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Comparative Analysis of Utilization options for Stranded Natural Gas in Nigeria

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ABSTRACT

The petroleum industry is continually seeking ways to utilise stranded natural gas emanating from the flare stack in oil processing facilities. The very common practice has been to reinject stranded and marginal gas for enhanced recovery purposes. Notwithstanding, there has been a growing concern as to how these stranded gasses can be brought to the market for direct use by end users. However, this study aims at reviewing available natural gas utilizations for stranded natural gas exploitation. In addition, this study focuses on performing economic evaluation of four major gas utilization options: gas-to-liquid (GTL), compressed natural gas (CNG), natural gas hydrate (NGH) and liquefied natural gas (LNG). Economic indicators such as internal rate of return (IRR), net present value (NPV) and Payout time (POT). Nonetheless, the analysis revealed that CNG yielded the highest productivity index of 3.01. This value was seconded by NGH with a productivity index of 1.33. Also, IRR results showed that GTL and LNG are nearly mutually exclusive projects since they have approximately same IRR of about 20%. Sensitivity analysis performed on these gas utilization options, showed that NGH is a great utilization for medium and small gas supply chains. Meanwhile, CNG is best for very large stranded natural gas exploitations. More so, either LNG or GTL can be used for large stranded natural gas exploitations. Nevertheless, GTL will be more economically viable considering the number of cuts that can be obtained from it (diesel, methane gas, ethane, DPK and even PMS through catalytic cracking procedures).

1. INTRODUCTION

The term stranded gas is used to describe gas reserves that are either located remotely from consumers or in deep water. Conversely, marginal gas is a term used to describe situations where the field is too small to justify a gas pipeline for long-term production (Nweke and Adewale, 2015). However, both cases of stranded and marginal gas can exist as either non-associated or associated gas. Natural gas is playing an important role in the supply of energy for both industrial and domestic use. The world's abundant gas supply sources, the desire for less carbon-intensive fuels, and the need for cleaner air are driving a continuous innovation of gas utilizations. Recent literatures have reported that a considerable portion of the world natural gas reserves fall into the category termed as "stranded" (Dong *et al.*, 2008; Nweke and Adewale, 2015). Also, the conventional means of transporting stranded gas is through pipeline is usually not practical or economical because of geographical, political, or diplomatic limitations (Dong *et al.*, 2008). The owners of the "stranded" gas face a challenge on how to monetize the large, stranded gas resources. This drive leads to the developments in

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liquefied natural gas and gas to liquid (LNG and GTL) utilization options. The utilization options available for natural gas conversions are Liquefied natural gas (LNG) utilizations, compressed natural gas (CNG) utilizations, Gas-to-wire (GTW) utilizations, Gas to solid also referred to as Natural gas hydrates (NGH) utilizations, Gas to liquids (GTL) utilizations, natural gas liquids (NGL) extraction utilizations (Wood *et al.*, 2012; Okologume *et al.*, 2019a). LNG is essentially a physical process converting natural gas to liquid for easy transportation, while GTL is a chemical process that converts natural gas to commercial products such as naphtha, transportation fuels, methanol, and gasoline (using methanol to gasoline (MTG) direct process).

As the development of oil and gas business continues to rise in Nigeria, investment in this sector is expected to increase as well. This will require the feasibility of developing natural gas utilizations like gas to liquid utilization (GTL), liquefied natural gas (LNG) etc. at Niger Delta offshore locations. Operators need to be acquainted with these utilizations before they can adequately be fit to work in such gas project. Also, it is imperative that these utilizations are evaluated economically with the intent of determining the most cost-effective utilization that will yield optimum profits (Okologume *et al.*, 2019b).

The petroleum industry is constantly seeking ways to reutilise stranded natural gas emanating from the flare stack in an oil processing facility. The very common practice has been to reinject stranded and marginal gas for enhanced recovery purposes. Notwithstanding, there has been a growing concern as to how these stranded gases can be brought to the market for direct use by end users. Invariably, this has not been actualised since the petroleum industry is still sceptical about the most economical method or utilization to employ in reutilising stranded gas. Thus, this study is very relevant as it seeks to perform economic analysis on different stranded gas utilizations. The aim of this study is to evaluate different the stranded natural gas utilisation options with a view to finding the most economically viable method using economic indicators like NPV, IRR, POT, and straight-line depreciation.

1.1 Theories and Definition

1.1.1 Natural gas utilization options

This section discusses the available utilizations for the exploitation of stranded natural gas. These utilizations include Natural gas hydrate (NGH), liquefied natural gas (LNG), compressed natural gas (CNG), and gas to liquid utilization (GTL). Most times the natural gas production becomes excessive because of the distance between the production to the end user (Pascoela, 2019). Therefore, operators are looking for ways to turn the “liability” of this excessive gas into a profitable venture via a gathering line/facility, gas processing facility, and suitable route for transporting. Pascoela (2019) suggested five major utilizations used in the transportation of natural gas namely: pipelines, LNG, GTL, CNG, and GTW or power generation as shown in Figure 1.

From Figure 1, it is seen that the means of transportation for natural gas depends on the volume of gas to be transported and its delivery distance. For large gas volume delivery, pipeline and/or LNG transportation remain the most competitive options (Mokhatab *et al.,* 2014). Consequently, pipeline option is unpractical when the distance between the fields to the market is further than 2,000 km or 3,200 miles and when the market is separated by a large body of water. When these situations occur, LNG become more viable in bring the natural gas to the market user (Pascoela, 2019). Contrary to some location, natural gas might not have its place in the market but the demand for other petroleum products are high. In this case, natural gas can be converted to petroleum product or synthetic crude oil to serve the domestic market or the market nearby.

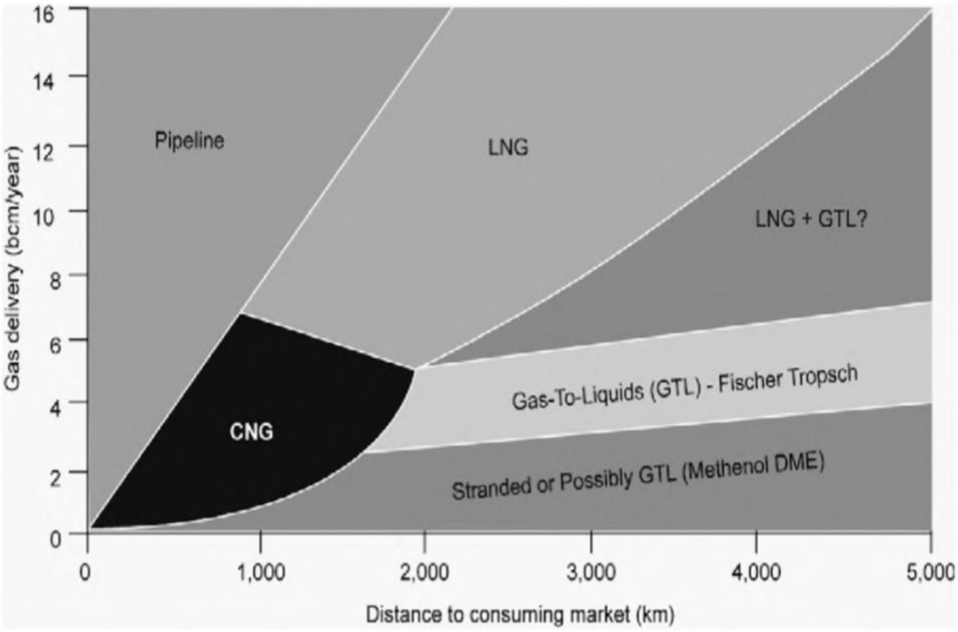

Figure 1: Means of transporting natural gas to the market based on the gas delivery volume and the distance to the market (Wang and Economides, 2009)

Gas to liquids utilization (GTL) projects are scalable, allowing design optimisation and application to smaller gas deposits. The key influences on their competitiveness are the cost of capital, operating costs of the plant, feedstock costs, scale and ability to achieve high utilisation rates in production (Nweke and Adewale, 2015). Gas-to-liquids (GTL) utilization has the potential to convert a significant percentage of the world's proved and potential natural gas reserves - estimated to be upwards of 14,000 trillion cubic feet - into several hundred billion barrels of oil equivalent - enough to supply the world's needs for the next 25 years. Emerging gas to liquid conversion (GTL) utilizations may play a significant role in developing and monetizing large quantities of remote and stranded undeveloped gas in offshore fields in Niger Delta. Offshore GTL utilization applications are important because approximately half of the stranded gas in Niger Delta fields is located offshore. GTL facilities can be used in small associated natural gas fields, for monetization of gas caps, short-term use as an early production system on large fields while a large permanent GTL is being built, and as a long-term solution for offshore gas in a range of water depths, including the expansion activity in deep water regions of Niger Delta. The mobility of the floating GTL facilities would permit their use at multiple offshore locations, thereby providing access to fields that are otherwise too small to justify permanent GTL facilities. Such facilities could also enable conversion and monetization of natural gas that is normally flared or wasted. By converting natural gas into liquid fuels, the utilization greatly reduces high transport costs, which in the past has prevented its access to distant markets. This utilization is destined to provide an important element in the future landscape of the energy industry. Every major oil and Gas Company is now energetically participating in further research and development of the utilization. GTL not only adds value, but capable of producing products that could be sold or blended into refinery stock as superior products with less pollutants for which there is growing demand. Reflecting its origins as a gas, gas to liquids processes produces diesel fuel with an energy density comparable to conventional diesel, but with a higher cetane number permitting a superior performance engine design.

Bjourn (2015) described liquefied natural gas (LNG) as an energy carrier suitable for transport of natural gas of small to moderate volumes and/or over long distances. Liquefaction of natural gas requires energy intensive refrigeration. Compared with pipeline transmission, both capital and operating costs of the facilities are larger for LNG, while the cost of additional transport distance is smaller. The LNG process first involves a gas treatment plant for removal of acid gas (sulfur, carbon dioxide), water, and other contaminants. The gas is then cooled to separate the heavier hydrocarbons such as C_3, C_4, and C_{5+} components. These heavier components are then fractionated to produce C5+ and Liquefied petroleum gas (LPG) products. At atmospheric pressure, liquefied natural gas occupies about 1/600 of its volume at standard conditions (15°C and 1 atm), which enables efficient transport of large quantities in specialized vessels. LNG can be regasified for use in conventional gas markets such as power generation and domestic applications.

LNG and GTL serve different energy markets with different marketing systems, policies and strategies. The comparison between LNG and GTL is the most prominent debate for resource owners, developers, and investors alike. Several factors must be considered to evaluate the project economics. LNG has the obvious advantage of having been developed for the past 40 years and has to-date enjoyed robust growth and has an excellent safety record. GTL on the other hand is a developing alternative to LNG with substantial benefits in terms of sustainable economic, social, and environmental development (Dong et al., 2008). With the recent development of GTL utilization, the debate between GTL and LNG is no longer "is the project economic" but rather "which project is most profitable".

1.2 Economic Contrasts of Natural Gas Utilization options in literature

Bjourn (2015) affirmed the fact that liquefaction is not the only alternative for increasing the energy density of natural gas. Compressed natural gas (CNG) is an alternative utilization for enhanced energy density, based on compressing the natural gas to 125-250 bar. Coselle is a CNG concept where the natural gas is compressed to about 210 bar and transported in a large coil of small-diameter pipe (Bjourn, 2015). In the Votrans concept, the natural gas is both compressed and cooled, before being transported stored in insulated large-diameter pipe sections (Thomas and Dawe, 2003; Economides *et al.*, 2006). Since the natural gas is not liquefied, CNG production is less energy intensive than LNG. LNG ships can, however, transport 2-3 times more gas (Economides *et al.*, 2006). Overall, CNG is a simpler alternative than LNG, but as the energy density is smaller larger cargo sizes are required (Khalilpour and Karimi, 2012).

Alternatively, natural gas can be converted into synthetic liquid fuels using a Fischer-Tropsch process or an oxygenation method (Thomas and Dawe, 2003). Due to its high energy density, gas to liquids (GTL) is an attractive fuel alternative (Khalilpour and Karimi, 2012). As opposed to LNG and CNG, GTL shipping does not require specialized vessels (Khalilpour and Karimi, 2012). GTL is a product ready for use, hence there is no need for a special facility at the import

terminal (Khalilpour and Karimi, 2012).
Based on a techno-economical evaluation, Khalilpour and Karimi (2012) found CNG to be the most profitable alternative for remote gas production when the distance from source to market is relatively short, irrespective of the reservoir capacity. For longer transport distances, LNG was found to provide the highest net present value for relatively small reservoirs, while GTL provided the best alternative for larger reservoirs. Thomas and Dawe (2003) and Economides *et al.* (2006) also concluded in their research that CNG, is preferable to LNG only for short transport distances.
Most of the existing LNG plant capacity is medium to large-scale, however with the demand of natural gas increasing the CAPEX (cash expenditure) for LNG project also increase. Recently, companies are looking into developing a small-scale LNG plant. By IGU definition small-scale LNG plant is a plant with capacity below 1 MTPA (million tonnes per annum). According to Energy Outlook, a small-scale LNG can provide access to markets unavailable to large terminal and large carriers and it can be size to meet the specific demand. Additionally, small-scale LNG is less risky to the investor since the CAPEX is lower and it is faster to build due to its prefabricated and modularization ability. The statement is further confirmed by statement, a small-scale liquefaction plant has capacity less than 500,000 TPA (Tonnes per annum) and is designed to serve specific market (Biscardini *et.al*, 2017).

2 METHODOLOGY

This study makes use of published data to perform economic analysis of four gas utilization options. In addition to the use of published data, vital data and other relevant information were gathered from professionals working in the natural gas industry.

2.1 Development of economic model

In this study, four commonly used utilizations for the exploitation of stranded natural gas were considered. They are; 1. Compressed natural gas (CNG) 2. Natural gas hydrate (NGH) 3. Liquefied natural gas (LNG) and 4. Gas to liquid (GTL)
The economic viability of the above-mentioned utilizations is dependent on four basic factors namely, Capital expenditure (CAPEX), operating expenditures (OPEX), product prices and net cash flows (Osokogwu *et al.*, 2011). However, the economic model utilised in this research made use of excel spreadsheet. The spreadsheet was programmed to perform cash flow analysis and generate profit indicators for the selected gas utilization options (CNG, LNG, GTL and NGH). To efficiently build the economic model, it is necessary that the input parameters are adequately specified for proper analysis. The economic analysis is based on the following input parameters; reserve (gas volume), operational expenditure, capital expenditure, gas price, project life, depreciation and discount rate

2.2 Model assumptions

The following assumptions were considered for the cash flow analysis calculations performed in this study; 1. Tax rate on taxable income (i.e. income after deducting annual operational expenditures and depreciation) is 40% 2. Project life is 15years from production 3. Discount or hurdle rate is 15% and 4. Capital expenditure (CAPEX) is considered at year 0 while operating expenditure (OPEX) starts at year 1.

2.2.1 Economic Analysis of Gas to Liquid (GTL)

This section presents the capital expenditure of GTL (for both upstream and downstream), the operating expenditure (both fixed and variable), the price of gas relative to each option and the consideration of other economic parameters like tax rate, discount rate, project life span, gas volume and depreciation.

A GTL facility (processing 1BSCFD) to

produce approximately 100,000BPD of GTL products is considered for this study. Based on the utilization employed, the facility may include about 5-6 trains. The indicative capital cost for such facility is estimated at around $ 2.9 billion (Osokogwu *et al.*, 2011). The capital costs of GTL facility can conveniently be divided into the following units: Gas plant (20%), Synthesis unit including the air separation unit (24%), Fischer-Tropsch unit (12%), Product upgrading unit (8%), Utilities (12%) and Offsets (16%)

The upstream capital cost involves the number of wells, platform and pipeline. The breakdown is given below:

1 Wells (7) 2. Platform (1) and 3. Pipeline (40 miles of 18" diameter)

Thus, the GTL option gives a total CAPEX of $2.922 billion (Osokogwu *et al.*, 2011). The operating expenditure is assumed as $300 million for fixed operating expenditure and $1.1/bbl annually to account for project management, maintenance, and administrative cost among others. The liquid product price is assumed as $30/bbl. Since GTL products include gasoline, diesel and sometimes jet-fuel, its price was assumed to be 50% of an average crude oil price ($60/bbl). The summary of cash flow analysis parameters or data for gas to liquid utilization is presented in Table 1.

Table 1: Cash flow analysis data for GTL

Parameter	Value
Gas volume	197MMMscf
Liquid price	$30/bbl
Liquid Volume	35MMbbl
Tax rate	40%
Variable OPEX	$1.1/bbl
Life span	15 years
CAPEX	$2,922,000,000
Salvage value	0
Plant capacity	100,000BPD
Operational duration	360ys/year

2.2.2

2.2.3 Economic analysis of natural gas hydrates

The economics of Natural Gas Hydrates (NGH) is based on calculations using mass and energy balance for each unit of the hydrate production process, temperature and pressure.

i. Compressor: the installed cost for the compressor is estimated by using Douglas' equation.

$$\text{Installed cost}(\$) = \left(\frac{\text{M\&S}}{280}\right) \times 658.3 \times (\text{BHP})^{0.82} \times (2.11 + F_c) \quad (1)$$

Where M&S is the Marshall and Swift cost index used for updating the cost correlation.

And F_c which is the fixed cost, depends on the compressor type.

ii. Condenser: the installation cost is also determined by using Douglas' equation and is illustrated in equation 2 below:

$$\text{Installed cost}(\$) = \left(\frac{\text{M\&S}}{280}\right) \times 474.7 \times \text{A}^{0.82} \times (2.29 + F_c) \quad (2)$$

However, F_c depends on the heat exchange type, design and operational pressure.

iii. Heat exchanger: the installation cost is similar to that of the condenser described before now.

iv. Separator: it is based on the capacity of the plant, i.e. the volumetric flow rate of the feed natural gas, the volume of gas hydrate produced per unit time is obtained (25MMScf/d). The volume of the separator as well as its diameter and height are estimated based on the assumption that; one cubic meter of solid methane hydrate will release 170 standard cubic meter of methane, 10 minutes as residence time of the solid hydrate clods in the separator, finally, the overall void fraction equals 80%. The installed cost of the pressurized tank can be used to estimate cost of separator using Douglas' equation.

v. Dryer: using a rotary type, the installed cost of the dryer is estimated using the cost correlations given by Peters and Timmerhaus:

$$\text{Installed cost}(\$) = \left(\frac{\text{M\&S}}{561}\right) \exp\left(0.853 \times \text{In}\left(\frac{\text{A}}{0.093}\right) + 5.778\right) \quad (3)$$

Where A is the peripheral surface area of the dryer in m^2

vi. Reactor: It serves as heat exchanger, and it is used in its cost estimate.

vii. Pump: It is assumed that the pump pressurizes the feed water from atmospheric condition to the reactor pressure. The installed cost is estimated using Peters and Timmerhaus correlations just like for dryers, except that, "A" represents the peripheral surface area of the pump.

viii. Hydrate storage tank: this uses same cost estimate correlation with the separator.

The CAPEX of NGH is obtained by adding all the installation costs (compressor, heat exchanger, separator, dryer, reactor, pump and hydrate storage tanks)

In this study, Operational costs for NGH facility was assumed to be 12% of Capex (Cash expenditure) for each year. The summary of cash flow analysis parameters or data for natural gas hydrate utilization is presented in Table 2.

2.2.4 Economic analysis of Compressed Natural Gas (CNG)

A compressor with a capacity of producing 10 million tonnes/year of CNG, requiring 50 billion scf/year at a gas price of $3/Mscf was assumed for economic evaluation of CNG.

Meanwhile, **t**he breakdown of capital expenditure is as follows;

i. Compressor cost (plant) - $1.2 billion
ii. Processing plant - $0.783 billion
iii. Utilities – $0.6 billion

Thus, total Capex is estimated as $2.583billion. Meanwhile, Opex was assumed to be 12% of capex.

The cash flow analysis data for CNG is shown in Table 3

Table 2: Cash flow analysis data for NGH

Parameter	**Value**
Gas price	$3/Mscf
Tax rate	40%
OPEX	12% of Capex
Life span	15 years
CAPEX	$59,120,000
Salvage value	0
Plant capacity	25MMscf/day
Operational duration	360days/year

2.2.5

2.2.6 Economic analysis of LNG

According to Mazyan *et al.* (2020), the breakdown for the Capex of a 45MTPA capacity LNG plant are as follows;

i. Construction (32% of CAPEX) – 350.2 MMUSD

ii. Engineering and Project Management (8% of CAPEX) - 87.5 MMUSD

iii. Equipment (30% of CAPEX) (Compressors, cryogenic & exchangers, storage tanks) - 328.3 MMUSD

iv. Bulk Materials (20% of CAPEX) - 218.8 MMUSD

v. Owner's costs (10% of CAPEX) - 509.4 MMUSD

However, total capex is estimated as 5094.4MMUSD. The summary of the data needed for economic evaluation of LNG is provided in Table 4.

Table 3: Cash flow analysis data for CNG

Parameter	**Value**
Gas price	$3/Mscf
Tax rate	40%
OPEX	12% of Capex
Life span	15 years
CAPEX	$2,583,000,000
Salvage value	0
Plant capacity	50MMMscf/year
Operational duration	360days/year

Table 4: Cash flow analysis data for LNG

Parameter	Value
Depreciation	8% of Capex

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Gas price	\$3/Mscf
Tax rate	40%
OPEX	12% of Capex
Life span	15 years
CAPEX	\$5,094,000,000
Salvage value	0
Plant capacity	680.775MMMscf/year
Operational duration	360days/year

2.3 Model equations

The economic variables used for economic evaluations in this study are; the Payout time (POT), the discounted cash flow rate of return (DCF-ROR) or Internal Rate of Return (IRR), the net cash flow (NCF), the net present value (NPV) and the profitability index "PI" (i.e. Profit per investment ratio (PIR) +1). However, the model equations used are presented in equations. 4, 5 and 6.

$$C_f = (R_a - OPEX - D_a) \times F_{it} + D_a \quad (4)$$

Where C_f = net cash flow; OPEX = variable cost (VC) + fixed cost
R_a = Annual revenue which is often Volume/year × gas price
D_a = Annual depreciation; F_{it} = fractional tax income i.e. (1-taxFraction). In our case, (1-0.4) – since a tax rate of 40% was assumed.

Taxable income, T_{in} is calculated as;

$$T_{in} = (R_a - OPEX - D_a) \quad (5)$$

$$\text{Depreciation} = \frac{\text{Equipment cost} - \text{salvage value}}{\text{lifespan of project}} \quad (6)$$

The mathematical expression for other economic variables are outlined as follows;

1. **Profit Per Investment Ratio (PIR)**

The Profit Investment Ratio (PIR) or Return on Investment (ROI) is the net present value divided by the total project investment. This and the following ratios demonstrate the dollars earned per dollar invested, or in other words the capital efficiency of the project.

$$PIR = \frac{NPV}{INVESTMENT}$$

2. **Profitability Index**

It is a measure of how profitable a project is relative to the original investment. It is also used for ranking projects and making critical project decisions. Projects with PI greater than 1 are usually accepted and those less than one are rejected. Also, projects with higher values of PI ranks first and vice versa. Meanwhile, profitability index, PI = PIR+1;

3 RESULTS AND DISCUSSION

All results of economic analysis performed on the four gas utilization options are presented in Appendix A of this paper.

3.1 Discussion of Cashflow results from GTL

The cashflow analysis results obtained from the GTL facility considered in this study is illustrated in Table 1. First, an undiscounted net cashflow was computed with the intent of coming up with a POT (Pay-out time) chart. Thereafter, the net cash flows were discounted to estimate the Net present value (NPV) at a discount rate of 15%. The NPV at this rate was estimated to be \$131,262,770.7. Also, sensitivity analysis was performed to investigate the impact of several discount rates on NPV. The result from the sensitivity analysis is as shown in Figure 2. A plot of Undiscounted Net Cash Flow against time was done to obtain the Pay-Out Time (POT) as indicated in Figure 1. The plot shows a pay-out time of 5.8 years. This simply implies that the investment would take approximately 6 years to breakthrough (i.e. to recover the total initial investment cost.). Productivity Index (PI) was estimated to be 1.0449. Conventionally, a productivity index greater than 1 indicates the economic viability of the supposed project. Since the productivity index is greater than 1, it is reflective of the fact that, the GTL project is economical.

3.1 Discussion of Cash flow results from NGH

Table 3 illustrates the cash flow analysis results obtained from the Natural Gas Hydrate (NGH) utilisation utilization. Moreover, the economic procedure is similar to that performed on GTL. Net cash flows were discounted at 15% and the Net Present Value (NPV) at this discount rate was estimated to be $19,935,820. In addition, sensitivity analysis was performed to investigate the influence of diverse discount rates on NPV. The result from the sensitivity analysis is represented in Figure 4. It was observed from the plot that a discount rate greater than 22% will result in a negative NPV. A plot of undiscounted Net Cash Flow against time was done to obtain the Pay-Out Time (POT) as shown in Figure 3. The plot shows a pay-out time of 4 years. This simply implies that the investment would take just 4 years to break even (i.e. to recover the total initial investment cost.). Productivity Index (PI) was estimated to be 1.337. Since the productivity index is greater than 1, it is indicative that, the NGH project is economical.

3.2 Discussion of Cash flow results from CNG

Table 4.3 shows the cashflow analysis results obtained from Compressed Natural Gas (CNG) utilisation utilization. In addition, Net cash flows were discounted at 15% and the Net Present Value (NPV) at this discount rate was computed as **$5,198,118,780.** Also, the result from the sensitivity analysis performed on CNG is represented in Figure 4.6. It was observed from the plot that a discount rate greater than 54% will result in a negative NPV. This is nonetheless reflective of the fact that the project is very viable with high hurdle rate (within 5% and 53%). A plot of undiscounted Net Cash Flow against time was done to obtain the Pay-Out Time (POT) as shown in Figure 5. The plot shows a pay-out time of 4 years. This simply implies that the investment would take just 2 years to break even (i.e. to recover the total initial investment cost.). Productivity Index (PI) was estimated to be 3.1 which implies about 3 times the initial investment cost.

3.3 Discussion of Cashflow results from LNG

Table 4 shows the cash flow analysis results obtained from Liquefied Natural Gas (LNG) 687,550MMscf volume capacity utilisation utilization. Net Present Value (NPV) at a specified discount rate of 15% was computed as **$791,819,246.** Also, the result from the sensitivity analysis performed on LNG is shown in Figure 8. It was observed from the plot that a discount rate greater than 19% will result in a negative NPV. With this hurdle rate, it shows that the project has a very high chance of failing at discount rates greater than 19%.

Pay-Out Time (POT) for LNG utilisation is as shown in Figure 7. The plot shows a pay-out time of 4 years. This simply implies that the investment would take 5 years to break even (i.e. to recover the total initial investment cost.). Productivity Index (PI) was estimated to be 1.16.

3.4 Comparative Analysis on GTL, CNG and LNG

A comparative analysis was performed on GTL, CNG and LNG gas utilisation utilizations using IRR (Internal Rate of Returns) as an indicator. The comparison is illustrated in Figure 9. From the NPV plots, it was observed that CNG has the highest IRR of 53%. Meanwhile, LNG and GTL were found to be somewhat mutually exclusive as they share approximately the same Internal Rate of Return (IRR) of 20%. It is important to note that IRR corresponds to the discount rate at which the discounted cash flows (NPV) equals to zero.

4 CONCLUSION

This study has demonstrated the economic viability of four majorly used natural gas utilization technological options i.e. NGH, LNG, CNG and GTL. Economic models such as IRR, NPV, POT (Pay-Out Time) and PI (Profitability Index) were employed to evaluate these gas utilizations. It was observed however, that CNG has the highest profitability index of 3.01, followed by NGH with a profitability index of 1.33. CNG also gave the highest IRR (Internal Rate of Returns) thus, further proving its economic viability. Moreover, NGH was noticed to be profitable for medium capacity projects and not large projects. Conversely, CNG may not be so viable for small gas projects. Comparisons between LNG and GTL showed that they are nearly mutually exclusive since they both have an IRR value of approximately 20% (17% for GTL and 19% for LNG).

More so, sensitivity analyses were performed on NGH, LNG, GTL and CNG by plotting their respective NPVs on a range of discount rates. Again, CNG subsisted with a positive NPV at a discount rate less than 54%. On the other hand, GTL was observed to hit a negative NPV at a hurdle rate greater than 17%.

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Appendix A

Table 1a: Cash flow analysis for GTL

Years	CAPEX($)	OPEX($)	Depreciation	Gas Volume(BBL)	REVENUE($)	Taxable Income(T_{in})
0	2922000000	0	0	0	0	0
1		3.4E+08	194800000	36000000	1080000000	545600000
2		3.4E+08	194800000	36000000	1080000000	545600000
3		3.4E+08	194800000	36000000	1080000000	545600000
4		3.4E+08	194800000	36000000	1080000000	545600000
5		3.4E+08	194800000	36000000	1080000000	545600000
6		3.4E+08	194800000	36000000	1080000000	545600000
7		3.4E+08	194800000	36000000	1080000000	545600000
8		3.4E+08	194800000	36000000	1080000000	545600000
9		3.4E+08	194800000	36000000	1080000000	545600000
10		3.4E+08	194800000	36000000	1080000000	545600000
11		3.4E+08	194800000	36000000	1080000000	545600000
12		3.4E+08	194800000	36000000	1080000000	545600000
13		3.4E+08	194800000	36000000	1080000000	545600000
14		3.4E+08	194800000	36000000	1080000000	545600000
15		3.4E+08	194800000	36000000	1080000000	545600000

Table 1b: Cash flow analysis for GTL (cont’d)

YEARS	INCOME AFTER TAX	CASHFLOW	NCF	Discounted Cashflow@15%
0	0	-2922000000	-2922000000	-2922000000
1	327360000	522160000	-2399840000	454052173.9
2	327360000	522160000	-1877680000	394827977.3
3	327360000	522160000	-1355520000	343328675.9
4	327360000	522160000	-833360000	298546674.7
5	327360000	522160000	-311200000	259605804.1
6	327360000	522160000	210960000	225744177.5

7	327360000	522160000	733120000	196299284.8
8	327360000	522160000	1255280000	170695030.2
9	327360000	522160000	1777440000	148430461.1
10	327360000	522160000	2299600000	129069966.1
11	327360000	522160000	2821760000	112234753.2
12	327360000	522160000	3343920000	97595437.54
13	327360000	522160000	3866080000	84865597.86
14	327360000	522160000	4388240000	73796172.05
15	327360000	522160000	4910400000	64170584.39
			NPV=	**$131,262,771**

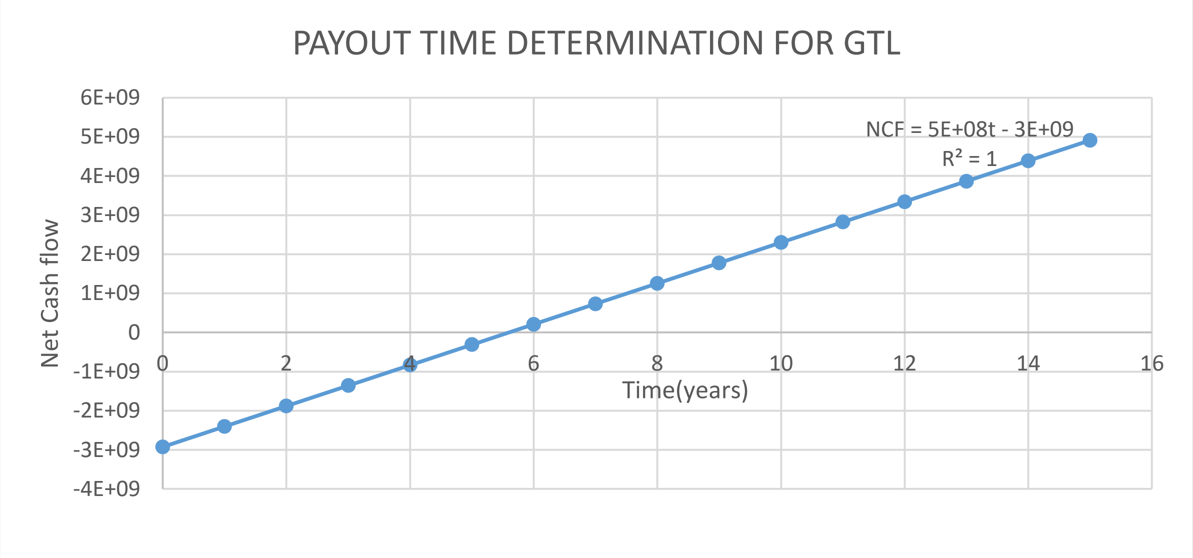

Figure 1: Pay out Time (POT) chart for GTL

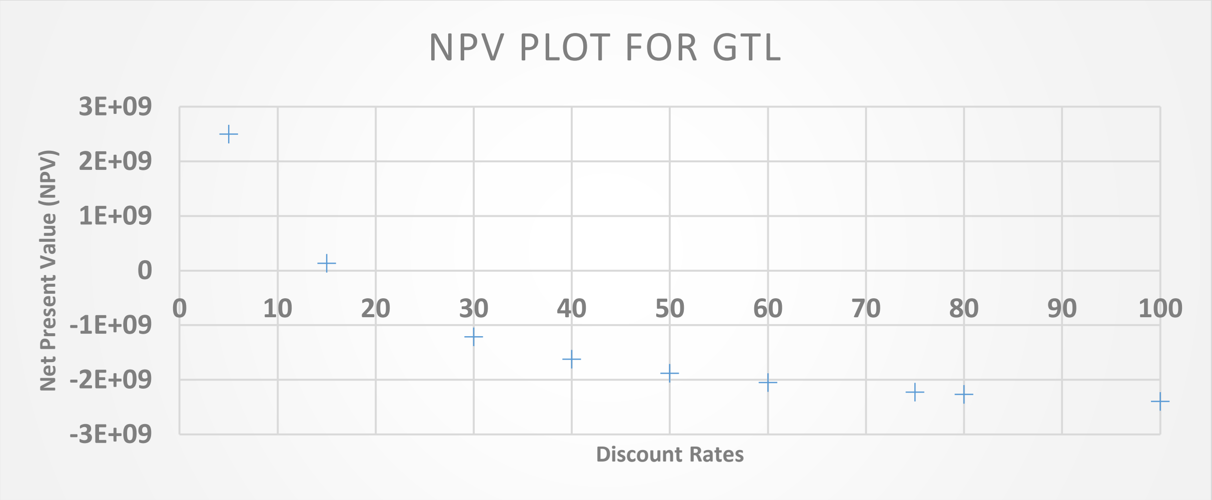

Figure 2: Sensitivity Analysis for GTL with NPV at different discount rates

Table 2a: Cash flow analysis for NGH

YEARS	CAPEX ($)	OPEX ($)	Depreciation	Gas Volume (Mscf)	REVENUE ($)	Taxable Income (T_{in})

0	59120000	0	0	0	0	0
1		7094400	3941333.333	9000000	27000000	15964266.67
2		7094400	3941333.333	9000000	27000000	15964266.67
3		7094400	3941333.333	9000000	27000000	15964266.67
4		7094400	3941333.333	9000000	27000000	15964266.67
5		7094400	3941333.333	9000000	27000000	15964266.67
6		7094400	3941333.333	9000000	27000000	15964266.67
7		7094400	3941333.333	9000000	27000000	15964266.67
8		7094400	3941333.333	9000000	27000000	15964266.67
9		7094400	3941333.333	9000000	27000000	15964266.67
10		7094400	3941333.333	9000000	27000000	15964266.67
11		7094400	3941333.333	9000000	27000000	15964266.67
12		7094400	3941333.333	9000000	27000000	15964266.67
13		7094400	3941333.333	9000000	27000000	15964266.67
14		7094400	3941333.333	9000000	27000000	15964266.67
15		7094400	3941333.333	9000000	27000000	15964266.67

Table 2b: Cash flow analysis for NGH (cont'd)

YEARS	INCOME AFTER TAX	CASHFLOW	NCF	Discounted Cashflow@15%
0	0	-59120000	-5.9E+07	-59120000
1	9578560	13519893.33	-4.6E+07	11756428.99
2	9578560	13519893.33	-3.2E+07	10222981.73
3	9578560	13519893.33	-1.9E+07	8889549.327
4	9578560	13519893.33	-5040427	7730042.893
5	9578560	13519893.33	8479467	6721776.429
6	9578560	13519893.33	21999360	5845022.982
7	9578560	13519893.33	35519253	5082628.68
8	9578560	13519893.33	49039147	4419677.113
9	9578560	13519893.33	62559040	3843197.489
10	9578560	13519893.33	76078933	3341910.86
11	9578560	13519893.33	89598827	2906009.444
12	9578560	13519893.33	1.03E+08	2526964.734
13	9578560	13519893.33	1.17E+08	2197360.638
14	9578560	13519893.33	1.3E+08	1910748.381

15	9578560	13519893.33	1.44E+08	1661520.331
				$19,935,820

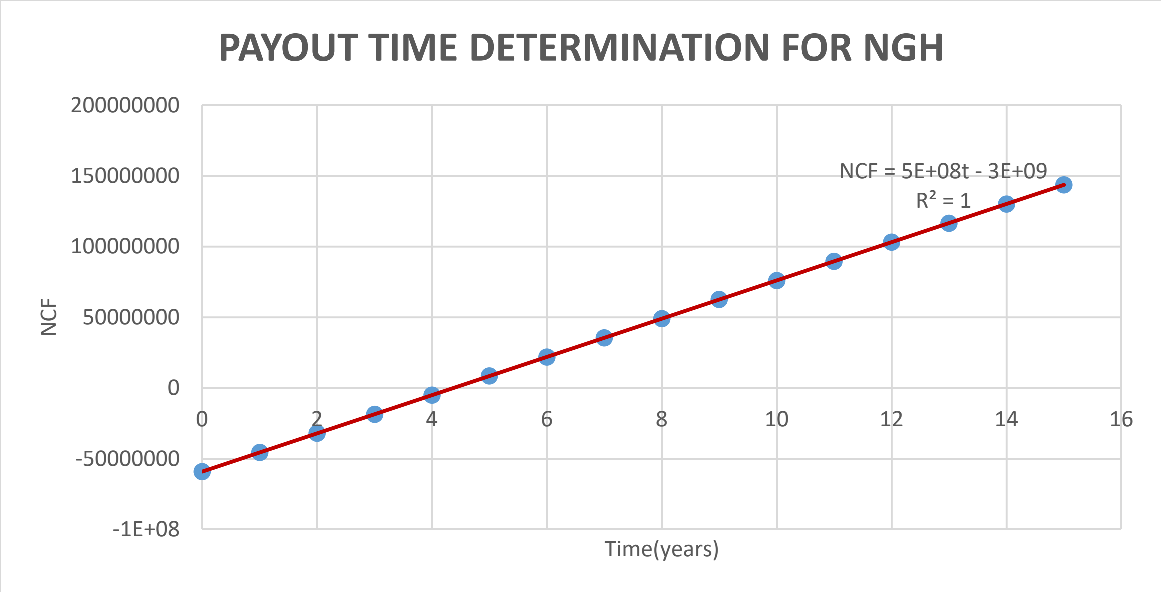

Figure 3: Pay out Time (POT) chart for NGH

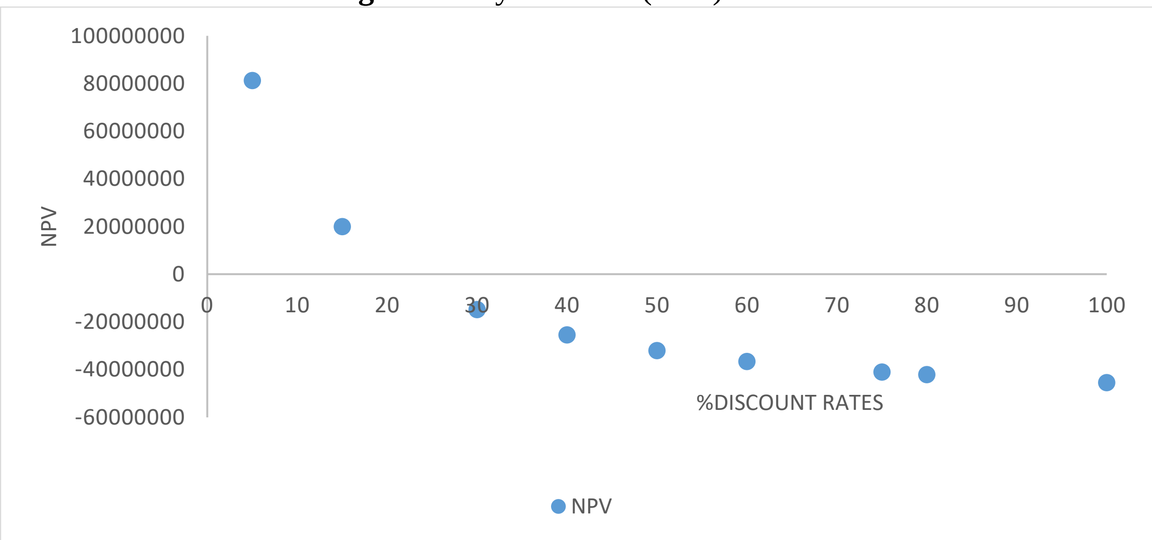

Figure 4: Sensitivity Analysis for NGH

Table 3a: Cash flow analysis for Compressed Natural Gas (CNG)

YEARS	CAPEX($)	OPEX($)	Depreciation	Gas Volume(Mscf)	REVENUE($)	Taxable Income(T_{in})
0	2.58E+09	0	0	0	0	0
1		6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
2		6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
3		6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
4		6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
5		6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
6		6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
7		6.20E+08	2.07E+08	900,000,000	2700000000	1873440000

8	6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
9	6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
10	6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
11	6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
12	6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
13	6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
14	6.20E+08	2.07E+08	900,000,000	2700000000	1873440000
15	6.20E+08	2.07E+08	900,000,000	2700000000	1873440000

Table 3b: Cash flow analysis for CNG (cont'd)

YEARS	INCOME AFTER TAX	CASHFLOW	NCF	Discounted Cashflow@15%
0	0	-2583000000	-2583000000	-2583000000
1	1124064000	1330704000	-1252296000	1157133913
2	1124064000	1330704000	78408000	1006203403
3	1124064000	1330704000	1409112000	874959480.6
4	1124064000	1330704000	2739816000	760834330.9
5	1124064000	1330704000	4070520000	661595070.4
6	1124064000	1330704000	5401224000	575300061.2
7	1124064000	1330704000	6731928000	500260922.8
8	1124064000	1330704000	8062632000	435009498.1
9	1124064000	1330704000	9393336000	378269128.8
10	1124064000	1330704000	10724040000	328929677.2
11	1124064000	1330704000	12054744000	286025806.2
12	1124064000	1330704000	13385448000	248718092.4
13	1124064000	1330704000	14716152000	216276602.1
14	1124064000	1330704000	16046856000	188066610.5
15	1124064000	1330704000	17377560000	163536183
				$5,198,118,780

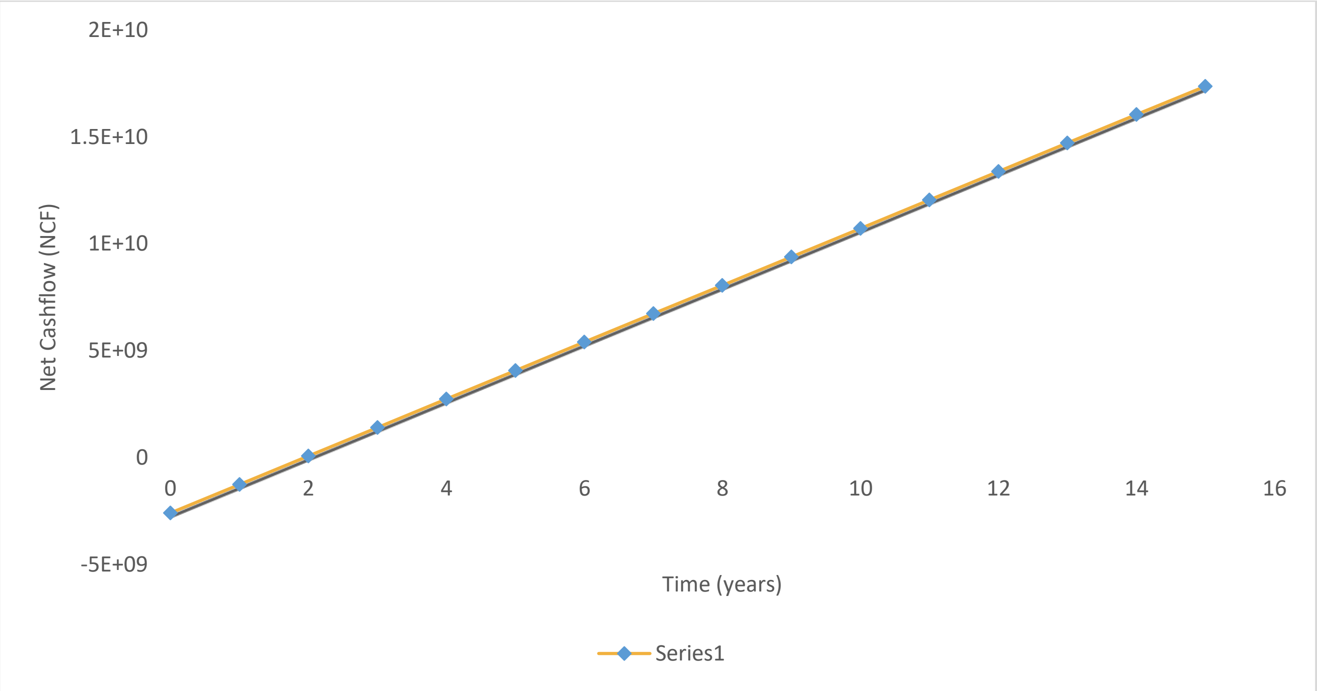

Figure 5: Pay out Time (POT) chart for Compressed Natural Gas (CNG)

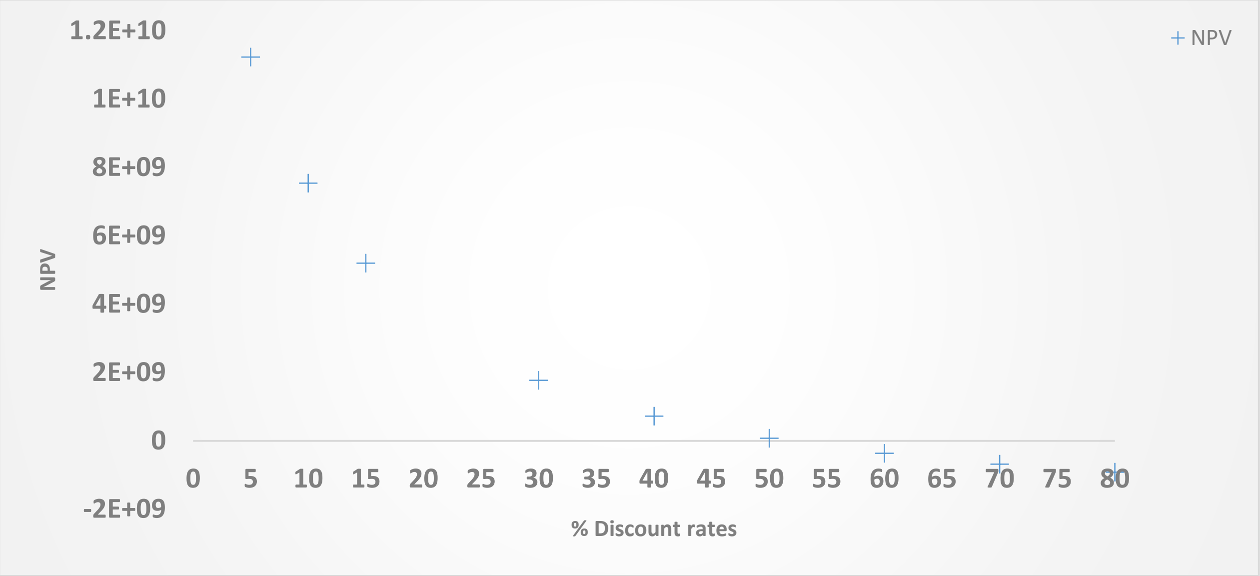

Figure 6: Sensitivity Analysis for CNG

Table 4a: Cash flow analysis for Liquefied Natural Gas (LNG)

YEARS	CAPEX($)	OPEX($)	Depreciation	Gas VolumeMscf)	REVENUE ($)	Taxable Income(T_{in})
0	5.09E+09	0	0	0	0	0
1		611328000	339626666.7	687,550,000	2062650000	1111695333
2		611328000	339626666.7	687,550,000	2062650000	1111695333
3		611328000	339626666.7	687,550,000	2062650000	1111695333
4		611328000	339626666.7	687,550,000	2062650000	1111695333
5		611328000	339626666.7	687,550,000	2062650000	1111695333
6		611328000	339626666.7	687,550,000	2062650000	1111695333
7		611328000	339626666.7	687,550,000	2062650000	1111695333
8		611328000	339626666.7	687,550,000	2062650000	1111695333

9	611328000	339626666.7	687,550,000	2062650000	1111695333
10	611328000	339626666.7	687,550,000	2062650000	1111695333
11	611328000	339626666.7	687,550,000	2062650000	1111695333
12	611328000	339626666.7	687,550,000	2062650000	1111695333
13	611328000	339626666.7	687,550,000	2062650000	1111695333
14	611328000	339626666.7	687,550,000	2062650000	1111695333
15	611328000	339626666.7	687,550,000	2062650000	1111695333

Table 4.4b: Cashflow analysis for LNG (cont'd)

YEARS	INCOME AFTER TAX	CASHFLOW	NCF	Discounted Cashflow@15%
0	0	-5.1E+09	-5094400000	-5094400000
1	667017200	1.01E+09	-4087756133	875342492.8
2	667017200	1.01E+09	-3081112267	761167385
3	667017200	1.01E+09	-2074468400	661884682.6
4	667017200	1.01E+09	-1067824533	575551897.9
5	667017200	1.01E+09	-61180666.67	500479911.2
6	667017200	1.01E+09	945463200	435199922.8
7	667017200	1.01E+09	1952107067	378434715.5
8	667017200	1.01E+09	2958750933	329073665.6
9	667017200	1.01E+09	3965394800	286151013.6
10	667017200	1.01E+09	4972038667	248826968.4
11	667017200	1.01E+09	5978682533	216371276.8
12	667017200	1.01E+09	6985326400	188148936.4
13	667017200	1.01E+09	7991970267	163607770.8
14	667017200	1.01E+09	8998614133	142267626.7
15	667017200	1.01E+09	10005258000	123710979.8
				$791,819,246

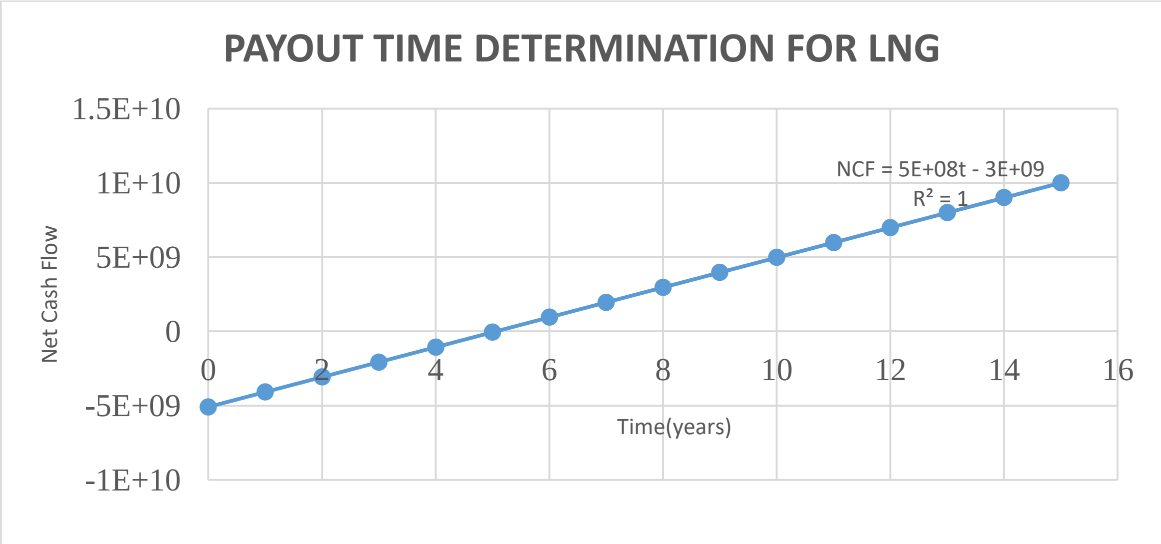

Figure 7: Pay out Time (POT) chart for Liquefied Natural Gas (LNG)

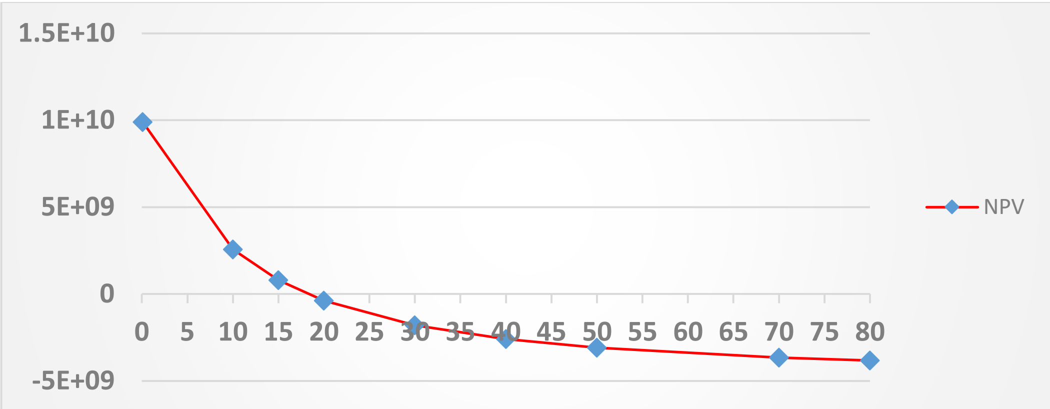

Figure 8: Sensitivity Analysis for LNG

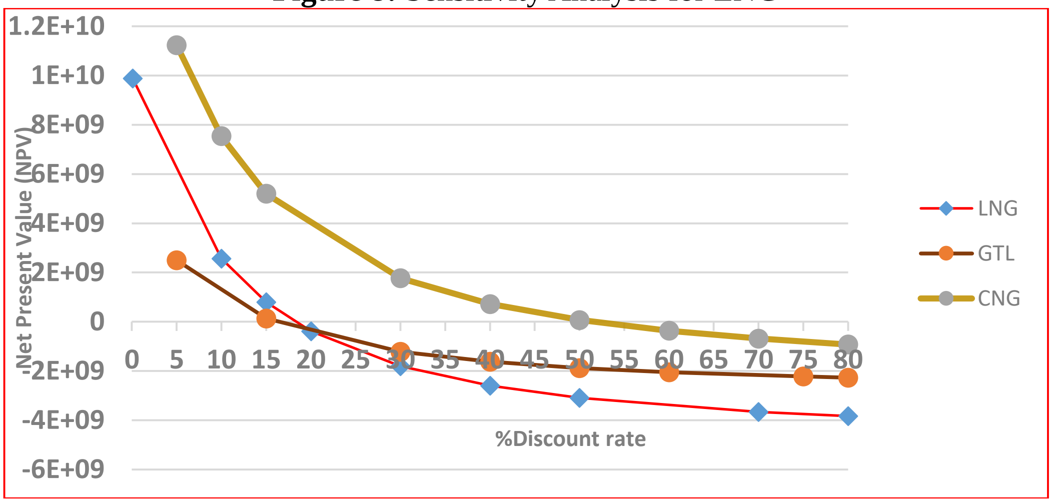

Figure 9: IRR Analysis for GTL, CNG and LNG