

ECONOMIC MODEL AND RISK ANALYSIS FOR NATURAL GAS PLANT IN A DYNAMIC GAS PRICING SYSTEM IN NIGERIA

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Abstract

The monetization of natural gas in Nigeria, rather than its wrong usage to alter the natural state of the environment via flaring, has taken the front stage of the investment portfolio. However, investors should be well informed of the profitability of the investment. This paper seeks to value the viability of investment in the natural gas plant from the source to consumers. Developing economic and cash flow model, determination of economic/profitability indicators, and sensitivity analysis are the stages adopted for this work. The sensitivity analysis is in two parts: deterministic and stochastic sensitivities. CAPEX, OPEX, LPG percentage recovery, wellhead gas, dry gas and LPG prices (input variables) and NPV, IRR, and PI (forecast variables) were selected for the sensitivity analysis. In the stochastic analysis, Monte Carlo Simulation was carried out using @RISK software. Results obtained shows that the estimated deterministic economic indicators, are NPV: \$3889.5, IRR: 58.3% (real) and 84.86% (nominal), PI: 3.59 and payback time: 1.46 years, which meet the criteria for viable investment in the gas processing plant. The stochastic values show that the NPV is \$3674.22 million, IRR is 82.23% (nominal) and 55.75% (real), and PI is 3.462, and the likelihood is 58.91%, 59.92%, and 58.27%, indicating 40% uncertainty in achieving these values. The sensitivity analysis reveals that this uncertainty is the risk imposed by the CAPEX, OPEX and wellhead gas price. The LPG price and percentage recovery have a high positive impact on the forecast variables. This work will enable decision makers to make an informed decision before investment.

Keywords: Monetization; Risk and Uncertainty; @RISK, Forecast; Monte Carlo; Profitability indicators; Gas infrastructure.

1. Introduction

The drive for a cleaner source of energy is inevitable, to reduce environmental pollutants, sustain the natural state of the ecosystems and natural gas has been a cleaner source of energy when combusted. Nigeria has over 180 Tcf of natural gas reserves [1-3]. The total natural gas reserve in Nigeria is 192.065 Tcf. This total gas reserve has a breakdown of 97.208 Tcf Associated Gas (AG) reserves and 94.857 Tcf Non Associated Gas (NAG) reserves [4]. According to [1] and [2], (between 2008 and 2014), natural gas has under gone utilization in Nigeria, but not optimal utilization. The recent discovery of new oil and gas fields may have to increase Nigeria natural gas reserves to 192 Tcf, as stated by [3] and [4] (Figure 1).

Nigeria natural gas reserve is enormous but it is under-utilize, and gas flaring activities have taken advantage of this under-utilization which is as a result of poor gas infrastructural development. Nigeria's economy can have a boost if this enormous natural gas reserve is monetized via the different monetization options (Gas-To-Liquid (GTL), Compressed Natural Gas (CNG), Natural Gas Liquid (NGL), Liquefied Petroleum Gas (LPG), and Liquefied Natural Gas (LNG)) [5]. Each of these monetization options utilizes natural gas as the feedstock.

Presently, many homes in Nigeria utilize Liquefied Petroleum Gas (LPG) for domestic cooking and heating, because of its clean nature when burnt. Many more homes are bracing up to join the numbers. Industries that use heavy machinery in production drive their machinery with power generated from natural gas (main methane) and these industries are continuously

investing more on their production systems. In addition, the Gas to Power industry is another consumer of natural gas. Therefore, there is every tendency that natural gas utilization will increase in the future through the expansion of the market for its products. These are pointers for potential investors in the natural gas downstream sector.

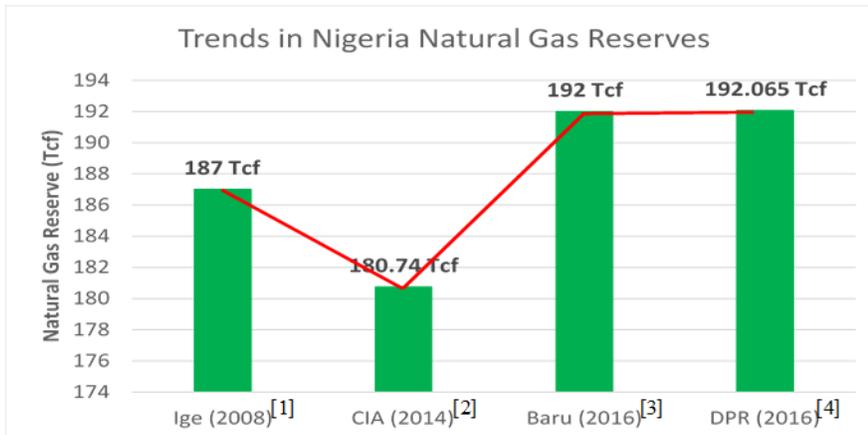


Figure 1. Natural gas reserve status in Nigeria

In Nigeria, there are fewer investors (XEN Energy-25MMScfd, PNG Gas-30MMScfd, Greenville-80MMScfd, Niger Delta (Ogbele Gas Processing Plant)-100MMScfd and Giga Gas-140MMScfd), in the natural gas business, thus monetization is not optimal, possibly due to “lack of willingness of oil producers to mobilize funds to monetize what is essentially seen as a low value by-product compared to oil”^[6]. In addition, lack of information about the economics (financial implication and returns) and risk associated with the business, will hamper investor’s interest. Therefore, this work seeks to bring to bear an economic model and analysis of the profitability, risk, and uncertainty for investment in natural gas plant, via cash flow model development and sensitivity analysis, with LPG and dry natural gas as target products.

2. Literature review

2.1. Natural gas processing and infrastructure

The development of natural gas fields requires gas developers to make the right decision in terms of siting a gas plant, gas infrastructure and long term economic benefit of the processing plant. In this way, the gas developers will be able to predict and control capital spending, while maximizing the value of their natural gas and Natural Gas Liquids (NGLs)^[7].

Making the right decisions during the initial stages of a gas processing plant project is important for the ultimate business outcome and long term survival in the gas business. These decisions can include “technology selection, plant configuration, plant sizing, and site selection together with determining the optimal contracting and construction strategies.”^[8] The development of gas processing systems can require considerable infrastructure decision and sound economic judgment, which can maximize cost recovery. Figure 2, shows a typical configuration in the block flow diagram of the natural gas processing plant, and whatever type of configuration, the Capital Expenditure (Capex) and Operating Expenditure (Opex) depend on the compositions, components, and extent of processing of the natural gas.

Construction and project cost can come under control via two essential aspect of any project: feasibility studies and project oversight in-house, and that proper design, accurately modelled facility performance, and identifying optimal operating strategies can reduce operating cost to a minimum^[10].

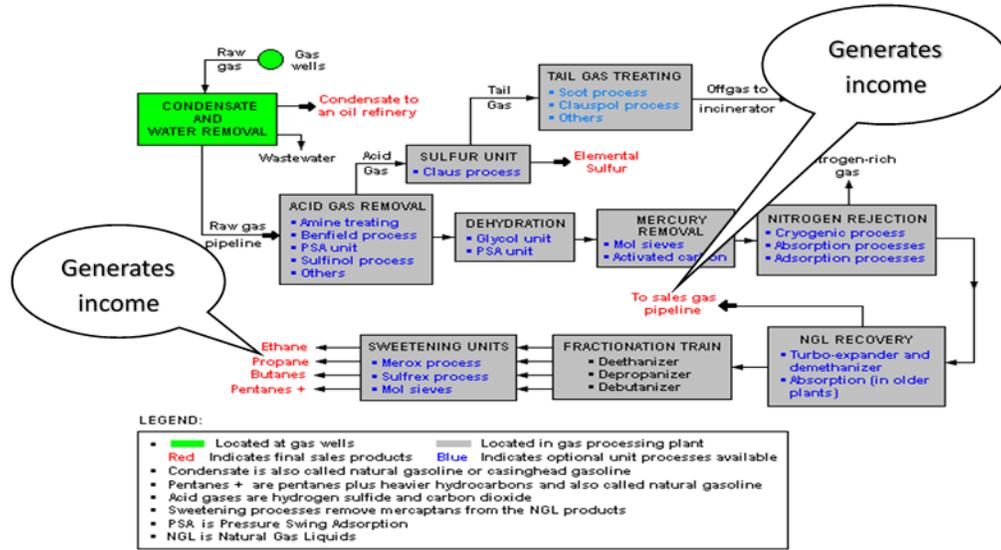


Figure 2. Block flow diagram of a natural gas processing plant [9]

2.2. Natural gas and product price dynamics

The dynamic of demand and supply of natural gas is dictated by its market price, which (in this paper) is divided into two parts: wellhead gas price (producer price) and product price (consumer price). The price of natural gas is not stable because of dwindling oil price and demand for natural gas during winter and summer (in polar region). Countries like Nigeria, demand natural gas and LPG depends on the number of residents and companies that are available to use it.

However, “depending on market condition, either the consumers’ or the producers’ perspective tends to dominate the pricing decision, and a number of alternative pricing mechanisms have emerged in the market.” [11]

Simple Regression (Equation 1) by regressing West Texas Index (WTI) and Henry Hub Spot Price, using weekly price information, was developed by [12].

$$P_{HH} = -0.1104 + 0.1393P_{WTI} \quad (1)$$

The Henry Hub sports price is dependent on short-term price. Hence, any change in demand and supply will affect the natural gas price, thereby, making it more volatile. For the year 2017, the average spot price for natural gas is \$3.01/MMBtu (\$3.10/MScf).

Nigeria National Petroleum Corporation (NNPC) report, February 2017, quoted the price of natural gas as \$2.9/MScf, which is almost the same with the Henry Hub natural gas spot price of \$2.85/MMBtu (\$2.92/MScf), at the same month and year. The price of dry natural gas (from processing plant) supplied to industries and power generation companies (Gas-to-Power), was reviewed and approved by Nigeria National Petroleum Corporation (NNPC), from \$1.5/MScf to \$2.5/MScf. Transportation tariff of \$0.8/MScf was added to this price, making a total of \$3.3/MScf price of gas supplied to the industries and power sector.

Reports by [13], shows that one truck of LPG (20 metric tonnes) was valued at N3.5 millions at the second half of 2016. At this time, the official currency exchange rate was \$1/N190. The report also reveals that, when the official rate hiked to above \$1/N300 in the first quarter of 2017, 20 metric tonnes of LPG increased to above N5 millions. The attendant effect of this price dynamics is the hike in the retailer’s price.

Recent data from [14] shows that, the average price of refilling LPG of 12.5kg cylinder, increased by 2.64% monthly and by 33.11% yearly, from N4, 830.22 in April 2017 to N4, 957.88 in May 2017. The hike in natural gas and product prices has resulted in a push in the inflation rate in Nigeria. The Consumer Price Index (CPI), which measures the inflation rate,

reveals that gas prices and other commodities have increase Nigeria's inflation rate to 18.55% in December 2017 [14].

2.3. Natural gas processing economics

The natural gas industry is bedeviled with risk and uncertainties, in terms of market structure, the available market for the products, dynamics of demand and supply for wellhead gas and the products, price dynamics for wellhead gas and the products, infrastructure, government policies and working fiscal regimes. These risk and uncertainties call for careful decision making before investing in natural gas infrastructure.

Data from various liquefaction projects were used by [15] to calculate the average cost breakdown by plant area and by category for natural gas liquefaction processes and found that the liquefaction and refrigerator systems require about 50% of the total plant cost.

CAPEX), OPEX, and natural gas price are intrinsic parameters in developing an economic and cash flow models. These parameters are used to determine useful economic indicators (NPV, IRR, PI, PVR, GRR, and payback time) on which decision making is relied on, to determine the viability of investing in a natural gas infrastructure project. However, to enhance decision making, further economic analysis such as Monte Carlos Simulation (stochastic Analysis) should be done.

Economic model and analysis on the development of Nigerian offshore marginal fields using Probabilistic approach were presented by [16]. Economic yardsticks (payback time, NPV, IRR, PI, PVR, and profit to investment ratio) were investigated and Monte Carlo Simulation (using Crystal Ball) was used to perform sensitivity analysis which shows that NPV, IRR, and payback time are more sensitive to changes in oil price, gas price and tax rate. However, the economic model for natural gas as a separate unit was not developed in their work.

The economic model for exploiting stranded natural gas in Niger Delta Offshore fields, using two natural gas monetization options: Gas-to-Liquid and Liquefied Natural Gas with pipelines and gas processing were developed by [17]. The NPV for both monetization options, shows that, at a lower price of oil and gas, the LNG monetization option is more attractive, but as the natural gas price increases, both monetization options becomes less attractive for investment. However, sensitivity analysis to further determine the option that poses more risk to investors was not done.

An engineering economic technique for valuation of the viability of marginal oil and gas fields' project in Nigeria using Financial Simulation Analysis was adopted by [18]. Like the sensitivity analysis done by [16] using Crystal Ball, [18] also, carried out sensitivity analysis using Crystal Ball, the input variables are "oil price per barrel, development/capital cost, real discount rate, operating cost, abandonment cost, total field production, Petroleum Profit Tax (PPT) and royalty", and the forecast variable was Post-tax NPV. Among the input variables, [18] found out that PPT, oil price, and royalty have much more impact on the NPV. Again, like the work done by [16], Natural gas processing unit was not considered in the economic model and analysis.

3. Materials and method

Cash flow models are unique to a particular investment in the oil and gas business. It is unique in the sense that, the target product(s) determines the facilities that form the entire plant and it also determines the capital and operating expenditure for a project. However, the process of economic valuation is the same including the natural gas plant considered in this paper. Therefore, the materials used in this work are Excel spreadsheet and @RISK software, and the method adopted was divided into three stages.

3.1. Stage one: Developing the economic and cash flow model

The economic model for the natural gas processing plant was developed using an excel spreadsheet. Figure 2 shows the entire process from which the economic and cash flow model was developed.

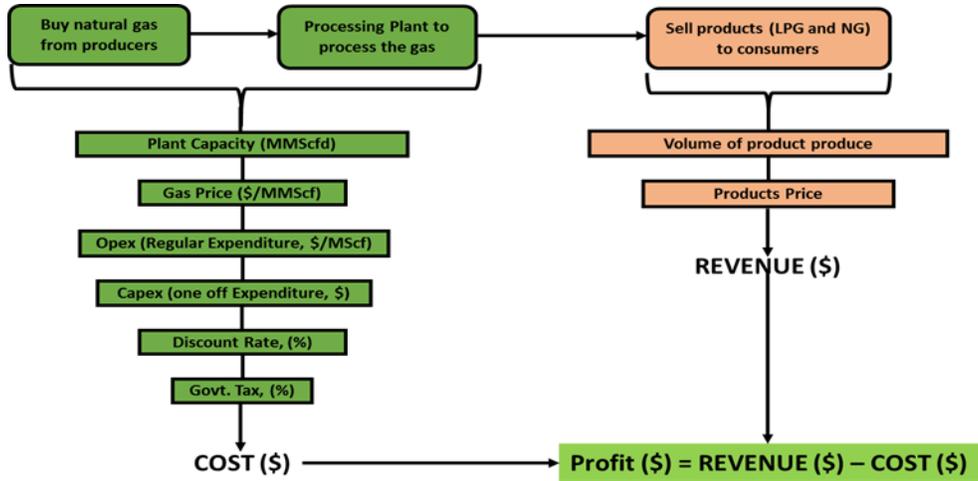


Figure 3. Simplified schematic of the entire process

The natural gas processing plant of interest has a design capacity of 70 MMScfd and an operating capacity of 60 MMScfd. However, the operating capacity was used in the development of the cash flow model. In addition, 356 operating days, 20 years operation of the natural gas processing plant, inflation rate of 17% and straight-line depreciation for 5 years were assumed. Table 1, shows a summary of the input parameters and assumptions.

Table 1. Summary of input parameters and assumptions

Plant capacity (Operating)		60	MMScfd
Wellhead gas price	P_{wg}	4	\$/MScf
Discount rate (Real)	r_R	15	%
Government tax	CIT	30	%
Operating days		356	days
No. of years forecasted	t	20	year
depreciation method	SLD	5	year
Products	Symbol	Price	Unit
Natural gas	P_{NG}	3.3	\$/MScf
LPG	P_{LPG}	280	\$/mt

In developing the cash flow model, Equation 2 was modeled using LPG production data from a major gas processing plant, to estimate the volume of LPG recovered from the NGL, which was extracted from the feed gas.

$$V_{LPG} = 153.53\beta\alpha_r q \text{ (mt/day)} \quad (2)$$

where: β is the mole fraction of C_3/C_4 recovered from the NGL; α_r is the percentage of NGL recovered from the feed gas and, q is the operating capacity of the plant (MMScfd).

The q is dependent on the source of the feed gas while β and α_r are dependent on the treatment plant recovery process and are cash flow model parameters.

3.2. Stage two: Determination of profitability indicators

The process of decision making on the viability of oil and gas property requires estimation of profitability indicators, which are summarized in Table 2.

Net Present Value (NPV)

The NPV is the surplus of cash resulting from the present value, and it is the difference between the present value of cash inflows and the present value of cash outflows at a company's or investor's hurdle rate (or discount rate).

Internal rate of return (IRR)

The “Internal rate of return (IRR) has been a popular managerial indicator since the 1950s, and it is still widely used today” [19]. The IRR is the discount rate that produces zero NPV. In addition, is the discount rate such that the present value of cash outflows is equal to the present value of cash inflows, and it determines the maximum borrowing cost of capital to make the investment viable. The IRR is measured in percentage.

Profitability index (PI)

The screening of investment by the use of NPV may be very attractive, especially when it passes the screening test, but it does not take into account the size of the investment. To take care of the weakness of NPV, the PI was introduced to measure the total return for every dollar invested in a project

Present value ratio (PVR) and Growth rate of return (GRR)

The PVR and GRR are investment screening indicators and are a function of PI and discount rate. The PVR measures the gain per dollar invested, and the GRR measures the capability of reinvestment of capital at the prevailing discount rate. PVR must be greater than zero, and the GRR must be greater than the discount rate for viable investment.

Payback period

The payout measures the time to recoup an investment. At this point, the cumulative net cash loss is exactly equal to the cumulative net cash gain (break-even point).

Table 2. Economic indicators for managerial decision making process

S/N	Indicators	Equation
1	Net Present Value (NPV) (nominal)	$NPV^N = \sum_{t=0}^n \frac{(NCF^N)_t}{(1+r_N)^t}$
2	Internal Rate of Return (IRR) (nominal)	$NPV^N = \sum_{t=0}^n \frac{(NCF^N)_t}{(1+r'_N)^t} = 0$
3	Profitability Index (PI)	$PI = 1 + \frac{NPV^N}{I_o}$
4	Present Value Ratio (PVR)	$PVR = \frac{NPV^N}{I_o}$
5	Growth Rate of Return (GRR)	$RR = (PI)^{\frac{1}{t}}(1+i) - 1$
6	Payback Time	Time (years) at which $\text{Cum}NCF = 0$
7	Unit Technical Cost (UTC)	$UTC = \frac{\text{Discounted Cost (CAPEX + OPEX)}}{\text{Discounted Reserves / Production}}$
8	Nominal Discount Rate (r_N)	$r_N = (1+i_r)r_R + i_r$

where r_R is the real discount rate, r_N is the nominal discount rate (which is as a result of inflation) and i_r is the inflation rate, $r'_N = IRR^N$, is the nominal IRR, $r'_R = IRR^R$ is obtained by substituting r'_N for r_N and calculating r'_R , I_o is the present value of Capital Expenditure (CAPEX) at the given discount rate r_R , used in discounting NPV.

3.3. Stage three: Deterministic and stochastic sensitivity model of the variables

Two methods of determining the sensitivity (deterministic and stochastic) of the forecast variables to changes in the input variables were presented, to capture risk and uncertainty in the natural gas project.

The deterministic sensitivity is a single point model of one input variable and one forecast variable. The input variable is price, and the forecast variable is NPV, with these two single point variables, an NPV profile was generated, using Equations 3.

$$NPV_d = f(P) \tag{3}$$

where NPV_d is the Net Present Value under deterministic sensitivity; P is the price for wellhead gas, dry natural gas, supplied to industries and LPG price for domestic purpose.

Stochastic sensitivity involves Monte Carlo simulation using @RISK software, such that, more than one decision variable in the investment model will be varied at the same time, to

determine their different level of impact on a forecast variable. Each input variable (wellhead gas, dry gas and LPG prices, Opex, Capex and percentage recovery of NGL), is described by a Probability Distribution Function (PDF). The PDF for the gas prices is Lognormal Distribution. The lognormal PDF has lower boundary but no upper boundary, and this inform its choice for the gas prices, because, the price of gas can never be zero as time passes. Opex and Capex are Uniform Distribution, since it is uncertain about the most likely Opex and Capex for the gas plant. The PDF for percentage recovery of NGL is triangular. The choice for this distribution was based on the maximum (most likely) recovery of the LPG from the NGL, which is dependent on the plant design and target product.

4. Results and discussion

Table 3, shows the economic indicators estimated from the cash flow model.

Table 3. Economic indicators before and after income tax

Indicators	Before income tax	After income tax	Unit
NPV	6 199.3	3 889.5	\$MM
IRR	112.86	84.86	%
PI	5.13	3.59	
PVR	4.13	2.59	
GRR	46.02	43.44	%
Payout Time	1.08	1.46	year

The indicators, before income tax, are greater than the indicators after income tax, except payout time. This is because of the impact of income tax, and the essence of depreciating the asset is for the income tax purpose. The estimated NPV of the cash flow after income tax is positive (\$3889.5 million > 0), which indicates viable investment. The estimated IRR in Table 3 are the nominal values, the real IRR was calculated to be 0.583 (58.3%) after income tax, and it is greater than the discount rate, 0.15 (15%). The implication is that, at 58.3%, the NPV is zero indicating the maximum borrowing cost of capital to make the project of investment viable. Above this value, the investment starts to generate negative NPV. Also, the IRR must not go below the cost of capital. Therefore, it is profitable if the company hurdle rate is between the discount rate and the IRR (15% < hurdle rate of \leq 58.3%). The GRR estimated from the cash flow, meets the criteria (Table 4), but can be used in decision making, only when the investment has the capability that capital from this project can be re-invested at the prevailing discount rate.

The PVR measures the gain per capital invested. Thus, the estimated PVR (2.59), indicates that there is \$2.95 gain for every \$1 invested, thereby making the gas processing plant viable for investment. The estimated PI (3.59) after income tax, indicating that the natural gas processing plant will return a total of \$3.59 for every \$1, where \$2.59 is gain for every \$1 invested. The estimated payout time after income tax is 1.46 years. Although, the work done by [16] was based on oil and gas marginal field, but gave a payout time of 1.42, which agrees with the value obtained in this work.

Table 4 Summary of profitability measures and decision rules

Profitability measure	Decision rules	
	Accept if	Reject if
Payback period @ d	\leq Desired	\geq Desired
Net present value (NPV) @ d	> 0	< 0
Internal rate of return (IRR) @ d	$> d$	$< d$
Profitability index (PI) @ d	> 1	< 1
Present value ratio (PVR) @ d	> 0	< 0
Growth rate of return (GRR) @ d	$> d$	$< d$
Unit technical cost @ d	$<$ Average Product Price	$>$ Average Product Price

4.1. Deterministic sensitivity analysis

Market forces of demand and supply of natural gas, are dynamic in nature, and they dictate the prices of wellhead gas and its products. Using Equations 3, NPV profile of Figures 4 and 5 were generated for wellhead gas and LPG prices respectively.

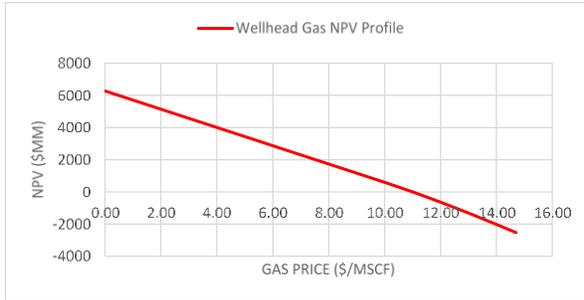


Figure 4. Wellhead Gas NPV sensitivity profile

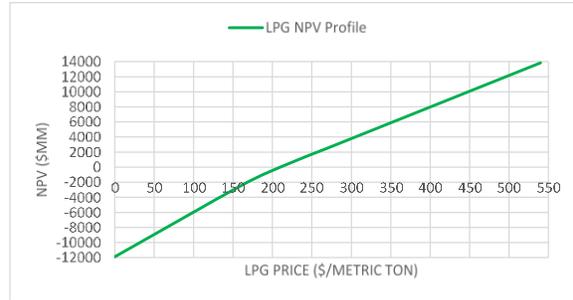


Figure 5. LPG NPV sensitivity profile

The maximum price to buy wellhead gas from the producer so that the investment continues to generate positive income was \$10.99/MScf, and this value is the Break-even price of the wellhead gas (Figure 4). Above this price, the investment starts to generate negative NPV, and as the price decreases, the NPV increases, which favours the investors. In transfer pricing, increasing the wellhead gas price favours the producer, but becomes a loss to the gas processing company, vice versa. The minimum amount at which the LPG can be sold was \$210.42/ metric ton (Figure 5). This is the Break-even price for the LPG. Below this price, the NPV becomes negative, indicating a loss to the investors. This price is an important parameter to be monitored such that it does not fall below a unit production cost. The break-even price for the dry natural gas on the cash flow model was very low (less than \$0.2/MScf), indicating the favourable market for dry natural gas down to a price as low as \$0.2/MScf.

Unit Technical Cost (UTC) indicates what the product is costing to develop the processing plant and to produce the product. The UTC is calculated when $NPV = 0, PI = 1.0$, and discount rate is the IRR. Therefore, the UTC is the same as the minimum price at which the product can be sold, but its screening criteria is that, it must be lower than ($\$210.42/mt < \$280/mt$) the proposed product price or the prevailing market price of the product (LPG).

4.2. Stochastic sensitivity analysis: @RISK base simulation

The Monte Carlo Simulation using @RISK was done with 5,000 iterations. From Figures 6 and 7, the Monte Carlo simulations show that the NPV and IRR are lognormal distributed with a mean (expected) value of \$3672.22 million and 82.05% (nominal) with a standard deviation of \$1176.50 million and 18.62%. The likelihood of these values is 0.5891 (58.91%) and 0.5992 (59.92%), indicating 40% uncertainty in getting the expected NPV and IRR (Figures 6 and 7). This uncertainty poses a risk on the cost of capital; once there is an escalation in gas price, procurement and installation costs.

Figure 8 shows that of the PI, which measures the size of the project, with an expected value is 3.462, which is well above 1.0, indicating that for every \$1 million dollars invested, there is \$3.462 million total return, with the likelihood of 58.27% (i.e. probability of 0.5827). This implies that investors are 58.27% certain that the investment will return \$3.462 million, the rest is the risk associated with the investment due to uncertainty in price escalation.

Figures 9, 10, and 11, shows the sensitive response of the NPV, IRR, and PI from the input variables. The chances of achieving their expected values are above 50%. This culminates from the individual impact of the input variables. For the three forecast variables, the LPG price and percentage recovery have the highest positive impact on them, indicating that, increasing these values will increase their output and vice versa. The dry gas price has the least positive effect on the forecast variables, indicating that more returns will be achieved if the processing company focuses on increasing LPG production.

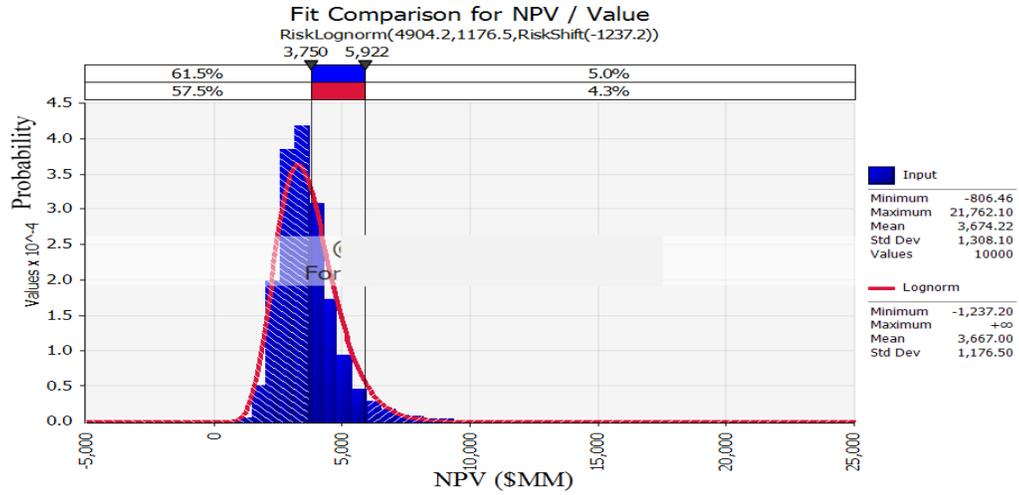


Figure 6. Simulated NPV fitted with normal distribution function

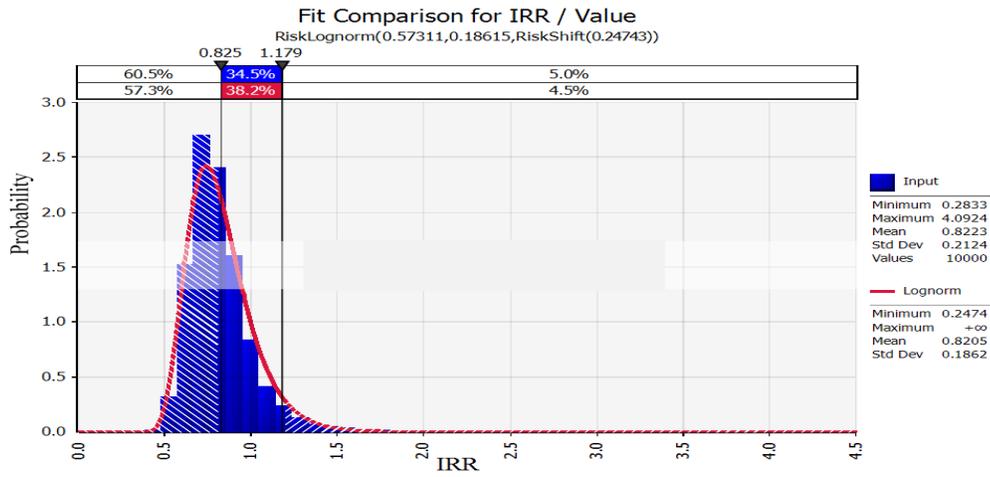


Figure 7. Simulated IRR fitted with normal distribution function

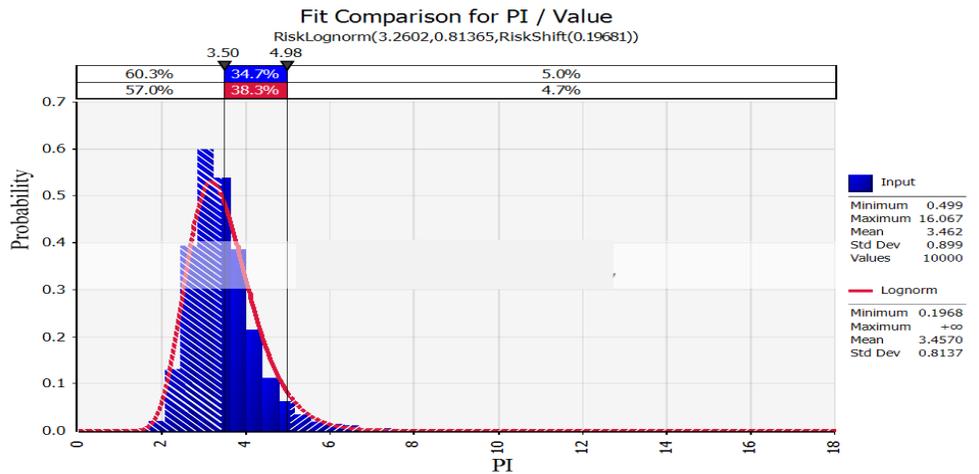


Figure 8. Simulated PI fitted with normal distribution function

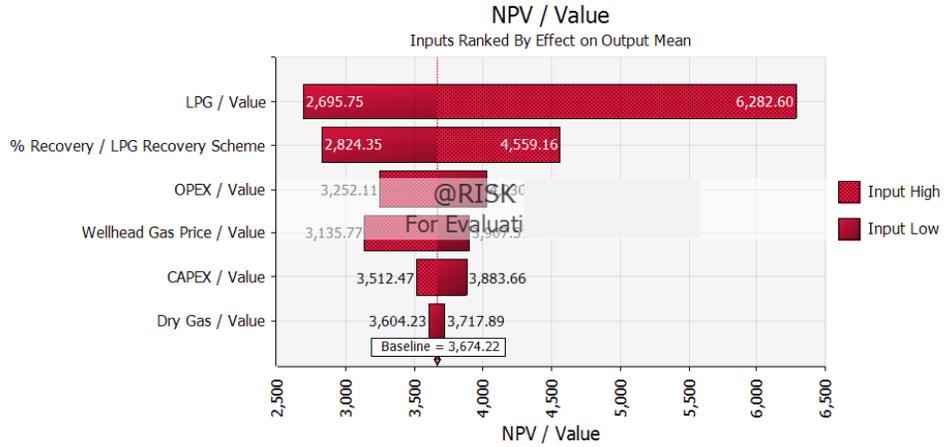


Figure 9. Tornado diagram of the NPV response based on effect of output mean

The OPEX has the highest negative impact on the NPV and IRR, (Figure 9 and 10). Therefore, the gas plant should be designed to maximize recovery of LPG (this is where the percentage recovery in Equation 2, comes in) and minimize OPEX, thereby minimizing the negative effect of the OPEX on the NPV and IRR.

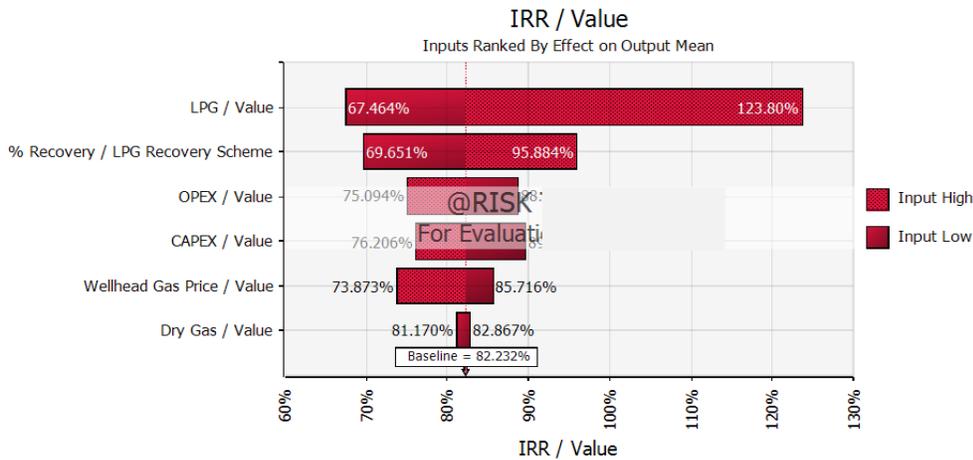


Figure 10. Tornado diagram of the IRR response based on effect of output mean

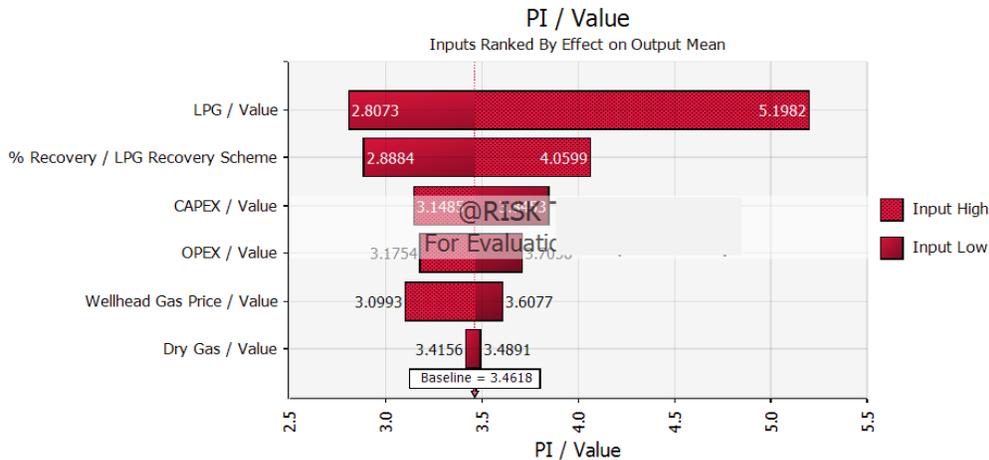


Figure 11. Tornado diagram of the PI response based on effect of output mean

The negative effect of the OPEX and CAPEX on the NPV and IRR imposes a risk on the cost of capital in the midst of inflation. When there are an inflation and price escalation, the nominal discount rate will increase (Table 2), thereby reducing the expected values and the chances of achieving them. Figure 11 shows that the CAPEX has an impact that is more negative on the PI.

The negative impact of CAPEX, imposes a risk on the investment, indicating that increasing the CAPEX will reduce the likelihood of getting the expected PI. However, since the CAPEX is a one-off cost, the risk will come in the form of the delay in completing the installation of the gas processing facilities, commissioning and startup operations. During this delay, cost of procurement and installation might escalate, as stated by [15], and in the process, escalate the CAPEX and payback time, thereby decreasing the likelihood of achieving the expected return from the investment. Timely completion and startup operation will minimize the risk imposed by the CAPEX on the PI.

Figures 12, 13 and 14 are the spider charts of the sensitivity analysis. The chart shows the sensitive response of the forecast variables, which is dependent on the steepness of the input variables.

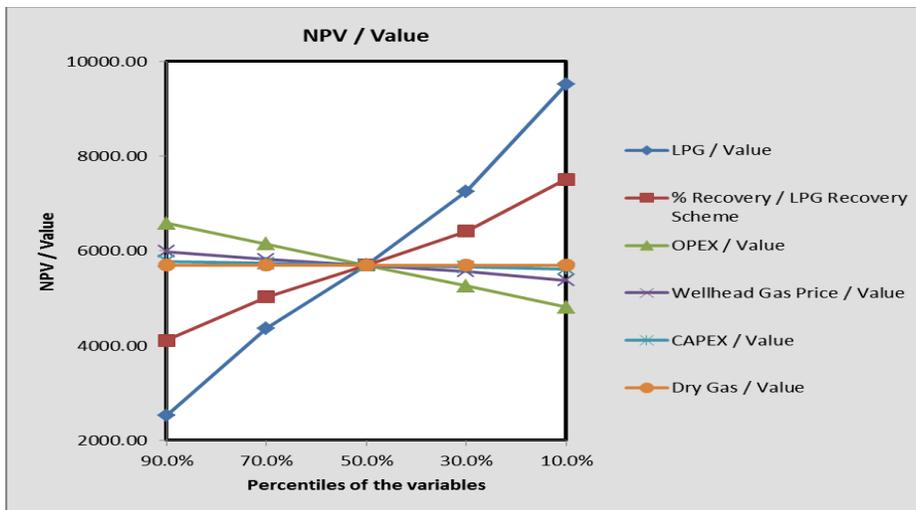


Figure 12. Stochastic spider diagram for the NPV

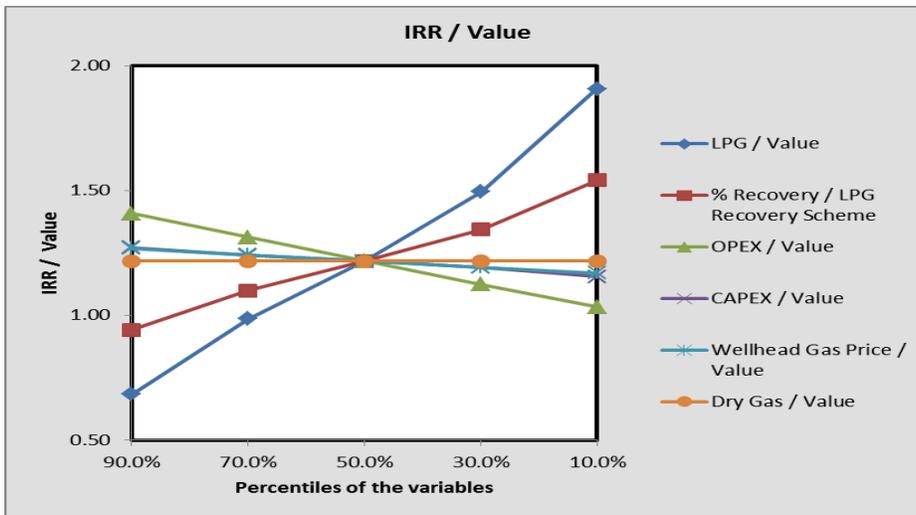


Figure 13. Stochastic spider diagram for the IRR

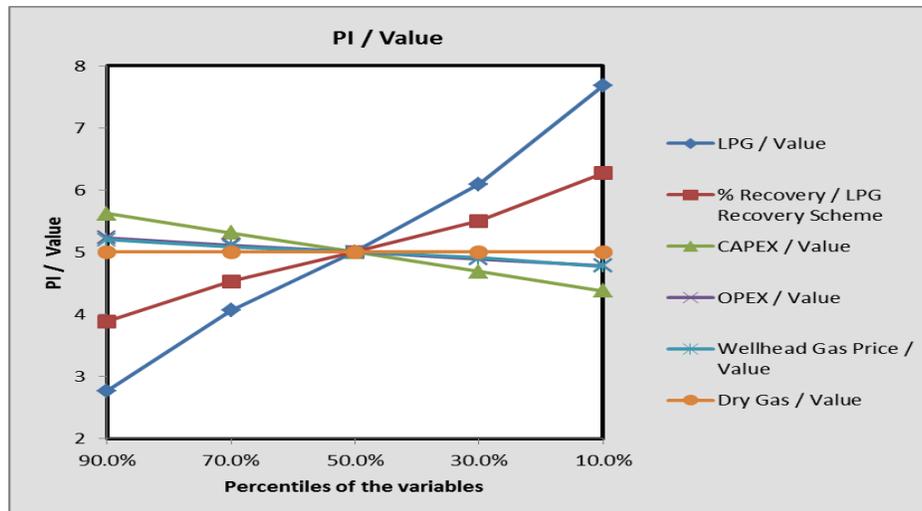


Figure 14. Stochastic spider diagram for the PI

Figures 12 to 14, show that LPG price and percentage recovery, have the most positive steepness and thus increases the value of the forecast variables. CAPEX, OPEX and wellhead gas price have negative steepness, indicating an inverse relationship with the forecast variables.

These findings, are in agreement with the stochastic analysis done by [16,18], which shows that CAPEX has a more negative impact on forecast variables, and the dry gas price has a positive effect on the forecast variables.

5. Conclusions

The starting point for economic valuation of oil and gas project is the development of cash flow (which is unique to a particular project) to determine the viability of the project using economic indicators. The analysis of the cash flow shows that the expected stochastic values of the indicators are less than the deterministic (best average) values, because of the risk associated with the project. The stochastic values are \$3674.22 million, 82.05% (0.8205) and 3.462, while the deterministic values are \$3889.5 million, 84.86% (0.8486) and 3.59 for NPV, IRR, and PI respectively.

Investment in natural gas infrastructure is viable, but decision makers must pay more attention to the instability of wellhead gas price, product price and investment capital in the midst of inflation and escalation of the cost of procurement and installation of plant facilities. These input parameters pose risk and uncertainty on the parameters that define the profitability of the investment. Therefore, decision makers should advice investors based on stochastic values rather than deterministic values, because the stochastic values are associated with risk and uncertainty.

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