OPTIMIZATION MODEL FOR CRUDE OIL ALLOCATION IN NIGERIA UNDER GLOBAL ENERGY TRANSITION DYNAMICS

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Summary

Under the imperative of global energy transition, Nigeria's oil production needs to decline by 3% per annum to 2050 as its contribution to meet the global target of keeping temperature increases under 1.5°C. The aim of this paper is to seek an optimal allocation of Nigeria's oil production under declining upstream oil production, increasing domestic demand for petroleum products, volatile energy prices, and a build out of domestic refining capacity. A Reference Energy System model for crude oil utilization through a network of possible end-uses forms the basis for the development of a mathematical programme for the optimal allocation of crude oil, with system-net-benefits maximization objective. Within this framework, an optimal future pathway for oil allocation under energy transition dynamics is generated. Metrics such as Oil Export/Production ratio, and Refined Product Import/Demand ratio are used to characterise the optimal pathway. The percentage of oil production, which is exported declines from 43% in 2025 to 6% in 2040. Furthermore, refined products exports peak at 116 MMbbls in 2025 and then declines to 78MMbbls in 2040, representing an export of 37% of domestic production in 2025, which declines to 25% in 2040.

1. INTRODUCTION

Crude oil production in Nigeria has, over time, distributed for different end uses such as domestic refining, direct export, and offshore refining or swap for petroleum products. The distribution of produced oil has changed with time in response to refined petroleum product demand, the state and capacity of domestic refining, and the fiscal demands of the government. Demand for petroleum products, which consists mostly of transportation fuels (gasoline, diesel, and kerosene) has continued to grow from estimated 169 Mbpd (~27 MMlitres/day) in 1995 to 440 Mbpd (70 MMlitres/day) in 2018. Most demand has been met by imports such that by 2018, approximately 96% of the petroleum products demand was imported. Added to this context is that domestic refinery performance has been vacillating and declining, thus giving leeway to the high level of oil exports, such that by 2018, 100% of Nigeria's oil production was exported compared to 78% of OPEC's aggregate production, which was exported in 2018. In the upstream segment, Nigeria's crude oil production increased rapidly from approximately 50 Mbpd in 1961 to a peak of 2.30 MMbpd in 1979 (2.07 MMbpd on average, between 1974 and 1979) and then declined to 1.24 MMbpd in 1983. It was not until 2001, that oil production reached the level observed in 1979. In 2001 the daily oil production rate was 2.36 MMbpd and in 2005, production peaked at 2.52 MMbpd from which it declined to 1.91 MMbpd in 2018. As of 2021, Nigeria produced 1.39 MMbpd, which represents an effective annual decline of 5% from the 2005 peak of 2.52 MMbpd as evident in Figure 1.

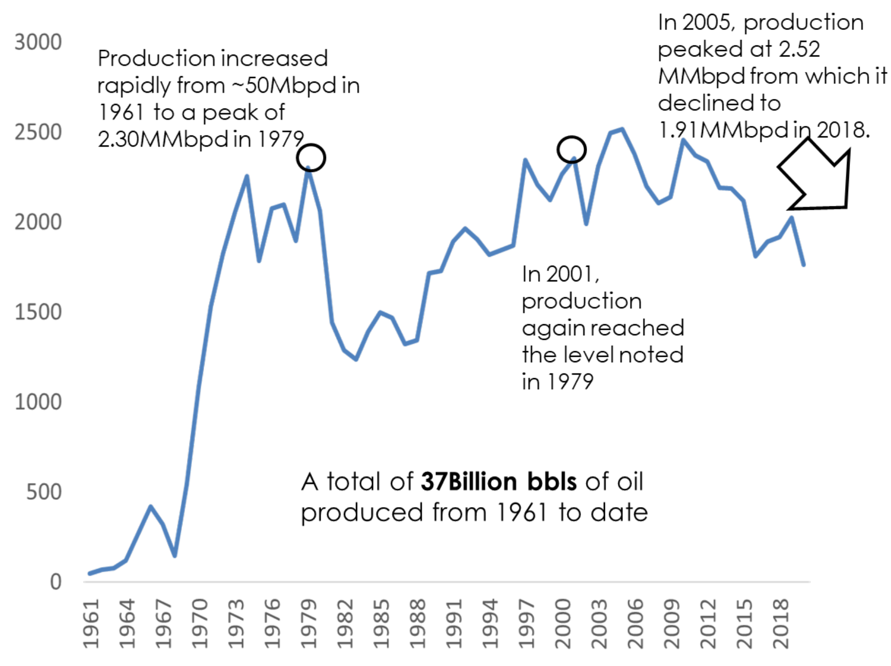

Figure 1: Nigeria Oil Production Path

In recent years, the discourse on energy transition has taken a new sense of urgency. The IEA in their "Net Zero by 2050" report (aka NZE2050) indicated that to stem carbon emissions and keep target temperature increases under 1.5°C, exploration for new fossil supply sources was not required and, no new oil and gas fields were necessary other than projects already approved for development (IEA, 2021). Implementing the IEA recommendations would require global oil supply to decline an average of 4.5% per annum from 2020 to 2050 without new investments. For OPEC as a block, this average decline is expected to be 3.3% per annum from 33 MMbbls/day (2020) to 13 MMbbls/day (2050). The IEA also stipulated the elimination of fossil fuel subsidies to reduce fossil demand and thus mitigate carbon emissions. Additionally, the decline in oil supply would be accompanied by a decline in oil prices by 1.3% per annum to 2050.

Consequently, under the scenario of declining oil production (as favoured by the IEA and IPCC), the increasing transport fuels demand in Nigeria, the increase in refining capacity gives rise to the question of the optimal allocation of crude oil production for the various end uses viz: domestic refining, direct export, and offshore refining or swap for petroleum products. A mathematical model is espoused in the paper to address the allocation optimality question. Thus, the aim of this paper is to utilize a mathematical program to determine the optimal allocation of declining oil production as well as refined petroleum products to satisfy increasing demand, under the dictates of the energy transition dynamics.

2. LITERATURE REVIEW

The practice of energy system modelling presents several sophisticated platforms for modelling energy systems for research and policy reasons (Fattahi, *et. al.*, 2019; Subramanian, *et. al.*, 2018; Neshat, *et. al.*, 2014; Bhattarcharya, *et. al.*, 2010; Beller, 1976; Hoffman & Wood, 1975). Arising from the variety of the modelling approaches, motivated by the purpose, emphasis, and scope, several modelling frameworks are plausible (Fattahi, *et. al.*, 2019; Laha and Chakraborty, 2017; Timilsina, 2011). Bhattarcharya, *et. al* (2010) conducted a comparative overview of the existing energy system models by reviewing available literature published between the 1970s and 2010. Table 1 is a categorization of energy system models, which the authors identify and then map to known "institutional" models.

Table 1: Model Types Compared in Bhattarcharya, et. al. (2010)

S/N	Model Type	Examples
1	Bottom-up, optimization-based	- Energy Flow Optimisation model (EFOM) - Market Allocation model (MARKAL)
2	Bottom-up, accounting models	- Long-range Energy Alternatives Planning model (LEAP)
3	Top-down, econometric models	- Department of Trade and Industry model (DTI[1])
4	Hybrid Models	- National Energy Modelling System (NEMS) - Prospective Outlook on Long-term Energy Systems (POLES) - World Energy Model (WEM)
5	Electricity system models	- Wien Automatic System Planning (WASP) - Electricity Generation Expansion Analysis System (EGEAS)

[1] Now called Department for Business, Enterprise and Regulatory Reform, BERR

The model types identified in Table 1 correspond, roughly to the classification in the schematic from the World bank depicted in Figure 2 (Timilsina, 2011).

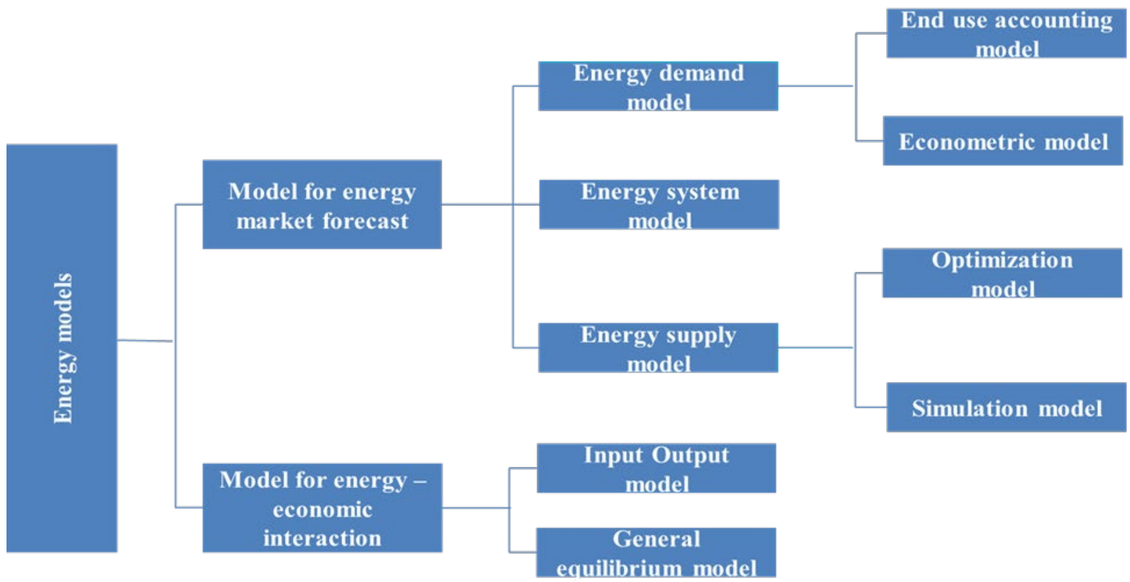

Figure 2: Energy models classification adapted from Alahmadi (2016)

3. METHODOLOGY

The technique of mathematical programming solves the problem of determining the optimal allocations of limited resources required to meet a given objective. The technique finds use in different domains – specific to oil and gas, it has been applied to upstream production operations (Kaufman *et. al.*, 2020; Ghaelia, 2019; Gao, 2009; Aziz, 2002; Wang, *et. al.*, 2002;), refinery production (Murty, 2020; Ejikeme-Ugwu, 2012, Chairat, 1971), and oil and gas portfolio optimization (Huang, 2019; Domnikov, *et al.*, 2017; Aibassov, 2007). Other areas of application have been in financial asset portfolio optimization (???), factory production scheduling (??),

Where energy system modelling is concerned, optimization is a common methodology (Fattahi, *et. al.*, 2019), that allows answers to specific energy modelling questions – such as the optimal allocation of an energy resource to achieve a stated objective. The objective might be to maximize social welfare (Rowse 2008, 1987), minimize the emissions and cost of a combination of technologies (Askar, 2012) or minimize energy imports (Kazemia *et. al.*, 2012).

This paper seeks to optimize the allocation of declining oil production (consistent with the dictate of the energy transition) to meet increasing transport fuels demand, subject to capacity constraints.

3.1 Nigeria Crude Oil Utilization: Reference Energy System

Figure 3 represents a typical Reference Energy System (RES) applied to crude oil from production for utilization by end-users. A RES is a network representation of all the technical activities required to supply various forms of energy to end-use activities (Hoffman & Wood, 1975). The optimization model of this paper is derived from the network schematic in Figure 3.

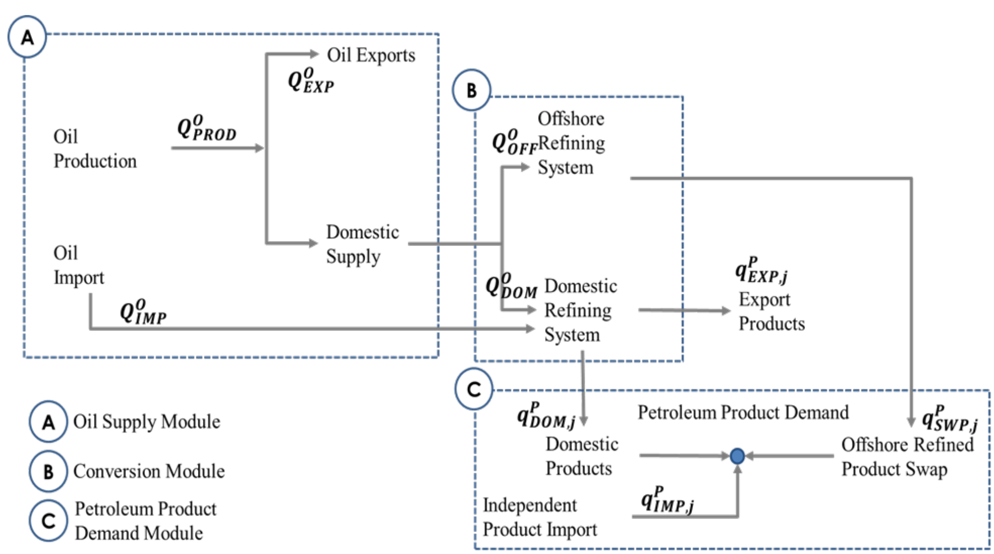

Figure 3: Schematic Showing Crude Oil Utilization for Product Supply

3.2 Model Development

The optimization model developed to address the central objective of this paper is given by the general framework:

$$\text{Maximize } \boldsymbol{Z} = \boldsymbol{C^T X}$$
$$\text{Subject to } AX \leq b \qquad \text{.... 1}$$
$$X \geq 0$$

Where, $Z = C^T X$ is the Objective Function, $AX \leq b$ represents the functional constraint, and $X \geq 0$ is the non-negative constraint. The symbols used in the model are explained as follows:

- $\boldsymbol{P^O}$ is the price of crude oil ($/bbl)
- $\Delta\boldsymbol{P^O}$ is the quality differential for crude oil imported ($/bbl)
- $\boldsymbol{P^P_{EXP,j}}$ is the price of refined product *j* for export ($/bbl)
- $\boldsymbol{P^P_{DOM,j}}$ is the price of product *j* to domestic ($/bbl)
- $\boldsymbol{P^P_{IMP,j}}$ is the price of product *j* in the source market (to be imported) ($/bbl)
- $\boldsymbol{C^P_{DIST}}$ is the cost of product distribution to domestic ($/bbl)
- $\boldsymbol{C^P_{LOSS,j}}$ is the cost of loss of jth product distribution to domestic ($/bbl)
- $\boldsymbol{C^O_{DIST}}$ is the cost of oil distribution to domestic ($/bbl)
- $\boldsymbol{C^O_{PROD}}$ is the cost of upstream oil production ($/bbl)
- $\boldsymbol{C^O_{DT}}$ is the dirty tanker freight (oil shipping) ($/bbl)
- $\boldsymbol{C^P_{CT}}$ is the clean tanker freight (product shipping) ($/bbl)
- $\boldsymbol{C^O_{DREF}}$ is the variable cost of domestic refining ($/bbl)
- $\boldsymbol{C^O_{OREF}}$ is the processing fee for offshore refining ($/bbl)
- $\boldsymbol{C^O_{LOSS}}$ is the cost of crude oil loss ($/bbl)
- $\boldsymbol{FC_{DREF}}$ is the fixed cost of domestic refining ($MM)
- $\boldsymbol{FC_{DIST}}$ is the fixed cost of domestic distribution ($MM)
- $\boldsymbol{Q^O_{PROD}}$ is the upstream crude oil production (MMbbls)
- $\boldsymbol{Q^O_{EXP}}$ is the crude oil exported (MMbbls)
- $\boldsymbol{Q^O_{DOM}}$ is the crude oil for domestic refining (MMbbls)
- $\boldsymbol{Q^O_{OFF}}$ is the crude oil to offshore refining (MMbbls)
- $\boldsymbol{Q^O_{IMP}}$ is the crude oil imported into the domestic refining system (MMbbls)
- $\boldsymbol{q^P_{DOM,j}}$ is the jth product from domestic refining into the domestic market (MMbbls)
- $\boldsymbol{q^P_{EXP,j}}$ is the jth product from domestic refining which is exported (MMbbls)
- $\boldsymbol{q^P_{SWP,j}}$ is the jth Product from offshore refining/swap (MMbbls)
- $\boldsymbol{q^P_{IMP,j}}$ is jth product imported independently into the domestic market (MMbbls)
- $\boldsymbol{q^P_{DEM,j}}$ is the jth product demand of the domestic market (MMbbls)
- $\boldsymbol{TDRC}$ is the Total Domestic Refining Capacity (MMbbls)
- $\boldsymbol{TORC}$ is the Total Offshore Refining Capacity (MMbbls)

where *j = 1 ... 5* is the subscript representation for the five (5) different petroleum products – Naphtha, Gasoline, Diesel, Kerosene, and Fuel Oil.

The Objective Function

The objective is to maximize the profit (or net benefit) of the system, which is the difference between the "Inflows" and "Outflows" summed up across the nodes of the network.

The Inflow is given by Equation 2 as:

$$\text{INFLOW} = P^{O}\left[Q^{O}_{EXP} + Q^{O}_{DOM}\right] + \sum_{j=1}^{5} P^{P}_{EXP,j}\left[q^{P}_{EXP,j}\right] + \sum_{j=1}^{5} P^{P}_{DOM,j}\left[q^{P}_{DOM,j} + q^{P}_{SWP,j} + q^{P}_{IMP,j}\right] \quad \text{....2}$$

There are three components to Equation 2;

The first,$\mathbf{P^{O}\left[Q^{O}_{EXP} + Q^{O}_{DOM}\right]}$, which represents inflow from crude oil sale to the export market and domestic refining. The second,$\sum_{j=1}^{5} \mathbf{P^{P}_{EXP,j}\left[q^{P}_{EXP,j}\right]}$, captures the receipts from the export of domestically refined products, and the third component, $\sum_{j=1}^{5} \mathbf{P^{P}_{DOM,j}\left[q^{P}_{DOM,j} + q^{P}_{SWP,j} + q^{P}_{IMP,j}\right]}$, which represents the receipts from refined products sale into the domestic market.

Further, the Outflow is represented in Equation 3.

$$\begin{aligned} \text{OUTFLOW} = {} & Q^{O}_{EXP}\left[C^{O}_{PROD} + C^{O}_{LOSS}\right] \\ & + Q^{O}_{OFF}\left[C^{O}_{DT} + C^{O}_{OREF} + C^{O}_{PROD} + C^{O}_{LOSS}\right] + Q^{O}_{DOM}\left[C^{O}_{DIST} + C^{O}_{DREF} \right.\\ & \left. + C^{O}_{PROD} + C^{O}_{LOSS}\right] + Q^{O}_{IMP}\left[P^{O} + \Delta P^{O} + C^{O}_{DIST} + C^{O}_{DREF} + C^{O}_{LOSS}\right] \\ & + \sum_{j=1}^{5} q^{P}_{SWP,j}\left[C^{P}_{CT,j} + C^{P}_{DIST,j} + C^{P}_{LOSS,j}\right] \\ & + \sum_{j=1}^{5} q^{P}_{IMP,j}\left[P^{P}_{IMP,j} + C^{P}_{CT,j} + C^{P}_{DIST,j} + C^{P}_{LOSS,j}\right] \\ & + \sum_{j=1}^{5} q^{P}_{DOM,j}\left[C^{P}_{DIST,j} + C^{P}_{LOSS,j}\right] + \sum_{j=1}^{5} q^{P}_{EXP,j}\left[C^{P}_{LOSS,j}\right] + FC_{DREF} + FC_{DIST} \end{aligned} \quad \text{.... 3}$$

The "Outflow" equation has nine components: The first, $\mathbf{Q^{O}_{EXP}\left[C^{O}_{PROD} + C^{O}_{LOSS}\right]}$,captures the cost of upstream oil production which includes costs associated with crude oil losses. The second, $\mathbf{Q^{O}_{OFF}\left[C^{O}_{DT} + C^{O}_{OREF} + C^{O}_{PROD} + C^{O}_{LOSS}\right]}$, represents the cost of refining in an offshore refinery; the third, $\mathbf{Q^{O}_{DOM}\left[C^{O}_{DIST} + C^{O}_{DREF} + C^{O}_{PROD} + C^{O}_{LOSS}\right]}$, represents the cost of domestic refining, while the fourth term, $\mathbf{Q^{O}_{IMP}\left[P^{O} + \Delta P^{O} + C^{O}_{DIST} + C^{O}_{DREF} + C^{O}_{LOSS}\right]}$, captures the costs associated with oil imports to domestic refineries. The fifth term, $\sum_{j=1}^{5} \mathbf{q^{P}_{SWP,j}\left[C^{P}_{CT,j} + C^{P}_{DIST,j} + C^{P}_{LOSS,j}\right]}$, describes the costs associated with refined product swaps, the sixth term, $\sum_{j=1}^{5} \mathbf{q^{P}_{IMP,j}\left[P^{P}_{IMP,j} + C^{P}_{CT,j} + C^{P}_{DIST,j} + C^{P}_{LOSS,j}\right]}$, captures the costs of direct petroleum product imports while the seventh component, $\sum_{j=1}^{5} \mathbf{q^{P}_{DOM,j}\left[C^{P}_{DIST,j} + C^{P}_{LOSS,j}\right]}$, represents the expense associated with distributing domestically refined products into the domestic market. $\sum_{j=1}^{5} \mathbf{q}^{\mathbf{P}}_{\mathbf{EXP,j}}[\mathbf{C}^{\mathbf{P}}_{\mathbf{LOSS,j}}]$ is the eighth term which captures losses associated with refined products exports and $\mathbf{FC_{DREF}} + \mathbf{FC_{DIST}}$ is the ninth term which is the fixed costs associated with domestic refining and pipeline distribution.

Subtracting Equation 3 from Equation 2 provides the objective function to be maximized.

$$\begin{aligned} Z = {} & Q^{O}_{EXP}[P^{O} - C^{O}_{PROD} - C^{O}_{LOSS}] \\ & + Q^{O}_{OFF}[-C^{O}_{DT} - C^{O}_{OREF} - C^{O}_{PROD} - C^{O}_{LOSS}] + Q^{O}_{DOM}[P^{O} - C^{O}_{DIST} - C^{O}_{DREF} \\ & - C^{O}_{PROD} - C^{O}_{LOSS}] + Q^{O}_{IMP}[-P^{O} - \Delta P^{O} - C^{O}_{DIST} - C^{O}_{DREF} - C^{O}_{LOSS}] \\ & + \sum_{j=1}^{5} q^{P}_{SWP,j}[P^{P}_{DOM,j} - C^{P}_{CT,j} - C^{P}_{DIST,j} - C^{P}_{LOSS,j}] \\ & + \sum_{j=1}^{5} q^{P}_{IMP,j}[P^{P}_{DOM,j} - P^{P}_{IMP,j} - C^{P}_{CT,j} - C^{P}_{DIST,j} - C^{P}_{LOSS,j}] \\ & + \sum_{j=1}^{5} q^{P}_{DOM,j}[P^{P}_{DOM,j} - C^{P}_{DIST,j} - C^{P}_{LOSS,j}] + \sum_{j=1}^{5} q^{P}_{EXP,j}[P^{P}_{EXP,j} - C^{P}_{LOSS,j}] \\ & - FC_{DREF} - FC_{DIST} \end{aligned} \quad \ldots 4$$

The Constraints

The quantity of oil for export, domestic use and offshore refining constrained by upstream production and expressed as:

$$Q^{O}_{EXP} + Q^{O}_{DOM} + Q^{O}_{OFF} = Q^{O}_{PROD} \quad \ldots 5$$

Quantity of products to domestic and for export from domestic refining is constrained by the crude oil supply to domestic refining expressed as:

$$\sum_{j=1}^{5} q^{P}_{DOM,j} + \sum_{j=1}^{5} q^{P}_{EXP,j} = Q^{O}_{IMP} + Q^{O}_{DOM} \quad \ldots 6$$

Quantity of crude oil supplied into domestic refining system is constrained by the Total Domestic Refining Capacity, TDRC, which is expressed as follows:

$$Q^{O}_{IMP} + Q^{O}_{DOM} \leq TDRC \quad \ldots 7$$

Quantity of oil sent to the offshore refinery system is constrained by Total Offshore Refining Capacity, TORC, expressed as follows:

$$Q^{O}_{OFF} \le \text{TORC} \qquad \text{.... 8}$$

Refined products from offshore refining constrained by crude allocated to offshore refining and the contractual arrangement adopted in the exchange arrangements (Sayne *et. al.*, 2015)

$$\sum_{j=1}^{5} q^{P}_{SWP,j}\left[P^{P}_{IMP,j} + F^{P}_{SWP,j}\right] = Q^{O}_{OFF}\left[P^{O} - C^{O}_{OREF}\right] \qquad \text{.... 9}$$

$F^{P}_{SWP,j}$ is the "Swap Fee" which is a contractually negotiated fee.

Sum of refined products from domestic refining, offshore refining and independent import constrained by domestic demand for refined products expressed as follows:

$$\sum_{j=1}^{5} q^{P}_{DOM,j} + \sum_{j=1}^{5} q^{P}_{IMP,j} + \sum_{j=1}^{5} q^{P}_{SWP,j} = \sum_{j=1}^{5} q^{P}_{DEM,j} \qquad \text{....10}$$

The yield constraints from the domestic refining system are non-linear constraints expressed as follows:

$$LB_j \le \frac{q^{P}_{DOM,j} + q^{P}_{EXP,j}}{Q^{O}_{IMP} + Q^{O}_{DOM}} \le UB_j \qquad \text{....11}$$

LB_j and UB_j represent the Lower and Upper Bound respectively for the yield of product j from the domestic refining system. Linearizing the above constraint however results in the following pair of constraints for each product yield:

$$q^{P}_{DOM,j} + q^{P}_{EXP,j} - UB_j Q^{O}_{IMP} - UB_j Q^{O}_{DOM} \le 0 \qquad \text{....12}$$

$$q^{P}_{DOM,j} + q^{P}_{EXP,j} - LB_j Q^{O}_{IMP} - LB_j Q^{O}_{DOM} \ge 0$$

The non-negative constraints are expressed thus:

$$Q^O_{EXP} \geq 0 \qquad q^P_{DOM,j} \geq 0$$

$$Q^O_{OFF} \geq 0 \qquad q^P_{IMP,j} \geq 0$$

$$Q^O_{DOM} \geq 0 \qquad q^P_{EXP,j} \geq 0 \qquad \text{....13}$$

$$Q^O_{IMP} \geq 0 \qquad \text{For } j = 1 \ldots 5$$

$$q^P_{SWP,j} \geq 0$$

The Input Data

Data input for the optimization framework is obtained from varied sources, which are summarized in Table 2. Forecast of these inputs are prepared to be fed into the optimization model.

Table 2: Parameters and Sources

S/N	Parameters	Data Source
1	Oil price, $\boldsymbol{P^O}$	IEA NZE2050 scenario
2	Oil production, $\boldsymbol{Q^O_{PROD}}$	IEA NZE2050 scenario
3	Cost of upstream oil production, $\boldsymbol{C^O_{PROD}}$	Regression model (Gbakon, *et. al.* 2021)
4	Dirty Tanker Freight, $\boldsymbol{C^O_{DT}}$	Argus Media
5	Oil pipeline distribution costs, $\boldsymbol{C^O_{DIST}}$	Sayne *et. al.* 2015
6	Price differential of imported oil, $\Delta\boldsymbol{P^O}$	Argus Media
7	Variable cost of domestic refining, $\boldsymbol{C^O_{DREF}}$	Sayne *et. al.* 2015
8	Fixed cost domestic refining, $\boldsymbol{FC_{DREF}}$	NNPC F&O reports, Reuters
9	Offshore refining processing fee, $\boldsymbol{C^O_{OREF}}$	Sayne *et. al.* 2015
10	Clean Tanker Freight, $\boldsymbol{C^P_{CT}}$	Argus Media
11	Domestic demand of refined products, $\boldsymbol{q^P_{DEM,j}}$	Woodmac
12	Product yields: domestic refineries $\boldsymbol{LB_j}$, $\boldsymbol{UB_j}$	NNPC ASB, EIA Dangote refinery
13	Domestic prices of refined products, $\boldsymbol{P^P_{DOM,j}}$	PPPRA, Platts

Cost of Upstream Oil Production, $\boldsymbol{C^O_{PROD}}$

Gbakon *et. al.* (2021) designed a model of unit cost of oil production in Nigeria derived from Petroleum Profit Tax assessments, annual production level and royalty receipts from 2010 to 2019. They found that over the period considered, unit costs were on average ~ 70% of oil price as seen in Figure 4. This relationship is key to establish the upstream unit cost of production.

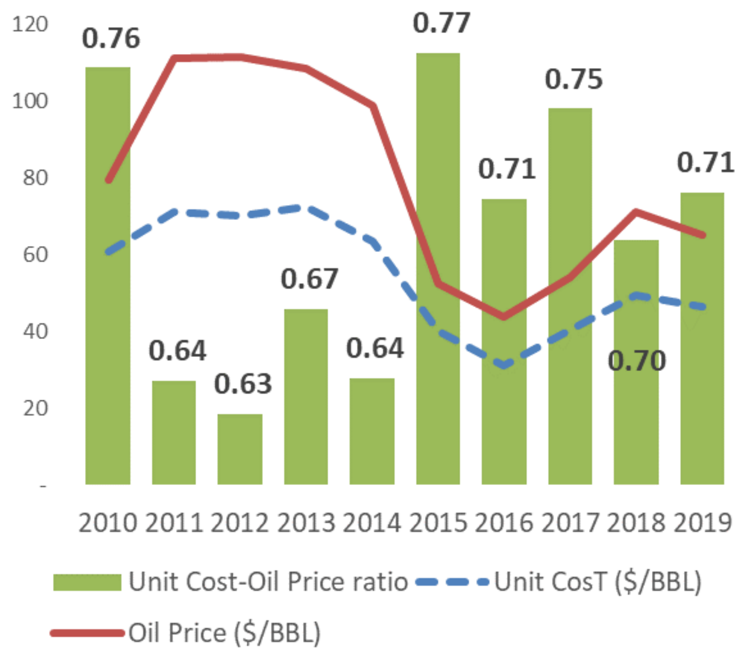

Figure 4: Relationship between Upstream Unit Cost and Oil Price (Gbakon et. al., 2021)

Dirty & Clean Tanker Freight, $\boldsymbol{C_{DT}^{O}}$, $\boldsymbol{C_{CT}^{P}}$

Dirty tanker freight refers to the costs for shipping crude oil on ocean going vessels, while the clean tanker freight is that for shipping refined products. Forecasts of the tanker freight was based on the ten-year historical average for dirty and clean tankers. The dirty tanker freights used are for a 130kt vessel from West Africa (WAF) to United Kingdom Continental (UKC), while the clean tanker freight is for a 37kt vessel from the UKC to WAF. The historical freights and forecasts are illustrated in Figure 5. The average dirty tanker freight is $1.66/bbl while that for the clean tanker is $3.02/bbl.

Price Differential of Imported Oil, $\Delta \boldsymbol{P^{O}}$

It is the assumption that the oil that will be imported will be at a discount to Brent. Specifically, Urals crude has been assumed on the basis that the Kaduna Refinery is designed to also process this type of crude oil. Using historical Brent and Urals prices between 2010 and 2020, it is noted that Urals is discounted at an average of 1.64% to Brent.

Fixed Cost Domestic Refining, $\boldsymbol{FC_{DREF}}$

Cognizance is taken of the profile of capital investment required to deploy the refining capacity under the energy transition dynamics. The CAPEX estimate of $19 billion for the Dangote Oil refinery (DOR) (Clowes W., 2021), the estimated $1.50 billion for the rehabilitation of the Port-Harcourt refinery (PHR) (Olatunji, H., 2021) and the estimated $480 million/annum legacy costs of maintaining the existing domestic refinery capacity.

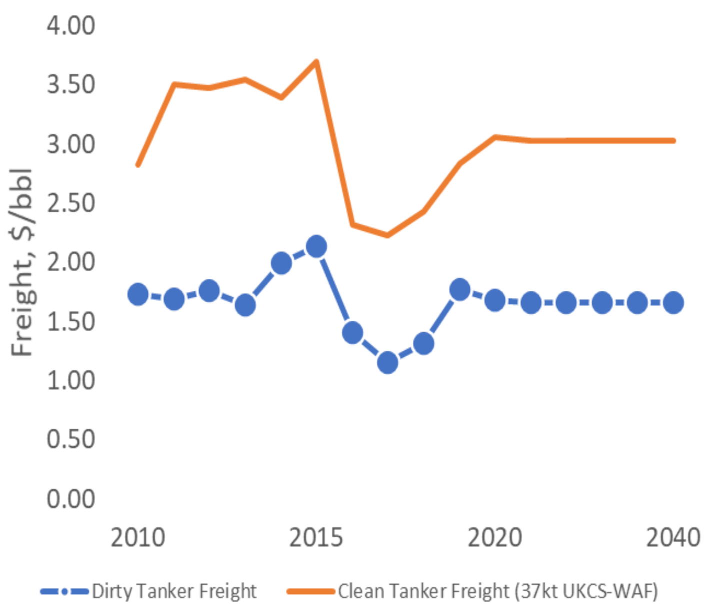

Figure 5: Dirty and Clean Tanker Freight Rates

The following Capital Recovery Factor (CRF) formula is used to enable the spread of the refinery CAPEX over the period of evaluation.

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \quad \text{....14}$$

Where i represents the discount rate (est. 15%) and n is 20-years.

<u>Domestic Demand of Refined Products,</u> $\boldsymbol{q^P_{DEM,j}}$

For the projection of product demand, the forecasts provided by Wood MacKenzie from their Sub-Saharan Africa product markets 2021 outlook to 2050 (2021) are utilized. Abdullahi *et. al.* (2016) had developed forecasts of petroleum product consumption in Nigeria which agreed with the forecasts provided by Wood MacKenzie at the time. Consequently, the Wood MacKenzie forecasts of petroleum product demand utilized is shown in Table 3.

Table 3: Nigeria Petroleum Product Demand Forecast (Woodmac)

	Gasoline (MMbbls)	DPK (MMbbls)	AGO (MMbbls)	Fuel Oil (MMbbls)	Total (MMbbls)
2021	118.24	23.66	31.79	8.06	181.75
2025	135.13	25.01	35.39	6.71	202.24
2030	153.06	27.19	42.93	7.03	230.21
2035	171.59	28.69	50.59	6.77	257.64
2040	188.89	30.73	60.53	6.82	286.97

Product Yields: Domestic Refineries $\boldsymbol{LB_j}$, $\boldsymbol{UB_j}$

Given the diversity of the Nigeria refining system, the product yields of our main products have been provided as a range. Table 4 shows the range of product yields assumed for the domestic refining system.

Table 4: Lower and Upper Bound Product Yields from Domestic Refineries

Products	**Lower Bound,** $\boldsymbol{LB_j}$	**Upper Bound,** $\boldsymbol{UB_j}$
Naphtha	1.00%	2.56%
Gasoline (PMS)	35.74%	44.64%
Jet / Kero (DPK)	8.07%	15.21%
Diesel (AGO)	24.62%	33.94%
Fuel Oil (FO)	4.88%	18.37%

Note that neither the Lower nor Upper Bound yields sum to a 100% as the yields at the bounds do not represent a given refinery profile.

Domestic Prices of Refined Products, $\boldsymbol{P^P_{DOM,j}}$

Product prices within Nigeria are established with reference to the prices of products in Europe. Regression models provide the relationship between Brent oil price and petroleum product prices in Europe as shown in Equation 15.

$$\begin{bmatrix} P_{\text{Naphtha}} \\ P_{\text{PMS}} \\ P_{\text{DPK}} \\ P_{\text{AGO}} \\ P_{\text{FO}} \end{bmatrix} = \begin{bmatrix} 0.8587 \\ 0.9668 \\ 1.1187 \\ 1.1086 \\ 0.8728 \end{bmatrix} X\, \mathbf{P^O} + \begin{bmatrix} 2.6575 \\ 11.4860 \\ 4.7279 \\ 6.1560 \\ -1.6680 \end{bmatrix} \quad \ldots.15$$

where:

- $\boldsymbol{P_{Naphtha}}$ $\boldsymbol{P_{PMS}}$ $\boldsymbol{P_{DPK}}$, $\boldsymbol{P_{AGO}}$ and $\boldsymbol{P_{FO}}$ are the NWE FOB prices of Naphtha, Gasoline, Jet, Diesel, and Fuel oil respectively in **$/bbl**
- $\mathbf{P^O}$ is the Price of Brent oil in **$/bbl**

The resulting product prices are adjusted for local distribution costs. The subsidy on gasoline price is factored in by imposing a further 33% discount – this level of discount is the average calculated over the period between 2010 and 2018.

3.3 The Energy Transition Scenario

The cluster of assumptions presented in Table 5 forms the basis on which optimization will be conducted to determine the optimal allocation of crude oil under the energy transition. The scenario localizes attributes contained in IEA NZE2050 policy for Nigeria to be consistent with the goal of Net Zero Emissions by 2050.

Table 5: Description of Energy Transition Scenario

S/N	Dimension	Scenario: Energy Transition
1	Oil Production	Production decline by 3.30% pa as per the IEA NZE2050
2	Oil Price Profile	Oil price (RT2019) declines as per IEA NZE2050 scenario from $37/bbl (2021) to $29/bbl (2040)
3	PMS price subsidy	No subsidy from 2024
4	Domestic Refining Capacity Build-up	DORC (start 2023) + PHRC (start 2025)

According to the IEA NZE 2050 report, oil supply from OPEC should decline from 33 MMbpd in 2020 to 13 MMbpd in 2050 to achieve the net zero target – a 3.3% decline per annum. We assume Nigeria's continued membership of OPEC and hence production from Nigeria should follow similar trajectory.

In the IEA NZE scenario, oil prices are set to achieve equilibrium between supply and demand. The operating costs of the marginal project, which is required to meet demand determines the oil prices. Under the scenario of declining oil production to meet net zero targets, continued investment in existing supply sources is required while, exploration for new supply sources is not required (IEA, 2021). Table 6 shows the oil production and price outlook under the energy transition constraint.

Table 6: Oil Price and Production (Nigeria) under Energy Transition

	Oil Price $/bbl (RT2019)	Oil Production (MMbbls)
2021	37.27	623.04
2025	35.55	545.99
2030	33.40	462.94
2035	31.25	392.53
2040	29.10	332.82

On fuel subsidies, the IEA sets as a priority, the phasing out of fossil fuel subsidy, introduction of carbon pricing, and other market reforms that send appropriate price signals and reduce emissions in the NZE scenario. Thus, the assumption in the energy transition scenario is that gasoline, which in Nigeria is the subject of subsidized pricing, is priced at the full market value from year 2024 onwards.

Consistent with the drive to reduce emissions, the in-country refining capacity is moderated with the assumption that only the 650 Mbpd Dangote refinery and the 210 Mbpd Port-Harcourt refineries are operational under this scenario. In the outlook, the Dangote refinery, which is at the advanced stage of construction commences production in 2023, while the PHRC, which is under rehabilitation, commences operation in 2025 as indicated in Figure 5.

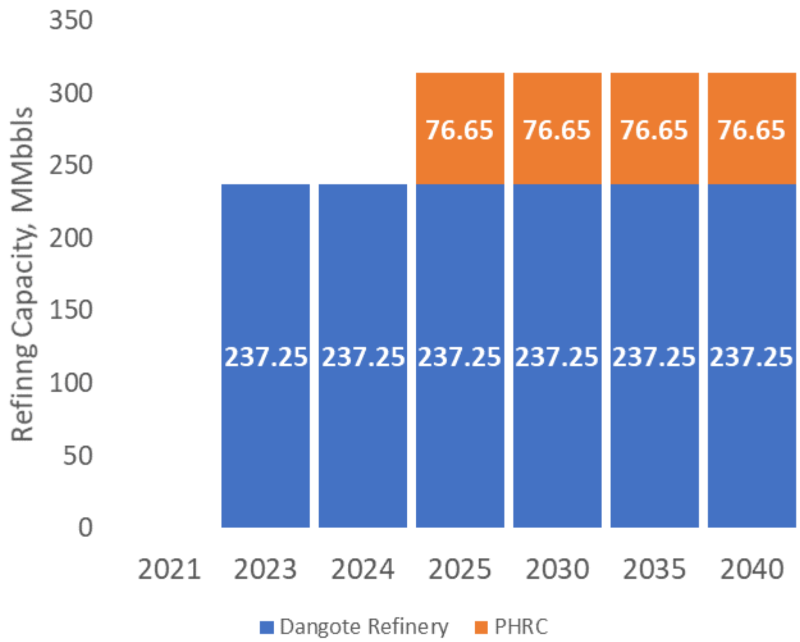

Figure 6: Nigeria's Expected Refinery Capacity Build-up under Energy Transition

The 235 Mbpd (86 MMbbls) name plate refining capacity of the Kaduna and Warri refineries does not come on stream in this scenario. However, it is considered that there will be costs to maintain the facilities in idle state and hence the estimated $480 million/annum "legacy" costs as part of the "fixed refinery cost" established earlier.

4. RESULTS AND DISCUSSIONS

Empirical results from the optimisation model estimating the optimal allocations of crude oil production in Nigeria among end-users under energy transition dynamics are presented as follows with respects to crude oil exports, products export, domestic products demand, and net benefits.

Oil Exports

With increasing petroleum products demand, empirical model results show a declining optimal pathway in crude oil exports from 623 MMbbls in 2022 to ~ 19 MMbbls in 2040 as observed in Figure 7. Conversely, domestic utilization of crude oil production stays constant at 314 MMbbls 2025 to 2040. It is also worthy to note that there is no oil dedicated to offshore refining.

In percentage terms, the graphic in Figure 8 shows that optimally, the export ratio declines from 100% (in 2021) to 6% (in 2040). The decline in the oil export ratio arises due to increased utilization of declining production to meet increasing domestic demand of transport fuels. This dynamic puts downward pressure on the volume of oil that can be exported.

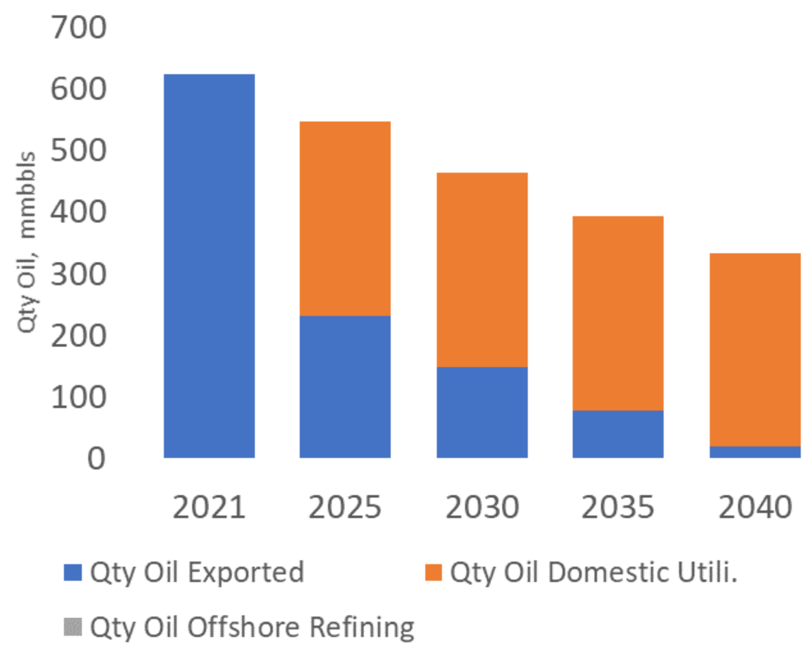

Figure 7: Optimal Allocation of Nigeria's Oil Production under Energy Transition

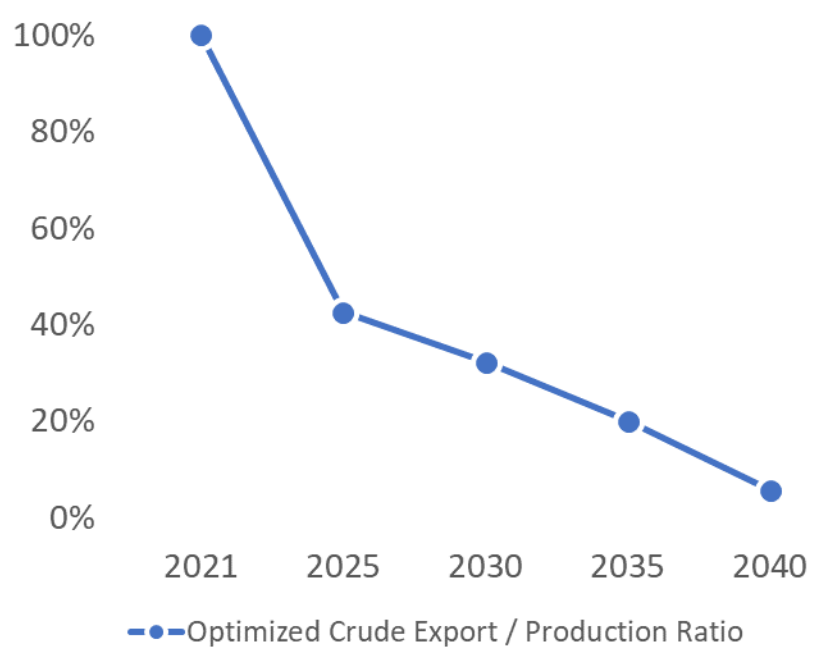

Figure 8: Nigeria's Optimal Crude Oil Export Allocation under Energy Transition

<u>*Petroleum Products Exports*</u>

The optimal profile for product export from domestic refineries shows that product exports start in 2023 at 67 MMbbls, which coincides with the coming on-stream of the 650 Mbpd Dangote refinery. As soon as the rehabilitated Port-Harcourt refinery starts to produce again in 2025, the increase in domestic refining capacity, petroleum product exports rise to 117 MMbbls but declines to ~78 MMbbls by 2040 due to increasing domestic products demand. The distribution of products exports is shown in Figure 9.

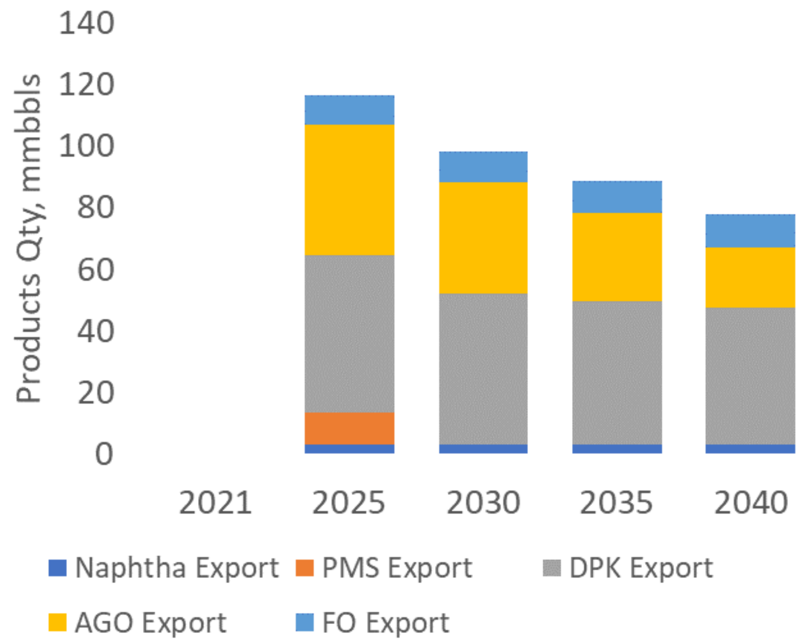

Figure 9: Optimal Petroleum Product Export Profile

Note that DPK and AGO constitute the bulk of products which are exported. PMS is minimally exported at 10.4 MMbbls in 2025 and from 2030 onwards, no PMS is exported. Expressing the petroleum exports as a fraction of domestic refining production is depicted in Figure 10.

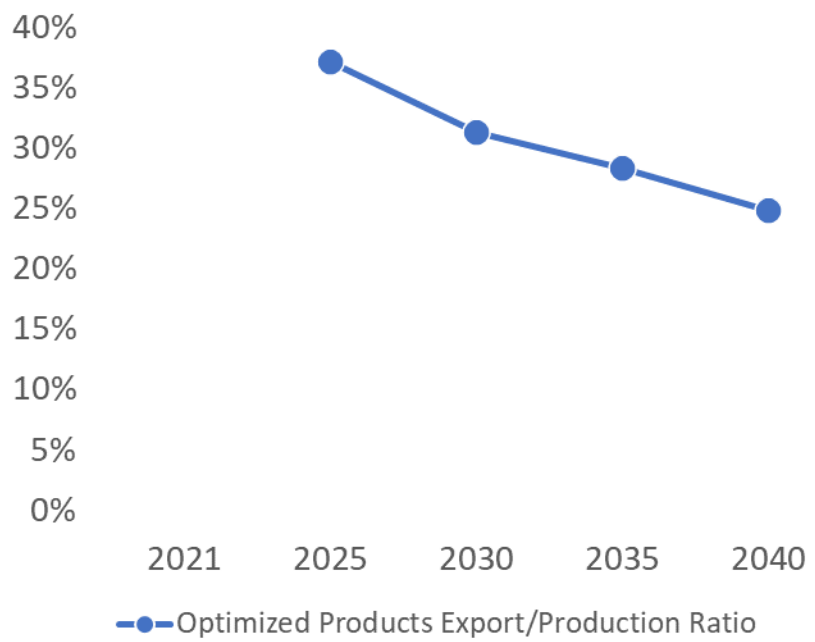

Figure 10: Profile of Nigeria's Optimal Petroleum Product Export Ratio

Further, the results show that the ratio of refined products exported in 2025 as 37%, subject to the both the Dangote and Port-Harcourt refineries coming on-stream at capacity. The ratio declines to 25% in 2040. This decline in the percentage of refined products exported is occasioned by increasing domestic demand of transport fuels especially PMS and AGO. Segregating the export ratio by products is illustrated in Figure 11.

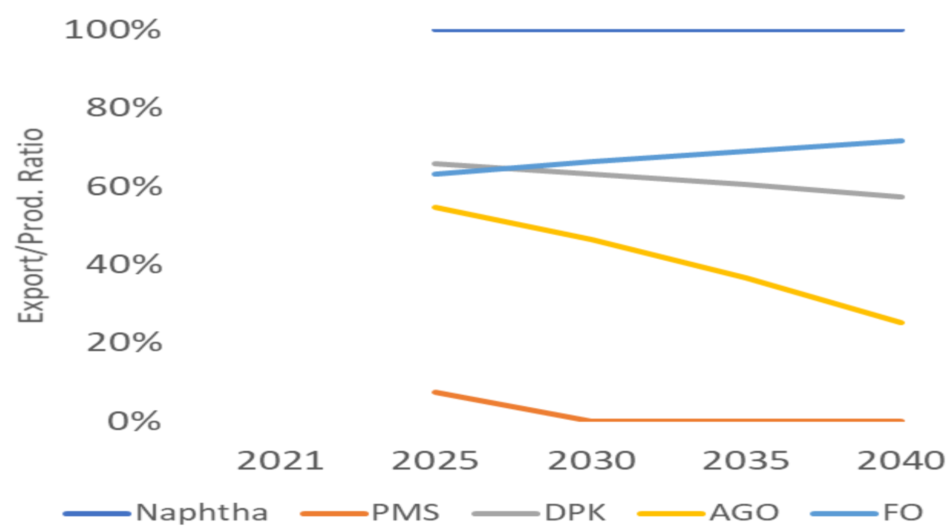

Figure 11: Petroleum Products' Export Ratio

In the aggregate, Figure 10 shows that the percentage of petroleum products exported declines. However, considering individual products, Figure 11 shows a more nuanced representation. For example, PMS exports decline from 7% of refinery production in 2025 to 0% by 2030 and beyond. AGO exports decline from 55% in 2025 to 25% in 2040, while DPK declines from 66% in 2025 to 57% in 2040. Fuel Oil exports, however, increase from 63% in 2025 to 71% in 2040; Naphtha exports are maintained at 100% throughout the period as minimal domestic demand is envisaged.

<u>*Domestic Petroleum Products Demand*</u>

There are three sources of supply to satisfy the domestic demand for refined petroleum products--domestic refining, direct products imports, and imports by swap arrangements. The optimal mix of this sources to satisfy domestic products demand under the energy transition scenario using demand related ratios are presented in Figure 12.

Approximately 130 MMbbls of PMS is supplied from domestic refining in 2025 and increases to 140 MMbbls from 2030 and beyond. DPK supply rises from 26.5 MMbbls (2025) to 33 MMbbls (2040), while AGO supply from the domestic refineries to the domestic market rises from 35.5 MMbbls (2025) to 58 MMbbls (2040). Additionally, due to the anticipated refining capacity of 860 Mbpd by 2025 from Dangote 650 Mbpd and PHRC 210 Mbpd, there is a minimal fuels imports required to meet domestic products demand. Thus, Figure 13 shows there are zero products imports between 2025 and 2029.

The year 2030 marks the first time products are imported and this is comprised only of PMS. The quantity imported increases from ~ 6 MMbbls in 2030 to ~45 MMbbls – this is doubtless on the back of increasing PMS demand envisaged. It is inferred from Figure 12 and Figure 13, that domestic demand for AGO, DPK is met entirely by domestic refining with excess produced for export (See. Export graphic Figure 9). Figure 14 assesses the extent to which domestic products demand is satisfied by the mix of the domestic refining system and product imports. In 2025, domestic demand is 100% fulfilled by domestic refining production. However, this declines to 84% in 2040.

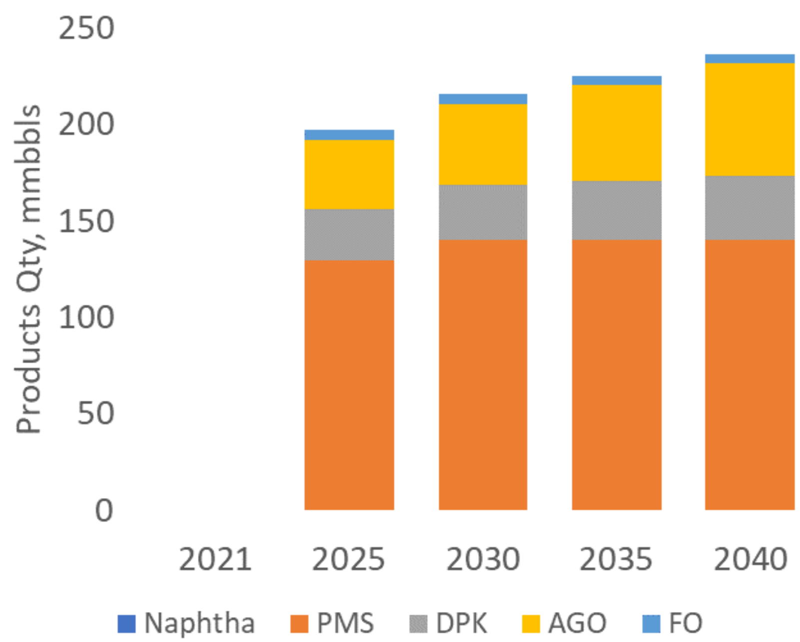

Figure 12: Optimal Supply of Petroleum Products from Domestic Refinery System

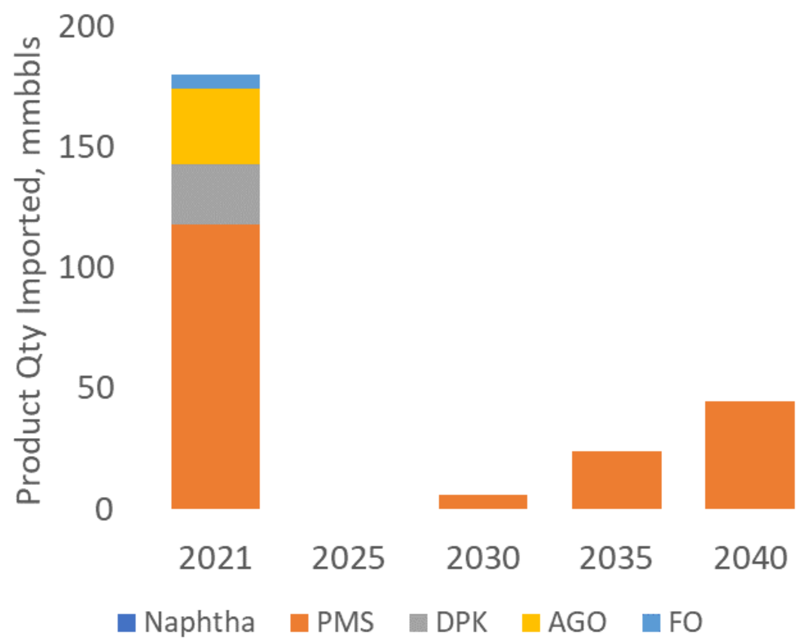

Figure 13: Optimal Petroleum Products' Import Profile

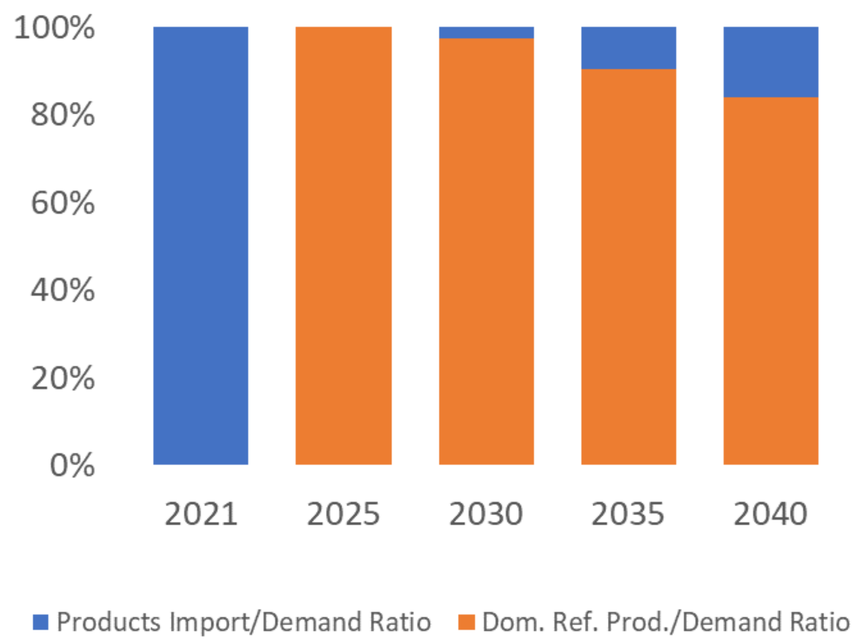

Figure 14: Optimal Mix of Petroleum Products Supply to Domestic Market

<u>*Net Benefits*</u>

Recall that the objective of the optimization model is the maximization of net benefits indicated as the difference in revenue inflows and cost outflows as per the Reference Energy System (Figure 3). Under the energy transition scenario, in which this objective is pursued, the profile of the net benefit is presented in Figure 15.

The net benefit (all in RT2019) rises from $3.76 billion in 2021 to a peak of $13.81 billion in 2025 and then declines in tandem with oil production and oil price to $11.45 billion in 2040. In undiscounted terms, the sum of these benefits over the period amounts to $228 billion.

Arising from the fact that the net benefit is the culmination of several factors relating to oil supply, product exports, imports and other fixed costs, the contribution of these factors to the net benefit is illustrated in Figure 16.

Note that the greatest contribution to the net benefits comes from the net value derived from domestic sales of products from the domestic refineries. Between $11.4 billion and $12.5 billion is attributable to product supply to the domestic market from the domestic refining system. The net value contribution from product exports range declines from $4 billion (2025) to $2.1 billion (2040). The net value from crude oil sales (both to export and to domestic refineries) declines from $2.9 billion (2025) to $0.81 billion (2040). These statistics on the net value contributions to the system net benefits highlight the importance of product supply to the domestic market from domestic refining and the diminishing import of the value from oil supply (both to export and domestic refining system).

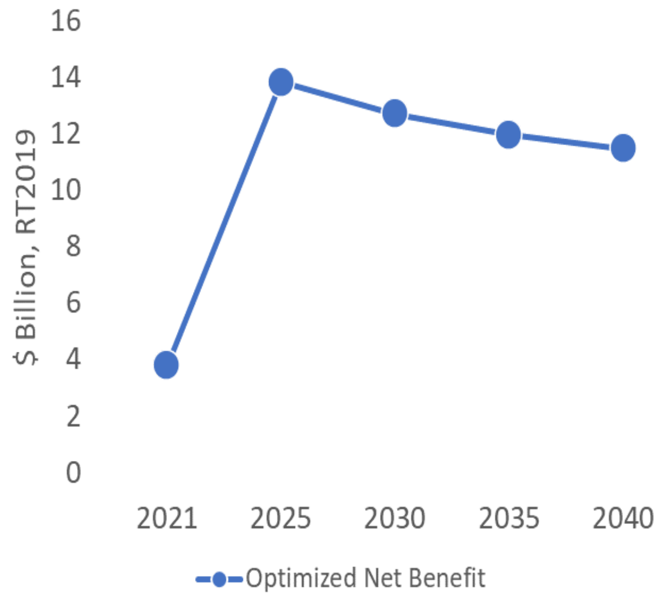

Figure 15: Profile of Optimal Net Benefits

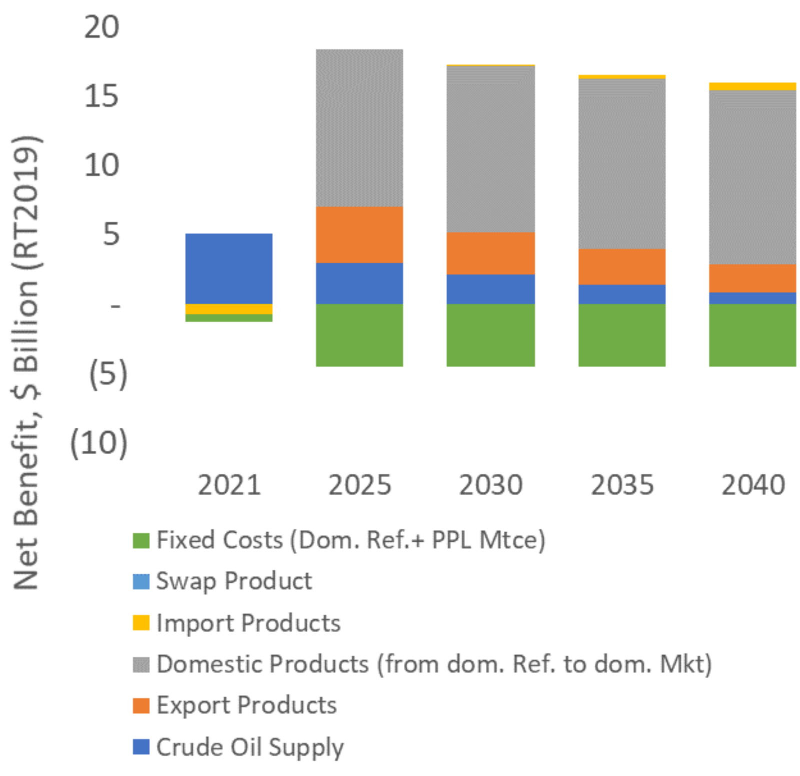

Figure 16: Distribution of Optimal Net Benefits

5. CONCLUSION

A mathematical program has been developed for optimal end-use allocation of nationally produced crude oil under energy transition dynamics. Teasing the characteristics of this transition with respect to Nigeria, this paper establishes the scenario under which optimisation would occur in terms of declining oil production, fuel subsidy phase out, stunted refinery capacity growth, and declining crude oil price.

Based on petroleum products demand projection, oil exports decline – from 43% of oil production in 2025 to 6% in 2040 while domestic demand is satisfied wholly from domestic refining from 2025 and 2030, beyond which gasoline imports are specifically required to augment domestic production. Gasoline imports reach 45 MMbbls in 2040, representing 16% of total petroleum product demand by 2040. While oil exports decline, refined petroleum exports increase from 67 MMbbls in 2023 to a peak of 117 MMbbls in 2025 and decline to 78 MMbbls in 2040. Refined products exports are driven by jet (DPK) and diesel (AGO), while gasoline enjoys minimal export of 10.4 MMbbls in 2025 and quickly declines to zero, few years later. In aggregate, 37% of domestic refining output is exported in 2025 which declines to 25% in 2040.

In terms of net benefits, the drivers are products supplied to the domestic market and refined product exports; while oil supply diminishes in importance as a driver of net benefits. Optimal allocation of oil and refined products under conditions consistent with the energy transition sees a shift of value to the domestic market, and products exports market with implications for foreign exchange earnings. Additionally, the Dangote refinery investment holds the potential to crowd out future large refinery investments as these will be left to service the domestic market by substituting for gasoline imports only. This will challenge the economics of any refinery investment after the Dangote refinery.

It is important to state that the conclusion is subject to the underlying characteristics of the energy transition as modelled. Consequently, investment decisions and strategic policy choices will need to consider likelihood of a future that is consistent with the energy transition assumptions. This may be very true for Sub-Sahara Africa energy systems and highlights the need for energy modelling that employs stochastic analysis to address energy trilemma challenges.

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