: the operating costs of pipeline and LNG facilities are not discussed in the paper). The model also includes future cost reduction caused by technological progress. It is assumed that the production costs will decrease by 1.0 to 1.5% per year. For transport facilities, it is assumed to decrease by 0.5 to 1.5% per year. However, due to the maturity of technology, it is estimated that the annual cost reductions are diminished by 3% annually.

The results of the model are forecasted investments in production and transport capacities. The model predicts that there will be an increase in long-term marginal supply costs due to development of new gas sources and cross-border prices that should cover the investment costs. The results also indicate the importance of gas imports and transits for the future European supplies.

4.1.2 GASTALE Model
Lise and Hobbs (2008) extend the GASTALE model (Boots et al., 2003), including four types of investments for expansion of pipeline, liquefaction, regasification, and storage capacity. Investments in gas production capacity are assumed to be exogenous. The model is calibrated at higher aggregation level (less details) than EUGAS (Perner & Seeliger, 2004) by grouping the European countries into two groups, called EU15 and CEEC10. The model also includes four exporting region as follows: Algeria, Norway, Russia, and world LNG.

The model addresses the market participants such as producers, TSOs (Transmission System Operators), SSOs (Storage System Operators), and consumers in various sectors. The model assumes that producers have market power (to define the amount of capacity put in the market) and thus, a recursive-dynamic game theoretic principle is used in the model. The model is built to maximize profit of producer, TSOs, and SSOs. The model also has market clearing condition, and thus, produces a single wholesale gas price.

As inputs, the model considers production capacity and marginal production costs at each region and also capacity, investment costs, and marginal transportation costs for both pipeline and LNG facilities. The model also includes capacities, investment costs and marginal operational costs of storage facilities in both consumer regions.

The results of the model are wholesale gas prices from the market clearing until year 2030, security of supply level based on share of EU15 production from the EU E15 consumption, and new investments needed for storage (in EU15 and CEEC10), gas pipelines (connecting exporting regions to importing regions), liquefaction (exporting regions), and regasification facilities (in EU15 and CEEC10) from 2005 to 2030.
4.1.3 InTraGas

Neumann et al. (2009) build an investment model, called Intragas (investments into transmission facilities of natural gas) with an objective to maximize welfare and subject to constraints of natural gas infrastructure facilities, e.g. maximum capacity and flow or volume balance. The welfare function deducts gross consumer surplus (assuming a linear demand function for each country) by the accumulated costs for production, pipeline transport, and LNG transport.

Data for production and demand in this model are taken from the IEA and BP Statistics (2006). Data for production costs are taken from OME (2005) with a range from 0.45€/MMBtu in Algeria to more than 1.70€/ MMBtu in the U.K. According to the report, the majority of exporters produce in a cost range of 0.30 to 0.60€/ MMBtu.

The output of the model is the optimized volume or gas flow at each infrastructure that maximize the welfare function. The main parameters of the results are average price (€/MMBtu), LNG regasification utilization and pipeline utilization (from exporting region to importing region, e.g. Russia-EU, Africa-EU, and Caspian-EU). The average (nodal market) price is derived from the obtained optimal demand d (from the energy balance equation) and the linear demand function p(d).

4.1.4 TIGER Model

Lochner (2007) builds a linear dispatch model to optimize natural gas supply to all European countries, called TIGER (Transport Infrastructure for Gas with Enhanced Resolution). It provides enhanced resolution because the model consists of elements from the European Database of Gas Infrastructure (EDGIS) such as more than 500 nodes and more than 650 pipeline sections with their individual characteristics, e.g. diameter, pressure, capacity, length, and owner. The model also includes gas production in Europe and neighboring countries which are aggregated to 17 production regions, non-European production from four regions which enter the system through LNG import terminals, more than 147 gas storage facilities, at least 24 LNG terminals, 53 demand regions and 58 demand profiles distinguished by country and sector. Lochner (2007) identifies production, consumption and infrastructure as three main parameters in the model. For the consumption data, he uses demand forecast from Gas Strategies (2007), and for production capacities and costs, he refers to the EUGAS model. For the infrastructures, the model relies on data from the EDGIS.

Lochner (2011) explains the gas price assumption in the model, which is based on locational marginal pricing that assigns an individual competitive locational price to each node (entry or exit point). He assumes the market to be competitive, so that the price will equal to the total system marginal costs of supplying one additional unit of gas volume at the respective location. He also states that the prices in natural gas market are not exclusively determined by supply and demand, but also by the availability of the gas transport infrastructure (Lochner, 2009). He argues that scarcity or lack of transportation capacity might cause the prices form in (local) residual markets and could differ regionally, and thus, in turn, temporal and regional price differences could determine the value of storage and transport capacity when there is a scarcity.

The results of the model (Lochner, 2007) are utilization of the capacities of each infrastructure, i.e. pipelines, storage, and LNG facilities. The model also runs several scenarios and compares not only
A Review of Gas Infrastructure Models and Option Valuation Techniques

the utilization of infrastructure capacities but also import quantities from various sources. Lochner (2011) continues the experiment further and uses the model to analyze congestion mark-ups at each inter-connection points, which could be used as investment signals to expand current capacity of the infrastructures or build new routes of pipelines.

4.1.5 The Baker Institute World Gas Trade Model

According to Hartley and Medlock (2005), the WGTM model uses a principle of spatial and inter-temporal equilibrium of the world market for natural gas (also called a dynamic spatial general equilibrium model). The use of the model is to calculate patterns of production, transportation routes, and prices to equate both demands and supplies with a main objective to maximize the present value of producer rents, assumed that the markets are competitive.

Data for supplies and demands in each location are taken from several sources, such as the United States Geological Survey, the Energy Information Administration (EIA), the International Energy Agency (IEA), the World Bank and various industry sources. The costs of constructing new pipelines and LNG facilities are estimated based on previous and potential projects from the EIA and industry sources. Hartley and Medlock (2005) forecast the demands for the model based on five major determinants: population, economic development, resource endowments and other country specific attributes, the relative price of different primary fuels, and new technological developments. For the supplies, they use the geologic data surveys.

The model is then built on a commercial software platform that can calculate a dynamic spatial equilibrium where supply and demand is balanced at each location in each period. According to Hartley and Medlock (2005), the model will seek an equilibrium in which the sources of supply, the demand sinks, and the transportation links that connect the sources and the sinks, are developed over time so that the net present value of new supplies and transportation projects could be maximized. The outputs of the model include regional natural gas prices, pipeline and LNG capacity addition and flows, growth in natural gas reserves from existing fields and undiscovered deposits, and regional production and demand.

Insights

All models that have been presented in the previous sub-sections use different approaches or basic principles. For instance, the EUGAS is built based on a dynamic optimization model, the GASTALE adopts game theory principles, while the TIGER model uses a simpler linear dispatch model, and the WGTM uses a dynamic spatial general equilibrium principle. Based on the level of aggregation, the GASTALE model extension by Lise and Hobbs (2008) is the highest because it groups the European countries into two main groups. The WGTM model, although includes most countries in the world, uses a lower aggregation by identifying each gas infrastructure (location) in each country. The TIGER model has the lowest aggregation level with its 500 nodes, 650 pipeline sections, and more than 147 gas storages in Europe. Therefore, in this research, the author will have to define the level of aggregation which depends on the availability of data needed to build the model.

The previous models mostly share same kinds of data needed, for example, gas reserves, gas production, gas demand, capacity of each gas infrastructure, including the investment (construction) and the operating costs. Some models also explicitly state which data are exogenously defined and
what assumptions are used in the model. This information is very useful to build the gas infrastructure model for Southeast Asia. Some models have gas prices as output of the model. However this will be less applicable in this research because most trades are based on long-term contracts and there is no gas hub or trading points that could generate new gas prices. Therefore, instead of as an output, the gas price will be included as a key parameter in the model, and be referred to Japan-cif index because Japan and other countries in Northeast Asian are the main destinations for LNG exports from Southeast Asia.

All reviewed models give assurance for the author that additional capacity requirement for each gas infrastructure could be produced by the model (as output) and could be used as investment signals for expansion or to build new facilities. Some scenarios based on key parameters such as gas production, gas demand, and gas prices also could be built to test the performance of the model and observe the changes in the capacity (gas flow or volume) allocation, additional capacity requirement, and net present value of the investment or the profit (or revenues) gained by the operators/ producers/ traders. However, unlike the liberalized markets in Europe, the gas markets in Southeast Asia (except for Singapore) are still dominated by vertical integration of the state-owned gas companies. Therefore, the separation of actors’ role during the gas value chain is less relevant for the Southeast Asian case.

4.2 VALUATION OF INVESTMENT

Various methods are available to help decision makers valuing an investment. Discounted cash flow (DCF) method has been widely used and being regarded as traditional valuation method (Kodukula & Papudesu, 2006; Mun, 2002). One of its limitations is its inability to capture the value of flexibility in a project, especially when the project is in highly uncertain environment and some information which is not available at present, could be available in the future and change the environment and the value of the project itself. As noted by Copeland and Keenan (1998), simple NPV rule in DCF method could not capitalize on emerging opportunities during the lifetime of the project as it ignores the possibilities that there are options to expand, defer, or abandon the project. This then promotes a newer valuation method, which is called Real Options Valuation (ROV) or Real Options Analysis (ROA) that could incorporate the value of flexibility. In this research, these two methods (i.e. DCF and ROA) will be used to value the investment options of the gas infrastructure projects in Indonesia. In some cases, the methods will be combined with Monte Carlo Simulation and decision tree analysis (DTA).

4.2.1 Adjusted Discounted Cash Flow

The basis of DCF method is the calculation of net present value of a project that includes all revenues and costs during the life of the project which are discounted back to the present value using a number which is called a discount rate or discount factor. The first thing to do is to build a cash flow model to enlist all revenues and costs. The NPV formula of a project (Kodukula & Papudesu, 2006) could be written as follows:

\[
\text{Project NPV} = PV\ of\ free\ cash\ flow - PV\ of\ investment\ cost \quad (4.1)
\]

The cash flow will include all costs, e.g. operating cost, shipping cost, except the investment cost. The most important factor in using DCF method is the value of the discount rate. Generally, a low discount rate could make a project with high up-front capital investment be accepted as long as the NPV is
positive. On the other hand, the project might be rejected if higher discount rate is used which could turn the NPV into a negative value. Boardman, Greenberg, Vining, and Weimer (2011) present several approaches to calculate the discount rate depending on the source of the fund. They are marginal rate of return on private investment if the project is entirely financed by domestic financial market, social marginal rate of time preference if the project is entirely financed by tax, government’s borrowing rate if the project is entirely financed through foreign borrowing, and weighted average approach by assigning specific weight to each funding source, assuming that a project could be financed by some portion of domestic financial market, tax, and foreign borrowing.

Another more common approach is the risk adjusted discount rate, in which higher discount rate is used to discount project’s cash flow that is more risky, and lower discount rate when valuing safer assets (Damodaran, 2008). According to Kodukula and Papudesu (2006), there are two important factors that determine the discount rate for a cash flow: magnitude of risk (cash flow uncertainty) and type of risk (private risk versus market risk). If there is no risk associated with the cash flow, or in other words, the cash flows are pretty certain, then a risk-free interest rate should be used to discount the cash flows. In practice, the risk-free interest rate (also called riskless rate) is based on the interest rate paid by the U.S. Treasury. Since it might be difficult to differentiate private risk from the market risk, the discount rate could be calculated based on the cost that has to be paid by a company to obtain the required investment capital. The value could be derived from the weighted average cost of capital (WACC) that represents different cost components of issuing debt, preferred stock, and common equity (Brandao, Dyer, & Hahn, 2005; Kodukula & Papudesu, 2006). The value of the common equity is usually calculated using the capital asset pricing model (CAPM).

In this research, the discount rate will be based on approximation from Kotzot, Durr, Coyle, and Caswell (2007) that have applied the CAPM and WACC formulas. This is due to the limitation of information available about each company financial resources. In practice, each gas project might involve several companies and it will be hard to find information of the capital structure of each company. A sensitivity analysis will be performed to see the change in the NPV value when the discount rate is changed.

In an adjusted DCF model, the cash flow will be built based on the cost structure in the PSC (see section 2.2.2). Therefore, in the cash flow, there will be a term of FTP for the government, FTP for the contractor, cost recovery, tax, and profit sharing between the government and the contractor. As the results, there will be two NPVs, one for the government, and the other one for the contractor. The investment cost will not be valued separately because there will be a cost recovery in the annual cash flow to recover the investment cost. At the end, the formula of the project NPV is:

\[ \text{Project NPV} = \text{PV of adjusted cash flow (including investment cost)} \]  
(4.2)

4.2.2 Real Options Analysis

ROA uses the tools and methods provided by (financial) options theory to evaluate physical or real assets in the real world (Sadowski, 2007). Unlike financial options, real options do not have precise exercise prices and fixed expiration dates. Their exercise prices and expiration dates are functions of the resources involved in the project and competitive environment created by their competitors (Miller & Waller, 2003) or specific bilateral contract agreement with the government, especially in the case of oil and gas projects. ROA has been widely used to evaluate oil and gas investments, e.g. to
value oil or gas fields (Copeland & Keenan, 1998; Leslie & Michaels, 1997) or to value the future contracts (Rodriguez, 2008; Smith & Mccardle, 1999).

According to Miller and Waller (2003), ROA makes a good combination with scenario planning as tools for managers to make strategic investment decisions under uncertainty. On one hand, scenario planning could capture the contingencies, uncertainties, trends, and opportunities of the future, while on the other hand, ROA provides a quantitative approach to measure the potential of value creation if flexibility under uncertainty is maintained during the project. The essential value of real options, according to Damodaran (2008) is its ability to facilitate learning, in which investors or managers could observe conditions in the real world and adapt their behavior to increase the potential upside from the investment and to decrease the possible downside.

Trigeorgis (2002) enlists types of project options that are essential to be valued with real options: option to defer investment, option to abandon staged investment, option to expand, option to contract, option to temporarily shut down (and re-start) operations, option to abandon for salvage value, and option to switch use (inputs or outputs). Kodukula and Papudesu (2006) introduces option to choose, which in practice is a combination between option to expand, option to contract, and option to abandon. They also present ways to calculate what they call as compound options, which is similar to option to stage the investment. Compound options could be done sequentially or in parallel, depending on the stages during the investment. According to Kodukula and Papudesu (2006), the Black-Scholes formula and binomial method are two most commonly used methods to value real options. In this report, the author will use these two methods to value the infrastructure options in each potential gas project in Indonesia.

Black-Scholes Formula
The Black-Scholes formula has been widely employed in financial options valuation, especially to value the European financial options that are based on assumptions that the option is exercised only on a fixed date and no dividends are paid during the option life (Kodukula & Papudesu, 2006). It also assumes the underlying asset value has a lognormal distribution, which in practice may not be always true. Another weakness of this method is its mathematical complexity that seems like a ‘black box’ approach that makes the intuition behind the application lost (Kodukula & Papudesu, 2006).

The formula used to calculate the option value is as follows (Damodaran, 2002):

\[
\text{Option value (call)} = S \cdot N(d_1) - K \cdot e^{-rt} \cdot N(d_2)
\]

\[
\text{Option value (put)} = K \cdot e^{-rt} \cdot (1 - N(d_2)) - S \cdot (1 - N(d_1))
\]

Where

\[
d_1 = \frac{\ln \left( \frac{S}{K} \right) + (r + 0.5 \sigma^2)t}{\sigma \sqrt{t}}
\]

\[
d_2 = d_1 - \sigma \sqrt{t}
\]
To get the value of the underlying asset or the stock price, analysts need to compute the present value of the cash flow, excluding the investment costs. Basically, this shares similar principle with DCF method except for the riskless rate and volatility that enable ROA method to value the option flexibility.

**Binomial Method**

The binomial method offers more flexibility compared to the Black-Scholes formula (Kodukula & Papudesu, 2006). According to Kodukula and Papudesu, the key advantage of the model is its transparency in its underlying framework which makes the results easy to explain and to be understood by the management. However, the value resulted through the binomial method is more like an approximation of the Black-Scholes formula. A closer result with Black-Scholes formula could be obtained with smaller time interval (δt) which will make the lattices become longer. The main input parameters needed in this model are relatively similar with the Black-Scholes formula, except for the δt. There are three option parameters that need to be calculated: upside volatility movement (u), downside volatility movement (d), and probability (p). Figure 4.1 illustrates the binomial lattice form with t = 3, and δt = 1. The formulas to calculate the option parameters are presented afterwards.

![Figure 4.1 Binomial lattice form](image-url)
Following is a set of formula to build the binomial lattice (4.5).

\[ u = \exp(\sigma \sqrt{\delta t}) \]
\[ d = \frac{1}{u} \]
\[ p = \frac{\exp(r \delta t) - d}{u - d} \]

When there is a leakage (l), the \( p \) becomes:

\[ p = \frac{\exp((r - l) \delta t) - d}{u - d} \]

Brandao et al. (2005) propose a method to calculate the project volatility (\( \sigma \)). Given that \( V_0 \) is the expected present value of the project at time 0, then \( V_t \) could be calculated using a risk-adjusted discount rate \( \mu \) as follows:

\[ V_t = \sum_{i=t}^{n} \frac{C_i}{(1 + \mu)^{i-t}} \]  \hspace{1cm} (4.6)

Afterwards, the volatility \( \sigma \) could be calculated as the standard deviation of \( \ln \left( \frac{V_1}{V_0} \right) \) of the project returns between time 0 and 1 that is obtained from the simulation results. According to Brandao et al. (2005), the volatility could be defined as the annualized percentage standard deviation of the returns.

**Combined ROA and DTA**

ROA is quite flexible in essence that it could be combined with other methods, such as decision tree analysis (DTA), or Monte Carlo simulation. Further in this research, the author will try to combine DTA and ROA to value the gas infrastructure options. DTA incorporates probabilities that are defined by the management to account for market or private risk (Kodukula & Papudesu, 2006). In practice, the probabilities are not always well known. Sensitivity analysis by changing the values of the assigned probabilities could be done if the management wants to compare the results of the DTA. Both DTA and ROA share similar principle of path dependency, in which the optimal decisions at each stage are based on the outcomes at prior stages (Damodaran, 2008).

In this research, the author will try to use DTA to incorporate the private risk of the company, i.e. the ability of the company to execute the project, which is translated to the probability of success or failure of the project. This especially will be applied to cases that have staged investments. The real options will be embedded in the model as flexibility options (e.g. expand, abandon, defer) either the project succeeds or fails.

**Insights**

Each valuation technique has its own strengths and weaknesses. DCF is easier to perform compared to ROA. Even in ROA, the DCF calculation is still needed to calculate the underlying value of one particular asset or project. DCF could be adjusted to the PSC structure of each host country. However, it lacks of flexibility to take into account multiple options and fails to accommodate new information (which at present, being regarded as uncertainties) that might be available in the future. ROA, on the other hand, with the binomial lattice method could show the extent to which the project value might change when new information is available (captured by the volatility up and down). However, in practice, there could
be multiple sources of uncertainties and it would be difficult to estimate the volatility. Therefore, it is possible that the information regarding the uncertainties is not available at all or has been too late when being known, and consequently no change in decision could be made. Both DCF and ROA share similar strength in which they could be combined with other methods such as Monte Carlo Simulation and Decision Tree Analysis.
5 GANESA Model

Information presented in the preceding chapters will be used to build a gas network model for Southeast Asia. The model will represent the existing gas infrastructure and future projection of the gas production and consumption in each Southeast Asian country. The results from this model will be used as inputs for the second model, the option valuation model. The option valuation model will take into account possible options to develop the existing gas infrastructure, either through expansion or build a new infrastructure. This chapter will focus on the conceptualization, development, verification, and validation of the gas network model. A first glance of the conceptualization for the option valuation model will be included in this chapter. Discussions regarding the development of the option valuation model can be found in chapter 8.

5.1 MODEL DEFINITION

GANESA model represents the existing Gas Network in Southeast Asia, mainly consists of cross-border gas pipelines and LNG infrastructures, i.e. liquefaction plants and regasification terminals. Discussion regarding gas storages in Southeast Asia has not been much raised. Since there is no information available regarding the existing gas storages in the region, gas storages will be excluded from the model.

Figure 5.1 shows the simplified model of the activities along the natural gas value chain. This illustrates a condition that could happen in a country that has gas reserves, does production, uses or consumes the gas, and also gets involved in gas trading (export-import).

![Figure 5.1 Natural gas value chain](image)

In this model, only seven countries (out of the ten ASEAN members) are included because they are major gas producers or consumers. The producing countries must have some amount of proven gas reserves. These reserves are taken out through production activities, go through refinement and sometimes be liquefied to become LNG. Afterwards, the gas could be transported either via pipelines or LNG shipping. Generally, the natural gas be liquefied so that it could be shipped to long-distance places, i.e. for export. However, in countries that have large and wide territory, e.g. Indonesia, LNG shipping is also utilized to fulfil domestic demand. For example, LNG could be shipped from LNG liquefaction facilities in Kalimantan, Sulawesi, or Papua to meet gas demand in Java.
The producing countries usually have some bilateral long-term contracts to export the natural gas either via pipelines or LNG shipping. These contracts have minimum amounts that have to be delivered or taken out every year until the contracts expired. This mechanism depends on the contract. For example, there is a clause of take-or-pay in the gas sales agreement between Indonesia and Singapore (Sovacool, 2009). This means Singapore, as the consumer, has to take the minimum amount of gas as is agreed in the contract otherwise pays a penalty to Indonesia, as the supplier. Other special clauses used in the contract for other cross-border gas pipeline trades in Southeast Asia are not publicly known.

5.1.1 Functional Requirements

To evaluate the proposed gas infrastructure expansion plan (as in section 2.3), the model must be able to perform following functions:

A. The model must find optimal allocation of natural gas (or LNG) for domestic and export-import trade
B. The model must produce capacity utilization of each gas infrastructure in each country
C. The model must be able to capture additional capacity required at each gas infrastructure in each country
D. The model must accommodate uncertainties in the gas market

Design space with selected options (words in bold) is made to achieve those functions as presented in table 5.1. The design space is developed based on the model review in chapter 4. The selections are based on several considerations, mainly related to the current market condition and data available.

Table 5.1 Design space and considerations in model definition

<table>
<thead>
<tr>
<th>Functions</th>
<th>Design Space</th>
<th>Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td><strong>Principles:</strong> linear programming</td>
<td>Gas markets in most Southeast Asian countries have not been liberalized, i.e. vertical integration, no separation of actors along the value chain (subsidiaries of the parent state-owned company); no geological data available; long-term contracts dominated by oil-linked pricing mechanism</td>
</tr>
<tr>
<td></td>
<td>game theory</td>
<td>Domestic production and consumption are given exogenously. Amount of LNG shipping (for export) is assumed to be equal to amount of natural gas processed in the liquefaction while LNG imported is equal to LNG regasified. Volume of export-import can be derived from capacity utilization at liquefaction, regasification and pipeline transmission facilities.</td>
</tr>
<tr>
<td></td>
<td>dynamic optimization</td>
<td></td>
</tr>
<tr>
<td></td>
<td>dynamic spatial general equilibrium</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Activities: production (include gas lifting and refinement), <strong>liquefaction</strong>, regasification, gas pipeline transmission, storage, LNG shipping, trading, consumption</td>
<td></td>
</tr>
<tr>
<td>B</td>
<td><strong>Level of aggregation:</strong> Country-based</td>
<td>Data available; time to process the data; see section 5.1.2</td>
</tr>
<tr>
<td></td>
<td>Infrastructure-based</td>
<td>Note: Country-based is a higher aggregation of infrastructure-based. Infrastructure-based takes into account each (physical) infrastructure distinctively.</td>
</tr>
<tr>
<td></td>
<td>Source of import and export destination: not specified</td>
<td></td>
</tr>
<tr>
<td></td>
<td>region</td>
<td></td>
</tr>
<tr>
<td></td>
<td>country</td>
<td></td>
</tr>
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</table>
Table 5.1 Continued

<table>
<thead>
<tr>
<th>Functions</th>
<th>Design Space</th>
<th>Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>C</td>
<td>Dummy variables</td>
<td>It is needed to know additional capacity requirement of each gas infrastructure.</td>
</tr>
<tr>
<td></td>
<td>Introduce dummy variables for all decision variables (gas pipeline, liquefaction plant, regasification terminal).</td>
<td></td>
</tr>
<tr>
<td>D</td>
<td>List of uncertainties: amount of proven reserves, domestic production growth, domestic consumption growth, future export/import contract, new pricing mechanism, market liberalization, change in PSC structure or gas sales agreement (i.e. more flexibility), unconventional gas resource development</td>
<td>Key uncertainties that will significantly change the investment strategy (see chapter 6) and can be included in the model.</td>
</tr>
<tr>
<td></td>
<td>The way other uncertainties might affect the investment strategy will be discussed in chapter 10 (discussion).</td>
<td></td>
</tr>
</tbody>
</table>

5.1.2 Level or Scale of the Model

Figure 5.2 shows the representation of cross-border gas pipelines (P), liquefaction plants (L), and regasification terminals (R) in Southeast Asia with their maximum capacities. More details have been presented in table 2.5, table 2.6, and table 2.7 that can be found in chapter 2.

The GANESA model will use a higher aggregation or higher level perspective by adding up all capacities from the liquefaction plants and regasification terminals located at each country. For the cross-border pipelines, the capacity of pipelines with the same routes are also combined. This is done to reduce the number of decision variables in the model which otherwise will be too complex and unnecessary since the higher level perspective (country perspective) is already sufficient to provide the results expected from the model, i.e. capacity requirement of each gas infrastructure in each country.

Figure 5.3 shows the representation of the simplified gas network connecting the countries in Southeast Asia. As a result, there is only one pipeline connection between the countries, although in practice, there are several routes of cross-border pipelines connecting the same countries. For example, there are two cross-border pipelines connecting Indonesia and Singapore, e.g. West Natuna – Jurong (since 2001), and South Sumatra – Singapore (since 2003). There are even 3 cross-border pipelines connecting the gas fields in Myanmar to Thailand. The minimum capacities of these cross border gas pipelines are based on the historical gas trades data from BP (2014c) while the maximum capacities are gathered from various sources that have information about the project, e.g. Sovacool (2009), Offshore-Technology website. The minimum capacities of LNG exported from the liquefaction plants are also based on the historical gas trades data from BP (2014c), while the maximum capacities for both liquefaction plants and LNG terminals are based on a report published by the IEA and ERIA (2013).

Sources of LNG import and export destinations outside Southeast Asia will not be addressed in the model. In LNG trade, as long as the infrastructures (liquefaction-shipping-regasification) are available and have sufficient capacity, LNG could be delivered from and to any places. Including potential buyers and suppliers could give an insight with respect to the most efficient trade, i.e. shortest distance or routes to ship LNG. However, there is no guarantee that the buyers will select the nearest suppliers.
Countries outside Southeast Asia started importing LNG in 2014. Economic deals might have greater influence, however, these suppliers. Other factors such as political relation between buyer countries and suppliers, and other economic deals might have greater influence, however, these could not be easily modeled.

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**Figure 5.2 Gas network infrastructure in Southeast Asia based on data at the end of 2013**

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**Figure 5.3 Simplified gas network model based on data at the end of 2013**
5.1.3 Conceptualization of GANESA Model

The model will be built on the basis of linear programming for following reasons:
- The main function of the model is to find the optimal allocation of natural gas that goes through liquefaction facilities (for export), regasification facilities (for import), and cross border gas pipelines (export/import). This can be seen as a network flow problem and can be solved with linear programming (Ragsdale, 2008).
- The objective function and constraints of the model are linear.
- The model has no discrete decision variables. In other words, all decision variables of the model are continuous.

The time frame of the model is 32 years, from 2014 to 2045. It will be started from 2014 because the latest reports of natural gas or LNG trade were published in 2014 and the latest data used was 2013’s data. An approximate duration of 30 years is selected. In practice, pipeline networks could reach 40 to 50 years of lifetime (Herder et al, 2011).

The objective function in this model is to maximize cash-flow balance (maximize profit or minimize loss) in all included countries in the model.

\[
\text{Maximize: } \sum_{t=1}^{32} \sum_{i=1}^{7} \text{NCB}_{i,t}
\]

In this model, LNG export destinations and sources of LNG import are neglected. Therefore, the formula of LNG trade transactions can be generalized and used by each country. However, this is not applicable for the pipelined gas trade. Pipelined gas trade involves both supplier (exporting country) and buyer (importing country) that are located in Southeast Asia. Besides physical gas movement, there is also cash (money) movement. Therefore the pipelined gas trade is addressed differently for each country, i.e. node to node or bilaterally.

In this model, single gas price referring to JCC index is used for both LNG and pipelined gas trades. The revenues gained by each country come from export activities and domestic gas market. The prices for domestic gas market (except Singapore) are usually determined by the government. In gas producing countries the domestic gas prices, normally, are lower than the export prices. The costs incurred include production, liquefaction (plus LNG shipping), import, and regasification activities. The formula to calculate the cash-flow can be summarized as follows:

\[
\text{NCB}_{i,t} = \text{CB}_{i,t} + \text{pipeline transaction}_{m,t};
\]

Where:
- \( \text{NCB} \) = net cash-flow balance; \( \text{CB} \) = cash-flow balance; \( i \) = index of countries;
- \( m \) = index of cross-border pipelines; \( t \) = years
- \( \text{CB}_i = \) domestic revenue - production cost + lng_export_revenue - (lng liquefaction_cost + LNG_shipping_cost + LNG_import_cost + LNG_regasification_cost)
  - domestic_revenue \( i \) = domestic_gas_price \* domestic_consumption \( i \)
  - production_cost \( i \) = wellhead_price \* production_volume \( i \)
  - lng_export_revenue \( i \) = single_gas_price \* (lng_export \( i \) + lng_export_dummy \( i \))
- total_liquefaction_cost\ _i = \text{liquefaction\_cost} \ \times \text{lng\_export} \ _i + (\text{liquefaction\_cost} + k) \ \times \text{lng\_export\_dummy} \ _i
- \text{lng\_import\_cost}\ _i = \text{single\_gas\_price} \ \times (\text{lng\_import} \ _i + \text{lng\_import\_dummy} \ _i)
- total_regasification_cost\ _i = \text{regasification\_cost} \ \times \text{lng\_import} \ _i + (\text{regasification\_cost} + k) \ \times \text{lng\_import\_dummy} \ _i
- total_shipping_cost\ _i = \text{shipping\_cost} \ \times (\text{lng\_import} \ _i + \text{lng\_import\_dummy} \ _i)

Assumed to be paid by producer or exporting countries because the gas price refers to Japan-CIF\(^3\) index

**Pipeline transaction**

Exporting country will gain revenues as follows:
\[
\text{single\_gas\_price} \ \times (\text{pipeline\_volume} \ _m + \text{pipeline\_volume\_dummy} \ _m) - \text{transmission\_cost} \ \times \text{pipeline\_volume} \ _m - (\text{transmission\_cost} + k) \ \times \text{pipeline\_volume\_dummy} \ _m
\]

Importing country will pay costs as follows:
\[
\text{single\_gas\_price} \ \times (\text{pipeline\_volume} \ _m + \text{pipeline\_volume\_dummy} \ _m)
\]

The decision variables in this model consist of capacity utilization at each cross border gas pipelines, volume of exported LNG which is equal to the capacity utilization of the liquefaction plants, volume of imported LNG which is equal to the capacity utilization of the regasification terminal; each with its dummy variable that indicates additional capacity requirement. In total, there are 38 decision variables.

**Decision variables:**
- Volume gas transmitted via pipeline (5 variables)
  - P12, P17, P27, P54, P58 (next will be called pipeline m, where m is from 1 to 5)
  - Index: P12 \rightarrow pipeline from 1 to 2
  - Country index: 1 = Indonesia; 2 = Malaysia; 3 = Brunei; 4 = Thailand; 5 = Myanmar; 6 = Vietnam; 7 = Singapore; 8 = China
- Volume LNG exported (7 variables)
- Volume LNG imported (7 variables)
- **Dummy variable** (or capacity needed) for existing transmission pipeline (5 variables)
- **Dummy variable** (or capacity needed) for export through liquefaction facilities (7 variables)
- **Dummy variable** (or capacity needed) for import through regasification facilities (7 variables)

The constraints are (for all i, m, t):
- balancing\_volume = 0,
  where balancing\_volume = production\_volume + lng\_import + lng\_import\_dummy \ - \ (domestic\_consumption + lng\_export + lng\_export\_dummy) \ +/\ - \text{pipeline\_volume} \ _m \text{pipeline\_volume\_dummy}
- lng\_export \ \geq \ \min\_export\_capacity \ (based\ on\ historical\ &\ existing\ long-term\ contract)
- lng\_export \ \leq \ \max\_export\_capacity \ (based\ on\ existing\ liquefaction\ capacity)
- lng\_import \ \geq \ \min\_import\_capacity \ (based\ on\ existing\ long-term\ contract)
- lng\_import \ \leq \ \max\_import\_capacity \ (based\ on\ existing\ regasification\ capacity)

---

\(^3\) Cost, Insurance, and Freight; a trade term that requires the seller to arrange the shipping of goods to a port of destination
5.1.4 Conceptualization of Option Valuation Model

The results from the GANESA model will be a basis to develop the options which later will be valued by the option valuation model. The aim of the option valuation model is to evaluate the alternatives and find the most profitable alternatives under different possible scenarios. The number of scenarios will depend on the parameters such as production level, domestic consumption growth, gas prices, etc.

**Objective function:** maximize cash-flow balance (or maximize NPV) and minimize regret value (or opportunity loss) of alternative $k$

The number of alternatives and type of the alternatives will be defined after analyzing the results of GANESA model. In general, the alternatives would be gas pipeline project or LNG project (liquefaction or regasification) as proposed by the Southeast Asian countries.

The regret value is the amount of revenues that would have been gained if the particular alternative has already been in operation. The regret value could be calculated in following ways:

1. Amount of gas showed by the dummy variables * gas export price (pipeline or LNG)
2. Evaluate case by case. For example, if pipeline connection from East Natuna (Indonesia) to Thailand has been in operation, Thailand will not import more LNG. Thus, there is a regret value for Indonesia because they loss the opportunity to sell the gas to Thailand. This opportunity loss could be regarded as a leakage of the revenue, indicated by a leakage rate (see formula 4.5).
Each alternative could be developed further by introducing technology options, i.e. means to deliver the gas from the gas fields to the market, e.g. gas pipelines, onshore LNG plants, FLNG, or regasification terminal. Each technology option has its own degree-of-freedom or design selection. Liquefaction plants for example, has design variables such as location (onshore or floating), capacity (in mt gas unit), and type of liquefaction technology. See chapter 3 for more details.

The project alternatives could be developed much further by including options, such as options to expand the capacity, options to shutdown, option to abandon, and option to switch (e.g. a case in Indonesia when they converted the Arun liquefaction facility to become a regasification terminal).

![GANESA Model diagram](image)

**Figure 5.5 GANESA model extension with option valuation**

**Decision variables:** Type of technology options or options selection (delay, abandon or expand, and time to execute the options)

**Constraints:** As in GANESA model, with addition of:
- Minimum (and maximum) capacity of alternative $k$ (and its technology options) if some gas sales agreements have been concluded
- PSC structure, e.g. FTP, profit sharing, cost recovery mechanism, tax

**Additional input:** CAPEX, OPEX, and construction time of each technology option
5.2 MODEL DEVELOPMENT

5.2.1 Gas price assumption

In reality, each long-term contract has a unique formula to determine its gas selling price. The common approach is by referring to JCC index (see section 2.2.4). In this model, it is assumed that there is a single gas price based on Japan cif price, which will be used as the price for LNG export, import and gas pipeline. BP (2014c) provides a historical record of Japan cif price. However, extrapolation of Japan cif price until 2045 (time frame used in the model) is not available. To estimate the future Japan cif price, correlation of the historical data of the Japan cif price with Brent-oil index (available from EIA (2014)) will be observed.

Regression analysis has been commonly used to study the formula of LNG pricing and correlation between LNG price and oil index (Agerton, 2012; Capra, 2014). Performing a regression analysis for historical data of the Japan cif and Brent-oil index results in a formula: \( y = 0.1298x \) with \( R^2 \) value of 0.9279. The r-squared value, also known as coefficient of determination, indicates that the model could explain 92 to 93% of the variability of the data around its mean.

Capra (2014) uses a better way to find an LNG pricing formula with a closer correlation with the Brent-oil index. He takes into account the lag (in months) between the Brent-oil index and actual realization of the LNG price, resulted in higher correlation coefficient of 0.984 (compared to correlation coefficient of 0.963 in this model) and \( R^2 \) value of 0.969. However, due to the limitation of data available in monthly and time step of yearly period in the model of this research, the model as in Capra (2014) could not be used. Considering this weakness, the difference of results produced by formula \( y = 0.1298x \) and the actual historical values are observed to find the standard error of the regression model. The calculation results in a value of 1.20. With 95% confidence interval, the observation then should fall within +/- 2.40 (2 times the standard error). This will be taken into account in the simulation model of the gas price. See Appendix A for a more detail calculation.

EIA (2014) provides three scenarios of oil price. Using regression analysis, the outcome of these scenarios will be converted into gas price. Figure 5.6 shows the results of gas price extrapolation for each scenario. Since the extrapolation of oil price from EIA only available until 2040, five forward steps forecast are added to the extrapolation data.

5.2.2 Unit cost assumption

Currently, the wellhead gas price in Indonesia is 5.80 USD per MMBtu (Sunardi, 2013). The wellhead gas prices in other Southeast Asian countries are not known. Based on the report of Parkinson (2014), the wellhead gas price in Vietnam should be around 7 to 8 USD per MMBtu to get a break-even, considering the barriers of deep water offshore location and high CO₂. This is supported by Batubara, Purwanto, and Fauzi (2014) who perform a feasibility study of East Natuna gas field in Indonesia that also contains high CO₂, estimating the wellhead gas price to be 8 USD per MMBtu. According to EIA report, the natural gas wellhead price in the U.S. before the successful development of shale gas was 3 to 5 USD per MMBtu during 2000-2004 and 5 to 7.66 USD per MMBtu during 2005-2008. After the shale gas was deployed, the wellhead price was 2.56 to 4.30 (2009-2012). In this model, it is assumed the wellhead gas price for existing production to be 5.80 USD per MMBtu and for new gas fields to be 8 USD per MMBtu.
The length or distance of most cross-border gas pipelines in Southeast Asia is less than 500 km, except for Indonesia (West Natuna) – Singapore along 654 km. According to Brito and Sheshinski (1997), the cost of transporting gas via pipeline is 0.30 USD per MMBtu per 1000 km. A newest update by Schwimmbeck (2008) in Messner and Babies (2012), as shown in figure 5.7, indicates the pipeline transmission cost to be +/- 0.5 USD per MMBtu. This indicates a two-third rise in pipeline operating cost over 10 years. As in table 2.5, the diameter of the cross-border pipelines in Southeast Asia varies from 24, 28 to 36 inch. Both offshore and onshore pipelines are used in the installations. Considering the cost of offshore pipeline would be higher than onshore pipeline, for this model, it is assumed the pipeline transmission cost for all routes to be 0.5 USD per MMBtu because the length of the pipelines is less than 1000 km.

IEA (2014) publishes a report about future LNG development in Asia. According to the report, LNG liquefaction operational cost is USD 0.20 per MMBtu and LNG regasification operational cost varies between USD 0.70 to 0.90 per MMBtu. Based on data up to 2009, the operating cost for a liquefaction plant is around USD 0.10 per mcf and the fuel cost is USD 0.08 per mcf (Shively, Ferrare, & Petty, 2010). Taking into account these two main variable costs of the operational expenditure and exclude the annual cost of capital, the total operating expenditure for a liquefaction plant is around USD 0.19 per MMBtu.

In this model, the liquefaction cost and the regasification cost are assumed to be USD 0.20 per MMBtu and USD 0.80 per MMBtu, respectively. LNG shipping cost depends highly on the shipping route. Based on a report from Petronas (2013), LNG shipping cost to Malaysia is around 3.50 USD per MMBtu. While for Singapore, it varies from USD 1.0 per MMBtu (from Australia or Papua New Guinea) to USD 4.2 per MMBtu if shipped from Russia Yamal or Norway. If it is shipped from the U.S. Gulf and East, the cost is estimated to be between USD 3.3 to 3.9 per MMBtu. According to Mavrinac (2013), the LNG shipping cost is in the range of USD 1.5 to 3.5 per MMBtu. In this model, the destinations of export and sources of import have not been distinguished. It is assumed the LNG shipping cost to be USD 2.50 per MMBtu.
Domestic gas price varies for each country and also varies for each sector (i.e. households or residents, commercials, industry, power plants, etc.). However, in this model, the domestic gas price will be assumed to be 9.0 USD per MMBtu, akin to gas selling price to PLN, the Indonesian power state company.

Summary of unit costs used in the model (unit in USD/MMBtu)

- Wellhead price 5.80
- Domestic gas price for each country 9.0
- Pipeline transmission cost 0.50 (sellers will bear the cost)
- LNG liquefaction operational cost 0.20
- LNG shipping cost 2.50 (in the case of Japan cif price, sellers will bear the shipping cost)
- LNG regasification operational cost 0.80
- dummy variables cost (k USD higher than cost for the existing infrastructures)

Note: for all costs and prices, the unit of USD/MMBtu will be converted to USD/bcm as the model will use bcm as the volume unit.

Other assumptions

- Prices of LNG and gas pipeline are identical (exogenous; from extrapolation)
- LNG shipping cost and pipeline transmission cost are borne by sellers
- Supply is constant until proven reserves depleted
- Domestic demand growth is based on the IEA report, otherwise 1.0% per annum
- The minimum amount of export/import LNG and gas pipeline will be fulfilled until the expiration of the contracts as reported by GIIGNL (2014)
5.2.3 Data Library

Set:
- \( i = \text{n countries} \ (i = 1, \ldots, 7) \)
- \( t = \text{n periods} \ (t = 1, \ldots, 32) \)
- \( m = \text{pipeline route} \ (m = 1, \ldots, 5) \)

<table>
<thead>
<tr>
<th>Table 5.2 Data library of GANESA model</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Exogenous variables</strong></td>
</tr>
<tr>
<td>single_gas_price</td>
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<tr>
<td>liquefaction_cost</td>
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<tr>
<td>regasification_cost</td>
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<tr>
<td>shipping_cost</td>
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<td>transmission_cost</td>
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<td>wellhead_price</td>
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<td>domestic_consumption</td>
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<table>
<thead>
<tr>
<th><strong>Constraints (lower and upper bounds)</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>min_export_capacity</td>
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<tr>
<td>max_export_capacity</td>
</tr>
<tr>
<td>max_import_capacity</td>
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<tr>
<td>min_pipeline_capacity</td>
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<td>max_pipeline_capacity</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Decision variables (for each i, t, and m)</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>lng_export</td>
</tr>
<tr>
<td>lng_export_dummy</td>
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<td>lng_import</td>
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</tr>
<tr>
<td>pipeline_volume</td>
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<tr>
<td>pipeline_volume_dummy</td>
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</tbody>
</table>

See Appendix B1 for the script of the MATLAB code.

5.3 VERIFICATION & VALIDATION

Verification is a step to see if the conceptual model has been correctly translated into the computerized model while validation is needed to ensure that the computerized model could represent the real world system under study.

5.3.1 Verification

First the model was built as a spreadsheet model using Ms. Excel. The model was built in a single year and three years period. Afterwards, with the same inputs and assumptions, the model was built in MATLAB 2014b. The results then were compared. When the results of the objective function and decision variables are same, the number of years in MATLAB and other data inputs were increased.
from 1 year, 3 years, to 32 years which is the time frame of the model. The same approach was also done to verify the option valuation model.

5.3.2 Validation

There are several types of validation (Knepell & Arangno, 1993), e.g. conceptual or theoretical validity, internal validity, operational validity, data validity; and validation techniques as presented by Sargent (2013). Conceptual or theoretical validity refers to the adequacy of the underlying conceptual or theoretical model in characterizing the real world system. The conceptualization of the GANESA model has followed the natural gas (and LNG) value chain. The data inputs, constraints, and assumptions were built under a thorough literature review. Therefore, it could be said that the assumptions underlying the conceptual model are correct and could represent the real world.

According to Sargent (2013), operational validity is fulfilled when the output behavior of the model has a satisfactory range of accuracy to serve the intended purpose and applicability of the model. As the model is able to produce the results that were expected by the author, it could be said that the model serves its purpose. Comparing simulated and real data, sensitivity analysis based on design of experiment and regression analysis, and risk or uncertainty analysis using Monte Carlo sampling are techniques that could be used to validate the model (Kleijnen, 1995). These techniques could be used to assess operational validity. Following steps are done by the author to check the operational validity of the model.

- The input of gas price is validated by comparing the result of the regression analysis with the actual data. The differences then being measured as error measurement and will be taken into account as a range of possible gas prices when performing Monte Carlo simulation.
- The parameters of the GANESA model, e.g. production level, domestic consumption growth, and extension of gas pipeline long-term contracts are changed and the model could still run as expected. See Appendix B2 for the results of changing the parameters (combined as model A0, A1, and A2). The parameters of the option valuation model, e.g. discount rates, CAPEX, inflation, are also changed and included in the sensitivity analysis of the project (see chapter 8).

Data validity refers to the accuracy of the data (real and computer generated) and the data’s adequacy to build the model and conduct experiments to solve the problem (Sargent, 2013). The author would say that this requirement has been fulfilled since the author has collected information about the inputs and assumptions of gas network model from the selected studies in chapter 4 and gather those data from various national (e.g. BPPT, SKK Migas, Pertamina, PGN) and international agency reports, such as EIA, IEA, and BP Statistics.
6 Scenario Planning

When the model has been verified and validated, the next step is to run the model in several scenarios. In this research, two scenarios will be used: Business-as-Usual (BAU) scenario, and Reference (REF) scenario. The scenarios will be built following the Shell’s methodology by taking into account strategic focus and competitive position of the company, or in this case, the Indonesian government. The outputs of this phase are production and consumption profile of each Southeast Asian country, capacity utilization of the gas infrastructures (i.e. gas pipelines and LNG facilities) in each country, and additional capacity requirements that are indicated by the dummy variables.

6.1 SHELL’s METHODOLOGY

Scenario analysis/development/or planning has been widely used in various sector to deal with uncertainty of the future. In the GANESA model, changes in gas production growth, domestic consumption growth, and national gas policy will change the gas trade flows in the region. Gas price also becomes another determining factor, especially with respect to investment decision.

Shell has been widely known as a company who develops and uses scenario planning. According to Schoemaker and van der Heijden (1992) who studied scenario planning development at Shell, there are four elements to integrate scenarios into strategic planning as is shown in figure 6.1.

![Figure 6.1 Shell’s methodology](Schoemaker & van der Heijden, 1992)

In this report, this methodology will be used from a higher level perspective, i.e. not from the perspective of a company as in the common practice, but from the perspective of the government, especially the Indonesian government. According to Tumiran (2014), member of the Indonesian National Energy Council, the objective of national energy policy in Indonesia is to increase social
welfare of the Indonesian citizens by establishing energy security, independency, sustainability, environmental protection, and cost efficiency. This then will be the strategic focus of the Indonesian government.

In the world gas market, Indonesia is known as major LNG exporter since 1960s. In Southeast Asia, Indonesia has the largest amount of proven gas reserves. However, to achieve its aim of energy security, Indonesia might have to reduce its export volume, and consequently loses its market share. Gas has become the main alternative to reduce domestic consumption’s dependency on oil and is expected to increase the national budget surplus. On one hand, increasing domestic gas consumption will reduce oil import. On the other hand, it will also reduce the volume of gas export, and thus reduce the nation’s income. However, some analysts believe that it will result in surplus of the national budget, or in other words, the loss in gas export will be less than the surplus gained from reducing oil import (Tjandranegara, 2012). At the next section, more focus will be given to scenarios development. Options planning will be discussed in the next chapter.

6.2 SCENARIOS DEVELOPMENT

Scenarios are stories about plausible alternative futures (Wright, 2003). Schoemaker and van der Heijden (1992) define scenarios as tools for improving decision-making process against a background of possible future environments. Definitions, purposes and benefits of scenario planning from various authors can be found in Wright (2003). Ringland (1998) presents methods to develop scenario planning and examples of the scenarios developed by various organization sectors. There are four steps that could be followed to develop scenarios (Schoemaker & van der Heijden, 1992), as follows:

- **Step 1: Selecting the issues**
  Some critical issues such as economic growth, product demand, and energy prices appear in most Shell scenarios. Other issues (e.g. carbon emission, consumer behavior or preference, new technologies) will be added or subtracted depending on the agenda.

- **Step 2: Analyze the areas of concern**
  The analysis should pinpoint the driving forces, predetermined elements, critical uncertainties, possible discontinuities, and linkages with other areas of business environment. The areas of concern include energy, economics, social change, environment, politics, and technology.

- **Step 3: Organize the scenario around a logical concept**
  This step is needed to determine whether a scenario is plausible and internally consistent. Not all uncertainties or variables should be included. The assumptions also could be challenged by current trend, public opinion, government policy, etc.

- **Step 4: Focusing the scenario**
  A sharper focus is needed and could be achieved by defining the boundaries of the scenarios, e.g. time frames, geographic regions, industries, business sectors, or major projects.

As have been stated in the introduction of this chapter, production level, domestic consumption, national gas policy, and gas prices are critical issues in developing gas network model and valuation of investments. Production level will depend on the amount of proven reserves and technology development. New findings of gas fields or development of unconventional gas resources (e.g. CBM
and shale gas) will increase the production level. However, this really depends on technology, expertise, and contract agreements between government as the owner and gas companies as the contractors.

Domestic consumption growth will significantly change the map of natural gas flow in the country. As domestic consumption in Indonesia is expected to grow 2.2 to 2.7% per annum (BPPT, 2014), this will reduce the volume of gas export. This will also change the contract arrangement, i.e. the Indonesian government will require more domestic market allocation. The growth of domestic consumption in Indonesia will be pushed or created by the government as the government wants to reduce its oil import dependency (Agustiawan, 2014; Lumeno, 2015). Gas is projected to replace some share of oil in transportation sector and also as the fuel for the power plants, due to its less emission compared to coal.

Currently, the gas prices in most gas-export sales agreements are linked to oil price. This will still dominate the contract in Southeast Asia region unless there is an Asian gas hub that will set the gas price. Singapore has initiated a gas hub by expanding its regasification terminal that could also functions as a liquefaction facility and build a balancing system of gas supply and demand (Barker & Turner, 2013; Collins, 2013). However, since it is just started, the Asian gas hub price is still far away (Forster, 2014), and JCC pricing would still be the main reference for the gas-export sales contract.

In this report, two scenarios will be presented, business-as-usual scenario and reference scenario. The main difference between these two scenarios lays on the assumptions of the production level, domestic growth, and possibility of long-term contract extension for the gas pipelines between Indonesia and Singapore. Other inputs regarding gas price and unit cost of the activities along the value chain are based on previous assumptions as in chapter 5.

6.2.1 Business as Usual (BAU) Scenario
This scenario is built based on the gas outlook published by the Indonesian Center for Energy Resources Development Technology (BPPT, 2014). The assumptions used in the outlook are based on resources from the Indonesian Ministry of Energy and Mineral Resources. According to BPPT (2014), the domestic gas demand will grow at 2.2% in the period of 2012 to 2035, while the gas supply will start to decline after 2017 at a rate of 4.14% from 2018 to 2023 and 3.80% from 2023 to 2035. Since the time frame of the scenario is only up to 2035, the growth assumption used in this report (up to 2045) will use the same growth assumption as in BPPT (2014).

The long-term contracts for cross-border gas pipelines will follow data as in table 2.5, and the contract for the LNG trades (medium or long-term contract) will follow data from GIIGNL (2014). This scenario also takes into account the long-term contract of LNG import by Pertamina from Cheniere which will be started in 2018 and lasts for 20 years.

6.2.2 Reference Scenario
The reference scenario is more optimistic compared to the BAU scenario. This scenario assumes the domestic gas demand will grow at 2.7% as also assumed by BPPT (2014). For the production, the author assumes Indonesia will have a constant growth rate of 0.5% while BPPT uses the same
assumption as in BAU scenario. This is mainly due to author’s consideration of the Reserve Replacement Ratio (RRR) in Indonesia. Figure 6.2 shows the historical data of RRR in Indonesia from 2007 to 2013 with an average of 134% which indicates a positive growth. If the potential gas fields are developed, e.g. Abadi gas field, East Natuna gas field, and other smaller gas fields, the positive growth of gas supply in Indonesia is very likely to happen.

Since Indonesia has a positive growth of gas supply, this scenario assumes that Indonesia could still export the pipelined gas to Singapore (or Malaysia). This scenario assumes that the existing long-term contract of pipelined gas from Indonesia to Singapore, which will expire in 2023 could be prolonged. The LNG trades in this scenario will follow the contracts from GIIGNL (2014) as in the BAU scenario. Table 6.1 summarizes the input assumptions used in the two scenarios. Table 6.2 shows the gas production and domestic consumption growth in each country will be based on the IEA scenario (until 2035), BPPT scenario, and author’s assumptions.

![Graph of Gas Reserve Replacement Ratio in Indonesia](image)

*Figure 6.2 Gas reserve replacement ratio in Indonesia
Source (SKKMigas, 2013)*

<table>
<thead>
<tr>
<th>Table 6.1 Summary of the scenarios</th>
<th>BAU</th>
<th>Reference Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic consumption; others based on IEA scenario</td>
<td>Indonesia 2.2%</td>
<td>Indonesia 2.7%</td>
</tr>
<tr>
<td>Export LNG</td>
<td>GIIGNL</td>
<td>GIIGNL</td>
</tr>
<tr>
<td>Production Others based on IEA scenario</td>
<td>Decline after 2017; -4.14% from 2018-2023; -3.8% from 2023-end</td>
<td>Indonesia has constant growth of 0.5%</td>
</tr>
<tr>
<td>Pipelined gas export to Singapore and Malaysia after 2023</td>
<td>Stop after 2023</td>
<td>2 bcm/y to Singapore</td>
</tr>
<tr>
<td>LNG import from Cheniere</td>
<td>v</td>
<td>v</td>
</tr>
</tbody>
</table>
Table 6.2 Summary of gas production and domestic demand growth in Southeast Asian countries

<table>
<thead>
<tr>
<th>Country</th>
<th>Production growth (%)</th>
<th>Domestic consumption growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Indonesia</td>
<td>Declines after 2017 vs. constant at 0.05</td>
<td>2.2 vs. 2.7</td>
</tr>
<tr>
<td>Malaysia</td>
<td>0.60; declines by 2% at period 23 and after</td>
<td>1.5</td>
</tr>
<tr>
<td>Brunei</td>
<td>0.50; declines by 5% at period 23 and after</td>
<td>1</td>
</tr>
<tr>
<td>Thailand</td>
<td>Declines by 5.50</td>
<td>1</td>
</tr>
<tr>
<td>Myanmar</td>
<td>2.60; declines by 11% at period 23 and after</td>
<td>1</td>
</tr>
<tr>
<td>Vietnam</td>
<td>Constant growth of 1.30% until 2045</td>
<td>1</td>
</tr>
<tr>
<td>Singapore</td>
<td>-</td>
<td>1</td>
</tr>
</tbody>
</table>

6.3 SOUTHEAST ASIAN GAS OUTLOOK to 2045

This section presents the results after running the two scenarios in the GANESA model. The results show the gas production and domestic consumption, operating capacity of the LNG liquefaction plants and regasification terminals in each country and also volume of gas transported through the cross-border pipelines within the time frame of the model.

6.3.1 BAU Scenario

Domestic gas production and consumption

![Production and Consumption in Indonesia](image1)
![Production and Consumption in Malaysia](image2)
![Production and Consumption in Brunei](image3)
![Production and Consumption in Thailand](image4)
![Production and Consumption in Myanmar](image5)
![Production and Consumption in Vietnam](image6)

Figure 6.3 BAU Scenario: Production and domestic consumption volume
Figure 6.3 shows the gas production and domestic consumption in six Southeast Asian countries. Singapore as an exception, does not have any gas reserves and thus, there is no gas production activities in the country. Based on this scenario, gas production from Malaysia will surpass Indonesia’s production after 2020, given that Malaysia could exploit all its proven and possible gas reserves while Indonesia does nothing to increase its production level. Thailand who has been a net gas importer will continue to import gas either via pipelines from Myanmar or LNG import from various suppliers. The production from Thailand’s gas fields is expected to keep declining and finally be totally depleted after 2022 if the country fails to find any new gas fields. Most producing countries show both a positive (at earlier periods) and negative growth trend (at later periods). The declining growth trend is expected to happen within the time frame of the model, except for Vietnam. Vietnam shows a positive growth trend within the time frame due to later development of its gas fields. However, Vietnam will have to manage its production growth faster than the domestic consumption growth otherwise the country will have to rely on import to supply the unmet demand from domestic supply.

Based on the previous result of the gas production and domestic consumption, excluding the gas trades either via pipelines or LNG shipping, the independency level of each country along the time frame of the model is shown in figure 6.4. The independency level is based on the ratio of domestic gas production to domestic gas consumption.

The figure shows that Thailand has the second lowest independency level after Singapore and will totally rely on import in 2023. With no new gas field development, Indonesia will start to lose its independency in 2027. Vietnam has the closest balance between domestic gas supply and demand. However, following a concern of security of gas supply, it will be better if Vietnam could develop its gas fields faster so that the independency level could increase above 1.0.

Both Malaysia and Brunei show a declining trend of independency level due to a higher growth of their domestic consumptions compared to their gas productions. However, during the time frame of the model, their independency level is still above the standard line of 1.0. Myanmar shows a positive trend of growth until 2035 and decline afterwards. In practice, the independency level of Myanmar is much lower because it has several pipelined gas export contracts to Thailand and China.
Cross-border gas pipelines

As indicated in figure 6.5, pipelined gas contract from Indonesia to Malaysia will expire in 2021 and to Singapore in 2023. Pipelined gas from Malaysia to Singapore will last a bit longer, up to 2025. Afterwards, the scenario assumes that Singapore decides not to extend the pipeline contracts and will rely on LNG import. Pipelined gas from Myanmar to Thailand will decline gradually because in practice, there are three pipeline connections from Myanmar to Thailand which have different dates of expiration. The last pipelined gas is from Myanmar to China which has just started in operation at the end of 2014 and the contract will last for 30 years. The figure shows the pipeline could operate at its maximum capacity from 2030 to 2035, and will start to decline afterwards.

![Figure 6.5 BAU Scenario: Cross-border gas pipelines](image)

LNG infrastructures

Figure 6.6 shows the volume of natural gas processed at the liquefaction plants in Indonesia, Malaysia and Brunei. Both Indonesia and Malaysia also have regasification terminals that are mainly used for their domestic needs. However, both Indonesia and Malaysia also import LNG from other sources, i.e. Indonesia through Pertamina imports LNG from Cheniere, and Malaysia imports LNG from Statoil.

![Figure 6.6 BAU Scenario: LNG liquefaction and regasification capacities in Indonesia, Malaysia, and Brunei](image)
Based on the existing pattern of domestic gas production in Indonesia, Indonesia will have to increase its regasification terminal capacity, especially to manage the imported LNG. This is caused by the declining gas production and growing domestic gas demand. Based on the figure, Indonesia will need to increase its regasification capacity after 2030. However, this should be started earlier considering the utilization of the regasification terminals for LNG domestic supply is not captured in the figure.

In the Malaysian case, Malaysia does not need to increase its regasification capacity. The figure shows that the amount of regasified import LNG in Malaysia is quite small, mainly from its long-term contract with Statoil and be used as a back-up supply when its gas production gets disrupted.

Within the time frame of the model, Brunei does not need to build a regasification terminal because its domestic gas production is still sufficient to meet its domestic gas demand. Brunei also does not have any regasification terminal because its geography is less scattered, unlike in the case of Indonesia and Malaysia.

Figure 6.7 shows the regasification capacities in Thailand and Singapore. Both Thailand and Singapore do not have any liquefaction plants because both countries are known as net gas importer. If domestic gas consumption in Thailand keeps growing by 1.0%, Thailand will have to significantly increase its regasification capacity. This is also due to declining supply from Myanmar’s pipelined gas. Therefore, Thailand really needs to strive to find new gas fields, otherwise the country will have to rely heavily on imported LNG.

![Figure 6.7 BAU Scenario: LNG regasification capacities in Thailand and Singapore](image)

The latest contract agreement between Indonesia and Singapore requires Singapore to pay USD 17 per MMBtu for the pipelined gas. Singaporean analysts find that they could get LNG import from the U.S. with a cheaper price than the current pipelined gas price. This has led Singapore to build a regasification terminal in Jurong in order to have more alternatives of gas supply and more bargaining power.

Based on the results of the BAU Scenario, after the pipelined gas contracts from Indonesia expire, Singapore will have to start increasing its regasification capacity after 2025, given the domestic gas consumption keeps growing by 1.0%. The country will face a harder challenge to become an Asian gas hub if it only relies on imported LNG. Adding more capacities to its regasification terminal is not a simple matter because it has a very limited land availability. Therefore, getting pipelined gas supplies from its neighboring countries could be an alternative. Another option to increase its regasification capacity is building floating storage and regasification facilities. However, it might be more costly compared to existing pipelined gas supplies from Indonesia or Malaysia.
Figure 6.8 shows the liquefaction and regasification capacities in Myanmar and Vietnam. Currently both Myanmar and Vietnam do not have any LNG infrastructures. The figure shows that both countries need to build a regasification terminal at the first 5 to 7 years of the model’s time frame. In Myanmar’s case, the reason for the need to import LNG as indicated by the dummy capacity for a regasification terminal is because of its long-term pipelined gas contracts. In the period of 2005 to 2013, Myanmar sold more than 8 bcm/y of its pipelined gas to Thailand. However, given the existing production level, Myanmar will not be able to fulfil the same pattern of pipelined gas supply. The possible options are to increase its production level, reduce its domestic gas consumption or reduce its pipelined gas supply to Thailand. These options are more likely to happen than Myanmar builds a new regasification terminal only to fulfil 5-years short of supply.

The figure also indicates that Vietnam needs to build a regasification terminal because in the earlier period, it is expected that Vietnam’s domestic gas production will not be able to meet its domestic gas consumption. This condition has already been realized by the Vietnamese government because they have announced a plan to build two regasification terminals. Afterwards, it is expected that Vietnam will have excess supply and the government could choose either export the excess supply through LNG shipping or try to manage its production level. However, looking at the excess supply, the amount is not that economically viable to build a liquefaction plant. Therefore it will be better for Vietnam to store its gas excess.

6.3.2 Reference Scenario

Domestic gas production and consumption

There is no change in the production level and domestic consumption growth of the Southeast Asian countries, except for Indonesia. In this section, the author will only discuss the change that happen in Indonesian gas production and domestic consumption. Figure 6.9 shows the comparison of Indonesian gas production and domestic consumption in the BAU scenario and Reference scenario. With a constant growth of 0.05% after 2017, Indonesia will be able to meet its domestic gas demand, at least until 2044. This will make the country needs to reduce its gas export sales agreement or even not
export gas anymore after the existing long-term contracts expired. This could be avoided if the country could successfully manage its potential gas fields as in East Natuna or Arafura Sea. This will be a matter of discussion in the next chapter.

![Domestic Gas Production and Consumption in Indonesia](image)

**Figure 6.9** Comparison of domestic gas production and consumption between BAU and Reference scenario

Cross-border gas pipelines

The Reference scenario assumes that both Indonesia and Singapore agree to extend their pipelined gas contract as long as the reserves are available. Figure 6.10 shows the gas traded through the cross-border gas pipelines in the region. The main difference with the BAU scenario is at the second pipeline route, from Indonesia to Singapore.

![Cross-border gas pipelines](image)

**Figure 6.10** REF Scenario: Cross-border gas pipelines
LNG infrastructures
Since the change is only at Indonesia’s gas production and domestic consumption, the results of other countries LNG infrastructures’ capacity utilization remain the same. Figure 6.11 shows a comparison of the capacity used in LNG liquefaction and regasification facilities in Indonesia according to the BAU and Reference scenarios. In the Reference scenario, the liquefaction capacity is more utilized compared to the BAU scenario. While, for the regasification capacity, in the Reference scenario, the imported LNG is only based on the long-term contract with Cheniere that will be started from 2018 to 2037. The figure also indicates that from 2044 onwards, Indonesia will need to import LNG because the domestic gas production will not be able to meet the domestic gas demand anymore. The utilization of LNG regasification terminal under the Reference scenario, especially for import, is much lower compared to the BAU scenario.

Figure 6.11 Comparison of BAU and REF Scenarios: LNG liquefaction and regasification capacities in Indonesia

As a result of extending pipelined gas contract between Indonesia and Singapore, the capacity needed for regasification terminal in Singapore will decrease. Figure 6.12 shows the comparison of the regasification capacities used in Singapore according to the BAU and Reference Scenario. The figure indicates that in the Reference Scenario, Singapore will need a later time to expand its regasification capacity, at least until 2040 (compared with 2025 in the BAU scenario). There are also some allowance for its regasification capacity which will bring more flexibility for Singapore to handle more LNG import and re-distribute the LNG to other countries who need it. This will support the Singaporean goal to become an Asian gas hub, unlike in the BAU scenario where the regasification capacity is not even sufficient to fulfil its domestic consumption.

Figure 6.12 Comparison of BAU and REF Scenarios: LNG regasification capacities in Singapore
6.4 BRIEF ANALYSIS PER COUNTRY

Based on the results of the two scenarios, further development of gas infrastructure in each Southeast Asian country could be analyzed deeper.

**Indonesia**

Based on the BAU scenario, Indonesia will become a net gas importer in 2027 because its domestic gas production is not sufficient to meet its domestic gas consumption. In this scenario, Indonesia needs to focus on developing its potential gas fields then tries to secure other LNG import long-term contracts. Otherwise, the government’s plan to develop national gas infrastructure and increase gas utilization share in its energy portfolio will be useless. If the RRR in the coming years falls sharply below 100%, then the government will have to re-evaluate its national energy plan.

Based on the Reference scenario, Indonesia still shows a positive growth of gas production. However, still, with its current production and domestic consumption growth, the amount of gas export will reduce significantly and consequently, the state revenues will also decrease. From the economic and political perspective, this could be a problem as (oil and) gas export has a significant contribution to the state revenues. There are at least two ways to resolve the problem, such as:

- Developing other sectors that could replace revenues from the gas sector
- Exploration and increase production volume at least at the same growth with domestic consumption level. The main parameter to decide new investment in new gas fields exploration and production or build new LNG liquefaction infrastructure is the gas price. Indonesia should find ways to develop its unconventional gas resources, i.e. shale gas and CBM. This happened in the U.S. and consequently, the gas price has reduced significantly after the deployment of shale gas.

The regasification terminals in Indonesia (in this model) only represent the capacity used to handle imported LNG. In practice, the use of LNG regasification terminal in Indonesia is also for domestic consumption, especially for industries and power plants. The need to add the capacity of the LNG regasification terminal will depend on the projection of the domestic-sectoral consumption growth in Indonesia.

Although both figures 6.6 and 6.11 do not show any needs for adding liquefaction capacities, in practice, this might be needed due to the problem of location. Usually, the liquefaction plants are located near the gas fields. If these gas fields have depleted, the liquefaction plants will need to find other gas supplies. If there is no gas supplies from nearby gas fields, the liquefaction plants will have to stop operating, as in the case of Arun liquefaction plant which has been switched to a regasification facility because the Arun gas field has depleted. Therefore, although not indicated explicitly in the figure, additional liquefaction capacities might still be needed to support the production of new gas fields.

Based on the current plan of the gas infrastructure expansion in Southeast Asia (see section 2.3), Indonesia has a plan to expand *Tangguh LNG liquefaction* in Papua and develop *Abadi FLNG* in Arafura Sea. Based on the existing plan (IEA & ERIA, 2013), these two projects will be started in 2016. However, due to the dramatic fall of gas price in 2014, these projects are unlikely to be started as planned. In
the case of Abadi FLNG which is operated jointly by Inpex (65%) and Shell (35%), currently there is a
discussion either to expand or delay the project. The project has long been considered too small
because its capacity is only 2.5 mtpa (3.5 bcm/y) compared to the Masela block in the Arafura Sea
which is estimated to contain 524 bcm of natural gas (Stefanini, 2014). The second option is to delay
the project even to the late 2020s until it becomes more economical.

Another plan led by Indonesian oil and gas company, Pertamina, is to develop the East Natuna gas
field. This is a part of the TAGP master-plan (ACE, 2013) by connecting East Natuna to JDA-Erawan
(Thailand), Kerteh (Malaysia), Java (Indonesia), and Vietnam. The results of this model indicate a need
of Vietnam for imported gas, especially before 2020, and Thailand for a much longer period due to
depletion or expired long-term contracts of its pipelined gas supplies from Myanmar. PTTEP, the Thai
state-owned company, has taken the first step by joining the consortium to develop East Natuna gas
field, together with Pertamina, ExxonMobil, and Total. Developing new pipeline connections to
Erawan and Java could be a better way to meet the gas demand in these two countries, i.e. Thailand
and Indonesia. This is also supported by the presence of Pertamina and PTTEP as the national gas
company in the consortium. Connecting the pipeline to Vietnam and Malaysia will be less likely to
happen considering the need of Vietnam is only during the first 8 years with a small amount of gas,
and Malaysia which actually has already had sufficient gas supplies for its domestic consumption.

Malaysia
Malaysia faces similar condition as Indonesia in the Reference scenario, assumed that the amount of
its proven is as estimated by the IEA and EIA (2013). If not, then Malaysia would need to start importing
earlier, in 2030 (if based on the BP, 2014). Based on the existing plan (IEA & ERIA, 2013), Malaysia has
a plan to build Rotan FLNG in Sabah that has a capacity of 1.5 mtpa (or 2.0 bcm per year). This project
was planned to be started in 2016. Other plans are to build regasification facilities in Lahad Datu
(Sabah, with a capacity of 1.1 bcm/y) in 2016 and Pengerang (Johor, with a capacity of 5.2 bcm/y) in
2017.

In case when the amount of proven reserves are only half of the IEA and EIA prediction, the gas
reserves will deplete in 2030 and afterwards, Malaysia will rely on imported gas. Currently, like
Indonesia, Malaysia also uses its LNG regasification for domestic needs. New regasification facilities
might be needed, following the growth of domestic consumption, especially in the western area of
Malaysia. Malaysia seems not to opt for the TAGP connection from East Natuna because Petronas
stepped out of the consortium, replaced by PTTEP. Malaysia has also secured a long-term LNG contract
from a Norwegian company, Statoil, started in 2012 until the reserves in Hammerfest depleted.
Petronas also invests in global projects in North America, Australia, and East Africa (IEA, 2014),
indicating the future plan of the country to secure LNG import supplies from various sources.

Brunei
There is no information regarding Brunei’s future plan to develop its gas infrastructure. Based on the
results in this model, Brunei will still be able to meet its domestic demand from its domestic gas
production.
Thailand
Thailand has a plan to double the *Ma Ta Phut regasification terminal* by adding 5 mtpa (or 6.90 bcm/y) to its current capacity (IEA & ERIA, 2013). In total, the capacity of Ma Ta Phut regasification terminal will be 10 mtpa. PTTEP has also invested in upstream development and secure long-term contracts in East Africa (IEA, 2014). As stated before, PTTEP also stepped in the consortium of East Natuna, indicating its serious plan to build TAGP connecting East Natuna and Erawan, Thailand.

As the highest gas consumer country in Southeast Asia, it is unavoidable for Thailand to secure its long-term gas supply in order to support the growth of its domestic consumption. Even if its domestic consumption stops to grow, Thailand will still have to find new gas supplies as its existing gas fields will be depleted soon. Relying on LNG import will not solve the problem of growing demand as it only could replace the supply from Myanmar’s pipelined gas. Building TAGP from East Natuna seems hardly to meet all domestic demand in Thailand if it keeps growing by 1.0 or 2.10% per annum (as assumed in this model or assumed by IEA as in model A1; see Appendix B2). Therefore, Thailand will need to find alternative fuel sources that could replace gas, e.g. nuclear or renewable sources, otherwise it will become too dependent on gas import. As the gas price is quite volatile, Thailand’s economy will also become volatile if the share of gas in its energy portfolio keeps growing.

Myanmar
There is no information regarding Myanmar’s future plan for its gas infrastructure. The latest information is its existing pipelined gas export to China which has already been started at the end of 2014 and currently Myanmar does not have any plans regarding LNG infrastructure development. Since early 2000, Myanmar has been known as the major gas supplier to Thailand. However, this might change as the Yadana and Yetagun gas fields will be depleted around 2030. Currently, the domestic consumption accounts for one-third of Myanmar’s production and it is expected to be not growing faster than the current rate.

Following the current scenario in this model, Myanmar will have no gas reserves after 2044 and need to start importing afterwards to meet its domestic demand. It will be wiser if Myanmar could arrange its production in the earlier periods or store the gas when there is excess production.

Vietnam
According to the future natural gas infrastructure expansion plan (IEA & ERIA, 2013), Vietnam wants to build its first LNG regasification terminal in Thi Vai with a capacity of 1 mtpa in 2016 and adds one more in Bin Thuan with a capacity of 3 mtpa in 2018. These plans are in accordance with the finding of this model that indicates a need of Vietnam for a regasification terminal, especially in the first decade of the model’s time frame. If Vietnam realizes this plan, the TAGP connection from East Natuna to Vietnam will be less likely to happen as the capacity of these regasification terminals will be more than sufficient for Vietnam to facilitate import supplies that could meet its domestic production shortage. Vietnam has also secured a long-term contract with a Russian company, Gazprom (IEA, 2014), in which Gazprom will lead gas exploration projects in Vietnam’s territory.
Singapore
Singapore does not have any gas reserves and has been known as a net gas importer in Southeast Asia. Singapore has a plan to shift its gas supplies from pipelined gas (from Indonesia and Malaysia) to LNG. It has secured long-term contracts with Australia, Papua New Guinea, and the U.S. (GIIGNL, 2014; Gronholt-Pedersen & Tan, 2014), and are also participating in upstream development and discussing possible contracts in East Africa region (Flynn, 2013; IEA, 2014).

Following its ambitious plan to become an Asian gas hub, Singapore has contracted British Gas that will play a role as an aggregator to balance the demand and supply of natural gas or LNG in Singapore (Collins, 2013). Inpex, Japan’s oil and gas explorer has also set up an office in Singapore as a trading post with an aim to grow buyers’ pool in Asia as demand in Japan shrinks (Tan & Tsukimori, 2013). To support this plan, the LNG terminal located in Jurong was designed to allow multi-party use and also to accommodate both imports and exports of LNG (Inkson, 2013).

With this tremendous plan, it is hardly seen that Singapore will continue its pipelined gas import from Indonesia and Malaysia. However, considering its intention to reach a higher level of security of gas supply, some smaller amount of pipelined gas import might still be needed. This will depend on the price demanded by the exporters and agreement regarding the contract duration, i.e. Singapore will be required by the exporters to extend the contracts before they are expired. In other words, it is unlikely that Singapore could postpone the pipelined gas import from 2023 (after the contracts expired) until for example 2040, when the growth of the demand has surpassed the LNG terminal capacity, and Singapore will need additional supply or capacity. This also means the regasification terminal in Singapore will have excess capacity if Singapore continues to import the pipelined gas. However, this will bring more flexibility for Singapore and support its role as a gas hub since it could arrange the dispatch of gas supply to various destinations or buy and store more gas when the price is cheaper and sell it at the spot market with a higher price.

Conclusions
The Reference Scenario only affects supply and demand profiles of Indonesia. When the domestic gas production in Indonesia shows a positive growth, Indonesia could still supply pipelined gas to Singapore, and Singapore would not need to increase its regasification capacity at least until 2040. This will strengthen Singapore’s position as a gas hub because it will have excess capacity for LNG storage and regasification which could be used to meet supply and demand gap of other countries in the region. In the Reference Scenario, Indonesia also has opportunity to supply its excess production in a form of LNG to Thailand or Vietnam. On the other hand, in the BAU Scenario, Indonesian gas production will decline. In 2027, Indonesia will become a net gas importer since its gas productions are less than its consumptions. These two possible scenarios will determine the way new gas projects in Indonesia should be developed. When the environment shows trends as such in the BAU Scenario, the Indonesian government will need to allocate more gas for domestic market and reduce allocation for export. On the contrary, when the trends are as such in the Reference Scenario, gas allocation for exports could be increased.
7 Option Planning

The existence of the two scenarios used in this research could be regarded as an uncertainty itself. Considering these two scenarios is important because they will affect technology options selected to develop new gas projects in Indonesia. Currently, there are three proposed gas projects: LNG train expansion in Tangguh-Papua, developing new gas fields in Abadi-Arafura Sea, and developing East Natuna gas fields. Several technology options are available to develop these fields, i.e. pipelined gas or LNG. This chapter will discuss possible technology options, including their technical and cost aspects.

7.1 PROJECT DESCRIPTION

7.1.1 Tangguh LNG Expansion

Tangguh LNG started its operation in 2009 with two trains, each has a capacity of 3.8 mtpa with 40 km pipelines connecting the platforms to the LNG plants (Egger, 2006). Tangguh LNG is operated by BP Berau Ltd., and the shareholders consist of BP 37.16%, MI Berau B.V (Mitsubishi and Inpex) 16.30%, CNOOC 13.90%, Nippon Oil Exploration 12.23%, KG Berau/ KG Wiriagar (subsidiary of Mitsui & CO., Ltd., and Japan Oil, Fas and Metals national Corporation) 10.0%, LNG Japan Corporation 7.35%, and Talisman 3.06% (BP, 2014a).

According to Jim Egger, VP LNG Marketing of BP Indonesia, Tangguh field contains 408 bcm of proven reserves from six gas fields, located in 60 meter water depth and calm seas, with a possible addition of 153 bcm and a probable addition of 110 bcm. In total, the estimated amount of the gas reserves is 671 bcm (3P). This leads to an expansion plan for the third train with the same capacity equivalent to 5.2 bcm per year. The CAPEX of this expansion project is estimated to be USD 12 billion (BP, 2014a). Hewitt, Fuestier, and Burns (2012) from the Credit Suisse estimate the cost of train 3 expansion for Tangguh LNG to be around USD 2,875 per tpa or in total of USD 11 billion. The estimated CAPEX from these two sources are much higher compared to the cost of expansion in Malaysian LNG which is below USD 600 per tpa (Songhurst, 2014). Songhurst (2014) summarizes various LNG liquefaction project and generates liquefaction plant metric cost as shown in table 3.6. According to his analysis, the most expensive CAPEX for a complete facility at high cost location falls between USD 1,400 to 1,800 per tpa. Songhurst (2014) also notes that the increases in Malaysian and Indonesian liquefaction plants during 2005 to 2012 reflect an increasing cost of approximately 100%. The CAPEX estimation from Credit Suisse and BP probably take into account the cost of field development (upstream cost) and other costs besides costs for the liquefaction facility.

Therefore, when calculating the cash flow balance of the Tangguh LNG expansion project, CAPEX estimation from Credit Suisse and BP will be used and the well-head price of gas supply for the liquefaction plant will be assumed to be 0 as it has already included in the CAPEX.

In 2014, BP has received environmental and social impact assessment approval (AMDAL) from the Indonesian government and announced its FEED contract to two ‘domestic’ consortia (as required in the contract). As published in BP press release (2014), BP and the Tangguh Partners have signed a sales and purchase agreement with the Indonesian state owned electricity company, PT. PLN, to
supply 1.5 mtpa LNG from 2015 to 2033. This means 40% of the annual production from Train 3 will go to the domestic market. The supply will initially be provided from the existing two LNG trains.

### 7.1.2 Abadi FLNG

Abadi FLNG is a part of future natural gas infrastructure plan in Indonesia (IEA & ERIA, 2013). With a train capacity of 2.5 mtpa, it will be located in the Masela Block in the Arafura Sea that has water depths in the range of 300 to 1,000 meters (SUBSEAIQ, 2014). In 1998, Inpex acquired a 100% working interest in the Masela Block and PreFEED was completed a decade after (BarrelFull, 2014). As published in BarrelFull (2014), in 2009, Indonesian domestic energy company, called EMPI, acquired a 10% stake in the project, however, they stepped out in 2011 and Shell stepped in, changing the share distribution and ended with Inpex owns 65% of the share and Shell owns 35%. The latest update was Inpex launched subsea FEED in 2012 and FLNG FEED in 2013. In 2014, Indonesian government also granted environmental permit for the project (BarrelFull, 2014; SUBSEAIQ, 2014). At present, final investment decision still has not been made, waiting for the completion of the FEED.

In general, there are two design options for FLNG: barge based facility that could carry the size of onshore LNG plant, e.g. Shell Prelude FLNG project at offshore Western Australia; and ship based design that has smaller capacity (1.5 to 3 mtpa), e.g. FLNG project in Papua New Guinea by Flex and Hoegh (Ledesma, 2011). According to Ledesma (2011), developers estimate the CAPEX of FLNG in the range of USD 700 million to 1 billion per million metric ton and even could be higher. Kerbers and Hartnell (2010) distinguish the FLNG capital cost based on the scale, and claim the CAPEX for smaller scale FLNG (less than 3mtpa) to be in the range of 600 to 1,200 USD per tonnes and over USD 800 per tonnes for the higher scale (3.5 to 6.0 mtpa). In its press release, Douglas-Westwood estimates global FLNG CAPEX to increase from 2014 to 2020 with an average of 64% per annum (from USD 2.2 billion to USD 43 billion; only for the liquefaction infrastructure) especially after the completion of Shell Prelude FLNG and Petronas Kanowit PFLNG1 (CIMC-Raffles, 2014).

There are different estimations regarding the CAPEX of the whole project. Gordon (2013) estimates the CAPEX to be around USD 20 billion with 18 production wells and five semi-submersible drilling centers, and the production could be started in 2019. While Hamlen (2014) states that the price tag of the project is about USD 14 billion. According to Hewitt et al. (2012), the cost of this option (only for the FLNG infrastructure) will be at least USD 3,000 per tpa. With a capacity of 2.5 mtpa, the total cost for the infrastructure will be at least USD 7.5 billion.

In terms of the current PSC with the Indonesian government, currently, Inpex is trying to extend the original contract of 20 years period that will end in 2028 to be 40 years (end in 2048). The negotiation is still in progress as the Indonesian government wants at least 30% of the production from Abadi FLNG for its domestic use (Hamlen, 2014). Currently, both Inpex and Shell are also looking for alternative options besides building FLNG with 2.5 mtpa capacity. As summarized by Hamlen (2014), at first the reserves in the block was estimated to be 283.3 bcm, and now, the proven and probable (2P) reserves is expected to be 524.1 bcm. This then leads Inpex and Shell to consider alternative options.
Option 1 (earlier option): FLNG with a capacity of 2.5 mtpa
The operating cost of FLNG has not been much known since the technology is still new and majority of the projects are under construction. A report by Flex-LNG (2009) estimates the OPEX of large FLNG with a scale of 3.5 mtpa to be USD 220,000 per day or USD 0.45 per MMBtu.

Option 2 (conventional): Build an onshore LNG with a capacity of 5.0 mtpa and could be expanded to 10 mtpa
a) Located at Aru Island: +600 km of pipeline
b) Located at Tanimbar Island: + 150 km of pipelines

Inpex and Shell claim that they could save up to 25% with the conventional model compared to building a FLNG (Hamlen, 2014). According to liquefaction plant metric cost from Songhurst (2014), with a complete facility the cost range from USD 5 to 6 billion at normal cost location and USD 7 to 8 billion if the location belongs to a high cost location. In this report, author will use a cost estimation of USD 6.5 billion as an average cost. This is also due to development of Donggi LNG that costs USD 1,000 per tpa. Thus, an estimation of USD 1,300 per tpa for Abadi LNG is still reasonable. Taking into account the pipeline connection needed, for 600km pipeline, the pipeline construction cost would be assumed to be approximately USD 2 billion (see offshore pipeline cost calculation at the next section).

7.1.3 TAGP from East Natuna
East Natuna gas field was first discovered in 1970 by an Italian company, Agip. The field, was estimated to contain 46 tcf (1,302.72 bcm) of gas, and is the biggest gas field in Southeast Asia (Offshore-Technology). In 1980, Pertamina and Exxon agreed to establish a joint-venture to develop the field. Both Pertamina and Exxon owned 50% of the shares. According to a feasibility study conducted by Exxon, gas from East Natuna field has high CO2 content (around 71%) and found to be uneconomic to develop at that time (Offshore-Technology). This might be one of the reasons for the slow development of the field besides geological challenge of the location. In 2007, the Indonesian government terminated the contract with Exxon. However, in 2012, a new joint-venture was established, consisted of Pertamina (35%), Exxon (35%), Total (15%), and PTTEP Thailand (15%) who replaced Petronas in the joint-venture (2b1stconsulting, 2012). First conceptual study had been done and the development cost (CAPEX) was estimated to be 20 to 40 billion USD. According to 2b1stconsulting (2012), the uncertainty on the cost is related to the large possible solutions to develop the field, especially after the gas extraction. The latest update refers to conventional scenario using a set of platforms to extract the oil and gas combined with:

- Floating production storage and offloading (FPSO) vessels and
- A network of export gas pipelines to supply onshore LNG plants or connected directly to consumer

Based on the latest master-plan of TAGP project (ACE, 2013), there are four possible routes from East Natuna, as follows: East Natuna to Erawan (Thailand) as far as 1,500 km, Kerteh (Malaysia) as far as 600km, Java (Indonesia) around 1,400 km, and to Vietnam is approximately 900 km. Considering the companies in the joint-venture, gas pipelines to Erawan and Java are more likely to be constructed. There is also a possibility to transport the gas to Singapore through West Natuna gas pipeline (Corbeau, 2014). The cost to complete the pipeline networks was estimated to be around 7 billion USD.
In 2013, the Indonesian government agreed to provide several incentives in order to accelerate the project execution, such as extending the contract’s period until 50 years (the common practice of contract duration in Indonesia is 20-30 years), splitting share of 45% Government and 55% Contractor (the common practice is 70% Government and 30% Contractor), and the possibility of having 5 years tax holiday (Suryadi, 2013).

It is still unclear whether the companies will only select one option, e.g. build onshore LNG plant or build one route of gas pipelines, or combine several options. On one hand, LNG solution would give more flexibility to the development of the project as it could be easier to expand by adding number of the LNG trains. However, as stated by Corbeau (2014), TAGP project could still be a valuable solution as the network could provide flexibility and diversity of supplies within the region with the TAGP serves as backbone.

One of the technical challenges in cross-border gas pipelines is different gas quality. As reported by Corbeau (2014), Singapore for example, sets minimum methane level for its transmission pipeline to be 80% of the volume and CO2 to be less than 5%. In Thailand, natural gas from its onshore fields contains 76% methane and 13% CO2 while the offshore fields in Myanmar (that is exported through gas pipelines to Thailand) contains 72.4% methane, 6.2% CO2 and 16% nitrogen (Corbeau, 2014). Besides the location characteristic, i.e. onshore pipeline or subsea pipelines, diameter and length of the pipeline, CO2 mass flow rate is another determining factor for capital expenditures to build pipelines (ECCO, 2011). Higher content of CO2 mass flow rate will consequently result in higher pipeline capital cost for the same length of pipelines.

Technology Options and Cost Assumptions
According to SUBSEA IQ (2013), the field has been under construction since 2012 (fixed platform installation) and is expected to begin production in 2020. The development cost and water depth are unknown. Batubara et al. (2014) conduct a feasibility study of the East Natuna gas field, assuming there will be an LNG plant with a capacity of 3.8 mtpa in Natuna Island along with 200-km gas pipeline to connect the field to the main land, and construction of two Natuna – Cirebon (Java) gas pipelines with 42 inch diameter, length of 1400 km, and a capacity of 3200 mmmscfd. They distinguish three phases in the production with a capacity of 1300 mmmscfd in 2023 (800 mmmscfd clean gas goes to pipeline and 500 mmmscfd to LNG plant), 2600 mmmscfd in 2031 (1600 mmmscfd goes to pipeline and 1000 mmmscfd to LNG plant) and 3900 mmmscfd in 2039 (2900 mmmscfd goes to pipeline and 1000 mmmscfd to LNG plant).

Considering the latest estimation of the reserves (46 tcf) and 71% CO2 content, however, the scenarios by Batubara et al. (2014) seem to be too optimistic. Build the four routes of gas pipelines based on the master plan of the TAGP also seems to be less economically viable as the reserves would not be able to support the production for the four pipelines in a long-term period. Therefore, in this report, we will only assess the development of gas pipeline to Thailand, Indonesia, and Singapore. The option to build an onshore liquefaction plant in Natuna Island will also be taken into consideration. For the main concern in this research is to find the “best” option of (transporting) gas infrastructure, the cost of exploration, well development, and permitting will not be included in the computation. It will be
assumed the wellhead price for this offshore gas field to be 8 USD per MMBtu as recognized by Batubara et al. (2014) and Parkinson (2014).

**Option A: Gas Pipeline from East Natuna to Erawan – 1500km**

Designing a long-distance pipeline for transportation of natural gas requires knowledge of flow formulas for calculating capacity and pressure requirements (Guo, Lyons, & Ghalambor, 2007, p. 148). Pipeline design includes determination of material, diameter, wall thickness, insulation, and corrosion protection measure (Guo et al., 2007, p. 153). According to Guo et al., weight coating and trenching for stability control are also included for the offshore pipelines. Langelandsvik (2008) builds one-dimensional pipeline model to simulate the transport of natural gas in Norway’s large-diameter export pipelines. He finds the most important parameters in the simulations are gas density, ambient temperature, flow rate measurements, and inner diameter of pipeline. Due to the limitation of the data of the gas field characteristics and the operational measure (i.e. gas flow, pressure, etc.), approximation from the existing gas pipelines design will be used.

Practically, the diameter of pipeline should be determined based on flow capacity calculations (Guo et al., 2007, p. 153). Summarizing from table 2.5, the common pipeline designs used in cross-border Southeast Asian gas pipelines are as follows:

<table>
<thead>
<tr>
<th>Outside diameter (inch)</th>
<th>22</th>
<th>24</th>
<th>28</th>
<th>36</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max. Capacity (mmcmd)</td>
<td>250</td>
<td>300</td>
<td>325</td>
<td>500</td>
</tr>
<tr>
<td>Length (km)</td>
<td>96</td>
<td>277</td>
<td>654</td>
<td>410</td>
</tr>
<tr>
<td>Location</td>
<td>West Natuna to Duyong</td>
<td>Yetagun to Thailand</td>
<td>West Natuna to Jurong</td>
<td>Yadana to Thailand</td>
</tr>
</tbody>
</table>

In order to comply with all gas quality standard, it is assumed that the allowable content of CO2 is 4% and the total amount of natural gas that could be transported reaches 15.18 tcf.

*Proven reserves = 46 tcf with 71% CO2*

*Allowance of 4% result in 33% * 46 tcf = 15.18 tcf*

To replace gas supply from Yadana and Yetagun gas fields, Thailand will need a supply of approximately 800MMCFD. Given a long-term contract of 30-years, the total reserve needed is 8.76 tcf. If the supply is increased to 1000MMCFD and 1200MMCFD, the total reserve needed is 10.95 tcf and 13.14 tcf, respectively. With this scheme, the rest of the reserves still could be transported either to an onshore liquefaction or smaller gas pipeline connection.

Moshfeghian and Hairston (2013) present a case study of 1600-km gas pipeline, operated at different designs, based on the diameter and number of compressors. Based on the results, the highest cost-efficient design is 36-inch pipeline with 3 compressor stations – Case D (USD 4.2 billion), followed by 42-inch pipeline also with 3 compressor stations – Case B (USD 4.6 billion). 42-inch pipeline with single compressor station is the most expensive (USD 5.4 billion) although it has the lowest capital cost of compressor. This is caused by higher inlet pressure and wall-thickness of the design which make the pipeline is heavier, and thus, has higher line pipe cost and material cost.
Given a similar inlet and outlet pressure, for the capacity of 800 to 1000 MMCFD (could be up to 1160 MMCFD), 36-inch pipeline will be the most cost-efficient design, while for the capacity of 1000 to 1200 MMCFD (could be up to 1760 MMCFD), 42-inch pipeline would be more suitable as it offers capacity flexibility. Formula 7.1, called pipeline sizing equation (ICC, 2009), can be used to find the capacity of each pipeline design.

\[
Q = 2,237 \ D^{2.623} \ \left(\frac{P_1^2 - P_2^2}{Cr \cdot L}\right)^{0.541}
\]

(7.1)

Where:
- \(Q\) = rate, cubic feet per hour (cfh; could be converted to mmcf/d)
- \(D\) = inside diameter of pipe (inch)
- \(P_1\) = upstream pressure (psia)
- \(P_2\) = downstream pressure (psia)
- \(Y\) = super expansibility factor = 1/super compressibility factor
- \(Cr\) = factor for viscosity, density and temperature, in which equal to:

\[
Cr = 0.00354 \cdot S \cdot T \left(\frac{Z}{S}\right)^{0.152}
\]

- \(S\) = specific gravity of gas at 60°F and 30-inch mercury column; equal to 0.60
- \(T\) = absolute temperature; \(t (°F) + 460\)
- \(Z\) = viscosity of gas, equal to 0.012
- \(L\) = length of pipe (feet)

Following the simulation of Moshfeghian and Hairston (2013), compressor stations in case B increase pressure from 1,015 to 1,858 psia, while in case D, since the diameter is smaller, the pressure increases from 1,015 to 2,835 psia. See Appendix C1 for detail calculation. The calculation using formula 7.1 shows that capacity of 42-inch pipeline in case B is up to 990 MMCFD, while the 36-inch pipeline in case D is 1160 MMCFD. Increasing the pressure of compressor stations in case B to be as same as in case D could significantly increase the capacity up to 1760 MMCFD.

Since the cost calculations by Moshfeghian and Hairston (2013) are for onshore pipelines, some adjustments need to be made because the gas pipeline connections from East Natuna will be offshore pipelines. ECCO (2011) gives CAPEX approximation for offshore pipelining, excluding the cost for compressor. Therefore, cost for the compressors will follow the findings of Moshfeghian and Hairston (2013). CAPEX calculation of the offshore pipelines will follow rules of thumbs as in table 3.3. The calculation of several design options can be found in Appendix C2.

The total CAPEX for 36-inch pipeline with 3 compressor stations operated as in case D of Moshfeghian and Hairston (2013) is USD 5.46 billion while for 42-inch pipeline with 3 compressor stations as in case B is USD 5.94 billion. Increasing the capability of the compressor to get higher capacity of 1760 MMCFD will require more investment up to USD 6.05 billion. In this case, under the same range of pressure, 36-inch pipeline design is more superior than the 42-inch because it offers more capacity with less expensive cost. Since the actual maximum capacity is unknown, giving flexibility to the capacity design might be attractive because it also offers option to expand the capacity in the future. In this case, the cost of option flexibility is USD 0.59 billion. The value of the option flexibility itself could be known by
subtracting the additional revenue obtained from additional (flexibility) capacity to additional cost required to have the flexibility.

**Option B: Gas Pipeline from East Natuna to Java – 1400 km**

In the Reference scenario, constructing a gas pipeline from East Natuna to Java is not really necessary. However, following the BAU scenario, it will significantly reduce the amount of imported LNG. The price would be less expensive compared to importing LNG since the gas field is within the territory of Indonesia and Pertamina is also a major shareholder. For Pertamina has more shares compared to PTTEP, and the fields owned by the Indonesian government, Pertamina has more bargaining power to build a pipeline connection to Java if the domestic production will really decline after 2017.

In the BAU scenario, after 2021, Indonesia will need to import gas in order to meet both its domestic consumption and long-term contract export responsibilities. In period 2022-2045, Indonesia will need a total gas supply of 50.88 bcm or 19,925 tcf. Following the BAU scenario, constructing a gas pipeline to Erawan will be less likely to happen due to insufficient amount of the proven reserves (allocated for gas pipeline connection to Java).

Changing the length of pipeline to 1400 km and given a similar condition of 4% CO2 allowance as in the previous section with 36-inch and 42-inch pipeline design result in a capacity up to 1200 MMCFD for 36-inch pipeline, and 1800 MMCFD for 42-inch pipeline. Assumed that the production could start at its maximum volume in 2022 to 2045 (24 years), the reserves used within this period is 10.5 tcf for 36-inch pipeline and 15.77 for 42-inch pipeline. Based on the results of imported LNG needed from the BAU scenario, the ideal daily capacity of East-Natuna to Java gas pipeline is shown in figure 7.1.

![Figure 7.1 Daily transporting capacity needed from East Natuna to Java in BAU scenario](image-url)

In this case, the capacity of 42-inch pipeline with 3 compressor stations is only suitable for the first 11 years. Afterwards, the capacity need to be increased continually to be more than double after 2042. There are several options to solve this problem, such as:

1. Build one gas pipeline with a capacity up to 1800 MMCFD at the beginning, add more compressor stations then build a second gas pipeline with similar capacity that has to be in operation at period 19.
2. Build one gas pipeline with a capacity up to 5,000 MMCFD since the beginning
3. Build one gas pipeline with a capacity up to 2500 at the beginning, then build a second gas pipeline with the same capacity that should be in operation at period 24.

However, the required supply for the Indonesian gas market will also depend on other gas projects, especially Tangguh LNG expansion and Abadi project. If these two projects are executed, gas pipeline from East Natuna does not need to be operated at a very high capacity. Figure 7.2 shows the change in supply needed from East Natuna if the expansion of Tangguh LNG could operate in its maximum capacity in 2023 and 40% (or even 100%) of the production will be sold to the domestic market.

The average daily capacity is approximately 2,400 MMCFD for only East Natuna and plus 40% of Tangguh LNG capacity. For the use of 100% LNG Tangguh expansion capacity, the average daily capacity is 2,200 MMCFD. Operating at a capacity of 2,400 MMCFD will cause the reserve depleted after 17 years (period 26). The CAPEX of building 42-inch pipeline with 3 compressor stations operated in a high pressure will cost approximately USD 6.67 billion. If Abadi gas field is operated, the required supply from East Natuna will be less. However, it is still uncertain and there are also several options to develop the Abadi gas field, i.e. FLNG or onshore LNG.

The pipeline construction time either to Erawan or Java is assumed to be completed in 3 years. This is based on the experience of West Natuna gas pipeline that was operated in 3 years (2001) after the final contract agreement was reached in 1999 (JonesDay). The OPEX for the pipeline operation is assumed to be USD 0.7 per MMBtu as indicated in Messner and Babies (2012).

Option C: Gas Pipeline from East Natuna to Singapore via West Natuna gas pipeline
This option could be combined with option A because there is still excess reserve that could be used. It is also possible to combine this option with option B if there is additional supply from Tangguh and Abadi gas fields. The characteristic of gas pipeline from West Natuna to Jurong, Singapore is 28-inch pipeline with 325 MMCFD capacity. The total amount of reserves needed for a 30-years long-term contract is 3.56 tcf. Following the CAPEX calculation as in table 3.3 with a distance of 300 km (assumption) and lower compressor’s pressure, the CAPEX needed is approximately USD 1.5 billion.
Option D: LNG liquefaction plant in Natuna Island

This option could be combined with option A, B, and C. The main design variable for an LNG plant is its capacity. According to Morgan and White (2012), the size range of an LNG plant can be categorized into three, as follows:

- mini LNG with a capacity less than 0.1 mtpa
- mid-scale LNG with a capacity from 0.2 to 1.5 mtpa, and
- base-load LNG with a capacity from 3 to 5 mtpa (could reach 8 mtpa as in Qatar).

Songhurst (2014) finds that the train size growth has been bigger and bigger from less than 2 mtpa in period 1960-1990, 2-3 mtpa during the next decade, and 3-5 mtpa during 2000-2010. Songhurst (2014) uses data of the cost estimation of 36 liquefaction projects between 1965 to 2014/2015 that was produced by Wood Mackenzie, finds that the CAPEX of LNG liquefaction plant has risen to 1,200 USD per tpa from 300 USD per tpa in 2000. He tries to figure out the reason by breaking-down the cost based on plant area (1% site preparation, 7% gas treatment, 3% fractionation, 28% liquefaction, 14% refrigeration, 20% utilities, and 27% off sites) and category (10% owner’s costs, 8% EPC, 30% equipment, 20% bulk materials, and 32% construction). The first way of the cost breakdown explains why the cost for a repeat liquefaction train is around 50% of a completely new facility and the latter explains the major determinant of the cost components, i.e. construction costs, that causes the liquefaction projects in country such as Australia (higher labour cost) to be more expensive. As included in Songhurst’s report, the cost of Donggi LNG liquefaction plant (Indonesia) that was built in 2014 is around 1000 USD per tpa and the expansion of Malaysian LNG train 10 2014 cost around 500 to 600 USD per tpa.

Batubara et al. (2014) propose a plan to build an onshore LNG plant with a capacity of 3.8 mtpa at Natuna Island along with 200-km gas pipeline to connect the offshore field to the main land. This train capacity is similar with LNG train in Tangguh gas fields. According to Egger (2006), the LNG train of 3.8 mtpa capacity need a gas supply up to 750 mmcfd. The contract for an LNG plant is usually up to 20 years. Therefore, it requires 5.5 tcf of gas reserves to secure the gas supply for the LNG plant for 20 years period or 8.2 tcf for 30 years period.

If the gas pipeline of either to Erawan or Java operates at 800 to 1000 MMCFD, the option of 3.8 mtpa LNG plant is still operationally viable. However, if the pipeline capacity goes to 1200 MMCFD or even higher, the LNG plant should be operated in a lower capacity, i.e. mid-scale LNG.

The CAPEX of 3.8 mtpa onshore LNG liquefaction plant is assumed to be USD 4.94 billion or USD 1,300 per tpa as is assumed in the case of Abadi LNG plant. Taking into account 200 km pipeline connection, the total CAPEX is assumed to be USD 5.67 billion. Table 7.1 summarizes the options development at East Natuna, Abadi, and Tangguh gas fields.
<table>
<thead>
<tr>
<th>Project and Technology Option</th>
<th>Other options</th>
<th>CAPEX</th>
<th>OPEX</th>
<th>Other information</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tangguh LNG</strong></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Technology Option: expansion by adding one train with a capacity of 3.8 mtpa</td>
<td>Delay; abandon</td>
<td>USD 11 billion (credit Suisse)</td>
<td>USD 0.20 per MMBtu</td>
<td>EPC takes 4 years; no well-head cost; CAPEX volatility 100% per 8 to 10 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>USD 12 billion (BP)</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>(probably) Included upstream cost</td>
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<tr>
<td><strong>Abadi gas field</strong></td>
<td></td>
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<tr>
<td>Tech. option1: FLNG with a capacity of 2.5 mtpa</td>
<td>Delay; abandon; expand</td>
<td>USD 20 billion (Gordon, 2013)</td>
<td>USD 0.45 per MMBtu</td>
<td>Development time (FEED + EPC) takes 5 years; CAPEX volatility 64% per year</td>
</tr>
<tr>
<td></td>
<td></td>
<td>USD 14 billion (Hamlen, 2014)</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>USD 7.5 billion (Hewitt et al., 2012)*</td>
<td></td>
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</tr>
<tr>
<td>Tech. option2: Build an onshore LNG with a capacity of 5.0 mtpa</td>
<td></td>
<td>USD 10.5 billion (Hamlen, 2014)</td>
<td>USD 0.20 per MMBtu</td>
<td>CAPEX volatility 100% per 8 to 10 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>USD 8.5 billion (author estimation)</td>
<td></td>
<td></td>
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<tr>
<td><strong>East Natuna gas field</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tech. option1: Gas Pipeline from East Natuna to Erawan – 1500km</td>
<td>Delay; abandon; expand; multi-stage investment</td>
<td>36-inch pipeline + 3 compressor station (CS) = USD 5.46 billion</td>
<td>USD 0.7 per MMBtu</td>
<td>Pipeline construction takes 3 years; CAPEX volatility 10% per year (author’s assumption).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>42-inch pipeline + 3 CS = USD 5.94 billion</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>42-inch pipeline + 3 CS+ = USD 6.05 billion</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tech. option2: Gas Pipeline from East Natuna to Java – 1400 km</td>
<td></td>
<td>42-inch pipeline + 3 CS++ = USD 6.67 billion</td>
<td>USD 0.7 per MMBtu</td>
<td>Pipeline construction takes 3 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>28-inch pipeline + 3CS = USD 3.4 billion</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tech. option3: Gas Pipeline from East Natuna to Singapore via West Natuna gas pipeline</td>
<td></td>
<td>28-inch pipeline + 3 compressor station (CS) = USD 1.5 billion</td>
<td>USD 0.7 per MMBtu</td>
<td>Pipeline construction takes 2 years</td>
</tr>
<tr>
<td>Tech. option4: LNG liquefaction plant in Natuna Island</td>
<td></td>
<td>3.8 mtpa + 200 km pipelines = USD 5.67 billion</td>
<td>USD 0.20 per MMBtu</td>
<td>EPC takes 4 years; CAPEX volatility 100% per 8 to 10 years</td>
</tr>
</tbody>
</table>
7.2 DISCUSSION

According to Schoemaker and van der Heijden (1992), there are four important aspects that need to be considered in option planning: multiple options, effect of uncertainty, competitive implications, and explicit trade-offs. The first part of this chapter has presented multiple options either from technological perspective or other options theory, i.e. option to delay, option to abandon, or option to expand.

7.2.1 Effect of Uncertainty

Some major uncertainties such as domestic gas production, domestic gas consumption, and gas prices have been incorporated into the two scenarios. Regarding the project valuation itself, there are some uncertainties, such as CAPEX and OPEX volatility, and discount rate used in the valuation. These uncertainties will be taken into account during options valuation in the next chapter. The interdependency among the projects also could not be ignored since it will significantly affect the supply absorption, especially by the domestic market.

7.2.2 Competitive Implication

In this case, Tangguh LNG expansion is the project that is most likely to happen because 40% of its production has been reserved by PLN. However, still, there is possibility to delay or even abandon the project in the future. Given additional domestic supply from Tangguh LNG at most 3.8 mtpa (5.2 bcm/y), there will be a change in the domestic production level. This will indirectly determine additional domestic supply needed to meet domestic gas demand and export requirement. Figure 7.3 shows the relation among the new projects development.

![Figure 7.3 Relation among new gas projects development](image)

The development of both East Natuna and Abadi gas field will have no effect to Tangguh LNG expansion project because Tangguh project is much ahead and less risky compared to the other projects. This is because Tangguh project is an expansion of the existing infrastructure. On the other
hand, East Natuna and Abadi gas project will significantly affect each other. The status of both projects is also similar in which the consortium has been established a long time ago and currently just be reformed. They are also waiting for the accomplishment of feasibility study regarding several technology options available to develop the projects. The situation is much more complex in the BAU scenario because Indonesia is in deficit condition of gas supply. Figure 7.4 shows the way Abadi gas field decision could affect the decision of East Natuna development.

<table>
<thead>
<tr>
<th>BAU Scenario</th>
<th>Reference Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off</td>
<td>Connecting gas pipeline to Erawan with a capacity up to 800 MMCFD; could be combined with gas pipeline to Java with smaller capacity or with onshore LNG or pipeline connection to West Natuna-Singapore</td>
</tr>
<tr>
<td>2.5 mtpa</td>
<td>Connecting gas pipeline to Erawan with a capacity up to 1,200 MMCFD; could be combined with onshore LNG or pipeline connection to West Natuna-Singapore</td>
</tr>
<tr>
<td>5.0 mtpa</td>
<td>As in '2.5 mtpa' case, with more allocation for export.</td>
</tr>
</tbody>
</table>

*Figure 7.4 East Natuna's technology options based on exercising Abadi's technology options*

In the BAU scenario, there is more certainty to build gas pipeline from East Natuna to Java due to highly deficit of gas supply even after getting supply from 40% Tangguh LNG and probably 30% Abadi LNG/FLNG. The domestic market could only get more allocation if the buyers are willing to pay as much as the international buyers otherwise the contractor will choose to sell the gas to the international buyers.

Based on this scenario, Indonesia needs to get additional LNG import contracts especially after the deficit surpasses the pipeline capacity from East Natuna gas field (after 2036). Since the technology option selected to develop the gas field is more certain, PTTEP will probably step out of the consortium because its main interest, i.e. to get gas supply to Thailand is not served. Another option is exporting the gas to Thailand through LNG shipping. However this will not last long because in the BAU scenario, Indonesian domestic gas demand has surpassed its production in 2027.

In the Reference scenario, the situation is much more complex because the technology options for East Natuna could be combined depending on the regional gas market condition, e.g. Singapore and Thailand gas demands. With this scenario, Indonesia needs to optimize the condition in order to get more profit from selling the gas. However, this also depends on the domestic market obligation requirement (DMO). The allocation for DMO could be transported either as pipelined gas to Java (e.g.
up to 300 to 500 MMCFD) or LNG shipping from East Natuna to the domestic market. The decision to extend the pipeline connection to West Natuna then Singapore could come afterwards, i.e. after the core infrastructure (e.g. pipeline connection to Erawan or onshore LNG) be in place.

In terms of the main shareholders in East Natuna consortium, each shareholder has different level of bargaining power, i.e. power to lead or to select technology options used to develop the field. Pertamina as the Indonesian-state (oil and) gas company has slightly higher bargaining power compared to ExxonMobil although they have same amount of share. However, Exxon Mobil could be considered to have more experience and expertise than Pertamina to manage the field, especially with the high content of CO2 in East Natuna gas field. Total is also an international player with international focus and mainly profit oriented as ExxonMobil, but with a lower share than Exxon Mobil. The presence of Total in the consortium could help the management to be more critical in assessing the technology options and business case of the field development. PTTEP, the Thai (oil and) gas state company has a similar focus as Pertamina although with a lower share. However, this makes both PTTEP and Pertamina have conflicting interest since both of them will try to get gas supply from East Natuna for their own sake. Since Pertamina has higher share and thus higher power, Pertamina’s interest will be prioritized compared to PTTEP’s. Figure 7.5 shows the shareholders position in the consortium.

![Shareholders Position](image)

Figure 7.5 East Natuna’s shareholder position

### 7.2.3 Trade-offs

In the case of Tangguh LNG expansion project, there is only one technology option because the FEED contract was announced with a specific design requirement for the LNG train with a capacity of 3.8 mtpa as the previous two trains. Other options available are from real option theory, i.e. option to delay, abandon or expand. Option to expand will depend on any new finding of gas field. However, the expansion will not directly related to this project. From the past experience, the expansion will be in the form of new LNG train and the contractor will tend to wait until this project be accomplished and gain success before continuing the expansion. Option to abandon is also less likely to happen because the gas sales agreement had been reached. It is possible after the contract expired. Option to delay is most likely to happen comparing to other options because delaying production might result in higher profit for the contractor given that the gas price keeps rising. However, this also depends on
the gas sales agreement, i.e. whether the buyer’s price is fixed or oil-indexed. Delaying the project, on one hand could bring higher profit for the contractor (if the future gas price is higher) while on the other hand could hamper the government’s plan to increase the utilization of natural gas and also there is opportunity loss for the contractor. As the availability of gas supply is uncertain or get delayed, the domestic buyers might try to find other supplies from international gas market or even abandon their business in Indonesia, especially for industries that need natural gas as feedstock or utilities. PLN as monopolist in the power sector might also change its plan and use other fuels, such as coal, or invest in renewable energy such as hydro or geothermal.

For Abadi gas field development, currently there are two technology options, i.e. FLNG with a capacity of 2.5 mtpa or onshore LNG with a capacity of 5 mtpa. Development of FLNG costs more compared to onshore LNG and also with less capacity. However, FLNG is more flexible since it could be moved and be used again for other offshore projects. The option of delay, abandon, or expand have similar implication as in the case of Tangguh LNG expansion. For this project, the commercial risk impact if the project gets delayed is lower compared to in Tangguh LNG expansion because Abadi has not (yet) signed any gas sales agreement, and thus, will not affect its credibility or buyers’ trust.

The development of East Natuna gas field has more complexities compared to the previous two projects because of different and even conflicting interests among the shareholders. The technology options selected in the two scenarios are also quite different. To ensure the production level of Indonesia, whether as in BAU scenario or Reference scenario, the management team of East Natuna gas field needs to wait at least until 2017 to see the trend and observe the reserve replacement ratio until that year. Another way to keep the progress of the project is to build the onshore LNG plant first. With this option, the production could be allocated either for domestic market in Indonesia or Thailand, and also international market. However, if the condition turns around afterward, for example in 2020 when the gas production of Indonesia declines sharply, and the government pushes to build gas pipeline connection to Java, then the onshore LNG could not be operated at its maximum capacity. Another possible option is building pipeline connection to Java with a smaller capacity, at least to fulfill the DMO. Afterward, the situation could be observed. If the production trend shows like in the BAU scenario, additional pipeline to Java could be built. In contrary, if the trend shows like in the Reference scenario, onshore LNG plant or pipeline connection to Thailand could be built, followed by pipeline connection to the existing West Natuna – Singapore gas pipeline.
8 Options Valuation

In the previous chapter, some possibilities of technology options to develop new gas projects in Indonesia have been discussed, including the integration of real options theory, e.g. options to expand, defer, or abandon. In this chapter, at first, the technology options will be evaluated using adjusted discounted cash flow method. “Adjusted” because the DCF method is ‘adjusted’ to the PSC structure of each project. Afterwards, real options valuation model will be used to value the projects, taking into account the embedded real options of the projects.

8.1 ADJUSTED DISCOUNTED CASH FLOW (DCF)

Options valuation based on discounted cash flow is a simple valuation method to give first insight to the management (or decision maker) about the value of the project. This approach is slightly different with a simple DCF because it follows the cost structure of the PSC between the government and the contractor. As the results, there will be two values of NPV, one for the government, and the other one for the contractor.

8.1.1 Input Assumptions

The main assumptions used in this model are summarized as follows:

- CAPEX, OPEX, and construction time of each project as presented in table 7.1. LNG shipping cost is assumed to be USD 2.5 per MMBtu and borne by suppliers. When the parameter of inflation 2% is ‘on’, it affects domestic gas price, OPEX, and LNG shipping cost (no effect for well-head cost).
- Discount rate is fixed over the time frame of the model. For projects with lower risks, the discount rates could vary between 6% to 10% while for projects with higher risks, the discount rates could vary between 10% to 15% (see Kotzot et al. (2007)).
- The domestic gas price for allocation from DMO is assumed to be at USD 9.0 per MMBtu as the latest gas price sold to PLN per 2014.
- Export pipelined gas or LNG will use a same gas price, referring to Japan-cif index with three scenarios of gas price: reference, high, and low gas prices.
- No disruption at production and either gas pipelines or LNG plants could operate at their maximum capacity after 2 years operation. The first two years are assumed to be operated at most of half maximum capacity.
- Cash flow structure (FTP, cost recovery, profit share, tax) follows the format of PSC in Indonesia. Interest that needs to be paid for (borrowed) CAPEX is excluded, and assumed to be borne by the contractor.

8.1.2 Capacity Allocation in BAU Scenario

Options valuation based on DCF method will be based on the ideal condition for the Indonesian government in order to have a sufficient gas supply within the time frame of the model. Figure 8.1 shows the overview of capacity allocation for each selected technology option in BAU Scenario.
For Abadi gas field, it is assumed that technology option of onshore LNG plant is more favorable than FLNG option because it offers lower cost with a higher capacity. The domestic allocation is assumed to be 30% of its maximum capacity. Allocation for Tangguh LNG expansion is treated as in the existing contract, as much as 1.5 mtpa until 2033. For East Natuna gas field, the option of onshore LNG will be executed first, followed by pipeline connection to Java. The figure shows that pipeline from East Natuna has the highest contribution to supply domestic gas consumption in Indonesia.

If all selected technology options are ready in operation at the desired time, long-term contract for LNG import is needed from 2039 and onwards. At year 2023, 2027, and 2038, a small amount of LNG import is needed with a volume less than 1.5 bcm and could be bought from the spot market. The government also could buy more LNG (more than DMO agreement) from Tangguh and Abadi. This ideal condition could be enforced by the government because the government has authority or power to delay or issue all legal permit requirements that should be complied by the contractors.

Figure 8.1 Overview of capacity allocation in BAU Scenario

8.1.3 DCF Options Valuation in BAU Scenario

This section presents valuation of four gas projects that are most likely to happen in Indonesia in the coming years: Tangguh LNG expansion with a capacity of 3.8 mtpa, onshore LNG plant near Abadi gas field with a capacity of 5.0 mtpa, onshore LNG plant in Natuna Island with a capacity of 3.8 mtpa, and pipeline connection from East Natuna to Java that has a capacity up to 2,400 MMCFD. The script of the codes executed in Matlab 2014b can be seen in Appendix D.

Tangguh LNG expansion

The CAPEX used in this model has included costs for upstream development, and thus, there is no well-head price to be paid. The FEED contract has been launched and construction could directly be started afterwards. With a construction time of four years, the plant is expected to be in operation in 2020, given the final investment decision should be made at least at the end of 2015.
The DCF method calculation produces three measurement indicators: NPV revenues for government, NPV revenues for contractor, and time needed to recover the CAPEX. Indonesian PSC does not establish any ceiling for cost recovery which means that the contractor could use all 80% of the revenues (20% of the revenues is for FTP). The calculation results in 13 years to recover the whole CAPEX, and NPV revenues of USD 8.24 billion for the Indonesian government (70% FTP, 70% profit sharing, tax revenues of contractor) and USD 2.18 billion for the contractor (30% FTP, 30% profit sharing deducted by 44% tax income).

**Sensitivity Analysis**

The sensitivity analysis will be performed to observe the changes in NPV revenues for both government and contractor, and also cost recovery time. Changes are made to the CAPEX, discount rates, and inflation of the OPEX, LNG shipping cost, and domestic gas price. Table 8.1 shows the results of the three measurement indicators under different parameter settings.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Reference gas price</th>
<th>High gas price</th>
<th>Low gas price</th>
</tr>
</thead>
<tbody>
<tr>
<td>No inflation; discount rate = 8%; CAPEX = USD 12 billion [BASE case]</td>
<td>NPV government USD 8.24 billion NPV contractor USD 2.18 billion Time to recover CAPEX 13 years</td>
<td>NPV government USD 13.94 billion NPV contractor USD 3.58 billion Time to recover CAPEX 11 years</td>
<td>NPV government USD 3.56 billion NPV contractor USD 1.03 billion Time to recover CAPEX 16 years</td>
</tr>
<tr>
<td>No inflation; discount rate = 8%; CAPEX = USD 11 billion</td>
<td>NPV government USD 8.55 billion NPV contractor USD 2.25 billion Time to recover CAPEX 12 years</td>
<td>NPV government USD 14.31 billion NPV contractor USD 3.66 billion Time to recover CAPEX 10 years</td>
<td>NPV government USD 3.80 billion NPV contractor USD 1.08 billion Time to recover CAPEX 15 years</td>
</tr>
<tr>
<td>Inflation 2%; discount rate = 8%; CAPEX = USD 12 billion</td>
<td>NPV government USD 8.05 billion NPV contractor USD 2.14 billion Time to recover CAPEX 13 years</td>
<td>NPV government USD 13.75 billion NPV contractor USD 3.53 billion Time to recover CAPEX 11 years</td>
<td>NPV government USD 3.34 billion NPV contractor USD 0.98 billion Time to recover CAPEX 16 years</td>
</tr>
<tr>
<td>No inflation; discount rate = 6%; CAPEX = USD 12 billion</td>
<td>NPV government USD 11.85 billion NPV contractor USD 3.09 billion Time to recover CAPEX 13 years</td>
<td>NPV government USD 19.76 billion NPV contractor USD 5.02 billion Time to recover CAPEX 11 years</td>
<td>NPV government USD 5.11 billion NPV contractor USD 1.44 billion Time to recover CAPEX 16 years</td>
</tr>
<tr>
<td>No inflation; discount rate = 10%; CAPEX = USD 12 billion</td>
<td>NPV government USD 5.84 billion NPV contractor USD 1.58 billion Time to recover CAPEX 13 years</td>
<td>NPV government USD 10.03 billion NPV contractor USD 2.6 billion Time to recover CAPEX 11 years</td>
<td>NPV government USD 2.53 billion NPV contractor USD 0.75 billion Time to recover CAPEX 16 years</td>
</tr>
</tbody>
</table>
If the CAPEX is USD 11 billion as is estimated by Credit Suisse (Hewitt et al., 2012), the NPV revenues for both government and contractor will certainly increase, and the cost recovery time will also be faster by 1 year for every gas price scenario. This actually could be estimated from the annual revenue as a result of selling the gas to the domestic market or export which is around USD 1 billion at the first two years of its operation. The change in NPV for the contractor is varied, 3.2% for reference gas price, 2.23% for high gas price, and 4.85% for low gas price scenario.

Given a constant inflation of 2.0% for the OPEX, LNG shipping cost, and domestic gas price, the cost recovery time for every gas price scenario remains the same. Inflation of 2% results in a decreasing of NPV for the contractor by 1.83% for reference gas price, 1.40% for high gas price, and 4.85% for low gas price.

Changes in the discount rate, either by 6% or 10% only change the NPV value (from USD 3.09 billion to USD 1.58 billion for the contractor) and has no correlation with cost recovery time. This is due to the exclusion of interest payment in the cash-flow calculation which is quite important from the contractor perspective, especially if the CAPEX is borrowed. The exclusion of the interest payment is relevant from the government perspective because the government, actually, does not care with the way the contractor gets the fund for the CAPEX. Later, this information, i.e. NPV revenue for the contractor, could be used by the contractor to analyze whether the project is still profitable or not from their perspectives by considering the allocation of cost needed to pay the interest.

In sum, the project of Tangguh LNG expansion with a capacity of 3.8 mtpa has a positive NPV both for government and contractor in all observable parameter settings. The time needed for the contractor to recover the CAPEX is varied depending on the gas price scenario. The use of inflation of 2% has little influence in the calculation because the inflation of OPEX & LNG shipping cost (cost) and domestic gas price (revenue) could offset each other.

Monte Carlo Simulation

Monte Carlo simulation is used to simulate the gas prices over the time frame of the model. The gas prices used in the previous section is based on regression analysis resulted from Brent-oil index (see section 5.2.1). To fulfill the requirement of 95% confidence interval, the gas prices are simulated within the range of +/- 2.4 USD per MMBtu of its reference price. Figure 8.2 shows the results of NPV revenues for the contractor in different number of trials. Table 8.2 summarizes the results of the average NPV revenues with their ranges for both government and contractor under different number of simulation trials. When the number of the simulation trials increases, the ranges of the results for both NPVs are also increased. The average value of the NPVs for contractor under different four numbers of trials are similar at USD 2.18 billion. This value is as same as the previous result (see base case parameter setting, reference gas price scenario). On the other hand, the average NPVs for the government in the four simulations are slightly different, within the average range of USD 8.23 billion to USD 8.26 billion. The NPV for the government in the first DCF calculation is USD 8.24 billion, which is still within the range. These differences could be explained by the standard deviation value. In 100,000 trials simulation, the standard deviation for the NPV value of the government is USD 216.50 million, while for the contractor is USD 53.80 million. This is also explained by the shape of the belt curve as is shown in figure 8.3 which also includes the cumulative density function for both NPV values of the government and the contractor.
Table 8.2 Summary of the results of Monte Carlo Simulation for Tangguh LNG expansion project

<table>
<thead>
<tr>
<th># trials</th>
<th>Average NPV_gov (USD billion)</th>
<th>Range NPV_gov (USD billion)</th>
<th>Average NPV_con (USD billion)</th>
<th>Range NPV_con (USD billion)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>8.2577</td>
<td>7.73 to 8.81</td>
<td>2.1881</td>
<td>2.06 to 2.32</td>
</tr>
<tr>
<td>1,000</td>
<td>8.2334</td>
<td>7.60 to 8.90</td>
<td>2.1823</td>
<td>2.02 to 2.35</td>
</tr>
<tr>
<td>10,000</td>
<td>8.2419</td>
<td>7.46 to 9.12</td>
<td>2.1844</td>
<td>1.99 to 2.40</td>
</tr>
<tr>
<td>100,000</td>
<td>8.2417</td>
<td>7.31 to 9.13</td>
<td>2.1843</td>
<td>1.95 to 2.40</td>
</tr>
</tbody>
</table>

Figure 8.3 Density and cumulative probability of the NPV for the government and contractor – Tangguh LNG
Abadi onshore LNG plant

With a capacity up to 5 mtpa, Abadi onshore LNG plant stands right after Tangguh LNG expansion train and is required to be in operation in 2025. Therefore, the FEED and EPC contract should be announced at least at the end of 2019. The latest information stated that the Indonesian government requires a DMO of at least 30% from Abadi gas field’s production. The estimated CAPEX of this project is between USD 8.5 billion to 10.5 billion. FTP, cost recovery, tax, and profit sharing allocation used in this calculation is similar with the calculation of Tangguh LNG expansion. For this project, the CAPEX has not included the upstream cost, and thus a well-head cost of USD 8 per MMBtu will be assumed sufficient to cover the upstream cost. The discount rate of this project (10%) is higher than Tangguh project (8%) because in Tangguh case, the risks and uncertainties are better known.

The reference gas price scenario with a CAPEX of USD 10.5 billion, indicates a cost recovery time of 20 years, with NPV revenue for the government as much as USD 995,457,188.67, and for the contractor as much as USD 307,273,462.93. Although this project is expected to be started a bit later than Tangguh LNG expansion project, the life-time of the project (until 2045) is still relevant since the latest information stated that Inpex as the contractor of Abadi gas field is negotiating the PSC with the Indonesian government to extend the duration of the contract until 2048. Therefore, with an assumption that the plant could still be operated at its maximum capacity until 2045, the difference of the actual end of life-time of the project is insignificant.

If we compare the NPV for both the government and the contractor between Abadi project and Tangguh project, the revenue of Abadi project is much lower. This might due to the well-head cost which is in Tangguh project is assumed to be 0 since the initial CAPEX has already included the upstream cost or the well-head cost. The assumption of USD 8 per MMBtu for the well-head cost might be too much. Therefore, the contractor could make another calculation to count the real upstream cost.

**Sensitivity Analysis**

Changing the CAPEX with USD 8.5 billion results in a cost recovery time of 18 years. NPV of the revenues for the government and contractor increased by 18% and 12.9% respectively. Changing the well-head cost from USD 8 per MMBtu to USD 6 per MMBtu results in NPV of USD 1.99 billion for the government and USD 0.56 billion for the contractor. This also accelerates the cost recovery time by 4 years from the base case parameter setting. Given a discount rate in a range of 9% to 12% with the initial CAPEX of 10.5 billion and USD 8 per MMBtu of well-head cost, the NPV for the government declines from USD 1.23 to 0.66 billion and for the contractor, from USD 0.37 to 0.21 billion. Table 8.3 summarizes the results of the sensitivity analysis.

For the high gas price scenario, the cost recovery time is much faster, 13 years in the base case parameter setting and both 12 years if the CAPEX is reduced by USD 2 billion or if the real well-head cost is only USD 6 per MMBtu. An inflation of 2.0% for the OPEX, LNG shipping cost and domestic gas price accelerates the cost recovery time by 1 year for the reference gas price scenario, and no change for the high gas price scenario. This indicates the inflation of the domestic gas price is more beneficial for the contractor or has higher value than the inflation impact for the costs. For the low gas price scenario, the base case parameter setting does not produce a positive NPV for both the government and the contractor because the total costs are higher than the total revenues. The NPV loss reaches
USD 0.2 billion without CAPEX. Therefore, there is no indication of profitability to execute the project under this setting. It only leads to a positive NPV when the well-head cost is USD 6 per MMBtu. However, within the time-frame of the model, the CAPEX still has not been recovered, and the revenues only come from the FTP.

In sum, the project should not be executed if the gas price is low. The value of the NPV in the reference gas price scenario is also less attractive for the contractor compared to the NPV values at Tangguh LNG project. Therefore, the contractor should think of another option, e.g. option to expand the capacity or negotiate the PSC, e.g. tax holiday or new mechanism of profit sharing.

Table 8.3 Sensitivity analysis of Abadi LNG valuation with DCF method in BAU Scenario

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Reference gas price</th>
<th>High gas price</th>
<th>Low gas price</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No inflation; discount rate = 10% ; CAPEX = USD 10.5 billion [BASE case]</td>
<td>NPV government USD 1.00 billion</td>
<td>NPV government USD 3.73 billion</td>
<td>NPV government USD -</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NPV contractor USD 0.31 billion</td>
<td>NPV contractor USD 0.99 billion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Time to recover CAPEX 20 years</td>
<td>Time to recover CAPEX 13 years</td>
</tr>
<tr>
<td>No inflation; discount rate = 10% ; CAPEX = USD 8.5 billion</td>
<td>NPV government USD 1.18 billion</td>
<td>NPV government USD 4.07 billion</td>
<td>NPV government USD -</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NPV contractor USD 0.35 billion</td>
<td>NPV contractor USD 1.06 billion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Time to recover CAPEX 18 years</td>
<td>Time to recover CAPEX 12 years</td>
</tr>
<tr>
<td>No inflation; discount rate = 10% ; CAPEX = USD 10.5 billion Well-head cost = USD 6 per MMBtu</td>
<td>NPV government USD 1.99 billion</td>
<td>NPV government USD 4.94 billion</td>
<td>NPV government USD 0.166 billion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NPV contractor USD 0.56 billion</td>
<td>NPV contractor USD 1.29 billion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Time to recover CAPEX 16 years</td>
<td>Time to recover CAPEX 12 years</td>
</tr>
<tr>
<td>Inflation 2% ; discount rate = 10% ; CAPEX = USD 10.5 billion</td>
<td>NPV government USD 1.18 billion</td>
<td>NPV government USD 3.96 billion</td>
<td>NPV government USD -</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NPV contractor USD 0.36 billion</td>
<td>NPV contractor USD 1.05 billion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Time to recover CAPEX 19 years</td>
<td>Time to recover CAPEX 13 years</td>
</tr>
</tbody>
</table>

Monte Carlo Simulation

Based on 100,000 number of trials, the NPV for the government lies between USD 612.60 to 1,394.50 million with an average value of USD 997.70 million and a standard deviation of USD 96.07 million. For the contractor, the NPV lies in a range of USD 204.65 million to USD 411.18 million with an average value of USD 307.72 million and a standard deviation of USD 25.33 million. Based on author’s observation on the results from 500 number of trials, the cost recovery time for the project is between 18 to 21 years. Figure 8.4 shows the density and cumulative probability of the NPV distribution for the government and the contractor in the simulation. See Appendix D1 for the script to build the model.
East Natuna onshore LNG plant

Onshore LNG plant in Natuna Island is the first technology option selected to deliver gas from East Natuna gas field to domestic market in Indonesia. Later, in the reference case, this option will also be executed first, however, the destination will be for export.

There is no official information regarding the capacity of the LNG plant in East Natuna. Adapted from the study by Batubara et al. (2014), the capacity of the LNG plant in Natuna Island is estimated to be 3.8 mtpa or 5.2 bcm per year. According to Suryadi (2013), the profit sharing in the PSC of East Natuna will be 45% for the government and 55% for the contractor with 5-years tax holiday. Based on the ideal capacity allocation, the onshore LNG plant should be in operation at the beginning of 2026 and will remain operated at its maximum capacity until 2045. The estimated CAPEX of this project is USD 5.67 billion and the EPC will take four years to completion. Therefore the EPC contract should be announced at least at the end of 2021. The domestic gas price of USD 9 per MMBtu will not work if used for the calculation because the well-head cost is already USD per MMBtu. Therefore, it will be assumed that the domestic gas price follows japan-cif index. The LNG shipping cost will be assumed to be USD 1.75 per MMBtu (see Messner and Babies (2012)). The discount rate is assumed to be 12% because the risks and uncertainties are assumed to be much higher than the previous two projects.

Based on the reference gas price scenario with no inflation, the cost recovery time is 12 years from the first time when the CAPEX is put at 2021. The NPV revenue for the government is USD 836.70 million, and for the contractor is approximately USD 738.71 million.

**Sensitivity Analysis**

Given a discount rate in a range of 10% to 15%, based on the base case parameter setting, the NPV for the government declines from USD 1.25 to 0.47 billion and for the contractor, from USD 1.08 to 0.43 billion. If the CAPEX has a volatility of 100% after 8 to 10 year, assumed the CAPEX to be USD 11 billion, the cost recovery time will take a total of 17 years with NPV for the government and the contractor as much as USD 505.64 million and USD 533.95 million, respectively. The NPV for the contractor is slightly bigger due to the 5-years tax holiday. Since the cost recovery time takes longer compared with the lower CAPEX case, the tax duration within the time frame of the model becomes less, and consequently reduces the government income from tax. Table 8.4 summarizes the results of the sensitivity analysis.
Both high gas price scenario and low gas price scenario are built in matlab, and will be exempted from the 5-years tax holiday. This will not affect the cost recovery time and the total NPV. Assumed there is an inflation of 2.0% for the OPEX and LNG shipping cost, with an exemption of the tax holiday, results in 13 years cost recovery time for the reference gas price scenario, or one year later than the base case parameter setting. In the high gas price scenario with inflation, the cost recovery time remains the same within 8 years, with a decreasing of NPV for both the government and the contractor by 7.75% and 7.74% respectively. Unfortunately, the low gas price scenario does not produce any positive NPV under every parameter setting tested in this research. Therefore, the project could only be executed if the gas price follows the reference or high gas price scenario. The contractor could ensure this to happen by securing a long-term contract with a price floor and ceiling.

Table 8.4 Sensitivity analysis of East Natuna LNG valuation with DCF method in BAU Scenario

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Reference gas price</th>
<th>High gas price</th>
<th>Low gas price</th>
</tr>
</thead>
<tbody>
<tr>
<td>No inflation; discount rate = 12%; CAPEX = USD 5.67 billion DMO price = cif price [BASE case]</td>
<td>NPV government USD 0.84 billion NPV contractor USD 0.74 billion Time to recover CAPEX 12 years *including 5-year tax holiday</td>
<td>NPV government USD 2.84 billion NPV contractor USD 1.68 billion Time to recover CAPEX 8 years</td>
<td>NPV government USD - NPV contractor USD - Time to recover CAPEX - years</td>
</tr>
<tr>
<td>No inflation; discount rate = 12%; CAPEX = USD 11 billion (volatility +/- 100%)</td>
<td>NPV government USD 0.51 billion NPV contractor USD 0.53 billion Time to recover CAPEX 17 years *including 5-year tax holiday</td>
<td>NPV government USD 2.20 billion NPV contractor USD 1.39 billion Time to recover CAPEX 11 years</td>
<td>NPV government USD - NPV contractor USD - Time to recover CAPEX - years</td>
</tr>
<tr>
<td>Inflation 2%; discount rate = 12%; CAPEX = USD 5.67 billion</td>
<td>NPV government USD 0.76 billion NPV contractor USD 0.50 billion Time to recover CAPEX 13 years</td>
<td>NPV government USD 2.62 billion NPV contractor USD 1.55 billion Time to recover CAPEX 8 years</td>
<td>NPV government USD - NPV contractor USD - Time to recover CAPEX - years</td>
</tr>
</tbody>
</table>

Monte Carlo Simulation

The clause of 5-years tax exemption will be excluded in the Monte Carlo simulation. The tax holiday will not affect the cost recovery time, and thus will only affect the NPV for the government and the contractor. When there is no 5-years tax holiday, the NPV for the government and the contractor in the base case parameter setting is USD 959.78 million (USD 123.08 million higher than actual) and USD 615.63 million (USD 123.08 million lower than actual), respectively. Therefore, the tax values of USD 123.08 million could be seen as a transfer between the government and the contractor. In practice, the total NPV of both parties remains the same.

Based on 100,000 number of trials, the average NPV for the government is USD 961.12 million (stdev. USD 77.92 million) within a range of USD 648.50 to 1,290.60 million. While, for the contractor, the range is between USD 432.99 million to USD 807.06 million, with an average value of USD 616.22
million (std. USD 45.47 million). Based on the author’s observation of 500 results from the whole trials, the average cost recovery time is between 11 to 12 years.

TAGP East Natuna to Java

Pipeline from East Natuna to Java is designed with a capacity up to 2,400 MMCFD. The estimated CAPEX of this project is USD 6.67 billion with an OPEX of USD 0.7 per MMBtu. The pipeline construction is estimated to be completed in three years. According to the ideal capacity allocation, the pipeline is expected to be in operation in 2028 and continues to ramp up until reaches its maximum capacity. The amount of the proven reserve will enable the pipeline to be in operation at least until 2045. The assumptions for the cash flow structure (PSC cost components) is similar with the onshore LNG plant in Natuna Island.

Based on the reference gas price scenario, the expected cost recovery time for this project is 9 years, with NPV revenue for the government as much as USD 3.84 billion, and for the contractor as much as USD 3.06 billion. In the range of a discount rate of 10% to 15%, the NPV for the government and the contractor, could be expected to decline from USD 5.90 to 2.06 billion and USD 4.60 to 1.70 billion respectively.

**Sensitivity Analysis**

Similar with the onshore LNG plant in Natuna Island, the 5-years tax holiday clause will also be exempted at the sensitivity analysis for high gas price and low gas price scenario and also for the Monte Carlo simulation with the reference gas price scenario. The value of the tax holiday (or transfer) for this project reach USD 0.54 billion at base case parameter setting.

**Table 8.5 Sensitivity analysis of East Natuna Gas Pipeline (to Java) valuation with DCF method in BAU Scenario**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Reference gas price</th>
<th>High gas price</th>
<th>Low gas price</th>
</tr>
</thead>
<tbody>
<tr>
<td>No inflation; discount rate = 12%; CAPEX = USD 6.67 billion DMO price = cif price [BASE case]</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>NPV government USD 3.84 billion</td>
<td>NPV government USD 8.50 billion</td>
<td>NPV government USD 78.82 million</td>
</tr>
<tr>
<td></td>
<td>NPV contractor USD 3.06 billion</td>
<td>NPV contractor USD 4.80 billion</td>
<td>NPV contractor USD 84.27 million</td>
</tr>
<tr>
<td></td>
<td>Time to recover CAPEX 9 years including 5-year tax holiday</td>
<td>Time to recover CAPEX 7 years</td>
<td>Time to recover CAPEX 20 years (2044)</td>
</tr>
</tbody>
</table>

| Inflation 2%; discount rate = 12%; CAPEX = USD 6.67 billion | | | |
| | NPV government USD 3.90 billion | NPV government USD 8.28 billion | NPV government USD 33.06 million |
| | NPV contractor USD 2.245 billion | NPV contractor USD 4.68 billion | NPV contractor USD 40.41 million |
| | Time to recover CAPEX 9 years | Time to recover CAPEX 7 years | Time to recover CAPEX 21 years |

| Inflation 2% for DMO price = USD 9 per MMBtu and OPEX; discount rate = 12% | | | |
| | NPV government USD 2.08 billion | NPV government USD 3.06 billion |
| | NPV contractor USD 1.22 billion | NPV contractor USD 4.01 billion |
| | Time to recover CAPEX 11 years | Time to recover CAPEX 21 years |
The low gas price scenario produces positive values for both the government’s and the contractor’s NPV although the value is relatively small compared with the reference gas price and high gas price scenarios. If the gas price is assumed to be sold to domestic with a price of USD 9 per MMBtu in which this price is also affected by the inflation of 2.0%, the result shows a recovery time of 11 years with an NPV for the government as much as USD 2.08 billion and USD 1.22 billion for the contractor. However, if the inflation does not affect the domestic gas price (fixed price), the project would not be profitable which is indicated by negative values for both NPV. However, if the domestic gas price is changed to at least USD 10 per MMBtu, the NPVs are still positive even without any inflation. The NPV for the government is USD 11.24 million and for the contractor is USD 10.803 million. However, this would be very unattractive for the contractor because the value of the NPV is regarded too low compared to the previous projects.

**Monte Carlo Simulation**

Running a Monte Carlo simulation with 100,000 number of trials produces an average value of USD 3.90 billion for the government (with a standard deviation of USD 189.48 million) and USD 2.25 billion for the contractor (with a standard deviation of USD 105.51 million). Each lies within a range of USD 3.17 to 4.64 billion and USD 1.84 to 2.66 billion, respectively. The average cost recovery time of this project is between 8 and 9 years. Figure 8.5 and 8.6 show the density and cumulative probability of the NPV distribution for the government and the contractor in East Natuna onshore LNG case and the gas pipeline case.

![Figure 8.5 Density and cumulative probability of the NPV for the government and contractor – East Natuna LNG](image1)

![Figure 8.6 Density and cum. probability of the NPV for the govt. and cont. – East Natuna gas pipeline to Java](image2)
8.1.4 Capacity Allocation in Reference Scenario

Based on the results of the reference scenario, there is no need for additional capacity of regasification terminal or even the amount of LNG imported to Indonesia. This is due to the growth of Indonesian gas production that is assumed to grow constantly at 0.50% per annum. If this happen, Indonesia could maintain its position as dominant LNG exporter in the international gas market. According to this scenario, the development of new gas fields will be used mostly for export and gas allocation for the domestic market will only be based on the domestic market obligation agreement in the PSC contract.

The capacity allocation used in the BAU scenario assumes that 40% of Tangguh LNG (expansion) capacity will go to the domestic market based on the existing contract which will end in 2033. For the Abadi gas field, 30% of the production will also go to the domestic market. Since the two assumptions have already followed the current agreement, the value of these two projects based on DCF method will be the same either in the BAU scenario or Reference scenario. Therefore, in the following section, the author will only discuss the development of East Natuna gas field based on the Reference scenario.

8.1.5 DCF Options Valuation in Reference Scenario – East Natuna gas field

Total availability of clean gas reserves in East Natuna gas field is 15.18 tcf or 429.90 bcm (see page 82). There are four technology options that could be used to connect the East Natuna gas field to the gas market either domestic, regional, or international. The option to build an onshore LNG plant in East Natuna can serve any destination of gas market. It still could be used to ship the LNG to any islands in Indonesia, any countries within Southeast Asia, e.g. Singapore, Thailand, or any other customers across the world, e.g. Japan, South Korea, or China.

Considering the conflicting interest of Pertamina and PTTEP, the development of the onshore LNG plant in Natuna Island could better serve their interest because the output allocation of the plant could be adjusted depending on the latest situation. The drawback of this option is from the side of cost-efficiency. For example, in practice, delivering the gas to Java (Indonesia) or Thailand via gas pipelines would be more cost-efficient compared to transform the gas into liquid and ship the LNG.

The DCF calculation in the BAU scenario assumes that the price paid by the domestic market follows the Japan-cif gas price, and therefore the value of the project will be slightly the same (see page 100) except the assumption for the shipping cost needs to be adjusted. This will result in lower NPV for both the government and the contractor. Changing the shipping cost from USD 1.75 per MMBtu to USD 2.50 per MMBtu based on the base case parameter setting with reference gas price results in 13 years of cost recovery time or one year later compared with the case if the shipping is only to LNG terminals in Java or Sumatra. Based on the sensitivity analysis, the LNG project is only feasible when being executed in the reference or high gas price scenario. Therefore further option of deferring the project or abandoning the project if the gas price is too low might need to be considered. This will be analyzed further with the ROA method.

Combinations of technology options are possible to develop the field. Figure 8.7 shows one possible multi-stage investment with several technology options. The red color indicates the time when the CAPEX is put and the grey color indicates the construction time. The First stage is to develop the onshore LNG plant with a capacity of 3.8 mtpa. The second stage option is to build a gas pipeline to
Thailand with a capacity up to 1,200 MMCFD. This project could be executed 3 years after the LNG plant starts its operation. This scheme could reduce the operational risk of the field since the production trend is better known after the operation of the LNG plant. Afterward, the gas pipeline to Singapore through West Natuna could be built with a capacity up to 325 MMCFD as in the case of the West Natuna gas pipeline. It is unpractical to build a pipeline with 5 years operation, and thus, the gas reserve should be secure until the next 10 years, which will include a total reserve of 50.40 bcm for 18 years duration of the project.

Executing all the stages needs 338.36 bcm. Therefore, there is still some amount of reserves that could be used, up to 91.54 bcm. This amount could be used to extend the contracts up to 5 years for the LNG plant and gas pipeline to Thailand or only to expand the LNG plant by adding one more train with similar capacity. The exploration of the possible options will be discussed in the next section. Table 8.6 shows the results of DCF method if the projects are executed based on this scheme.

<table>
<thead>
<tr>
<th>Projects and Parameters</th>
<th>Reference gas price</th>
<th>High gas price</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Onshore LNG plant</strong> in East Natuna 3.8 mtpa</td>
<td>NPV government USD 1.13 billion (USD 1.27 B) NPV contractor USD 0.73 billion (USD 0.81 B) Time to recover CAPEX 13 years (or 12 years)</td>
<td>NPV government USD 3.26 billion (USD 3.53 B) NPV contractor USD 1.93 billion (USD 2.08 B) Time to recover CAPEX 9 years</td>
</tr>
<tr>
<td>CAPEX = USD 5.67 billion At period 4 – 2019; No inflation; discount rate = 12%; extended contract (5 years)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Gas Pipeline to Thailand</strong> up to 1,200 MMCFD</td>
<td>NPV government USD 2.47 billion (USD 2.85 B) NPV contractor USD 1.43 billion (USD 1.64 B) Time to recover CAPEX 7 years</td>
<td>NPV government USD 5.27 billion (USD 5.96 B) NPV contractor USD 2.99 billion (USD 3.37 B) Time to recover CAPEX 6 years</td>
</tr>
<tr>
<td>CAPEX = USD 5.46 billion At period 11 – 2026; No inflation; discount rate = 12%; extended contract (5 years)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Gas Pipeline to Singapore</strong> up to 325 MMCFD</td>
<td>NPV government USD 0.117 billion (USD 0.276 B) NPV contractor USD 0.071 billion (USD 0.159 B) Time to recover CAPEX 5 years</td>
<td>NPV government USD 0.261 billion (USD 0.555 B) NPV contractor USD 0.151 billion (USD 0.314 B) Time to recover CAPEX 4 years</td>
</tr>
<tr>
<td>CAPEX = USD 1.5 billion At period 22 – 2037; No inflation; discount rate = 12%; extended contract (10 years)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The gas prices only refer to the reference and high gas price scenario because the previous calculation with the low gas price scenario shows no positive NPV for both the government and the contractor. The 5-years tax-holiday will also be excluded. The table shows the NPVs within the time frame of the
model (until 2045), and also including the option to extend the contract, i.e. 5 years for LNG plant and gas pipeline to Thailand, and 10 years for gas pipeline to Singapore, indicated in the parentheses. The gas prices used for the extended duration are assumed to be the same with the latest price in 2045.

From the three technology options, the gas pipeline option to Thailand offers the highest NPVs for both the government and the contractor. This is due to its lower operational expenditures compared to operating an LNG plant. On the other hand, the technology option of gas pipeline to Singapore seems less attractive. However, when the contract duration is extended to 10 years after the time frame in the model, the NPVs increase more than double. If the contractor still thinks that the project is unattractive, then they could allocate the capacity of this gas pipeline to support the LNG plant expansion. The expansion of the LNG plant is quite promising since it only requires capital expenditures to build the LNG plant (no exploration cost). The risks are much lower because the first plant has already been in operation. The CAPEX value of the gas pipeline projects might change since they will be constructed 11 to 22 years after the base calculation of the CAPEX in 2011-14 values.

8.2 REAL OPTION ANALYSIS (ROA)

Real options analysis will be conducted to evaluate technology options development of the projects in the Reference scenario. In the BAU scenario, the allocation requirement by the domestic gas market has been well-estimated and thus, the contractors have no much option to delay or abandon the project because they are bound to the PSCs or gas sales agreements. In the Reference scenario, the contractors have more flexibility to defer, expand, or even abandon the project because the domestic gas market is not dependent on their productions. This will make the government has less interest to intervene the contractors in managing the gas fields.

The ROA will be used to value the technology options for the development of Abadi gas field and East Natuna gas field. The contractors of Abadi and East Natuna gas fields probably will have the rights to develop the fields until more than 2045. However, in this model it will be assumed to be ended in 2045 for the Abadi gas field, and until 2050 or could be faster if the reserves are depleted for the East Natuna gas field. Tangguh gas field project is not included because the project has been more certain, i.e. only one technology option, the gas sales agreement has been signed, and the FEED contract has been announced. The methods used to compute the real options value will follow the Black-Scholes formula and binomial lattice method.

8.2.1 ROA of Abadi gas field

Option to defer

The contractor could at least exercise three types of options during the option life: option to defer, option to expand, and option to abandon. The input parameters in this model are:

- $S_0$ (value of underlying asset or PV cash flow without CAPEX) = USD 5.39 billion

This value comes from the calculation of total revenues given the CAPEX is put at the end of 2015 minus total costs with an inflation of 2% per year and a discount rate of 10%, excluding the CAPEX, FTP, cost recovery, profit sharing, and tax.
• \( \sigma \) (volatility of the underlying asset per period) = 6.13%
The volatility is derived from the standard deviation of the natural logarithm value from the ratio of the PV year 1 (100,000 trials with Monte Carlo simulation) and PV year 0 (DCF spreadsheet). This formula is based on Brandao et al. (2005). See section 4.2.2. However, this only includes fluctuation of the reference gas price, i.e. not cover the whole gas price scenario. If high and low gas price scenarios are included, the volatility will be higher. Later, in the sensitivity analysis, higher volatility will be considered to see the change in the option values.

• \( r \) (riskless interest rate) = 8%
Damodaran (2008) uses a riskless interest rate of 8% when doing real options valuation of an oil gas field. Later, in the sensitivity analysis, the author will compare the results of the option values when the riskless interest rate is changed.

• \( T \) (option life) = 30 years
• \( \delta t \) = 1 year

As in Kodukula and Papudesu (2006), additional inputs needed to evaluate the option to defer are:

• \( X_1 \) (exercise price; cost of developing the project) = USD 10.5 billion

• \( f_1 \) (leakage rate) = 5%, average opportunity loss per year if the LNG plant could operate at its maximum capacity

• It will be assumed that the option to defer could only be made in the first 5 years. Afterwards the project should has already been in construction phase, otherwise the PSC contract will be terminated assuming the contractor is not able to develop the field. This is also due to the general lifetime of the LNG project which is around 20 years. Therefore, if the LNG plant is operated less than its optimum lifetime due to contract expiration, it will be less profitable for the contractor.

According to simple DCF rule, this project should not be executed because the NPV is negative (USD 5.39 billion – USD 10.5 billion), or in other words, results in a loss. Following the steps to build a binomial lattice model from Kodukula and Papudesu (2006), after framing the problem and identifying the input parameters, the next steps are calculating the option parameters, build the binomial lattice and calculate the asset values at each node of the lattice, calculate the option values at each node of the lattice by backward induction, and finally, analyze the results.

Following formula 4.5, the value of \( u, d, \) and \( p, \) respectively are 1.063, 0.941, and 0.733. However, based on these parameters, until the end of year 5, the asset values are still lower than the strike price, and thus the value of the option is 0. Afterwards, the author tries to change the parameter settings and compared the results with the Black-Scholes formula. Table 8.7 shows the comparison of the option value to defer based on binomial method and Black-Scholes formula (note: the leakage rate could not be captured by the Black-Scholes formula).

The option values from the binomial model will converge to the Black-Scholes model as the number of time step increases and the length of each time (\( \delta t \)) becomes shorter (Chance, 2008). The proof has been provided by several author as mentioned in Chance (2008). In this report, the author will not try to prove the claim or performing Monte Carlo simulation with smaller \( \delta t \). The main insight that could be gained from this findings is that option to defer will have a significant value when the volatility of the asset value is quite high. Therefore, in a case when there are uncertainties regarding the underlying
asset value (e.g. because of natural gas price, inflation, or growth of the OPEX), option to defer could be considered. A leakage rate or opportunity loss is also an important parameter because it reduces the option value significantly, and thus, need to be taken into account.

Table 8.7 Abadi onshore LNG – Option to defer

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Binomial lattice</th>
<th>Black-Scholes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volatility = 6.13%</td>
<td></td>
<td>USD 8,245,032,91</td>
</tr>
<tr>
<td>Leakage rate = 5%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volatility = 6.13%</td>
<td>-</td>
<td>USD 460,920,752.97</td>
</tr>
<tr>
<td>Leakage rate = 0% [5%]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volatility = 20%</td>
<td>USD 340,662,876.25</td>
<td>USD 111,836,187.37</td>
</tr>
<tr>
<td>Leakage rate = 0% [5%]</td>
<td>[USD 111,836,187.37]</td>
<td></td>
</tr>
<tr>
<td>Volatility = 30%</td>
<td>USD 919,010,523.23</td>
<td>USD 930,035,724.66</td>
</tr>
<tr>
<td>Leakage rate = 0% [5%]</td>
<td>[USD 470,549,415.29]</td>
<td></td>
</tr>
</tbody>
</table>

Figure 8.8 illustrates the binomial lattice method that is used to calculate the option value of deferring the project, given σ = 30%, with a leakage rate of 5%.

Figure 8.8 Abadi onshore LNG – Binomial lattice of option to defer (all values in USD million)

Option to choose: expand or abandon

Besides an option to defer, there are also possibilities to expand or abandon the project. There are two additional inputs needed to calculate the option value of expanding the capacity of the project by adding one more LNG train with a capacity of 5 mtpa.

- \( X_2 \) (cost of expansion) = USD 8.5 billion at 2015, assumed to be USD 17 billion between 2026 to 2045
- \( f_2 \) (Expansion factor; increase in the underlying value of asset) = 2.0
- leakage rate = 5%; to accommodate opportunity loss of delaying to exercise the option
For the option to abandon, the additional input needed is the salvage value \( (X_3) \), which is assumed to be 10% of the initial CAPEX, i.e. USD 1.05 billion.

If we assumed that the project will be deferred until 2020, with 5 years FEED and EPC contracts, then the first LNG train will be in operation at 2026 or 20 years lifetime until 2045. The underlying asset value now become USD 3.42 billion or USD 8.88 billion at the end of 2025. The author will use this value to complete the option to choose from 2026 to 2045 with a \( \delta t \) of 1 year. Figure 8.9 illustrates how the calculation was made with the binomial lattice method. However, instead of building the lattice in a spreadsheet, the author use MATLAB to build the lattice in a matrix form. The script of the model can be seen in Appendix D2.

The NPV of the real option to choose between to expand or to abandon the project is USD 1.34 billion (compared with the value of (only) option to expand based on the Black-Scholes formula, as much as USD 2.1 billion).

![Figure 8.9 Abadi onshore LNG – Binomial lattice of option to choose (all values in USD billion)](image)

Figure 8.10 illustrates the binomial lattice of option to choose for the Abadi onshore LNG project. The blue color indicates times when the option to expand could be called, while the red color shows the times when the project could be abandoned. Based on the results of binomial lattice method, option to expand could be exercised in 2032 when the volatility is ‘up’ or positive. On the other hand, when the volatility of the natural gas price is down, then the option to abandon the project should be considered. The results of the binomial lattice model indicate that the contractor could exercise the option to abandon also from 2032 onwards, especially when the volatility is ‘down’. The zero values in the last column indicates no action being taken, due to expiration of the contract and it is assumed that the project has no value.
**Sensitivity analysis**

Here, the author would like to see the change in the NPV values of the option given that the values of the riskless rate and the volatility are changed. Changing the values of the volatility from 6.13% to 10%, 20%, and 30% respectively, results in net present real options values of USD 1.49 billion, USD 2.02 billion, and USD 2.58 billion. For each volatility, when the riskless rate is changed to 5%, the NPV becomes USD 0.925 billion, USD 1.62 billion, and USD 2.28 billion. For the base case parameter setting of 6.13% volatility, the NPV of the real options is USD 0.654 billion with riskless rate of 5%.

As a side note, combining Monte Carlo simulation with binomial lattice method (especially with high T and small δt) is less practical because it requires a high level of computer performance and large memory capacity. At the end of each node, there could be n trials or possibilities to build new patches which result in a very large data scale. Therefore, in this research, the real options valuation will end at the sensitivity analysis.

<table>
<thead>
<tr>
<th>2031</th>
<th>2032</th>
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<th>2043</th>
<th>2044</th>
<th>2045</th>
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<td>1,03E+10</td>
<td>1,2E+10</td>
<td>1,38E+10</td>
<td>1,58E+10</td>
<td>1,78E+10</td>
<td>2E+10</td>
<td>2,24E+10</td>
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<td>2,75E+10</td>
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</table>

Figure 8.10 Abadi Onshore LNG – Values of the option to choose in period 2031 to 2045

In sum, only simple DCF rule that suggest the project in Abadi gas field not to be executed because of its negative NPV (−USD 5.11 billion)). This is due to the principle of the method to discount all revenues and all costs, then compute the NPV which is the difference between the present values of the revenues and the costs. Therefore, according to this principle, a negative NPV indicates a loss which make the project is not economically feasible to be executed.

The approach with adjusted DCF method (considering cost structure based on PSC form) produces an NPV value of USD 1 billion for the government and USD 0.31 billion for the contractor in the base case parameter setting. The values would be much higher if the gas prices are high. However, the project should not be executed in the low gas price scenario, especially if the total operating costs are much higher than the expected revenues.

Option to defer and option to choose whether to expand or abandon could add the value of the project. The value of the option to defer varies significantly, from 0 to USD 900 million, depending on the volatility and leakage rate or the opportunity loss. While for the option to choose, the values vary from USD 1.34 billion to 2.58 billion given a riskless rate of 8% and volatility of 6.13% to 30%. Adding these
numbers to the simple DCF calculation still results in a negative NPV. However, in adjusted DCF method, these numbers would significantly affect the contractor’s decision whether to develop the field or not, as the option values are quite high especially if being added to the contractor’s NPV.

8.2.2 ROA of East Natuna gas field

The real option analysis of East Natuna gas field will be performed in a combination with decision tree analysis. The three technology options will be incorporated as a multi-stage investment decision. The underlying value of the asset assumed that the onshore LNG plant will be in operation in 2020, followed by the gas pipeline to Thailand in 2024 and gas pipeline to Singapore in 2031 is USD 24.73 billion. This is also based on a discount rate of 12%, 2% annual inflation for the OPEX, shipping cost, and domestic gas price, and reference gas price scenario for the export LNG price. The total CAPEX needed to build the three technology options is estimated to be USD 12.63 billion. Based on simple DCF rule, the NPV of the whole project is approximately USD 12.10 billion. This value could be smaller since not the whole CAPEX will be put up-front, and thus, there is possibility that the CAPEX for the gas pipelines would increase and consequently, reduce the NPV of the project.

In this section, the author will try to combine decision tree analysis with real option analysis. This is based on the multiple technology options that are available and could be built either in sequence or parallel. In practical, it could be built in parallel, however, if we considered that the contractor might want to wait for the results of the previous projects to minimize the risk, then the options would be built sequentially depending on the success or failure of the previous projects. Figure 8.11 shows the combination of decision tree and real options to value the projects in the East Natuna gas field.

Figure 8.11 East Natuna gas field – Combined decision tree and real options analysis
P1, p2, and p3, indicate the probability of success of the onshore LNG plant, gas pipeline to Thailand, and gas pipeline to Singapore. The values are assumed to be 90%, 95%, and 95%, respectively. The probability of failure is denoted by 1-p value. The time frame of the model is from 2015 to 2045. It is assumed that the final investment decision for the onshore LNG plant will be taken at the end of 2015, and thus, the LNG plant is expected to be in operation in 2020. Looking at the success of the project, the gas pipeline to Thailand could be built afterwards, and is expected to be in operation in 2024. Afterwards, the gas pipeline project to Singapore via West Natuna will follow and is expected to be in operation in 2031. The calculation will use backward induction method as in binomial lattice model. The option value at each node will be valued separately using the Black-Scholes formula (each with a volatility of 10%) that is applied in the spreadsheet model from Damodaran (2008). For the onshore LNG plant there is a salvage value which is assumed to be 10% of the CAPEX. The probability to exercise one of the option is 0.5. For the gas pipelines, the salvage values are assumed to be 0. Unlike the components of the onshore LNG plant which can be reused or switch to a regasification plant, the components of the gas pipeline are assumed to have less value. Taking into account the cost to remove the pipeline, therefore, the salvage value or the abandonment value is assumed to be 0, and thus, the option is only to expand the LNG plant. Table 8.8 summarizes the input or calculation of the value of each project with its options.

Table 8.8 East Natuna gas field – Input summary for combined DTA and ROA

<table>
<thead>
<tr>
<th>Description</th>
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<tbody>
<tr>
<td><strong>Total gross revenue project 3 at EOY 2031 (period 2031-2045)</strong></td>
</tr>
<tr>
<td>CAPEX is assumed to be doubled</td>
</tr>
<tr>
<td><strong>NPV project 3 (gas pipeline to Singapore)</strong></td>
</tr>
<tr>
<td><strong>Option to expand</strong></td>
</tr>
<tr>
<td>asset value at EOY 2031 (LNG variable cost is more costly than pipeline)</td>
</tr>
<tr>
<td>CAPEX value at EOY 2031 is assumed to be doubled with a lower capacity</td>
</tr>
<tr>
<td><strong>Option values project 3</strong></td>
</tr>
<tr>
<td><strong>Total gross revenue project 2 at EOY 2024 (period 2024-2045)</strong></td>
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<tr>
<td>CAPEX is assumed to be 1.5 times</td>
</tr>
<tr>
<td><strong>NPV project 2 (gas pipeline to Thailand)</strong></td>
</tr>
<tr>
<td><strong>Option to expand</strong></td>
</tr>
<tr>
<td>asset value at EOY 2024 (more costly for LNG)</td>
</tr>
<tr>
<td>CAPEX value at EOY 2024 is assumed to be doubled with identical capacity</td>
</tr>
<tr>
<td><strong>Option values project 2</strong></td>
</tr>
<tr>
<td><strong>Total gross revenue project 1 at EOY 2015 (period 2020-2045)</strong></td>
</tr>
<tr>
<td>CAPEX at 2015</td>
</tr>
<tr>
<td><strong>NPV project 1 (onshore LNG plant)</strong></td>
</tr>
<tr>
<td><strong>Option to abandon (10% of the CAPEX)</strong></td>
</tr>
<tr>
<td><strong>Option to wait (assumed to be able to recover 50% of the present value)</strong></td>
</tr>
</tbody>
</table>
The value at node gas pipeline to Singapore at EOY 2031 is:
\[
= 0.95 \times 3.74 \text{ billion} + (1 - 0.95) \times 0.95 \text{ billion} \\
= 3,599,255,514.61
\]
It is equal to $1,628,120,407.83 given a discount rate of 12%

The value at node gas pipeline to Thailand at EOY 2024 is:
\[
= 15.12 \text{ billion} + 0.95 \times 1.63 \text{ billion} + (1 - 0.95) \times 11.83 \text{ billion} \\
= 17,263,174,565.13
\]
It is equal to $6,225,273,811.19 given a discount rate of 12%

Finally, the value of the whole project at the end of 2015 is:
\[
= -2 \text{ billion} + 0.90 \times 6.23 \text{ billion} + (1 - 0.90) \times [0.5 \times 0.567 \text{ billion} + 0.5 \times 1.84 \text{ billion}] \\
= 4,554,119,650.20
\]
This value is smaller than the NPV resulted in the adjusted DCF method which is at USD 5.95 billion, combined the NPV for the government and the contractor. This is probably the result of taking into account the uncertainty and all possible options into the model. The advantage of this approach is its ability to combine multiple technology options (e.g. onshore LNG and gas pipeline) and multiple real options (e.g. option to abandon, option to expand) and integrate the options with the possibility of success and failure which are better known by the management or the contractor.

In sum, East Natuna gas field is worthy to be developed as long as the gas price does not follow the low gas price scenario, otherwise it will be better for the contractor to abandon the project.
9 Synthesis

This chapter will gather findings from the preceding chapters to construct answers to each sub-question in this research. Further discussion will be presented in the next chapter followed by answers to the main research question concluded in the last chapter.

9.1 FUTURE GAS SUPPLY AND DEMAND PROFILE IN SOUTHEAST ASIA

Future gas supply and demand in the ASEAN will mainly be determined by growth (or decline) in the natural gas production and consumption of its member states. In this research, the profiles of natural gas production and consumption of seven member states have been observed, i.e. Indonesia, Malaysia, Brunei, Thailand, Myanmar, Vietnam, and Singapore. The other three member states, i.e. Philippines, Laos, and Cambodia are not included because they have very little activities in natural gas production or consumption.

The values of growth or decline for each member state’s production and consumption are collected from various international agency reports, e.g. IEA and ERIA (2013), IEEJ (2011). The author has also looked at the historical records (BP, 2014c) of natural gas production and consumption of each member states. However, there is no convergence regarding the growth or decline values according to the trends indicated by the historical records and reports from the international agencies. Therefore, the author suggests to look into reports published by each individual country because they might have a better prediction since they have access to information that might be not available for public (or for the international agencies).

In this research, the author only looked at a report from the Indonesian governmental agency, i.e. BPPT (2014) and came up with two scenarios, Business-as-Usual (BAU) Scenario and Reference Scenario. The growth assumptions for other countries are same for both BAU and Reference Scenario, and are based on a report from IEA and ERIA (2013). The growth value assumptions can be adjusted when there is information available from the member states. In the BAU Scenario, the natural gas production in Indonesia is expected to decline after 2017, causes Indonesia becoming a net gas importer in 2027. In the Reference Scenario, meanwhile, the production will grow constantly at 0.5% per annum, with a domestic gas consumption growth of 2.7%. The graphical representation of supply and demand profile of each member state can be found in figure 6.3.

Based on the projection of natural gas production and consumption, the independency level of each member state could be known. The independency level is based on the ratio of domestic gas production to domestic gas consumption, excluding the trades both via pipelined gas and LNG. This could be an indicator of security of gas supply in one particular country. The country will be regarded as independent if the value of its independency ratio is higher than 1.0. The results indicate that Thailand has the second lowest independency level after Singapore and will totally rely on import in 2023. Myanmar shows a positive trend of growth until 2035 and decline afterwards due to the depletion of its gas reserves. However, in practice, the independency level of Myanmar is much lower because it has several long-term pipelined gas export contracts to Thailand and China. Vietnam has the closest match between domestic gas supply and demand. However, following a concern of security
of gas supply, it will be better if Vietnam could develop its gas fields faster so that the independency level could increase above the standard point.

Both Malaysia and Brunei show a declining trend of independency due to a higher growth of their domestic consumptions compared to their gas productions. However, during the time frame of the model (2014 to 2045), their independency levels are still above the standard line of 1.0. The independency level of Indonesia will depend on which production growths are proven, i.e. the BAU Scenario or the Reference Scenario. According to the Reference Scenario, the position of Indonesia could be regarded as highly independent, at least until 2040. In the Reference Scenario, Indonesia could also become a gas supplier to its neighbors who need imported gas to meet their domestic consumptions.

In particular, the natural gas production profile in Indonesia could significantly affect the supply side profile of Singapore. In the BAU Scenario, Indonesia will not be able to supply pipelined gas to Singapore which makes Singapore will have to increase its regasification capacity in 2025 and so forth. This will become problematic for Singapore as it has limited land availability. This will also inhibit its plan to become an Asian gas hub as it would have already been difficult to meet its domestic demand and no (or less) capacity available to meet deficit gas supplies of other countries in the region. On the other hand, in the Reference Scenario, Indonesia could supply pipelined gas to Singapore. This will support Singapore as they will only need to increase its regasification capacity after 2040. However, this will depend on the agreement between Indonesia and Singapore. Currently, Singapore has decided not to extend the long-term pipelined gas contract from Indonesia due to high price differences between pipelined gas supplies from Indonesia (i.e. from West Natuna and South Sumatra) and LNG imported, for instance from the U.S.

A more serious problem will be faced by Thailand as it will become a totally net gas importer (no gas production) as Singapore due to depletion of its gas reserves in 2023 and expiration of pipelined gas supplies from Myanmar. Adding regasification capacities will not solve the problem because Thailand is also the biggest gas consumer (based on volume) in Southeast Asia, and thus, even a small growth in consumption will make the country suffers to meet the demand. Therefore, Thailand will need to find alternative fuel sources that could replace gas, e.g. nuclear or renewable sources, otherwise it will become too dependent on gas import.

A more detail of explanation regarding the future supply and demand of each member state and capacity utilization of the gas infrastructures, i.e. gas pipelines, liquefaction plants, and regasification plants, can be found in chapter 6. Chapter 6 explains the two scenarios which are run in the GANESA model. The conceptualization, development, verification, and validation of the model can be found in chapter 5.

9.2 INFRASTRUCTURE OPTIONS IN THE INDONESIAN CASE

In the BAU Scenario, Indonesia will have to increase its regasification capacity after 2030 and no additional liquefaction capacity is needed. It is important to be noted that in the model, the regasification terminals only represent the capacity used to handle imported LNG. In practice, the use
of LNG regasification terminal in Indonesia is also for domestic consumption, especially for industries and power plants. Therefore, the need to add the capacity of the LNG regasification terminal will also depend on the projection of the domestic-sectoral consumption growth in Indonesia.

Even though both BAU Scenario and Reference Scenario do not indicate any needs for adding liquefaction capacities in Indonesia, in practice, this might be needed due to the problem of location. Usually, the liquefaction plants are located near the gas fields. If these gas fields have depleted, then the liquefaction plants will need to find other gas supplies. If there is no gas supply from nearby gas fields, then the liquefaction plants will have to stop operating. When new gas fields have been found, there might be a need to build a new liquefaction plant, especially if the field locations are far from the demand centers, as commonly happen in Indonesia where the gas supplies from the eastern area (e.g. Papua, Sulawesi, Kalimantan) are transported via LNG shipping to demand centers in the western area, such as Java and Sumatra.

Currently, there are three proposed gas projects in Indonesia. First is an LNG train expansion project at Tangguh gas field in Papua. This area is operated by BP Berau Ltd. The phase of the project has been at approval of environmental and social impact assessment, and announcement of FEED contract. The contractor has also signed a gas sales agreement which means it has secured a long-term buyer which will reduce the commercial risk of the project. Since the FEED design has been announced and the project is also an expansion of existing facilities, there is no change regarding technology options used for the project. According to the press release from BP Berau, the selected technology option is adding one train to the onshore liquefaction plant with a capacity of 3.8 mtpa, like the previous two trains. The estimated CAPEX of this project is USD 11 billion according to credit Suisse report and USD 12 billion according to BP’s estimate. This value has probably included the upstream costs since the cost for liquefaction facilities is between USD 600 to 800 per tpa at ‘low cost’ location and USD 1,000 to 1,200 per tpa at ‘high cost’ location (Songhurst, 2014).

The second project, which could be regarded as both old and new, is the development of Abadi gas field in the Arafura Sea (also located at the eastern part of Indonesia). It is old because INPEX, the contractor, has been awarded the right to develop the field since 1998, and it is new because the field has not been commercialized up to this time. There are two technology options to develop the field, first is a floating liquefaction plant (FLNG) with a capacity of 2.5 mtpa (initial option), and the second technology option is an onshore LNG plant with a capacity of 5.0 mtpa and could be expanded to 10 mtpa. The CAPEX estimations for the FLNG, including upstream costs, are USD 20 billion according to Gordon (2013) and USD 14 billion as estimated by Hamlen (2014). For the onshore LNG plant, the CAPEX excluding the upstream costs could fall between USD 8.5 billion (author’s own estimation following a study from Songhurst, 2014) and USD 10.5 billion (Hamlen, 2014). Since the CAPEX for the second option, i.e. the onshore LNG plant, is lower compared to the first option, and it also offers much larger capacity, the first option is less likely to be executed. However, the final decision has not been announced yet because the contractor is still waiting for the completion of the FEED.

Developing the East Natuna gas field is the third option owned by the Indonesian government. The field was found in 1980. However, due to its high content of CO₂ (approximately 71%), the field has not been developed, probably due to its economic infeasibility if was developed at the same time with the development of West Natuna gas field in 2000. CO₂ removal technologies have become more
mature and proven which might be less costly compared to the costs in 1990s or early 2000. Gas prices are also expected to rise due to depletion of existing gas reserves. Therefore, the option to develop the East Natuna gas field might be more economically viable at present.

Selected technology options to develop the field will depend on which scenarios (BAU or Reference Scenario) are close to the real practice. In case of the BAU Scenario, it will be better for the Indonesian government to build gas pipelines from East Natuna to demand centers in Java or Sumatra combined with an onshore LNG plant in East Natuna if exporting gas still needs to be done or connecting gas pipelines from East Natuna to West Natuna to supply pipelined gas to Singapore. Still, the gas allocation for domestic will be dominant. In the Reference Scenario, on the contrary, there are more needs for gas exports than for domestic. The previous three technology options could still be applied with smaller pipeline capacity from East Natuna to Java. There is also another option to build a gas pipeline from East Natuna to Erawan, Thailand, as initiated in the TAGP Master Plan (ACE, 2013). At present, PTTEP, Thailand’s state-owned gas company also joins in the East Natuna consortium, together with Pertamina, Exxon, and Total. Like in the Abadi’s case, no final investment decision has been made. The Indonesian government seems really want to develop the field as it has agreed to change the profit sharing in the PSC, from 70:30 (70% for the government and 30% for the contractor) to 45:55 with a possibility of 5-years tax holiday (Suryadi, 2013).

Besides the technology options, for each project, there are also real options either to delay, abandon, or expand the projects, and also creating multi-stage investment to develop the projects. A more detail of explanation regarding the technology options, real options, CAPEX and also discussion about the uncertainties, competitive implications and trade-offs between the options can be found in chapter 7. Chapter 8 presents valuations of the options based on adjusted DCF method (i.e. according to each PSC structure used in each project) and ROV method.

9.3 OPTIONS SELECTION

Two valuation techniques are used to value the possible technology options for each project, namely adjusted discounted cash flow and real options valuation. Adjusted DCF method combines simple DCF method with PSC structure of each project, taking into account all costs and revenues to find the net present value of the project. Sensitivity analysis and Monte Carlo simulation are also used to incorporate the uncertainties in the parameters such as gas prices (low, reference, high), discount rates (depending on the project risk, could vary from 6% to 15%) and inflation (no inflation or 2% inflation). ROV combines the gas infrastructure options (technology options) of each project with their embedded real options. The following are the results of the option valuation models with the two techniques.

9.3.1 Tangguh expansion project

There is only one technology option for the Tangguh expansion project, i.e. adding one LNG train with a capacity of 3.8 mtpa. The adjusted DCF method shows a positive NPV value in every observable parameter settings. Based on the reference gas price setting, time needed to recover the CAPEX is 12 to 13 years, while at high gas price setting, it will be one year faster, and 3 to 4 years later at the low gas price setting. The Monte Carlo simulation generates an average NPV of USD 8.24 billion for the
government and USD 2.18 billion for the contractor. For this project, real options method is not applied considering only one technology option with a specific capacity preference and the contractor has also signed a gas sales agreement. Therefore, options to defer, abandon, or expand the project is less applicable to make a final investment decision.

9.3.2 Abadi project

The author decided to focus on the valuation of one technology option, i.e. onshore LNG plant with a capacity of 5 mtpa. This is due to less CAPEX needed with a larger capacity offered compared to the FLNG option. According to simple DCF rule, this project should not be executed because the NPV is negative USD 5.11 billion, from subtracting the cash flow revenues of USD 5.39 billion with the CAPEX of USD 10.5 billion. This is mainly due to high upfront CAPEX that should be invested and higher discount rate assigned to the project (the project is more risky compared to Tangguh LNG expansion). High upfront CAPEX might turn the project to be unprofitable because the opportunity cost of using the CAPEX earlier are higher than using it in the future. Therefore, adjusted DCF method is used to take into account the real cash-flow calculation. Based on the adjusted DCF method, the project should not be executed if the gas prices are low or in other words, the gas prices show trends as such in the low gas price scenario. However, this project might be still profitable (indicated by positive NPV) if the contractor could suppress the upstream costs, i.e. the wellhead cost is less than USD 6 per MMBtu.

Based on the reference gas price setting, the cost recovery time is 19 to 20 years given the CAPEX is USD 10.5 billion and 18 years given the CAPEX is USD 8.5 billion. Based on the Monte Carlo simulation, the average NPV for the government is USD 997.70 million with a standard deviation of USD 96.07 million, while for the contractor is USD 307.72 million with a standard deviation of USD 25.33 million.

For this project, the author also calculates the value of option to defer and option to choose between expanding and abandoning the project. Option to defer could be executed if the volatility is high, i.e. more than 20%. The volatility itself might be caused by natural gas price fluctuation, inflation, or changes in the OPEX. With the ROV, the author could not directly divide or share the NPV for the government and the contractor. For the option to choose, with a riskless rate of 8%, the net present real option values are in between USD 1.49 billion to USD 2.58 billion for volatility of 10% to 30%. Adding these values to the simple DCF calculation still resulted in a negative NPV. However, as the adjusted DCF method also indicates a positive NPV as long as the gas prices are not low, the project could still be executed.

Policy implications

Currently the contractor (Inpex) is negotiating the PSC with the Indonesian government to extend the original contract from 20 years (which will end in 2028) to 40 years. The Indonesian government also expects to have more domestic allocation with a minimum of 30% of the production capacity. Inpex probably will agree with the requirement to change the DMO because if the length of the contract is not extended, there is no reason to execute the project. However, as the profit might look quite low (compared to the profit in Tangguh project), Inpex might try to negotiate the profit sharing. The NPV will significantly be affected by the gas price for export, gas price for domestic market (domestic gas price), CAPEX, and the upstream or wellhead costs. In this case, the contractor has the ability to suppress the upstream costs (could be below USD 8 per MMBtu) while the government has the ability to determine the price for domestic market. These provide rooms to negotiate the PSC, export GSA and domestic GSA.
9.3.3 East Natuna project

Two technology options, i.e. East Natuna onshore LNG plant with a capacity of 3.8 mtpa and gas pipelines from East Natuna to Java, are valued using adjusted DCF method. The onshore LNG plant should not be executed if the gas prices are low because the operating costs for the liquefaction plant and shipping costs are much higher than the gas selling price. When the gas prices follow high gas price scenario, the CAPEX would be recovered in 8 to 11 years, with an NPV of USD 2.20 to 2.84 billion for the Indonesian government and USD 1.39 to 1.68 billion for the contractor. Based on the reference gas price setting in the Monte Carlo simulation, time needed to recover the CAPEX is from 12 to 17 years, with an NPV of USD 0.51 to 0.84 billion for the government and USD 0.50 to 0.74 billion for the contractor.

For the gas pipeline to Java, the NPVs are positive for all observable parameter settings. The government could gain up to USD 3.90 billion (up to USD 3.06 billion for the contractor) according to the reference gas price scenario and up to 8.50 billion in high gas price scenario (up to USD 4.80 billion for the contractor), given the gas price for domestic is equal to gas price for export. Otherwise, given the government set the gas price for domestic market to be USD 9 per MMBtu, the possible NPV for the government is USD 2.08 billion, and for the contractor is USD 1.22 billion.

In the Reference scenario, building a gas pipeline to Thailand will be more profitable compared to exporting the gas via LNG to Thailand. A multi-stage investment scheme has been developed, including technology options of onshore LNG plant in East Natuna, gas pipeline to Thailand, and gas pipeline extension to Singapore, resulted in a total NPV of USD 4.40 billion for the government and USD 2.61 for the contractor at the reference gas price setting.

A combined decision tree analysis (DTA) and real options analysis (ROA) has been applied to value the multi-stage scheme of East Natuna gas field development according to the Reference Scenario. The options includes option to abandon or wait for the onshore LNG plant, option to abandon or expand the LNG plant if gas pipeline to Thailand or to Singapore are unsuccessful. The value of the multi-stage project is USD 4.55 billion. This value is lower compared with combined NPVs (results of the adjusted DCF in the Reference Scenario) of the government and the contractor because the combined DTA and ROA includes probability when the projects fail.

Policy implications

There are conflicting interests within the East Natuna consortium. Both PTTEP and Pertamina will want to secure gas supplies for their own domestic markets. Onshore LNG plant in Natuna Island might be a neutral option because if the Indonesian gas production keeps decline, the Indonesian government could instruct to allocate the production from East Natuna LNG plant for domestic market otherwise export the LNG to Thailand. The onshore LNG plant is expected to be in operation in 2021. In the BAU scenario, the production is expected to decline after 2017. Therefore, the government still has time to observe the production trend from other gas fields. If the growth trend is negative, the government should push the contractor or Pertamina to build the gas pipeline to Java directly after 2017 or not later than 2020. When the trend is positive, the government could go with the multi-stage investment scheme.
10 Discussion

Synthesis of the results and findings from the GANESA model and option valuation model has been presented in the previous chapter. This chapter will explore potential development of the Asian gas market and in particular, the Indonesian gas market. Discussion on the Indonesian gas market will be covered from both upstream and downstream sides. This chapter also includes discussion on the CAPEX and OPEX volatility of gas pipelines and liquefaction plants.

10.1 FUTURE ASIAN GAS MARKET

In the BAU scenario, Singapore, Thailand, and Indonesia will need to import more LNG in the future and more regasification capacities are needed. Even in the Reference Scenario, LNG will still play an important role for the Asian gas market. LNG will replace pipelined gas and contribute a significant portion in the countries’ energy mix. LNG trade also has a larger scope than pipelined gas trade, i.e. globally or inter-continent instead of regional or within the continent as in the case of pipelined gas trades. A larger scope of Asian gas market instead of only Southeast Asia will be discussed because the dynamics in Southeast Asian gas supply and demand will significantly affect the gas market in other Asian countries, especially the Northeast Asian countries, such as Japan, South Korea, and China which are the main destinations for LNG exports from Southeast Asia.

10.1.1 Global upstream investments

Projections of the future gas supply and demand in Southeast Asia from 2015 to 2045, at the end, do not bring any good news considering the gas producing countries in the region are facing depleting gas resources, and consequently will rely on imported LNG to meet the demands. Figure 6.4 in chapter 6 shows the independency level of each Southeast Asian country to meet its domestic demand. The independency level provides an insight with respect to country’s security of supply. Countries that have independency level above 1.0 are able to meet their domestic natural gas demands without imports. Any import activities will make the buyer countries rely on supplier countries and any disputes or tensions, not only between the two countries, but also in the region where the countries are located (e.g. conflicts between the EU and Russia), could hamper the natural gas supplies and might have a domino effect to other sectors that rely on natural gas, e.g. chemical industry, electricity generations.

Countries that have independency level below 1.0 need to find a way to increase their security of supply, e.g. through a long-term contract or investing in upstream development in other countries. Considering pipelined gas supplies from Indonesia will expire in 2023, Singapore through Singapore’s Pavilion has put investments in upstream gas fields development in Tanzania and Papua New Guinea (IEA, 2014). According to a report from the IEA regarding the investment of Asian companies, Thai state-owned companies, PTTEP has put an investment in upstream gas field development in Mozambique.

Malaysia, although has an independency level above 1.0 also actively invests in upstream development in several projects around the world, e.g. Canada, Australia, and across the Africa
continent, notably in South Africa, Sudan and Egypt (IEA, 2014). This indicates the strategic moves of Petronas-Malaysia in order to remain competitive in the international LNG market. Currently, Malaysia is the second largest LNG exporter in the world behind Qatar. Qatar has surpassed Indonesia (who is now ranked 4th) as the largest LNG exporter since 2006 (IEA, 2014).

The Indonesian gas company, Pertamina, on the other hand, has chosen not to put any investments in upstream gas development project outside the country. This might due to several potential gas fields in Indonesia that have not been developed or Pertamina will probably be assigned to manage the existing gas fields (after the expiration of the existing PSCs). According to one Indonesian domestic newspaper (Kompas, 2015a), recently in May 2015, Pertamina announced its new subsidiary in Malaysia and the company has also acquired several assets (mainly oil fields) in Algeria, Iraq, and Malaysia during 2013-2014. This indicates a possibility that in the future, the company might also invest in international upstream gas field development. The statistics show that the reason Indonesia loses its position as the biggest LNG exporter is due to declining gas production from the existing gas fields which have been exploited for the last three to four decades. The only way for Indonesia to gain its dominance back is developing new gas fields or maximizing the potential of its unconventional CBM and shale gas.

10.1.2 Potential LNG suppliers

Other Asian countries, especially the long-term buyers of Southeast Asian LNG, i.e. Japan, Korea, and China, have put investments in the U.S., Canada, Russia, Australia, and East Africa (IEA, 2014) to anticipate declining gas supplies from Southeast Asia. With the upstream investments, they could also secure sales contracts of natural gas or LNG supplies from those gas fields.

Geographically, the most potential LNG supplier for the Southeast Asian countries is Australia. This is due to its geographical location that is adjacent and consequently will have a lower shipping cost. However, the facts are different. Singapore, for example, chose to invest and buy LNG from Papua New Guinea (shipping cost is USD 1.0 per MMBtu) and Tanzania (shipping cost is USD 1.3 per MMBtu) than Australia with a lower shipping cost of USD 0.7 per MMBtu (IEA, 2014). This is due to the basis price of the Australian LNG that is more expensive because of its higher costs of labors and capital expenditures (IEA, 2014; Songhurst, 2014). Therefore, Australia is not the first target to supply LNG for the Southeast Asian countries. Indonesia also chose to buy LNG from the U.S. although it is more distant. This might due to the lower U.S. LNG price as the result of the shale gas deployment in the U.S.

The facts that the three biggest LNG consumers in the world, i.e. Japan, South Korea, and China, have put investments across the globe, indicate their strategies to diversify their LNG supplies and reduce their dependences on one particular supplier. They are also willing to pay different prices and sometimes more than double. South Korea for example, according to the data from the Korean International Trade Association (Huh, 2013), in 2012 and in USD per MMBtu unit, paid 14.3 for LNG from Malaysia, 18.1 and 18.5 for LNG from Indonesia and Australia respectively, and 23.8 and 24.2 for LNG from Qatar and Oman. The lowest price came from Russia at 9.9. Even though Russia offered the lowest price, not all supplies came from Russia. However, all talks about Russia always involve some political concerns due to the sensitivity of the relations between Russia and the EU and also Russia and the U.S.
In May 2014, Russia and China have signed a deal for a pipelined gas contract with a volume up to 38 bcm per year (Reuters, 2014). The deal seems absurd because Russia accepts to be paid lower than it normally gets paid by the EU (Mercouris, 2014). Russia seemingly wants to show the EU, its largest gas buyer, that it could be independent even without supplying gas to the EU. Asia then becomes its target as currently, Russia is also in negotiations to sign gas deals with Korea, Japan, Pakistan, and India (Mercouris, 2014). Russia also gets involved in the upstream development of gas fields in Vietnam, and it would be possible for Russia to supply gas to the Southeast Asian countries. However, it is not only a matter of selecting the cheapest supplier. Compared to Japan, Korea, and China, the economic development in the Southeast Asian countries are slower (and smaller), and they also rely on trades with the EU and the U.S. Therefore, LNG supplies from Russia to Southeast Asia might be possible but not in a large volume considering the deals could risk other economic deals with the EU and the U.S.

10.1.3 Alternative pricing mechanisms

Based on adjusted DCF method, both Abadi and East Natuna onshore LNG plants should not be executed if the gas prices are low. The Brent-crude oil price which is the reference of Japan cif price used in this research, has fallen dramatically from an average of USD 108.60 per barrel in 2013 to USD 99.00 in 2014, and is expected to have an average value of USD 59.32 in 2015 (EIA, 2015). This is due to abundant oil supplies in the market and economic slowdown after the financial crisis in 2008 (The-Economist, 2014). This value, i.e. USD 59.32 per barrel is much lower compared to the low gas price scenario projected by the EIA (2014) which is USD 73.62 per barrel for the year 2015. EIA (2015) predicts the prices will be slightly higher in 2016 with an average of USD 75.00 per barrel. It is expected that each oil producing country will adjust their production since they will gain less revenues if the oil prices keep low. As the prices could drop by 45% from 2013 to 2015, the prices could also rise and get back to the reference price setting within 2 or 3 years.

Currently, JCC index pricing for the LNG trade remains dominant in the Asian LNG market. Most of the existing medium and long term contracts are based on JCC index with a few based on Henry Hub (HH) index (Rogers & Stern, 2014), basically when the suppliers are U.S-based. The first practice of linking LNG price to oil was done in Japan in 1970s when oil accounted for 77.4% of the Japanese primary energy supply (Miyamoto & Ishiguro, 2009). The basic assumption was that crude oil would be the main competitor for LNG. Nowadays, oil shares in the Asian countries’ portfolio have declined significantly (IEA & ERIA, 2013; Miyamoto & Ishiguro, 2009). It will be less relevant to keep the old practice because the crude oil becomes less and less competitive as a reference. On the basis of competition, it is expected that coal would be the competitor of natural gas, especially in China and Southeast Asia (IEA & ERIA, 2013; Rogers & Stern, 2014).

There are at least two possible means to escape from the trap of volatile oil prices. First is to include a price floor and price ceiling in the long-term gas sales agreement to protect both buyers and sellers from big losses due to high volatility of the oil prices. A more challenging option is to de-link the gas price from the oil price. Miyamoto and Ishiguro (2009) try an alternative mechanism for LNG pricing in Asia based on a market value netback system. In this system, the price of natural gas in one particular country will be linked to the primary energy source used in that country, e.g. coal, petroleum products, and retail electric power prices. According to Miyamoto and Ishiguro (2009), this mechanism could reflect the competitiveness of natural gas and other energy sources in end-user markets. They
also argue that this system has an advantage because it could incorporate an evolving market value mechanism into gas pricing. In their opinion, this mechanism is more rational than the current oil price-indexed because it ensures the autonomous development of each country’s natural gas market. This fact, on the other hand, is also a disadvantage of this mechanism as it will be less applicable to be applied more widely for a regional gas pricing. According to Rogers and Stern (2014), this mechanism could rapidly become outdated in fast growing markets. Unless there is sufficient flexibility in the contract, i.e. to change the price when the market conditions change, long-term contracts based on this mechanism are less likely to be adopted. The national government policy might also become impediments and make this approach impracticable (Rogers & Stern, 2014), e.g. government subsidy for particular industries such as fertilizer or power plants or government policy to reduce particulates and CO2 emissions that are produced by coal.

Asian LNG price is relatively much higher compared to the U.S.-HH. This has led the U.S. suppliers to bring gas from the U.S. to Asia, enabled by shale gas deployment in the U.S. Both multinational gas companies and Asian buyers have agreed on several long-term contracts from the U.S. gas fields based on a mixed indexation involving oil price and HH index, which is also known as a hybrid model (Rogers & Stern, 2014). For the suppliers, they could get higher price than the HH price, and for the buyers, they could get lower price than current JCC pricing. This provides a win-win situation for both buyers and suppliers. According to IEA (2014), BG and BP are said to have sold LNG to Chinese companies based on their global portfolios (not specifically from the U.S. gas fields), but on the mixed indexation. This practice indicates a greater possibility in the future for the Asian gas market to move away from the JCC pricing.

10.1.4 Asian gas hub and LNG spot market
Growing demands of natural gas in Southeast Asia might lead to development of several gas hubs in the region. Singapore has taken a lead by developing the regasification terminal in Jurong Island (which also has a liquefaction facility) and contracted British Gas as an aggregator to manage the demand and supply of natural gas (or LNG) in Singapore. It is expected that in five to ten years, the gas hub in Singapore could have a pricing mechanism that reflect the condition of supply and demand in the market. According to IEA (2014), the mixed indexation mechanism referring to HH will become more popular in new LNG contracts. However, this is not sustainable since it could not truly represent the regional condition in Asia or Southeast Asia, and still, a regional-based hub pricing is needed.

By 2012, LNG supplies from the spot market had 19.1% share of the total Asian LNG supply and equal to 60% of all spot traded volume globally (Rogers & Stern, 2014). The volume traded in the spot market might increase during the transition away from the JCC pricing, especially when the negotiations for the long-term contracts are in impasse. This is likely to happen considering the buyers will require more flexibility clauses in the contract, e.g. flexibility in destination, reselling, and renegotiation for pricing. Another possibility is shorter duration of contract (medium – less than 10 years or short term duration – less than 5 years) with smaller volume traded.

The new pricing mechanisms could only be exercised when there are numbers of both buyers and sellers, i.e. competitive market. Otherwise, one party will have more bargaining power for its own advantages. The current condition supports this transition considering there are several potential
suppliers, e.g. the US, Canada, Australia, Russia, East Africa, and Middle East with numerous buyers, especially in Europe and Asia.

Singaporean gas hub has a great chance to succeed considering its physical infrastructures adequacy, i.e. not only natural gas or LNG facilities but also supporting facilities, such as port or harbor. Singapore is also a step ahead in terms of regulation certainty perception among the foreign investors or in the international market. The only limitation probably comes from its lack of alternative supply besides LNG due to no gas reserves in Singapore. This could be resolved if pipelined gas supplies from Indonesia or Malaysia remain available in the future (as in the Reference scenario). Otherwise it will be difficult for Singapore to maintain the balance, especially when there is disruption in its LNG facilities (regasification, storage, and liquefaction) operation. Malaysia, then, also has a great chance to succeed if it could catch up Singapore to build the hub facilities and establish the institutions needed to manage the hub operation. Malaysia has its own indigenous gas reserves and has several alternative of LNG supplies from its global upstream investments.

*It will be better for Indonesia to stay away from the ‘hub game’ (i.e. not to establish a gas hub) as long as the downstream infrastructures of its own market have not been in place and the development of its CBM and shale gas have not been fruitful.*

### 10.2 FUTURE INDOONESIAN GAS MARKET

This section will focus on potential development of the upstream and downstream sides of the Indonesian gas market (see figure 10.1), taking into account the findings from previous chapters and also earlier discussion of the Asian gas market.

#### 10.2.1 Upstream development

Gas upstream activities consist of gas field exploration and production. The activities are regulated through production sharing contracts. In this section, discussion on PSC structure and export/import strategy for the Indonesian government will be presented.

**PSC Structure**

Structure of the Indonesian PSC has been presented at section 2.2.2. The author finds that there are negotiable contract variables, such as profit sharing, domestic market allocation, contract duration (extension), and incentives such as tax holiday. These variables might vary among the gas projects. For example, the common profit sharing is 70% for the government and 30% for the contractor. However, the government is willing to have 45% profit sharing for the East Natuna gas project. This might concern other contractors and they could question the certainty of regulations in Indonesia or ask for contract re-negotiation. The government, therefore, should *establish criteria or build a more transparent regulation* so that all contractors could know under what conditions they are eligible to negotiate profit sharing, extend contract duration, or get some incentives. There are several fixed clauses in the PSC, e.g. FTP, cost recovery, tax, and DMO. The author would suggest the government to *review the current DMO* (i.e. increase the minimum DMO), especially if the government wants to increase the gas utilization in its energy mix or Indonesian gas production declines as such in the BAU scenario.
**Upstream**

Production Sharing Contract (PSC)

<table>
<thead>
<tr>
<th>Negotiable</th>
<th>Fixed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Profit Sharing Duration</td>
<td>Tax Holiday Domestic market allocation</td>
</tr>
<tr>
<td>FTP Tax</td>
<td>Cost Recovery DMO</td>
</tr>
</tbody>
</table>

| Large gas projects | Tangguh expansion | Abadi gas field | East Natuna gas field | Small gas fields | Unconventional gas projects |

**Between government & contractors**

**IMPORT**
- Pricing mechanism
- Amount or volume
  - [Long] [Medium] [Short] - term

**EXPORT**
- Im/Ex - Contract or GSA

**Downstream**

**Domestic GSA**
- Large Consumer or Small Consumer (based on volume)
- Pricing mechanism (Regulated (+subsidy) / market competition?)
- Duration (? Years)

**LIBERALISATION?**

- Electricity generation (24%)
- Industry (39%)
- Fertilizer (11%)
- Oil lifting (3-4%)
- City gas (< 1%)

Develop downstream gas infrastructure !!!

*Figure 10.1 Potential development of Indonesian upstream and downstream policy*

**Export (Import) Contract**

In 2013, gas allocation for export is 5.2% less than allocation for domestic market (SKKMigas, 2013). Based on the BAU Scenario, Indonesia should not extend any long-term gas export contracts or sign new gas export contracts. Indonesia will also lose its independency in 2027 (according to BAU Scenario), and thus, needs to find new suppliers for imported LNG. However, based on the Reference Scenario, Indonesia could still export its gas at least until 2030. After that, Indonesia has to stop its gas export and find LNG suppliers before 2040.

For the export (or import) contract, it will be better for Indonesia to adopt *wait, see, and learn*, i.e. not taking any steps opposing the current international gas market regime. The impact of current *hybrid pricing* in new contracts done by Japan, Korea, and China could be observed. Clearly, a hub pricing is not yet possible, and therefore, either JCC index or hybrid model could be applied at least for the upcoming five to ten years duration until the Singaporean (or other Asian) gas hub is well
developed. The government should *conduct a study* to better anticipate the impact of new pricing mechanism, especially to the common export (or import) contracts used by Indonesia.

### 10.2.2 Downstream development

Large consumers in the Indonesian domestic gas market can be grouped into three: electricity generation (23.52%), industry (19.40%), and fertilizer (11.08%). Approximately 42% of the domestic production in 2011 went to export, 3.81% for oil lifting and only 0.02% was used for city gas (Sirait, 2013). This shows an opportunity to develop the domestic market and move the gas allocation for export to industrial and city gas development.

**Domestic GSA**

According to the Ministry of Energy and Mineral Resources of Indonesia, the government adopts five gas price models to determine gas prices in the GSAs as follows (Sirait, 2013):

- Fixed or flat price, e.g. for industry or electricity generation
- Escalated per year, e.g. price increases 3% per year
- Related to oil price (JCC); usually for export
- Related to consumer product, e.g. for fertilizer (related to ammonia and urea)
- Related to combination between oil price and product price, e.g. for fertilizer (related to ICP-Indonesian Crude oil Price and ammonia)

The selection of one particular model will be determined bilaterally between the government or government representative agency and the buyers, or depending on consumer’s category (i.e. fertilizer, electricity generation, or other industries). For domestic gas prices (to large or small domestic consumers), it will be important for the government to *give minimum (or no) subsidy* to prevent a heavy burden in the future as in the case of the oil subsidy.

Competition-based pricing could be applied especially if the government enforces downstream market liberalization. The discourse of market liberalization has been rolled out, however, the final decision has not been made due to a change in the government regime (new parliaments and executives were elected in 2014). This topic will be covered at the next section.

**Downstream gas infrastructure and market liberalization**

According to studies from LKI (2013) and Tjandranegara (2012), substituting oil with gas and give more gas allocation to domestic consumers (e.g. for chemical and fertilizer industries, to build new gas-fired power plants) will offset the loss from gas export revenues and even bring more benefits for the economic growth of the country. This is supported by Seah (2014) who argues that developing natural gas could be a way out for the Indonesian government to reduce its oil subsidy burden. Her opinion is based on the scheme of natural gas subsidy in Indonesia that is less entrenched and there are more gas reserves available compared to oil. However, this will depend on the availability and adequacy of the downstream gas infrastructure. PGN⁴, the state-owned gas network (transmission and distribution) company actively refutes the government intention to liberalize the gas market. PGN’s main argument is that it needs an assurance of both gas supplies and gas demands to invest on gas facilities.

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⁴ Unlike Pertamina who plays both at oil and gas sector, PGN only focuses on gas sector. PGN has just started to play at the upstream through its subsidiary, PT. Saka Energi Indonesia.
infrastructures (Kompas, 2015c), e.g. constructing both transmission and distribution pipelines to ‘create and nurture’ the markets. Allowing more players at the downstream and requirement for third party access and unbundling will undermine PGN’s business strategy which according to one senior official has been proven to create a new demand center in West Java.

However, as have extensively been argued by the supporters of market liberalization, liberalization is the only way to bring more competition to the market, and consequently, competition could bring the gas to the society with a minimum cost and also secure or bring gas supplies from other parts of the world. It is important to keep in mind that the benefits from a more competitive market could only be gained when the market has been mature, i.e. infrastructures have been well developed, the investments to build the infrastructures have depreciated and returns start to increase as the existing infrastructures can be utilized at low marginal cost (IEA, 2013). Therefore, in the case of the Indonesian government, when the gas infrastructures are still lacking, it will be more important to create a conducive business climate (bring confidence) for the national companies such as Pertamina and PGN to build the gas infrastructures. In other words, the government should not liberalize the gas market until the starting condition for gas market liberalization is achieved.

A caveat of this plan is the financial capability of the Indonesian gas companies to build the gas infrastructures. The government might want to accelerate the plans to enhance the gas distribution network in Indonesia and the state-owned gas companies might have limited financial resources to fund and finish all of the projects within the time constraint. This contains a political issue because one period of the government regime in Indonesia lasts for five years and the current government regime might want to attract public sympathy in order to be elected again. Liberalization of gas market could attract more multi-national companies or foreign investors to invest in Indonesia. They are also more capable in terms of financial and human resources to make the plans into action within the time constraint. Another caveat is the political and economic pressure either from the regional organizations (e.g. ASEAN, ADB) or international organizations such as G-20, IMF, or World Bank that might be more favorable if Indonesia liberalizes its gas market. This, then, will depend on the negotiations by the Indonesian representatives to get the best or better deals for the country.

10.3 CAPEX & OPEX VOLATILITY OF GAS INFRASTRUCTURE
Changes in the values of CAPEX and OPEX of each technology options, i.e. gas pipelines and onshore LNG plants will change the value of the project. In this section, the author will look into the historical records of gas pipelines and onshore LNG plants to analyze the volatility and the causes.

10.3.1 Gas pipelines
There are two studies focusing on the variation of historical gas pipeline construction costs: Schoots et al. (2011) and Rui et al. (2011). Both gather historical records from the Oil and Gas Journal. Rui et al. (2011) use historical records of onshore gas pipeline constructions in the U.S. and Canada between 1992 and 2008, while Schoots et al. (2011) pick a longer period, between 1985 and 2009. According to Rui et al. (2011) the pipeline construction costs are dominated by material and labor costs which account to approximately 71% of the total cost. They also find that the learning rate and construction cost are varied, depending on factors such as pipeline designs (i.e. diameter, length) and location.
Schoots et al. (2011) state that no reductions can be observed for the gas pipeline construction costs for the last three to four decades. They argue that the costs are too volatile and thus, no long-term cost trends could be observed. With respect to the learning-by-doing practice, they hardly could observe it. Considering the key inputs of the costs, i.e. material and labor costs, Schoots et al. (2011) argue that the gas pipeline technology is rather rudimentary and thus, there is only a little room for improvement for the technical or labor related problems.

Another substantial cost is right-of-way (ROW) cost which in average contribute to 7% of total gas pipeline construction costs in the U.S. and Canada (Rui et al., 2011). According to Schoots et al. (2011), the ROW costs could differ between states and are primarily related to legal and permitting issues. In general, total pipeline construction costs in developing countries such as Indonesia are lower than in developed countries, mainly are caused by the wage differences for the labors. The IEA has a location factor to compare gas pipeline construction costs between countries and regions (Schoots et al., 2011). The location factor for Southeast Asia region (excluding Japan) is 0.8 while for the U.S. and Canada is 1.0. The highest location factor is in the UK which is 1.2.

For the OPEX, Brito and Sheshinski (1997) state that the cost of transporting 1000 cubic feet of gas 1000 miles by pipeline is approximately USD 0.50 or equivalent to USD 0.30 per MMBtu per 1000 km. Schwimmbeck (2008) as in Messner and Babies (2012) estimates the OPEX per MMBtu per 1000 km to be USD 0.60 to 0.70 for 28-inch gas pipeline with a capacity of 5 bcm per annum. While for larger diameter pipelines, i.e. 40-inch to 56-inch, the OPEX is between USD 0.30 to USD 0.50. In this research, the author uses an approximation of USD 0.70 for 42-inch gas pipelines from East Natuna, considering the distance to both Java and Thailand which are estimated to be 1,400 and 1,500 km (ACE, 2013). Assigning an inflation of 2.0% per annum for the OPEX does not change the NPV of the project significantly (i.e. from positive NPV to negative NPV or change the time needed for the cost recovery).

As a conclusion, the volatility of gas pipelines’ CAPEX is determined by the material and labor costs at locations where the gas pipelines are built. The OPEX is less volatile, and mainly constitutes of labor costs for maintenance and operation. Adjustment for the CAPEX should be made as in this research, the author has not considered the location factor and the CAPEX calculations were mainly based on the studies from ECCO (2011) and Moshfeghian and Hairston (2013).

10.3.2 LNG liquefaction plant

Location also significantly affects the CAPEX of LNG liquefaction plant as such in the case of gas pipelines. Kotzot et al. (2007) from KBR, one of key players in LNG technologies, engineering and construction state that the CAPEX of liquefaction plants is highly dependent on site specific factors, e.g. remote nature of the site, local content requirement, and marine conditions. Songhurst (2014) analyzes 36 liquefaction projects between 1965 and 2015, including projects which are under construction. He finds that different locations of the project (low to normal cost location versus high cost location) could bring a gap of USD 200 to 400 per annual ton capacity of the liquefaction plant. Regarding the trend, it is hardly found that learning-by-doing practices could contribute to cost reduction because in the period of 2000 to 2013, the CAPEX has quadrupled from USD 300 per tpa to USD 1,200 per tpa. However, the author could not confirm whether the project references in 2000 and 2013 are located in the same region. Shively et al. (2010) collect historical records of liquefaction plants’ CAPEX (note: the source of data is not mentioned) from 1988 to 2008 and find that between
1988 and 2003, the CAPEX showed a reduction from USD 550 per tpa to USD 200 per tpa (64% cost reduction in 15 years); while in between 2003 to 2008, the CAPEX showed an increasing trend up to USD 390 per tpa in 2008. According to Shively et al. (2010), the escalation of CAPEX for liquefaction plants that was started in 2005 was because a rapid rise of worldwide demand for materials such as steel, nickel and concrete that were needed for the liquefaction plant constructions.

Looking at 36 liquefaction projects gathered by Songhurst (2014), there are four projects located in Southeast Asia. Brunei LNG was built around 1970 with a cost of USD 700 per tpa. First Malaysian LNG was built in 1980s and experienced USD 200 per tpa cost reduction compared to Brunei LNG. A decade after, Malaysia expanded the liquefaction plant with a CAPEX of USD 400 per tpa. In 2014, Malaysia expanded and built the third train with a CAPEX of USD 500-600 per tpa. There is only one record of LNG project cost in Indonesia, which is Donggi LNG Plant in Sulawesi (was built in 2014) with a CAPEX of USD 1,000 per tpa. The higher CAPEX for Donggi LNG plant compared to Malaysian LNG is mainly caused by different scope of the project. Malaysian LNG expansion was only add the liquefaction train while Donggi LNG project was a complete LNG facility. According to Songhurst (2014), there are three main categories that constitute up to 82% of the total CAPEX based on the 36 liquefaction projects: construction (32%), equipment (30%), and bulk materials (20%). Kotzot et al. (2007) state that labor costs account up to 50% of the construction cost. As noted by Songhurst (2014), in a country with high construction costs such as Australia, the construction costs could contribute up to 60% of the total project cost.

The possible cost reduction, then, lays on the equipment and bulk materials. The main equipment needed for liquefaction facilities includes cryogenic heat exchangers, refrigeration compressors and drivers, power plant and LNG storage tanks (Songhurst, 2014). According to Songhurst (2014), there is limited competition in these specialized technologies. Songhurst (2014) also notes an extensive use of stainless steel in LNG projects which is more expensive than carbon steel. A rise in labor costs would be more predictable. Therefore, the volatility of liquefaction plants CAPEX will depend on the market for equipment (limited competition at present) and material price, i.e. stainless steel. Another possible cost reduction is through economies of scale, i.e. build a liquefaction plant with higher capacity. However, this will depend on the amount of gas reserves that could supply natural gas to the liquefaction plant.

Comparing the variable cost components, e.g. fuel, taxes, and operating costs from Shively et al. reports in 2004 and 2010, the fuel cost and taxes remain the same, as much as USD 0.08 per mcf and USD 0.15 per mcf while the operating costs reduce from USD 0.20 per mcf in the 2004 report to be USD 0.10 per mcf in the 2010 report. In this research, the OPEX for onshore LNG plant is assumed to be USD 0.20 per MMBtu. Similar with the gas pipeline case, assigning inflation to the OPEX does not change the NPV value of each LNG project significantly. This supports a claim from Kotzot et al. (2007) that capital cost has more influence compared to life cycle cost that is indicated by the OPEX.
Conclusions & Recommendations

11.1 CONCLUSIONS

Indonesia was known as the biggest LNG exporter in the world before Qatar overtook the position in 2006. The main destinations for Indonesian LNG export are countries in Northeast Asia such as Japan, South Korea, Taiwan, and China. Indonesia also exports its gas through cross-border gas pipelines to Singapore and Malaysia. Indonesia, however, is confronted with depleting gas reserves (from existing gas fields) that causes its domestic gas production declined since 2010. Together with other ASEAN member states, Indonesia has come up with plans to develop gas infrastructures throughout Southeast Asian region (see section 2.3 for details).

The Indonesian government also plans to increase natural gas utilization in its energy mix, and thus, reduce the oil share. Increasing gas allocation for domestic needs will reduce allocation for export. However, it is argued that the benefits from domestic allocation, e.g. industrial and city gas development, could offset the revenue losses from export. This lead to the following research question:

*What infrastructure investment strategy should be pursued by the Indonesian government to facilitate domestic gas supply and maximize profit from gas sales?*

Two scenarios are developed to particularly take into account the uncertain growth trend of gas production and consumption in Indonesia: *Business-as-Usual* (BAU) scenario where the Indonesian domestic gas production is expected to decline while domestic consumption grows at 2.2% per annum, and *Reference* scenario where the domestic gas production is expected to grow at 0.5% per annum (considering potential gas fields that have not been developed) and domestic consumption grows at 2.7% per annum.

Based on the BAU scenario, Indonesian gas production will decline after 2017. Consequently, new regasification capacity (excluded capacity used to handle domestic LNG supply) is needed to handle imported LNG and need to be put in place before 2033. This has not been accommodated in the current LNG infrastructure expansion plan. In terms of the TAGP, the East Natuna gas field should be used mainly for domestic needs. Therefore, gas pipelines connections from East Natuna to other countries will not be favorable for Indonesia to build and the government should not allow new (or renewal of the existing) gas export contracts.

On the other hand, the Reference scenario indicates possibilities for Indonesia to keep exporting gas. Indonesia could build onshore LNG plant in Natuna Island or subsea gas pipelines to Thailand and Singapore (connected to West Natuna – Singapore gas pipeline). According to this scenario, additional regasification capacity is not needed until 2044. Figure 11.1 summarizes gas infrastructure investment for the Indonesian government, given that domestic consumption grows according to the BAU and Reference scenarios.
11.2 POLICY RECOMMENDATIONS

Following policy recommendations are addressed to the Indonesian government.

Upstream related (Production Sharing Contract)

- Establish criteria for negotiable PSC variables
  Different gas projects in Indonesia could have different PSC content or agreements. The government should establish criteria for the negotiable variables (e.g. profit sharing, tax holiday, duration) of the PSC in a more transparent way to ensure a legal certainty among the multi-national gas companies.

- Review DMO
  When the domestic production and consumption follow trends as such in the BAU scenario, the government should increase the minimum DMO in the PSC or give a restricted condition, i.e. export is allowed after domestic demand has been fulfilled. If the production grows as such in the Reference scenario, increasing the DMO might be unnecessary. However, if the government is serious with the plan to increase natural gas share in its energy mix, the minimum DMO of 25% should be raised.

- Reduce CAPEX volatility by enforcing local content requirements
  The causes of the CAPEX volatility are equipment (related to technology and limited competition among the suppliers) and bulk materials (high materials’ price when demand increases). Another important variable is labor costs which could contribute up to 50% of the construction cost. Considering the following facts:
Indonesia has abundant natural resources, including steel, nickel, and concrete which are the main raw materials to build an LNG plant.

Indonesia has low labor costs

The country could reduce the volatility and gain more benefits, for instance by requiring the contractor to use local content resources, i.e. both materials and labors. However, the country should put more effort in order to ensure the compliance and quality of the materials’ composition and labors’ expertise to the International standards that are widely accepted.

Export/Import Contracts

One of the key uncertainties in the project valuations is volatility of the gas selling prices, especially for the onshore LNG project that might turn to be a loss when the gas prices are low. Currently, several alternatives of pricing mechanisms have been proposed to move away from the JCC pricing. With the upcoming Singaporean gas hub, an Asian gas hub pricing will not be a delusion anymore, only if there are wider acceptances and supports from other Asian countries. It could be expected that the volume of LNG traded in spot market will increase as both buyers and sellers will need more time to (re)negotiate the contracts during the transition. The contracts are also expected to be more flexible, i.e. flexible in destinations, including a price review or renegotiation clause with a shorter duration and smaller amount traded. The Indonesian government, therefore, need to conduct a study to better anticipate the impacts of the upcoming changes to its existing institutions. In the meantime (before gas hub pricing is well developed),

- For export contracts, Indonesia could use following pricing mechanisms:
  - JCC pricing with price floor and price ceiling
  - Fixed price (could be with n% escalation every t years) to ensure the new projects will be break-even with additional profit margin

- For import contracts, Indonesia could use the hybrid model (mixed JCC and HH index), especially if the sources of LNG supply come from the U.S. Otherwise, the same pricing mechanisms as in the export contracts could be used.

Downstream related

- Give minimum or no subsidy for domestic gas price
  The government should not give subsidies to its domestic gas price to prevent heavy subsidy burden in the future as in the case of the oil subsidy. The subsidies could be allocated to other incentives that could grow the domestic gas market and increase natural gas utilization in Indonesia.

- Focus on developing downstream gas infrastructures
  The downstream gas infrastructures in Indonesia are still lacking. Insufficient infrastructures will bring the Indonesian gas market nowhere. The government should put off the plan to liberalize national gas market in order to create a conducive business climate for the state-owned companies, e.g. Pertamina and PGN to build the infrastructures. The government could maintain the status quo for the upcoming 2 to 3 years. If the realization is less than expected or the state-owned companies do not have sufficient resources (e.g. financial, human or expertise) to realize the plan, then the government could push on with the liberalization, given that the multi-national companies (or foreign investors) will help to build the infrastructures and transfer the ownership to the state after t years, depending on the agreements.
Reflection

REFLECTION ON THE RESEARCH APPROACH

First, let us look back to the objectives of this research. This research has two objectives: to understand the current condition of the Southeast Asian gas market and to evaluate the long-term investment strategy for the gas infrastructure, especially in Indonesia and also make a recommendation when better options are available. An extensive literature review has been presented in chapter 2 to give a better understanding to the readers regarding the current condition in the Southeast Asian gas market. A broader context of Southeast Asian (and Asian) gas market needs to be understood because Indonesia export its gas to its neighboring countries, e.g. pipelined gas to Malaysia and Singapore, short term or spot LNG to Thailand, and most of its LNG to Japan, South Korea, China, and Taiwan.

The author realizes that the Southeast Asian gas market does not only consist of networks of physical gas infrastructures, e.g. gas pipelines, liquefaction plants, regasification terminals, but also networks of actors, e.g. multi-national and national (state-owned) gas companies who invest in and act as contractors or operators at each gas producing field. They could directly sell the gas to large domestic consumers or export the gas. Besides network of actors, each country also has its own PSC structure. Therefore, in this research, the author uses multi-disciplinary perspectives, i.e. taking into account the technical, economic, institutional, and organizational (actors) aspects of the system. The system here refers to the natural gas value chain (see section 5.1) with its multi-disciplinary ‘components’ as mentioned before.

The author chooses a modeling approach because it is impossible to know the future. When the model could represent the current condition, it is expected that the model could also represent the future condition. The model is developed following a system perspective that has three phases, i.e. definition, development, and deployment (see section 1.5). This helps the author to arrange the logic of the model and manage the coherence and linkages between each phase. The most critical step is the model definition in which the author needs to define the functions of the model, set a boundary and make a selection regarding the way to build the model. The author has developed functional requirements and a design space consists of means to achieve the functions. The design space provides alternatives to build and later, improve the model.

In this research, the gas network model is formulated as network optimization problem that is solved with linear programming. The model is aimed to maximize profit while fulfilling the capacity constraints, gas sales agreements, and a balance between gas supply (from domestic production and import) and demand (domestic demand and export). The selection of this basic principle (i.e. network optimization with linear programming) is due to the current condition of Southeast Asian gas market that is less connected (no hubs), not (yet) liberalized, and is still dominated by confidential long-term contracts and monopoly of the state-owned companies. Therefore, any approaches that focus on the role of different actors along the value chain will be less applicable at least until the market be fully liberalized or unbundled. The model, later, could be improved when the current condition changes (e.g. unbundling, third party access, or regional hub pricing), more data is available (e.g. gas export or
import prices, geological data of gas reserves, gas production plan), or the uncertainties become known or certain.

A combination of scenario planning and option planning is used in this research. This practice has been carried out in oil and gas companies, and pioneered by Shell (Schoemaker & van der Heijden, 1992). According to Miller and Waller (2003), ROA makes a good combination with scenario planning as tools for managers to make strategic investment decisions under uncertainty. The author uses scenario planning for the Indonesian case to take into account the uncertainties in domestic gas production (i.e. positive growth or decline), consumption (different rate of growth), existing pipelined gas contract to Singapore (extended or not). The results then are used to develop options (options planning) that could meet the capacity requirement of each gas infrastructure or fulfil the supply deficit to meet the demand.

The scenarios might look too simple (i.e. only include two uncertainties: domestic production and domestic consumption) for this complex problem. As a side note, it is complex because the gas market consists of not only physical infrastructures but also networks of actors and institutions that govern the interactions between the actors, interconnections of the gas infrastructures, or the way the actors use the infrastructures. The relations between the system components are not always clear, especially when the system is influenced by the environment or external forces (e.g. new technology, new pricing mechanism, new government, etc.). However, these two variables, i.e. domestic production and domestic consumption, are the core of the market because they represent the nation’s supply and demand sides which are the essence of the market functionality, i.e. a place where supplies meet demands. Therefore, these two scenarios are very relevant to be used by the Indonesian government to plan the infrastructure investment strategy. The strategy will help the government to decide whether capacity expansion of one particular infrastructure is needed and when it should be in place, the way to develop new gas fields (i.e. pipelined gas or LNG), gas allocation for domestic and export, and when the export should be stopped or when new import contracts are needed. The author sees the whole processes from the literature review, the first model development (gas network model), scenario planning, option planning, and the second model development (options valuation model) as necessary and effective to achieve the objectives of this research.

REFLECTION ON THE MODEL DEVELOPMENT

There are two types of model built in this research, each with its own intended functions. The first model is aimed to make a projection of capacity utilization and additional capacity requirement of each gas infrastructure type in each country. The model belongs to the group of gas network model (see section 4.1) and is based on top-down approach due to high level of aggregation (i.e. country-based; see section 5.1.1) and aggregate economic variables used in the model (e.g. gas proven reserves, domestic production and demand of natural gas). In this model, the gas infrastructures in each country are agglomerated into three groups: cross-border gas pipelines, liquefaction plants, and regasification facilities. As outputs, in every year, each country will only have one value for each capacity utilization and capacity requirement of those three groups.

Regarding the conceptualization of the model, gas storages are excluded (see section 5.1). In the future, when more information is available and gas hubs are started to develop, gas storages could be
included in the infrastructure options. Another limitation in the conceptual design of the model is the simplification of external (outside Southeast Asia) gas suppliers and buyers. In the model, the external gas suppliers are simplified as one node of import source, and for the external buyers as one node of export destination. Even though the conceptual model does not represent the real system completely, it still could provide insights to answer the research questions.

There are two main variables in this model which are assumed as exogenous variables: growth or decline of domestic gas production and consumption in each country. The values are based on estimates from the Energy Outlook for Southeast Asia (IEA & ERIA, 2013) and for Indonesia (BPPT, 2014). With respect to the use of top-down approach, it is argued that aggregated models in energy sectors could not capture the sectoral details and complexity of demand and supply (IPCC, 2001). The author will not deny this limitation. In this research, the author uses an aggregated estimate of domestic gas consumption growth instead of projected sectoral gas demand (e.g. industrial, households, transportation, electricity sectors). To estimate the sectoral gas demand, information regarding the elasticity of particular sectoral demand and GDP growth is needed (Batubara et al., 2014). However, due to the limitation of information available in the public-accessible reports, the sectoral analysis could not be done. From the supply side, to reduce uncertainty, geographical and geological data of the gas fields are needed to estimate the amount of reserves, together with operators’ production plan to estimate the growth or decline in natural gas production. However, this information is hardly available and will be too costly to measure directly from the fields. Therefore, the author decides to use information published by the national or international agency, considering the fact that they will have more information, expertise and also credibility to make projections of natural gas production and consumption.

According to Sterman (2002), almost nothing is exogenous due to the effects of feedbacks or interrelations among the variables. Besides natural gas production and consumption growth, another key variable is gas price. However, in the Southeast Asian gas market, there is no single gas price. Each long-term gas sales agreement has its own price setting formula. The most common reference is based on JCC pricing or Japan cif. Since there is no forecast available for the JCC index or Japan cif, the author uses extrapolation from the Brent-oil prices (EIA, 2014) combined with regression analysis between the Brent-oil price and Japan cif. In most gas network models, the gas price becomes an output of the model. However, it is less applicable for this research because there is no gas hub or trading points as in the cases of most European gas network models (see section 4.1). This model is also limited in terms of endogenizing the production and consumption as a result of changes in producers or consumers behavior. As this might fall outside the objectives of this research, this limitation is less significant and could be considered for further research.

The second type of the models is options valuation models which can be distinguished based on two valuation techniques, i.e. adjusted discounted cash flow and real options. These two techniques have been widely used to value options. The key variables in this model is the CAPEX of each infrastructure option and the gas selling price. Sensitivity analysis and Monte Carlo simulation have been performed to take into account the uncertainties such as interest rate, gas price setting (high, reference, or low), inflation, and different CAPEX estimates. The results of this model, i.e. NPV and cost recovery time, will significantly affect the final investment decision of each infrastructure option.
One of the most well-known phrases among the system scientists is “All decisions are based on models, and all models are wrong” (Sterman, 2002). The models are always wrong because the models are only representations of the real systems and the models could not capture all components, the components’ interactions within the system, and also the way the system would react when its environment changes. This is not the failure of the model, but mainly the bounded rationality of the modeler. The models would not be able to perform or produce outputs 100% as the real systems due to uncertainties and interaction or interrelations among variables or system components that are not known or failed to be noticed. The author has experienced this condition because the Brent-oil price has declined significantly and could not be captured by the EIA’s forecast. The prices fell below the low oil price scenario. This is commonly regarded as an unanticipated event. However, instead of putting blame on external uncertainties or unanticipated events, it will be more useful and valuable to consider factors or variables that might change or turn around the results of the model. This limitation needs to be admitted so that the policy (or decision) makers become aware while making investment decisions or changing policies.

FURTHER RESEARCH

Following recommendations are concluded for further research:

- **Disaggregation and challenge the supply and demand projection**
  The existing gas network model could be disaggregated. Instead of country-based, the model could adopt infrastructure-based and take into account the geographical and geological factors, e.g. location of the liquefaction plants or regasification terminals, amount of gas reserves available at each location (to better project the future production), and distance between supply sites and demand centers. The model could also include sectoral analysis to better project the demand growth.

- **Adjust gas price assumption**
  There are at least three ways to adjust the gas price setting in the model. First, a floor and ceiling of gas selling price could be included in the options valuation. The price floor could be estimated from the break-even point of the project, added by a small percentage of profit margin. The price ceiling could be based on the highest point of historical gas selling price added by some percentages of allowance which represents the willingness to pay of the buyers. Secondly, if possible, existing (or future contracts that have been in negotiation) gas sales contract from each liquefaction plant and to each regasification terminal could be included. This will raise the confidence level of the model outputs because the gas selling prices and amount of gas traded are better known. This approach is better applied together with the infrastructure-based model. However, there will be a large scale of data inputs. The third option is to produce the gas market prices as commonly used in the European gas network models. This could be done through a case study of the Singaporean gas hub, taking into account prospective gas suppliers and buyers within and outside the region.

- **Challenge the cost assumptions**
  The calculations of CAPEX and OPEX for each infrastructure option are based on studies of historical projects around the world and might not represent the actual costs of the projects in Indonesia. Therefore, the CAPEX could be adjusted through a discussion with the gas companies or operators of the gas fields in Indonesia, e.g. Tangguh, Abadi, and East Natuna.
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Appendix A
Japan CIF and Brent-oil index Correlation

<table>
<thead>
<tr>
<th>Year</th>
<th>Brent-oil reference (x)</th>
<th>Japan LNG cif (y)</th>
<th>( y' = 0.1298x )</th>
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<tr>
<td>1990</td>
<td>37.27</td>
<td>3.64</td>
<td>4.84</td>
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<tr>
<td>1991</td>
<td>30.36</td>
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</tr>
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<td>1992</td>
<td>28.59</td>
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<td>3.71</td>
</tr>
<tr>
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<td>3.20</td>
</tr>
<tr>
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<td>3.07</td>
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<td>3.65</td>
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**Regression Statistics**

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<tr>
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<td>R Square</td>
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<td>Observations</td>
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\[
S_e = \sqrt{\frac{\Sigma(y - y')^2}{n - 2}}
\]

**ANOVA**

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<th>MS</th>
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<td>30,04282</td>
<td>1,43061</td>
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<tr>
<td>Total</td>
<td>22</td>
<td>427,0162</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: The value of sig.F is < 0.05, thus, the results are reliable (statistically significant).
Appendix B: GANESA Model

Appendix B1. MATLAB Script

```matlab
%% Load data
load A_gas_price.mat;
load A_liquefaction_cost.mat;
load A_regasification_cost.mat;
load A_shipping_cost.mat;
load A_transmission_cost.mat;
load A_domestic_gas_price.mat;
load A_wellhead_price.mat;
load A_BAU1_production_volume.mat;%uncertainty
load A_BAU1_domestic_consumption.mat;%uncertainty
load A_BAU1_min_export_capacity.mat;%based on GIIGNL
load A_BAU1_max_export_capacity.mat;%based on GIIGNL
load A_BAU1_min_import_capacity.mat;%based on GIIGNL
load A_BAU1_max_import_capacity.mat;%based on GIIGNL
load A_BAU1_min_pipeline_capacity.mat;%based on Longterm contract
load A_BAU1_max_pipeline_capacity.mat;%based on LT contract and existing design

domestic_revenue = domestic_gas_price.* domestic_consumption;

total_production_cost = wellhead_price.* production_volume;

%% variables x and bounds
% note: lng_export(1to7), lng_export_dummy(8to14), lng_import(15to21),
% lng_import_dummy(22to28), pipeline_volume(29to33), balancing_volume(34to40)
nperiods = 32;
ncountries = 7;
npipelines = 5;
main_variables = 40;

lb = zeros(nperiods*main_variables,1);
ub = Inf(nperiods*main_variables,1);

% row is countries, column is year
cycle = 0;
for ii = 1:nperiods
    for cc = 1:ncountries
        lb(cycle+cc) = min_export_capacity(cc,ii);
        lb(cycle+14+cc) = min_import_capacity(cc,ii);
        ub(cycle+cc) = max_export_capacity(cc,ii);
        ub(cycle+14+cc) = max_import_capacity(cc,ii);
    end
    for pp = 1:npipelines
        lb(cycle+28+pp) = min_pipeline_capacity(pp,ii);
        ub(cycle+28+pp) = max_pipeline_capacity(pp,ii);
    end
    cycle = cycle + main_variables;
end

%% Equality constraints
% linear equality constraints: Aeq x = beq
Aeq = zeros(7*nperiods,nperiods*main_variables); beq = zeros(7*nperiods,1);
cycle1 = 0;
cycle2 = 0;
for ii = 1:nperiods
```

Aeq(1 + cycle1, [34 + cycle2, 15 + cycle2, 22 + cycle2, 1 + cycle2, 8 + cycle2, 29 + cycle2, ...
30 + cycle2]) = [1, -1, -1, 1, 1, 1, 1];
beq(1 + cycle1) = production_volume(1, ii) - domestic_consumption(1, ii);
Aeq(2 + cycle1, [35 + cycle2, 16 + cycle2, 23 + cycle2, 2 + cycle2, 9 + cycle2, 29 + cycle2, ...
31 + cycle2]) = [1, -1, -1, 1, 1, 1, 1];
beq(2 + cycle1) = production_volume(2, ii) - domestic_consumption(2, ii);
Aeq(3 + cycle1, [36 + cycle2, 17 + cycle2, 24 + cycle2, 3 + cycle2, 10 + cycle2, 29 + cycle2])
= [1, -1, -1, 1, 1, 1];
beq(3 + cycle1) = production_volume(3, ii) - domestic_consumption(3, ii);
Aeq(4 + cycle1, [37 + cycle2, 18 + cycle2, 25 + cycle2, 4 + cycle2, 11 + cycle2, 32 + cycle2])
= [1, -1, -1, 1, 1, 1];
beq(4 + cycle1) = production_volume(4, ii) - domestic_consumption(4, ii);
Aeq(5 + cycle1, [38 + cycle2, 19 + cycle2, 26 + cycle2, 5 + cycle2, 12 + cycle2, 32 + cycle2, ...
33 + cycle2]) = [1, -1, -1, 1, 1, 1, 1];
beq(5 + cycle1) = production_volume(5, ii) - domestic_consumption(5, ii);
Aeq(6 + cycle1, [39 + cycle2, 20 + cycle2, 27 + cycle2, 6 + cycle2, 13 + cycle2, 32 + cycle2])
= [1, -1, -1, 1, 1, 1];
beq(6 + cycle1) = production_volume(6, ii) - domestic_consumption(6, ii);
Aeq(7 + cycle1, [40 + cycle2, 21 + cycle2, 28 + cycle2, 7 + cycle2, 14 + cycle2, 30 + cycle2, ...
31 + cycle2]) = [1, -1, -1, 1, 1, 1, 1];
beq(7 + cycle1) = production_volume(7, ii) - domestic_consumption(7, ii);

cycle1 = cycle1 + 7;
cycle2 = cycle2 + main_variables;
end

%% Objective function
k = 10000; % additional capital, roughly assumed to indicate dummy capacity
revenues = zeros(nperiods * main_variables, 1);
%f = zeros(nperiods, 40);
cycle = 0;

for ii = 1:nperiods
revenues([15 + cycle, 16 + cycle, 17 + cycle, 18 + cycle, 19 + cycle, 20 + cycle, 21 + cycle, 22 + cycle, 23 + cycle, 24 + cycle, 25 + cycle, 26 + cycle, 27 + cycle, 28 + cycle, ...
1 + cycle, 2 + cycle, 3 + cycle, 4 + cycle, 5 + cycle, 6 + cycle, 7 + cycle, 8 + cycle, 9 + cycle, 10 + cycle, 11 + cycle, 12 + cycle, 13 + cycle, 14 + cycle, ...
29 + cycle, 30 + cycle, 31 + cycle, 32 + cycle, 33 + cycle]) = ...
1*(single_gas_price(ii)+regasification_cost(ii)) -
1*(single_gas_price(ii)+regasification_cost(ii)) -
1*(single_gas_price(ii)+regasification_cost(ii)) -
1*(single_gas_price(ii)+regasification_cost(ii)) -
1*(single_gas_price(ii)+regasification_cost(ii)) -
1*(single_gas_price(ii)+regasification_cost(ii)) -
1*(single_gas_price(ii)+regasification_cost(ii)) -
1*(single_gas_price(ii)+regasification_cost(ii)) ...
\[-1 \cdot (\text{single\_gas\_price}(ii) + \text{regasification\_cost}(ii) + k) - 1 \cdot (\text{single\_gas\_price}(ii) + \text{regasification\_cost}(ii) + k) - 1 \cdot (\text{single\_gas\_price}(ii) + \text{regasification\_cost}(ii) + k) - 1 \cdot (\text{single\_gas\_price}(ii) + \text{regasification\_cost}(ii) + k) - 1 \cdot (\text{single\_gas\_price}(ii) + \text{regasification\_cost}(ii) + k) ... \]
\[= \text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[
\text{single\_gas\_price}(ii) - \text{liquefaction\_cost}(ii) - \text{shipping\_cost}(ii) \]
\[\cdots \]
\[-1 \cdot \text{transmission\_cost}(ii) - \text{transmission\_cost}(ii) \]
\[
\text{cycle} = \text{cycle} + \text{main\_variables}; \\
\text{f} = \text{revenues}(); \\
\%	ext{ solve the problem:}
\[ [\text{x} \; \text{fval}] = \text{linprog}(-\text{f}, [], [], \text{Aeq}, \text{beq}, \text{lb}, \text{ub}); \]
\[
\hspace{1cm} \text{fval}
\]
\[
\hspace{1cm} \text{rr} = \text{ncountries};
\]
\[
\hspace{1cm} \text{cc} = \text{nperiods};
\]
\[
\hspace{1cm} \text{Total\_Revenue} = 0;
\]
\[
\hspace{1cm} \text{Total\_Costofproduction} = 0;
\]
\[
\hspace{1cm} \text{for} \; \text{ii} = 1:\text{rr}
\]
\[
\hspace{2cm} \text{for} \; \text{jj} = 1:\text{cc}
\]
\[
\hspace{3cm} \text{Total\_Revenue} = \text{Total\_Revenue} + \text{domestic\_revenue}(\text{ii},\text{jj});
\]
\[
\hspace{3cm} \text{Total\_Costofproduction} = \text{Total\_Costofproduction} + 
\]
\[
\hspace{3cm} \text{total\_production\_cost}(\text{ii},\text{jj});
\]
\[
\hspace{2cm} \text{end}
\]
\[
\hspace{1cm} \text{end}
\]
\[
\text{Net\_Revenue} = (\text{fval} - \text{Total\_Revenue} + \text{Total\_Costofproduction}) \times -1
\]
\[
\text{xsolution} = \text{x}(1:\text{nperiods} \times \text{main\_variables});
\]
\[
\text{xsolution1} = \text{reshape}(\text{xsolution}, [\text{main\_variables}, \text{nperiods}]);
\]
Appendix B2. Results of Model A0, A1, and A2
This appendix shows the results of the earlier GANESA model with assumptions as follows:

Summary of Unit Cost used in the model (unit in USD/mmbtu)
- Wellhead price 5.80
- Domestic gas price for each country 9.0
- Pipeline transmission cost 0.50 (seller will bear the cost)
- LNG liquefaction operational cost 0.20
- LNG shipping cost 3.50 (in case of Japan cif price, sellers will bear the shipping cost)
- LNG regasification operational cost 0.80
- dummy variables cost (k USD higher than cost for the existing infrastructures)

Note: for all costs and prices, the unit of USD/mmbtu will be converted to USD/bcm as the model will use bcm as the volume unit.

Other assumptions
- Price of LNG and gas pipeline are identical (exogenous; from extrapolation)
- LNG shipping cost and pipeline transmission cost are borne by sellers
- Supply is constant until proved reserves depleted
- Domestic demand growth is 2% per annum
- Since most of historical data end in 2013, the forecast will count year 2014 and 2015 until 2045 (32 years)
- After 2025, there will be no more responsibility to fulfil the minimum export of LNG and gas pipeline

Results of Model A0
In general, since the operational cost of gas pipeline estimated in this model is less than LNG for both buyers and sellers, the countries in Southeast Asia tend to prefer natural gas pipeline option than LNG. When the gas pipelines cannot cover all demand required (or there is excess supply), then the countries start to import LNG (or export LNG). Otherwise, the LNG trades are only based on the existing long-term contracts.

Cross-border pipelines

Figure B1. Model A0: Cross-border pipelines
Figure above shows the volume of natural gas transported through each cross-border pipeline in Southeast Asia region. The blue bars show amount of natural gas transported via the existing pipelines and the orange bars show amount of natural gas transported via dummy pipelines. For cross-border pipeline connecting Indonesia and Malaysia, the volume transported in the first 12 years is at its minimum capacity based on the long-term contract. After 2025, there will be no gas pipeline transported. This is due to the assumption in the model that all long-term contracts except for gas pipeline from Myanmar to China will end at 2025. However, started in 2030, Malaysia needs to import gas due to the depletion of its gas reserves. The amount of gas transported from Indonesia to Malaysia is decreasing from 2030 to 2045 due to assumption that the production volume is constant while domestic demand keeps growing 2% per annum. Adding gas pipeline capacity in period 2030 onwards could not happen unless Indonesia could increase its production volume and secure the availability of gas proved reserves nearby the cross-border pipeline location.

Similar condition also happens at cross-border pipeline connecting Indonesia and Singapore. However, volume of natural gas transported at this route is higher than the previous route, i.e. Indonesia-Malaysia. In reality, the gas selling price for cross-border pipeline Indonesia-Singapore is also higher than Indonesia-Malaysia. Thus, supplying gas pipeline to Singapore could be more prioritized compared to Malaysia. Figure B1 also shows a need for additional capacity at this route especially during 2030 onwards, mainly because decreasing amount of gas pipeline supply from Malaysia to Singapore. Adding additional capacity for Malaysia-Singapore gas pipeline also could not happen unless Malaysia find new gas proved reserves. Therefore, for these two countries, i.e. Malaysia and Singapore, importing LNG would be the main alternative to replace the natural gas pipeline supply.

Both natural gas pipeline from Myanmar to Thailand and Myanmar to China operate at their minimum capacity. This is due to the limited production volume of Myanmar and the amount of proved reserves available. Based on the current level of production, gas reserves in Myanmar will be depleted in 2035. For the gas pipeline contract to China lasts until 30 years, and roughly assumed to be ended in 2045, Myanmar will need to import gas to fulfil its domestic demand and long-term contract requirement. This could be prevented if Myanmar could find new gas reserves or manage its production level by reducing or stopping the gas pipeline to Thailand directly after the existing contracts end.

LNG trades

![LNG Liquefaction Capacities in Indonesia](image1)

![LNG Regasification Capacities in Indonesia](image2)

*Figure B2. Model A0: LNG liquefaction and regasification capacities in Indonesia*
The figure shows there is no need for additional capacity for both liquefaction and regasification capacities in Indonesia. Indonesia also stops LNG export activities after 2029 and use the production for its own domestic demand and small amount of gas pipeline to Singapore and Malaysia. The regasification capacities for import (at year 2024 and 2025) are not needed actually because the domestic demand in Indonesia is still less than its production level. This might due to minimum capacity of existing long-term contract with Malaysia and Singapore. The needs for regasification capacities in 2044 and 2045 are caused by the growth of domestic demand which at those time are above the production level. In reality, both liquefaction and regasification capacities in Indonesia are used more than the amount presented in the figure. It is common in Indonesia to transport the natural gas in LNG form from one island to other islands due to geographical conditions of Indonesia that are widely spread and separated by the sea.

In Malaysia, the liquefaction activities stop after 2030 because of its depleted gas reserves, and consequently the need for regasification capacities is increasing since 2030 onwards. In reality, as in the Indonesian case, the amount of liquefied and regasified natural gas are also more than the presented amount in the figure because Malaysia also uses them to transport natural gas from its eastern area to western area which is also separated by the sea.

Brunei will need to stop its liquefaction activities in 2038 due to depleted gas reserves and start importing unless they reduce the production level and keep it minimum (only to fulfil the requirement of the long-term contract) to sustain it longer for domestic needs.

Thailand is known as a net gas importer so it does not have any liquefaction facilities. Additional capacities for its regasification terminal are needed since early period and keep rising. After 2020, the rise goes faster because of decreasing supply from Myanmar gas pipeline.

Currently, Myanmar also does not have any liquefaction capacities. Myanmar will need to import LNG in period 2018 to 2025, mainly to fulfil the minimum long-term contract requirement for natural gas pipeline. However, this is unlikely to happen since Myanmar could still increase its production level before it depletes in 2036. The rest of additional capacities needed are used to fulfil domestic demand. Since the existing gas pipeline contract to China lasts for 30 year (until 2044 or 2045), Myanmar might...
need to start importing earlier because the domestic production will be secured to fulfil the contract or the growth of domestic consumption will be less than the assumption used in this model.

Currently, the amount of natural gas produced in Vietnam is used fully for its domestic consumption. Unlike other production countries in Southeast Asia (except Indonesia), Vietnam still has proved reserves available until 2045 onwards. The main problem is with its production level. Importing LNG might not be needed if Vietnam could increase its production level based on its domestic consumption. However, due to the reason of security of gas supply, Vietnam might still need to build an LNG regasification terminal as a countermeasure when the production disrupted.

![LNG regasification capacities in Thailand, Myanmar, Vietnam, and Singapore](image)

Figure B4. Model A0: LNG regasification capacities in Thailand, Myanmar, Vietnam, and Singapore

Singapore will use its regasification capacities when the long-term contracts of natural gas pipeline with Indonesia and Malaysia end or the current supply from Indonesia and Malaysia could not meet the Singaporean domestic demand. Due to several interruption of gas supply in the past (Barker & Turner, 2013), Singapore will activate its regasification terminal earlier as what has been done currently. This is also due to its ambition to become a gas hub in Southeast Asia and possible development of a more liberalized gas market in the future (Collins, 2013). Based on the result of the optimization model, Singapore still needs to increase its regasification capacities if the domestic demand keeps growing for 2% per annum and both Malaysia and Indonesia reduce or stop the supply of natural gas pipelines.

Results of Model A1

The main difference of this model with the previous model is the assumption of production level and growth of domestic gas consumption. The assumptions in this model are based on IEA scenario (IEA & ERIA, 2013) which has considered GDP growth and demographic condition in the Southeast Asian countries. It is assumed that the domestic consumption until 2035 for Indonesia, Malaysia, and Thailand respectively are 3.0%, 1.50%, and 2.10% per annum. From 2036 to 2045, the growth for all Southeast Asian countries will be assumed to be 1%. For other countries such as Brunei, Myanmar, Vietnam, and Singapore that have not been mentioned in the report, the growth will be assumed to be 1.0%. For the production level, the annual growth in Indonesia, Malaysia, Brunei, Thailand, Myanmar, and Vietnam are assumed to be 2.30%, 0.60%, 0.50%, -5.50%, 2.60%, and 1.30% respectively until 2035. Afterwards, it is assumed to be constant (no growth) until the gas reserves depleted. The amount of proved reserves in each country will also be based on the IEA scenario.
Production and Consumption

Figure B5 shows the production and domestic consumption in six Southeast Asian countries. The inflection points in the figure indicate the moment of depleted gas reserves in the particular country. The amount of proved reserves for Indonesia, Malaysia, and Brunei are more than the assumption in the previous model, thus, the depletion happens much later compared to the previous model.

Cross-border pipelines

In this model, there is no need for additional capacity at cross-border pipeline connecting Indonesia and Malaysia. The supply ends when the long-term contract expired in 2025. On the other hand, additional capacity for cross-border pipeline Indonesia-Singapore and Malaysia-Singapore are needed as long as the price can compete (not higher) than the LNG price. Supply from Myanmar natural gas pipeline to Thailand will end at latest in 2030, while supply to China will end until the contract expired. However, in this model, the gas reserves in Myanmar will also deplete before 2045, and thus, it is hard to fulfil both domestic demand and the long-term contracts without import.

Figure B5. Model A1: Production and domestic consumption volume
Both Indonesia and Malaysia have ability to export gas until 2044, right before the reserves depleted in 2045. However, this is unlikely to happen because the countries will tend to reduce their production and export volumes to secure the availability of gas supply for domestic consumption in a longer period of time. The gas reserves in Brunei will also be depleted around the time as in Indonesia and Malaysia. There is no much difference regarding the result of regasification capacities use in Thailand’s case. The gas reserves have already started to deplete and in the beginning of 2015, Thailand will have to add their regasification capacities. Unlike Singapore who has gas pipeline supply from Malaysia and Indonesia, Thailand only has gas pipeline supply from Myanmar, and practically, Myanmar gas reserves will deplete faster than Malaysia’s and Indonesia’s.

For the Singapore’s case in this model, it will need to import LNG directly when the gas reserves in Indonesia and Malaysia depleted. However, this only could happen if the prices of natural gas pipeline from Indonesia and Malaysia are less than total cost of LNG imported by Singapore. Otherwise, Singapore will rely more on LNG import and reduce the minimum amount of gas pipeline transported. Extremely, Singapore could terminate the supply from Indonesia or Malaysia gas pipeline if the price disparities are too far. Currently, Singapore pays 17 USD/mmbtu for gas pipeline from Indonesia and analysts estimate that Singapore could get LNG supply in a much lower cost (IEA, 2014).
The growth of consumption in Vietnam is expected to be faster than the production growth in the earlier periods of the model. However, after 2020, the production is expected to surpass the domestic consumption, and thus, there is a possibility for Vietnam to export the excess of its natural gas production. For after 2035, the production is assumed to be constant, and domestic consumption keeps rising by 1%, the excess capacity to be exported also become less and less. Thus, if Vietnam really wants to export its natural gas, it has to increase its production level, at least at the same speed with its domestic consumption growth.

Results of Model A2
Data for proved reserves, production volume and domestic growth consumption in this model will still follow the data from IEA scenario (IEA & ERIA, 2013). After 2035, it is assumed that the annual production growth is -2.0%. Based on desk research, Myanmar had discovered new gas fields and thus increased its proved reserves. There will be additional amount of proved reserves of 56 bcm from Zawtika M9 and 127 – 218 bcm (assumed to be 172.5 bcm) from Shwe gas fields. Gas from Zawtika M9 has been transported to Thailand since 2013 with a long-term contract duration of 20 years (until 2033) while gas from Shwe gas fields will be transported to China through pipeline with a long-term contract duration of 30 years (until 2044). Gas pipeline from Indonesia to Malaysia, Indonesia to Singapore, and Malaysia to Singapore are assumed to be ended in 2023 while other long-term LNG contracts are roughly assumed to be ended in 2025.
Production and Consumption

As is shown in Figure B10, after 2035, the production level in the producing countries decrease by 2.0%. With this scheme, producing countries such as Indonesia and Malaysia do not need to import gas until 2045. Brunei will need to decrease its production level earlier (before 2035) otherwise it will need to import gas in 2045. Thailand will be the fastest country that reaches depletion and be a net gas importer without any proved reserves as Singapore after 2020. Myanmar, with its new finding of gas fields will be able to stay longer than in the previous model. Vietnam on the other hand, does not need to reduce the production level as the proved reserves in 2045 remains 315 bcm. With its current capacity, the reserves could still be used until the next two decades after the last period counted in the model.

![Figure B10. Model A2: Production and domestic consumption volume](image)

Cross-border pipelines

Figure B11 shows the pipeline transactions. The red dashed borders show the transactions that are unlikely to happen due to termination of the contracts. In cases of gas pipelines from Indonesia to Singapore and Malaysia to Singapore, the amount of gas transported will not be as much as presented in the figure due to less competitive price of the gas pipeline in the contracts compared to LNG price. Gas pipeline from Myanmar to Thailand also will reduce significantly due to the depletion of Yadana and Yetagun gas fields. However, a significant amount of gas pipeline will be transported from Shwe gas field in Myanmar to China. Figure B12 shows the adjusted transaction of the cross-border pipelines. Small amount of gas pipeline (1 to 3 bcm) from Indonesia or Malaysia to Singapore could still exist as a practice of supply diversification or security of supply. However, this depends on the
Singaporean authority. If the Singaporean authority decides not to import gas pipeline anymore then Malaysia and Indonesia will need to sell this volume to the LNG market and Singapore will need to allocate more capacity to its LNG terminal.

Figure B11. Model A2: Pipeline transactions

Figure B12. Model A2: Adjusted pipeline transactions

**LNG trades (adjusted volume)**

Figure B13 shows the adjusted volume of LNG transaction as a result of adjusted volume in pipeline transactions. The red lines in figure B13 show the volume of LNG exported before gaining additional volumes from the gas pipeline trades, while the green lines show the volume of LNG import at the same condition. In period 2026 to 2041, Thailand will have to add more capacity compared to previous model assumption. However, still, with its current growth of domestic consumption and minus growth of its production level, Thailand will have to rely on LNG import and add more capacity to its LNG regasification terminal. There is a significant increase in the use of LNG regasification terminal in
Singapore compared to the results of previous models. The LNG import rises significantly after 2023, the period when the long-term gas pipeline contracts are expired. The results show that with the growth of 1.0% annually for domestic consumption, the existing capacity of LNG regasification terminal in Singapore (11.8 bcm/y) is still able to manage the amount of imported LNG, given that some amount of gas pipeline from Indonesia and Malaysia are still transported to Singapore, otherwise Singapore will have to increase its regasification terminal capacity and build gas storages as a means to secure its gas supply.

Figure B13. Model A2: LNG liquefaction capacities in Indonesia and Malaysia and LNG regasification capacities in Thailand and Singapore

Figure B14 shows the capacities used in LNG liquefaction and regasification infrastructures in Brunei, Myanmar, and Vietnam. The figure shows that Brunei will need to start importing gas in 2045. This could be prevented if Brunei could reduce its liquefaction volume in earlier years. Myanmar will face a problem of deficit supply in earlier period (until 2020) due to the existing long-term contracts of gas pipeline to Thailand and China and increasing domestic consumption. However, Myanmar will be unlikely to build a LNG regasification terminal. As a result, domestic consumption will be sacrificed. After 2030, Myanmar could have some gas surplus until 2040. However, the surplus availability fluctuates and only exist less than 10 years. It will be less appealing to invest in LNG liquefaction. This surplus could be used to supply the deficit in the future by reducing the production level during that period so that Myanmar does not need to import gas after 2040.

In Vietnam’s case, at earlier period, Vietnam needs to import gas as its production volume could not catch up its domestic consumption growth. The volume imported keeps decreasing as the production volume increases. Afterwards, the production volume keeps increasing, bringing a change to export its excess production.
Figure B14. Model A2: LNG liquefaction and regasification capacities in Brunei, Myanmar, and Vietnam
Appendix C: Project Calculation

Appendix C1. Pipeline Capacity

Using formula 7.1 of pipeline sizing equation (ICC, 2009)

\[ Q = 2,237 \, D^{2.623} \left( \frac{P_1^2 - P_2^2}{C_r \cdot L} \right)^{0.541} \]

Where:
- Q = rate, cubic feet per hour (cfh; could be converted to mmcf/d)
- D = inside diameter of pipe (inch)
- P\(_1\) = upstream pressure (psia)
- P\(_2\) = downstream pressure (psia)
- Y = super expansibility factor = 1/super compressibility factor
- C\(_r\) = factor for viscosity, density and temperature, in which equal to:
  \[ C_r = 0.00354 \cdot S \cdot T \left( \frac{Z}{S} \right)^{0.152} \]
- S = specific gravity of gas at 60°F and 30-inch mercury column; equal to 0.6
- T = absolute temperature; t (°F) + 460
- Z = viscosity of gas, equal to 0.012
- L = length of pipe (feet)

### 36-inch design with 3 compressor stations as in case D

<table>
<thead>
<tr>
<th>unit</th>
<th>Q</th>
<th>D-in</th>
<th>P1</th>
<th>P2</th>
<th>Y</th>
<th>Cr</th>
<th>S</th>
<th>T</th>
<th>Z</th>
<th>L</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>48476975.19 cfh</td>
<td>35 inch</td>
<td>2835 psia</td>
<td>1015 psia</td>
<td>1.666666667</td>
<td>0.00354</td>
<td>0.6</td>
<td>600</td>
<td>0.012</td>
<td>4921260 feet</td>
</tr>
<tr>
<td></td>
<td>1163447 mmcf/d</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Changing the length from 1,500 km to 1,400 km results in a daily capacity of 1,207 MMCFD.

### 42-inch design with 3 compressor stations as in case B

<table>
<thead>
<tr>
<th>unit</th>
<th>Q</th>
<th>D-in</th>
<th>P1</th>
<th>P2</th>
<th>Y</th>
<th>Cr</th>
<th>S</th>
<th>T</th>
<th>Z</th>
<th>L</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>41321540.62 cfh</td>
<td>41 inch</td>
<td>1858 psia</td>
<td>1015 psia</td>
<td>1.666666667</td>
<td>0.00354</td>
<td>0.6</td>
<td>600</td>
<td>0.012</td>
<td>4921260 feet</td>
</tr>
<tr>
<td></td>
<td>991717 mmcf/d</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Changing the length from 1,500 km to 1,400 km results in a daily capacity of 1,029 MMCFD.
42-inch design with 3 compressor stations as in case D

<table>
<thead>
<tr>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q</td>
<td>73413696,02 cfh</td>
</tr>
<tr>
<td>D-in</td>
<td>41 inch</td>
</tr>
<tr>
<td>P1</td>
<td>2835 psia</td>
</tr>
<tr>
<td>P2</td>
<td>1015 psia</td>
</tr>
<tr>
<td>Y</td>
<td>1,66666666</td>
</tr>
<tr>
<td>Cr</td>
<td>0,703173219</td>
</tr>
<tr>
<td>S</td>
<td>0,6</td>
</tr>
<tr>
<td>T</td>
<td>600</td>
</tr>
<tr>
<td>Z</td>
<td>0,012</td>
</tr>
<tr>
<td>L</td>
<td>4921260 feet</td>
</tr>
</tbody>
</table>

Changing the length from 1,500 km to 1,400 km results in a daily capacity of 1,829 MMCFD. Increasing the pressure (P1) to 3,835 psia results in a daily capacity of 2,626 MMCFD.

Appendix C2. CAPEX of East Natuna Gas Project

Table 3.3 Pipeline costing rules of thumb (ECCO, 2011)

<table>
<thead>
<tr>
<th>Direct Cost</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering</td>
<td>0.4 million$ + 6$/$m</td>
</tr>
<tr>
<td>Line pipe</td>
<td>1.3$/kg</td>
</tr>
<tr>
<td>Corrosion coating</td>
<td>9 $/D $/m</td>
</tr>
<tr>
<td>Weight coating</td>
<td>7 $/D $/m</td>
</tr>
<tr>
<td>Other material cost</td>
<td>1.2 $/D $/m</td>
</tr>
<tr>
<td>Tie-in or riser (each)</td>
<td>0.26 $/D million$</td>
</tr>
<tr>
<td>Installation cost</td>
<td>0.6 $/D million$ + 60 $/D $/m</td>
</tr>
<tr>
<td>Trenching and dumping cost</td>
<td>0.4 $/D million$ + 16 $/D $/m</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>Factor 1.1 to 1.3</td>
</tr>
<tr>
<td>Shore approach/ landfall</td>
<td>2 – 10 million$ (depend on the case)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Indirect cost</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Management &amp; supervision</td>
<td>5% of direct cost</td>
</tr>
<tr>
<td>Insurance</td>
<td>2% of direct and indirect cost</td>
</tr>
</tbody>
</table>

Note: D = diameter (inch); w = weight (kg)

*Weight (kg) per meter of steel pipe formula is retrieved from (Benqiu)

\( (\text{Outside Diameter mm} - \text{Wall Thickness mm}) \times \text{Wall Thickness mm} \times 0.02466 \)
### 36-inch design with 3 compressor stations as in case D

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length</td>
<td>1500 km</td>
</tr>
<tr>
<td>Given Diameter (outside)</td>
<td>36 inch</td>
</tr>
<tr>
<td>Wall Thickness</td>
<td>25 mm</td>
</tr>
<tr>
<td>Weight</td>
<td>548,3151 kg/m</td>
</tr>
</tbody>
</table>

#### Direct Cost

<table>
<thead>
<tr>
<th>Category</th>
<th>Cost (USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering</td>
<td>9,400,000,00</td>
</tr>
<tr>
<td>Line pipe</td>
<td>10,692,145,445,00</td>
</tr>
<tr>
<td>Corrosion coating</td>
<td>81,000,000,00</td>
</tr>
<tr>
<td>Weight coating</td>
<td>63,000,000,00</td>
</tr>
<tr>
<td>Other material cost</td>
<td>10,800,000,00</td>
</tr>
<tr>
<td>Tie-in or riser cost (each)</td>
<td>1,560,000,00</td>
</tr>
<tr>
<td>Installation cost</td>
<td>543,600,000,00</td>
</tr>
<tr>
<td>Trenching and dumping cost</td>
<td>146,400,000,00</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>2,309,969,334,00</td>
</tr>
<tr>
<td>Shore approach/landfall</td>
<td>5,000,000,00</td>
</tr>
</tbody>
</table>

**Total Direct Cost:**

4,239,943,779,00

#### Indirect Cost

<table>
<thead>
<tr>
<th>Category</th>
<th>Cost (USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>management &amp; supervision</td>
<td>211,997,188,95</td>
</tr>
<tr>
<td>insurance</td>
<td>89,038,819,36</td>
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</tbody>
</table>

**Total Indirect Cost:**

4,540,979,787,31

3 compressor stations for 36-inch pipe in case D: 915,000,000,00

**Total CAPEX:**

5,455,979,787,31
### 42-inch design with 3 compressor stations as in case B

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length</td>
<td>1500 km</td>
</tr>
<tr>
<td>Given Diameter (outside)</td>
<td>42 inch</td>
</tr>
<tr>
<td>Wall Thickness</td>
<td>25 mm</td>
</tr>
<tr>
<td>Weight</td>
<td>642,2697 kg/m</td>
</tr>
</tbody>
</table>

### # Direct Cost

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering</td>
<td>9.400.000,00</td>
</tr>
<tr>
<td>Line pipe</td>
<td>1.252.425.915,00</td>
</tr>
<tr>
<td>Corrosion coating</td>
<td>87.489.999,43</td>
</tr>
<tr>
<td>Weight coating</td>
<td>68.047.777,33</td>
</tr>
<tr>
<td>Other material cost</td>
<td>11.665.333,26</td>
</tr>
<tr>
<td>Tie-in or riser cost (each)</td>
<td>1.684.992,58</td>
</tr>
<tr>
<td>Installation cost</td>
<td>587.155.107,28</td>
</tr>
<tr>
<td>Trenching and dumping cost</td>
<td>158.130.073,04</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>2.611.199.037,50</td>
</tr>
<tr>
<td>Shore approach/landfall</td>
<td>5.000.000,00</td>
</tr>
</tbody>
</table>

### # Indirect Cost

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>management &amp; supervision</td>
<td>239.609.911,77</td>
</tr>
<tr>
<td>insurance</td>
<td>100.636.162,94</td>
</tr>
</tbody>
</table>

**Total** 5.132.444.310,13

3 compressor stations for 42-inch pipe in case B 804.000.000,00

**Total CAPEX** 5.936.444.310,13
42-inch design with 3 compressor stations as in case D
Equal to USD 5.132 billion + USD 0.915 billion (as the cost of compressor in case D) = USD 6.05 billion.

Changing the length from 1,500 km to 1,400 km (East Natuna – Java pipeline) and increasing compressor’s pressure results in a CAPEX of USD 6.67 billion.

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Length</td>
<td>1400 km</td>
</tr>
<tr>
<td>Given Diameter (outside)</td>
<td>42 inch</td>
</tr>
<tr>
<td>Wall Thickness</td>
<td>33 mm</td>
</tr>
<tr>
<td>Weight</td>
<td>841,285764 kg/m</td>
</tr>
</tbody>
</table>

|                               |                  |
| Direct Cost                   |                  |
| Engineering                   | 8,800,000,00     |
| Line pipe                     | 1,531,140,090,48 |
| Corrosion coating             | 81,657,332,80    |
| Weight coating                | 63,511,258,84    |
| Other material cost           | 10,887,644,37    |
| Tie-in or riser cost (each)   | 1,684,992,58     |
| Installation cost             | 548,270,663,09   |
| Trenching and dumping cost    | 147,760,887,92   |
| Miscellaneous                 | 2,872,455,444,11 |
| Shore approach/landfall        | 5,000,000,00     |

Total Direct Cost: 5,271,168,314,19

| Indirect Cost                 |                  |
| management & supervision      | 263,558,415,71   |
| insurance                     | 110,694,534,60   |

Total Indirect Cost: 5,645,421,264,50

3 compressor stations for 36-inch pipe in case D ++ 1,025,000,000,00

Total CAPEX: 6,670,421,264,50


Appendix D: Script Options Valuation Models

Appendix D1. MATLAB Script of Adjusted DCF Calculation for Abadi onshore LNG

```matlab
%% Initial Input
load BAU_Abadi_production.mat ;
load BAU_Abadi_domestic.mat ;
load BAU_Tangguh_cif_price.mat ; % reference price, still could be used

sold_to_export = production - sold_to_domestic ;
bcm_cif_gas_price = cif_gas_price ./ (2.72*10^-8) ;

initial_DMO_price = 9/(2.72*10^-8) ;
initial_shipping_cost = 2.5/(2.72*10^-8) ;
initial_OPEX = 0.20/(2.72*10^-8) ;
initial_CAPEX = 10.5*(10^9) ; %at period 4
initial_wellhead = 8/(2.72*10^-8) ;

% Parameters
inflation = 0;
discount_rate = 0.10 ;
gov_rate = 0.7 ;
con_rate = 0.3 ;
tax_rate = 0.44 ;
FTP_rate = 0.2 ;

% Set up
nperiods = 30;
allzero = zeros(1,nperiods);

%% Process Variables
domestic_gas_price = allzero ;
shipping_cost = allzero ;
OPEX = allzero ;
wellhead = allzero ;

for ii = 1:nperiods
    domestic_gas_price(ii) = initial_DMO_price * (1 + inflation)^ii ;
    shipping_cost(ii) = initial_shipping_cost * (1 + inflation)^ii ;
    OPEX(ii) = initial_OPEX * (1 + inflation)^ii ;
    wellhead(ii) = initial_wellhead * (1 + 0)^ii ; % no effect of inflation
end

domestic_revenue = sold_to_domestic .* domestic_gas_price ;
export_revenue = sold_to_export .* bcm_cif_gas_price ;
total_shipping_cost = sold_to_export .* shipping_cost ;
total_OPEX = production .* OPEX ;
total_wellhead = production .* wellhead ;

%% Cash-flow Structure
gross_revenue_1 = domestic_revenue + export_revenue - total_OPEX -
total_shipping_cost - total_wellhead ;
FTP_gov = gov_rate * (FTP_rate .* gross_revenue_1) ;
FTP_con = con_rate * (FTP_rate .* gross_revenue_1) ;
gross_revenue_2 = gross_revenue_1 - FTP_gov - FTP_con ;

CAPEX_balance = allzero ;
CAPEX_balance(1,4) = initial_CAPEX ;
```
cost_recovery_payment = allzero;
for ii = 5:nperiods
    if CAPEX_balance(1,ii-1) == 0
        cost_recovery_payment(1,ii) = 0;
        CAPEX_balance(1,ii) = 0;
    elseif CAPEX_balance(1,ii-1) > 0 && gross_revenue_2(1,ii) <= CAPEX_balance(1,ii-1)
        cost_recovery_payment(1,ii) = gross_revenue_2(1,ii);
        CAPEX_balance(1,ii) = CAPEX_balance(1,ii-1) - cost_recovery_payment(1,ii);
    else cost_recovery_payment(1,ii) = CAPEX_balance(1,ii-1);
        CAPEX_balance(1,ii) = CAPEX_balance(1,ii-1) - cost_recovery_payment(1,ii);
    end
end
gross_revenue_3 = gross_revenue_2 - cost_recovery_payment;
profit_gov = gov_rate .* gross_revenue_3;
tax = tax_rate * con_rate .* gross_revenue_3;
profit_con = (1 - tax_rate) * con_rate .* gross_revenue_3;

net_revenue_gov = FTP_gov + tax + profit_gov;
net_revenue_con = FTP_con + profit_con;

%% NPV calculation
PV_revenue_gov = allzero;
for ii = 1:nperiods
    PV_revenue_gov(1,ii) = net_revenue_gov(1,ii) / (1 + discount_rate)^ii;
end

PV_revenue_con = allzero;
for ii = 1:nperiods
    PV_revenue_con(1,ii) = net_revenue_con(1,ii) / (1 + discount_rate)^ii;
end

NPV_gov = sum(PV_revenue_gov)
NPV_con = sum(PV_revenue_con)
Appendix D2. MATLAB Script of ROA of Abadi onshore LNG – Option to Choose

%% Option to choose
% Main Input
stock_price = 8876129154 ;
volatility = 0.0613 ; % sensitivity: 10%, 20%
risk_rate = 0.08 ; % 5% or 10%
option_life = 20 ; % in operation from 2026 to 2045
delta_time = 1 ;
expansion_factor = 2 ; % double capacity
costExpansion = 2*8.5*10^9 ;
salvage_value = 0.10*10.5*10^9 ;

%% variables in formula
u = exp(volatility * (delta_time^0.5)) ;
d = 1/u ;
leakage_rate = 0.05;
p = ((exp((risk_rate - leakage_rate) * delta_time)) - d) / ( u - d ) ;

%% upper values
rr = (option_life / delta_time) + 1 ;
cc = rr ;
upper_values = zeros(rr,cc) ;
nn = 0;
for ii = 1:rr
    for mm = 1:cc
        upper_values(ii,mm) = stock_price * u^(mm-ii) * d^nn ;
    end
    nn = nn + 1;
end

%% Possible lower values
allones = ones(rr,cc);
allzeros = zeros(rr,cc);
expand_values = allzeros;
for ii = 1:rr
    for mm = 1:cc
        expand_values(ii,mm) = expansion_factor * upper_values(ii,mm) - costExpansion ;
    end
end
abandon_values = salvage_value * allones;

%% change the unused cells to 0
for ii = 2:rr
    for mm = 1:(ii-1)
        upper_values(ii,mm) = 0 ;
        expand_values(ii,mm) = 0;
        abandon_values(ii,mm) = 0;
    end
end

%% Selected option values
option_values = allzeros;
% backward induction
for ii = 1:rr
    if expand_values(ii,cc) > abandon_values(ii,cc) && ...
        upper_values (ii,cc) > costExpansion && expand_values(ii,cc) >
        upper_values(ii,cc)
        option_values(ii,cc) = expand_values(ii,cc) ;
    elseif abandon_values(ii,cc) > expand_values(ii,cc) &&
        abandon_values(ii,cc) > upper_values(ii,cc)
end
option_values(ii,cc) = abandon_values(ii,cc) ;
else option_values(ii,cc) = 0 ;
end

%%
keep_option = allzeros ;

mm = cc-1;
for aa = 1: cc-1 % backward induction column
    for ii = 1:mm
        keep_option(ii,mm) = (p * option_values(ii,mm+1) + (1-p) * option_values(ii+1,mm+1)) * exp(-(risk_rate)*delta_time);
        if keep_option(ii,mm) > expand_values(ii,mm) && keep_option(ii,mm) > abandon_values(ii,mm)
            option_values(ii,mm) = keep_option(ii,mm);
        elseif expand_values(ii,mm) > keep_option(ii,mm) && expand_values(ii,mm) > abandon_values(ii,mm)
            option_values(ii,mm) = expand_values(ii,mm);
        else option_values(ii,mm) = abandon_values(ii,mm);
        end
    end
    mm = (cc-1) - aa ;
end

%% Find NPV
discount_rate = 0.10 ;
option_values(1,1)
NPV_ROA = option_values(1,1)/((1+discount_rate)^10)