

An Economic Evaluation of Onshore and Floating Liquefied Natural Gas Receiving Terminals: the Case Study of Indonesia

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Abstract. Indonesia has abundant natural gas resources, however the primary fuel used for electricity generation is coal and oil. Insufficient natural gas infrastructure within the country acts as a barrier to increased natural gas usage. In Indonesia LNG is the most efficient and effective method for distributing natural gas given the difficult geographical conditions, the world's largest archipelago and located in a deep sea area. The Government is planning to initiate natural gas imports by 2019 to meet the country's energy demands. In order to allocate adequate amounts of natural gas across the geographic regions Indonesia must build more LNG regasification terminals. The Indonesia government has not yet determined if the additional regasification terminals will be floating or land-based facilities. This paper assesses the two options and identifies which facility attains greater profitability. The financial analysis of investing in the Sorong LNG regasification terminal project is conducted using NPV, IRR, and sensitivity analysis. This analysis demonstrates that FSRU facilities have greater economic viability than onshore LNG regasification facilities. The FSRU project earns greater than a 12% IRR as compared to a negative IRR earned by an onshore project. The government can make the onshore projects viable by increasing the sales fee from US\$10.00/MMBTU to US\$10.60/MMBTU.

1. Introduction

1.1. Background

Indonesia is well-known as an international exporter of natural gas (NG) since the 1970s.[1] In order to export NG to international markets which may be located several thousands of miles away the most efficient transportation is by liquefied natural gas (LNG) tanker ships. LNG infrastructure is required to convert the gas phase to a liquid phase at a liquefaction gas terminal, a liquefaction terminal is the same as a shipping terminal.[2] In 2016 Indonesia had four liquefaction terminals; Arun, Bontang, Tangguh, and Donggi Senoro. At least ten countries located in Asia, the Americas, and Africa became LNG importers of Indonesian NG in 2015. Indonesia has not been a net oil exporter since 2003, but is still a significant exporter of NG. Globally Indonesia is ranked tenth for NG exports and fifth for LNG exports specifically.

Indonesia has abundant NG resources and reserves, but the principle energy source used for electricity generation in Indonesia consists principally of coal and oil. In 2016, 31 % and 46 % of the power plants in Indonesia are supported by coal and oil, respectively. [3] Approximately 18 % of power



plants in Indonesia use NG as fuel. Indonesia exhibits a preference for oil as a fuel for power generation, which is imported from abroad, as compared to NG which is abundant in Indonesia. This situation has developed as the result of an inadequate number of LNG receiving terminals. [4] A LNG receiving terminal is the same as a LNG regasification terminal. To fulfill the nation's demand for NG, the government is planning to import natural gas for the first time by 2019. [5] In order to allocate an adequate supply of NG to all regions and areas, Indonesia must build more LNG regasification terminals. Indonesia has had relatively flat production during the past 5 years. With an increasing amount of NG retained for domestic consumption. Figure 1 below shows a decline in domestic LNG production of 13.2% (2,900,000 tonnes) between 2011 and 2015.

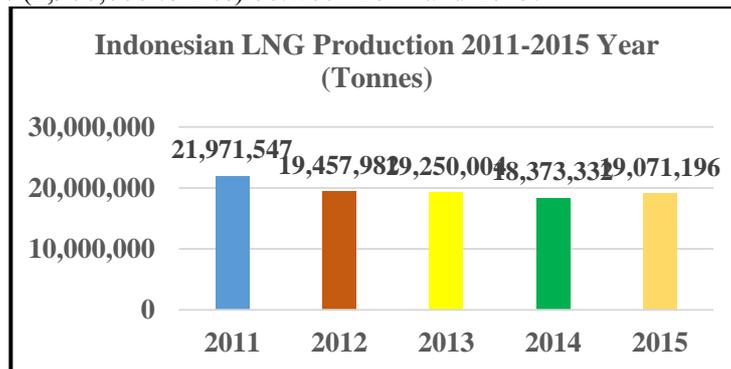


Figure 1. Indonesia LNG Production 2011-2015 [1]

LNG is the superior resource option for Indonesia because of complicated geographical conditions, which consist of several thousand islands, with some separated by a deep sea [5]. As can be seen in Figure 2 below the Indonesian archipelago is located between two oceans, the Pacific and Indian Oceans. The eastern region mainly consists of small islands relatively evenly distributed. [6] with seabed's ranging from 1,000 to 7,000 meters in depth. This configuration of small islands separated by a deep-sea has created a significant challenge to Indonesian government for developing infrastructures in the area. NG pipelines cannot be used in this depth of water for such long distances. It is not technologically appropriate economically efficient to deliver NG to the eastern region of Indonesia. [7] As a result, the Indonesian Government has decided to use a virtual pipeline, which is LNG shipping, to transport NG from areas with excess NG to areas experiencing a shortage of NG.



Figure 2. Map of Indonesia [6]

A total required investment of US\$1,484 million [5] has been estimated to develop all the requested LNG infrastructure to support this virtual pipeline. The financial analysis conducted by [5] is based on the total cost and total revenue estimates from all associated projects, and is not based on site specific facilities. The Indonesian government has not yet decided whether the LNG receiving terminals will be built in the form of floating or land-based facilities. The motivation for this research paper is develop a better understanding of the financial impact of each type of facility.

1.2. Indonesian Gas Allocation and Monetisation

In 2016, the Minister of Energy and Mineral Resources (MEMR) issued the Minister Regulation No. 6/2016 [8] regarding the allocation, monetisation, and market price of NG. In this regulation, the government arranges the priority and order of NG allocation. Exporting of NG is now the lowest ranking allocation after all domestic demand is fulfilled.

In order to supply any power plant with NG, the Indonesian State Electric Company (PLN), must propose an allocation of NG to the MEMR through SKK Migas. SKK Migas is an institution established by the Indonesian Government to manage the country's upstream oil and gas activities. According to MEMR the proposal consists of the expected gas price and the method of transporting the natural gas. The final gas price is than agreed between PLN and the NG contractor, through a legal contract. PLN has the option of selecting NG supplier to transport and process the NG or LNG. The MEMR will evaluate the PLN proposal and determine its decision with assistance from SKK Migas.

Prior to 2009 PLN was the monopoly power company of Indonesia and controlled both transmission and sales of electricity to households and industry. A major regulatory change occurred in 2009 when the Indonesian Government enacted the Law of National Electricity No.30/2009, [9] from which time private parties were allowed involvement in the electricity industry.

1.3. FSRU vs Onshore LNG Receiving Terminal

Capital expenditures for floating storage and regasification units (FSRU) may be lower than onshore, due to potential construction cost efficiencies, through repeatability gains (iteration of design) where there is a generic design concept, with minor adaptations for each specific project. [7] It is assumed that costs will be better controlled with construction/assembly activities that are organized through established shipyards and supply chains using established labour and materials resources. Finally, the lack of offshore pipelines and near/onshore facilities will reduce costs and there is no need to purchase or lease waterfront land for facilities.

However, certain key issues need to be addressed when considering floating liquefied natural gas (FLNG) facilities. FLNG are ships that transport LNG and are not designed for regasification. Concerns of host governments about the economic impacts on local employment opportunities and skills development and supporting industries may or may not arise from the FLNG ships being sourced domestically or internationally. [7] However, long-term local jobs will be created during the operational phase (the operation of an FLNG facility is similar to the operation of a conventional LNG liquefaction facility). Moreover, there will be a significant increase tax revenues for the host government, and significant expenditure on goods and services in the host country during both the construction and operations phases. [7]

1.4. How to Evaluate the Investment Profitability of a Project

Discounted Cash Flow (DCF) analysis offers the simplest approach and is the most common method used to value oil and gas projects. [10] There is little disagreement in the literature on the appropriate evaluation criteria. In contrast, there is much debate over the appropriate modelling methodology. The DCF method remains the preferred tool, particularly as managerial flexibility is less of an issue in an individual investment project. [11]

In order to validate the ratio of profitability change due to uncertainty of certain characteristics in the investment, a sensitivity analysis can be conducted on a proposed project. [12]-[14] A sensitivity analysis identifies the value of more accurate information and the influence of input parameters on the objective criteria for investment decision making. [13]

2. Data and Methodology

2.1. Data Collection

The numerical data analysed was obtained from research carried-out by IGN Wiratmaja Pudja (General Director of Oil & Gas, Ministry of Energy and Mineral Resources, Republic of Indonesia 2014-2019) entitled *Virtual Pipeline to Support Natural Gas Infrastructures Development in Eastern Indonesia Region* presented and published as part of the 2016 Australian Pipelines & Gas Association

(APGA) Annual Convention & Exhibition. [5] This is the preferred data and was selected as the project investment assumptions are based on Pertamina's "rule of thumb", and Pertamina's extensive experience in such Indonesian projects. The case study is developed based on the LNG receiving terminal planned for deployment in Sorong, West Papua Province, Indonesia. According to *Roadmap of Indonesian Natural Gas Policy 2014-2030*, the project is planned for development to start by 2020. [4]

2.1.1 Investment Cost Assumptions

The investment cost is partially or completely irreversible. [15] In other words, the initial cost of investment is at least partially sunk, or irretrievable. Also, there is uncertainty over the future rewards from the investment. Consequently, there is need to assess the probabilities of alternative outcomes that can result in greater or lesser profits (or losses) for the venture.

According to Griffin, [7] the common capital cost characteristics of each regasification terminal can be classified as follow:

- Onshore LNG Receiving Terminal: LNG carrier, pipeline, and land-based regasification unit.
- Floating LNG Receiving Terminal: LNG carrier, Floating Storage and Regasification Unit (FSRU), and pipeline.

The capital expenditure for this project is assumed only for the storage and regasification unit. It means that the company purchases the LNG and transports it by vessel chartered to the LNG receiving terminal. According to one of Pertamina's rule of thumb, the FSRU and land-based regasification project investment is assumed to be US\$0.6 million/MMSCFD and US\$2.1 million/MMSCFD respectively. [5]

2.1.2 Other Costs Assumption

There are two central operational activities for a LNG receiving business; shipping of LNG and operation of the regasification terminal. [7] It is assumed that the company charts the LNG carrier and pays for shipping costs. And the company pays for operational costs and maintenance of the regasification unit, which it owns.

The data presented in Table 1 below is from PLN, the anchor buyer of NG, and other parties that have contributed to LNG development. [5] PLN has investigated/estimated possible costs based on information from various liquefaction operator sources. Table 1 shows the cost of distribution (shipping and regasification) of LNG from Bontang to Sorong is US\$3.20/MMBTU.

Table 1. Estimated Distribution Cost from LNG source [5]

Origin	Primary Delivery	Demand	Capacity		Distance	Days 1-way	Round Trip	Ship Capacity	Storage Capacity	Shipping + Regas Cost
		[MMSCFD]	Weight [ton/day]	Volume [m3/day]	[km]	[day]	[day]	[m3]	[m3]	[\$/MMBTU]
Bontang	Sorong	27.9	642	1,335	1,600	3.2	10.1	13,468	17,509	3.20
	Jayapura	28.9	664	1,380	2,400	4.8	13.9	19,235	25,005	3.20
Salawati	Ambon	19.1	439	914	440	0.9	4.5	4,125	5,363	4.00

With regard to other related gas distribution costs, Perusahaan Gas Negara (PGN), Indonesia's state-owned gas company and the country's largest NG utility, has identified other costs: trading fees of US\$0.03/MMBTU; operating and maintenance costs of US\$1.38/MMBTU; and taxes of US\$0.41/MMBTU (Pudja et al., 2016). The feed price for NG is assumed to be US\$4.72/MMBTU. Interest rate on debt is assumed at be 4.75% per annum.

2.1.3 Revenue Assumption

It is assumed that PLN does not have to construct or commission ancillary infrastructures other facilities for purchasing and receiving NG directly to its power plant gates. Therefore, revenue for the NG supplier will be the purchase price paid by PLN.

There is no direct fee, fixed or variable, paid by PLN to the company that provides the LNG infrastructure and facilities. The fee is established and contracted based on a negotiated agreement of the NG seller and purchaser in a contract. According to Pudja (2016), the NG supply company is able to purchase NG at maximum price of US\$13.00/MMBTU from domestic NG producers for delivery to PLN.

2.1.4 Financial Calculation and Economic Evaluation

Project investment analysis seeks to analyse projected cash inflows (benefits) and projected cash outflows (costs) than compares the results with established decision-making criteria. [16] There are several techniques for analysing project investments, common methods include payback analysis, Net Present Value (NPV), Discounted Pay Back (DPB) and Internal Rate of Return (IRR). [17] This research evaluates LNG receiving terminal investments based on two of these financial analysis techniques; NPV and IRR.

a. Net Present Value

In order to calculate NPV, we calculate at the net cash flow in each period and then discount this stream back to the present time period. [18] The general mathematical equation for deriving the NPV is:

$$NPV = \sum_{t=0}^N \frac{Y_t}{\prod_{j=0}^t (1+i_j)} \quad (1)$$

Where NPV = the net present value
 Y_t = the net cash flow at the end of period t, i.e., at time t
 i_j = the interest (discount rate) for period j
 N = the life of project
 j = points in time prior to t
 t = the point in time under consideration [19]

The investment should be purchased if and only if the NPV positive. [15] [18]

b. Internal Rate of Return

The IRR is another method in capital investment appraisal which uses the time value of money but results in an answer expressed in percentage form. [20] The internal rate or return is found by solving for the value of K from the following formula [21]:

$$I_0 = \frac{FV_1}{1+K} + \frac{FV_2}{(1+K)^2} + \dots + \frac{FV_n}{(1+K)^n} \quad (2)$$

The investor determines whether the project is acceptable or not based on the calculated Internal Rate of Return. If the IRR is meets the required threshold, then the proposed project/investment is deemed acceptable and vice versa. [22]

2.1.5 Methodology

This paper conducts a quantitative financial analysis of two types of LNG receiving terminals; an onshore LNG receiving facility and a FSRU. The facility with the greater IRR would be considered the superior investment and the more viable project. A sensitivity analysis of service fees paid by PLN is conducted. The minimum fee level required to be paid by PLN must provide the NG supply company a 12% IRR.

3. LNG Receiving Terminal Project Investment Valuation

Given the information provide in section two the analysis shows that the FSRU Sorong investment is more profitable as compared to a land-based regasification facilities with a NPV if US\$16.95 million. Table 2 below reports a higher IRR value which is 13.77 %. The main determinant is that the total capital investment cost of the FSRU is lower than a land-based terminal. The total investments cost of the FSRU is only US\$16.74 million compare to US\$58.95 million for a land-based regasification unit.

[5] The lack of offshore pipelines and near/onshore facilities significantly reduces the cost of FSRU investments. [7] Moreover, there is no requirement to purchase or lease shoreline land for facilities. On the other hand, this analysis indicates a negative impact on project economics for the land-based regasification facilities. Table 3 below shows the simulation results. The IRR for land-based regasification facilities is -0.27 %. In addition to the higher capital costs, land-based regasification facilities have another economic disadvantage, that of stranded assets. At termination of the NG supply contract the assets of the company, pipeline and regasification unit, cannot be relocated as flexibly, if at all, as a FSRU. [7], [23] This supports the assumption that shutdown costs for land-based regasification facilities will be substantially greater than for FSRU facilities.

Table 2. Economic Evaluation of Investment Profitability in FSRU LNG Receiving Terminal Project

Year	Cost Component (Million USD)				Total	LNG Delivered (MMBTUD)	Revenue (Million USD)	Net Benefit (Million USD)
	Capital	LNG	Shipping & Regas	Other				
1	16.74				16.74			-16.74
2								
3		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
4		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
5		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
6		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
7		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
8		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
9		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
10		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
11		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
12		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
13		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
14		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
15		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
16		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
17		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
18		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
19		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
20		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
21		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
22		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
Present Value of Net Benefit (Million US\$)							US\$16.95	
Internal Rate of Return								13.77%

Table 3. Economic Evaluation of Profitability in Onshore LNG Receiving Terminal Project

Year	Cost Component (Million USD)				Total	LNG Delivered (MMBTUD)	Revenue (Million USD)	Net Benefit (Million USD)
	Capital	LNG	Shipping & Regas	Other				
1	58.59				58.59			-58.59
2								
3		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
4		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
5		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
6		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
7		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
8		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
9		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
10		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
11		51.53	34.93	19.87	106.33	29,908.80	109.17	2.84

12	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
13	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
14	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
15	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
16	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
17	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
18	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
19	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
20	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
21	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84
22	51.53	34.93	19.87	106.33	29,908.80	109.17	2.84

Present Value of Net Benefit (Million US\$) -US\$23.00

Internal Rate of Return -0.27%

Sensitivity analysis performed on investment profitability was conducted using different sales fees. Table 4 below shows that the IRR of the NG supplier can be increased to 12.94% if PLN would pay at least US\$10.60/MMBTU. The profitability of the project is highly sensitive to the sales fee as a US\$0.60 increase from US\$10.00/MMBTU to US\$10.60/MMBTU results in an IRR increases from -0.27% to 12.94%.

Table 4. Sensitivity Analysis of Sales Fee paid PLN versus the Profitability of Onshore LNG Receiving Terminal Project

Description	Unit	Sales Fee (US\$/MMBTU)			
		10	10.3	10.6	10.9
NPV	million US\$	-23.00	1	52.99	90.99
IRR	%	-0.27	7.38	12.94	17.66

Figure 3 illustrates the increase in both the NPV and the IRR that results from an increase in the sales fee. Less than a \$0.30 increase in sales fee changes the NPV from negative to positive. The same results are seen with the IRR.

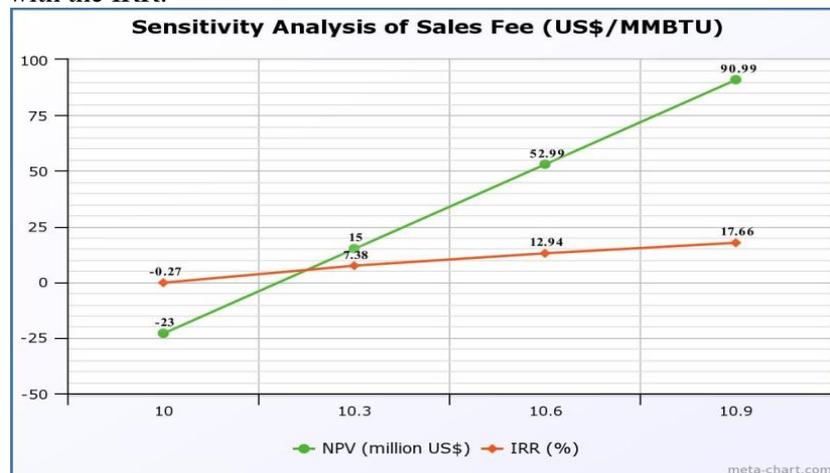


Figure 3. Sensitivity Analysis of Sales Fee paid by PLN versus Profitability of Onshore LNG Receiving Terminal Project

4. Conclusions and Recommendations

A FSRU is more economically viable than an onshore LNG receiving terminal. The FSRU project produces a greater IRR (12.94%) as compared to a negative IRR (-0.27%) for the onshore project in this case study, the Sorong LNG receiving terminal project. The primary reason for this result is the substantially lower initial investment cost required for FSRU projects. In addition, termination and

closer (shutdown) costs of onshore projects will be greater as storage and regasification facilities cannot be relocated as FSRU are capable.

If the Indonesian Government wants to promote investment in and deployment of onshore LNG facilities and infrastructure an increased sales fee will be required, an increase from US\$10.00/MMBTU to US\$10.60/MMBTU. This would raise the IRR up to 12.94%.

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