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Economic Analysis of Liquefied Natural Gas Floating Production Storage and Offloading Plant (LNG FPSO) Using Probabilistic Approach

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Abstract

The global yearning for clean and safe environment coupled with the need of monetizing stranded gas fields to meet the growing demand of Natural gas in the world today has called for understanding of the range of potential for commercial realization of Liquefied Natural Gas Floating Production Storage and Offloading Plant (LNG FPSO). This places a heavy burden on the economic evaluation process which will give the maximum insight into the basis for a decision to invest or not to invest in the LNG FPSO. An economic analysis of 5.2 million tonnes per annum (MTPA) LNG FPSO plant was undertaken. A Monte Carlo simulation method was adopted in this study through the use of Crystal Ball Software. The key uncertainties were represented and their respective impacts on economic viability defined. The deterministic model results obtained from the studies were very impressive with Net Present Value of \$2.3 billion at a discount value of 15% and Internal Rate of Return at 32.68%. Probabilistically, 74.96% certainty of having a positive net present value (NPV) and good IRR values far above the hurdle rate for investment in Nigeria was obtained. These clearly showed that LNG FPSO is profitable. Certainty of payback period of not exceeding 5 years was obtained to be 55.89%.

Key words: LNG FPSO; Offshore LNG liquefaction; Probabilistic approach; Sensitivity analysis; Economic yardstick

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INTRODUCTION

As gas flaring becomes more unacceptable from a political and environmental viewpoint, there is a need to adopt solution that will put an end to those practices. Floating Liquefied Natural Gas Plant will serve as the best solution to avoid flaring and gas re-injection into the wells. Gas re-injection sometimes offers a solution but this is expensive for deep wells and not desirable for all reservoir structures (CompactGTL, 2010). It will be good if proposals for new oilfield projects in remote or deepwater locations demonstrate how produced associated gas will be processed without continuous flaring.

Moreover, Liquefied Natural Gas demand is growing appreciably, especially for use as fuel for power generation in modern combined-cycle gas turbine plants and therefore reviewing cost reduction strategies and techniques is justified across the range of LNG plant types and sizes (Adrian *et al.*, 2004). As demand continues to grow and the value of natural gas remains high, the impetus to monetize non-traditional gas resources also grows (Barclay *et al.*, 2006). However, a considerable portion of the world's natural gas falls into the category termed "Stranded" where convectional means of transportation via pipeline is not convenient or economical (Ekekpe and Onyekonwu, 2007). The main driver of gas utilization projects in Nigeria and other developing countries had been the governments' desire to create more wealth by diversifying the economy of the country and end gas flaring. Also with a combination of new government incentives and pressure from the environment ministry to end flaring, coupled with rising domestic industrial demand for gas have now encouraged operators to go into gas projects (Centre for Energy Economics, 2009).

After the successful and proven track record of offshore crude oil field developments employing floating production, storage and offloading systems (FPSO) and use of barge transport for LNG facility, the industry is now looking with great interest into solutions for monetizing stranded offshore gas fields through the integration of onshore LNG and offshore FPSO technology concepts. The integrated application is known as Floating LNG Production or LNG FPSO (Adrian, 2004; Barclay *et al.*, 2006; Nexant, 2009). The LNG FPSO concept has generated interest because it offers the potential to:

- Avoid flaring or re-injection of associated gas;
- Eliminate the need for potentially long pipelines to shore;
- Monetise smaller or remote fields of non-associated gas;
- Reduce exposure to public and increase security of facilities;
- Lower LNG production costs.

The LNG (FPSO) concept is based on a ship-like vessel that will be able to produce, store and offload LNG in a marine environment (Barclay et al., 2006; Chiu, 2006; Wood et al., 2007; Wood, 2009; Nexant, 2009).

The drive to monetize and the clamour for environment degradation due to gas flaring was what led to the development of LNG FPSO for offshore environment. Floating liquefaction technology has emerged as a means of bringing on an additional LNG supply by accessing stranded gas reserves once deemed too remote, too small, or otherwise too difficult for conventional land-based LNG development. LNG FPSOs have shown a number of other inherent advantages over conventional onshore liquefaction plants that have boosted their profile. One of such advantages over conventional liquefaction plants for offshore resources is its ability to be stationed directly over distant fields thus avoiding expensive offshore pipelines and the ability to move the production facility to a new location once the existing field is depleted (Kerbers *et al.*, 2008). Therefore, the objective of this work is to provide a unique approach for assessing the economic viability of a 5.2 MTPA LNG FPSO plant. This would be achieved by carrying out a Monte Carlo simulation to forecast the likely possible outcomes with variable economic parameter such as LNG price, Feedstock price, plant capacity, capital expenditure and operating cost. This will ultimately give an idea of how economical it is to monetize Nigeria stranded gas deposit at the current Natural gas price.

1. TECHNOLOGY OF LNG FPSO

Offshore natural gas liquefaction is expected to be the next technology and commercial breakthrough for monetizing stranded natural gas resources. LNG FPSOs have shown a number of other inherent advantages over conventional onshore liquefaction plants that have boosted their profile (Kerbers *et al.*, 2008). Offshore natural gas liquefaction has different process requirements than the traditional on land, base-load liquefaction plants. The marinization of LNG technology is seen to be a key success criterion for selecting and applying the most appropriate technology concepts. While Onshore LNG facilities have traditionally focused on thermodynamic efficiency as the key criterion for process selection, offshore LNG will require blending this traditional requirement with space, weight, safety and marine operability considerations (Wood, 2009; Nexant, 2009).

Offshore liquefaction though still emerging is not a new or novel idea but have been developed along side Floating Production, Storage and Off-loading (FPSO) facilities which are now commonplace for oil production (Adrian, 2004). It was considered in the kangan natural gas field in the Persian Gulf during 1970s. Several studies have been made by Air Products for different companies for building a barge mounted LNG plant offshore. Moss Rosenberg also did the barge design for offshore liquefaction plant. The Salzgitter Group and LGA Gastechnik of Germany in the mid-1970 conducted feasibility studies on construction of barge mounted liquefaction plants using modular construction techniques (Chiu, 2006). The scheme envisaged constructing and outfitting a barge mounted plant in a European ship yard, towing it to West Africa and sinking the barge on the offshore. The idea was conceived to overcome poor site conditions existing along the coast of West Africa that require extensive land reclamation, dredging and long LNG loading line trestles. Kvaerner took the offshore concept further and did a full front end engineering design (FEED) on a two-train, 2.8 MTPA APCI process, mounted on a steel mono-hull vessel with 165,000 m^3 of Moss storage (Chiu, 2006). Now TEAM West Africa has gone ahead to bring this over 30 years of conceptualisation into reality. It is now constructing LNG FPSO in Korea capable of producing 5.2MTPA of LNG with provision for LPG and Condensate extraction and storage as well as space for LNG storage. It is meant to be deployed to offshore areas of West Africa by 2012.

This floating facility can be moved and reused; this will substantially reduce the risk associated with a stationary investment facility. An LNG project represents an integrated chain of investments and commercial agreements linking exploration, production, transportation and marketing activities. A floating liquefaction plant can reduce the cost of production link as well as provide maximum flexibility in developing gas resources. It has been estimated that a floating LNG project might be 20-30% cheaper than a comparable size of land based project and construction time 25% faster. The floating plant's mobility will reduce the construction cost of new pipelines and compression facilities that might otherwise be required to bring the gas to a land-based plant. It reduces years off of a project schedule in terms of land acquisition and reclamation and save over hundred ($100) millions of dollars in site preparation and dredging cost (Chiu, 2006).

The selection of the liquefaction technology and corresponding equipment in an LNG FPSO is critical to reducing risks and increasing project viability, while meeting production and market targets and controlling costs. Liquefaction technologies vary in sophistication and power requirements such that selecting the optimum design depends on many factors, which vary from project to project. Industry studies, including those performed by Nexant, suggest that liquefaction technology on its own does not substantially make one liquefaction process more efficient than any other. Rather each technology for onshore liquefaction plants is competitive within certain ranges of feed gas specifications, ambient conditions, and train sizes. Adrian *et al*. (2004), Barclay *et al*. (2006) and Nexant stated that Floating LNG facilities provide a choice for economical development of remote offshore gas fields. Adrian *et al.* (2004) further proved that refrigeration cycles using expanders are the best choice even for large offshore plants as they give a safer and more compact plant, thus minimizing the overall size and cost of the carrier vessel. Expander cycle has been widely acceptable to be the best for use in offshore LNG plant. Table 1 shows comparison of Expander cycle with other refrigeration cycle.

Table 1
Liquefaction Cycle Evaluation Against Criteria for Use Offshore

Criteria	Cascade	Mrc	Expander
Use proven technology	Yes	Yes	Yes
Overall Space Requirement	High*	High*	Low
Refrigerant Storage Hazard	Yes	Yes	No
Sensitivity to vessel motion	Moderate	Moderate	Low
Simplicity of operation	Moderate	Low	High
Ease of start-up/shutdown	Moderate	Low	High
Flexibility to feed gas changes	High	Moderate**	High
Efficiency	High	Moderate	Low
Total Capital Cost	High	High	Low

* Due to requirement for hydrocarbon refrigerant storage
** Requires adjustment of refrigerant composition

2. ECONOMIC ANALYSIS OF A TYPICAL LNG FPSO PLANT

A floating offshore facility designed by Team West Africa that will accommodate a 5.2 MTPA LNG processing plant was used as a focal point for this study based on its capacity. The facility is to have the capacity to store 350,000 m^3 of LNG, 160,000 m^3 of condensate, 40,000 m^3 of propane, and 40,000 m^3 of butane. After doing a cost analysis of Korea, Spain, and Japan shipyards, Korea has been chosen due its manufacturing ability, low cost, and stable workforce. The overall estimated cost for this project is approximately $2.2 billion as shown in Table 2.

Table 2
Breakdown of Capital Cost Analysis of FLNG FPSO

Parameter	Total Cost		
	Japan (US $MM)	Korea (US $MM)	Spain (US $MM)
LNG Tanks	100	100	100
Propane & Butane Tanks	24	24	24
Hull Steel	199	180	228
Hull Outfitting	46	42	39
Hull Machinery	1	1	--
Electric Outfitting	2	2	--
Accommodations	16	17	18
Cargo Fitting	27	24	--
Topsides Module Supports	2	2	3
Mooring Lines	.41	.41	.41
Topsides Equipment	1,375	1,375	1,375
Additional Marine Costs	130	130	130
External Turret	40	40	40
Loading Arms	15	15	15
Transportation-Floater	13	13	4
Installation Floater	15	15	15
Subtotal	**2,006**	**1,981**	**1,991**
Contingency (12%)	241	238	239
Total	2,247	**2,219**	2,230

Extracted for Adrian *et al*. (2004)

Moreover, the economic viability of harnessing stranded natural gas depends precisely on five major factors namely: Capital Expenditure ("CAPEX"), Operating Expenditure ("OPEX"), Natural gas (feedstock) prices, the cost of pipelining to the shore and LNG price as stated by Ekekpe and Onyekonwu (2007). A probabilistic approach of economic analysis through Monte Carlo simulation using Crystal ball software was used to determine the influential factors to the profitability of LNG FPSO plant.

2.1 Feedstock Availability

Liquefied natural gas (LNG) provides access to the global supply of natural gas and is a critical component in meeting the world's energy needs. Nigeria has a huge deposit of about 160 TCF of natural gas. The 5.2MTPA LNG plant is expected to consume approximately 5.34 TCF of gas within 20 years life cycle for 330 days/year of plant operation (On the basis that 1 tonne of LNG with specific gravity of 0.425 = 51, 350 ft^3 of gas). The natural gas sales price of $1/MMBTU ($1/MScf) was used as the feedstock price. This covers production and development cost of the natural gas. The total feedstock cost expenditure per annum will amount to $267,020,000,000.

2.2 Capital Expenditure

The capital expenditure or cost (CAPEX) of $2.2billion as stated earlier will be used for this analysis which basically covers the plants Engineering, Procurement and construction (EPC). The capital cost range of US$450 to US$750 per ton was predicted by different author and vendor such as Nexant, (2009), Flex, (2009) and Tusiani *et al.* (2007). Comparing with the specific capital cost of an onshore base load liquefaction plant of similar capacity can be as high as $1000 per ton of LNG production. This higher cost is as a result of pipeline to shore, site preparation, harbor dredging and docks. These costs range estimate excludes field development and shipping costs. Table 2 also shows the capital cost analysis of FLNG plant by three different countries as was given by Team Africa (2005).

2.3 Annual Operating Cost

The operating cost according to Nexant (2009) and Flex (2009) is $22 - $29/ton of LNG produced, depending on the liquefaction employed. Tusiani *et al.* (2007) estimated it as 2-5% of the capital expenditure. These costs comprise labor, fuel gas requirements, the consumption of catalyst, refrigerants, chemicals and lubricant, and maintenance programs that include materials, supplies, support services, and offshore logistics, operational maintenance of facilities, overhead cost, environmental compliance, payroll, etc and feedstock cost not included. $22 per ton is assumed to be the base case for annual operating expenditure since Nitrogen expander cycles is widely acknowledged to be the cheapest and best suitable for LNG FPSO.

2.4 Products Prices

Natural gas and LNG prices tend to be very volatile with relatively constant prices with occasional extremes which make it very difficult to predict its future prices. Some of the factors affecting the price volatility are demand (economic factors, weather and electricity sector), supply (drilling, pipelines and imports), prices of other fuels (Oil & coal), and storage. It has been shown to constantly vary from $3/mmbtu ($153.9/ton) to $13/mmbtu ($666.9/ton) (Argus, 2010). The base case of $300/ton was fitted to triangle distribution using the product cost range.

2.5 Model Backbone

The model for assessing the economic viability of LNG FPSO adopted here was according to Ikoku (1984), Mian (2002), Mamora (2005) and World Bank (2004) for cash flow analysis, Net Present Value, Internal Rate of Return, Payback time, Profitability Index, Present Value Rate, Undiscounted profit to Investment Ratio. This also corresponds to excel inbuilt formulas with corrections made by Charnes (2007) for NPV. The algorithms that were adopted in this economic analysis are in line with all Monte Carlo simulation processes. This includes identifying options, building a model, adding Stochastic assumptions, running the Crystal Ball, analyzing forecasts, running sensitivity analysis, running Tornado and Spider and finally making Decision (Ikoku, 1984; Mian, 2002; Mamora, 2005; Charnes, 2007).

3. METHODOLOGY

A spreadsheet-based deterministic economic model was utilized in the early evaluation stages of this study to appreciate and characterize the opportunities and the impact of uncertainties through single point sensitivity analysis as shown in Table 3. However, a purely deterministic approach is limited in capturing the full impact of the high number of interdependencies of the characteristic variables on the LNG FPSO. A stochastic approach was incorporated in this analysis. This probabilistic approach has an advantage over deterministic approach that uses a single point solution and would not show how optimistic or pessimistic the results might be as stated by William *et al*. (2007) and Charnes (2007). According to William *et al.* (2007), it is imperative for any economic analysis to be able to provide logical and well-thought through answers to the following questions such as: a) what is the probability of achieving the key profitability metrics? b) What is the probability of breakeven at a given price? c) What is the maximum exposure?

Table 3
LNG FPSO Cash Flow Analysis

Cashflow	Yr 0 (Millions)	Year 1 (Millions)	Year 2 (Millions)	Year 3 (Millions)	Year 4 (Millions)	Year 5 (Millions)	Year 6 (Millions)	Year 7 (Millions)	…	Year 20 (Millions)
Revenue		$1,560	$1,560	$1,560	$1,560	$1,560	$1,560	$1,560	…	$1,560
Royalty		$195	$195	$195	$195	$195	$195	$195	…	$195
Net Revenue		$1,365	$1,365	$1,365	$1,365	$1,365	$1,365	$1,365	…	$1,365
Operating Cost		$114.4	$114.4	$114.4	$114.4	$114.4	$114.4	$114.4	…	$114.4
Feed Cost		$267.02	$267.02	$267.02	$267.02	$267.02	$267.02	$267.02	…	$267.02
Depreciation		$110	$110	$110	$110	$110	$110	$110	…	$110
Pretax profit		$873.6	$873.6	$873.6	$873.6	$873.6	$873.6	$873.6	…	$873.6
Tax		$262,	$262,	$262,	$262,	$262,	$262,	$262,	…	$262,
Net Profit		$611	$611	$611	$611	$611	$611	$611	…	$611
Operating Cash flow		$721.5	$721.5	$721.5	$721.5	$721.5	$721.5	$721.5	…	$721.5
Investment	2,200	-	-	-	-	-	-	-	…	-
Net Cash flow	-2,200	$721.5	$721.5	$721.5	$721.5	$721.5	$721.5	$721.5	…	$721.5
Cumulative Cash flow	-2,200	-$1,478	-$756.99	-$35.48	$686.02	$1,407	$2,129	$2,850	…	$12,230

4. PROBABILISTIC ASSUMPTIONS

The probability distribution chosen reflects the fitted distribution for the historical realization of the variable. Triangular distribution was used for most of the variables because it best estimates the distribution using the maximum and minimum plus most likely values. To implement this aspect of generating the probabilistic data, a specially designed software package was used for the analysis called Crystal Ball 11.1.1. The software is an add-in to excel. It performs an iterative recalculation of values of the economic measures of the cash flow model already developed in spreadsheet when there are changes in any or all of the parameters that drives the cash flow model (Charnes, 2007). This software uses a Monte Carlo simulation procedure to generate for each trial values of the key parameters such as LNG Price, Capital Cost, Operating Cost and Feedstock cost corresponding to the economic measures (NPV, IRR, Proftability Index, Payback time, profit to Investment Ratio) as indicated by Ikoku (1984), Mian (2002), Mamora (2005), Ekekpe *et al.* (2007) and Charnes (2007). For this study sampled 10,000 trials for each of the six models was used.

5. RESULTS

The sensitivity analysis, Tornado and Spider charts of this study with respect to the Net Present Value (NPV) and the Internal Rate of Return (IRR) as yardsticks will be shown to enhance quicker and easier decision making. Probabilistic plots of acceptable ranges will be displayed to drive home the economic analysis.

5.1 LNG FPSO CASH FLOW ANALYSIS

Table 4 shows the input assumptions for the Monte Carlo simulation of the 5.2 MTPA LNG FPSO plant (these values are taken from section 3.1 to 3.5) while Table 5 shows the minimum, likeliest and maximum distribution types used alongside the input parameters.

Table 4
Monte Carlo Input Assumptions for LNG FPSO

Input assumption	Number
Plant Capacity(tons)	5,200,000
LNG Price ($/tons)	$300.00
Capital cost	2,200,000,000.00
Operating Cost($/tons)	22
Feedstock price ($/scf)	0.001

Table 5
Monte Carlo Distribution Assumptions

Input parameters	Minimum	Likeliest	Maximum	Distribution type
Plant Capacity(tons)	2,080,000	5,200,000	5,300,000	Triangular distribution
LNG Price ($/tons)	200	300	440	Triangular distribution
Capital cost	1,000,000,000	2,200,000,000	3,900,000,000	Triangular distribution
Operating Cost($/tons)	22	0	29	Uniform distribution
Feedstock price($/mscf)	0.0005	0.001	0.0015	Triangular distribution

5.2 DISCUSSION

The cash flow spreadsheet (Table 3) model result for LNG FPSO as presented in Table 4 shows the computation of the economic measures. The cash flow model result showed some impressive outcomes about the profitability of LNG FPSO projects based on deterministic model. It returned a positive and large *NPV* after tax of $2.3billion at a discount value of 15%. A discount rate of 15% was used in this study because by the World Bank standard it stands to be the hurdle rate for oil and gas investments in Nigeria (World Bank, 2004). The decision rule is to accept all projects with positive NPV values. The discount factor is assumed to take care of inflation and some uncertainty in the time value of money. The undiscounted cumulative profit to investment ratio deterministically is obtained as 5.56. This implies that the profit is 5.56 times as big as the initial investment. It is a good ratio for an investment without considering time value of money. The Present Value Rate tries to evaluate the effects of inflation rate and other uncertainty in the investment. It also helps to portray or quantify the size of the investment. Its decision rule is to accept investment with positive PVR. As shown in Table 6, the value of PVR is 1.05 at a discount factor of 15%**.** In addition, an Internal Rate of Return of 32.68% was obtained which is quite impressive as it is above the standard hurdle rate for investors in Nigeria (Adenikinju, 2008; World Bank, 2004). Internal Rate of Return takes care of factor such as high volatility of currency and exchange rate. This implies that inflation rate will hardly affect the profitability of the venture. The Net Present Value probability distribution as shown in Figure 1 gave the entire possible range of forecast for NPV taking recognizance of uncertainty in our input probability distribution.

Table 6
Deterministic Output Forecast

Output forecast	Number
Natural gas consumption(scf)	267,020,000,000
NPV	2,316,145,214.28
IRR	32.68%
Profit to Investment Ratio	5.56
PVR	1.05
Payback Period	3.05
Profitability Index	2.05

Table 7
Probabilistic Output Forecast Based on the Desired Output

	Certainty (%)	Lower range	Upper range	Desired output
Natural Gas Consumption(scf)	70	108,172,188,599	266,482,284,529	At least constant
NPV	74.96	0	$4,184,237,851.55	NPV of zero and above is desirable
IRR	72.46	15%	46.66%	IRR above 15% hurdle rate is desirable
Profitability Index	74.24	1	2.86	PI above 1 is desirable
PVR	74.24	0	1.86	PVR above zero is desirable
Payback Period, yr	55.89	1.45	5	Payback Period less than 5yr is good
Profit to Investment Ratio	94.37	1	8.14	Profit to Investment ratio above 1 is desire

Table 7 shows the range of values permissible for best economic output base on the probabilistic approach. For the Natural Gas consumption, a 70 % certainty for a constant availability and consumption was assumed. The NPV distribution (Figure 2) shows the certainty of having NPV between the breakeven points (NPV of zero) to the maximum value of NPV $4184, 237, 851.55 to be 74.96%. This shows a high confidence region in spite of uncertainties in the prices of LNG and Feedstock and other variables.

The distribution for the Internal Rate of Return (Figure 3) shows 72.46% certainty of having an Internal Rate of Return (IRR) above 15% hurdle rate for investments in Nigeria adopting World Bank guideline. This gave a possibility of having Internal Rate of Return up to 46.66% from this project.

The Payback period distribution (see Figure 4) is skewed to the left showing an early recovery of initial investment. This gave 55.89% certainty of recovering the initial investment between 1.45 and 5 years. Since Capital is a scarce resource, short Payback period is more desirable as it will help the investor recover the Capital quickly.

Profitability index of above 1 is desired. The certainty of having Profitability Index of 1 and above in this probabilistic approach gave 74.24% (see Figure 5). In the case of PVR, PVR above zero is desirable. The PVR of this project (Figure 6) laying above zero corresponds to a certainty of 74.24%. Also a certainty of 94.37 % was obtained for Profit to Investment ratio (see Figure 7) to have values spanning between 1 and 8.14.

Figures 8 to 10 show the sensitivity analysis on NPV, IRR and Payback Period respectively. It shows the various effects of changes in the value of LNG price, Natural Gas Feed stock Price, Capital Expenditure and Operating Cost on the economic indices like NPV, IRR and Payback Period. It was equally observed that the sensitivity analysis of Profitability Index, profit to Investment Ratio and Present Value Rate followed the same trend (figures not included) with IRR. This would aid decision making as LNG price was discovered to be the most sensitive parameter whose slight changes will affect the profit earning of any investor. For instance as shown on Figures 8 to 10, the LNG price will affect the Payback period by 36.2%, NPV by 42.9% and IRR by 38% . It is also clear from these figures that, increase in the value of LNG price reduces the Payback period while increasing the value of NPV and IRR.

Tornado charts (Figures 11 &13) are used to measure the effect of changes in any variable on a selected forecast (NPV). This was done deterministically by the Crystal ball software while sensitivity was done probabilistically. Figures 11 and 13 show the extreme values of NPV with respect to the effect of the changes made to the variable parameters (LNG price, Feedstock price, plant capacity, Capital cost and Operating cost). The spider charts (Figure 12 & 14) tries to depict the effect of the parameters with the steepness of the slope. The spider charts show that LNG price is most sensitive. This is also confirmed by the Tornado charts.

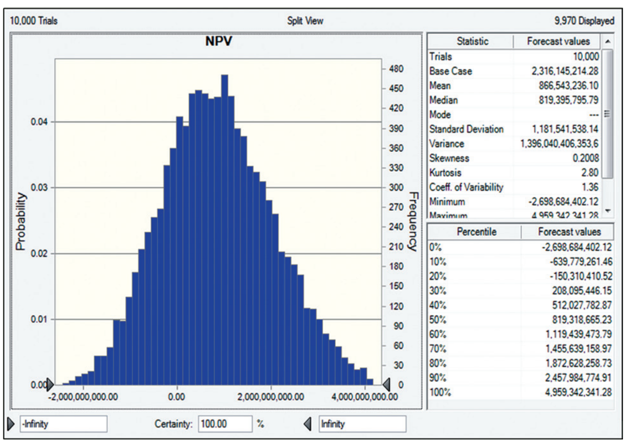

Figure 1
NPV Probability Distribution Chart

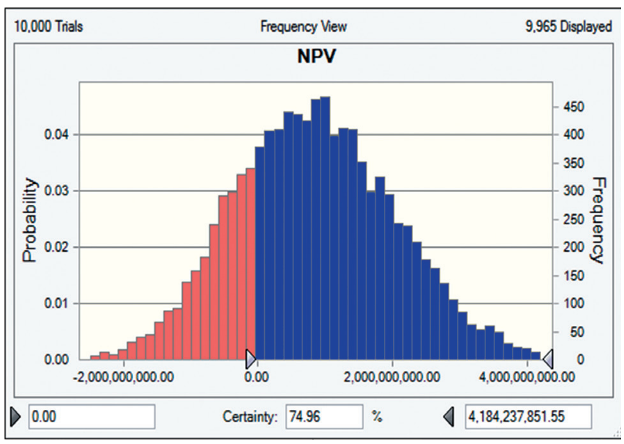

Figure 2
Desirable Range of NPV

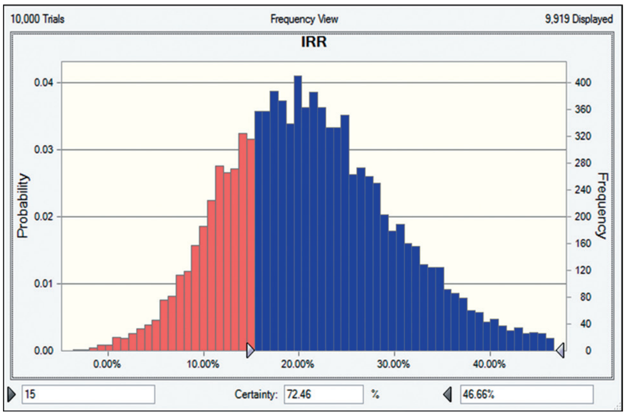

Figure 3
Desirable Range of IRR Above 15% Hurdle Rate

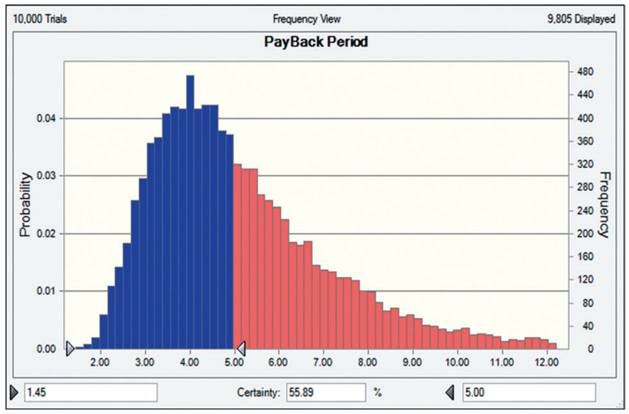

Figure 4
Acceptable Range of Payback Period (years not more than 5yr)

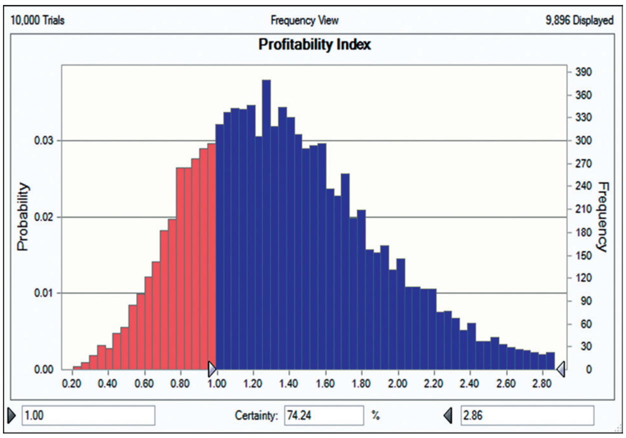

Figure 5
Desirable Range of Profitability Index Above One

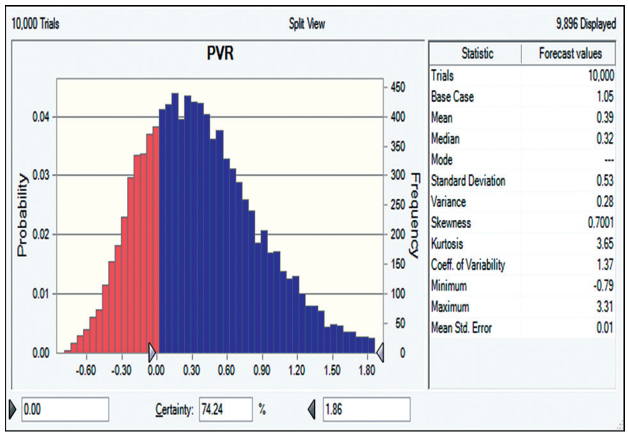

Figure 6
Desirable Range of PVR Above Zero

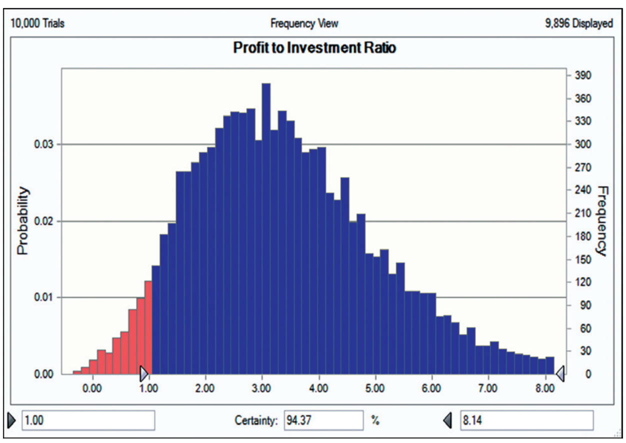

Figure 7
Desirable Range of Profit to Investment Ratio Above 1

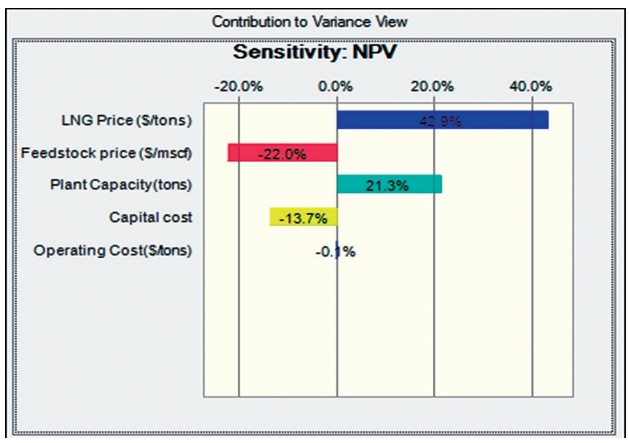

Figure 8
NPV Sensitivity Chart

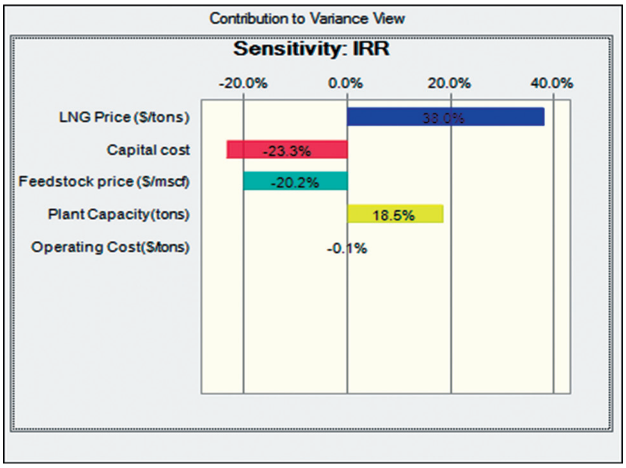

Figure 9
IRR Sensitivity Chart

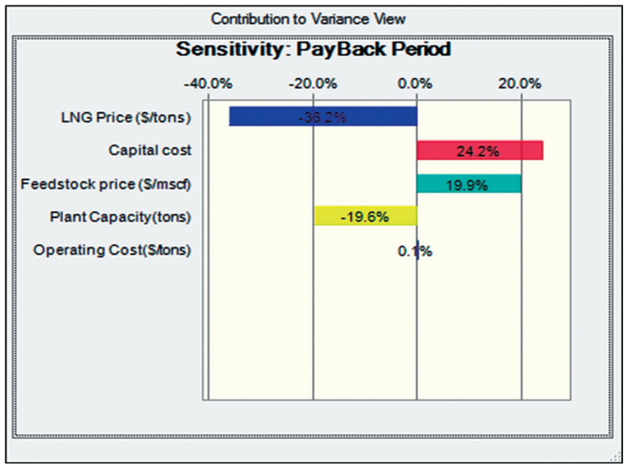

Figure 10
Payback Period Sensitivity Chart

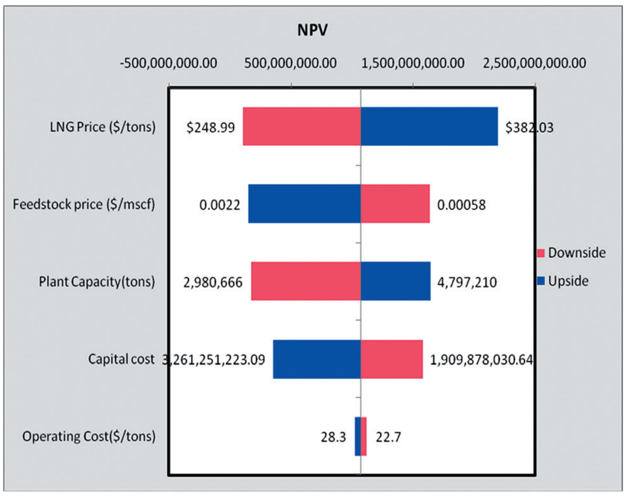

Figure 11
NPV Tornado Chart

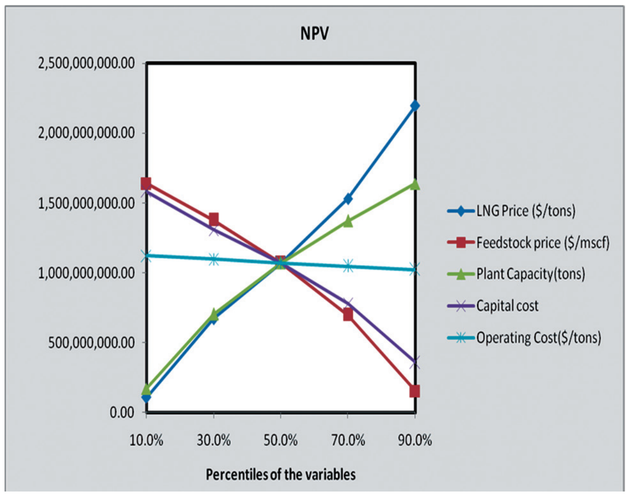

Figure 12
NPV Spider Chart

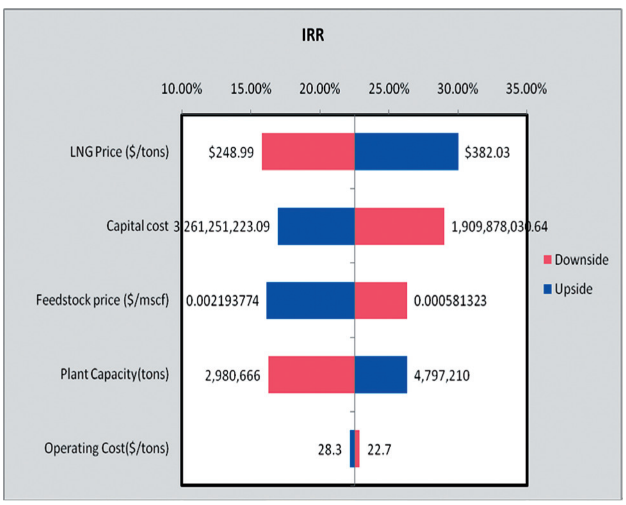

Figure 13
IRR Tornado Chart

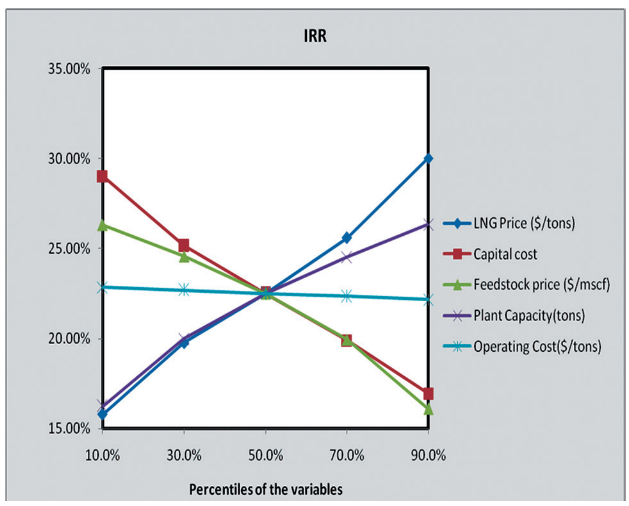

Figure 14
IRR Spider Chart

CONCLUSION

The results obtained from the studies were very impressive with NPV of $2.3 billion and IRR of 32.68% gotten from the deterministic model. Probabilistically, 74.96% certainty of having a positive net present value (NPV) and good IRR value were obtained and these clearly shows the profitability of this 5.2MTPA LNG FPSO. Certainty of payback period of not more than 5 years was obtained to be 55.89%. Any reserve with capacity of 5.34 TCF will be good for this plant as it will sustain the plant for twenty (20) years.

The sensitivity analysis outlined LNG Price and Feedstock Price as key sensitive parameters in maximising profit. The deterministic analysis decision making only would not have provided insights of certainty value and sensitive parameters. Therefore, the probabilistic approach helped to forecast the effects of the uncertainty associated with the variable parameters and gave ranges of all the possible profit/loss that would be encountered as in Figure 1. Offshore LNG liquefaction plant is economically viable. With the help of the range of the economic indices shown in Table 7, it is clear that Offshore LNG Plant will yield quick return on investment.

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