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TECHNOECONOMIC ANALYSIS OF REFINING NIGERIAN LIQUEFIED NATURAL GAS CONDENSATE

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ABSTRACT
Condensate refining is among the strategies proposed to solve the light oil glut around the globe. The Nigerian Liquefied Natural Gas (NLNG), which is the Nigerian government's best performing investment in the natural gas value chain, produces plant condensate as a by-product. In this paper, the economics of a refinery designed to use NLNG plant condensate is evaluated under an optimistic oil price forecast and a pessimistic oil price trend. A gasoline producing refinery configuration was chosen for this study, and it comprises of a naphtha splitter, a Penex isomerisation unit and a Continuous Catalytic Reforming (CCR) unit. The product yields and plant costs were determined by established correlations and industry estimates. The proposed refinery will convert 40,000 bpd plant condensate into 96% gasoline, 3% LPG and 1% hydrogen, and economic indicators such as Net Present Value (NPV), Internal Rate of Return (IRR) and Profitability Index (PI) were used to assess the economic viability of the refinery. The optimistic scenario of oil price forecast resulted in an NPV of $ 531.90 million, an IRR of 20.09% and a PI of 3.16, while the pessimistic scenario gave an NPV of $16.26 million, an IRR of 11.16% and a PI of 1.07. These results prove that a condensate refinery with the proposed configuration is economically feasible and interested investors in Nigeria's refining space should explore this possibility.

1. INTRODUCTION

Oil and gas contribute the most to the world energy mix (IEA, 2017), and a significant part of these are petroleum products like transportation fuels and petrochemicals. Therefore, nations must understand the dynamics of petroleum products demand and supply to guarantee energy security (Sovacool, 2012). Though renewable sources of energy are forecasted to grow in developing nations, the growth in petroleum energy demand is predicted to dwarf it up to 2040 (OPEC, 2017a). Nigeria's demand for gasoline increased by 50,000 bpd between 2012 and 2016 while its demand for diesel increased by 22,000 bpd (OPEC, 2017b). Nigeria has four refineries with a total capacity of 446,000 bpd, and they comprise the 210,000 bpd Port-Harcourt Refinery (old and new); the 125,000 bpd Warri Refinery; the 110,000 bpd Kaduna Refinery; and the 1,000 bpd Niger Delta Petroleum Resources Refinery. Nigeria has about 37.5 billion barrels of oil in proven reserves (OPEC, 2017b) but the bottleneck has been its failure in petroleum refining for domestic consumption, which has necessitated its heavy reliance on the importation of gasoline. Figure 1 shows the demand of petroleum products and Nigeria's local production in 2016 (OPEC, 2017b), and the difference was imported.

The Department of Petroleum Resources (DPR) has issued more than 30 licences for the establishment of new refineries in Nigeria to make up for the shortfall in domestic refining (DPR, 2018). The Dangote and OPAC Refineries are among the companies granted licensees that have made concrete moves towards establishment of their refineries. Other licensees are either sourcing for funding or at the design stage.

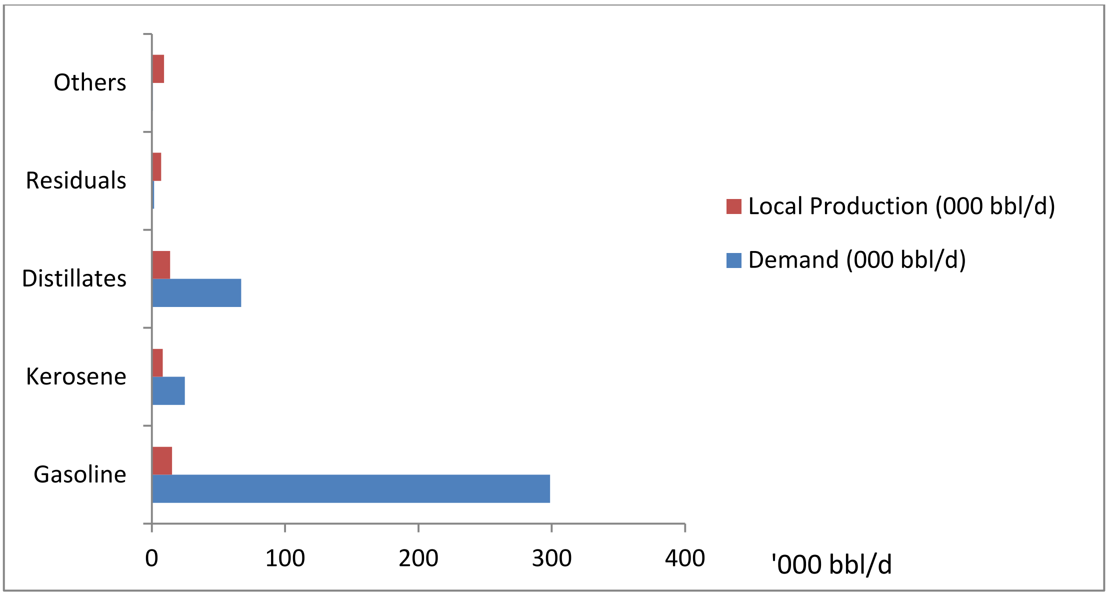

Figure 1: Nigeria's petroleum product demand versus local production 2016 (OPEC, 2017b)

There are different strategies that are used to improve transportation fuel pool in addition to traditional crude oil refining, and they include: whole naphtha blending with high octane gasoline (Lois *et al.*, 2003), use of Compressed Natural Gas (CNG) in place of transportation fuels (Tabar *et al.*, 2017), blending of biofuels with fossils fuels (Al-Mashadani & Fernando, 2017), and refining of Natural Gas Liquids (NGL) usually called gas condensates (Okorokov & Vilenskii, 1995).

Pyziur (2015) notes that condensates are used as diluents for heavy crudes, refinery blending feedstock, petrochemical feedstock, and boiler fuels but their increased production has necessitated its direct refining into gasoline.

Condensates are either lease condensates which are produced at the wellhead or plant condensates (also called natural gasoline) which are produced during natural gas processing activities (EIA, 2013) and more than 80% of condensates are of the lease type (Pyziur, 2015). Condensates can be refined like crude oil in a refinery. A condensate splitter or Condensate Fractionation Unit (CFU) is used to perform atmospheric distillation (Begum *et al.*, 2010). The main product of its distillation is naphtha, with kerosene, diesel, and some Liquefied Petroleum Gas (LPG) as co-products. The naphtha can be reformed to high octane gasoline or sold as petrochemical feedstock.

Condensate refining could be added to the mix of Nigeria's effort to close the demand and supply gap locally for petroleum products like gasoline and diesel.

Nigeria's plant condensate is from its numerous natural gas processing installations and Nigeria Liquefied Natural Gas (NLNG) plant. NLNG has the capacity to produce a minimum of 5 million tonnes per annum (mtpa) of plant condensate and LPG from its six trains which currently produce 22 mtpa of Liquefied Natural Gas (LNG), and the produced condensate is currently shared among the shareholders and exported by them. LNG plant condensate is usually very light and sweet, having been treated by the LNG process and hence, LNG plant condensate can easily be refined to petroleum products. Since NLNG has sixteen LNG long-term contracts with its clients (NLNG, 2018a), which guarantees its operations and availability of condensate feedstock for a refinery. This paper evaluates the techno-economics of locating a condensate refinery close to the NLNG plant in Bonny, Rivers State, Nigeria. The evaluation presented in this paper is pertinent because if a condensate refinery is successfully located close to NLNG plant, it would increase Nigeria's local refining capacity by adding value to the condensate produced by NLNG and save Nigeria some of the foreign exchange currently being spent in the importation of petroleum products.

There are several papers on condensate fractionation/refining modelling in the open literature and, to the best of our knowledge, none of them focused on the technoeconomics of condensate refining in Nigeria. Begum *et al.* (2010) used Aspen HYSYS V7.1 to model an actual condensate fractionation process in Bangladesh using different designs for the column and natural gas as feedstock, and their work only addressed condensate fractionation and excluded product upgrade processes. Bentahar *et al.* (2013) studied the use of local materials to formulate catalysts that can convert condensate fractions into high quality gasoline through isomerization. Mohamed *et al.* (2016) determined the optimum configuration of an isomerization unit in the Mideast Oil Refinery (MIDOR) located in Egypt and their work resulted in better products specification and reduced costs. In the work of Mohamed *et al.* (2016), eight different configurations for the same feed conditions were investigated and they concluded that adding a de-isopentanizer to the existing plant was the most economic modification with a return on investment (ROI) of 26.6% for a product with a RON of 87. Adjimah and Luki (2017) assessed the economics of refining condensate against condensate sales for Atuabo Gas Processing plant in Ghana, and their study was based on estimating the potential products from refining condensate through comparison with an existing plant owned by Sinopec in China. The findings of Adjimah and Luki (2017) indicated positive higher NPV for the case of refining plant condensate but their economic analysis did not consider escalation of costs and depreciation of assets. Gary *et al.* (2007) presented some detailed installation cost estimates for refining units such as desalter, atmospheric distillation column, vacuum distillation, continuous catalytic reformer (CCR), isomerization unit, etc. in the US Gulf Coast. The estimates of Gary *et al.* (2007) did not include costs of utilities, storage, and product purification but they provided utility costs per barrel of raw material processed in the units.

2. METHODOLOGY

The methodology adopted for this work includes: (1) LNG plant condensate characterization, (2) process modelling and simulation and (3) Cost Estimation and Economic Analysis. Figure 2 shows the sequence of steps adopted for the techno-economic evaluation presented in this paper.

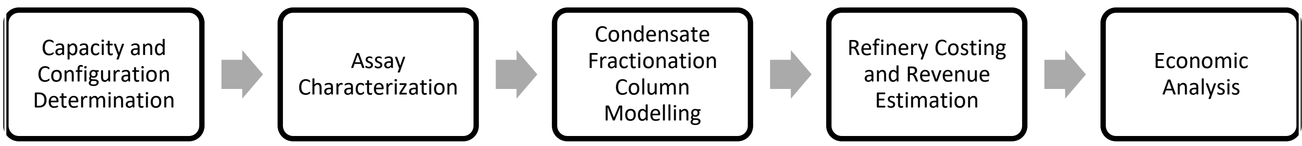

Figure 2: Research Steps.

2.1 LNG Plant Condensate Characterization

A commercial LNG plant condensate assay was used in this study. Table 1 shows some of its relevant properties, which include its density and ASTM D86 temperature profile (QatarPetroleum, 2018). Aspen HYSYS V8.0 was used for the characterization of the plant condensate, as well as the modelling of the CFU.

Table 1: Properties of Commercial LNG plant condensate

Parameters	Units	Method	Average	Low	High
Relative Density		ASTM D 40520	0.6665	0.6678	0.6696
API Gravity		ASTM D 129-80	79.88	80.4	99
SayboltColor		ASTM D 156+30	+30	+30	00
Free Water and Particulates		ASTM D 4176-94	Nil	Nil	Nil
B S & W	%vol	ASTM D 400795	Nil	Nil	Nil
RVP @ 100 ^{o}F	Psia	ASTM D 323-99/a	11.4	11.2	11.5
Distillation		ASTM D86			
Initial Boiling Point (IBP)	°C		36	35	37
10% Vol.	°C		46.5	46	47
50% Vol.	°C		58.5	57	60
90% Vol.	°C		100.5	99	102
Final Boiling Point (FBP)	°C		136	134	138
Recovery	%Vol.		99	99	99
Residue	%Vol.		0.5	0.5	0.5

2.2 Process Modelling and Simulation

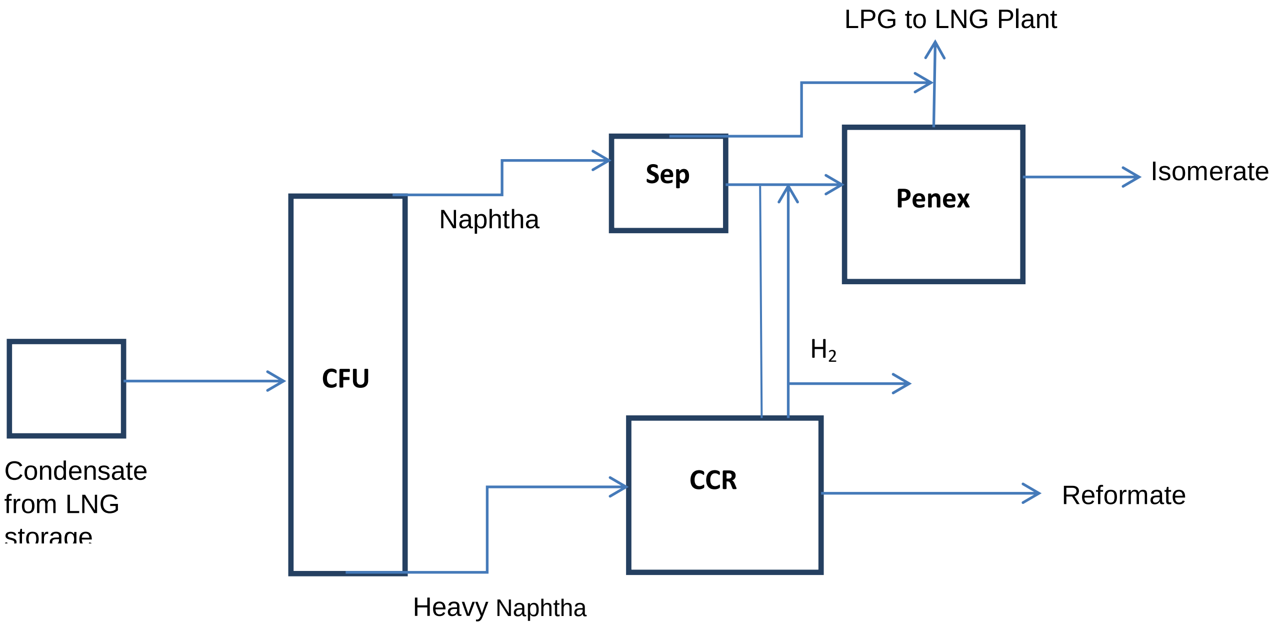

Figure 3: Block flow diagram (BFD) of adopted condensate refinery configuration

The suggested refinery configuration is shown in Figure 3. The condensate, which comprises mainly C_5 and C_6, is fractionated into light naphtha (LN) and heavy naphtha (HN). The light naphtha is converted into isomerate using the UOP Penex process while the heavy naphtha is converted to reformate using the UOP CCR process. A mixture of both products form the final gasoline output of the refinery. The capacity of the refinery is estimated as 40,000 bpd considering NLNG's 1.5 mtpa of condensate production and the condensate's density of 0.665g/cm^3.

Table 2: Some of the process parameters of the converged CFU model

Parameter	Value
Reflux Ratio	1.5
No of Trays	24
Feed Tray	10
Condenser Pressure	135.6 kpa
Reboiler Pressure	178.8
Tray Efficiency	80%
Feed Temperature	127 C

The Peng Robinson equation of state was used in the model as it has been proven to be accurate in predicting hydrocarbon behaviour. The CFU was modelled using a distillation column with a partial condenser and a reboiler. The process parameters used were based on an industrial naphtha splitter. Table 2 shows some of the process parameters of the converged CFU model.

The flowrates of the LN and HN were used to size the CCR and Isomerization units. The individual fixed capital cost components for the units were summed up to arrive at the total fixed cost or inside battery limit (ISBL) cost. The outside boundary limit (OSBL) cost was estimated as 10% of ISBL cost (i.e. 10% of the total capital cost). OSBL accounts for tankage, boilers, cooling towers, power generation, etc. and the 10% estimate was utilized because NLNG has some of these facilities existing already. A working capital of 5% of total capital cost was also assumed in this study. The assumptions for OSBL cost and working capital were based on the recommendations of Towler and Sinnot (2008).

2.3 Cost Estimation and Economic Analysis

The Aspen Plus Economic Analyser, V8.0 (APEA®, V8.0), which is based on 20212 US Dollar, was used to estimate the capital cost (CAPEX) and operating cost (OPEX) of the CFU. The CFU CAPEX and OPEX include the costs of maintenance and operations, consumables, piping, electrical, overheads, tankage, utilities, etc. The costing of the isomerisation process unit was based on the work of Cusher (2003), who provided cost estimates and yields for a 10,000 bpd UOP Penex isomerization process on a 2001 US Dollar basis. The costing of the CCR process unit was estimated from the work of Lapinski et al (2003), who provided cost estimates for a 20,000 bpd UOP CCR process on a 1995 US dollar basis. The various cost estimates were translated to a capacity basis of 40,000 bpd and 2017 US Dollar basis in this study using the "sixth tenth" rule and the Nelson-Farrar indices. The reason for choosing 2017 as the base year of the economic analysis is because yearly data was available up to 2017 and this study was conducted in 2018.

The 2018 CPI forecasts of United States Energy Information Agency (US EIA) were used to estimate the operating costs and shipping costs over the economic life of the refinery. The price of condensate was estimated using naphtha prices as a proxy. The price of naphtha was taken as a discounted price of gasoline. Gasoline and LPG prices were forecasted using linearly regressed models between their prices and crude oil price. The regression models used monthly data between 2010 and 2017 from S&P Platts. The price of hydrogen was estimated as the cost of producing hydrogen based on the work of James et al (2016).

The following assumptions were used for the economic analysis in this paper:

i. The estimations in this work are based on NLNG's stated plant condensate production of 1.5 mtpa (NLNG, 2018a).
ii. Base year of analysis is 2017. This is because yearly data was available up to 2017 as at the time this study was undertaken, which is 2018.
iii. The economic life of the refinery is 16 years as mentioned by Mian (2011) in his analysis of US tangible property classification.
iv. Naphtha is considered a proxy for plant condensate. Naphtha (condensate proxy) is assumed to be 85% of gasoline price.
v. Considering S&P Platts data, a $15 difference is assumed as the 2017 cost of shipping (CIF plus trader margin) between West Africa (WA) and North West Europe (NWE).
vi. A discount rate of 10% is assumed.
vii. Condensate is priced at export parity (i.e. NWE free on board (FOB) price less shipping); gasoline is priced at import parity (i.e. NWE FOB price plus shipping), while LPG is priced at NWE Cost plus Insurance and Frieght (CIF) price less shipping.
viii. Hydrogen price is de-escalated by 1% each year, assuming technology causes a drop in its production cost. The price was assumed as the projected lowest cost of hydrogen production by James et al. (2016), which is $2,580 per ton of hydrogen
ix. The refinery is estimated to take one and half years for construction and six months for commissioning and start-up.
x. The plant is assumed to run for 8000 hours in a year or 333 days. This is to allow for plant maintenance and unanticipated shutdown.

The CPI indices were used to escalate future shipping costs. Initial capital allowance of 50% and annual capital allowance of 25% was used to compute depreciation allowance as stated in the Companies Income Tax Act (CITA). Revenue was determined by the yearly volumes of products. A tax rate of 30% was used as stated in CITA while Education tax (ET) was computed based on 2% of operating margin. The NPV, IRR, PI, and Government take were estimated to show the economic feasibility of the proposed condesate refinery. A sensitivity analysis was performed to show the response of the NPV to changes in discount rate, project capital cost, operating costs, naphtha/gasoline spread and shipping costs. Finally, the analysis compared the economic indices for EIA's optimistic oil price forecast to its low oil price forecasts.

3. RESULTS AND DISCUSSION

3.1 Process Modelling and Simulation Results

The Aspen HYSYS model converged with light naphtha from the top of the CFU and heavy naphtha from the bottom of the CFU. Table 3 shows the predicted flowrates of light naphtha and heavy naphtha products with their ASTM D86 temperature profiles, while Table 4 shows the refinery products and the predicted gasoline research octane number (RON). The predicted light and heavy naphtha cuts temperature ranges are close to their standard specifications. The standard specification of light naphtha has a cut range of 25°C to 90°C while that of heavy naphtha is in the range of 85°C to 190°C. Figure 4 shows the converged Aspen HYSYS process model of the CFU.

Table 3 Model predicted product flowrates and D86 profile

Percentage	Light Naphtha	Heavy Naphtha
Flowrate (m^3/hr)	79.49	185.5
Flowrate (bpd)	28,000	12,000
D86 Profile (%)	Temperature (C)	
5	41.54	97.20
20	43.70	98.74
50	50.02	103.80
70	55.00	109.30
90	66.84	118.60
100	90.24	151.00

Table 4: Condensate refinery product summary

Product	**Daily Prod. (ton/day)**	**RON**
Gasoline Blend	4,071.80	92.76
LPG	138.06	
Hydrogen	24.55	

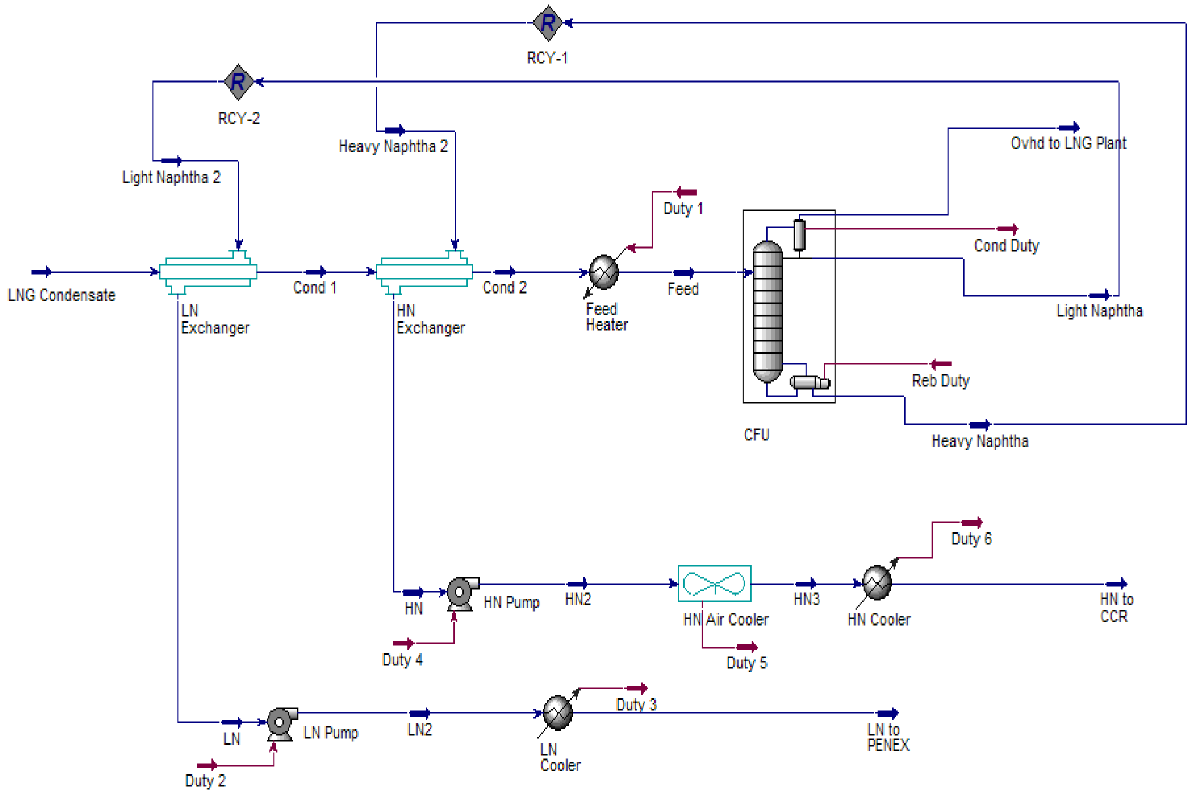

Figure 4: The converged CFU model on HYSYS

3.2 Estimated Costs and Economic Analysis Results

Table 5 shows the total costs of the condensate refinery in 2017 US dollar basis.

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Table 5: Total condensate refinery capital and operating costs

Cost	$
Total Unit Capital Cost	213,526,277.18
OSBL cost	21,352,627.72
Working Capital	11,743,945.24
Total Capital Cost	246,622,850.14
Total Operating Cost	70,265,232.37

The regressed relationships between oil price with gasoline and LPG are as follows:

$$Gasoline_p = 8.1306Oil_p + 103.08$$

$$LPG_p = 8.26580il_p - 44.035$$

where Oil price is in $/bbl of Brent Crude and Gasoline price is in US$/ton of Gasoline 95RON 10ppm FOB ARA Spot Barges. LPG price is in $/ton of Average Propane/Butane CIF North West Europe (NWE)

Table 6: Profitability Indices

Index	Optimistic Case (Base Case)	Low Price Case
NPV Refinery (MM$)	531.90	16.26
Govt. Take (MM$)	548.32	89.30
Partners' Take (MM$)	271.27	8.30
Discounted PO (years)	5.30	17.23
ROI (%)	37.00	9.00
PI	3.16	1.07
IRR (%)	20.09	11.16

Table 6 shows the economic indices of the refinery for two different forecasts of oil price, and Appendix A contains the EIA oil price forecasts and CPI data. The Nigerian Government's take represents its 49% equity (which translates to dividends) and the taxes received. The refinery NPV for the optimistic case is positive and has a value of $531.90 million; the IRR is 20.09%, which is higher than discount rate of 10%. These two factors make the refinery economically feasible. The refinery will return an estimated $531.90 million (present value) on a CAPEX of $246.62 million and this return is equivalent to investing in a venture with a rate of return of 20.09%. This is higher than the assumed interest rate of 10% if the money is kept in a bank. The after-tax ROI is 37% and the PI of 3.16 is greater than one, which implies positive returns on the dollar. The investment would break even in about 6 years as implied by the discounted PO of 5.3 years.

The NPV for the low oil price case is positive at $16.26 million and the IRR is 11.16% which is marginally higher than discount rate of 10%. These two factors make the refinery economically feasible; however, the low returns might encourage diversion of capital to other ventures. The refinery will return an estimated $16.26 million (present value) on a CAPEX of $246.62 million and this return is equivalent to investing in a venture with a rate of returns of 11.16%. The after-tax ROI is 9% and the PI is slightly greater than one at 1.07. This implies very little positive returns on the dollar. The investment would break even after 17 years as implied by the discounted PO of 17.23 years.

Oil prices strongly affect the profitability of the refinery eventhough the raw material is an LNG by-product. The comparison of the two cases shows that the higher the oil price the more profitable the refinery. This is because the price of gasoline, which mainly determines profitability, is positively correlated to the price of oil.
The government take is higher than its partners' take in both cases due to tax receipts. This makes the proposed condensate refinery beneficial to the government. The optimistic oil price case suggests the government could rake in about $100 Million yearly which is about 5% of the reported 2018 government subsidy of about $2 billion on gasoline (Vanguard, 2018).

The spider chart in figure 5 shows the sensitivities of the NPV of the investment to the data estimated for this study, which include: discount rate, OPEX (less raw material costs), CAPEX, Naphtha-Gasoline price ratio and shipping (CIF plus trader margin). The Naphtha-Gasoline price ratio affects the NPV the most and their relationship is inversely related. Every 5% increase in the Naphtha-Gasoline price ratio, which implied a decrease in price difference between gasoline and naphtha, results in about $300 million reduction of the NPV. Discount rate is also inversely related to NPV; however, its effect was far less than that of Naphtha-Gasoline price ratio. Every 10% change in discount rate results to about $50 million inverse change in NPV. OPEX and CAPEX affect the NPV of the investment slightly and they are inversely related to NPV. Every 10% change in these two factors result in about $10 million and $20 million changes in NPV. Shipping is the only factor that was directly related to NPV. Every 10% change in shipping results in about $30 million dollar change in NPV. This trend between NPV and Shipping is because of the import parity pricing of gasoline; an increase or decrease in shipping costs implies a huge increase or decrease in gasoline revenues and by implication NPV.

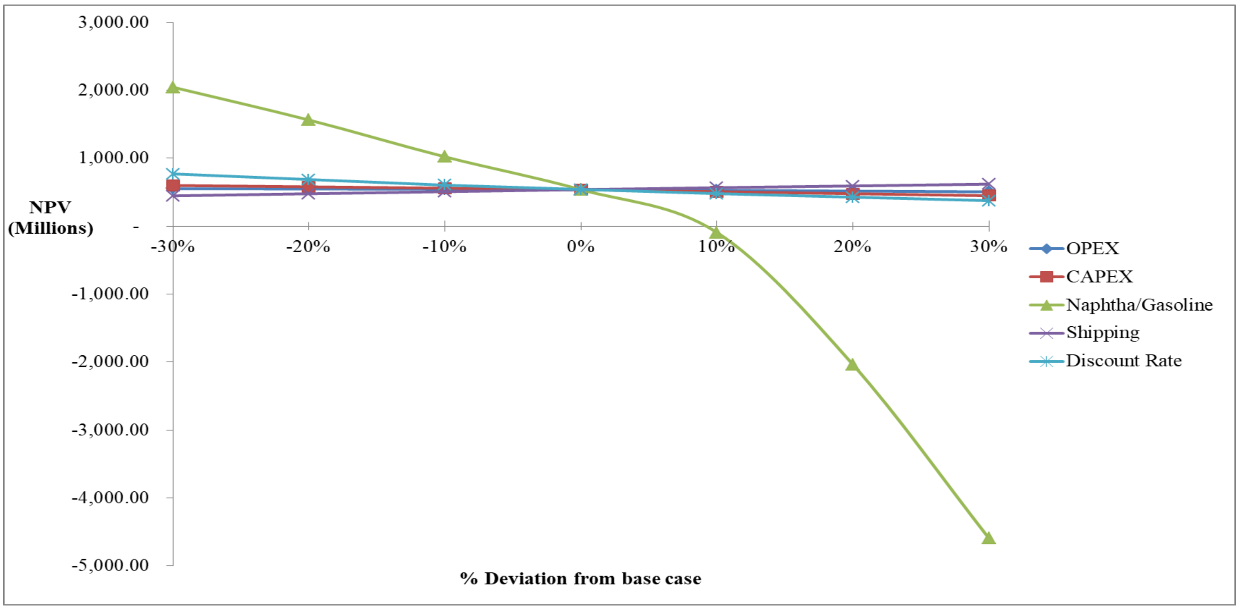

Figure 5: Sensitivity analysis of estimated factors

The difference between the gasoline price and plant condensate price which is represented by Naphtha-Gasoline price ratio is a major determinant of the profitability of the project. An increase in this ratio results in lower profitability or infeasibility of the project and vice-versa. The break-even ratio (i.e. when NPV is zero) for the optimistic case is 0.928 while that of the low oil price case is 0.855. Above these ratios, the proposed condensate refinery will be economically infeasible.

The effect of costs estimation has a less significant effect on the economics of the plant. The CAPEX and

OPEX were based on costs estimate which may have errors of up to 50% from actual costs. The sensitivity analysis showed that a 30% deviation from actual costs does not change the NPV significantly or result to economic infeasibility.

The CIF and trader margin represented by shipping estimate is significant to the economics of the refinery. This is because the gasoline revenue is based on import parity pricing. It trends proportionately to the NPV. The higher the shipping rates, the higher the import parity price of gasoline sold by the refinery.

The tax allowances for the parent NLNG plant as stated in the NLNG Act Schedule (2) (if any still exist) was not applied to the proposed condensate refinery since the condensate refinery will not be producing a pioneer product; however, an argument can be made for the pioneer nature of the process.

4. BENEFITS OF THE PROPOSED NLNG CONDENSATE REFINERY WORK

The techno-economic analysis of the condensate refinery proposed in this paper throws up the following benefits:

- The refinery has a gasoline capacity of about 5 million litres daily. This is about 10% of Nigeria's current consumption. Producing gasoline and selling at CIF Nigeria prices saves a part of subsidy paid for mother vessels demurrage as they are offloading into smaller vessels. This cost is pegged at $280,000 maximum for a period of 10 days by the Petroleum Products Pricing Regulation Agency (PPPRA). NLNG produced gasoline can be transported by smaller vessels.
- This investment can result to an increase in the tertiary education tax fund (TET Fund) which would translate to benefit for the educational sector of Nigeria.
- The refinery would pay investors what they currently earn from selling condensate since it would buy its raw material (condensate). This represents the current model of NLNG where it sells plant condensate. Therefore, the suggestion of a condensate refinery does not change its current earnings; it only presents an opportunity to increase its earnings through investment.
- The analysis is denominated in dollars due to the nature of oil and gas business and Nigeria's reliance on importation of plants machinery and parts. However, the refinery products are meant for the local market and would be bought by Nigerian petroleum marketers. Government could ensure all transactions are done in naira so that foreign exchange expenses on petroleum products could be reduced.

5. CONCLUSION

This paper shows that NLNG plant condensate could be used as feedstock for the production of gasoline by using a condensate refinery with isomerization and catalytic reforming process units. The unit capital cost of the refinery was estimated as $6000 per barrel. NLNG's current production of a minimum of 1.5 mtpa of condensate guarantees the raw material supply for a 40,000bpd condensate refinery. The suggested configuration will convert 40,000 bpd plant condensate into 96% gasoline, 3% LPG and 1% hydrogen.

The optimistic scenario of oil price forecast resulted in an NPV of $ 531.90 million, an IRR of 20.09% and a PI of 3.16, while the pessimistic scenario gave an NPV of $16.26 million, an IRR of 11.16% and a PI of 1.07. The government take for the optimistic case is $548.30 million while that of the low oil price case is $89.30 million. This proves the proposed condensate refinery is economically feasible provided that the Naphtha-Gasoline price ratios are low enough, which is very likely.
The benefits to the Nigerian government would include improved product supply by cutting lead time of some gasoline delivery, improved NLNG dividends that could upset about 5% of Nigeria's current subsidy, increased employment, reduced foreign exchange expense and increased technology transfer.

In summary, this work can serve as a primer to a more detailed analysis of the possibilities that lie in the NLNG condensate refinery investment proposed in this paper. Policy makers could also use this work as a basis for discussion on a quick way to satisfy petroleum products demand.

NOMENCLATURE

APEA	Aspen Plus Economic Analyser
ARA	Amsterdam-Rotterdam-Antwerp
ASTM	American Society for Testing and Materials
CAPEX	Capital Expenditure
CCR	Continuous Catalytic Reforming
CIF	Cost plus Insurance and Freight
CITA	Companies Income Tax Act

CNG	Compressed Natural Gas
CFU	Condensate Fractionation Unit
CPI	Consumer Price Index
DPR	Department of Petroleum Resources
EIA	Energy Information Administration
ET	Education tax
FOB	Free on Board
HN	Heavy Naphtha
IEA	International Energy Agency
IRR	Internal Rate of Return
ISBL	Inside Battery Limit
LN	Light Naphtha
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MIDOR	Mideast Oil Refinery
NGL	Natural Gas Liquids
NPV	Net Present Value
NLNG	Nigerian Liquefied Natural Gas
NEW	North West Europe
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operating Expenditure
OSBL	Outside Boundary Limit
PI	Profitability Index
PO	Pay Out
PPPRA	Petroleum Products Pricing Regulation Agency
ROI	Return on Investment
RON	Research Octane Number
TET	Tertiary Education Tax Fund
US	United States

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APPENDIX A

US EIA Forecasted Oil prices and CPI Data (EIA, 2018)

Year	CPI (Energy Commodities and Services)	EIA Optimistic Forecast for Brent Price ($)	EIA Low Oil Price Forecast for Brent Price ($)
2016	1.90	43.74	43.74
2017	1.99	52.43	52.43
2018	2.02	54.07	27.71
2019	2.13	58.85	30.68
2020	2.36	75.10	33.28
2021	2.50	85.10	36.99
2022	2.60	90.74	38.03
2023	2.71	95.75	39.32
2024	2.82	99.92	40.48
2025	2.90	103.74	41.55
2026	2.97	108.32	42.42
2027	3.06	112.26	44.49
2028	3.14	116.82	45.81
2029	3.24	121.29	47.25
2030	3.32	125.27	48.65
2031	3.42	130.82	50.81
2032	3.51	135.07	52.43
2033	3.60	139.99	54.37
2034	3.70	145.44	56.42
2035	3.79	150.43	58.53
2036	3.89	154.57	60.73
2037	4.01	161.98	63.59
2038	4.12	167.53	65.84
2039	4.24	172.93	68.53
2040	4.35	178.98	71.08