Technology Collaboration Programme
by iea

Evaluating technology options to mitigate greenhouse gas emissions

IEAGHG Technical Report
2020-04
May 2020

The Clean Refinery and the Role of Electricity Generation

IEA GREENHOUSE GAS R&D PROGRAMME

International Energy Agency

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 30 member countries and beyond. Within its mandate, the IEA created Technology Collaboration Programmes (TCPs) to further facilitate international collaboration on energy related topics. To date, there are 38 TCPs who carry out a wide range of activities on energy technology and related issues.

DISCLAIMER

The GHG TCP, also known as the IEAGHG, is organised under the auspices of the International Energy Agency (IEA) but is functionally and legally autonomous. Views, findings and publications of the IEAGHG do not necessarily represent the views or policies of the IEA Secretariat or its individual member countries.

This report was prepared as an account of the work sponsored by IEAGHG. The views and opinions of the authors expressed herein do not necessarily reflect those of the IEAGHG, its members, the organisations listed below, nor any employee or persons acting on behalf of any of them. In addition, none of these make any warranty, express or implied, assumes any liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product of process disclosed or represents that its use would not infringe privately owned rights, including any parties intellectual property rights. Reference herein to any commercial product, process, service or trade name, trade mark or manufacturer does not necessarily constitute or imply any endorsement, recommendation or any favouring of such products.

COPYRIGHT

Copyright © IEA Environmental Projects Ltd. (IEAGHG) 2020. All rights reserved.

ACKNOWLEDGEMENTS AND CITATIONS

To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release.

The IEAGHG manager for this report was: James Craig

The expert reviewers for this report were:

- Keith Burnard, IEAGHG
- Monica Garcia, IEAGHG

The report should be cited in literature as follows:

'IEAGHG, The Clean Refinery and the Role of Electricity Generation, 2020-04, May 2020.'

Further information or copies of the report can be obtained by contacting IEAGHG at:

IEAGHG, Pure Offices, Cheltenham Office Park
Hatherley Lane, Cheltenham,
GLOS., GL51 6SH, UK
Tel: +44 (0)1242 802911
E-mail: mail@ieaghg.org Internet: www.ieaghg.org

The Clean Refinery and the Role of Electricity Generation

(IEA/CON/18/251)

Key Messages

- The results of this study show that, in each of the three countries that were analyzed in this study (India, Nigeria and Brazil), the most favourable refinery configuration is one based on the conversion of opportunity crudes (high sulphur and extra-heavy crude oils), to the highest added-value distillate products.
- Refineries that produce higher value products, and environmental standards including CO_2 capture, will require policies that compensate for the extra costs of these measures.
- The economic analysis conducted as part of this study shows that the price of CO_2 needed to match the same Investment Rate of Return (IRR) of equivalent configurations without incorporated CO_2 capture would need to reach between US$32 – US$79 / ton of CO_2, depending on the refinery configuration (see Table 4).
- On-site electricity generation with CO_2 capture facilities can form part of the product portfolio, for export to local grids, from a Clean Refinery as an alternative to less refined and less desirable products. For example, in Brazil, fuel oil cannot be produced that meets the country's market-specification because of the very high viscosity of local crudes.
- As a common trend, and as expected, the yield in valuable distillates (LPG, gasoline, jet fuel and diesel) is directly proportional to the complexity of the configuration and relevant Nelson Index (which is a metric that allows comparison of the secondary conversion capacity of a refinery with its primary distillation capacity). Differences between the yields in the three countries are due to the very different nature of the processed crude oils.
- On the basis of the economic analysis of the refinery configurations developed in this study only two large-complex Indian refineries have a positive payback in less than 10 years. The other configurations have very unpromising paybacks of 16 – 20 years in three cases and indeterminate in the case of all three Brazilian cases and one Nigerian case (i.e. all four cases have negative Net Present Values (NPVs)). The Brazilian cases are penalized by the assumed crude cost in relation to the local product prices that are governed by market conditions and the relatively high Total Investment Cost (TIC).
- In a mature market, like the refining one, the key-drivers that still make a new refinery a profitable investment are: access to infrastructures; secure crude supply; medium-to-large capacity; and complexity.
- The economic analysis conducted as part of this study shows that the additional cost of CO_2 capture results in a loss of profitability if the value and environmental benefit of captured CO_2 is not credited.

Background to the Study

The oil refinery sector faces significant challenges in response to the Paris Agreement's 2050 projections for carbon emission reductions. Moreover, there is a global trend to process significant amounts of heavy, sour crude to produce high value products, such as ultra-low-sulphur diesel and gasoline, to achieve better refinery margins as well as meeting stringent environmental standards including green-house gas emission reductions. The option of CO_2 emission free electricity generation within refineries can help to meet these goals.

The primary aim of this study was to explore the role of the 'clean refinery' concept and how it could contribute to the Paris Agreement's long-term objective to curb peak global greenhouse gas emissions. Various options for refineries are available depending, not only on the complexity and degree of integration, but also on whether a refinery already exists or is still at the planning stage. In addition to these general considerations, the regional location, crude mix and local markets for refined products and electricity all influence the design, complexity and economic viability of 'clean refineries'.

The priority for a 'clean refinery' is to achieve the best balance of clean products, i.e. transportation fuels, petrochemicals and power, while reducing energy poverty. This balance is likely to vary from region to region. To gain some understanding of how the balance might look in rapidly developing economies, and the main drivers, three specific regions: Africa; South America; and Asia were selected.

The trend to processing heavier, sour crudes that can use bottom-of-the-barrel feedstocks are likely to vary regionally. Options for hydrogen, electricity and steam production, particularly the generation of clean electricity which incorporates CO_2 capture, were reviewed as part of the 'clean refinery' concept, in each region and based on processing crudes with a range of sulphur contents.

Capital investment and design for a 'clean refinery' concept needs to factor in bottom of the barrel solutions, access to electricity and the electricity market, and its impact on the choice of technology options. In this study, the future role of refineries in supplying clean power generation (including CCUS deployment) was evaluated.

A key objective of this study was to conceive and evaluate different refinery configurations that could achieve the best balance of clean products and electricity, based on the supply of heavy sour and opportunity crudes and include electricity generation for export. The macro-economics of maximising electricity production within the refinery complex in the selected regions has been examined as part of the energy management strategy. The study has also constructed a series of different conceptual refinery configurations in each of the three different regions (India, Nigeria and Brazil) to reflect market conditions in these rapidly developing economies. In each case alternative process configurations have been developed and evaluated from both an economic and a technical perspective. Coastal locations were selected for each refinery. The study then set out to identify the optimum integrated refinery configurations, flow schemes, layouts and plot plans. This was achieved by selecting different capacities and crude blends, including heavy sour crudes and opportunity crudes, that reflect both regional crude supplies and, in the case of India and to a lesser extent Nigeria, imports suited to refinery configurations and product demand. A series of linear programmes were used to generate refinery designs. The different refinery configurations included:

- Power integrated hydro-skimming refinery
- Power integrated semi-converted refinery
- Power integrated converted refinery

The refinery configurations had to process crudes that could produce distillates that met regional and international specifications; whilst maintaining energy self-sufficiency and, where possible, the capability to produce steam and electricity for export. CO_2 capture on power production and refinery operations was also included in these assessments. The study concluded with an economic analysis based on detailed capital investment costs for each alternative processing scheme, calculated revenues and operating costs. Standard economic tests (NPV and IRR) were applied to different scenarios to determine the economic and financial viability of the schemes. Finally, the carbon price was determined that would enable a viable refinery solution to function with CO_2 capture included.

Scope of work

Under the scope of the study, representative clean refineries were modelled for the emerging energy and petroleum product markets in Africa (Nigeria), South America (Brazil), and Asia (India). In all the selected countries, an increase of transportation liquid fuel demand, as well as an increase of electric energy demand, were assumed in each forecast.

For each country, three different refinery schemes were proposed, studied and finally compared.

Increasing size and complexity has been considered, by progressively adding to a base case scheme, i.e. the hydroskimming case. The addition of conversion units for transforming straight-run heavy material into valuable distillates is capital-intensive, but this is typically justified for medium-to-large refineries, which then benefit from better economies of scale.

In the following table, (Table 1) the acronyms in red are relevant to the selected Medium Conversion units (HCU=Hydrocracking, FCC=Fluid Catalytic Cracking), while the acronyms in blue are relevant to the selected High Conversion units (SDA=Solvent Deasphalting, DCU=Delayed Coking, IGCC=Integrated Gasification Combined Cycle). The refining capacities in terms of barrels per day (bpd) throughput for the hypothetical examples varied from low to medium (150,000 – 200,000 bpd) to very large scale (400,000 bpd). This span of values was used to test the effects of economies of scale.

Table 1 Refinery type and capacity for India, Nigeria and Brazil

Size	India	Nigeria	Brazil
Power integrated simple Hydro-skimming refinery Low to medium size CASE LC1	-	150,000 bpd	-
Power integrated Medium conversion refinery Medium to Large – Size 1 CASE MC1	250,000 bpd **HCU**	200,000 bpd **FCC**	150,000 bpd **HCU** with CO_2 capture
Power integrated Medium conversion refinery Medium to Large – Size 2 CASE MC2	-	-	250,000 bpd **HCU + FCC** with CO_2 capture
Power integrated bottom of the barrel solution Medium to very large size CASE HC1	400,000 bpd **HCU + FCC** SDA + DCU with CO_2 capture	200,000 bpd **FCC** SDA with CO_2 capture	300,000 bpd **HCU + FCC** SDA + IGCC with CO_2 capture
Power integrated bottom of the barrel solution Medium to very large size CASE HC2	400,000 bpd **HCU + FCC** SDA + IGCC with CO_2 capture	-	-

Bpd = barrels per day

CO_2 capture facilities have been envisaged in all the high conversion schemes and in the medium conversion schemes where fuel oil cannot be produced because of the constraints imposed by market specification (namely, in Brazil due to very high viscosity). The bottom of the barrel upgrading schemes are based on "clean processes" allowing for the selective removal of sulphur and CO_2.

- In the upgrading schemes, based on gasification, pre-combustion selective removal of CO_2 and H_2S is achieved in the Acid Gas Removal unit belonging to the syngas treatment line. This process is downstream of the CO shift conversion unit where most of the CO is converted to CO_2 with the production of hydrogen using steam.

- In the cogeneration power plant, boiler flue gas is treated in a dedicated flue gas desulfurization unit for the removal of SO_2 and in a post-combustion capture unit for the removal of CO_2.

In addition to these processes, post-combustion CO_2 capture has been considered for the major refinery heaters (i.e. Crude and Vacuum Distillation), while pre-combustion CO_2 capture (from syngas) has been considered for the steam methane reformer unit.

The detailed refinery balances have been obtained by means of a Linear Programming (LP) technique. The models have been run assuming the following mix of crudes summarised in Table 2.

Table 2 Typical (average) crude diets defined for each Country

India	Crude	API	Sulphur content % wt.
	Ekofisk (Norway)	42.4°	0.17
	Arabian Light (Saudi Arabia)	33.9°	1.77
	Maya (Mexico)	21.7°	3.18
Brazil	**Crude**	**API**	**Sulphur content % wt.**
	Marlim (Brazil)	20.0°	0.77
	Lula Tupi (Brazil)	28.8°	0.37
	Peregrino (Brazil)	13.4°	1.76
Nigeria	**Crude**	**API**	**Sulphur content % wt.**
	Agbami (Nigeria)	48.3°	0.04
	Bonny Light (Nigeria)	35.1°	0.15
	Doba Blend (Chad)	21.0°	0.09

In each case the following set of conditions were applied:

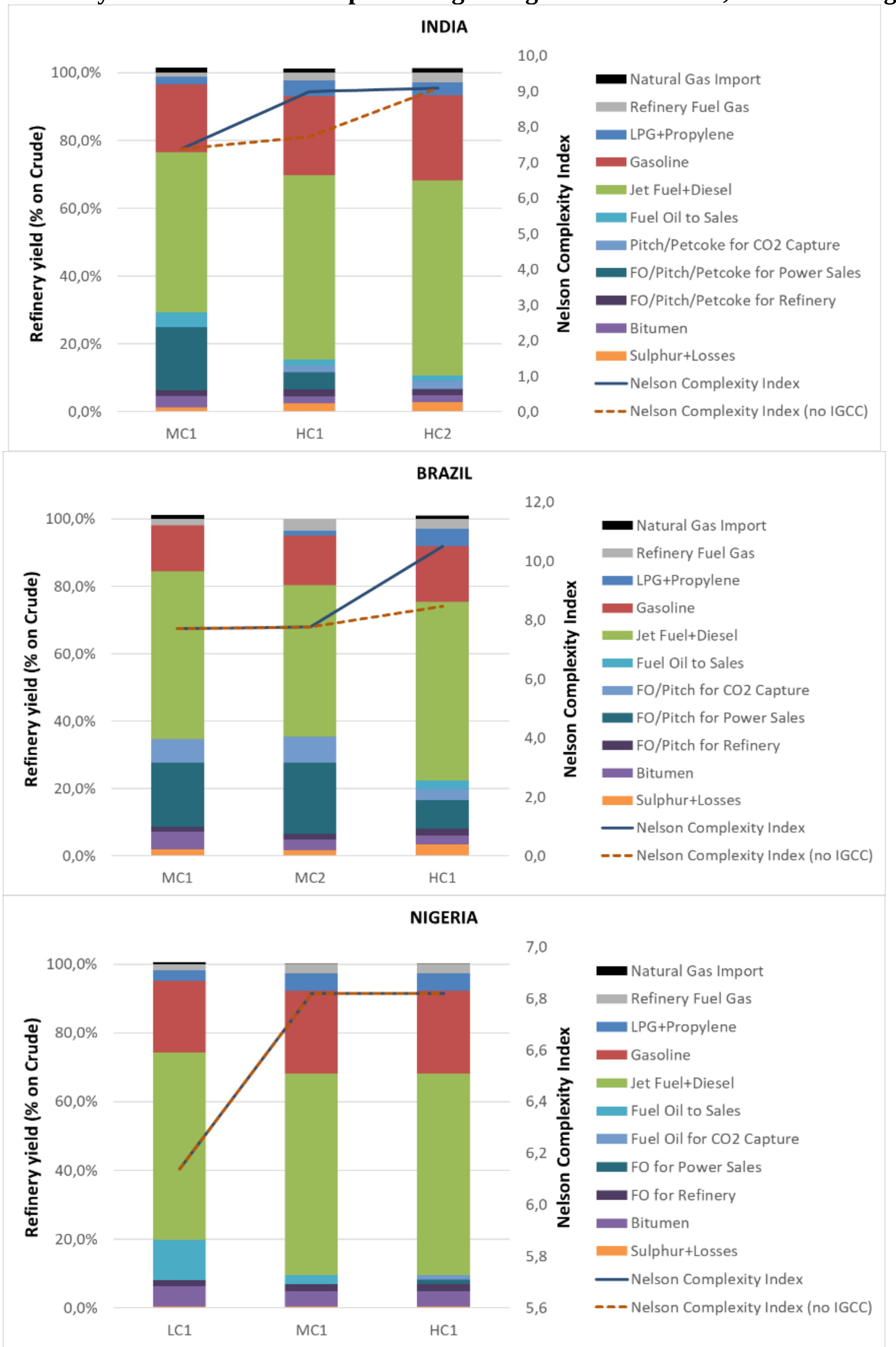
- Clean products' specifications
- Sets of crude, natural gas and products' prices which have been defined by Wood (the contractor) as a part of the Study
- Reasonable products' slates and market volumes
- Typical refinery units' performance from a Wood in-house database
- Typical (average) units' size and utilization factor
- Internal production of power and steam to satisfy the refinery needs.

Findings of the Study

The charts set out in Figure 1 show the products' yields of the nine configurations studied, defined as a percentage on crude oil feed, as well as the Nelson Complexity Index[1] calculated for each refinery. As a common trend, and as expected, the yield in valuable distillates (LPG, gasoline, jet fuel and diesel) is directly proportional to the complexity of the configuration (and relevant Nelson Index). Differences between the yields in the various countries are due to the very different nature of the processed crude oils (ranging from the light-sweet Nigerian crudes, through the balanced mix used for the Indian refinery, to the heavy-sour crude compositions of Brazil), as well as to the different configurations and related distillate outputs.

[1] Nelson complexity index (NCI) is a measure which allows comparison of the secondary conversion capacity of refinery with its primary distillation capacity. This index provides an easy metric for quantifying and ranking the complexity of various refineries and associated units.

Figure 1 Refinery Product Yields from processing configurations in India, Brazil and Nigeria



The charts depicted in Figure 2 show the reduction of CO_2 emissions that have been achieved in the various configurations, by recoverying CO_2 from the syngas (pre-combustion) and/or from the flue gases (post-combustion) of the main emitters: Power Plant / IGCC; Steam Reformer (SMR); Crude and Vacuum Distillation Units. By capturing CO_2 only from the main emitters, the achievable emission reduction is in the range -60 to -80%, depending on the case.

Figure 2 CO_2 reductions achieved from different refinery configurations in India, Brazil and Nigeria

The Total Investment Cost (TIC) for the various refineries has been estimated and is reported in Table 3. TIC has been estimated on a pro-rate capacity basis starting from the in-house Wood database for similar units, populated with cost data from previous projects. Location Factors and Cost Indexes have then been applied to the factored costs to properly reflect the plant location and to determine the cost of the reference plants. In particular, the location factor is relatively high for Nigeria meaning that for the same capacity/configuration the investment costs in that country are significantly higher than in the reference location (i.e. US Gulf Coast), so penalizing the profitability of a new project in this African country.

Other CAPEX figures include the cost of the first batch of catalysts and chemicals, the license fees, royalties and engineering fees, spare parts, start-up expenses, plus other initial capital expenditure.

Table 3 CAPEX investment for different refinery configurations in India, Brazil and Nigeria

INDIAN REFINERIES	**MC1** 250,000 bpd HCU	**HC1** 400,000 bpd HCU + FCC SDA + DCU with CO_2 capture	**HC2** 400,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
TIC Refinery Units [M US$]	*3,339*	*6,277*	*7,388*
TIC Power Units [M US$]	*2,214*	*2,455*	*1,354*
TIC CO_2 Capture [M US$]	-	*305*	*533*
Sub Total Units TIC [M US$]	5,553	9,037	9,275
Sub Total Other CAPEX [M US$]	458	843	834
Total CAPEX [M US$]	**6,011**	**9,880**	**10,108**

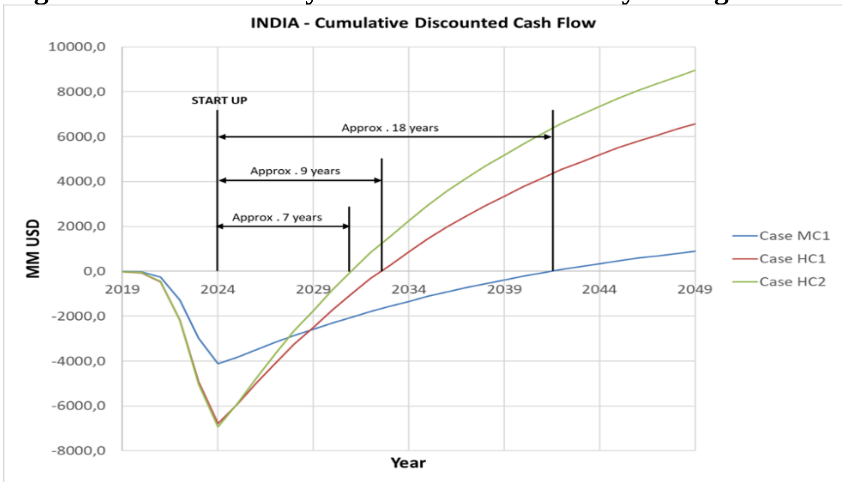
BRAZILIAN REFINERIES	**MC1** 150,000 bpd HCU with CO_2 capture	**MC2** 250,000 bpd HCU + FCC with CO_2 capture	**HC1** 300,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
TIC Refinery Units [M US$]	*2,609*	*4,416*	*5,780*
TIC Power Units [M US$]	*2,371*	*3,367*	*2,862*
TIC CO_2 Capture [M US$]	*805*	*1102*	*372*
Sub Total Units TIC [M US$]	5,785	8,885	9,014
Sub Total Other CAPEX [M US$]	445	699	834
Total CAPEX [M US$]	**6,230**	**9,584**	**9,848**

NIGERIAN REFINERIES	**LC1**	**MC1** 200,000 bpd FCC	**HC1** 200,000 bpd FCC SDA with CO_2 capture
TIC Refinery Units [M US$]	*2,536*	*3,707*	*3,707*
TIC Power Units [M US$]	*146*	*194*	*605*
TIC CO_2 Capture [M US$]	-	-	*240*
Sub Total Units TIC [M US$]	2,682	3,901	4,552
Sub Total Other CAPEX [M US$]	256	373	412
Total CAPEX [M US$]	**2,937**	**4,274**	**4,964**

The results of the economic analysis are reported in the following Figures 3, 4 and 5, (and accompanying tables) for the nine refinery configurations.

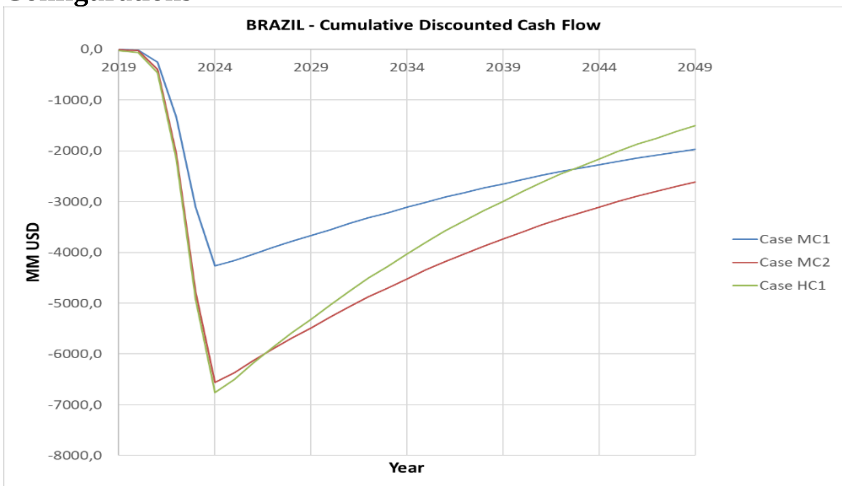
In addition to the key-financial indicators, i.e. Net Present Value (NPV) and Investment Rate of Return (IRR), the curves of cumulative discounted cash flow show the number of years of operation needed to reach the return of the investment point, i.e. cumulative discounted cash flow equal to zero. The end point of each curve (value on the y-axis in year 2049) is equal to the Net Present Value.

Figure 3 Economic analysis of the Indian Refinery Configurations



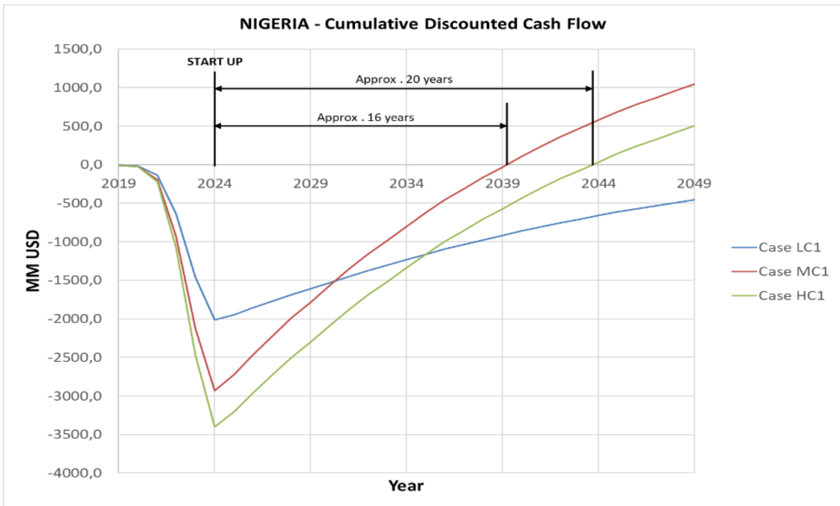
INDIA	MC1	HC1	HC2
	250,000 bpd HCU	400,000 bpd HCU + FCC SDA + DCU with CO_2 capture	400,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
NPV (MM USD)	895	6,567	8,949
IRR	10%	16%	18%

Figure 4 Economic analysis of the Brazilian Refinery Configurations



BRAZIL	MC1	MC2	HC1
	150,000 bpd HCU with CO_2 capture	250,000 bpd HCU + FCC with CO_2 capture	300,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
NPV (MM USD)	-1,972	-2,615	-1,505
IRR	3%	4%	6%

Figure 5 Economic analysis of the Nigerian Refinery Configurations



NIGERIA	LC1	MC1	HC1
		200,000 bpd FCC	200,000 bpd FCC SDA with CO_2 capture
NPV (MM USD)	-454	1,045	506
IRR	6%	11%	9%

It is noticeable that the economic analysis results show that only two large-complex Indian refineries have a positive payback within 10 years. The other configurations have very unpromising paybacks of 16 – 20 years in three cases and indeterminate in the case of all three Brazilian cases and one Nigerian case (i.e. they all four cases have negative NPVs).

The results of this study show that, in all three countries, the most favourable scheme is the one based on High Conversion, capable of creating the highest added-value from each single barrel of crude oil.

In a mature market, like the refining one, the key-drivers that still make a new refinery a profitable investment are:

- Access to infrastructures;
- Secure crude supply.
- Medium-to-large capacity;
- Complexity, flexibility and fit-for-purpose configuration, able to convert the crude oil into the products that the markets require;
- Energy efficiency.

In developing economies investment in new refineries, especially integrated with power production plants, offers strategic energy independency as well as social development in the surrounding areas. They could also stimulate employment and offer conducive conditions for the development of other industries.

The economic results of this study, which are based on an international parity basis of prices for crude oils, and on the current structure of prices for the automotive fuels in the selected countries, should only be regarded as indicative. The financial indicators would be significantly impacted by any form of incentive that governments could put in place for strategical and social purposes.

CO_2 capture is a fundamental measure to meet challenging greenhouse gas reduction targets. For this reason, in this study, CO_2 capture is considered as embedded in the concept of a clean refinery. However, CO_2 capture means additional costs and loss of profitability, evident from the economic results of the study. Therefore, to promote clean refineries with a lower carbon footprint, and to enable them to compete in a market on a fair basis, subsidies in some form would be needed that compensate for the extra costs for CO_2 capture or, alternatively, penalties for the CO_2 emitted to atmosphere or credits for captured, used or stored CO_2.

As a part of this study, the "base" cases with CO_2 capture, required the price of CO_2 to be evaluated assuming the same IRR as equivalent schemes (i.e. same refinery capacity and configuration) without CO_2 capture (Table 4).

Table 4 Impact of the TIC of CO_2 capture pant on IRR and CO_2 selling price on different refinery configurations in India. Brazil and Nigeria

INDIA	**MC1** 250,000 bpd HCU	**HC1** 400,000 bpd HCU + FCC SDA + DCU with CO_2 capture	**HC2** 400,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
TIC CO_2 Capture (US$ MM)		305	533
IRR Reference Case (w/o CC)		20%	17%
IRR Base Case (with CC)		17%	16%
Required CO_2 selling price (US$/ton)	-	79	32

BRAZIL	**MC1** 150,000 bpd HCU with CO_2 capture	**MC2** 250,000 bpd HCU + FCC with CO_2 capture	**HC1** 300,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
TIC CO_2 Capture (US$ MM)	805	1,102	372
IRR Reference Case (w/o CC)	10%	12%	8%
IRR Base Case (with CC)	3%	4%	6%
Required CO_2 selling price (US$/ton)	72	68	35

NIGERIA	**LC1**	**MC1** 200,000 bpd FCC	**HC1** 200,000 bpd FCC SDA with CO_2 capture
TIC CO_2 Capture (US$ MM)			240
IRR Reference Case (w/o CC)			11%
IRR Base Case (with CC)			9%
Required CO_2 selling price (US$/ton)	-	-	53

A common trend emerges from this study. The CO_2 selling price (or avoidance cost) is lower in the configurations with an IGCC complex, because the CO_2 capture facilities are integrated into the IGCC scheme (pre-combustion capture) which has a lower cost impact and energy consumption compared with the post-combustion capture applied in the other schemes.

It is also important to emphasise that the inclusion of CO_2 capture in a new refinery complex enables the integration of the CO_2 capture systems to be optimised with the rest of the plant. This approach leads to a significant reduction in CAPEX and OPEX compared with a retrofit scheme. The main reduction factors are:

- CAPEX: saving in utility and interconnecting facilities, synergy in the engineering and construction phases.
- OPEX: optimization of heat integration, saving in O&M staff and related costs.

Expert Review Comments

- The contractor Wood has produced a competent study covering many complex issues, although the executive summary needed to be improved to explain the rationale for the work and what it aimed to achieve.
- Clarification of the capture system which is based on post carbon capture amine absorption. More technical information has been supplied by Wood and included in the final report. This information has been cross-referenced with previous capture system investigations commissioned with Wood and Foster-Wheeler.
- More information on the capture technologies used and the quantities of CO_2 captured from select capture points across the refinery. More detailed information was supplied by Wood
- The potential for CO_2 storage or use for EOR. Although this is an important observation it was not part of the original scope, nevertheless there is potential for CO_2-EOR in all three countries and the technology is well established in Brazil. Preliminary initiatives have been instigated into the potential for CO_2-EOR in India and West Africa.
- CO_2 and power output should be shown as products and include carbon pricing. The final version includes in the economic analysis a representative unit cost of electricity for each country. CO_2 is valued in terms of the carbon price that would be necessary to achieve IRR parity with refinery configurations without CO_2 capture. Although carbon trading markets have been established in Europe and the USA they have not been established in any of the three countries included in this study.
- Clarification on hydrogen balances have been included based on specific units' hydrogen demands.
- Modifications have been made to block flow diagrams (BFDs) which now show the integrated power islands and links to feedstocks, following suggestions from reviewers.

Conclusions

- As a common trend, and as expected, the yield in valuable distillates (LPG, gasoline, jet fuel and diesel) is directly proportional to the complexity of the configuration (and relevant Nelson Index). Differences between the yields in the various countries are due to the very different nature of the processed crude oils.
- CO_2 capture facilities have been envisaged in all the high conversion schemes and in the medium conversion schemes where fuel oil cannot be produced on market-spec (namely, in Brazil due to very high viscosity) and, hence, the electric energy production is considered as part of the product portfolio of Clean Refinery in providing clean products instead of alternative less refined and less desirable ones.
- On the basis of the economic analysis of the refinery configurations developed in this study only two large-complex Indian refineries have a positive payback in less than 10 years. The other configurations have very unpromising paybacks of 16 – 20 years in three cases and indeterminate in the case of all three Brazilian cases and one Nigerian case (i.e. all four cases have negative NPVs).
- The results of this study show that, in all countries, the most favourable scheme is the one based on High Conversion, capable of creating the highest added-value from each single barrel of crude oil.
- In a mature market, like the refining one, the key-drivers that still make a new refinery a profitable investment are: access to infrastructures; secure crude supply; medium-to-large capacity; and complexity.
- Refineries designed with flexibility and fit-for-purpose configurations are able to convert crude oil into products that meet regional market demands and stringent environmental standards.
- The economic analysis conducted as part of this study shows that the additional cost of CO_2 capture results in a loss of profitability if the value and environmental benefit of captured CO_2 is not credited.
- Refineries that produce higher value products, and environmental standards including CO_2 capture, would require policies that compensate for the extra costs of these measures. To

place this observation in context the economic analysis conducted as part of this study shows that the price of CO_2 would need to be between US$32 – US$79 / ton of CO_2, depending on the refinery configuration, to match the same IRR of equivalent configurations without incorporated CO_2 capture.

Recommendations

If this work was to be taken further then we would recommend the following studies:

- A review of the markets for CO_2 in India, Brazil and Nigeria including the potential for CO_2-EOR.
- A detailed assessment of large point-source CO_2 emission sources in these countries and the potential for developing CO_2 supply hubs and transport networks including the use of sea tankers.
- A more detailed analysis of the electricity markets in these countries and the impact wholesale electricity prices might have on potential investment in new power generation capacity with CO_2 capture.

The clean refinery and the role of electricity generation

Study Report

Doc. No.: BD1047A-PR-0000-RE-001

REV.	ISSUE DATE	DESCRIPTION	PREPARED BY	CHECKED BY	APPROVED BY
2	2 Jan 2020	Final Issue (revised where indicated)	F.Manelli/ R.Brazzoli	C. Gilardi	C. Gilardi
1	11 Dec 2019	Final issue	F.Manelli/ R.Brazzoli	C. Gilardi	C. Gilardi
0	14 June 2019	First Issue for Review	V.Depetri/F.Manelli/ R.Brazzoli	C. Gilardi	S.Arienti

Table of Contents

List of Figures

List of Tables

Executive Summary

The oil refinery sector faces significant challenges in response to the Paris Agreement's 2050 projections for carbon emission reductions. Moreover, there is a global trend to process significant amounts of heavy, sour crude to produce high value products, such as ultra-low-sulphur diesel and gasoline, to achieve better refinery margins as well as meeting stringent environmental standards including green-house gas emission reductions. The option of CO_2 emission free electricity generation within refineries can also help to meet these goals.

The primary aim of this study is to explore the role of the 'clean refinery' concept and how it could contribute to the Paris Agreement's long-term objective to curb peak global greenhouse gas emissions. Various options for refineries are available depending, not only on the complexity and degree of integration, but also on whether the refinery already exists or is still at the planning stage. In addition to these general considerations, the regional location, crude mix and local markets for refined products and electricity all influence the design, complexity and economic viability of 'clean refineries.

The priority for a 'clean refinery' is to achieve the best balance of clean products, i.e. transportation fuels, petrochemicals and power, while reducing energy poverty. This balance is likely to vary from region to region. To gain some understanding of how the balance might look in rapidly developing economies, and the main drivers, three specific regions: Africa; South America; and Asia were selected.

The trend to heavier, sour crude, solutions to address bottom-of-the-barrel feedstocks are likely to vary regionally. Options for hydrogen, electricity and steam production, particularly the generation of clean electricity which incorporates CO_2 capture, were reviewed as part of the 'clean refinery' concept in each region.

As the capital investment required to develop bottom of the barrel solutions is a major consideration, access to electricity and the electricity market, and its impact on the choice of technology options, has been anticipated. In this study, the future role of refineries in supplying clean power generation (including CCUS deployment) was evaluated.

The macro-economics of maximising electricity production within the refinery complex in the selected regions has been examined as part of the energy management strategy. The study has also built a series of different refinery configurations in each of the three different regions (India, Nigeria and Brazil) to reflect market conditions in these rapidly developing economies. In each case alternative process configurations have been developed and evaluated from both an economic and a technical perspective. Coastal locations were selected for each refinery. The study then set out to identify the optimum integrated refinery configurations, flow schemes, layouts and plot plans. This was achieved by selecting different capacities and crude blends, including heavy sour crudes and opportunity crudes, that reflect regional conditions. A series of linear programmes were used to generate refinery designs. The different refinery configurations included

- Power integrated hydro-skimming refinery
- Power integrated semi-converted refinery
- Power integrated converted refinery

The refinery configurations had to process crudes that could produce distillates that met regional and international specifications; whilst maintaining energy self-sufficiency and, where possible, the capability to produce steam and electricity for export. CO_2 capture on power production and refinery operations was also included in these assessments.

The study concludes with an economic analysis based on detailed capital investment costs for each alternative processing scheme, calculated revenues and operating costs. Standard economic tests (NPV and IRR) were applied to different scenarios to determine the economic and financial viability of the schemes. Finally the carbon price was determined that would enable a viable refinery solution to function with CO_2 capture included.

For each country, three different refinery schemes have been proposed, studied and finally compared.

Increasing size and complexity have been considered, by progressively adding to a "base scheme", i.e. the hydroskimming case, some conversion units for transforming straight-run heavy material into valuable distillates. The addition of these types of unit, which are capital-intensive, is typically justified for medium-to-large refineries, which benefit from better economies of scale. In the table, the acronyms in red are relevant to the selected Medium Conversion units (HCU=Hydrocracking, FCC=Fluid Catalytic Cracking), while the acronyms in blue are relevant to the selected High Conversion units (SDA=Solvent Deasphalting, DCU=Delayed Coking, IGCC=Integrated Gasification Combined Cycle).

Size	India	Nigeria	Brazil
Power integrated simple Hydro-skimming refinery Low to medium size CASE LC1	-	150,000 bpd	-
Power integrated Medium conversion refinery Medium to Large – Size 1 CASE MC1	250,000 bpd **HCU**	200,000 bpd **FCC**	150,000 bpd **HCU** with CO2 capture
Power integrated Medium conversion refinery Medium to Large – Size 2 CASE MC2	-	-	250,000 bpd **HCU + FCC** with CO2 capture
Power integrated bottom of the barrel solution Medium to very large size CASE HC1	400,000 bpd **HCU + FCC** SDA + DCU with CO2 capture	200,000 bpd **FCC** SDA with CO2 capture	300,000 bpd **HCU + FCC** SDA + IGCC with CO2 capture
Power integrated bottom of the barrel solution Medium to very large size CASE HC2	400,000 bpd **HCU + FCC** SDA + IGCC with CO2 capture	-	-

CO_2 capture facilities have been envisaged in all the high conversion schemes and in the medium conversion schemes where fuel oil cannot be produced on market-spec (namely, in Brazil due to very high viscosity) and, hence, the electric energy production is considered as part of the product portfolio of this Clean Refinery in providing clean products instead of "black" ones. More specifically, the bottom of the barrel upgrading schemes are based on "clean processes" allowing for selective removal of sulphur and CO_2.

- In the upgrading schemes based on gasification, pre-combustion selective removal of CO_2 and H_2S is achieved in the Acid Gas Removal unit belonging to the syngas treatment line, downstream of the CO shift conversion unit where most of the CO is converted to CO_2 with the production of hydrogen using steam.
- In the cogeneration power plant, boiler flue gas is treated in dedicated flue gas desulfurization for SO_2 removal and in a post-combustion capture unit for CO_2 removal.

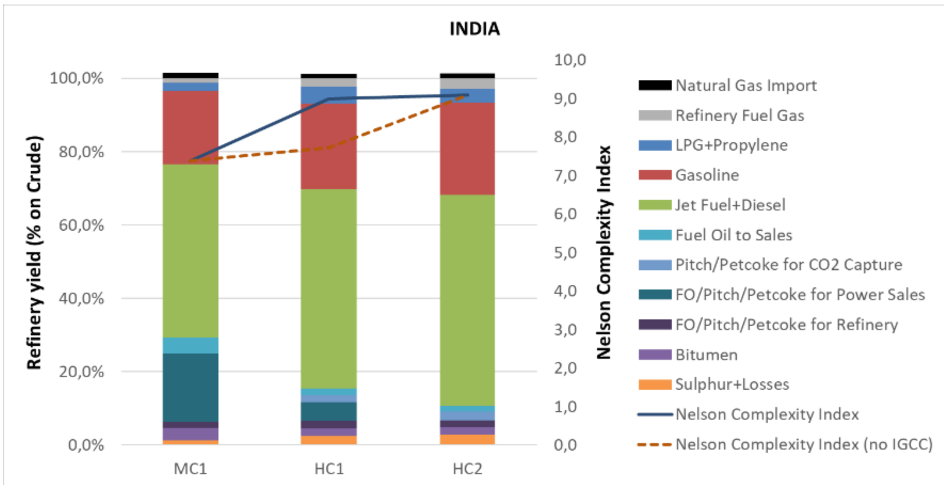
On top of this, post-combustion CO_2 capture has been considered for the major refinery heaters (i.e. Crude and Vacuum Distillation), while pre-combustion CO_2 capture (from syngas) has been considered for the steam methane reformer unit.

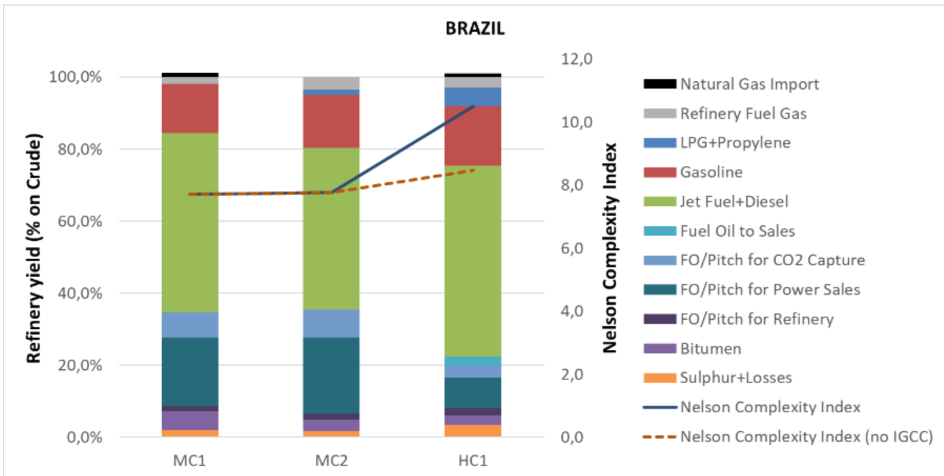
When feasible, i.e. for gasification and steam methane reformation, pre-combustion CO_2 capture has been preferred since it's more efficient in terms of capital cost and energy consumption, as demonstrated by Wood as a part of previous studies carried out for IEAGHG ("Coproduction of Hydrogen and Electricity with CO2 capture" study of 2012, "Techno-economic Evaluation of H_2 Production with CO_2 Capture" study of 2016). The detailed refinery balances have been obtained by means of a Linear Programming (LP) technique. The models have been run based on:

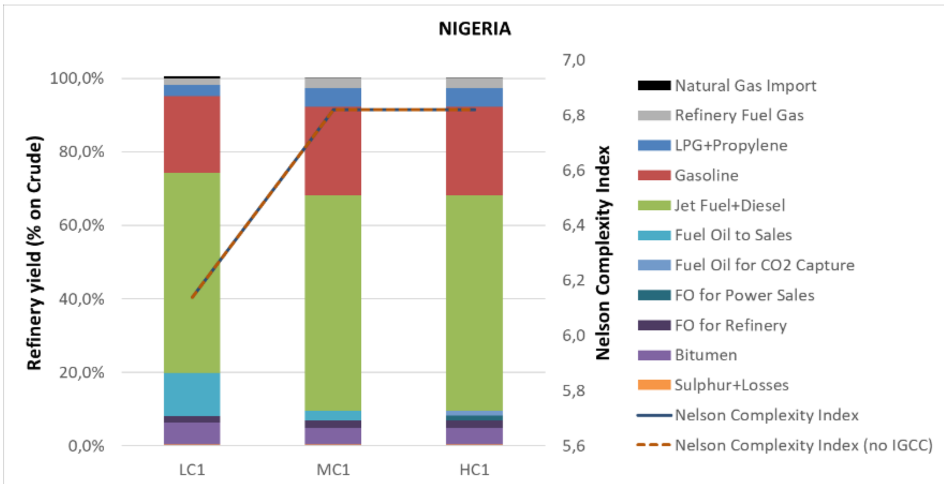
1) Typical (average) crude diets defined for each Country, and in particular:
   a) Asia (India)
      - Ekofisk (Norway), 42.4° API, Sulphur content 0.17% wt.
      - Arabian Light (Saudi Arabia), 33.9° API, Sulphur content 1.77% wt.
      - Maya (Mexico), 21.7°API, Sulphur content 3.18% wt.
   b) South America (Brazil)
      - Marlim (Brazil), 20.0° API, Sulphur content 0.77% wt.
      - Lula Tupi (Brazil), 28.8° API, Sulphur content 0.37% wt.
      - Peregrino (Brazil), 13.4° API, Sulphur content 1.76% wt.
   c) Africa (Nigeria)
      - Agbami (Nigeria), 48.3° API, Sulphur content 0.04% wt.
      - Bonny Light (Nigeria), 35.1° API, Sulphur content 0.15% wt.
      - Doba Blend (Chad), 21° API, Sulphur content 0.09% wt.
2) Clean products' specifications

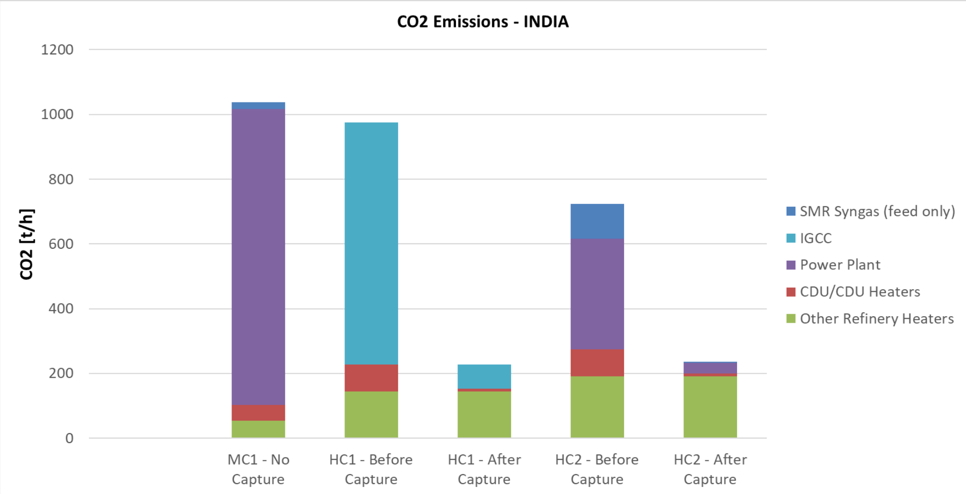
3) Sets of crude, natural gas and products' prices which have been defined by Wood as a part of the Study
4) Reasonable products' slates and market volumes
5) Typical refinery units' performance from a Wood in-house database
6) Typical (average) units' size and utilization factor
7) Internal production of power and steam to satisfy the refinery needs.

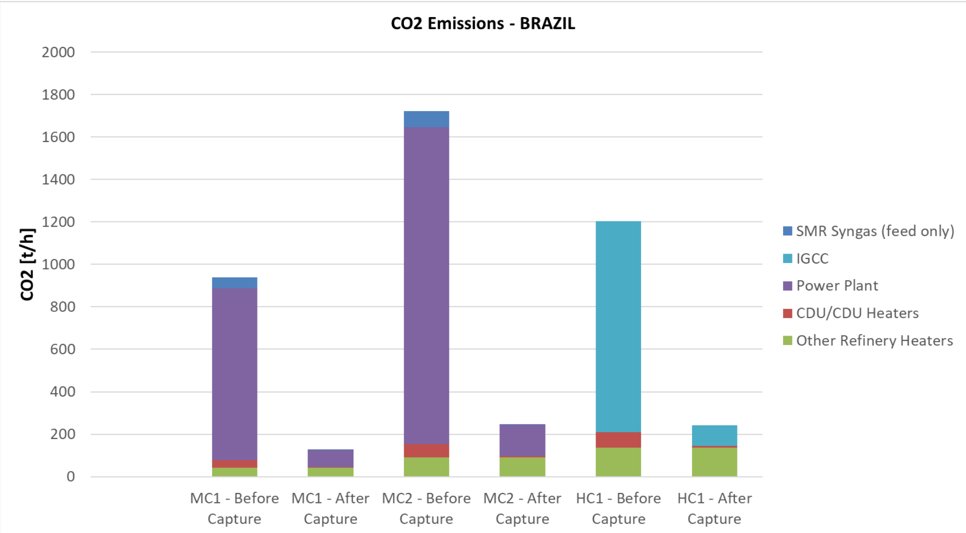
The charts on the right side of this page show the products' yields of the nine configurations studied, defined as a percentage on crude oil feed, as well as the Nelson Complexity Index calculated for each refinery. As a common trend, and as expected, the yield in valuable distillates (LPG, gasoline, jet fuel and diesel) is directly proportional to the complexity of the configuration (and relevant Nelson Index). Differences between the yields in the various countries are due to the very different nature of the processed crude oils (ranging from the light-sweet Nigerian crudes, through the balanced mix of India, to the heavy-sour crude slate of Brazil), as well as to the different examined configurations.

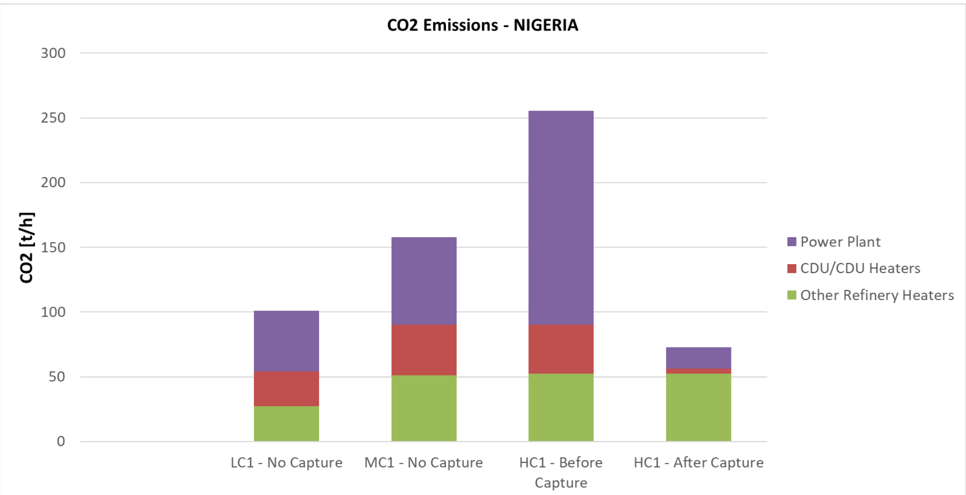












The charts on the left side of this page show the reduction of CO_2 emissions that have been achieved in the various configurations, by recoverying CO_2 from the syngas (pre-combustion) and/or from the flue gases (post-combustion) of the main emitters: Power Plant / IGCC, Steam Reformer (SMR), Crude and Vacuum Distillation Units. By capturing CO_2 only from the main emitters, the achievable emission reduction is in the range -60 to -80%, depending on the case.

The Total Investment Cost (TIC) for the various refineries has been estimated and is reported in the following tables. TIC has been estimated on a pro-rate capacity basis starting from the in-house Wood database for similar units, populated with cost data from previous projects. Location Factors and Cost Indexes have then been applied to the factored costs to properly reflect the plant location and to actualize the cost of the reference plants. In particular, the location factor is relatively high for Nigeria (1.31), meaning that for the same capacity/configuration the investment costs in that country are significantly higher than in the reference location (i.e. US Gulf Coast), so penalizing the profitability of this new project.

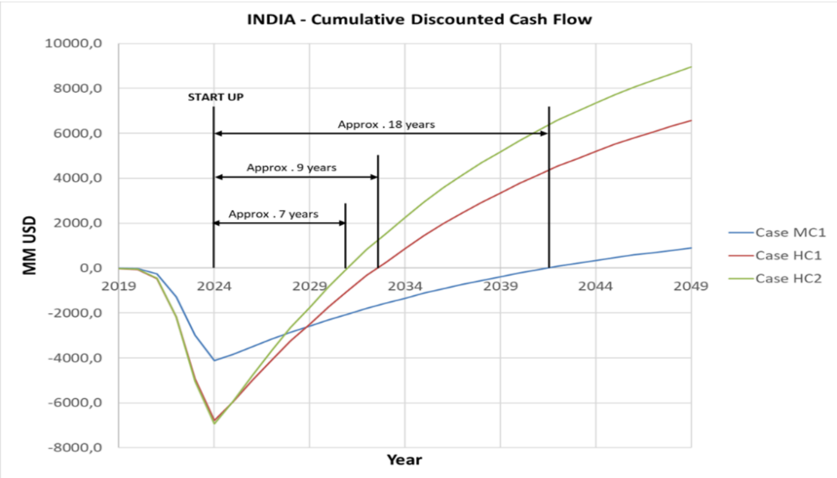
Other CAPEX figures include the cost of the first batch of catalysts and chemicals, the license fees, royalties and engineering fees, spare parts, start-up expenses, plus other initial capital expenditure.

INDIAN REFINERIES	**MC1** 250,000 bpd HCU	**HC1** 400,000 bpd HCU + FCC SDA + DCU with CO_2 capture	**HC2** 400,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
TIC Refinery Units [MM USD]	*3,339*	*6,277*	*7,388*
TIC Power Units [MM USD]	*2,214*	*2,455*	*1,354*
TIC CO2 Capture [MM USD]	*-*	*305*	*533*
Sub Total Units TIC [MM USD]	5,553	9,037	9,275
Sub Total Other CAPEX [MM USD] (*)	458	843	834
Total CAPEX [MM USD]	**6,011**	**9,880**	**10,108**

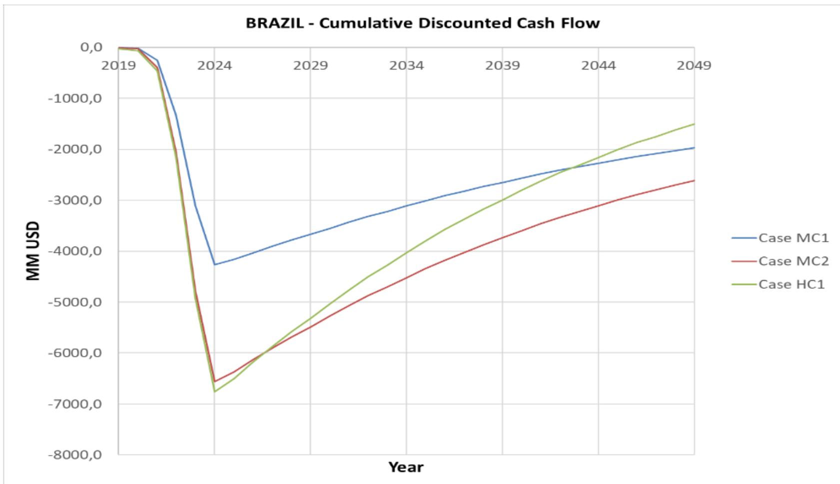
BRAZILIAN REFINERIES	**MC1** 150,000 bpd HCU with CO_2 capture	**MC2** 250,000 bpd HCU + FCC with CO_2 capture	**HC1** 300,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
TIC Refinery Units [MM USD]	*2,609*	*4,416*	*5,780*
TIC Power Units [MM USD]	*2,371*	*3,367*	*2,862*
TIC CO2 Capture [MM USD]	*805*	*1102*	*372*
Sub Total Units TIC [MM USD]	5,785	8,885	9,014
Sub Total Other CAPEX [MM USD] (*)	445	699	834
Total CAPEX [MM USD]	**6,230**	**9,584**	**9,848**

NIGERIAN REFINERIES	**LC1**	**MC1** 200,000 bpd FCC	**HC1** 200,000 bpd FCC SDA with CO_2 capture
TIC Refinery Units [MM USD]	*2,536*	*3,707*	*3,707*
TIC Power Units [MM USD]	*146*	*194*	*605*
TIC CO2 Capture [MM USD]	*-*	*-*	*240*
Sub Total Units TIC [MM USD]	2,682	3,901	4,552
Sub Total Other CAPEX [MM USD] (*)	256	373	412
Total CAPEX [MM USD]	**2,937**	**4,274**	**4,964**

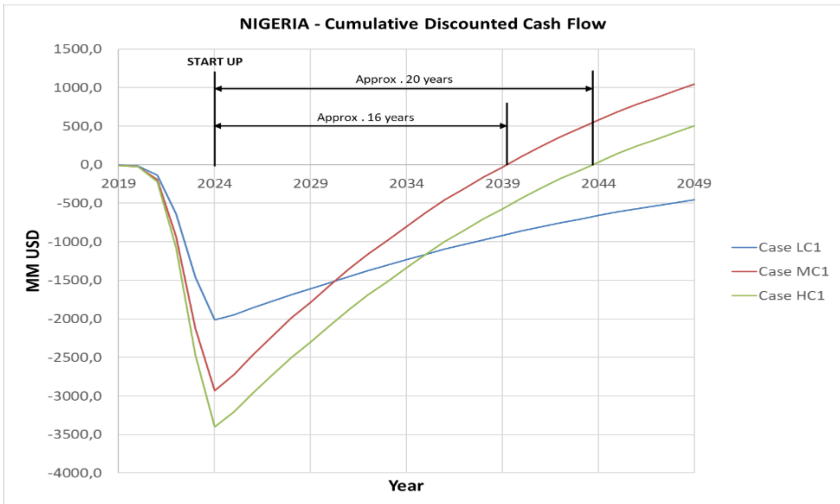
The results of the financial analysis are reported in the following charts and tables, for the nine refineries. In addition to the key-financial indicators, i.e. Net Present Value (NPV) and Investment Rate of Return (IRR), the curves of cumulative discounted cash flow show the number of years of operation needed to reach the return of the investment point, i.e. cumulative discounted cash flow equal to zero. The end point of each curve (value on the y-axis in year 2049) is equal to the Net Present Value.



INDIA	MC1 250,000 bpd HCU	HC1 400,000 bpd HCU + FCC SDA + DCU with CO2 capture	HC2 400,000 bpd HCU + FCC SDA + IGCC with CO2 capture
NPV (MM USD)	895	6,567	8,949
IRR	10%	16%	18%



BRAZIL	MC1 150,000 bpd HCU with CO2 capture	MC2 250,000 bpd HCU + FCC with CO2 capture	HC1 300,000 bpd HCU + FCC SDA + IGCC with CO2 capture
NPV (MM USD)	-1,972	-2,615	-1,505
IRR	3%	4%	6%



NIGERIA	LC1	MC1 200,000 bpd FCC	HC1 200,000 bpd FCC SDA with CO2 capture
NPV (MM USD)	-454	1,045	506
IRR	6%	11%	9%

It is noticeable that the financial results are positive only for the two large-complex Indian refineries, which have a payback time of less than 10 years, while they are not very promising for the other plants.

The results of this Study show that, in all countries, the most favourable scheme is the one based on High Conversion, capable of creating the highest added-value from each single barrel of crude oil.

In a mature market, like the refining one, the key-drivers that still make a new refinery a profitable investment are:

- Access to infrastructures;
- Secure crude supply.
- Medium-to-large capacity;
- Complexity, flexibility and fit-for-purpose configuration, able to convert the crude oil into the products that the markets require;
- Energy efficiency;

In developing economies investment in new refineries, especially integrated with Power Production Plants, offers strategic energy independency as well as social development in the surrounding areas. They could also stimulate employment and offer conducive conditions for the development of other industries.

The economic results of this Study, which are based on an international parity basis of prices for crude oils, and on the current structure of prices for the automotive fuels in the selected countries, should only be regarded as indicative. The financial indicators would be significantly impacted by any form of incentive that Governments could put in place for strategical and social purposes.

CO_2 capture is a fundamental measure to meet challenging greenhouse gas reduction targets. For this reason, in this study, CO_2 capture is considered as embedded in the concept of a clean refinery. However, CO_2 capture means additional costs and loss of profitability, evident from the economic results of the study. Therefore, to promote clean refineries with a lower carbon footprint, and to enable them to compete in a market on a fair basis, policies should be introduced based on some subsidies that compensate for the extra costs for CO_2 capture or, alternatively, penalties for the CO_2 emitted to atmosphere.

As a part of this study, the "base" cases with CO_2 capture, required the price of CO_2 to be evaluated assuming the same IRR as equivalent schemes (i.e. same refinery capacity and configuration) without CO_2 capture.

INDIA	**MC1** 250,000 bpd HCU	**HC1** 400,000 bpd HCU + FCC SDA + DCU with CO_2 capture	**HC2** 400,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
CO_2 selling price (USD/ton)	-	**79**	**32**

BRAZIL	**MC1** 150,000 bpd HCU with CO_2 capture	**MC2** 250,000 bpd HCU + FCC with CO_2 capture	**HC1** 300,000 bpd HCU + FCC SDA + IGCC with CO_2 capture
CO_2 selling price (USD/ton)	**72**	**68**	**35**

NIGERIA	**LC1**	**MC1** 200,000 bpd FCC	**HC1** 200,000 bpd FCC SDA with CO_2 capture
CO_2 selling price (USD/ton)	-	-	**53**

A common trend emerges from this study. The CO_2 selling price (or avoidance cost) is lower in the configurations with a IGCC complex, because the CO_2 capture facilities are integrated into the IGCC scheme (pre-combustion capture) which has a lower cost impact and energy consumption compared with the post-combustion capture applied in the other schemes.

It is also important to emphasise that the inclusion of CO_2 capture in a new refinery complex enables the integration of the CO_2 capture systems to be optimised with the rest of the plant. This approach leads to a significant reduction in CAPEX and OPEX compared with a retrofit scheme. The main reduction factors are:

- CAPEX: saving in utility and interconnecting facilities, synergy in the engineering and construction phases.
- OPEX: optimization of heat integration, saving in O&M staff and related costs.

Background of the Study

Global trends have indicated that refineries are increasingly required to process significant amounts of heavy, sour crude (to achieve a better refinery margin) and at the same time to meet the demand and other stringent requirements to produce high value products, such as ultra-low-sulphur diesel and gasoline. As deregulation (unbundling) in the power sector is evolving and gaining acceptance worldwide, it is prudent that refineries should also review and consider the supply of clean electricity as part of their product portfolio in providing clean products.

Promotion of the 'clean refinery' is integral to achieving these requirements. Various options are available to refineries depending, not only on the complexity and degree of integration, but also on whether the refinery already exists or is still at the planning stage.

As the capital investment required to deploy bottom of the barrel solutions is a major consideration, it is anticipated that access to electricity and the electricity market would impact on the choice of technology options. In this study, the future role of refineries in supplying clean power generation (including CCUS deployment) will be evaluated, given that refineries can integrate diversification and are known to be efficient in managing and optimizing their energy requirements.

This document is the report of the study "The clean refinery and the role of electricity generation", which has been contracted by IEAGHG to Wood with the aim of evaluating the future role of refineries in supplying clean products and clean power, given that refineries can integrate diversification of products and can be efficient in optimizing their energy requirements. In this study carbon capture and the reutilization of CO_2 to produce chemicals is also considered and evaluated.

The main objective of the study is to conceive and evaluate different refinery configurations to achieve the best balance of clean products and electricity, given that the refineries are fed with heavy sour and opportunity crudes and have the potential to export electricity. Options for hydrogen, electricity and steam production in the refinery, as well as measures to meet challenging greenhouse gas reduction targets, have been reviewed as part of the strategy to implement bottom-of-the-barrel solutions and minimize heavy oils production. The configurations were analysed and compared from a technical and economic stand point (over the whole life time of each refinery).

A companion study to this exercise evaluating the costs of retrofitting CO_2 captured in an integrated oil refinery: "Technical design basis and economic assumptions", was published as an IEAGHG Technical Review 2017-TR5. Some of the tasks to be addressed in the current work may overlap closely with those undertaken for the earlier study.

Basis of the Study

The primary goal of this study is to explore what role the 'clean refinery' could play in the Paris Agreement's long-term objective to reach global peaking of greenhouse gas emissions as soon as possible.

The priority for a 'clean refinery' is to achieve the best balance of clean products, i.e. transportation fuels, petrochemicals and power, while reducing energy poverty. This balance is likely to vary from region to region. To gain some understanding of how the balance might look, and the main drivers, the refinery sector has examined three selected regions: West Africa; South America; and Asia, specifically the Indian subcontinent.

With the trend to heavier, sour crude, solutions to address this bottom-of-the-barrel feedstock are likely to vary regionally. Options for hydrogen, electricity and steam production, particularly the generation of clean electricity, together with possible measures to meet challenging greenhouse gas (GHG) reduction targets, have been reviewed. The strategy to implement bottom-of-the-barrel solutions has included three examples from each of the selected regions to take account of representative crude oil blends and regional markets for refined products.

The macro-economics of maximising electricity production within the refinery complex has also been examined in the selected regions as part of the energy management strategy, to take advantage, for example, of high electricity prices in deregulated electricity markets.

Since the optimum configuration strongly depends on local conditions in different areas of the world in terms of crude characteristics, required products, price of electricity, and other economic parameters, the study was differentiated into three regions by IEAGHG. Under the scope of the study, representative clean refineries were selected from Africa, South America, and Asia.

While IEAGHG already indicated India as the best candidate to represent Asia in this study, Wood developed an analysis to define the best candidates of the other two regions, which was the starting point of the study activities. The main driving forces in the country selection were:

- Demand of crude oil forecast;
- Demand for transportation liquid fuels;
- If the crude oil and liquid fuel consumptions can be met with the expansion of new infrastructure, i.e. with a new Clean Refinery.

It is worth underlying that in all the selected countries, an increasing demand for electric energy is also foreseen in the near future according to the most recent market trends. According to these considerations, the best candidates for Africa and South America were agreed between IEAGHG and Wood to be Nigeria and Brazil, respectively.

The Study "The clean refinery and the role of electricity generation" was divided in five different Tasks and the structure of this report follows the major activities performed throughout the study execution as conceived and agreed between IEAGHG and Wood.

Section 1 (Task 1) describes the activities undertaken by Wood for feedstock selection, characterization and evaluation as follows. For each geographical region, three crudes have been identified for processing. To evaluate the best crude diet for each country, one "light" crude, one "heavy" crude, and one sour crude or opportunity crude was selected, to be processed in a mixture of all three crudes. The selected crude oils have been characterized and their costs evaluated based on the market values of the main refinery products and applying a typical refinery margin based on a pre-selected refinery scheme.

For each geographical region, Wood identified the most attractive refinery products, in terms of selling prices and market demands, as well as the relevant specifications based on the information available in literature and in the current countries' regulations. The key properties of each product (e.g. gasoline octane number, automotive fuels sulphur content, etc.) were taken into account for formulating suitable processing schemes. These activities and the relevant results and comments are collected in Section 2 (Task 2).

The sets of prices used in this study has been proposed by Wood and agreed with IEAGHG during the Study development.

In Section 3 (Task 3) for each geographical region, Wood shows the selected different options of complexity and size for the refineries, with the aim of assessing the capacities/schemes that are deemed as the most promising to fit the local products' demand and to be representative of a realistic example of a local "clean refinery". A hydro-skimming refinery has been taken as a reference for developing and evaluating more converted refinery schemes (medium and high conversion) depending on the "quality" (in terms of heaviness and sulphur content) of the selected crude oils diet. The refinery "core" business is the production of liquid fuels for automotive and heating purposes coupled with the power and steam generation block and CO_2 capture and reuse options. Therefore, a petrochemical block fed by LPG/naphtha produced by the Refinery has not been considered. This approach has been based on the fact that the large variety/complexity (and impact on CAPEX) of the schemes that could potentially originate could divert the focus of the reader from the main scope of the study (i.e. the Clean Refinery).

In Section 4 (Task 4) Wood shows the financial performance of the selected refinery schemes. The definition of financial indicators requires the determination of Capital Expenditure (CAPEX) and Operating Expenditure (OPEX). The methodology to be considered in the study has been proposed by Wood and agreed with IEAGHG during the Study development. The CAPEX estimation is based on a "Unit-factored Estimate", i.e. historical data are used to define the other estimate details from unit costs. The unit costs are calculated unit by unit using in-house data. Main operating costs (raw materials, main utilities) are already accounted for in the refinery balances. Additionally, other fixed operating costs are generally determined as a percentage of the Total Investment Capital (TIC). The financial analysis is then based on the calculation of the financial parameters Net Present Value (NPV) and Internal Rate of Return (IRR). Therefore, the financial analysis is a high-level economical evaluation only, while the rigorous project profitability for the specific case is beyond the scope of the present study.

Wood compares the alternative process schemes in Section 5 (Task 5), based on technical parameters and based on the results of the financial parameters obtained in Task 4. The configurations are compared both on a qualitative and quantitative basis. A conceptual plot plan is also provided for each configuration. Wood also explored the effect of CO_2 capture on economic parameters, defining a cost of the captured CO_2 for comparison with a no capture scenario. Moreover, a sensitivity analysis on key parameters was performed in order to see the effect on the resultant financial performance (i.e. IRR). The selected sensitivity scenarios included:

- Sensitivity on Total Investment Cost and Electricity Price;
- Sensitivity on Reduction of Crude Oil Price.

At the end of the study Wood proposes recommendations for optimum configurations and a project implementation plan.

This report also includes as reference documents the detailed information about the integrated refinery mass and energy balances, carbon balance, techno-economic assumptions, data evaluation and CO_2 avoidance cost, that could be adapted and used for future economic assessment of high conversion schemes, and CCS installation in the oil refining industry.

1 Task 1 - Feedstock selection, characterization and evaluation

The scope of this Section is to provide a description of the methodology and results relevant to the selection of a representative crude diet for each geographical region (Asia, Africa, and South America respectively) and the assessment in terms of crude oil characterization and relevant pricing. The selection has been proposed by Wood and agreed with IEAGHG.

This chapter includes the sets of data and assumptions used to build the refinery balances developed in Task 3. Moreover, a detailed explanation and validation procedure of the crude oil pricing model is provided. The methodology normally used for refinery configuration studies has been adopted, trying however to:

- remove all the site-specific constraints coming from Wood's past projects;
- obtain generic but realistic balances, with the level of accuracy needed for the purposes of this study.

1.1 Selection of crude oils

IEAGHG selected three regions under the scope of the Study: Africa, South America, and Asia (namely India) to represent regional diversity in crude blends, distillate markets and potential electricity markets. In order to develop the refinery balances, three crudes per area have been identified, including one light, one heavy, and one sour or opportunity crude.

The crude basket in each case has been selected as representative of different supply regions, products' yields and qualities, and is deemed to be a fair representation of the "average" operation of the refineries located in each of the different areas of the world. In particular, the following sections describe the main drivers and factors for feedstock selection in these different regions.

1.1.1 Asia (India)

India is already the third-largest importer of crude oil in the world and its demand for oil is expected to increase by 6 million barrels per day, accounting for the highest growth in the world. Moreover, transportation fuels account for a 65% of the rise. These quoted figures have been retrieved from World Energy Outlook – WEO 2017 by IEA (Figure 1).

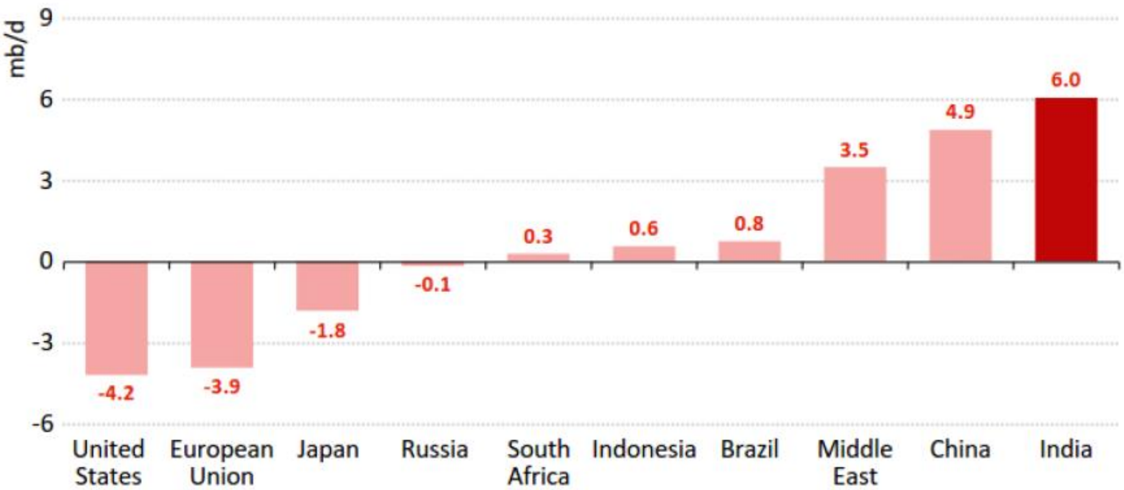


Figure 1: Change in oil demand by selected countries and region in 2014-2040 (International Energy Agency)

India imports more than 85% of crude oil treated in its refineries. In 2016-2017 the total amount of imported crude is 238 MMT (see Figure 2) versus an internal oil production of 38 MMT. Indian refineries in the two-year period 2015-2016 processed 71% of sour crude "Dubai" and "Oman" type and 29% of sweet crude "Brent" type.

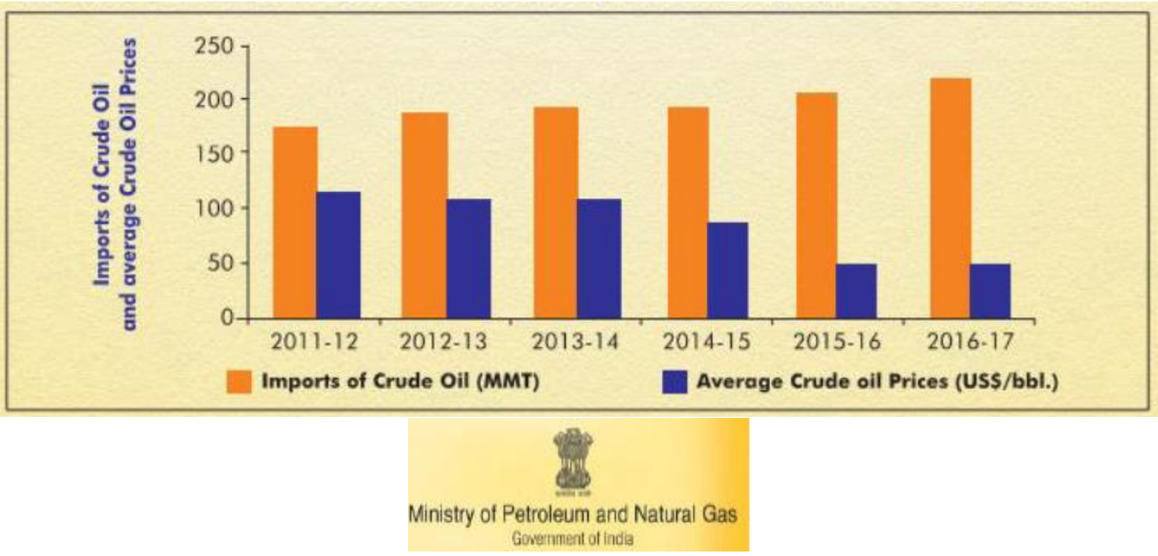


Figure 2: Quantity of Crude oil imports and International Crude oil prices of the Indian basket (according to Government of India, Ministry of Petroleum and Natural Gas, Annual Report 2015-2016)

Based on this information, Wood has considered for this Study the crude basket indicated in the following Figure 3. The quality of the selected crude oils is reported in Table 1.

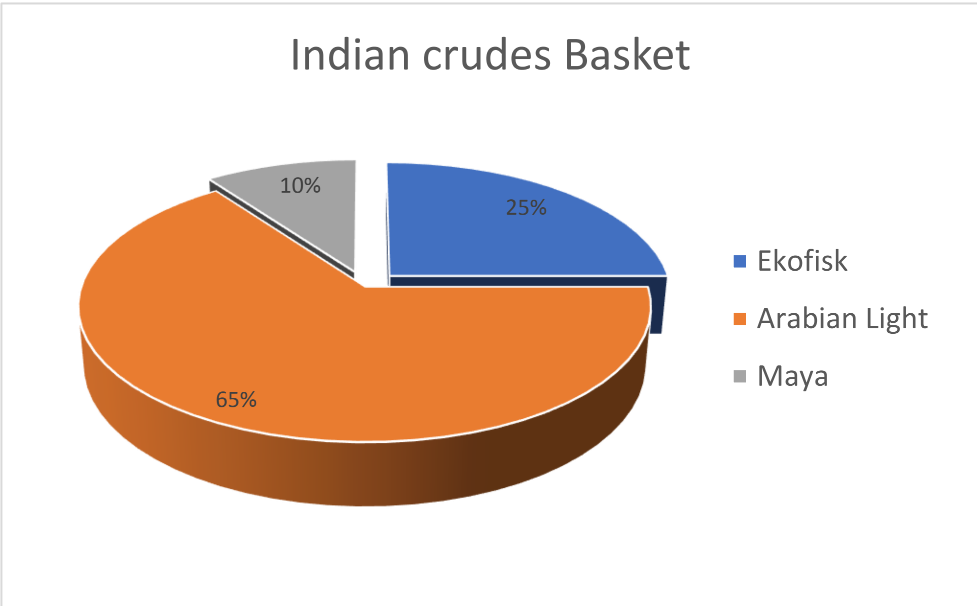


Figure 3: Indian Crudes Basket

Table 1: Quality of Indian Crude Oil Basket

Indian crudes Basket					
% Tot	**Crude**	**Type**	**Origin**	**API Gravity**	**Sulphur content [%wt]**
25%	Ekofisk	"Brent"	Norway	42.4	0.17
65%	Arabian Light	"Oman" and "Dubai"	Saudi Arabia	33.9	1.77
10%	Maya	Opportunity Crude	Mexico	21.7	3.18

1.1.2 South America (Brazil)

According to the forecast of BP Energy Outlook (2018), Brazil will continue to expand its oil production increasing output from 2.7 Mb/d to 4.0 Mb/d by 2040, and accounting for just under 4% of world oil supply. For the next 10 years, a cumulative growth of 19% is expected to take place in the demand for major oil products and biofuels (Figure 4).

This estimated increase of 467,000 barrels per day in consumption can be met both by the expansion of the infrastructure for import of oil products and by new investments that may increase the domestic production of oil products.

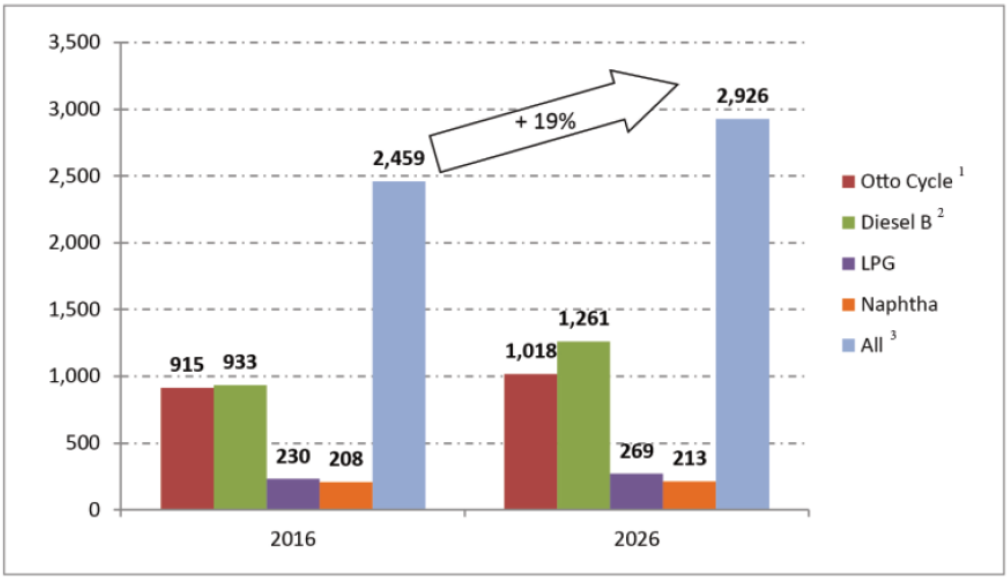


Figure 4: Demand for major oil products and biofuels (in thousand barrels per day) in 2016 and projection for 2026 (from Fuel Production and Supply, Opportunities in Brazil, ANP, National Agency of Petroleum, Natural Gas and Biofuels)

Based on the information from O&G – World Oil and Gas Review 2016 – ENI (Figure 5), Wood has proposed the crude basket indicated in Figure 6 for this study. The quality of the selected crude oils is reported in Table 2.

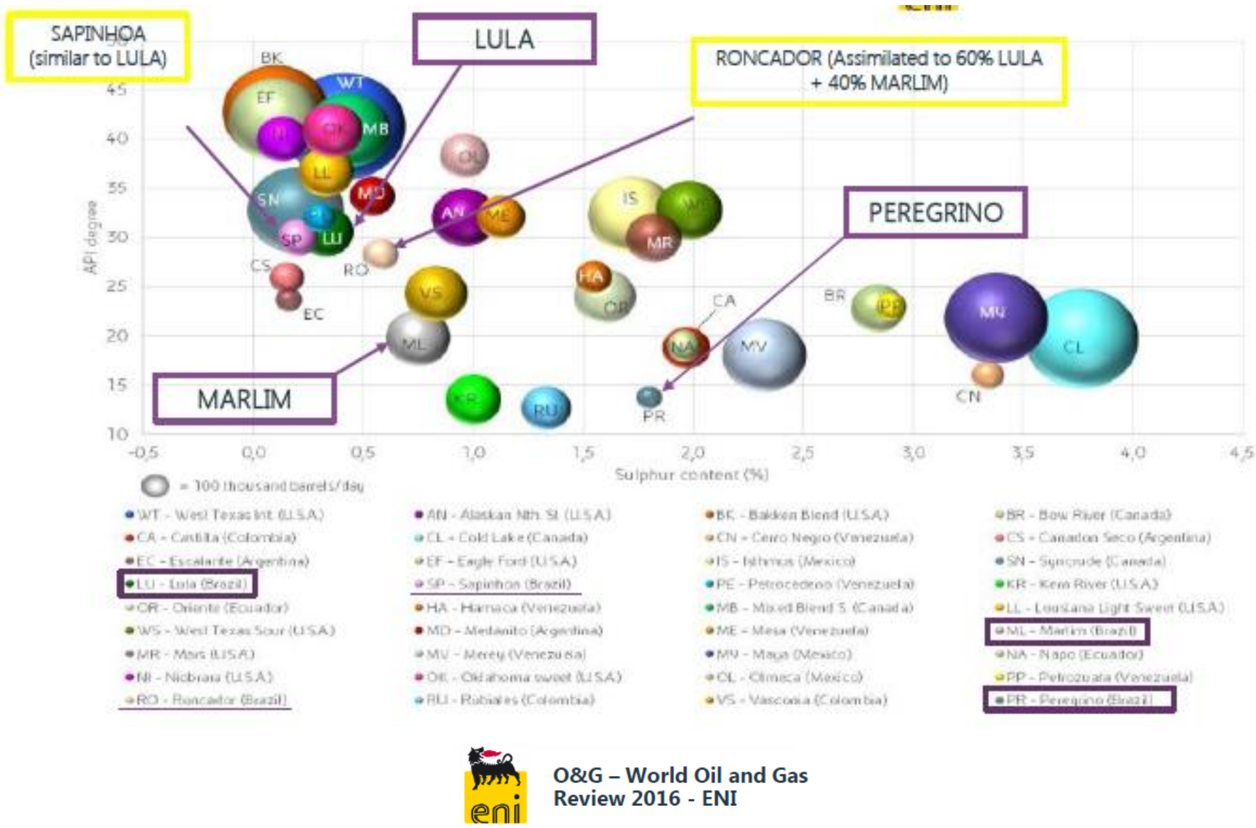


Figure 5: Quality and production volumes of main crudes in 2015 in thousand bbl/days (from ENI, O&G – World Oil and Gas Review 2016)

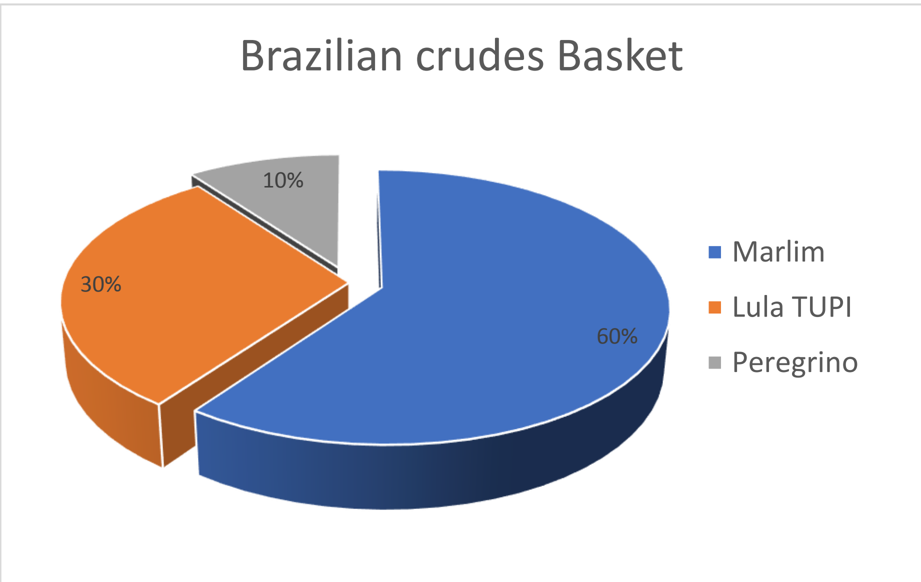


Figure 6: Brazilian Crudes Basket

Table 2: Quality of Brazilian Crude Oil Basket

Brazilian crudes Basket					
% Tot	Crude	Type	Origin	API Gravity	Sulphur content [%wt]
60%	Marlim	Naphthenic	Brazil	20	0.77
30%	Lula TUPI	Intermediate	Brazil	28.8	0.37
10%	Peregrino	Naphthenic	Brazil	13.4	1.76

1.1.3 Africa (Nigeria)

With relative peace in the Niger Delta, and oil prices comfortably above 60 USD/bbl, oil producers have said there is no better time than now for Nigeria to increase drilling and oil production and grow its reserves (S&P Global Platts). Moreover, Nigeria has the largest reservoirs of the West Africa Region and oil reserves have notably increased in the last decade (Figure 7 and Figure 8). It is Nigeria's ambition to refine more of its crude at domestic refineries and be less dependent on product imports, and also to start exporting refined products to the wider region. Nigerian distillate production is expected to grow by 17% between 2012 and 2030 (according to IEA Energy outlook 2012).

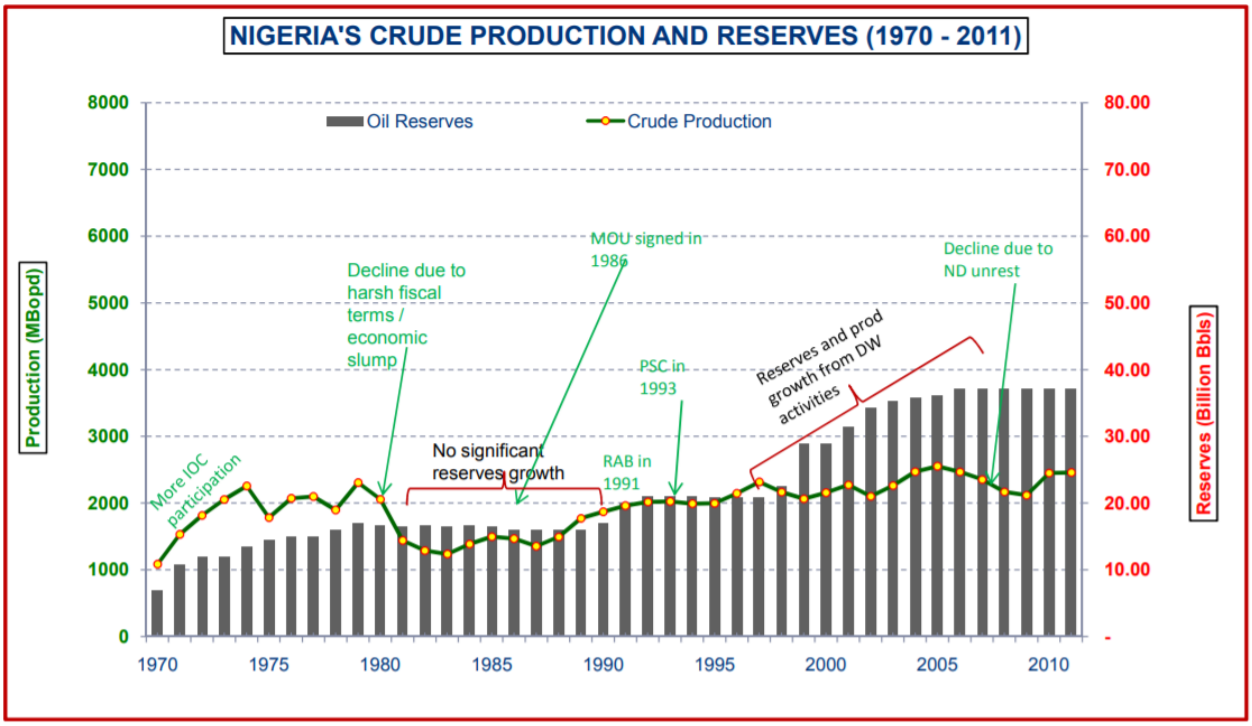


Figure 7: Crude oil production and reserves in Nigeria between 1970 and 2011 (IEA Energy outlook 2012)

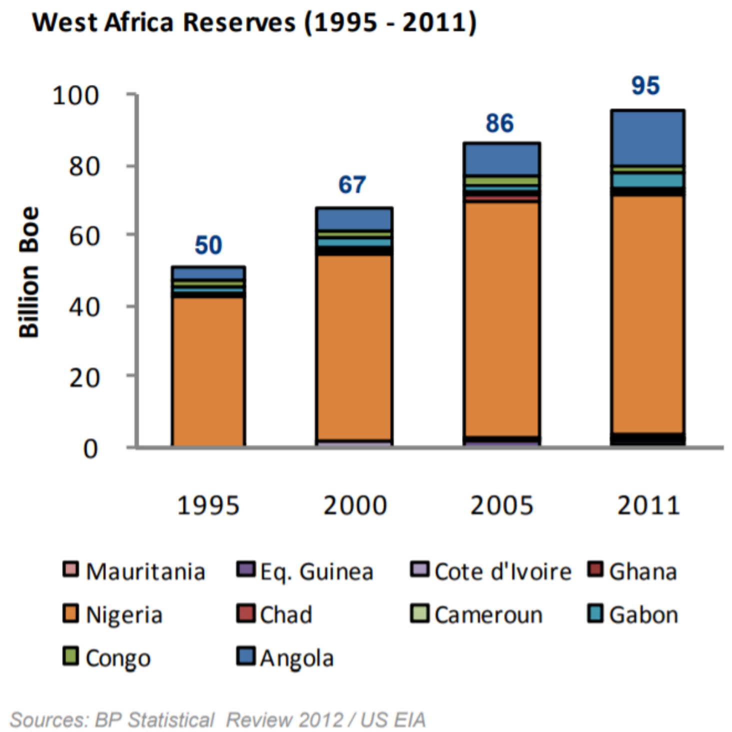


Figure 8: Crude oil reserves by country in Africa between 1995 and 2011 (BP Statistical Review, 2012)

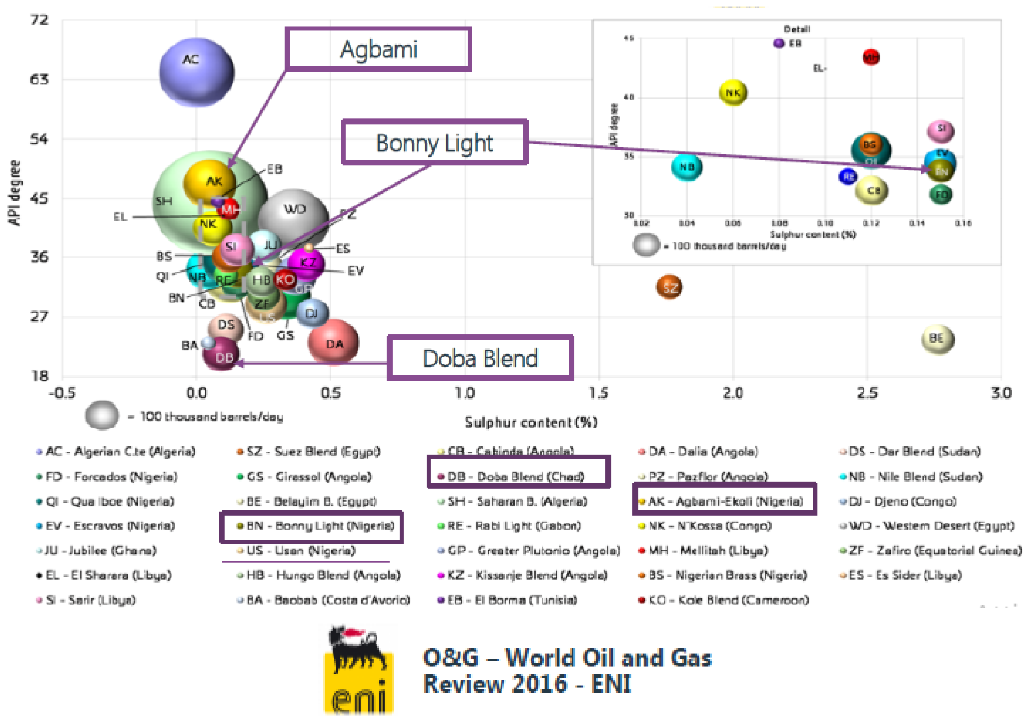


Figure 9: Quality and production volumes of main crudes in 2015 in thousand bbl/days (from ENI, O&G – World Oil and Gas Review 2016)

Based on the information from O&G – World Oil and Gas Review 2016 – ENI (Figure 9), Wood has proposed the crude basket indicated in Figure 10 for this study. The quality of the selected crude oils is reported in Table 3.

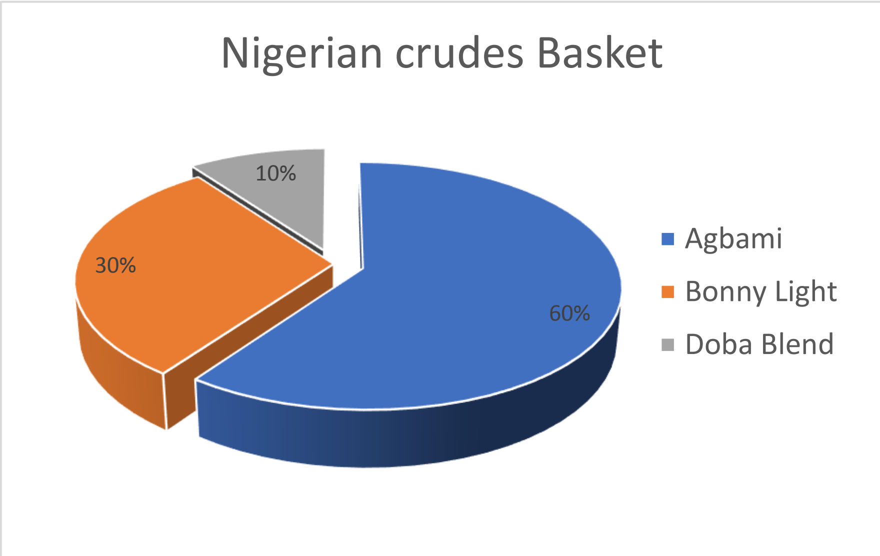


Figure 10: Nigerian Crudes Basket

Table 3: Quality of Nigerian Crude Oil Basket

Nigerian crudes Basket					
% Tot	**Crude**	**Type**	**Origin**	**API Gravity**	**Sulphur content [%wt]**
60%	Agbami	Extra light and Sweet	Nigeria	48.3	0.04
30%	Bonny Light	Medium and Sweet	Nigeria	35.1	0.15
10%	Doba Blend	Opportunity Crude	Chad	21	0.09

1.1.4 *Summary of selected crude oils*

This section summarizes the crude oils selection for each country as reported in the above Table 1, Table 2 and Table 3 reported in the previous sections:

- Asia (India)
  - Ekofisk (Norway), 42.4° API, Sulphur content 0.17% wt.
  - Arabian Light (Saudi Arabia), 33.9° API, Sulphur content 1.77% wt.
  - Maya (Mexico), 21.7°API, Sulphur content 3.18% wt.
- South America (Brazil)
  - Marlim (Brazil), 20.0° API, Sulphur content 0.77% wt.
  - Lula Tupi (Brazil), 28.8° API, Sulphur content 0.37% wt.
  - Peregrino (Brazil), 13.4° API, Sulphur content 1.76% wt.
- Africa (Nigeria)
  - Agbami (Nigeria), 48.3° API, Sulphur content 0.04% wt.
  - Bonny Light (Nigeria), 35.1° API, Sulphur content 0.15% wt.
  - Doba Blend (Chad), 21° API, Sulphur content 0.09% wt.

As far as the opportunity crude oils are concerned (i.e. Maya, Peregrino, Doba), Wood and IEAGHG agreed that they will be processed only in a mixture with the light crude of the regional basket, in the proportion 50/50% wt. In more detail: Maya crude in a mixture with Arabian Light; Peregrino crude in a mixture with Lula Tupi; and Doba crude in a mixture with Agbami. These combinations avoid crude distillation units that are typically not designed for extra-heavy crudes but can instead accommodate them in blended modes.

1.2 Crude oil data

The main properties of the nine selected crude oils have been reported in grid data tables (see Appendix 1), where the distillation curves and the properties of some representative large cuts (ideal distillation fractions) are reported.

A Chevron crude assay database has been used as source of the crude data.

Moreover, by using a specialized Crude Oil Management software (i.e. Haverly HCAMS), all the crudes have also been cut into narrow fractions. The properties of these narrow, ideal cuts have then been used as input to the process simulator, as described in the following section.

The following charts show the theoretical distillation curves of the nine crudes considered in the Study, collected for each geographical region. The distillation curves plot the True Boiling Point (TBP) against the weight percentage of distillate collected.

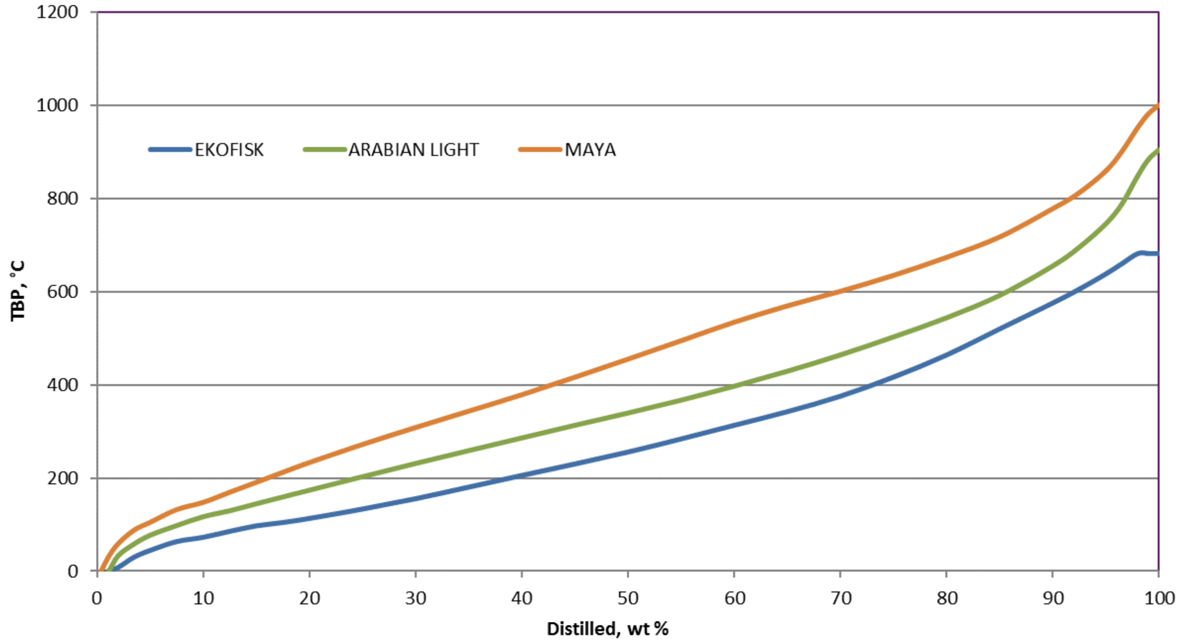


Figure 11: Crude Distillation Curves - India

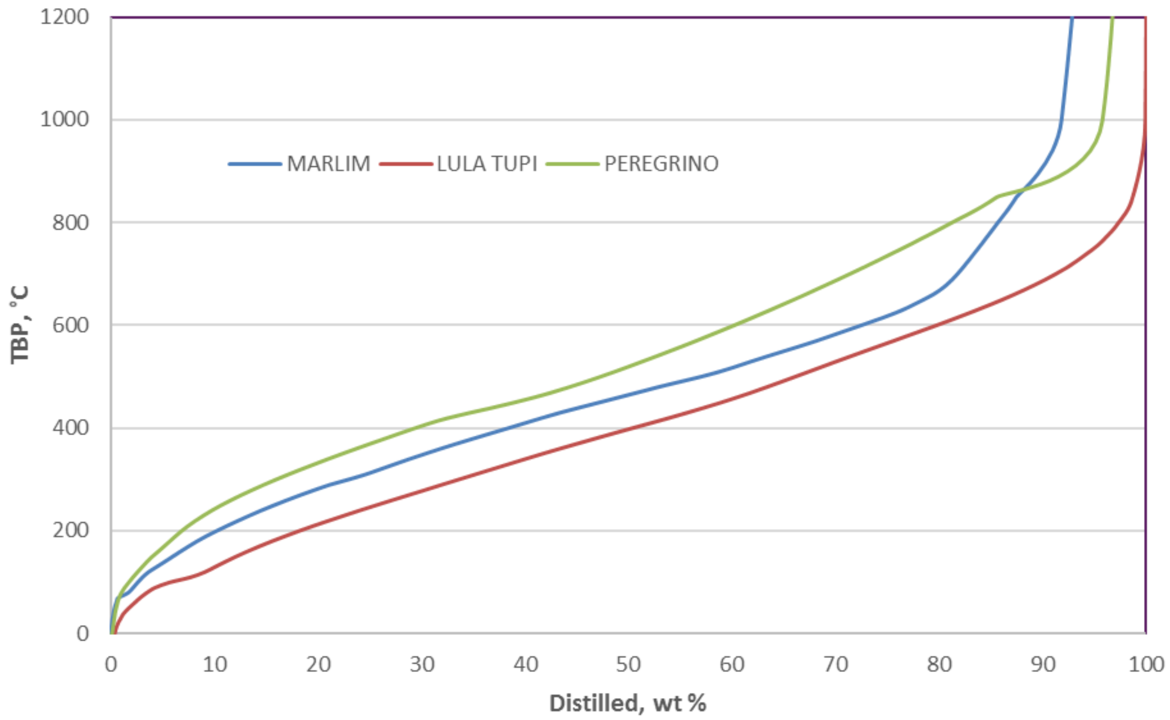


Figure 12: Crude Distillation Curves - Brazil

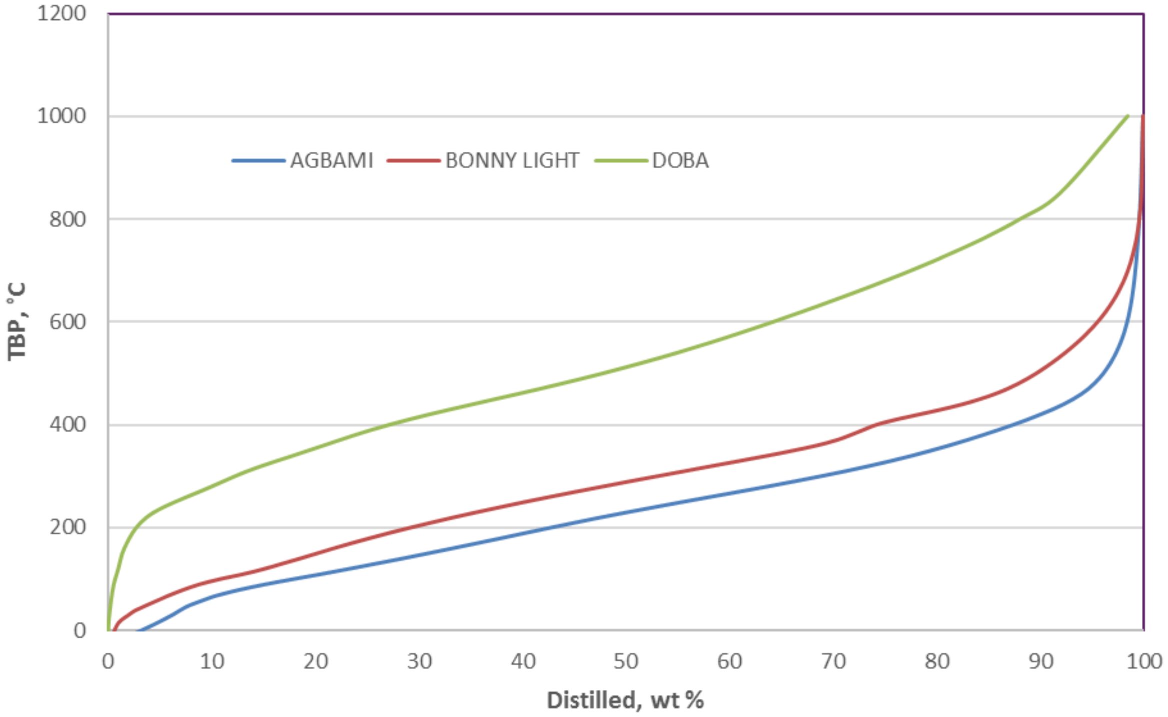


Figure 13: Crude Distillation Curves - Nigeria

1.3 Simulation of Primary Distillation Units

In order to produce more realistic and accurate refinery balances, process simulation models have been created for a Crude Distillation Unit (CDU) and a Vacuum Distillation Unit (VDU). It should be noted that the effect of distillation assuming real efficiencies will improve the definition of the yields and qualities of the different distillation fractions that feed the downstream treating and conversion units of the refineries.

Aspentech Hysys v.8.6 is the software used for process simulation. For each crude, a flowsheet of CDU/VDU has been created.

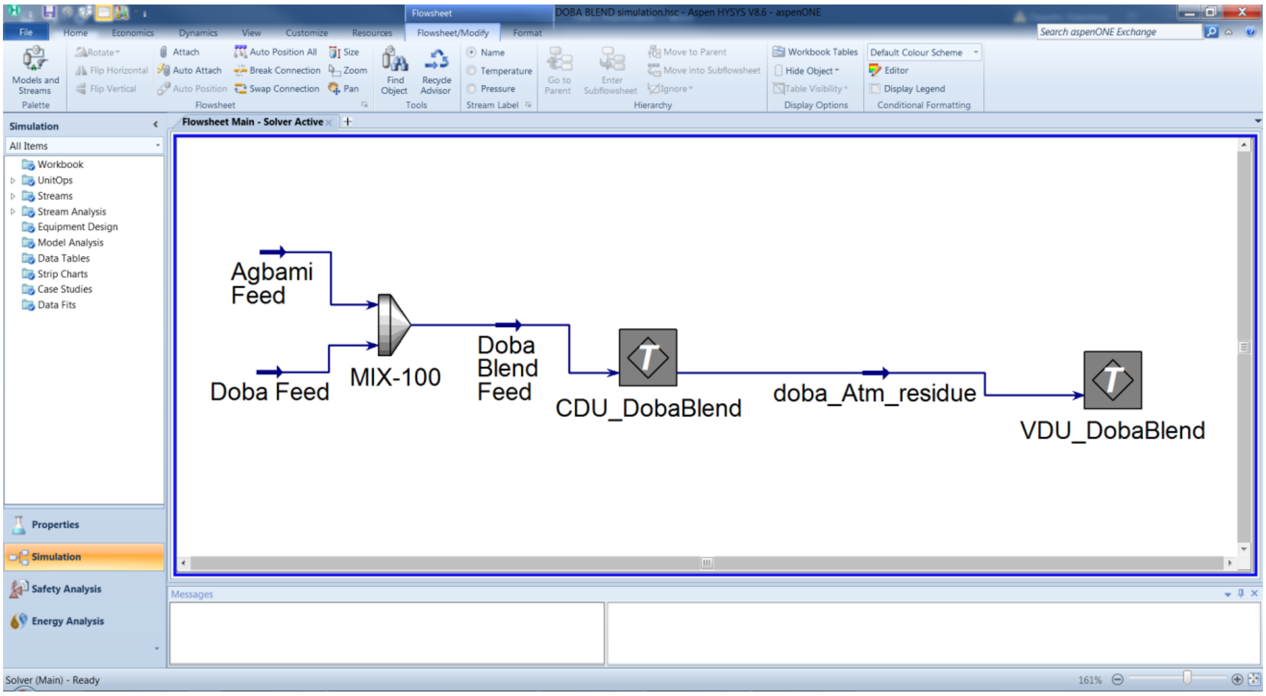


Figure 14: Main flowsheet of CDU/VDU simulation

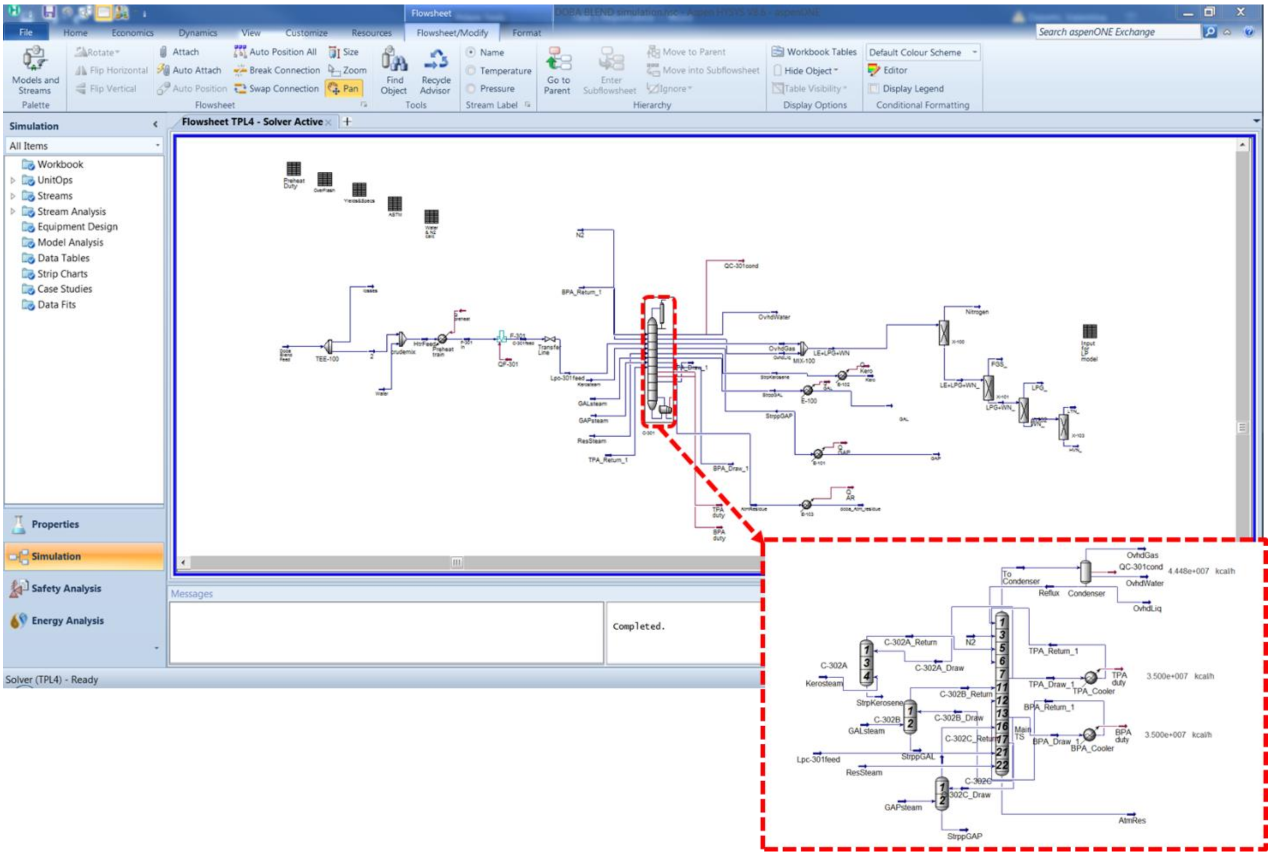


Figure 15: Flowsheet of CDU simulation model

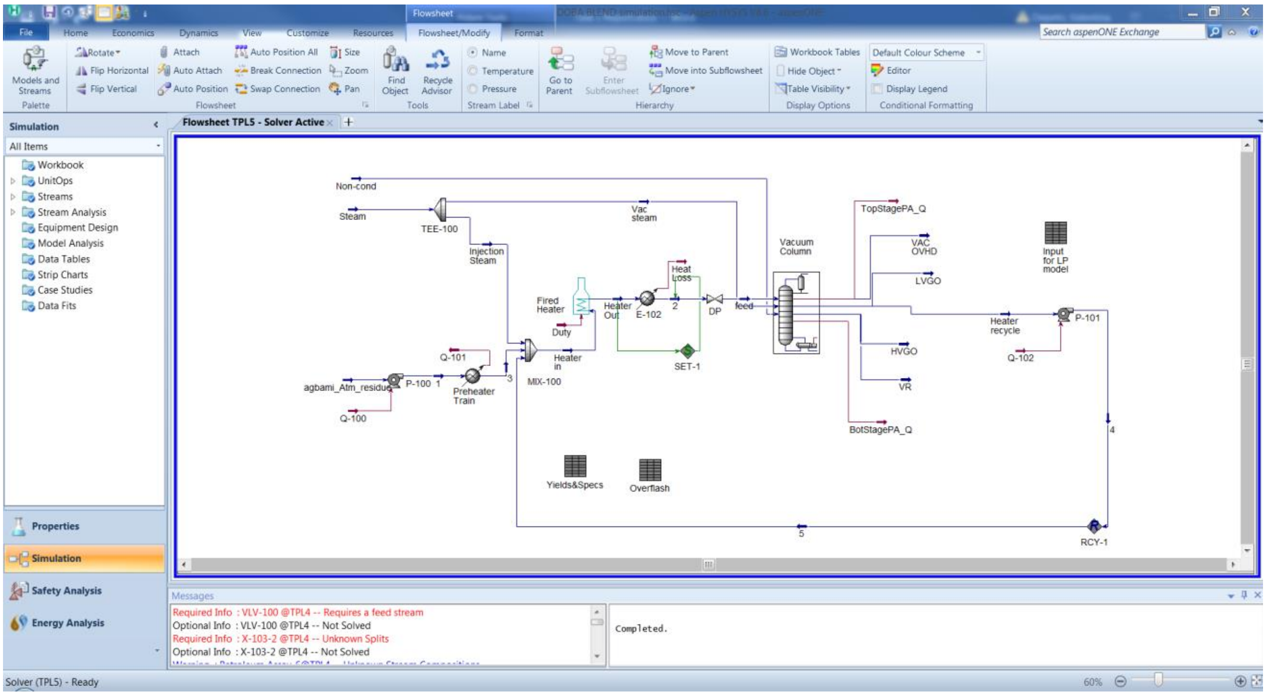


Figure 16: Flowsheet of VDU simulation model

Table 4, Table 5, Table 6 and Table 7 include the sets of yields and main qualities of the straight-run distillation cuts that result from this simulation activity.

Table 4: Yields of crude distillation cuts

Crude cuts	Yields on crude, wt%		
	EKOFISK	ARAB LT	MAYA BL
Offgas + LPG	1.65%	0.89%	0.79%
Light Naphtha	10.57%	3.70%	3.12%
Heavy Naphtha	19.30%	11.17%	9.04%
Full Range Naphtha	29.87%	14.87%	12.16%
Kero	18.21%	15.70%	13.10%
Light Gasoil (LGO)	18.30%	22.09%	19.50%
Heavy Gasoil (HGO)	4.54%	3.50%	3.20%
Atmospheric Residue	27.43%	42.95%	51.25%
Light Vacuum Gasoil (LVGO)	3.13%	7.19%	6.00%
Heavy Vacuum Gasoil (HVGO)	12.21%	13.97%	14.06%
Vacuum Residue	12.09%	21.79%	31.19%

Crude cuts	Yields on crude, wt%		
	AGBAMI	BONNY LT	DOBA BL
Offgas + LPG	0.21%	0.06%	0.11%
Light Naphtha	3.86%	1.06%	1.99%
Heavy Naphtha	4.07%	1.12%	2.10%
Full Range Naphtha	8.56%	6.19%	4.48%
Kero	18.25%	12.34%	10.35%
Light Gasoil (LGO)	26.81%	18.53%	14.84%
Heavy Gasoil (HGO)	24.59%	21.03%	14.76%
Atmospheric Residue	27.34%	28.05%	20.05%
Light Vacuum Gasoil (LVGO)	3.23%	4.22%	3.10%
Heavy Vacuum Gasoil (HVGO)	13.98%	27.04%	45.15%
Vacuum Residue	3.22%	4.40%	3.71%

Crude cuts	Yields on crude, wt%		
	MARLIM	LULA TUPI	PEREGRINO BL
Offgas + LPG	0.02%	0.03%	0.02%
Light Naphtha	0.14%	0.54%	0.39%
Heavy Naphtha	0.16%	0.57%	0.41%
Full Range Naphtha	1.48%	2.79%	1.79%
Kero	4.41%	8.78%	5.66%
Light Gasoil (LGO)	5.89%	11.57%	7.45%
Heavy Gasoil (HGO)	9.76%	13.52%	9.91%
Atmospheric Residue	16.04%	17.73%	15.24%
Light Vacuum Gasoil (LVGO)	2.21%	3.44%	3.11%
Heavy Vacuum Gasoil (HVGO)	65.94%	53.17%	63.87%
Vacuum Residue	5.19%	4.74%	4.71%

Table 5: Specific gravity (SG) of crude distillation cuts

Crude cuts	SG		
	EKOFISK	ARAB LT	MAYA BL
Light Naphtha	0.712	0.675	0.674
Heavy Naphtha	0.768	0.746	0.738
Full Range Naphtha	0.747	0.727	0.721
Kero	0.801	0.802	0.798
Light Gasoil (LGO)	0.849	0.853	0.858
Heavy Gasoil (HGO)	0.879	0.898	0.906
Atmospheric Residue	0.915	0.948	0.990
Light Vacuum Gasoil (LVGO)	0.884	0.901	0.908
Heavy Vacuum Gasoil (HVGO)	0.906	0.930	0.939
Vacuum Residue	0.938	0.977	1.033

Crude cuts	SG		
	AGBAMI	BONNY LT	DOBA BL
Light Naphtha	0.657	0.660	0.657
Heavy Naphtha	0.739	0.750	0.742
Full Range Naphtha	0.711	0.717	0.714
Kero	0.788	0.825	0.803
Light Gasoil (LGO)	0.831	0.878	0.857
Heavy Gasoil (HGO)	0.871	0.915	0.900
Atmospheric Residue	0.923	0.956	0.941
Light Vacuum Gasoil (LVGO)	0.873	0.910	0.894
Heavy Vacuum Gasoil (HVGO)	0.914	0.941	0.926
Vacuum Residue	1.054	1.029	0.962

Crude cuts	SG		
	MARLIM	LULA TUPI	PEREGRINO BL
Light Naphtha	0.681	0.665	0.664
Heavy Naphtha	0.756	0.742	0.744
Full Range Naphtha	0.736	0.722	0.723
Kero	0.829	0.811	0.816
Light Gasoil (LGO)	0.883	0.863	0.874
Heavy Gasoil (HGO)	0.922	0.900	0.917
Atmospheric Residue	0.989	0.958	0.997
Light Vacuum Gasoil (LVGO)	0.918	0.898	0.915
Heavy Vacuum Gasoil (HVGO)	0.958	0.930	0.950
Vacuum Residue	1.029	0.993	1.037

Table 6: Sulphur content of crude distillation cuts

Crude cuts	Sulphur, wt%		
	EKOFISK	ARAB LT	MAYA BL
Light Naphtha	0.00007	0.06510	0.05547
Heavy Naphtha	0.00257	0.03610	0.07052
Full Range Naphtha	0.00168	0.04331	0.06660
Kero	0.018	0.086	0.268
Light Gasoil (LGO)	0.111	0.981	1.362
Heavy Gasoil (HGO)	0.242	2.175	2.366
Atmospheric Residue	0.481	3.399	3.990
Light Vacuum Gasoil (LVGO)	0.258	2.216	2.386
Heavy Vacuum Gasoil (HVGO)	0.379	2.764	2.866
Vacuum Residue	0.642	4.201	4.809

Crude cuts	Sulphur, wt%		
	AGBAMI	BONNY LT	DOBA BL
Light Naphtha	0.00000	0.00000	0.00000
Heavy Naphtha	0.00000	0.00184	0.00002
Full Range Naphtha	0.00000	0.00123	0.00001
Kero	0.008	0.026	0.009
Light Gasoil (LGO)	0.044	0.156	0.055
Heavy Gasoil (HGO)	0.090	0.238	0.100
Atmospheric Residue	0.181	0.350	0.120
Light Vacuum Gasoil (LVGO)	0.093	0.230	0.094
Heavy Vacuum Gasoil (HVGO)	0.154	0.293	0.110
Vacuum Residue	0.410	0.563	0.133

Crude cuts	Sulphur, wt%		
	MARLIM	LULA TUPI	PEREGRINO BL
Light Naphtha	0.014	0.028	0.031
Heavy Naphtha	0.051	0.041	0.058
Full Range Naphtha	0.042	0.038	0.052
Kero	0.210	0.073	0.312
Light Gasoil (LGO)	0.545	0.204	0.679
Heavy Gasoil (HGO)	0.678	0.318	0.846
Atmospheric Residue	0.941	0.563	1.406
Light Vacuum Gasoil (LVGO)	0.669	0.313	0.845
Heavy Vacuum Gasoil (HVGO)	0.787	0.414	1.008
Vacuum Residue	1.109	0.718	1.703

Table 7: Main properties (other than Sulphur and SG) of Atmospheric and Vacuum Residue

Crude cuts	Conradson Carbon Residue (CCR), wt%		
	EKOFISK	ARAB LT	MAYA BL
Atmospheric Residue	4.8	10.5	14.8
Vacuum Residue	11.0	20.6	24.9

Crude cuts	Conradson Carbon Residue (CCR), wt%		
	AGBAMI	BONNY LT	DOBA BL
Atmospheric Residue	4.5	4.4	7.1
Vacuum Residue	25.9	16.3	13.4

Crude cuts	Conradson Carbon Residue (CCR), wt%		
	MARLIM	LULA TUPI	PEREGRINO BL
Atmospheric Residue	7.0	6.7	13.2
Vacuum Residue	13.8	12.5	22.0

These more realistic yields have been used also for the crude oil price assessment. Pricing procedure and its validation are described in the following section.

1.4 Crude oil price assessment

There are a number of key elements which build up the refinery crude pricing assessment:

- Product revenues
- Operating costs
- Transportation costs
- Import/export taxation (outside of this Study's scope)

As agreed between the parties Wood and IEAGHG during the Kick-off Meeting:

- The international parity pricing has been chosen and crude prices have been linked to the European pricing hub (without accounting for government incentives, for example, as agreed between IEAGHG and Wood). For the European pricing hub, a set of crude oil and product prices were available from the previous ReCAP Study, performed by Wood in 2012. This set of crude oil and product prices have been actualized by means of the ratio between the current Brent crude oil price and the past price of 2012(i.e. 738 USD/ton, corresponding to 98 USD/bbl). Indeed, Brent is the European benchmark in Europe, for which the set of crude oil and product prices are available;
- For products and feedstock values, FOB (Free on Board) prices should be used for the applicable port, with an allowance for current or anticipated transportation costs, tariffs and other import charges;
- Coastal refinery locations are assumed. This assumption also influences the costs associated with the transportation of raw material and refined products.

Crude oil prices at the European hub have been calculated by Wood based on the market values of the main refinery products. For each crude oil, the price has been calculated by "recombining" the market value of each single oil product multiplied by the relevant yield from the crude, and then by adding the two following contributions:

- A fixed outlay cost, which includes the operative expenditures associated to personnel and maintenance, insurance, charges and general expenses, all of which are largely unaffected by the quantities refined.
- A typical refining margin, also known as "crack spread", which accounts for the difference between the value of the products obtained and the cost of the crude entering the refinery. This margin estimates the profit that a refinery can expect to generate from cracking the long-chain hydrocarbons of crude oil into useful petroleum products.

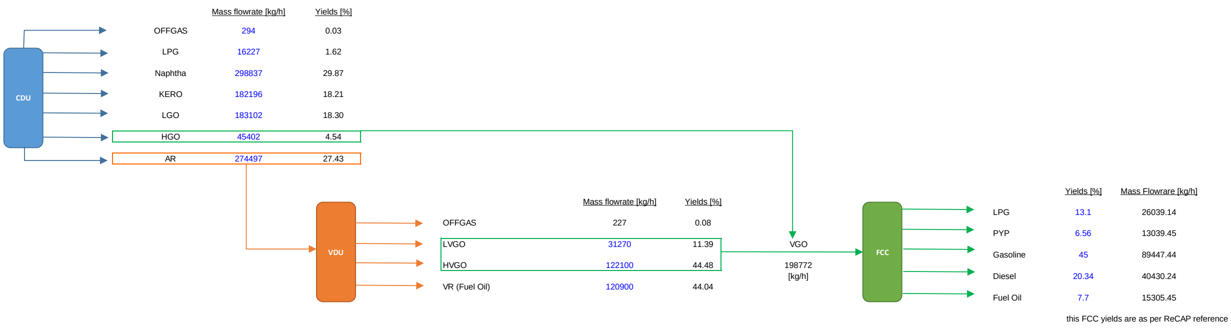
In order to evaluate the yield of the valuable products that can be sold from the crude oil entering the refinery, two different representative capacities and complexities of the schemes have been considered as follows:

- A small-size (100 KBPD), hydroskimming scheme for very light crudes (Atmospheric Residue <30% wt., like Agbami and Bonny Light)
    - Operating costs ~ 2.5 USD/bbl
    - Refinery margin 2.5 USD/bbl

- A medium-size (220 KBPD), FCC scheme for the medium to heavy crudes
  - Operating costs ~ 2.3 USD/bbl
  - Refinery margin 5 USD/bbl

In order to validate the above described pricing model, the following procedure has been applied:

- Product yields for Ekofisk, Arab Light, and Maya blend are available from previous ReCAP study as well as oil and product set of prices. A preliminary FCC conversion scheme has been applied to account for LPG, propylene, gasoline, diesel, and fuel oil production from Vacuum Gasoil (i.e., Light and Heavy Gasoil coming from the VDU and Heavy Gasoil coming from the CDU).



- The oil and product set of prices dated back to 2012 have been actualized considering the ratio with the current Brent price.
- The product revenues in [USD/ton] have been calculated for each crude by multiplying the product yields with the respective prices.

Prices 2018 (to be used as reference scenario for all the coutries)
North West Europe
All figures in $/t except when otherwise stated

Feedstocks and components	
North Sea/Low Sulphur	557
West African	551
Russian	509
Middle East medium sour	531
Middle East sour	519
Condensate	642
Crude input average	533
$/bbl	*96.8*
Chemical Naphtha	788
Natural Gas	683
Atm Residue (North Sea)	572
Ethanol	450
Other Feed average	593
Jet fuel	988
Road diesel 10ppm S	933
Heating Oil 1000ppm S	885
Blendstock Import average	943
All Input	705
Maya	**494**
New Maya Blend	**513**
Old Maya Blend	**513**

Products		Mass flowrate [kg/h] to sales			Yields [%]		
		Ekofisk			Ekofisk		
LPG	558	42266			4.22		
Ethylene	1003						
Propylene	932	13039			1.30		
Butylenes	626						
Benzene	785						
Toluene	676						
Xylenes	744						
Chemical Products average	895						
Gasoline Regular 92 unleaded	620						
Gasoline Premium 95 unleaded	627	388284			38.81		
Gasoline Premium 98 unleaded	634						
Gasoline Export (US) unleaded	622						
Gasoline average	625						
Jet fuel	747	182196			18.21		
Road Diesel	703	223532			22.34		
Non Road Diesel	703						
Heating Oil	670						
Marine Diesel	670						
Diesel & Heating Oil average	693						
Fuel Oil 0.6% Sulphur	415	136205			13.61		
Fuel Oil 1.0% Sulphur	389						
Fuel Oil 3.5% Sulphur	337						
Export Fuel Oil 1.5% Sulphur	354						
Bunker Low sulphur	382						
Bunker High Sulphur	370						
Fuel Oil average	377						
Bitumen	331						
Lubricant base oils	667						
Pet Coke HS Fuel grade	95						
Sulphur	38						

- The gross margin in [USD/bbl] is the difference between product revenues and the crude oil price and represents the allowance of operative expenditures and distillation margin.
- The assumed operative expenditures of 180 MMUSD/y have been subtracted to the gross margin, giving the distillation margin.

This procedure allowed us to validate the 5 USD/bbl distillation margin to be applied for the pre-selected refining scheme of FCC, which is in line with previous market studies. Similarly, distillation margin of 2.5 USD/bbl for Hydroskimming has been validated with Ekofisk set of data.

Once calculated the crude oils' prices in Europe, they have been used to calculate the oil prices in the various Countries covered by the Study, by taking into account the transportation costs.

The following factors have been considered for each region:

- Location of operational refineries
- Location of oil wells
- Availability of pipelines

Transportation costs have been assessed based on previous market study in different areas of the world, which resulted in this formula based on the distance in [km]:

$$P_{transportation} = C * distance$$

Where C is a factor depending upon the transportation method in [USD/bbl/1,000 km]:

- Pipeline: C = 2
- Rail: C = 3
- Truck: C = 5
- Ship: C = 0.5

For each country the locations of the refineries, of the available pipelines and of the selected oil wells have been identified. Transportation price from oilfield to Europe has been subtracted from the import parity basis price, while the transportation price from oilfield to India/Nigeria/Brazil has been added to obtain the price at refinery gate (input for the refinery balance modelling).

1.4.1 Asia (India)

The refinery location in Figure 17, in the Mumbai area, has been assumed.

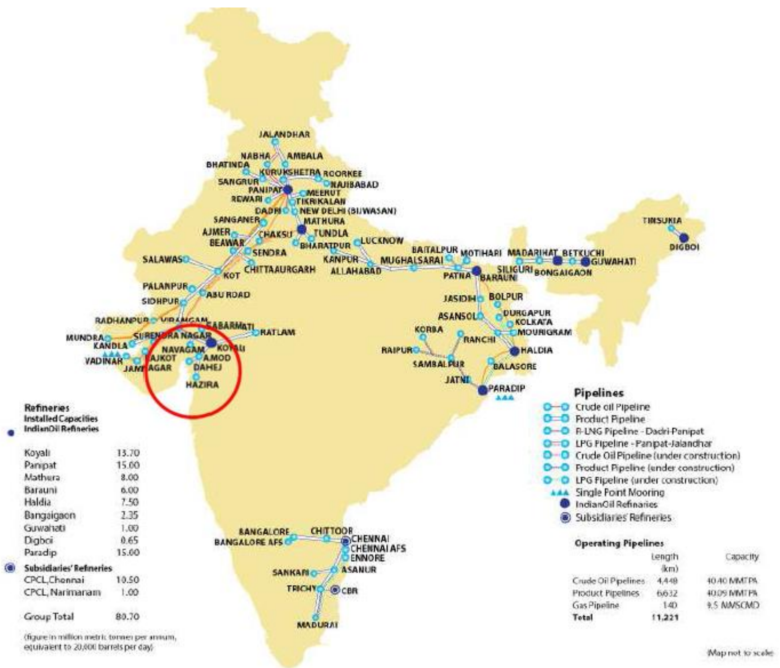


Figure 17: Selected Clean Refinery location in India

According to the Indian crude oil basket and the selected location for the new Clean Refinery:

- Ekofisk produced from the Ekofisk area is transported via the Norpipe oil pipeline to Teesside in the UK. Transportation has been assumed to be by pipeline to a Teesside terminal and then by ship from a Teesside terminal either to Europe or to India;
- Arab Light is mainly produced from the super-giant Ghawar field in Saudi Arabia. Wood has assumed the transportation by pipeline to different ports (Yanbu for Europe route and Dammam for India route) and then transportation by ship from ports to Europe or refinery in India;
- Maya is produced from the offshore Cantarell field and then shipped from the ports of Dos Bocas and Cay Arcas on the Gulf of Mexico and from Salina Cruz on the Pacific Coast. Transportation by pipeline to the port of Dos Bocas has been assumed as well as transportation by ship from the port of Dos Bocas to Europe or refinery in India.

Figure 18, Figure 19, and Figure 20 show the contributions of transportation from the European market back to the oil field and from the oil field to the refinery gate to build the prices of Ekofisk, Arab Light, and Maya, respectively.

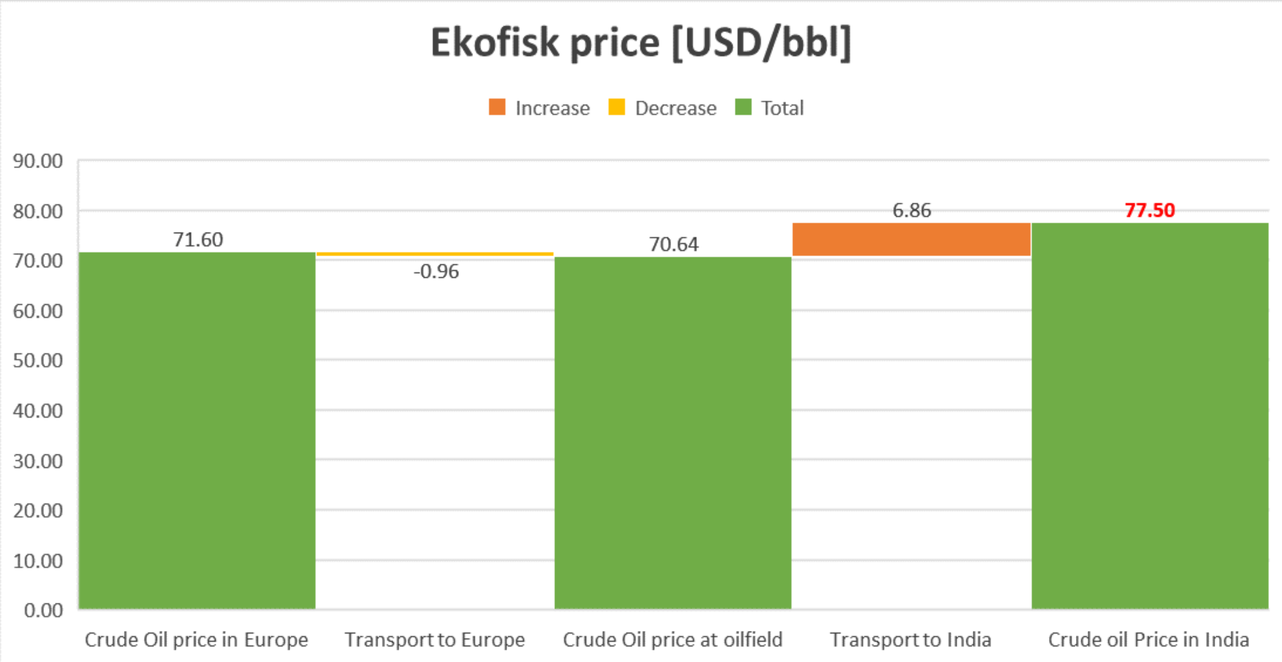


Figure 18: Ekofisk refinery gate price assessment

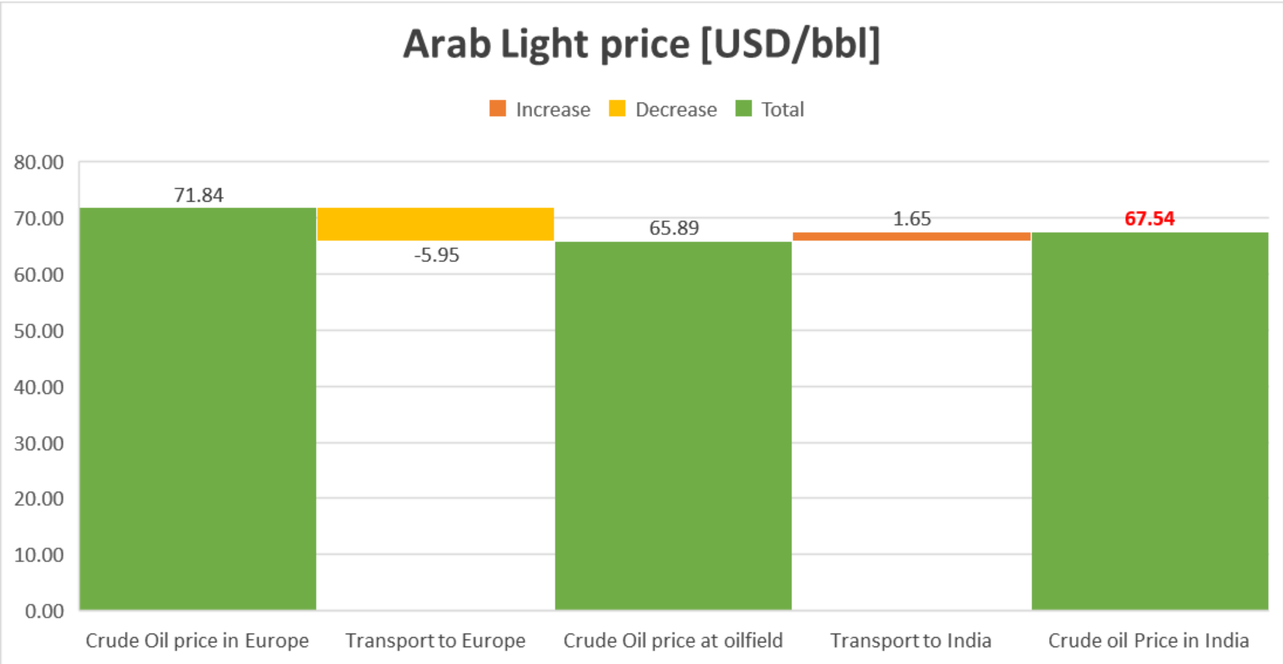


Figure 19: Arab Light refinery gate price assessment

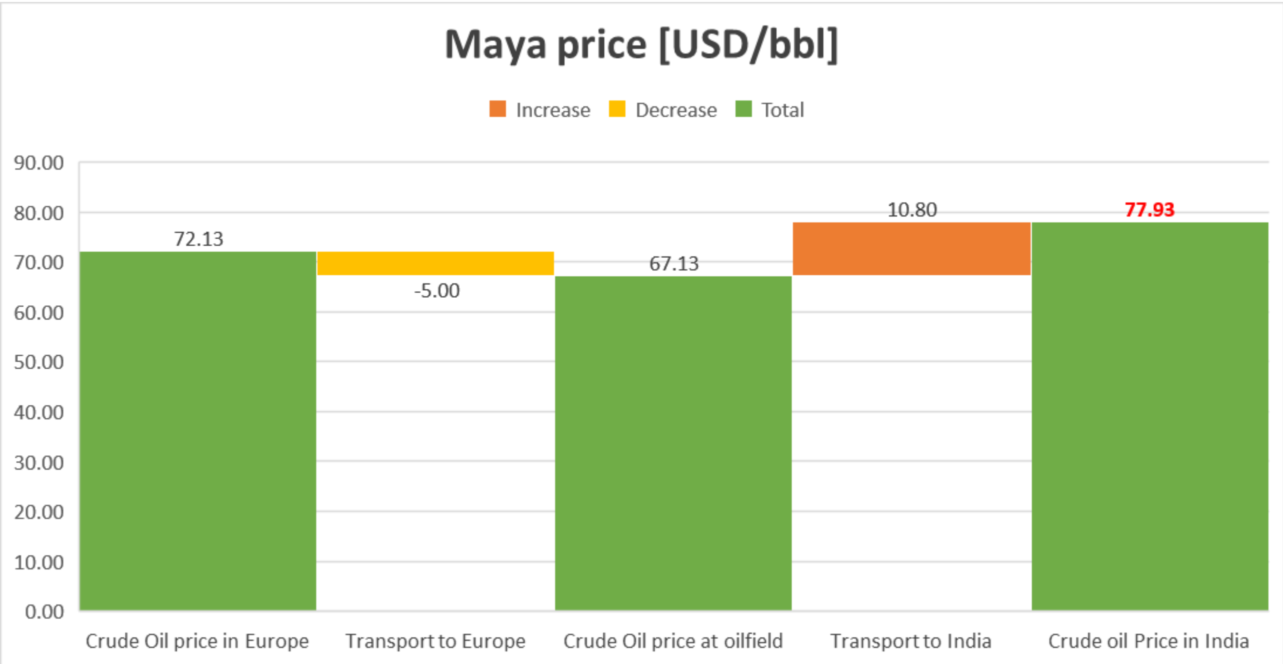


Figure 20: Maya refinery gate price assessment

1.4.2 South America (Brazil)

For the prices of each crude oil entering Brazilian refineries, we have built the price by considering the product revenues and subtracting OPEX and distillation margin contributions. These results are based on the European parity market. The price in Brazil is linked to the European one by the transportation price differential. For this purpose, we have considered a refinery located near Sao Paulo, as represented in Figure 21.

Figure 21: Selected Clean Refinery location in Brazil

According to the Brazilian crude oil basket and the selected location for the new Clean Refinery:

- Marlim is located in the north-eastern part of Campos Basin roughly 110 km offshore Rio de Janeiro;
- Tupi is the largest accumulation in the offshore province crossing the Espírito Santo, Campos and Santos basins;
- Peregrino oil field is located approximately 85 km offshore Brazil, in the Campos basin.

Hence, transportation by ship has been considered for all the crude oils, resulting in the following prices of Marlim, Lula Tupi, and Peregrino at the oil field and and at the refinery gate (Figure 22, Figure 23, and Figure 24).

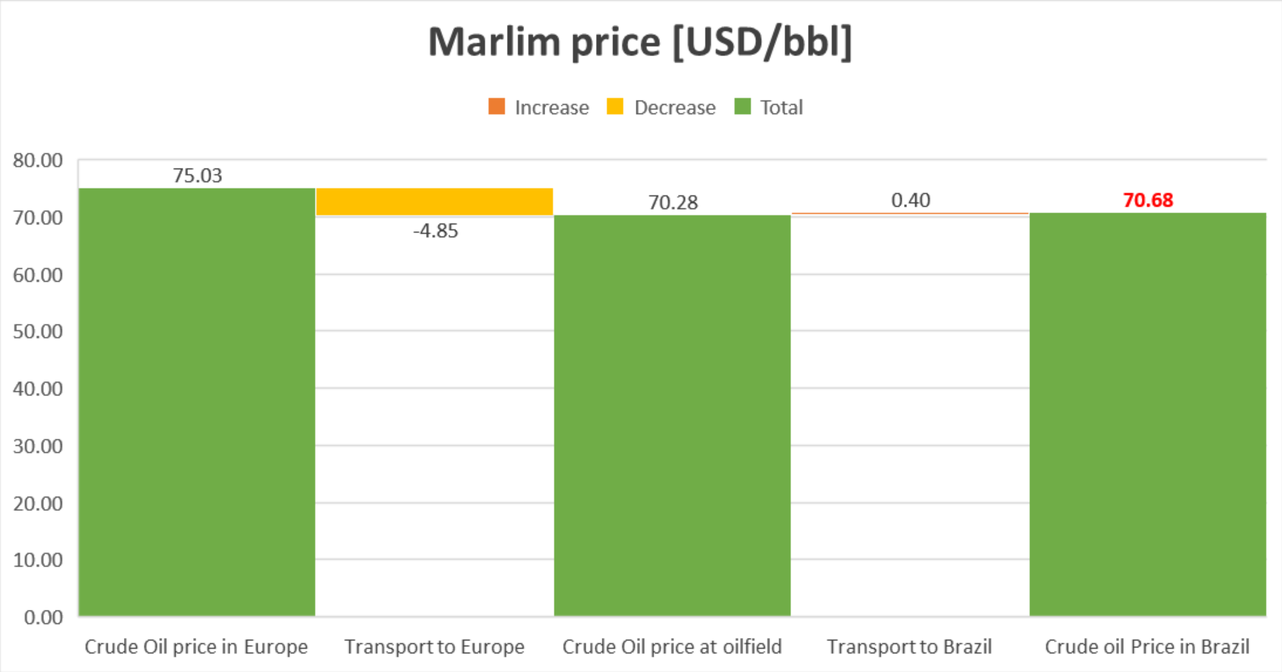


Figure 22: Marlim refinery gate price assessment

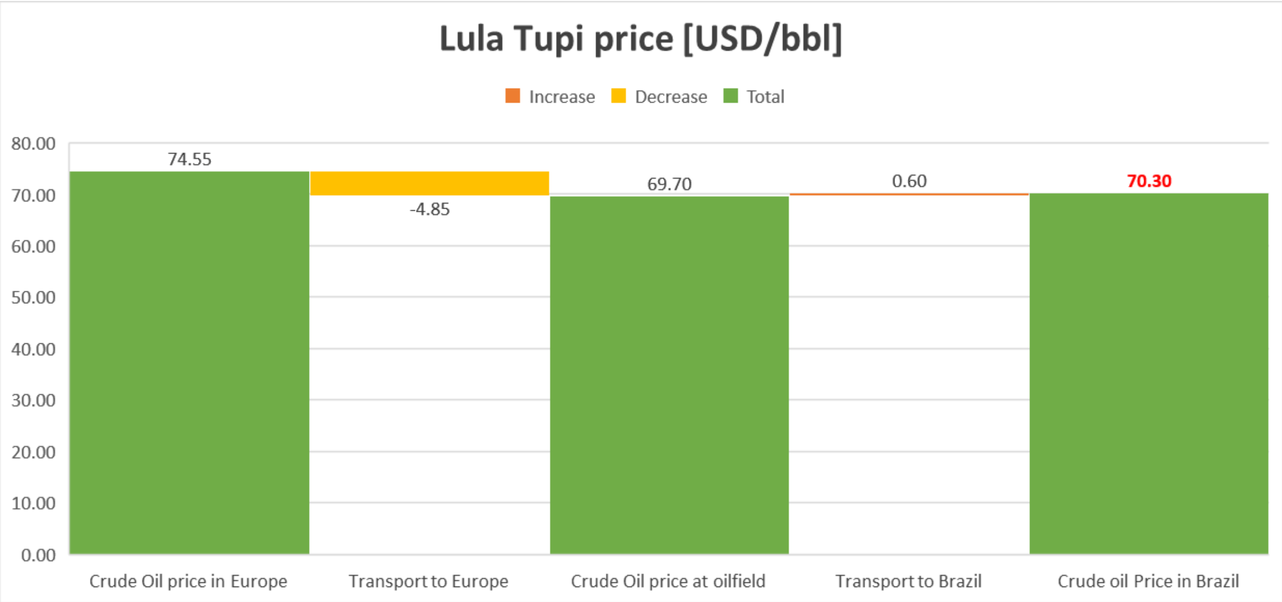


Figure 23: Lula Tupi refinery gate price assessment

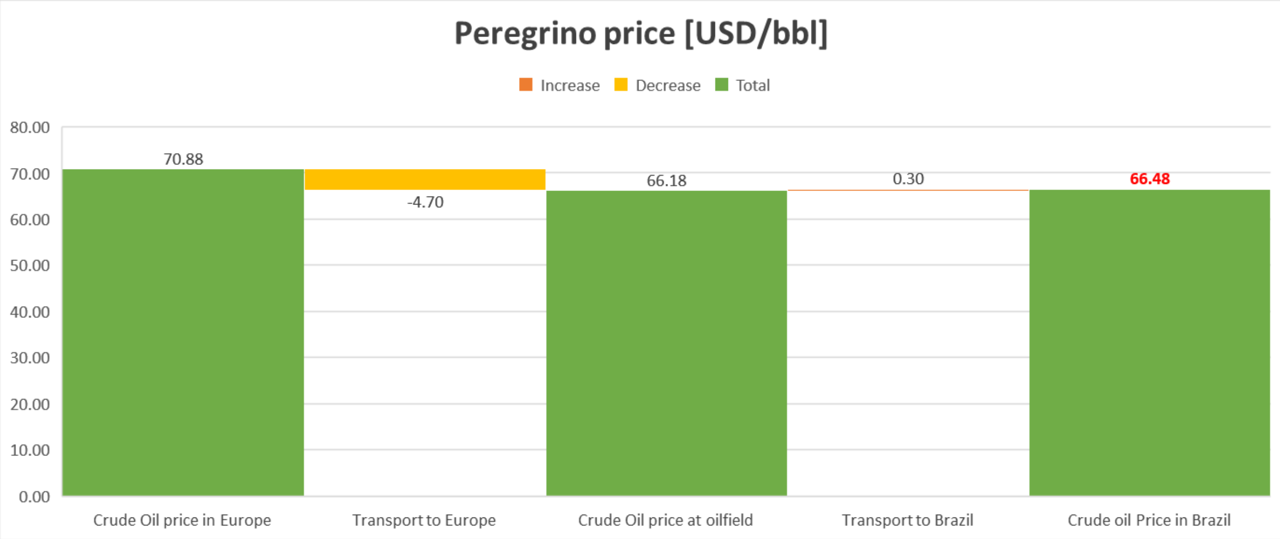


Figure 24: Peregrino refinery gate price assessment

1.4.3 Africa (Nigeria)

For the prices of each crude oil entering Nigerian refineries, the price has been built by considering the product revenues and subtracting OPEX and distillation margin contributions, on the European parity market. The price in Nigeria is linked to the European one by the transportation price differential. For this purpose, a refinery located near the Gulf of Guinea has been considered, from which two of the selected crudes are extracted (Figure 25).

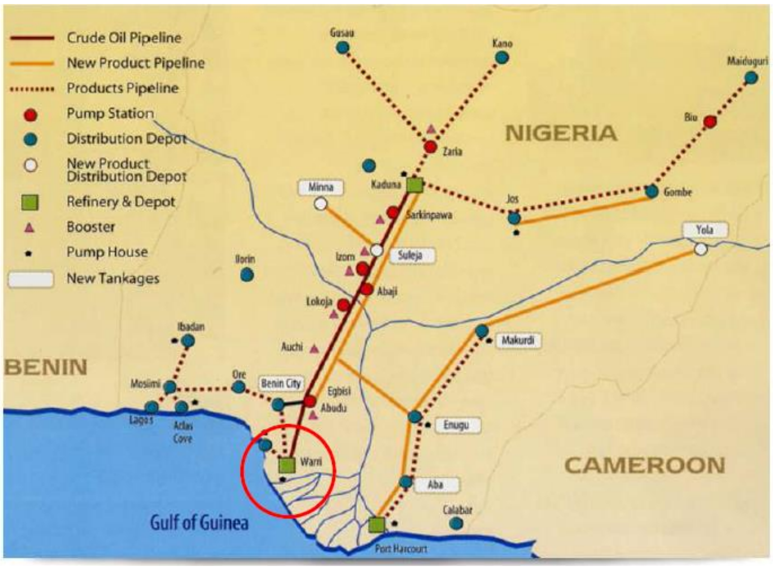


Figure 25: Selected Clean Refinery location in Nigeria

According to the Nigerian crude oil basket and the selected location for the new Clean Refinery:

- Agbami field lies approximately 220 miles south-east of Lagos and 70 miles offshore Nigeria, in the central Niger Delta. Transportation by ship has been considered;
- Bonny Light is produced from Bonny Island Oil Terminal. Wood assumed transportation by pipeline from oilfield to the Bonny Light terminal, while by ship from Bonny Light terminal to Europe and refinery in Nigeria;
- Doba Blend is produced in Chad and pumped via pipeline to the Kome-Kribi Terminal, located approx. 6 miles off the coast of Cameroon, 12 miles south west of the port of Kribi. Based on this location, Wood assumed transportation by

pipeline from oilfield to Kribi (terminal), by ship from Kribi (terminal) to Europe, and by rail from Kribi (terminal) to the refinery in Nigeria. An extension of about 100 km would be needed to connect the existing railway from Nigeria border to the hypothetical costal location of the new refinery. Transportation by rail has been selected (vs. ship transportation) considering the relatively short distance and the higher reliability of rail transportation vs. marine shipping.

Figure 26, Figure 27, and Figure 28 show the contributions of transportations from the Europe to the oil field and from the oil field to the refinery gate in building the prices of Agbami, Bonny Light, and Doba Blend, respectively.

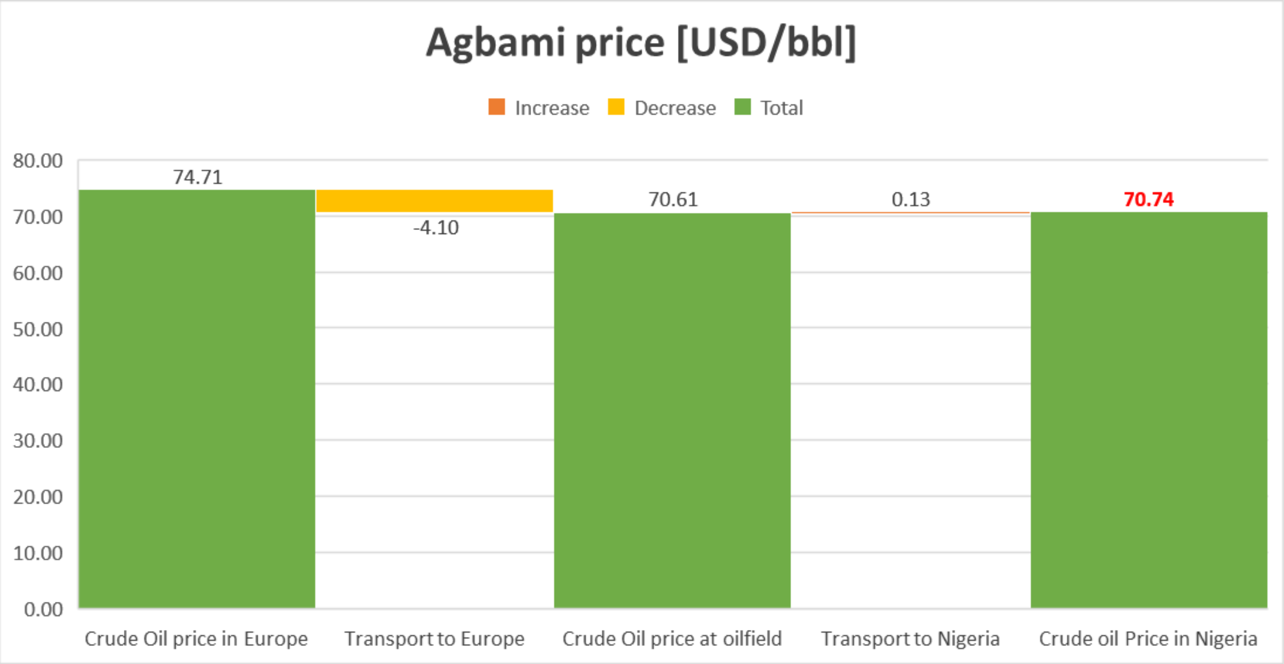


Figure 26: Agbami refinery gate price assessment

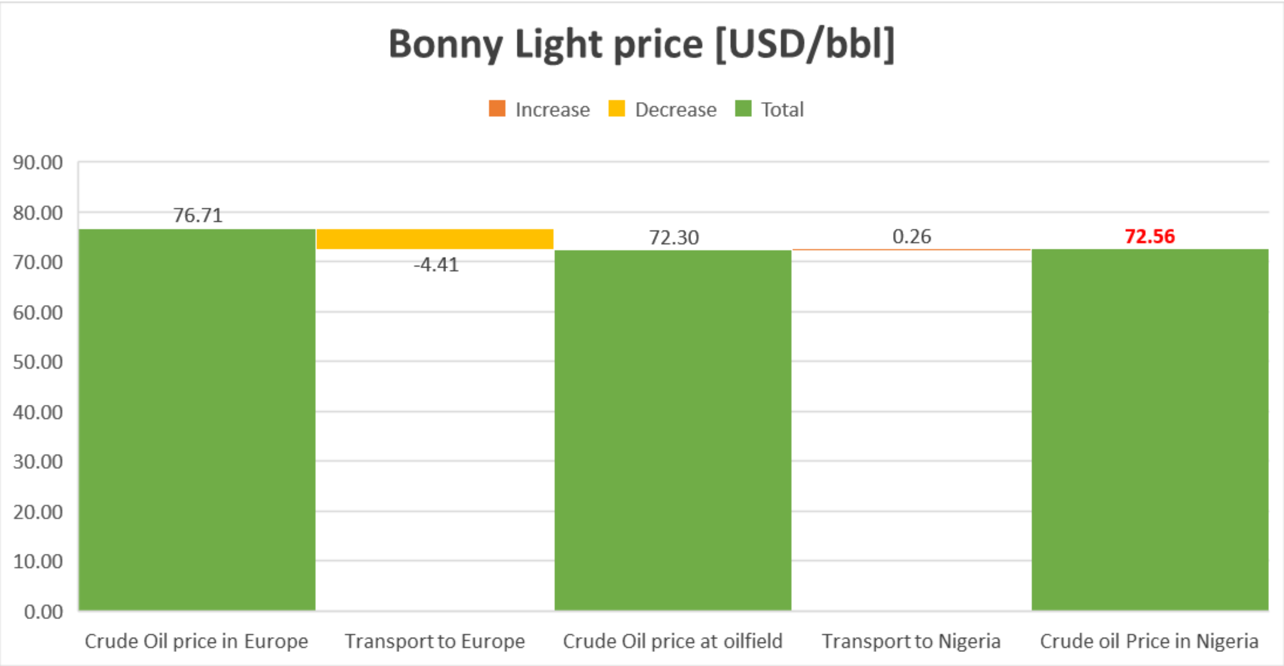


Figure 27: Bonny Light refinery gate price assessment

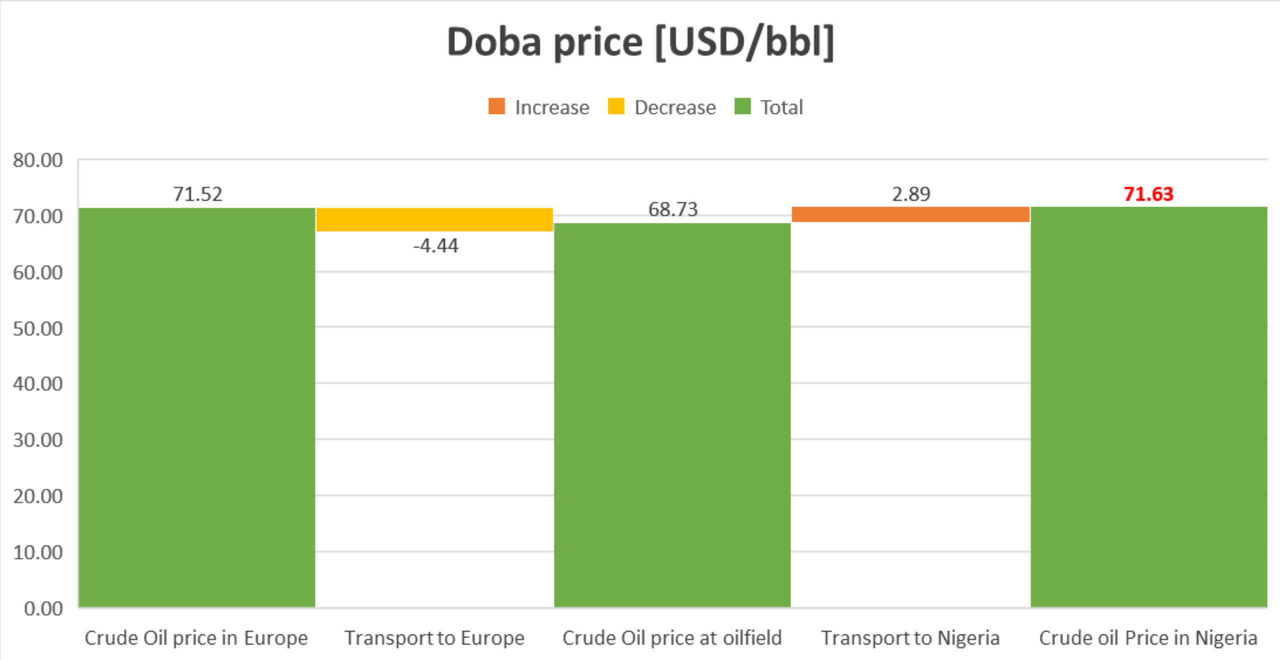


Figure 28: Doba Blend refinery gate price assessment

1.4.4 Summary of selected crude oil prices

The crude oil prices retrieved from Task 1 activities are summarized in Table 8, which includes the main physical properties of the crude oil diets and the prices on the European parity market and at the refinery gate. The price at the refinery gate (expressed in USD/ton) will be input to the linear programming model in Task 3 for the optimisation of refinery schemes.

Table 8: Summary of selected crude oil prices

Region	Crude Oil	Origin	API Gravity	Sulphur, %wt.	PRICE IN EUROPE [USD/bbl]	PRICE IN EUROPE [USD/ton]	PRICE AT REFINERY [USD/bbl]	PRICE AT REFINERY [USD/ton]
INDIA	EKOFISK	Norway	42.4	0.17	71.6	556.6	77.5	602.5
	ARAB LIGHT	Saudi Arabia	33.9	1.77	71.8	531.2	67.5	499.4
	MAYA	Mexico	21.7	3.18	72.1	494.0	77.9	533.7
BRAZIL	MARLIM	Brazil	20	0.77	75.0	508.2	70.7	478.7
	LULA TUPI	Brazil	28.8	0.37	74.6	534.2	70.3	503.8
	PEREGRINO	Brazil	13.4	1.76	70.9	459.1	66.5	430.6
NIGERIA	AGBAMI	Nigeria	48.3	0.04	74.7	600.4	70.7	568.5
	BONNY LIGHT	Nigeria	35.1	0.15	76.7	571.3	72.6	540.3
	DOBA	Chad	21	0.09	71.5	487.6	71.6	488.3

It has to be reminded that the prices in Table 8 are consistent with a price scenario consistent with Brent crude oil (benchmark) sold at 73 USD/bbl (August 2018).

2 Task 2 - Products selection, specifications and evaluation

The scope of this Task is the definition of the most attractive refinery products, in terms of selling prices and market demands, as well as the relevant specifications based on the information available in literature for the three regions under the scope of this Study. Based on Wood's experience, the profitability of the various refinery schemes is influenced more by the differential price of the various products with respect of the crude oil (e.g. gasoline price vs. crude oil price) than by the "absolute" price of the crude oil. The sets of prices to be considered was proposed by Wood and agreed with IEAGHG during the review of the initial phases.

All the new «Clean Refineries» will produce the following products:

- LPG
- Gasoline
- Jet Fuel
- Diesel
- Marine Diesel
- Fuel Oil
- Bitumen

Heating Oil is not produced because the demand of this fuel in the selected countries is very low due to the climatic conditions.

The following sections list the selected products in terms of market demands, specifications, and prices assessment. No seasonal variations are considered.

2.1 Market Demands

Products' market demands represent the natural constraints to the refinery balances. Hence, they have been input into the LP model (Task 3) in order to "drive" the model solution to reflect the typical products' slates of the new clean refineries in India, Brazil, and Nigeria.

2.1.1 Gasoline

Gasoline Export is 30 to 40% wt. of the total gasoline production in India. The rest of gasoline production is sold in India. For Brazil and Nigeria, no constraints for the internal market have been envisaged.

2.1.2 Jet fuel

Sales of Jet Fuel represent approx. 10% wt. of the total crude intake for India and Brazil. Jet Fuel production is increased to 13% wt. of total crude intake for Nigeria.

2.1.3 Gasoils

Automotive Diesel represents a minimum of 75% wt. of the total gasoil production. The remaining 25% of gasoil production is Marine Diesel.

2.1.4 Bitumen

Bitumen sold in all the cases is approx. 400 kt/y. Bitumen is produced in all the cases since the asphalt demand is deemed reasonable in the selected growing countries.

2.2 Product Specifications

For Brazil and India, diesel and gasoline specifications have been selected according to the Local Legislation; for all the other products IEAGHG and Wood agreed to use European specifications for the purpose of this Study.

For Nigeria, European specifications have been considered for the design of the new refineries, since the current regulations are not in line with the concept of the Clean Refinery. For instance, Figure 29 and Figure 30 show that according to 2020 regulations Nigeria would accept the highest sulphur limits in Diesel and Gasoline among all the countries (i.e. between 2,001 and 10,000 ppm in Diesel and between 501 and 2,500 ppm in Gasoline).

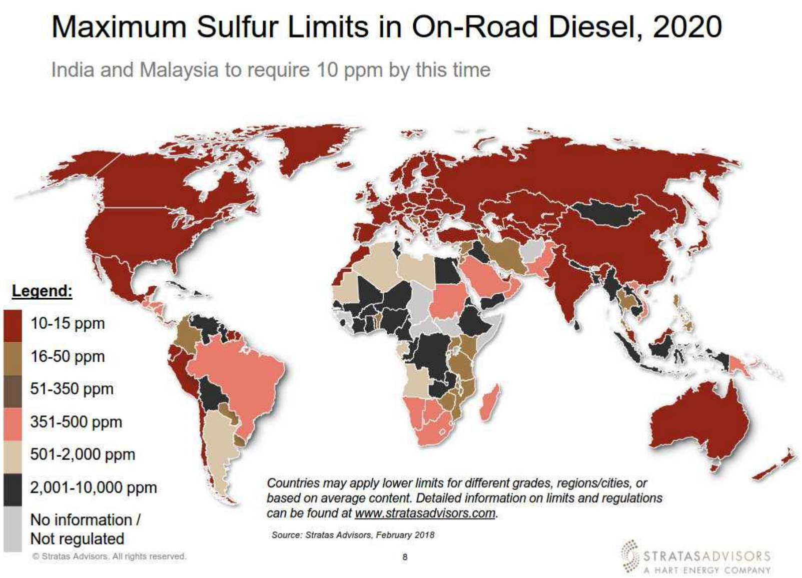


Figure 29: Maximum Sulphur limits in Diesel according to 2020 regulation by countries

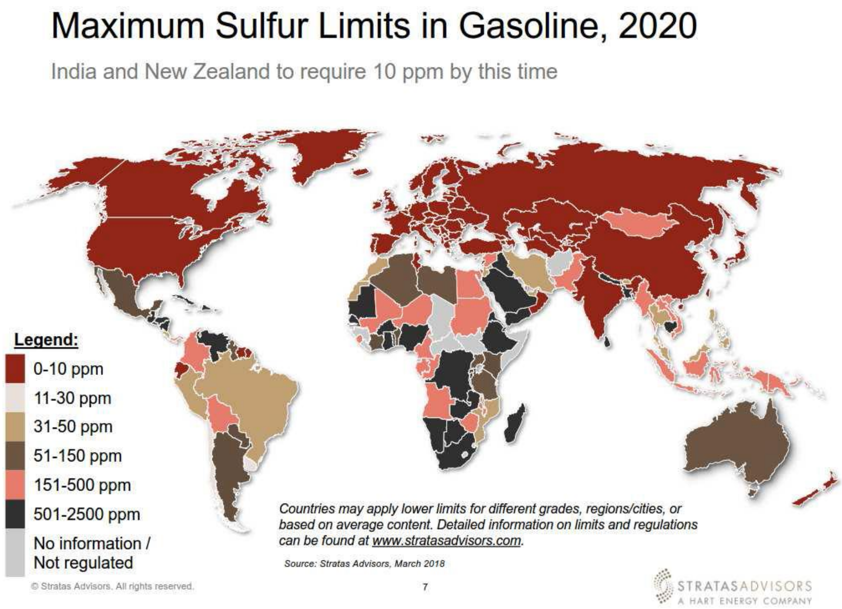


Figure 30: Maximum Sulphur limits in Gasoline according to 2020 regulation by countries

2.2.1 Bio additives

Bio-ethanol is an additive to Gasoline, while Bio-diesel is an additive to Automotive Gas Oil (Diesel). Both their contents depend on Local Legislations and for the three countries under the scope of this Study the requirements (if any) and the limitations have been tabulated in the following sections.
For the sake of clarity, to produce the typical refinery balances, the quantity of bio-additives in each finished product has been set/limited to the values reflecting the average country qualities:

- bio-ethanol blended into Brazilian Gasoline has been limited to 7% vol. max according the "official" specification;
- bio-diesel has been fixed in the range 25 - 27% vol. on Diesel in Brazil;
- No limitations or specific requirements have been raised for India and Nigeria in terms of "official" specification.

2.2.2 India

Table 9 and Table 10 collect the product specification for gasoline and diesel in India, respectively. These specifications are retrieved from current local regulations. Wood and IEAGHG agreed that, for India, the Sulphur content in diesel and gasoline is in line with the European specification and in line with the concept of a new clean refinery.

Table 9: Gasoline specification in India

Feature	Unit	Bharat Stage VI - Regular	Bharat Stage VI - Premium
Anhydrous Ethanol Content	% V/V	-	-
Density @ 15°C	kg/m3	720 ÷ 775	720 ÷ 775
Residue, max	% V/V	-	-
D86 @ 90% recovered, max	°C	-	-
MON, min		81	85
RON, min		91	95
Reid Vapor Pressure (RVP) @ 37.8°C, max	kPa	60	60
Sulphur, max	ppm	10	10
Benzene, max	% V/V	1.0	1.0
Lead, max	g/L	0.005	0.005
Phosporous, max	mg/L	-	-
Aromatics, max	% V/V e	35	35
Olefins, max	% V/V	21	18
Oxygen Content, max	% wt	2.7	2.7

Table 10: Diesel specification in India

Feature	Unit	Bharat Stage VI
Biodiesel Content	% V/V	-
Total Sulphur, max	mg/kg	10
Density @ 15°C	kg/m3	min 820, max 860
D86 @ 95% recovered, max	°C	370
Flash Point (Abel), min	°C	35
Viscosity @ 40°C	mm2/s	min 2, max 4.5
Cetane number, min		51
Ash, max	% wt	0.01
Carbon Residue on 10% residue, max		0.3
Polycyclic Aromatic Hydrocarbon (PAH), max	% wt	11
Water content, max	mg/kg	200

2.2.3 Brazil

Table 11 and Table 12 collect the product specification for gasoline and diesel in Brazil defined according PETROBRAS product specification.

Table 11: Gasoline specification in Brazil

Feature	Unit	Petrol Joint (type C)	Gasoline Premium (Type C)
Anhydrous Ethanol Content	% V/V	27% (note 1)	25% (note 1)
Density @ 20°C	kg/m3	-	-
Residue, max	% V/V	2.0	2.0
D86 @ 90% recovered, max	°C	190	190
MON, min		82	-
Anti Knock Index, min		87	91
Vapor pressure @ 37.8°C, max	kPa	69.0	69.0
Sulphur, max	mg/kg	50	50
Benzene, max	% V/V	1.0	1.0
Lead, max	g/L	0.005	0.005
Phosporous, max	mg/L	0.2	0.2
Aromatix, max	% V/V	35	35
Olefins, max	% V/V	25	25

Table 12: Diesel specification in Brazil

Feature	Unit	S50	S500
Biodiesel Content	% V/V	7% (note 2)	7% (note 2)
Total Sulphur, max	mg/kg	50	500
Density @ 20°C	kg/m3	min 820, max 850	min 820, max 865
Flash Point	°C	38.0	38.0
Viscosity @ 40°C	mm2/s	min 2.0, max 5.0	min 2.0, max 5.0
Cetane number, min		46	42
Ash, max	% wt	0.01	0.01
Water and sediment, max	% V/V	0.05	0.05

Since the Sulphur content in diesel S500 – Type B is not in line with the concept of a clean refinery, it was not considered in this study. IEAGHG and Wood agreed on a Sulphur content of 50 ppm, which is low enough for a new clean refinery.

2.2.4 Nigeria

For Nigeria product specifications reference has been made to EURO V specifications as reported in Table 13 and Table 14.

Table 13: Gasoline specification in Nigeria

Feature	Unit	Regular	Premium
Anhydrous Ethanol Content	% V/V	-	-
Density @ 15°C	kg/m3	-	-
Residue, max	% V/V	-	-
D86 distillation: percentage evaporated @ 150°C, min	%V/V	75.0	75
MON, min		85	84
RON, min		95	92
Vapor Pressure (Summer period), max	kPa	60.0	60.0
Sulphur, max	mg/kg	10.0	10.0
Benzene, max	% V/V	1.0	1.0
Lead, max	g/L	0.005	0.05
Phosporous, max	mg/L	-	-
Aromatics, max	% V/V	35.0	35.0
Olefins, max	% V/V	18.0	18.0
Oxygen Content, max	% wt	3.7	3.7

Table 14: Diesel specification in Nigeria

Feature	Unit	Regular
Biodiesel Content	% V/V	-
Total Sulphur, max	mg/kg	10.0
Density @ 15°C, max	kg/m3	845.0
D86 @ 95% recovered, max	°C	360.0
Flash Point (Abel), min	°C	-
Viscosity @ 40°C	mm2/s	-
Cetane number, min		51
Ash, max	% wt	-
Carbon Residue on 10% residue, max		-
Polycyclic Aromatic Hydrocarbons (PAH), max	% wt	8.0
FAME content, max	mg/kg	7.0

2.3 Product Prices

The sets of prices considered in the LP models have been calculated by Wood and agreed with IEAGHG.
They have been provided only for the purpose of calculations and they do not represent prices for any specific refinery.

2.3.1 *Methodology*

The first attempt to estimate diesel and gasoline costs, available from the ReCap Project (year 2012), and used for the calculation of crude oil prices, have been compared to the average cost at pump stations in the three countries (Table 15).

Table 15: Average price at pump station in the selected three countries (data retrieved from www.globalpetrolprices.com)

INDIA						
	USD/lt	density	USD/kg	USD/ton	ReCap cost [USD/ton]	**Delta [USD/tonn]**
Diesel	1.06	0.85	1.25	1247	703	**544**
Gasoline	1.18	0.75	1.57	1573	627	**946**
BRAZIL						
	USD/lt	density	USD/kg	USD/ton	ReCap cost [USD/ton]	**Delta [USD/tonn]**
Diesel	0.88	0.85	1.04	1035	703	**332**
Gasoline	1.13	0.75	1.51	1507	627	**880**
NIGERIA						
	USD/lt	density	USD/kg	USD/ton	ReCap cost [USD/ton]	**Delta [USD/tonn]**
Diesel	0.57	0.85	0.67	671	703	**-32**
Gasoline	0.41	0.75	0.55	547	627	**-80**

In India and Brazil, the delta price appears high enough to cover fuel transportation costs (from refinery to retail stations) and taxes, while in Nigeria, costs of diesel and gasoline at the pump station looks inconsistent with crude oil prices calculated on an import parity basis due to the low quality of the fuel specifications (to overcome this issue, see Section 2.3.4) for the proposed method of price evaluation for clean products).

For the evaluation of the price of products other than diesel and gasoline, the same vector considered for the evaluation of the crude price at the refinery gate was used. The most used automotive fuel between diesel and gasoline was identified for each country. The prices of all the other products were then considered proportional to the selected actualized price of the most spread automotive fuel (i.e. gasoline or diesel).
The methodology is applied in the following sections for each region.

2.3.2 India

The ratio between refinery gate price and retail price for both gasoline and diesel in India have been retrieved from Bharat Petroleum source and are:

- Gasoline: 2.1;
- Diesel: 1.7.

Refinery gate price has been recalculated considering the cost at pump station in WEEK 38 (16-22/09) of year 2018 for consistency with the period considered for the feedstock (crude oil):

- For gasoline the retail price at pump station was 85.2 Indian Rupee and, considering the ration between refinery gate and retail price of 2.1, the resulting refinery gate price is 40.6 Rupee equal to 0.56 USD/lt (see Table 16 and Figure 31 here below). This gasoline is intended as Gasoline Regular 91 Type.
- For diesel the retail price at pump station was 76.4 Indian Rupee and, considering the ration between refinery gate and retail price of 1.7, the resulting refinery gate price is 45.0 Rupee equal to 0.62 USD/lt (see Table 17 and Figure 32 here below).

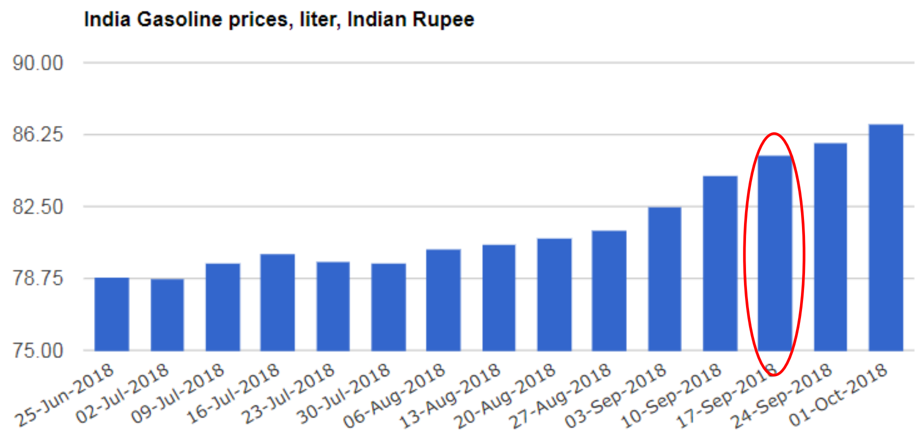


Figure 31: Weekly retail gasoline prices in India

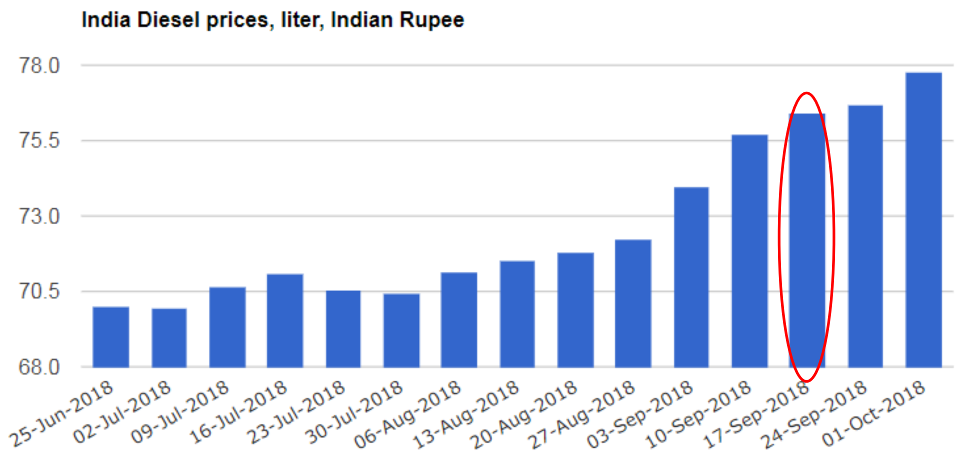


Figure 32: Weekly retail diesel prices in India

Table 16: Gasoline retail and refinery gate prices in India; Exchange rate: 1 USD = 72.1 Indian Rupee (16/09/2018)

	Retail price [Rupee/lt]	Refinery Gate price [Rupee/lt]	Refinery Gate price [USD/lt]	Density [kg/m3]	Refinery Gate price [USD/kg]	Refinery Gate price [USD/t]
Gasoline	85.2	40.6	0.56	750.0	0.75	750

Table 17: Diesel retail and refinery gate prices in India; Exchange rate: 1 USD = 72.1 Indian Rupee (16/09/2018)

	Retail price [Rupee/lt]	Refinery Gate price [Rupee/lt]	Refinery Gate price [USD/lt]	Density [kg/m3]	Refinery Gate price [USD/kg]	Refinery Gate price [USD/t]
Diesel	76.4	45.0	0.62	850.0	0.73	734

Since Diesel is the most used automotive fuel in India, this product will be used as reference to re-scale European prices vector, resulting in Table 18 price vector. The only exception to this methodology is the gasoline prices (both Regular 91 and Premium 95). Gasoline Regular 91 was calculated considering the ratio between refinery gate price and retail price of 2.1, while Gasoline Premium 95 price was calculated considering the ratio between regular and premium costs in Europe.

Table 18: Products price vector in India

Products	USD/t
LPG	583
Ethylene	1046
Propylene	973
Butylenes	653
Benzene	820
Toluene	706
Xylenes	776
Chemical Products average	934
Gasoline Regular 91 unleaded	750
Gasoline Premium 95 unleaded	758
Gasoline Export (US) unleaded	753
Gasoline average	757
Jet fuel	779
Road Diesel	734
Non-Road Diesel	734
Heating Oil	699
Marine Diesel	700
Diesel & Heating Oil average	724
Fuel Oil 0.6% Sulphur	433
Fuel Oil 1.0% Sulphur	406
Fuel Oil 3.5% Sulphur	351
Export Fuel Oil 1.5% Sulphur	370
Bunker Low Sulphur	399
Bunker High Sulphur	386
Fuel Oil average	394
Bitumen	346
Lubricant base oils	696

Pet Coke HS Fuel grade	99
Sulphur	39

Based on in-house data and previous ReCap Study the following prices for other products have been assumed for India:

- Natural Gas: 528.9 USD/ton (12 USD/MMBtu)
- Methyl tert-butyl ether MTBE: 1100 USD/ton
- Ethanol: 450 USD/ton

2.3.3 Brazil

With regard to the price structure for gasoline and diesel in Brazil, Wood intended, in agreement with IEAGHG, that the refinery gate price already includes the cost for the additives (ethanol and biodiesel) because the additives content is mandatory to obtain on-spec fuels, while taxes are excluded from the price composition.

The ratio between refinery gate price and retail price for both gasoline and diesel in Brazil has been retrieved from a Petrobras source. Diesel and Gasoline pump station prices in WEEK 38 (16-22/09) for the year 2018 have been considered for the product prices evaluation at refinery gate (see Figure 33 and Figure 34).

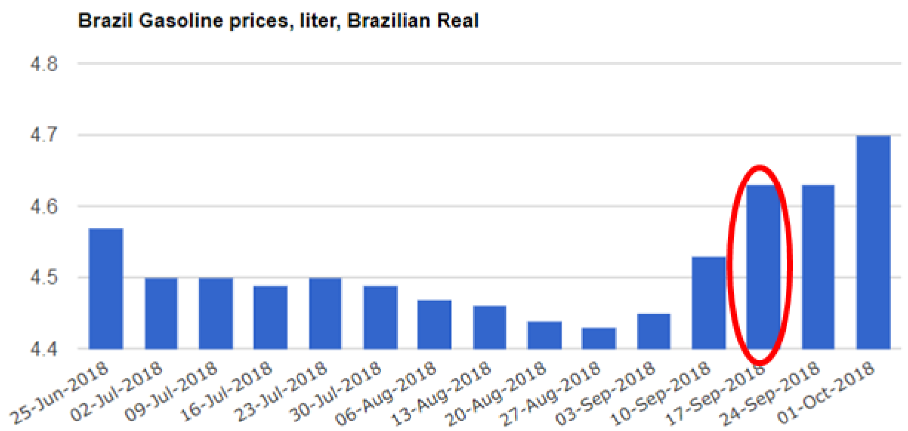


Figure 33: Weekly retail gasoline prices in Brazil

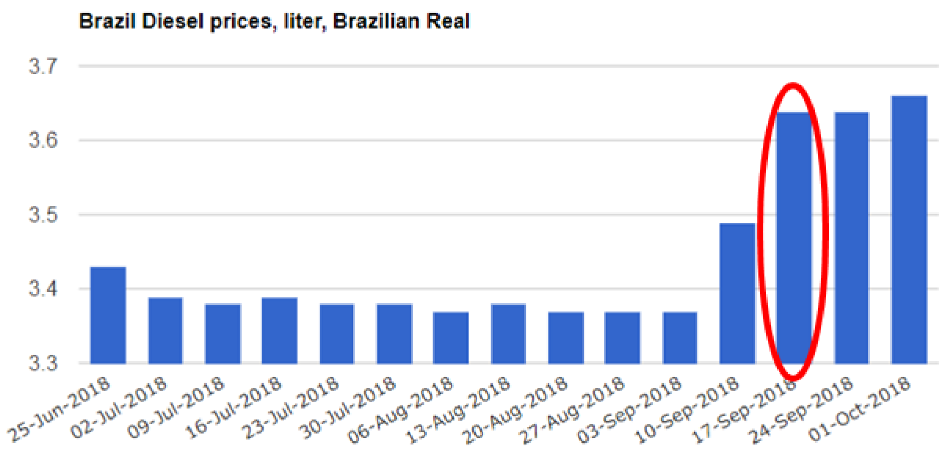


Figure 34: Weekly retail diesel prices in Brazil

The refinery gate price of diesel and gasoline has been calculated equal to 47% and 63% of retail price, respectively. It, already includes the costs of the additives (Table 19).

Table 19: Gasoline and Diesel retail and refinery gate prices in Brazil; Exchange rate: 1 USD = 4.13 R$ (16/09/2018)

	Retail price [R$/lt]	Refinery Gate price [R$/lt]	Refinery Gate price [USD/lt]	Density [kg/m3]	Refinery Gate price [USD/kg]	Refinery Gate price [USD/t]
Diesel	3.64	2.29	0.56	850	0.65	653
Gasoline	4.63	2.18	0.53	750	0.70	703

Based on the fuel composition (Figure 35 for gasoline and Figure 36 for diesel), the Bio-ethanol and Bio-diesel prices have been calculated as shown in Table 20 and Table 21 here below.

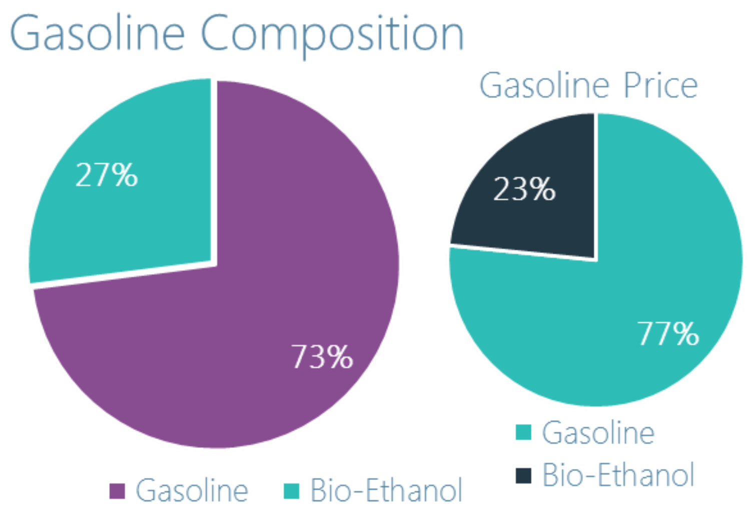


Figure 35: Gasoline components and price composition in Brazil

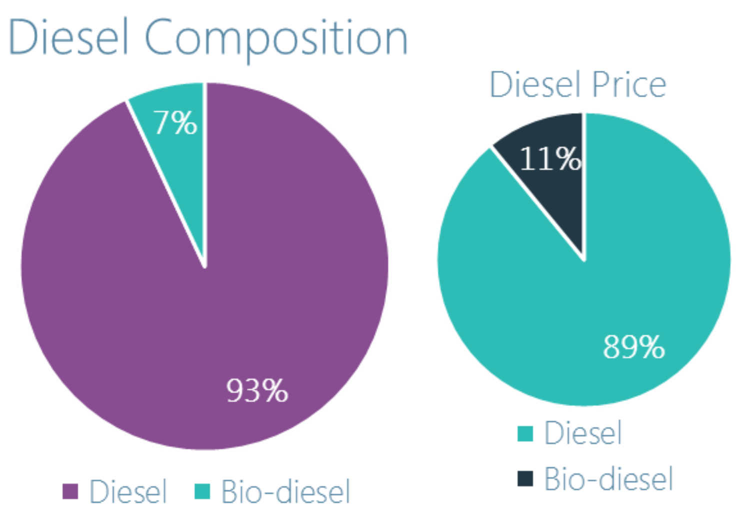


Figure 36: Diesel components and price composition in Brazil

Table 20: Gasoline and Bio-ethanol costs in Brazil

GASOLINE		
Refinery Gate price	0.53	USD/lt
Gasoline Contribution	0.40	USD/lt
Bio-Ethanol Contribution	0.12	USD/lt
Gasoline Cost	0.55	USD/lt
Bio-Ethanol Cost	0.46	USD/lt
Gasoline Cost	**737**	**USD/t**
Bio-Ethanol Cost	**579**	**USD/t**

Table 21: Diesel and Bio-diesel costs in Brazil

DIESEL		
Refinery Gate price	0.56	USD/lt
Diesel Contribution	0.49	USD/lt
Biodiesel Contribution	0.06	USD/lt
Diesel Cost	0.53	USD/lt
Biodiesel Cost	0.87	USD/lt
Diesel Cost	**626**	**USD/t**
Biodiesel Cost	**1021**	**USD/t**

Since Diesel is the most used automotive fuel in Brazil, this product will be used as reference to re-scale European prices vector, resulting in Table 22 price vector. The only exception to this methodology is the gasoline prices (both Regular 92 and Premium 96). Gasoline Regular 96 was calculated considering the ratio between refinery gate price and retail price, while Gasoline Premium 92 price was calculated considering the ratio between regular and premium costs in Europe.

Table 22: Products price vector in Brazil

Products	USD/t
LPG	519
Ethylene	932
Propylene	866
Butylenes	582
Benzene	730
Toluene	629
Xylenes	691
Chemical Products average	832
Gasoline Regular 92 unleaded	703
Gasoline Premium 96 unleaded	710
Gasoline Export (US) unleaded	705
Gasoline average	709
Jet fuel	694
Road Diesel	653
Non-Road Diesel	653
Heating Oil	622
Marine Diesel	623
Diesel & Heating Oil average	644
Fuel Oil 0.6% Sulphur	385
Fuel Oil 1.0% Sulphur	362
Fuel Oil 3.5% Sulphur	313
Export Fuel Oil 1.5% Sulphur	329
Bunker Low Sulphur	355
Bunker High Sulphur	344
Fuel Oil average	351
Bitumen	308
Lubricant base oils	620
Pet Coke HS Fuel grade	88
Sulphur	35

Based on in-house data and previous ReCap Study the following other prices have been assumed for Brazil:

- Natural Gas: 528.9 USD/ton (12 USD/MMBtu)

2.3.4 Nigeria

The same methodology applied for product specification has been considered for the product pricing in Nigeria, i.e. Nigerian products were aligned to European prices in order to evaluate a new clean refinery in this country. Indeed, the current prices of diesel and gasoline at the pump stations in Nigeria look inconsistent with the crude oil prices calculated on an import parity basis. The current product prices, which are very low, could be correlated to the very poor quality of the products currently sold on the local market.

Since the scope of this study is the "evaluation of different refinery configurations to achieve the best balance of the clean products", for Nigeria IEAGHG and Wood agreed in defining the minimum product prices to justify the profitability of the new clean refineries, i.e. the price structure for refinery products assumes a 'clean' refinery design and therefore a higher environmental standard compared with the existing refined products produced in Nigeria. For this reason, the same price vector as for Europe has been considered.

Table 23: Products price vector in Nigeria

Products	USD/t
LPG	558
Ethylene	1003
Propylene	932
Butylenes	626
Benzene	785
Toluene	676
Xylenes	744
Chemical Products average	895
Gasoline Regular 92 unleaded	620
Gasoline Premium 95 unleaded	627
Gasoline Export (US) unleaded	622
Gasoline average	625
Jet fuel	747
Road Diesel	703
Non-Road Diesel	703
Heating Oil	670
Marine Diesel	670
Diesel & Heating Oil average	693
Fuel Oil 0.6% Sulphur	415
Fuel Oil 1.0% Sulphur	389
Fuel Oil 3.5% Sulphur	337
Export Fuel Oil 1.5% Sulphur	354
Bunker Low Sulphur	382
Bunker High Sulphur	370
Fuel Oil average	377
Bitumen	331
Lubricant base oils	667
Pet Coke HS Fuel grade	95
Sulphur	38

The price vector will be then commented in the Section 5.1.3, dedicated to the results of the financial analysis of the Nigerian refineries.

Based on in-house data and previous ReCap Study the following other prices have been assumed for Nigeria:

- Natural Gas: 528.9 USD/ton (12 USD/MMBtu)
- MTBE: 1100 USD/ton
- Ethanol: 450 USD/ton

2.4 Electricity Export and relevant selling price

According to the scope of this Study, the electricity power output is not only a utility of the new Clean Refinery, but it is also considered as a part of its product portfolio in providing clean products. Consequently, the power plant of the new clean refineries is designed to be normally synchronized with the grid to export electricity instead of heavy or sour products like high Sulphur fuel oil. Indeed, in the selected countries, as expanding economies, the demand for refinery products will grow as well as the electricity power demand; so there should be room to export electricity from the refinery power plant. For the electrical energy pricing, reference has been made to in-house data.

In particular:

- For India, which is the third largest electricity consumer in the world, the electricity consumption has grown by 720% in the last four decades (IEA Statistics) and the forecast shows the same ascending trend. For India a unit selling price of electricity is 0.07 USD/kWh has been considered as input to the LP model based on in-house data.
- For Brazil, which is the eighth largest electricity consumer in the world, the electricity consumption has grown by 470% in the last four decades (IEA Statistics) and the forecast trend is also ascending. For Brazil an electricity selling price of 0.13 USD/kWh has been considered as input to the LP model. It is important to clarify that the assumed electricity price in Brazil at refinery gate was selected to obtain a reasonable gross margin for medium and high conversion schemes in this country (see Section 3.5 for a more detailed explanation).
- For Nigeria the electricity consumption has grown by 400% in the last four decades (IEA Statistics) and according to the most recent forecast, it is expected to ascend further. For Nigeria an electricity selling price of 0.07 USD/kWh has been considered as input to the LP model based on in-house data.

3 Task 3 - Processing options formulation

3.1 High-level definition of refinery schemes

For each country, three different refinery schemes have been proposed, studied and finally compared.

Increasing size and complexity have been considered, by progressively adding to a "base scheme", i.e. the hydroskimming case, some conversion units for transforming straight-run heavy material into valuable distillates. The addition of these types of units, which are capital-intensive, is typically justified for medium-to-large refineries, which benefit from better economies of scale.

Each refinery unit is identified, in this study, by a different acronym. The acronyms used are listed below:

- **CDU – Atmospheric Crude Distillation Unit**
- **VDU – Vacuum Distillation Unit**
- **NHT – Naphtha Hydrotreater**
- **NS – Naphtha Splitter**
- **CRF – Catalytic Reformer**
- **ISO – Isomerization Unit**
- **KME – KERO Sweetening Unit**
- **KHT – Kerosene Hydrotreater**
- **HDS – Hydro Desulphurization Unit**
- **VBU – Visbreaker Unit**
- **BPU – Bitumen Oxydation Unit**
- HDT – Hydrotreater Unit
- FCC – Fluid Catalytic Cracking Unit
- PTU – Post Treatment Unit (for FCC Gasoline)
- HCU – Hydrocracking Unit
- SMR – Steam Reformer
- SDA – Solvent Deasphalting
- DCU – Delayed Coker
- IGCC – Integrated Gasification Combined Cycle

Hydroskimming Refinery – Low Conversion Scheme

Units in bold characters are the ones which are present in the "base" hydroskimming configuration, which are therefore included in all the schemes studied.

The Hydro-skimming refinery is essentially composed of primary distillation units (Atmospheric and Vacuum), a gasoline block (Naphtha Hydrotreater, Splitter, Isomerization and Catalytic Reformer) for the production of on-spec gasolines, a Kerosene Sweetening unit for jet fuel production and middle-distillates Hydro-desulphurization units for the production of automotive diesel, marine diesel and heating oil. The residue from Vacuum distillation unit is partially sold as bitumen and partially sent to Visbreaking Unit, for partial conversion into distillates and viscosity reduction of the residue to comply with fuel oils' specifications.

The Hydrogen Rich Gas from the Heavy Naphtha Catalytic Reformer is compressed, sent to a Pressure Swing Absorber (PSA) module to increase the hydrogen concentration, and finally used for the desulphurization of products. No Steam Methane Reformer is included in the process scheme.

Vacuum Gasoil Conversion – Medium Conversion Scheme

On top of the "base" scheme, in a typical medium conversion scheme, Vacuum Gasoil (VGO) is converted either in an FCC or in a HCU. Typical yields for these units are shown in Figure 37 and Figure 38, which show that FCC unit promotes conversion of VGO to Gasoline, while HCU promotes conversion of VGO to Diesel (and Jet Fuel).

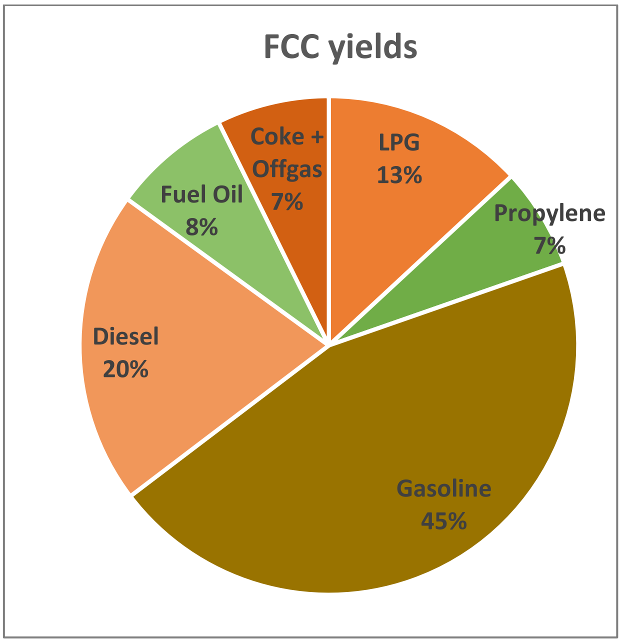


Figure 37: Typical product yields from FCC

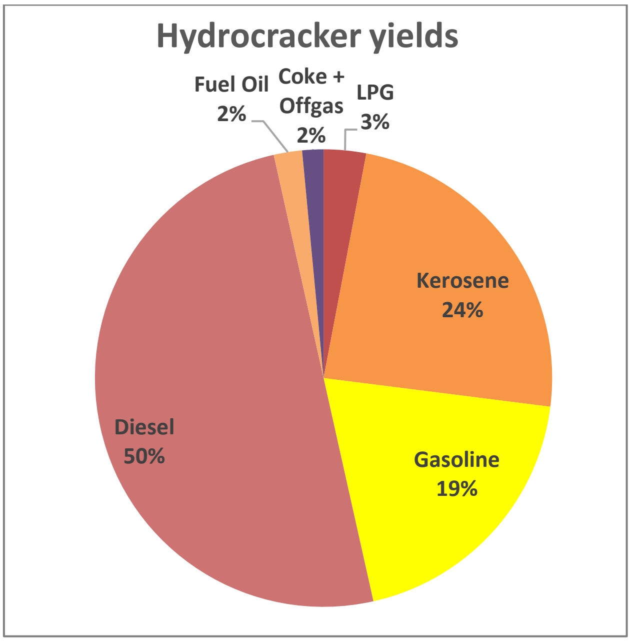


Figure 38: Typical product yields from HCU

The type of unit for VGO conversion (i.e. FCC vs. Hydrocracker) for each refinery is selected on the basis of the local demand for gasoline or diesel, considering that new refinery products will be sold on the Local Market in each country.
It has also to be considered that, both for FCC and HCU, the maximum commercial size is around 60,000 BPSD. Therefore, when the availability of VGO feed is higher, multiple units in parallel have been considered.

- In India, diesel demand is expected to increase more than gasoline demand, so for medium conversion refinery, hydrocracking scheme has been considered for VGO conversion, while for bigger refineries, the maximum flexibility is given by one FCC train in parallel to a hydrocracker train. Due to the quality of the Indian crude oil basket, if no residue conversion facilities are foreseen, the fuel oil produced will be high-sulphur type that could not be easily disposed to the market. Therefore, Wood and IEAGHG agreed to focus on refinery schemes that include some bottom-of-the-barrel technologies for fuel oil minimization/destruction. Two different schemes for high conversion refinery have been evaluated.
- In Brazil, diesel demand is expected to increase more than gasoline demand. By looking at the crude quality, the relatively high density of the crude (approx. 20°API) is an indication of the low content of straight-run distillates. To make a new refinery profitable, therefore, the inclusion in the scheme of Vacuum Gasoil conversion units seems to be mandatory, to increase the yield in automotive fuels. For a 150,000 bpd medium conversion refinery, hydrocracking scheme has been considered, while for bigger refineries, the maximum flexibility is given by an FCC train in parallel to a Hydrocracker train.
- In Nigeria, Gasoline demand is three times higher than gasoline demand and for Medium/High conversion refinery, FCC scheme has been considered. The capacity of a new refinery in Nigeria is proposed in the low-medium range, with the aim of covering the transportation fuels and power demand of the Country without export.

Bottom of the Barrel Solutions – High Conversion Scheme

For high conversion schemes, to minimize heavy oils production Wood evaluated two possible configurations:

- Use of the Solvent Deasphalting (SDA) technology to process heavy oil and produce deasphalted oil (fed to the conversion units of the refinery) and asphalt. Asphalt is then burnt in a steam boiler of a cogeneration power plant to produce steam and electric power or alternatively fed to a gasification plant. The resulting syngas from the gasifier is properly treated and fed to the hydrogen unit for hydrogen production and to the combined cycle unit for production of steam and electric power.
- Use of the Delayed Coker technology to process the asphalt from the SDA and produce petcoke and light products. Petcoke is then burnt in a boiler of a cogeneration power plant to generate steam and electric power.

CO_2 Capture Facilities

CO_2 capture facilities have been envisaged in all the high conversion schemes and in the medium conversion schemes where fuel oil cannot be produced on market-spec and, hence, the electric energy production is considered as part of the product portfolio of Clean Refinery in providing clean products instead of "black" ones. In general, CO_2 capture options have been considered for the large-scale power plants and for the major refinery heaters (i.e. CDU and VDU). Pre-combustion CO_2 capture has been considered for the steam methane reformer (SMR) unit. In this case, the SMR balances with CO_2 capture have been produced by considering the results of a previous study made by WOOD (former Amec Foster Wheeler) in collaboration with IEAGHG.

More specifically, the bottom of the barrel upgrading schemes are based on "clean process" allowing for selective removal of sulphur and CO_2.

- In the upgrading schemes based on gasification, pre-combustion selective removal of CO_2 and H_2S is achieved in the Acid Gas Removal unit belonging to the syngas treatment line, downstream of the CO shift conversion unit where most of the CO is converted to hydrogen and CO_2 by using steam. Reference is made to Figure 46.
- In the cogeneration power plant, boiler flue gas is treated in dedicated flue gas desulfurization for SO_2 removal and in a post-combustion capture unit for CO_2 removal.

High Level Refinery Schemes

Table 24 is a summary of the proposed high-level refinery schemes for the three countries under the scope of this Study. In the table, the acronyms in red are relevant to the selected Medium Conversion units, while the acronyms in blue are relevant to the selected High Conversion units.

Table 24: High level definition of refinery schemes

Size	India	Nigeria	Brazil
Power integrated simple Hydro-skimming refinery Low to medium size	-	150,000 bpd	-
Power integrated Medium conversion refinery Medium to Large – Size 1	250,000 bpd HCU	200,000 bpd FCC	150,000 bpd HCU
Power integrated Medium conversion refinery Medium to Large – Size 2	-	-	250,000 bpd HCU + FCC
Power integrated bottom of the barrel solution Medium to very large size	400,000 bpd HCU + FCC SDA + DCU	200,000 bpd FCC SDA	300,000 bpd HCU + FCC SDA + IGCC
Power integrated bottom of the barrel solution Medium to very large size	400,000 bpd HCU + FCC SDA + IGCC	-	-

Figure 39 to Figure 44 report the simplified block flow diagrams for the different cases considered in the high level definition of refinery schemes. It is intended that the reader can find in these samples the preliminarily expected configuration of the refinery schemes without the tuning/optimization resulted from the following detailed modelling activities. In particular:

- The necessity of the Light Naphtha Isomerisation (ISO) unit has been evaluated in each refinery scheme, looking at technical reasons and, where applicable, at economic convenience (based on gross pay out time). For instance, the isomerization unit may not be necessary if the octane number in the blended gasoline is high enough (e.g. by considering the octane booster effect of other additives like ethanol).
- With reference to the Kerosene treating units, a high-level gross pay-out calculation has been envisaged in order to choose between a Kerosene Hydrotreating and a Kerosene Sweetening unit, when only one of these units is needed for process reasons.
- The Visbreaker unit may be necessary to reduce the viscosity of vacuum residue before being sold as fuel oil.

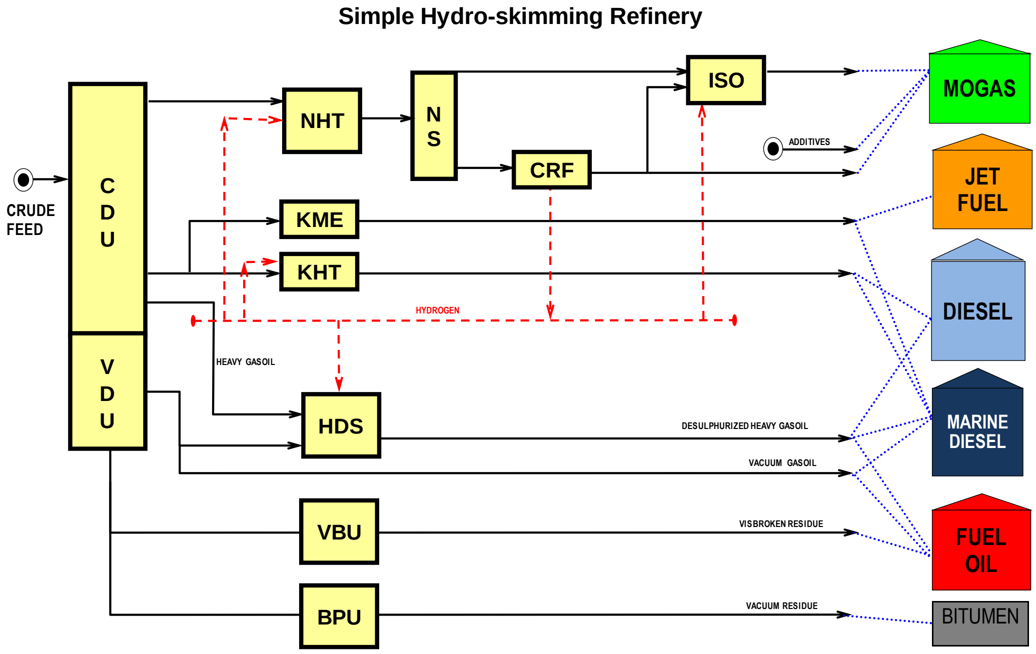


Figure 39: Simplified block flow diagram for Hydroskimming refinery

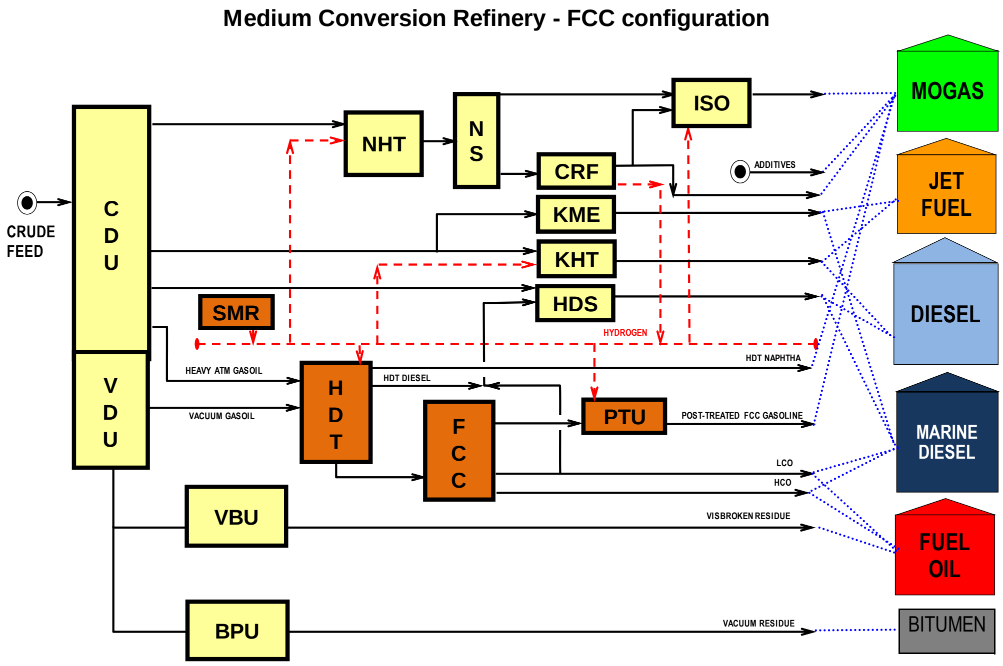


Figure 40: Simplified block flow diagram for Medium Conversion refinery with FCC unit

Medium Conversion Refinery - HCU configuration

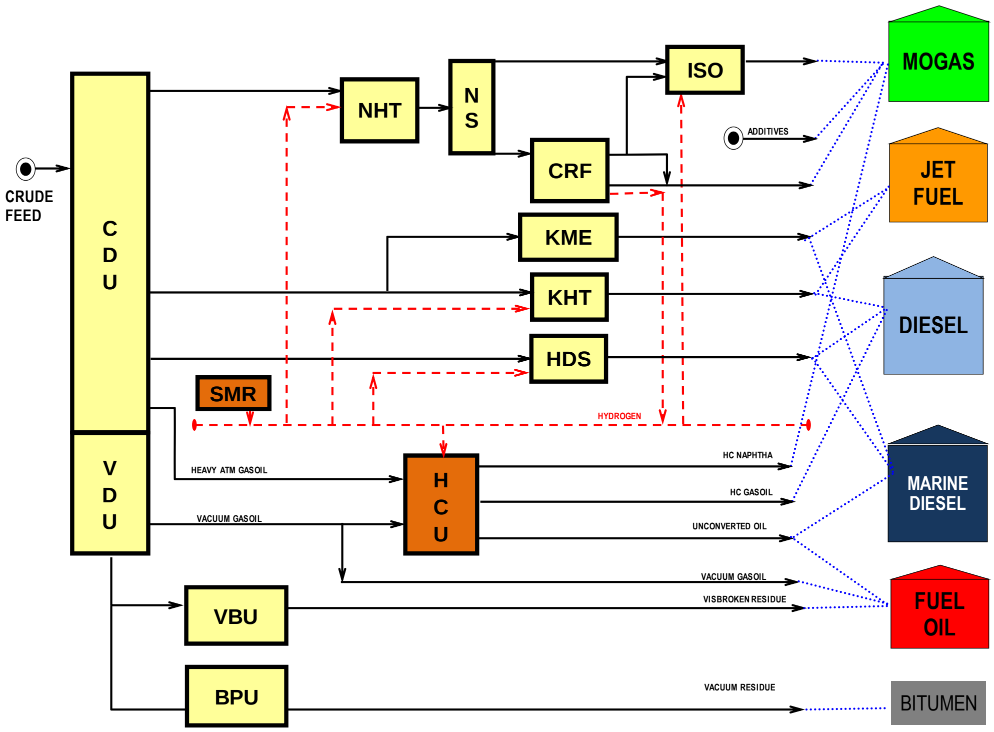


Figure 41: Simplified block flow diagram for Medium Conversion refinery with HCU

Medium Conversion Refinery - HCU + FCC configuration

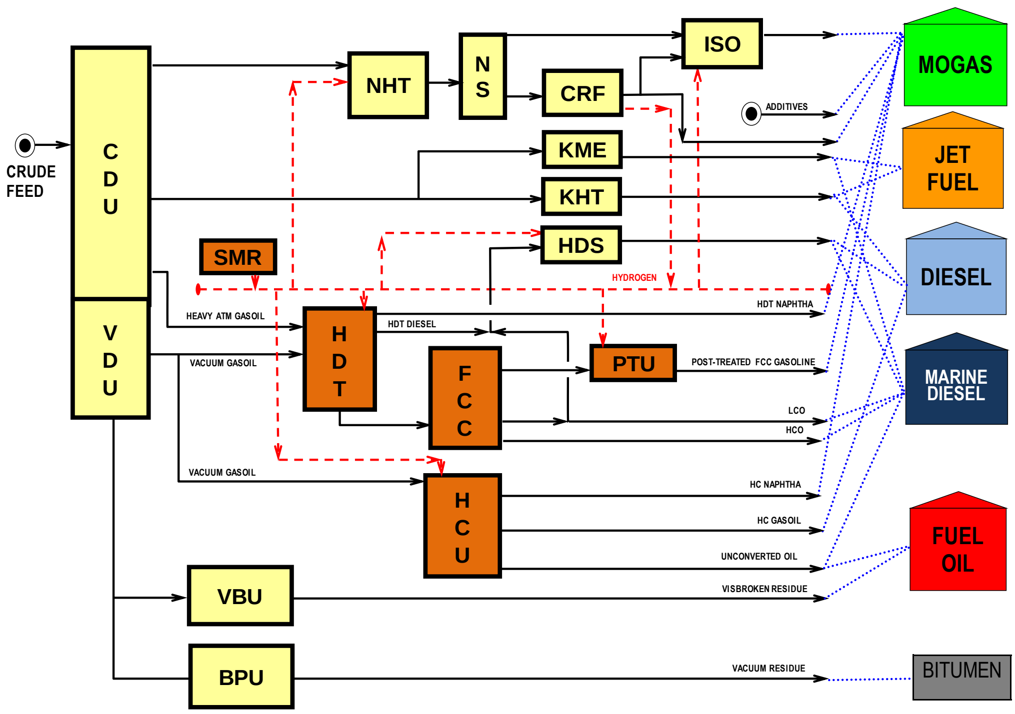


Figure 42: Simplified block flow diagram for Medium Conversion refinery with FCC and HCU

High Conversion Refinery - HCU + SDA + DCU Configuration

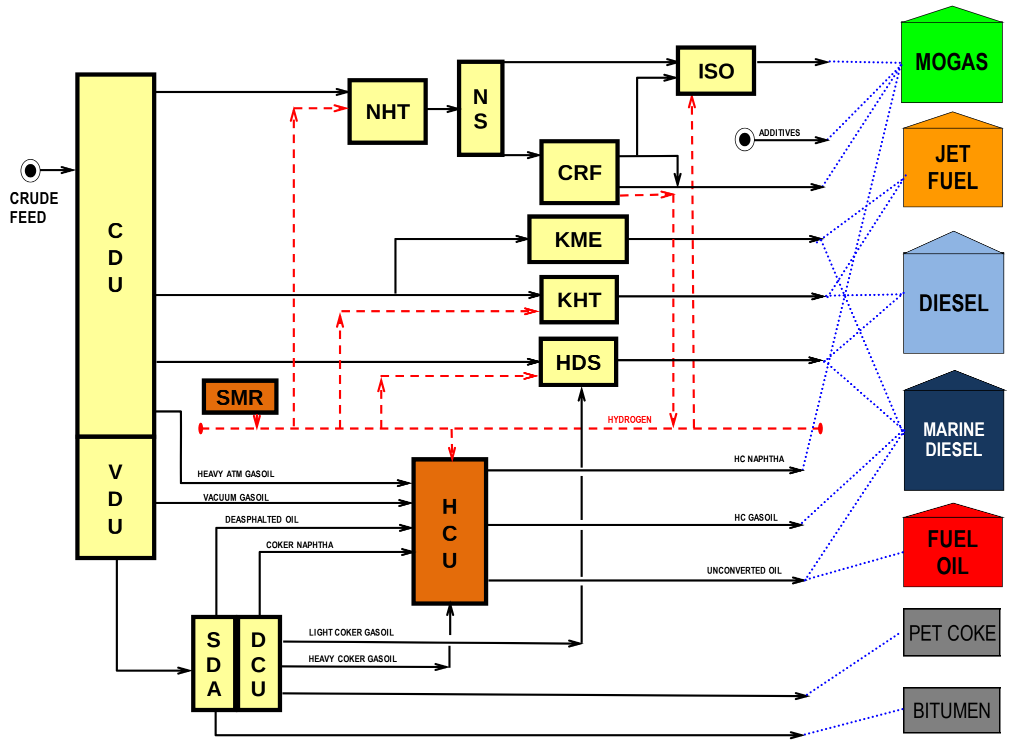


Figure 43: Simplified block flow diagram for High Conversion refinery with SDA+DCU

High Conversion Refinery - HCU + SDA + IGCC Configuration

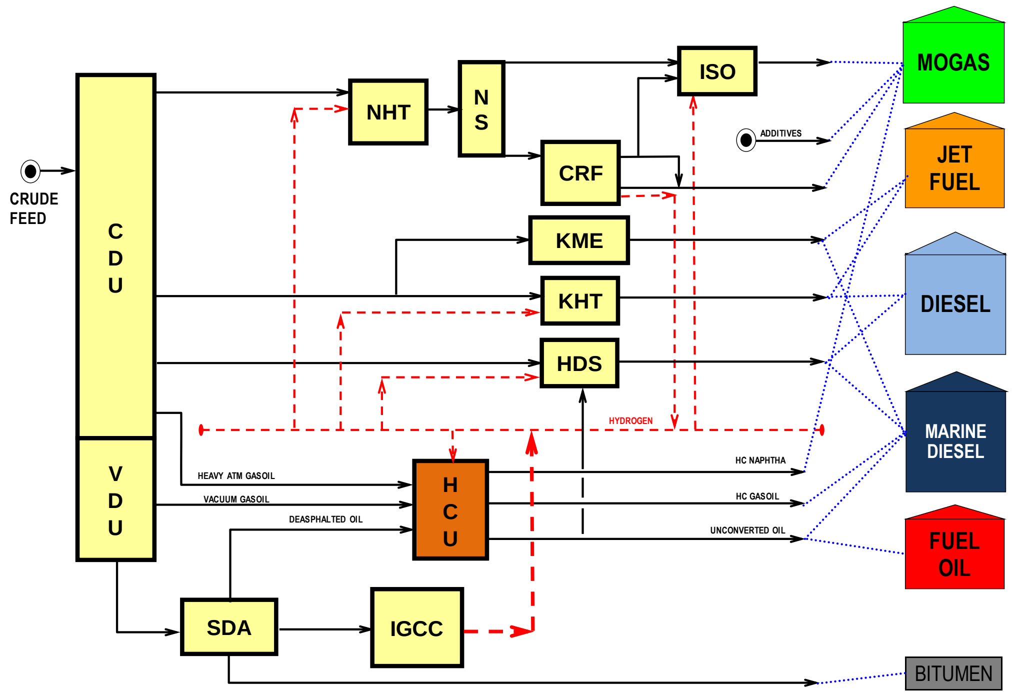


Figure 44: Simplified block flow diagram for High Conversion refinery with SDA+IGCC

3.2 Refinery balances - methodology and general assumptions

Refinery balances have been obtained by means of a Linear Programming (LP) technique, making use of typical refinery units' performances from a Wood in-house database.

The methodology normally used for refinery configuration studies has been adopted, trying however to:

- remove all the site-specific constraints coming from Wood's past projects;
- obtain generic but realistic balances, with the level of accuracy needed for the purposes of this Study.
- Haverly Systems GRTMPS software (v. 5.0) has been used to build the refinery LP models.

Linear programming (LP) is an optimisation technique widely used in petroleum refineries.

LP models of refineries are used for capital investment decisions, the evaluation of term contracts for crude oil, spot crude oil purchases, production planning and scheduling, and supply chain optimisation.

For each process unit, typical yields' structure, products' qualities and specific utility consumptions have been input, based on the Wood in-house database.

In particular, as far as the primary distillation units are concerned (i.e. Crude Atmospheric and Vacuum Units), some process simulation models have been run in order to evaluate the distillates' yields and main qualities, as previously described at section 1.3.

The models have been run based on:

- the typical (average) crude diets defined in Task 1 for each Country,
- products' specifications defined in Task 2,
- the sets of crude, natural gas and products' prices defined in Task 1 and Task 2,
- typical (average) units' sizes and utilization factors,
- reasonable products' slates and market volumes as defined in Task 2.

Moreover, in the LP models, an internal production of power and steam to satisfy the refinery needs has been considered.
In the following sections, more details are provided to describe the main input data and constraints of the linear programming models.
This section includes the sets of data and assumptions, common to all the cases, used to build the refinery LP models.

3.2.1 *On-stream Factor*

350 operating days per year have been used in the LP projections to develop the overall material balances of the refineries, reflecting an average of:

- 1 week shutdown per year for unplanned shutdowns/catalyst replacements/minor repairs, plus
- 4 weeks general planned turnaround every 4 years for maintenance/major repairs.

3.2.2 *Typical Utilization Factors*

Starting from the operating capacity resulting from the LP model runs, the design capacities of the various process units (were then used to determine the relevant CAPEX) have been defined by assuming typical -average- utilization factors for each process.

As a matter of fact, the process units resulting from LP model activities represent the average yearly operation of the new clean refinery, while, during a year there could be some "peak operations" (e.g. processing pure crudes instead of blends) which will require extra available capacity in some processes. The presence of some intermediate storage tanks would contribute in reducing the capacity margins needed to smooth the operation peaks.

Average utilization factors (i.e. the ratio between the average operating capacity and the design capacity) for the process units have been considered in the range 0.65-1.

In particular, CDU has been considered fully utilized in all schemes (utilization factor 1), since all the refineries tend to maximize the crude processing capacity to maximize their profit.

"Black" units, i.e. the units that are treating heavy feedstocks with a tendency to fouling/coking, need to be put out of service more frequently than the other units, for planned/unplanned shutdowns. Therefore, their utilization factor has been set to approximately 0.7.

The Sulphur Recovery Units and the Hydrogen Production Units have a wide overdesign in order to make them able to manage possible peaks in sulphur treatment and hydrogen demand from other refinery units, respectively. Therefore, their utilization factor has been set to approximately 0.65-0.75.

Other treating/conversion units have utilization factors in the range 0.85-0.9.

3.2.3 Primary Distillation units

Some process simulations have been run to determine the achievable rates/qualities of the distillates from the primary fractionation units (i.e. CDU/VDU), to account for fractionation inefficiency and technological limits in these units.

This activity, which has been described in more detail in Section 1.3, leads to a significant improvement of the accuracy of the overall refinery balances.

3.2.4 Hydrogen network

Hydrogen demand from refinery units is assumed to be internally saturated. The produced hydrogen is high purity, with the following typical specification:

- H_2 purity: 99.9% vol.
- $CO+CO_2$: 20 ppmv. max.
- CH_4+ inert (Ar or He or N_2): balance.

If the hydrogen from the Heavy Naphtha Catalytic Reformer is not enough to cover the overall hydrogen demand of the refinery, a Steam Methane Reformer (SMR) is foreseen to close the hydrogen balance.

In the cases with IGCC in the scheme, hydrogen is supplied to the refinery from IGCC.

Hydrogen balances have been developed by considering the units' specific hydrogen demands reported in Table 25.

The following notes apply:

- Specific consumptions are dependent on feed quality;
- Specific consumptions include chemical consumptions, solution losses and mechanical losses.

The hydrogen balances are reported in the block flow diagrams developed for each case.

Table 25: Specific hydrogen consumptions of process units

Unit		Feed	H_2 consumption (wt% on feed)
NHT	Naphtha Hydrotreater	Straight-run Naphtha	0.12
		VB Naphtha/Coker Naphtha	0.15
ISO	Isomerization	Hydrotreated Light Naphtha	0.085
KHT	Kero HDS	Straight-run Kerosene	0.2

HDS	Gasoil HDS	Straight-run Light Gasoil	0.7
		VB Gasoil	0.8
		Light Coker Gasoil	0.8
		Light Cycle Oil	0.8
		Heavy Cracked Naphtha	0.25
VHT	Vacuum Gasoil Hydrotreater	Straight-run Heavy Gasoil	1.2
		Light Vacuum Gasoil	1.2
		Heavy Vacuum Gasoil	1.5
		Heavy Coker Gasoil	1.5
		Deasphalted OIl	1.57
HCK	Vacuum Gasoil Hydrocracker	Straight-run Heavy Gasoil	2.0
		Light Vacuum Gasoil	2.0
		Heavy Vacuum Gasoil	2.9
		Heavy Coker Gasoil	4.0

3.2.5 *Sulphur Recovery*

The H_2S produced in the desulphurization units are recovered by means of an Amine Washing and Regeneration Unit (ARU) and a Sour Water Stripper (SWS). The acid gases recovered from the top of Amine Regenerator and the Sour gases from the top of the SWS column are then sent to a Sulphur Recovery Unit. An overall sulphur recovery of 99.5% has been considered, assuming that a Tail Gas Treatment section is installed downstream the SRU Claus section.

3.2.6 *Utility Conditions*

In the LP models, the utility conditions have been considered as per the following table.

Table 26: Utilities Design Data

Utility	Pressure (barg)		Temperature (°C)	
	Operating	**Design**	**Operating**	**Design**
HP Steam	48	54 / FV	380	425
MP Steam	17.5	20 / FV	280	330
LP Steam	7	10 / FV	180	250
HP Condensate	18.5	54 / FV	210	425
MP Condensate	8	20 / FV	170	330
LP Condensate	1.5	10 / FV	130	250
Cooling Water Supply	5	8	30	65
Cooling Water Return	3	8	40	65
Demi Water	5	9	ambient	65
Utility Water	5	9	ambient	65
Raw Water	5	10	ambient	65
Fire Water	13	16	ambient	65
Potable Water	5	9	ambient	65
Instrument Air	7	11	40	65

Plant Air	7	11	40	65
Nitrogen	6	10	AMB	65
Refinery Fuel Gas	3.0/4.0/5.5	7.0	10/40/45	130

The following main utility balances have been developed for each case:

- Fuel Gas
- Fuel Oil
- Electric Power
- Steam (High Pressure (HPS), Medium Pressure (MPS), Low Pressure (LPS))
- Cooling Water

The specific utility consumptions of the main process units have been retrieved from Wood in-house database, which has been populated with data of past Projects. Reference is made to Figure 27; negative values indicate specific utility productions, for those units that could export to the refinery headers the surplus of utilities (typically, steam) internally generated. On top of the demand of the main process units, a refinery base load of power and steam is considered, to take into account all the remaining users (e.g. minor process units, utility and offsite units, buildings, etc.). Refinery base load is different for the various cases, depending on the size/complexity of the refinery.

Table 27: Specific utility consumptions for main process units

SELECTED SPECIFIC CONSUMPTIONS

FOR LP MODELS

		Capacity expressed as	EL. POWER Rated kWh/unit	FIRED FUEL Gcal/unit	COOLING W. Flow m3/unit	COOLING W. DT °C	LPS t/unit	MPS t/unit	HPS t/unit
PROCESS UNITS									
CDU	Crude Distillation Unit	t feed	5.8	0.128	1.2	10	0.065	0.018	0.004
SGP	Saturated Gas Plant		included in CDU						
NHT	Naphtha HDT	t feed	3.6	0.033	2.2	10	-0.006	0.000	0.110
NS	Naphtha Splitter	t feed	2.7	0.040	0.2	10	0.000	0.000	0.000
ISO	Isomerization	t feed	19.8	0.000	2.2	10	0.500	0.069	0.257
CRF	Catalytic Reforming	t feed	33.5	0.561	10.3	10	0.000	0.000	-0.134
KME	Kero Sweetening Unit	t feed	1.0	0.000	0.0	10	0.000	0.000	0.000
KHT	Kero HDS	t feed	6.1	0.034	2.8	10	0.000	0.059	0.000
HDS	Gasoil HDS	t feed	13.2	0.093	1.3	10	0.000	0.018	0.000
VGO HDT	VGO Hydrotreating	t feed	34.9	0.124	0.03	10	0.021	0.020	0.000
HCU	HP Hydrocracking	t feed	68.6	0.214	0.9	10	-0.096	0.000	0.000
FCC	Fluid Catalytic Cracking	t feed	5.0	0.376	48.3	10	0.000	0.133	0.085
VDU	Vacuum Distillation Unit	t feed	4.7	0.059	10.9	10	0.016	0.063	0.000
SMR	Steam Reforming & PSA	t feed	75.8	2.689	11.6	10	0.000	0.000	-3.032
SDA	Solvent Deasphalting	t feed	20.5	0.225	0.2	10	0.000	0.081	0.000
DCU	Delayed Coking	t feed	0.0	0.000	0.0	10	0.000	-0.044	0.040
BPU	Bitumen Production Unit	t feed	0.0	0.032	0.0	10	0.025	-0.099	0.000
VBU	Visbreaker Unit	t feed	4.7	0.059	10.9	10	0.016	0.063	0.000
AUXILIARY UNITS									
ARU	Amine Washing and Regeneration	t feed (H2S)	7.458	0.000	1.1	10	0.532	0.000	0.000
SWS	Sour Water Stripper		included in BASE LOAD						
SRU	Sulphur Recovery Unit	t feed (H2S)	5.364	0.036	3.5	10	0.000	-0.140	0.000
TGT	Tail Gas Treatment		included in SRU						
WWT	Waste Water Treatment		included in BASE LOAD						
UTILITY UNITS									
			included in BASE LOAD						
OFF-SITES									
			included in BASE LOAD						

Table 28: Refinery base loads of power and steam

Size	India	Nigeria	Brazil
Power integrated simple Hydro-skimming refinery Low to medium size		EL. POWER: 13.5 MW LPS: 18 t/h MPS: 18 t/h HPS: 9 t/h	
Power integrated Medium conversion refinery Medium to Large – Size 1	EL. POWER: 22.5 MW LPS: 30 t/h MPS: 30 t/h HPS: 15 t/h	EL. POWER: 18 MW LPS: 24 t/h MPS: 24 t/h HPS: 12 t/h	EL. POWER: 13.5 MW LPS: 18 t/h MPS: 18 t/h HPS: 9 t/h
Power integrated Medium conversion refinery Medium to Large – Size 2			EL. POWER: 22.5 MW LPS: 30 t/h MPS: 30 t/h HPS: 15 t/h
Power integrated bottom of the barrel solution Medium to very large size	EL. POWER: 30 MW LPS: 40 t/h MPS: 40 t/h HPS: 20 t/h	EL. POWER: 18 MW LPS: 24 t/h MPS: 24 t/h HPS: 12 t/h	EL. POWER: 22.5 MW LPS: 30 t/h MPS: 30 t/h HPS: 15 t/h
Power integrated bottom of the barrel solution Medium to very large size	EL. POWER: 30 MW LPS: 40 t/h MPS: 40 t/h HPS: 20 t/h		

3.2.7 Refinery Fuel Balance

The refinery fuel balance accounts for both fuel gas and fuel oil.

The off-gases produced in the various process units, after removal of H_2S in amine absorbers (to achieve a residual H_2S content of 50 ppm vol. max.), are collected into a Refinery Fuel Gas system to constitute the primary fuel of the refinery. Imported natural gas is mixed with refinery off-gases to saturate the fuel demand.

All the refinery heaters are 100% fuel gas fired in order to cope with the stringent requirements imposed by the Best Available Technologies (BAT) in terms of air emission limits. Indeed, according to the BAT the flue gases from the various fired heaters must contain less than 35 mg SO_x/Nm^3 in line with the concept of "Clean refinery". The refinery heaters (fuel gas fired) do not require flue gas desulphurization systems.

Low Sulphur Fuel Oil with 0.5% wt. Sulphur content has a degree of flexibility in supplying local market and/or in being sent to the refinery power plant for steam and electric energy generation.

High Sulphur Fuel Oil with 3.5% wt. Sulphur content, when produced, is entirely burnt in the refinery steam boiler(s) for production of steam production electricity in a steam turbine.

The choice of limiting the fuel oil in the power plant means that the Flue Gas Desulphurization is foreseen only in the Boiler.

Upstream of the FCC, a Vacuum Gasoil Hydrotreating (VHT) unit is present to decrease the sulphur content of FCC feedstock, in order to respect SO_x limits at FCC stack.

3.2.8 Modelling of Steam/Power Cogeneration Plant

For the cogeneration power plant satisfying refinery demands and exporting electric power to the external network, the balance is based on the available feedstock from the refinery and on the refinery steam requirements at different steam levels. It is obtained by applying reasonable efficiency figures to the boiler and the condensation steam turbine, taken from the Wood data base on similar power plants.

The power and steam generation cycle is modelled as boiler(s) producing very high pressure steam (HHPS at 170 barg, 550°C). Part of steam produced is expanded into the backpressure steam turbine with extractions at 48 barg, 17.5 barg and 7 barg to allow the production of HPS, MPS and LPS that are exported to the refinery complex. The remaining portion of HHPS is admitted to condensation steam turbine(s) for power generation.

The simplified configuration of the power plant is shown in Figure 45:

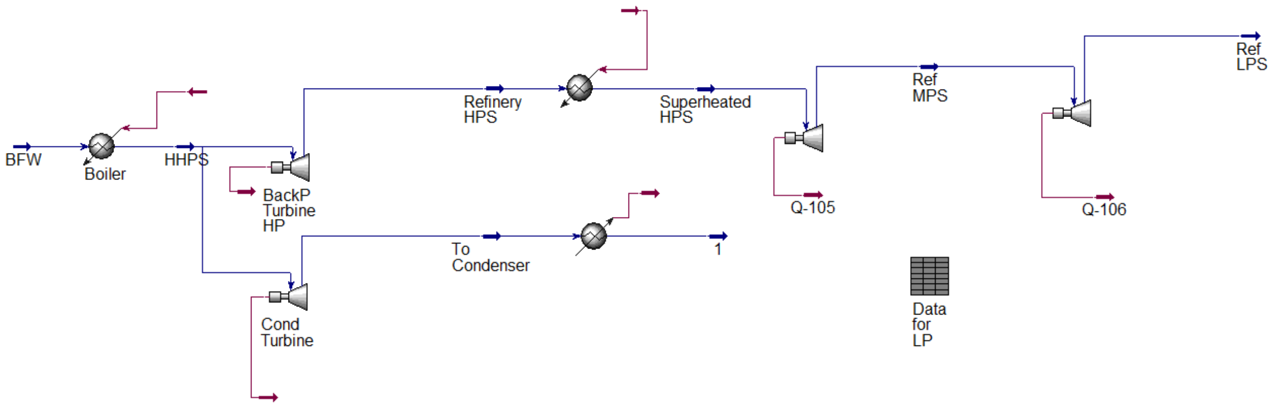


Figure 45: Simplified Power Plant configuration considered in the LP models

Depending on the type of fuel, different boiler efficiencies have been considered:

- Boiler fed with fuel oil: 92%
- Boiler fed petcoke: 90.5 %
- Boiler fed with pitch coming from SDA unit: 90.5 %

It has to be remarked that direct combustion of asphalt (pitch) in the conventional boiler island would be possible only through the solidification of the pitch, which is an unusual technology, or blending the asphalt with lighter products to reduce the viscosity, which would however result in some distillate losses.

Part of the electric power and steam produced in the cycle is internally consumed in the Power Plant. In the LP models, the net exports have been considered.

3.2.9 Modelling of Gasification Plant

Figure 46 shows the simplified block flow diagram of the Gasification Plant.

IGCC cogeneration plants produce hydrogen, electric power and steam for the refinery, as well as electric power exported to the grid.

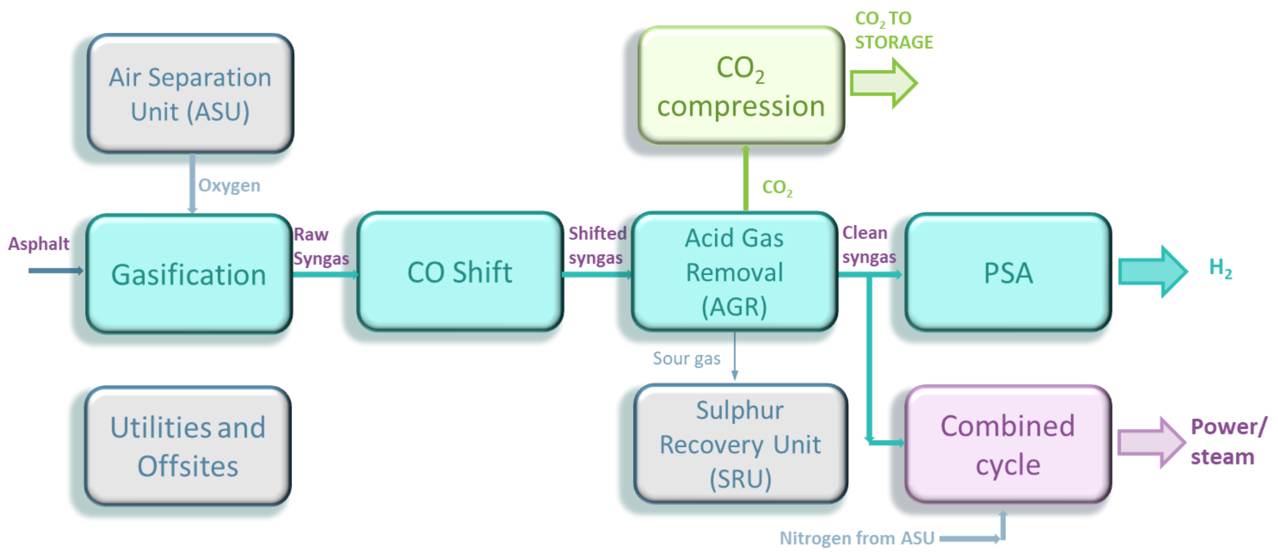


Figure 46: Simplified Block Flow Diagram for Gasification Complex

Due to the complexity of the scheme, the preparation of the balance requires more steps which shall be integrated to obtain a coherent balance of the whole plant:

- Firstly the balance of the gasification unit is prepared based on Wood in house data on the gasification technology adopted (in this case a quench type technology). This balance determines the syngas flowrate and composition, as well as the gasification oxygen demand and the associated Air Separation Unit capacity.
- Then the syngas treatment process units are simulated by the Hysys program.
- Part of the treated syngas is available for producing the hydrogen necessary to the refinery.
- The remaining and major part of the treated syngas is available to feed the Combined Cycle of the IGCC for producing the steam and electric power necessary for the refinery and the electric power exported to the external grid. The gas turbine balance is derived from a Wood in-house data base on different gas turbine models. The steam cycle of the Combined cycle is simulated by the Gatecycle program.

In all the cases the emissions of the boilers and gas turbines are in line with the last BAT limits.

3.2.10 Modelling of CO2 Capture Systems

Post-combustion CO_2 capture, based on proprietary formulated proprietary amine solvent, has been considered for the flue gases from CDU and VDU heaters, as well as from the Steam boiler(s) of the power plant.

In the power plants, the flue gas from the Flue Gas Desulphurisation section (FGD) is sent to the pre-scrubber of the CO_2 removal section. The purpose of the pre-scrubber is to cool down the flue gas to improve absorption efficiency and to further reduce the SO_x in the flue gas by adding caustic to the wash water, to minimize solvent degradation.

Cooled flue gases are sent to the CO_2 absorber, where CO_2 is absorbed by counter-current contact with lean amine. Decarbonized flue gases are discharged into the atmosphere from the top of the absorber, prior to being washed to reduce amine slip in the flue gas. A gas-gas heater used against the flue gas upstream of the FGD can be installed to heat the gas above the dew point and reduce the stack discharge height. The CO_2 absorber is equipped with intercooling stages to remove absorption heat and improve removal efficiency.

The rich solvent from the bottom of the absorber is pumped to the regenerator, where it is regenerated with low pressure steam. The water saturated CO_2 stream from the regenerator overhead condenser is sent to the compression and dehydration section, prior to being sent to plant's battery limit Lean solvent is recirculated back to the absorber.

Reclaiming section and amine storage tank are also included in the CO_2 capture unit.

CO_2 capture requires a significant amount of low pressure steam to be sent to the regenerator reboiler, and cooling water to the absorber intercooler and regenerator overhead condenser. Due to confidentiality issues, specific consumption figures cannot be disclosed in a public report. Reference can be made to previous IEAGHG Report 2018/04 and Report 2014/03 for the overall consumption of the CO_2 capture and compression units evaluated at different ambient and site conditions.

Post-combustion CO_2 capture efficiency has been assumed to be 90%. Specific energy consumptions (per ton of CO_2) have been taken into account from a Wood in-house project database.

For the Steam Methane Reformer (SMR), pre combustion CO_2 Capture from syngas has been assumed to reach a removal efficiency of 98%. In this case, the SMR balances with CO_2 capture have been produced by considering the results of a previous study made by WOOD (former Amec Foster Wheeler) in collaboration with IEAGHG – Ref. IEA Technical Review 2017-TR3 "Reference Data and Supporting Literature Reviews for SMR Based Hydrogen Production with CCS".

For pre combustion CO_2 capture in the Acid Gas Removal (AGR) unit of gasification plants (see Figure 46), the balance has been prepared starting from Wood in-house data on similar AGR units in previous Wood projects. The resulting CO_2 pre combustion efficiency is equal to 90%.

The following CO_2 concentrations and conditions are considered to be representative of the typical gases sent to the CO_2 capture units from the selected sources:

- IGCC syngas to CO_2 capture: CO_2 concentration approximately 35-40% vol, temperature 40-45°C, pressure 35-40 barg for medium pressure gasification (as the one considered in this study) or 60-65 barg for high pressure gasification
- Steam Reformer (SMR) syngas to CO_2 capture: CO_2 concentration approximately 20% volume, temperature 40-45°C, pressure 23-27 barg
- Power Plant (Petcoke fired) Flue gas to CO_2 capture: CO_2 concentration approx. 16-18% volume, temperature 140-160°C, close to atmospheric pressure
- Power Plant (FO fired) Flue gas to CO_2 capture: CO_2 concentration approximately 11% volume, temperature 130-140°C, close to atmospheric pressure
- CDU/VDU flue gases to CO_2 capture: CO_2 concentration approximately 8% volume, temperature 200-220°C, close to atmospheric pressure

3.3 Task 3 – Indian Refinery Balances

As already presented in Section 3.1, three different refinery configurations have been investigated:

- INDIA – Medium conversion Refinery
  - Capacity: 250,000 BPSD
  - Configuration with Hydrocracking Unit
- INDIA - High conversion Refinery – Scheme 1:
  - Capacity: 400,000 BPSD
  - Configuration with Hydrocracking and FCC Unit
  - Bottom of the barrel solution: SDA + gasification
- INDIA - High conversion Refinery – Scheme 2:
  - Capacity: 400,000 BPSD
  - Configuration with Hydrocracking and FCC Unit
  - Bottom of the barrel solution: SDA + DCU + Boiler power plant

In this section the main results of the three refinery configurations have been presented. In particular, the overall material balance, the simplified block flow diagram and the overall utilities consumption are hereafter attached.

A detailed comparison between the different refinery configurations is included in Section 5 of this report.

For each case, product qualities summary tables are enclosed in Attachment 6.2.

3.3.1 *Tuning of the configurations based on LP Models*

For the three Indian refinery schemes, the main outcomes of the LP modelling activities are listed below:

- The Isomerization Unit is confirmed. The limitation on the ethanol content to 5 %wt implies that a unit able to increase the octane number is mandatory.
- Both KERO Sweetening and KERO Hydrotreater have been considered in the medium conversion refinery:
  - Kerosene produced in the Sweetening Unit presents a sulphur content too high to allow its blending in diesel. It is possible to route this product only to Marine Diesel and Jet Fuel (both these products present a limitation on the quantities that can be produced);
  - KERO HDT, due to the desulphurization achieved, this product can be blended in diesel.
- The Visbreaker unit inclusion is confirmed to reduce fuel oil viscosity and to achieve limited conversion into distillates.

3.3.2 INDIA – Medium conversion refinery

Table 29: Overall Material Balance – Medium Conversion Refinery - INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
Medium Conversion Refinery - 250,000 BPSD
Rev.0 - January 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, $/t	Sales, kt/y	Annual Revenues, 10^6 $/y
LPG Product	583	255.3	148.8
Unl. Premium (95) INDIA	758	1790	1356.6
Unl. Premium (91) INDIA	750	767	575.3
Jet Fuel A1	779	1200	934.8
Diesel	734	3298	2420.5
Marine Diesel	700	1099	769.4
Low Sulphur Fuel	433	516	223.4
Medium Sulphur Fuel	406	0	0
High Sulphur Fuel	351	0	0
Bitumen	346	400	138.4
Sulphur	39	64.4	2.5
	Subtotal	**9389.2**	**6569.7**
RAW MATERIALS	Material Cost, $/t	Purchases, kt/y	Cost, 10^6 $/y
Ekofisk	603	2959.3	1783.0
Arab. Light	499	7694.3	3842.5
Maya (pure)	534	1183.7	631.8
Purchased MTBE	1100	98.1	107.9
Ethanol	450	92.8	41.8
Purchased Natural Gas	529	171.4	90.7
	Subtotal	**12199.8**	**6497.7**
POWER PLANT	Material Cost, $/unit	Consumptions, unit/y	Cost, 10^6 $/y
High Sulphur Fuel Oil to Power Plant (kt/y)		2401.0	
Electrical Power exported to refinery (kWh/y)	-	5.58E+08	
Electrical Power sold on the market (kWh/y)	0.07	9.44E+09	660.7
	Subtotal	**-**	**660.7**
		kt/y	
Fuels and Losses		**2810.6**	
Gross Margin, 10^6 $/Y		**732.7**	

Table 30: Process Units and Operating Capacity – Medium Conversion Refinery - INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
Medium Conversion Refinery - 250,000 BPSD
Rev.0 - January 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	250000	250000	100%
Vacuum Distillation Unit	BPSD	115000 (1)	90662	79%
Naphtha Hydrotreater	BPSD	60000	55169	92%
Light Naphtha Isomerization	BPSD	26000	23094	89%
Heavy Naphtha Catalytic Reforming	BPSD	47000	42292	90%
Kero Merox	BPSD	31000	27650	89%
Kerosene Hydrotreater	BPSD	11000	9557	87%
Diesel Hydrotreater	BPSD	43000	38828	90%
Hydrocracker	BPSD	40000	35230	88%
Visbreaker	BPSD	50000	37852	76%
Bitumen Oxidation	t/d	1300	1143	88%
Sulphur Recovery Unit	t/d Sulphur	270 (2)	184	68%
Steam Reformer	Nm^3/h Hydrogen	35000	25106	72%

Notes

1) VDU design capacity set to manage the operation with Maya Blend
2) Three Claus trains in parallel.

Table 31: Main Utilities Balance – Medium Conversion Refinery - INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
Medium Conversion Refinery - 250,000 BPSD
Rev.0 - January 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	POWER MW	HP STEAM tons/h	MP STEAM tons/h	LP STEAM tons/h	COOLING WATER (2) m3/h
MAIN PROCESS UNITS	454.2	41.6	14.3	86	141	13483
BASE LOAD		22.5	15	30	30	
POWER PLANT	2797	-1222.3	-29	-116	-171	187824
COOLING WATER SYSTEM (REF)		2.3				-13483
COOLING WATER SYSTEM (PP)		32.2				-187824
TOTAL	**3251**	**-1124**	**0**	**0**	**0**	**0**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	17.5	147.3	5%
NATURAL GAS to fuel system	20.4	171.4	6%
HIGH SULPHUR FUEL OIL (3)	285.8	2401.0	88%
TOTAL	**323.8**	**2719.8**	

CO2 EMISSIONS

	t/h			
From Steam Reformer (feed only)	20.1			
From FG/NG combustion (CDU/VDU furnaces)	48.4			
From FG/NG combustion (other sources)	54.3			
From HSFO combustion	914.7			
TOTAL	**1037.5**	*corresponding to*	***8714.7***	*kt/y*
			736.2	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) HSFO is burnt in power plant

Clean refinery and the role of electricity generation

INDIA - Medium Conversion Refinery - 250,000 BPSD

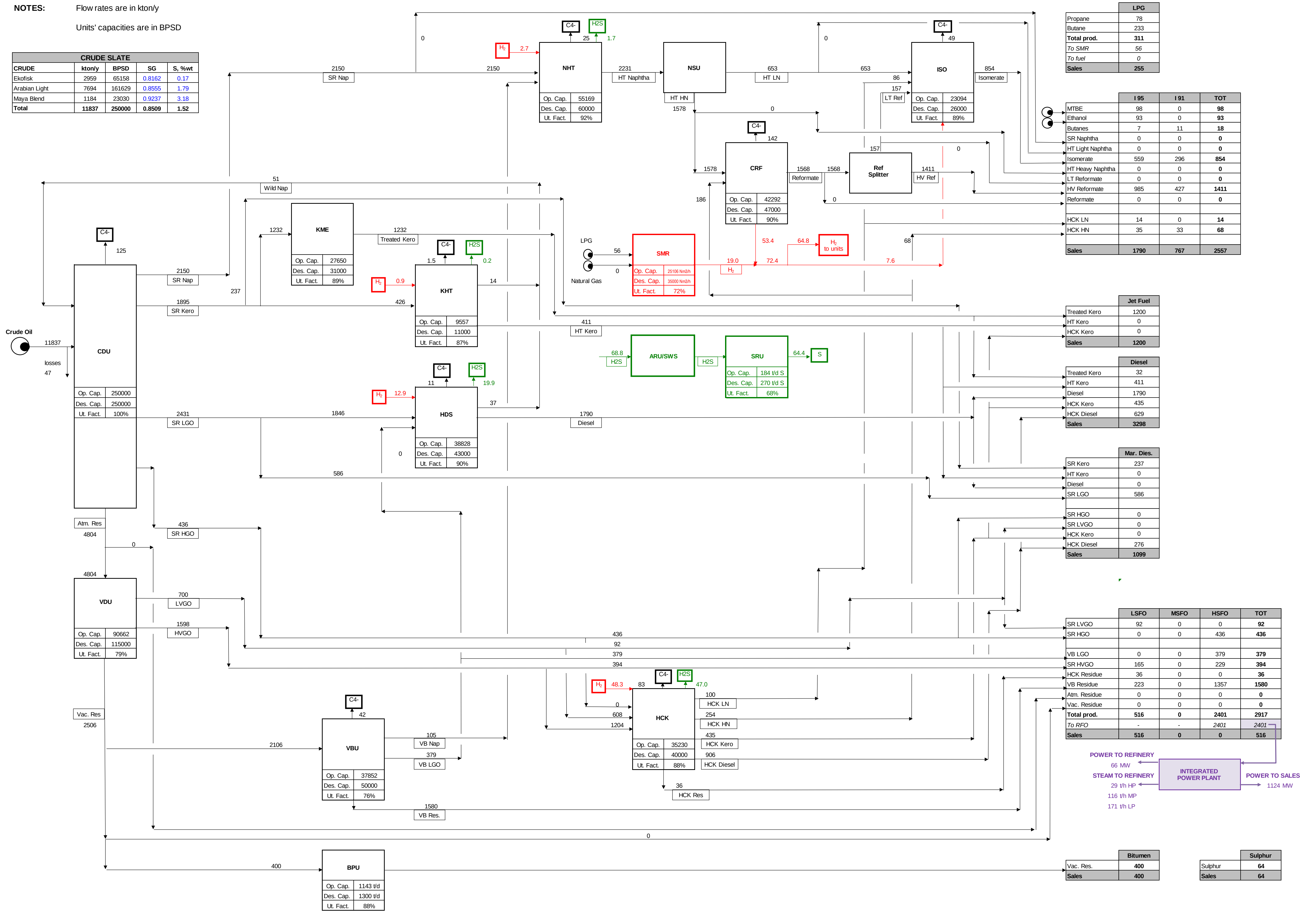
Rev. 1 - December 2019

BLOCK FLOW DIAGRAM

NOTES: Flow rates are in kton/y

Units' capacities are in BPSD

CRUDE SLATE				
CRUDE	kton/y	BPSD	SG	S, %wt
Ekofisk	2959	65158	0.8162	0.17
Arabian Light	7694	161629	0.8555	1.79
Maya Blend	1184	23030	0.9237	3.18
Total	**11837**	**250000**	**0.8509**	**1.52**



	LPG
Propane	78
Butane	233
Total prod.	311
To SMR	*56*
To fuel	*0*
Sales	255

	I 95	I 91	TOT
MTBE	98	0	98
Ethanol	93	0	93
Butanes	7	11	18
SR Naphtha	0	0	0
HT Light Naphtha	0	0	0
Isomerate	559	296	854
HT Heavy Naphtha	0	0	0
LT Reformate	0	0	0
HV Reformate	985	427	1411
Reformate	0	0	0
HCK LN	14	0	14
HCK HN	35	33	68
Sales	1790	767	2557

	Jet Fuel
Treated Kero	1200
HT Kero	0
HCK Kero	0
Sales	1200

	Diesel
Treated Kero	32
HT Kero	411
Diesel	1790
HCK Kero	435
HCK Diesel	629
Sales	3298

	Mar. Dies.
SR Kero	237
HT Kero	0
Diesel	0
SR LGO	586
SR HGO	0
SR LVGO	0
HCK Kero	0
HCK Diesel	276
Sales	1099

	LSFO	MSFO	HSFO	TOT
SR LVGO	92	0	0	92
SR HGO	0	0	436	436
VB LGO	0	0	379	379
SR HVGO	165	0	229	394
HCK Residue	36	0	0	36
VB Residue	223	0	1357	1580
Atm. Residue	0	0	0	0
Vac. Residue	0	0	0	0
Total prod.	516	0	2401	2917
To RFO	-	-	*2401*	*2401*
Sales	516	0	0	516

	Bitumen
Vac. Res.	400
Sales	400

	Sulphur
Sulphur	64
Sales	64

Figure 47: INDIA – Medium Conversion Refinery- Block flow diagram

3.3.3 INDIA – High conversion refinery – Scheme 1

Table 32: Overall Material Balance – High Conversion Refinery Scheme 1- INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
High Conversion Refinery #1 - 400,000 BPSD
Rev.1 - May 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, \$/t	Sales, kt/y	Annual Revenues, 10^6 \$/y
LPG Product	583	715.3	417.0
Unl. Premium (95) INDIA	758	3205	2429.3
Unl. Premium (91) INDIA	750	1374	1030.2
Jet Fuel A1	779	1900	1480.1
Diesel	734	6296	4621.5
Marine Diesel	700	2099	1469.1
Low Sulphur Fuel	433	344	148.7
Medium Sulphur Fuel	406	0	0
High Sulphur Fuel	351	0	0
Bitumen	346	400	138.4
Sulphur	39	270.7	10.6
Propylene	973	154.4	150.3
	Subtotal	**16757.5**	**11895.2**
RAW MATERIALS	Material Cost, \$/t	Purchases, kt/y	Cost, 10^6 \$/y
Ekofisk	603	4735.0	2852.8
Arab. Light	499	12310.9	6148.1
Maya (pure)	534	1894.0	1010.8
Purchased MTBE	1100	0.0	0.0
Ethanol	450	167.4	75.3
Purchased Natural Gas	529	229.2	121.2
	Subtotal	**19336.4**	**10208.2**
IGCC COMPLEX	Material Cost, \$/unit	Consumptions, unit/y	Cost, 10^6 \$/y
Pitch to Gasification Complex (kt/y)		1997.4	
Electrical Power exported to refinery (kWh/y)	-	1.11E+09	
Electrical Power sold on the market (kWh/y)	0.07	3.37E+09	236.0
	Subtotal	**-**	**236.0**
		kt/y	
Fuels and Losses		**2578.9**	
Gross Margin, 10^6 \$/Y		**1923.0**	

Table 33: Process Units and Operating Capacity– High Conversion Refinery Scheme 1- INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
High Conversion Refinery #1 - 400,000 BPSD
Rev.1 - May 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	400000 (2)	400000	100%
Vacuum Distillation Unit	BPSD	180000 (1)	145059	81%
Naphtha Hydrotreater	BPSD	95000 (2)	85523	90%
Light Naphtha Isomerization	BPSD	29000	26708	92%
Heavy Naphtha Catalytic Reforming	BPSD	75000 (2)	67391	90%
Kero Merox	BPSD	50000	42631	85%
Kerosene Hydrotreater	BPSD	16000	15393	96%
Diesel Hydrotreater	BPSD	91000 (2)	81897	90%
VGO Hydrotreater	BPSD	60000	52990	88%
Fluid Catalytic Cracker	BPSD	55000	47008	85%
FCC Gasoline Post-Treatment Unit	BPSD	21000	18120	86%
Hydrocracker	BPSD	60000	55000	92%
Solvent Deasphalting	BPSD	80000	72532	91%
IGCC Complex	t/d	7000	5707	82%
Sulphur Recovery Unit	t/d Sulphur	650 (3)	453	70%

Notes
1) VDU design capacity set to manage the operation with Maya Blend
2) Two units in parallel
3) Three Claus trains in parallel.

Table 34: Utility Balance– High Conversion Refinery Scheme 1- INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
High Conversion Refinery #1 - 400,000 BPSD
Rev.1 - May 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	POWER MW	HP STEAM tons/h	MP STEAM tons/h	LP STEAM tons/h	COOLING WATER (2) m3/h
MAIN PROCESS UNITS	932.9	86.8	65.6	199	205	32304
BASE LOAD		30.0	20	40	40	
POST-COMBUSTION CO2 CAPTURE		1.9	0.0	0.0	87.3	5695.5
IGCC COMPLEX (note 1)	2178	-526.6	-86	-239	-332	*80000*
COOLING WATER SYSTEM (REF)		6.6				-38000
TOTAL	**3111**	**-401**	**0**	**0**	**0**	**0**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	41.3	346.5	13%
NATURAL GAS to fuel system	27.3	229.2	9%
FCC Coke	11.4	95.3	4%
Pitch to IGCC (note 3)	237.8	1997.4	75%
TOTAL	**317.7**	**2668.5**	

CO2 EMISSIONS

	t/h			
From FG/NG combustion (CDU/VDU furnaces)	8.4			
From FG/NG/FCC coke combustion (other sources)	144.2			
From IGCC	74.7			
TOTAL	**227.2**	*corresponding to*	***1908.6***	*kt/y*
			100.8	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) Part of pitch fed to IGCC is converted to hydrogen and is not to be considered as "fuel"
4) 70000 m3/h as once-through sea cooling water + 10000 m3/h as closed loop cooling water

.

Clean refinery and the role of electricity generation

INDIA - High Conversion Refinery Scheme 1 - 400,000 BPSD

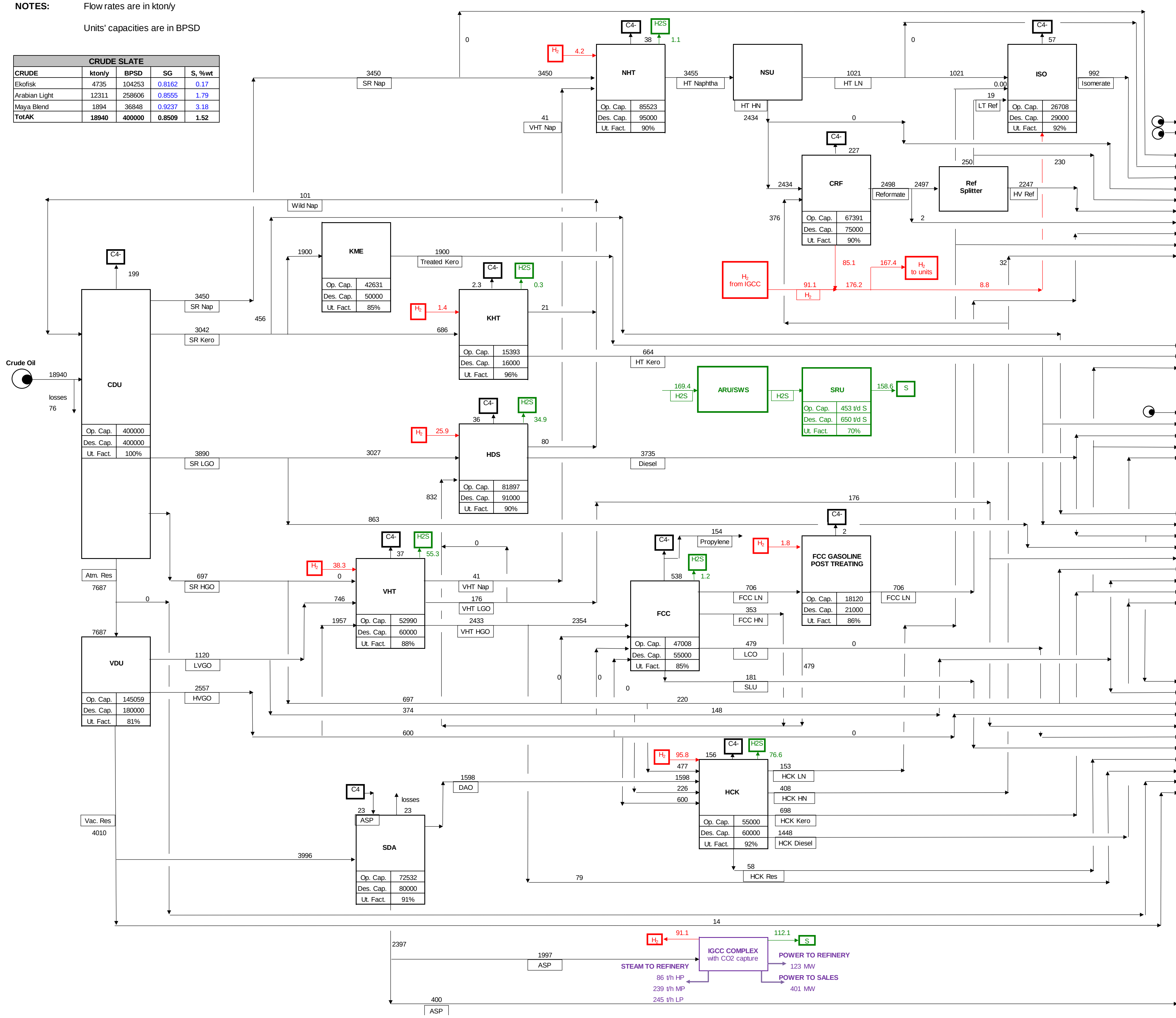
Rev. 1 - December 2019

BLOCK FLOW DIAGRAM

NOTES: Flow rates are in kton/y

Units' capacities are in BPSD

CRUDE SLATE				
CRUDE	**kton/y**	**BPSD**	**SG**	**S, %wt**
Ekofisk	4735	104253	0.8162	0.17
Arabian Light	12311	258606	0.8555	1.79
Maya Blend	1894	36848	0.9237	3.18
TotAK	**18940**	**400000**	**0.8509**	**1.52**



	LPG
Propane	150
Butane	565
TotAK prod.	**715**
To SMR	*0*
To fuel	*0*
SAKes	**715**

	Propylene
Propylene	**154**
SAKes	**154**

	I 95	I 91	TOT
MTBE	0	0	**0**
Ethanol	167	0	**167**
Butanes	24	25	**49**
SR Naphtha	0	0	**0**
HT Light Naphtha	0	0	**0**
Isomerate	666	326	**992**
HT Heavy Naphtha	0	0	**0**
LT Reformate	175	55	**230**
HV Reformate	1529	718	**2247**
Reformate	2	0	**2**
FCC LN	641	65	**706**
HCK LN	0	153	**153**
HCK HN	0	32	**32**
Sales	**3205**	**1374**	**4578**

	Jet Fuel
Treated Kero	1900
HT Kero	0
HCK Kero	0
Sales	**1900**

	Diesel
Biodiesel	0
HT Kero	664
Diesel	3723
HCK Kero	698
HCK Diesel	1211
Sales	**6296**

	Mar. Dies.
Treated Kero	0
SR Kero	456
HT Kero	0
Diesel	0
SR LGO	863
VHT LGO	176
SR HGO	220
SR LVGO	148
HCK Kero	0
HCK Diesel	236
Sales	**2099**

	LSFO	MSFO	HSFO	TOT
Diesel	11	0	0	**11**
SR LVGO	0	0	0	**0**
SR HGO	0	0	0	**0**
SR HVGO	0	0	0	**0**
VHT LGO	0	0	0	**0**
LCO untreated	0	0	0	**0**
SLU	181	0	0	**181**
HCK Residue	58	0	0	**58**
VHT HGO	79	0	0	**79**
Atm. Residue	0	0	0	**0**
Vac. Residue	14	0	0	**14**
Total prod.	**344**	**0**	**0**	**344**
To RFO	*0*	-	-	*0*
Sales	**344**	**0**	**0**	**344**

	Sulphur
Sulphur	**271**
Sales	**271**

	Bitumen
Asphalt from SDA	**400**
Sales	**400**

Figure 48: INDIA – High Conversion Refinery Scheme 1 - Block flow diagram

3.3.1 INDIA – High conversion refinery – Scheme 2

Table 35: Overall Material Balance– High Conversion Refinery Scheme 2- INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
High Conversion Refinery #2 - 400,000 BPSD
Rev.0 - January 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, $/t	Sales, kt/y	Annual Revenues, 10^6 $/y
LPG Product	583	531.6	309.9
Unl. Premium (95) INDIA	758	3467	2627.6
Unl. Premium (91) INDIA	750	1486	1114.2
Jet Fuel A1	779	1900	1480.1
Diesel	734	6736	4944.2
Marine Diesel	700	2245	1571.7
Low Sulphur Fuel	433	313	135.3
Medium Sulphur Fuel	406	0	0
High Sulphur Fuel	351	0	0
Bitumen	346	400	138.4
Sulphur	39	214.4	8.4
Propylene	973	164.3	159.8
	Subtotal	**17456.3**	**12489.8**
RAW MATERIALS	Material Cost, $/t	Purchases, kt/y	Cost, 10^6 $/y
Ekofisk	603	4735.0	2852.8
Arab. Light	499	12310.9	6148.1
Maya (pure)	534	1894.0	1010.8
Purchased MTBE	1100	0.0	0.0
Ethanol	450	181.1	81.5
Purchased Natural Gas	529	250.4	132.4
	Subtotal	**19371.3**	**10225.6**
IGCC COMPLEX	Material Cost, $/unit	Consumptions, unit/y	Cost, 10^6 $/y
Petcoke to Power Plant (kt/y)		788.3	
Electrical Power exported to refinery (kWh/y)	-	1.69E+09	
Electrical Power sold on the market (kWh/y)	0.07	2.53E+07	1.8
	Subtotal	**-**	**1.8**
		kt/y	
Fuels and Losses		**1915.0**	
Gross Margin, 10^6 $/Y		**2265.9**	

Table 36: Process Units and Design Capacity– High Conversion Refinery Scheme 2- INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
High Conversion Refinery #2 - 400,000 BPSD
Rev.0 - January 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	400000 (2)	400000	100%
Vacuum Distillation Unit	BPSD	180000 (1)	145059	81%
Naphtha Hydrotreater	BPSD	102000 (2)	92556	91%
Light Naphtha Isomerization	BPSD	32000	28601	89%
Heavy Naphtha Catalytic Reforming	BPSD	80000 (2)	72936	91%
Kero Merox	BPSD	59000	53569	91%
Kerosene Hydrotreater	BPSD	17000	14839	87%
Diesel Hydrotreater	BPSD	100000 (2)	89538	90%
VGO Hydrotreater	BPSD	60000	53912	90%
Fluid Catalytic Cracker	BPSD	55000	50000	91%
FCC Gasoline Post-Treatment Unit	BPSD	22000	19273	88%
Hydrocracker	BPSD	70000	62480	89%
Solvent Deasphalting	BPSD	50000	41612	83%
Delayed Coker Unit	BPSD	40000	32771	82%
Sulphur Recovery Unit	t/d Sulphur	870 (2)	612	70%
Steam Reformer	Nm3/h	190000	135936	72%

Notes
1) VDU design capacity set to manage the operation with Maya Blend
2) Two units in parallel
3) Three Claus trains in parallel.

Table 37: Utility Balance– High Conversion Refinery Scheme 2- INDIA

Clean refinery and the role of electricity generation
Refinery Balances

INDIA
High Conversion Refinery #2 - 400,000 BPSD
Rev.0 - January 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	**POWER** MW	**HP STEAM** tons/h	**MP STEAM** tons/h	**LP STEAM** tons/h	**COOLING WATER** (2) m3/h
MAIN PROCESS UNITS	1125.5	106.7	-30.3	191	396	45079
BASE LOAD		30.0	20	40	40	
POWER PLANT	797	-204.7	10	-231	-880	504
COOLING WATER SYSTEM ref+power plant		13.5				-78738
CO2 CAPTURE		52			444	33155
TOTAL	**1923**	**-3**	**0**	**0**	**0**	**0**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	54.4	457.1	29%
NATURAL GAS to fuel system	29.8	250.4	16%
FCC Coke	12.1	101.4	6%
PETCOKE (3)	93.8	788.3	49%
TOTAL	**190.1**	**1597.2**	

CO2 EMISSIONS (after CO2 capture)

	t/h			
From FG/NG combustion (CDU/VDU furnaces)	8.4			
From FG/NG/FCC coke combustion (other sources)	190.7			
SMR (feed only)	2.2			
From Petcoke burnt in Power Plant	34.1			
TOTAL	**235.4**	*corresponding to*	***1977.2***	*kt/y*
			104.4	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) Petcoke is burnt in power plant

.

Clean refinery and the role of electricity generation

INDIA - High Conversion Refinery Scheme 2 - 400,000 BPSD

Rev. 1 - December 2019

BLOCK FLOW DIAGRAM

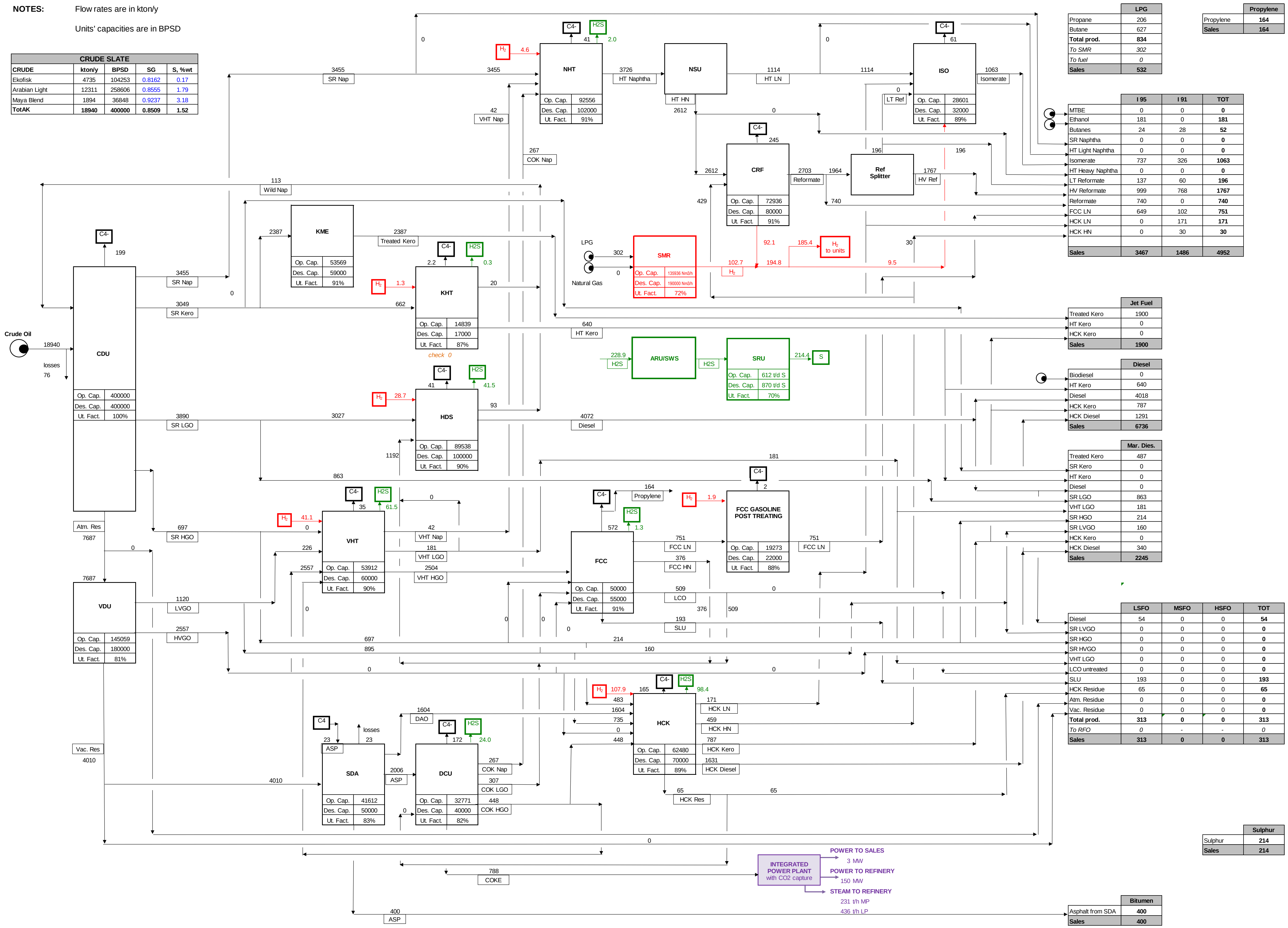


Figure 49: INDIA – High Conversion Refinery Scheme 2- Block flow diagram

3.4 Task 3 – Nigerian Refinery Balances

As already presented in Section 3.1, three different refinery configurations have been investigated:

- NIGERIA – Hydroskimming Refinery
  - Capacity: 150,000 BPSD
  - No VGO conversion Units
- NIGERIA - Medium conversion Refinery
  - Capacity: 200,000 BPSD
  - Configuration with FCC Unit
- NIGERIA - High conversion Refinery
  - Capacity: 200,000 BPSD
  - Configuration with Hydrocracking and FCC Unit
  - Bottom of the barrel solution: Boiler power plant

In this section the main results of the three refinery configurations have been presented. In particular, the overall material balance, the simplified block flow diagram and the overall utilities consumption are hereafter attached.

A detail comparison between the different refinery configurations is included in Section 5 of this report.

For each case, product qualities summary tables are enclosed in Attachment 6.2.

3.4.1 *Tuning of the configurations based on LP Models*

For the three Nigerian refinery schemes, main outcomes of the LP modelling activities are listed below:

- Isomerization Unit is confirmed. A unit able to increase the octane number is mandatory to achieve the gasoline RON specification.
- Both Kero Sweetening and Kero Hydrotreater have been considered in the medium conversion refinery:
  - Kerosene produced in the Sweetening Unit presents a sulphur content that is too high to allow it to be blended with diesel. It is possible to route this product only to Marine Diesel and Jet Fuel (but both these products present a limitation on the quantities that can be produced);
  - Hydrotreated Kero, due to the desulphurization achieved, can be blended in diesel.
- In the medium Conversion Refinery Scheme, the Steam Reformer Unit (SRU) has been deemed not necessary. The hydrogen produced by the catalytic reform is enough to cover the entire hydrogen demand of the entire plant.
- The Visbreaker unit inclusion is confirmed to reduce fuel oil viscosity and to achieve limited conversion into distillates.
- Bottom of the barrel feedstock, derived from primary distillation of 200,000 BPD of the selected crudes (low sulphur content, good quality), is limited to approximately 6,000 BPD. Consequently, the economy of scale does not favour the installation of complex units like gasifiers or delayed cokers.
- The selected option is the integration of the refinery with a power plant that allows the export of electric energy to the market burning the entire amount of the low sulphur fuel oil (LSFO) produced.

3.4.2 NIGERIA – Hydroskimming refinery

Table 38: Overall Material Balance – Hydroskimming Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
Hydroskimming Refinery - 150,000 BPSD
Rev. 0 - January 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, $/t	Sales, kt/y	Revenues, 10^6 $/y
LPG Product	558	210.8	117.6
Unl. Premium (95) NIGERIA	627	541	339.2
Unl. Premium (92) NIGERIA	620	951	589.9
Jet Fuel A1	747	850	635.0
Diesel	703	2151	1512.4
Marine Diesel	670	717	480.5
Low Sulphur Fuel	415	804	333.9
Medium Sulphur Fuel	389	0	0
High Sulphur Fuel	337	0	0
Bitumen	331	400	132.4
Sulphur	38	2.1	0.1
	Subtotal	**6628.3**	**4140.9**
RAW MATERIALS	Material Cost, $/t	Purchases, kt/y	Cost, 10^6 $/y
Agbami	569	4093.9	2327.4
Bonny Light	540	2047.0	1106.0
Doba (pure)	488	682.3	333.2
Purchased MTBE	2000	52.0	104.0
Ethanol	450	27.7	12.5
Purchased Natural Gas	529	38.4	20.3
	Subtotal	**6941.4**	**3903.4**
POWER PLANT	Material Cost, $/unit	Consumptions, unit/y	Revenues, 10^6 $/y
Low Sulphur Fuel Oil to Power Plant (kt/y)	-	122.4	-
Electrical Power exported to refinery (kWh/y)	-	2.69E+08	-
Electrical Power sold on the market (kWh/y)	0.07	0.00	0.0
	Subtotal	**-**	**0.0**
		kt/y	
Fuels and Losses		**313.0**	
Gross Margin, 10^6 $/Y		**237.6**	

Table 39: Process Units and Operating Capacity – Hydroskimming Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
Hydroskimming Refinery - 150,000 BPSD
Rev. 0 - January 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	150000	150000	100%
Vacuum Distillation Unit	BPSD	39000 (1)	31351	80%
Naphtha Hydrotreater	BPSD	43000	38592	90%
Light Naphtha Isomerization	BPSD	15500	13730	89%
Heavy Naphtha Catalytic Reforming	BPSD	27000	24595	91%
Kerosene Hydrotreater	BPSD	38000	34149	90%
Diesel Hydrotreater	BPSD	42000	37892	90%
Vacuum Gasoil Hydrotreater	BPSD	7000	6191	88%
Visbreaker	BPSD	4000	2317	58%
Bitumen Oxidation	t/d	1250	1143	91%
Sulphur Recovery Unit	t/d Sulphur	10 (2)	6	60%

Notes
1) VDU design capacity set to manage the operation with Doba Blend
2) Two parallel Claus trains

Table 40: Main Utilities Balance – Hydroskimming Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
Hydroskimming Refinery - 150,000 BPSD
Rev. 0 - January 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	POWER MW	HP STEAM tons/h	MP STEAM tons/h	LP STEAM tons/h	COOLING WATER (2) m3/h
MAIN PROCESS UNITS	230.6	17.5	23	43	89	5847
BASE LOAD		13.5	9	18	18	
POWER PLANT	143	-32.0	-32	-61	-107	
COOLING WATER SYSTEM		1.0				-5847
TOTAL	**373**	**0**	**0**	**0**	**0**	**0**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	14.8	124.6	44%
PURCHASED NATURAL GAS	4.6	38.4	13%
LOW SULPHUR FUEL OIL (3)	14.6	122.4	43%
TOTAL	**34.0**	**285.3**	**100%**

CO2 EMISSIONS

	t/h			
From FG/NG combustion (CDU/VDU furnaces)	27.2			
From FG/NG combustion (other sources)	27.1			
From LSFO combustion	46.6			
TOTAL	**100.9**	*corresponding to*	***847.3***	*kt/y*
			124.2	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) LSFO is burnt in power plant

Clean refinery and the role of electricity generation

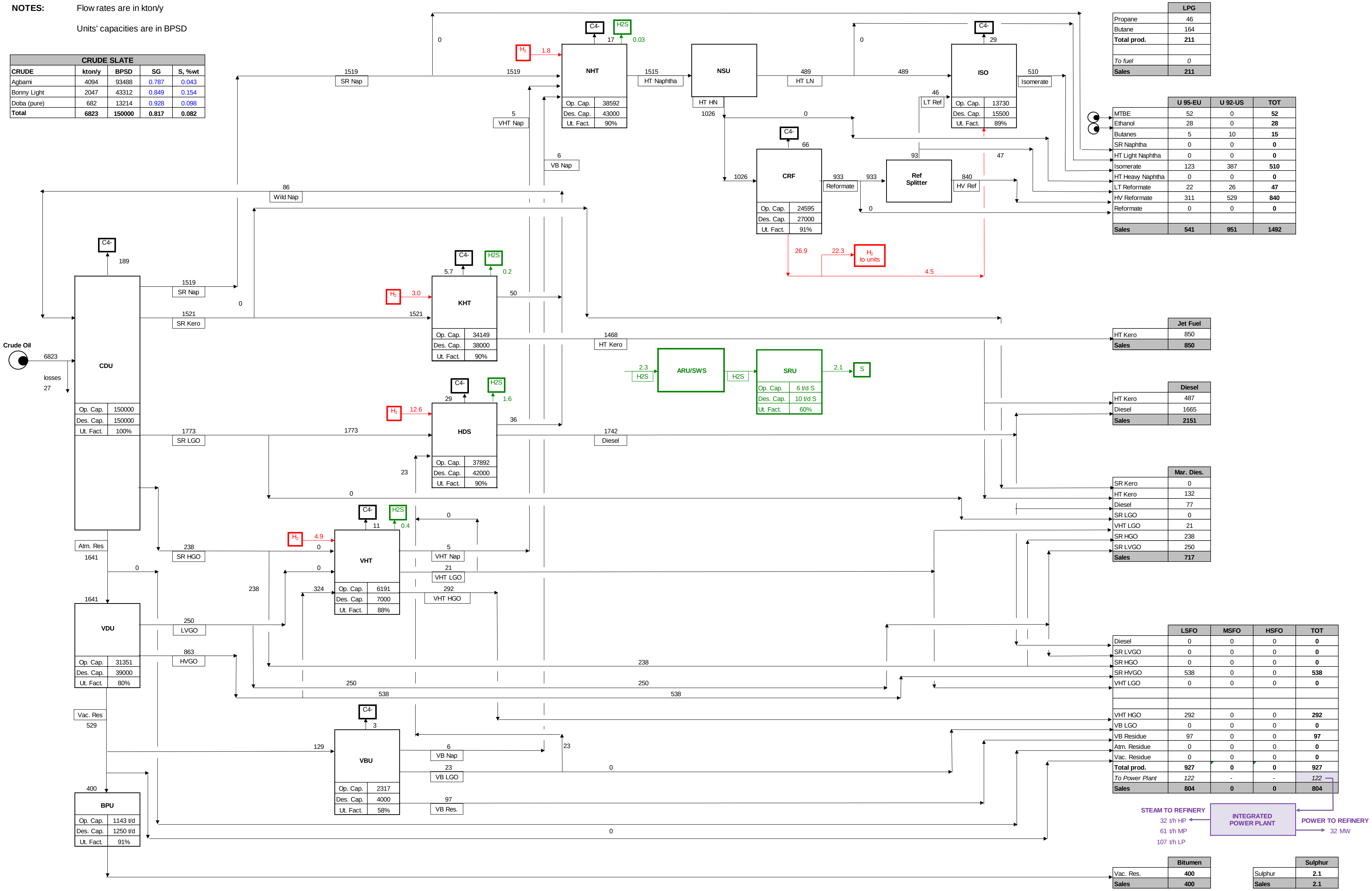
Nigeria - Low Conversion Refinery - 150,000 BPSD

Rev. 1 - December 2019

BLOCK FLOW DIAGRAM

NOTES: Flow rates are in kton/y

Units' capacities are in BPSD



CRUDE SLATE				
CRUDE	kton/y	BPSD	SG	S, %wt
Agbami	4094	93488	0.787	0.043
Bonny Light	2047	43312	0.849	0.154
Doba (pure)	682	13214	0.928	0.098
Total	**6823**	**150000**	**0.817**	**0.082**

	LPG
Propane	46
Butane	164
Total prod.	**211**
To fuel	*0*
Sales	**211**

	U 95-EU	U 92-US	TOT
MTBE	52	0	**52**
Ethanol	28	0	**28**
Butanes	5	10	**15**
SR Naphtha	0	0	**0**
HT Light Naphtha	0	0	**0**
Isomerate	123	387	**510**
HT Heavy Naphtha	0	0	**0**
LT Reformate	22	26	**47**
HV Reformate	311	529	**840**
Reformate	0	0	**0**
Sales	**541**	**951**	**1492**

	Jet Fuel
HT Kero	850
Sales	**850**

	Diesel
HT Kero	487
Diesel	1665
Sales	**2151**

	Mar. Dies.
SR Kero	0
HT Kero	132
Diesel	77
SR LGO	0
VHT LGO	21
SR HGO	238
SR LVGO	250
Sales	**717**

	LSFO	MSFO	HSFO	TOT
Diesel	0	0	0	**0**
SR LVGO	0	0	0	**0**
SR HGO	0	0	0	**0**
SR HVGO	538	0	0	**538**
VHT LGO	0	0	0	**0**
VHT HGO	292	0	0	**292**
VB LGO	0	0	0	**0**
VB Residue	97	0	0	**97**
Atm. Residue	0	0	0	**0**
Vac. Residue	0	0	0	**0**
Total prod.	**927**	**0**	**0**	**927**
To Power Plant	*122*	-	-	*122*
Sales	**804**	**0**	**0**	**804**

	Bitumen
Vac. Res.	**400**
Sales	**400**

	Sulphur
Sulphur	**2.1**
Sales	**2.1**

Figure 50: NIGERIA Hydroskimming Refinery- Block flow diagram

3.4.1 *NIGERIA – Medium Conversion refinery*

Table 41: Overall Material Balance – Medium Conversion Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
Medium Conversion Refinery - 200,000 BPSD
Rev. 1 - March 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, $/t	Sales, kt/y	Revenues, 10^6 $/y
LPG Product	558	406.0	226.5
Unl. Premium (95) NIGERIA	627	397	249.0
Unl. Premium (92) NIGERIA	620	1813	1124.3
Jet Fuel A1	747	1130	844.1
Diesel	703	3140	2207.5
Marine Diesel	670	1047	701.3
Low Sulphur Fuel	415	262	108.8
Medium Sulphur Fuel	389	0	0
High Sulphur Fuel	337	0	0
Bitumen	331	400	132.4
Sulphur	38	3.7	0.1
Propylene	932	63.7	59.4
	Subtotal	**8662.9**	**5653.4**
RAW MATERIALS	Material Cost, $/t	Purchases, kt/y	Cost, 10^6 $/y
Agbami	569	5458.6	3103.2
Bonny Light	540	2729.3	1474.6
Doba (pure)	488	909.8	444.2
Purchased MTBE	2000	0.0	0.0
Ethanol	450	20.7	9.3
Purchased Natural Gas	529	15.4	8.1
	Subtotal	**9133.7**	**5039.5**
POWER PLANT	Material Cost, $/unit	Consumptions, unit/y	Revenues, 10^6 $/y
Low Sulphur Fuel Oil to Power Plant (kt/y)	-	176.7	-
Electrical Power exported to refinery (kWh/y)	-	3.74E+08	-
Electrical Power sold on the market (kWh/y)	0.07	0.00	0.0
	Subtotal	**-**	**0.0**
		kt/y	
Fuels and Losses		**470.9**	
Gross Margin, 10^6 $/Y		**613.9**	

Table 42: Process Units and Operating Capacity – Medium Conversion Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
Medium Conversion Refinery - 200,000 BPSD
Rev. 1 - March 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	200000	200000	100%
Vacuum Distillation Unit	BPSD	52000 (1)	41801	80%
Naphtha Hydrotreater	BPSD	57000	51695	91%
Light Naphtha Isomerization	BPSD	18500	16809	91%
Heavy Naphtha Catalytic Reforming	BPSD	37000	32947	89%
Kerosene Hydrotreater	BPSD	50000	45591	91%
Diesel Hydrotreater	BPSD	62000	55707	90%
Vacuum Gasoil Hydrotreater	BPSD	10000	8255	83%
Fluid Catalytic Cracker	BPSD	21500	19404	90%
FCC Gasoline Post Treatment	BPSD	8500	7479	88%
Visbreaker	BPSD	9000	5486	61%
Bitumen Oxidation	t/d	1300	1143	88%
Sulphur Recovery Unit	t/d Sulphur	20 (2)	11	53%

Notes
1) VDU design capacity set to manage the operation with Doba Blend
2) Two Claus trains in parallel

Table 43: Main Utilities Balance – Medium Conversion Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
Medium Conversion Refinery - 200,000 BPSD
Rev. 1 - March 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	POWER MW	HP STEAM tons/h	MP STEAM tons/h	LP STEAM tons/h	COOLING WATER (2) m3/h
MAIN PROCESS UNITS	354.5	24.2	39	75	115	13528
BASE LOAD		18.0	12	24	24	
POWER PLANT	206	-44.6	-51	-99	-139	
COOLING WATER SYSTEM		2.3				-13528
TOTAL	**560**	**0**	**0**	**0**	**0**	**0**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	24.1	202.3	47%
PURCHASED NATURAL GAS	1.8	15.4	4%
FCC COKE	4.7	39.4	9%
LOW SULPHUR FUEL OIL (3)	21.0	176.7	41%
TOTAL	**51.6**	**433.8**	**100%**

CO2 EMISSIONS

	t/h			
From FG/NG combustion (CDU/VDU furnaces)	39.2			
From FG/NG/FCC coke combustion (other sources)	51.1			
From LSFO combustion	67.3			
TOTAL	**157.7**	*corresponding to*	***1324.4***	*kt/y*
			145.6	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) LSFO is burnt in power plant

Clean refinery and the role of electricity generation

Nigeria - Medium Conversion Refinery - 200,000 BPSD

Rev. 1 - December 2019

BLOCK FLOW DIAGRAM

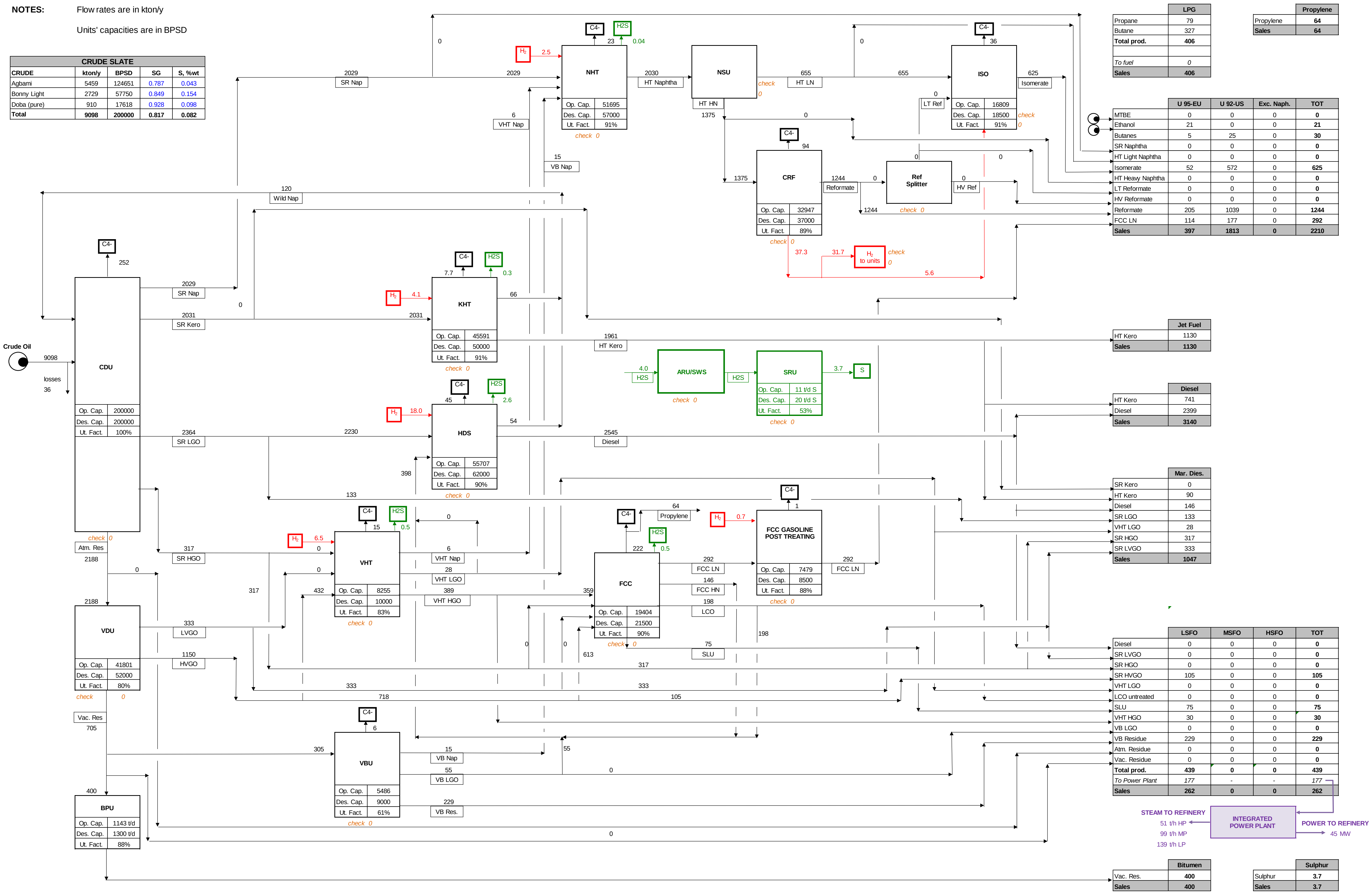


Figure 51: NIGERIA Medium Conversion Refinery- Block flow diagram

3.4.2 NIGERIA – High Conversion refinery

Table 44: Overall Material Balance – High Conversion Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
High Conversion Refinery - 200,000 BPSD
Rev. 0 - January 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, $/t	Sales, kt/y	Revenues, 10^6 $/y
LPG Product	558	406.0	226.5
Unl. Premium (95) NIGERIA	627	397	249.0
Unl. Premium (92) NIGERIA	620	1813	1124.3
Jet Fuel A1	747	1130	844.1
Diesel	703	3140	2207.5
Marine Diesel	670	1047	701.3
Low Sulphur Fuel	415	0	0.0
Medium Sulphur Fuel	389	0	0.0
High Sulphur Fuel	337	0	0.0
Bitumen	331	400	132.4
Sulphur	38	3.7	0.1
Propylene	932	63.7	59.4
	Subtotal	**8400.7**	**5544.6**
RAW MATERIALS	Material Cost, $/t	Purchases, kt/y	Cost, 10^6 $/y
Agbami	569	5458.6	3103.2
Bonny Light	540	2729.3	1474.6
Doba (pure)	488	909.8	444.2
Purchased MTBE	2000	0.0	0.0
Ethanol	450	20.7	9.3
Purchased Natural Gas	529	15.4	8.1
	Subtotal	**9133.7**	**5039.5**
POWER PLANT	Material Cost, $/unit	Consumptions, unit/y	Revenues, 10^6 $/y
Low Sulphur Fuel Oil to Power Plant (kt/y)	-	438.9	-
Electrical Power exported to refinery (kWh/y)	-	5.67E+08	-
Electrical Power sold on the market (kWh/y)	0.07	5.66E+08	39.6
	Subtotal	**-**	**39.6**
		kt/y	
Fuels and Losses		**733.0**	
Gross Margin, 10^6 $/Y		**544.7**	

Table 45: Process Units and Operating Capacity – High Conversion Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
High Conversion Refinery - 200,000 BPSD
Rev. 0 - January 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	200000	200000	100%
Vacuum Distillation Unit	BPSD	52000 (1)	41801	80%
Naphtha Hydrotreater	BPSD	57000	51695	91%
Light Naphtha Isomerization	BPSD	18500	16809	91%
Heavy Naphtha Catalytic Reforming	BPSD	37000	32947	89%
Kerosene Hydrotreater	BPSD	50000	45591	91%
Diesel Hydrotreater	BPSD	62000	55707	90%
Vacuum Gasoil Hydrotreater	BPSD	10000	8253	83%
Fluid Catalytic Cracker	BPSD	21500	19404	90%
FCC Gasoline Post Treatment	BPSD	8500	7479	88%
Visbreaker	BPSD	9000	5486	61%
Bitumen Oxidation	t/d	1300	1143	88%
Sulphur Recovery Unit	t/d Sulphur	20 (2)	11	53%

Notes

1) VDU design capacity set to manage the operation with Doba Blend
2) Two Claus trains in parallel

Table 46: Main Utilities Balance – High Conversion Refinery - NIGERIA

Clean refinery and the role of electricity generation
Refinery Balances

NIGERIA
High Conversion Refinery - 200,000 BPSD
Rev. 0 - January 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	POWER MW	HP STEAM tons/h	MP STEAM tons/h	LP STEAM tons/h	COOLING WATER (2) m3/h
MAIN PROCESS UNITS	354.5	44.5	39	75	328	28956
BASE LOAD		18.0	12	24	24	
POWER PLANT	511	-136.8	-51	-99	-351	11254
COOLING WATER SYSTEM ref		5.0				-28956
COOLING WATER SYSTEM PP		1.9				-11254
TOTAL	**866**	**-67**	**0**	**0**	**0**	**0**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	24.1	202.3	29%
PURCHASED NATURAL GAS	1.8	15.4	2%
FCC COKE	4.7	39.4	6%
LOW SULPHUR FUEL OIL (3)	52.2	438.9	63%
TOTAL	**82.9**	**695.9**	**100%**

CO2 EMISSIONS

	t/h			
From FG/NG combustion (CDU/VDU furnaces)	3.8			
From FG/NG/FCC coke combustion (other sources)	52.4			
From LSFO combustion	16.6			
TOTAL	**72.8**	*corresponding to*	***611.2***	*kt/y*
			67.2	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) LSFO is burnt in power plant

Nigeria - High Conversion Refinery - 200,000 BPSD

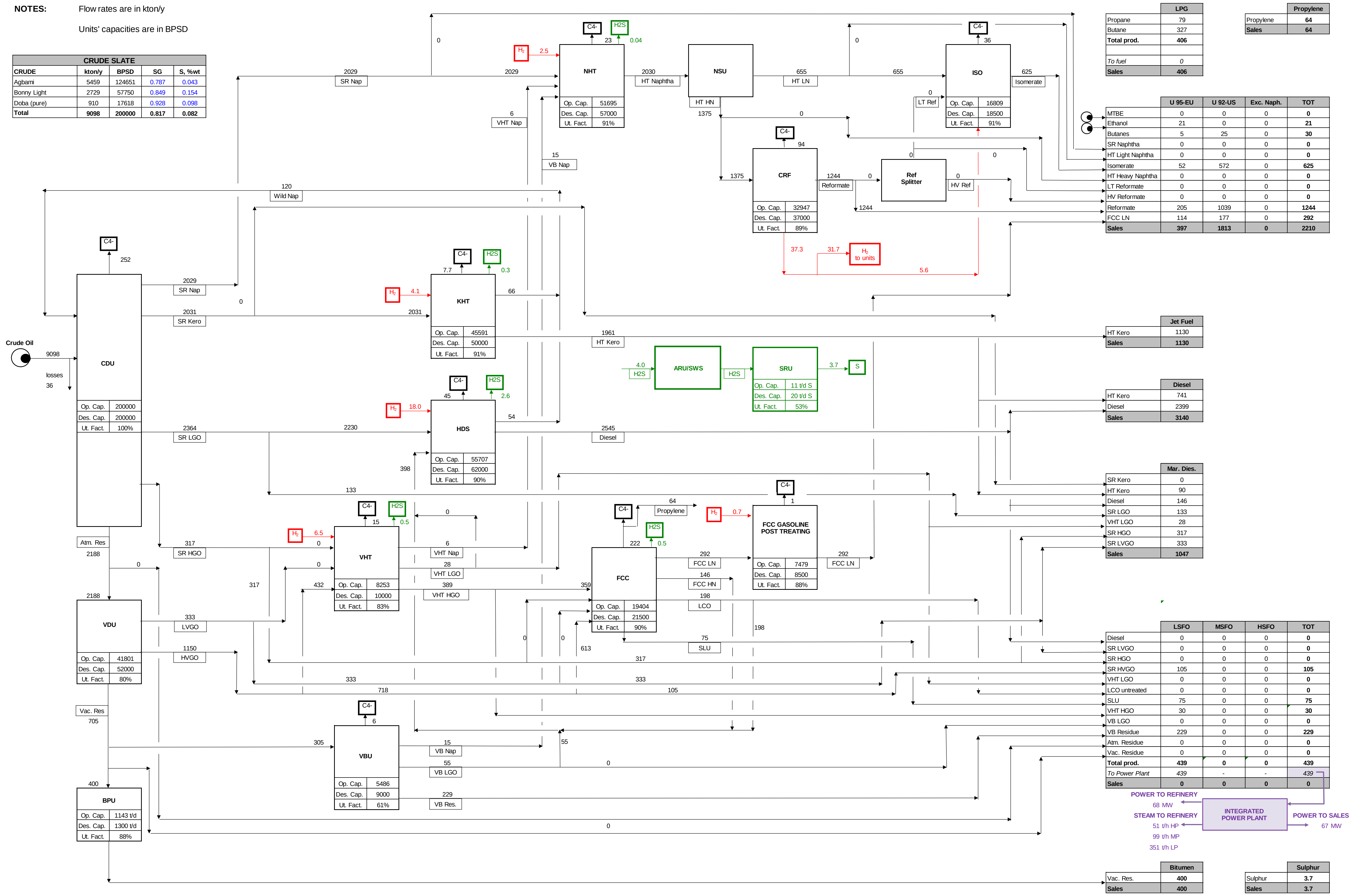
Rev. 1 - December 2019

BLOCK FLOW DIAGRAM

NOTES: Flow rates are in kton/y

Units' capacities are in BPSD

CRUDE SLATE				
CRUDE	kton/y	BPSD	SG	S, %wt
Agbami	5459	124651	0.787	0.043
Bonny Light	2729	57750	0.849	0.154
Doba (pure)	910	17618	0.928	0.098
Total	9098	200000	0.817	0.082



	LPG
Propane	79
Butane	327
Total prod.	406
To fuel	0
Sales	406

	Propylene
Propylene	64
Sales	64

	U 95-EU	U 92-US	Exc. Naph.	TOT
MTBE	0	0	0	0
Ethanol	21	0	0	21
Butanes	5	25	0	30
SR Naphtha	0	0	0	0
HT Light Naphtha	0	0	0	0
Isomerate	52	572	0	625
HT Heavy Naphtha	0	0	0	0
LT Reformate	0	0	0	0
HV Reformate	0	0	0	0
Reformate	205	1039	0	1244
FCC LN	114	177	0	292
Sales	397	1813	0	2210

	Jet Fuel
HT Kero	1130
Sales	1130

	Diesel
HT Kero	741
Diesel	2399
Sales	3140

	Mar. Dies.
SR Kero	0
HT Kero	90
Diesel	146
SR LGO	133
VHT LGO	28
SR HGO	317
SR LVGO	333
Sales	1047

	LSFO	MSFO	HSFO	TOT
Diesel	0	0	0	0
SR LVGO	0	0	0	0
SR HGO	0	0	0	0
SR HVGO	105	0	0	105
VHT LGO	0	0	0	0
LCO untreated	0	0	0	0
SLU	75	0	0	75
VHT HGO	30	0	0	30
VB LGO	0	0	0	0
VB Residue	229	0	0	229
Atm. Residue	0	0	0	0
Vac. Residue	0	0	0	0
Total prod.	439	0	0	439
To Power Plant	439	-	-	439
Sales	0	0	0	0

	Bitumen
Vac. Res.	400
Sales	400

	Sulphur
Sulphur	3.7
Sales	3.7

Figure 52: NIGERIA High Conversion Refinery- Block flow diagram

3.5 Task 3 – Brazilian Refinery Balances

As already presented in Section 3.1, three different refinery configurations have been investigated:

- BRAZIL – Medium conversion Refinery – Scheme 1
  - Capacity: 150,000 BPSD
  - Configuration with Hydrocracking Unit
- BRAZIL - Medium conversion Refinery – Scheme 2:
  - Capacity: 250,000 BPSD
  - Configuration with Hydrocracking and FCC Unit
- BRAZIL - High conversion Refinery
  - Capacity: 300,000 BPSD
  - Configuration with Hydrocracking and FCC Unit
  - Bottom of the barrel solution: SDA + Pitch Gasification

In this section the main results of the three refinery configurations have been presented. In particular, the overall material balance, the simplified block flow diagram and the overall utilities consumption are hereafter attached.

A detail comparison between the different refinery configurations is included in Section 5 of this report.

For each case, product qualities summary tables are enclosed in Attachment 6.2.

3.5.1 *Tuning of the configurations based on LP Models*

For the three Brazilian refinery schemes, the main outcomes of the LP modelling activities are listed below:

- The Isomerization Unit inclusion is confirmed for the Medium conversion refinery with Scheme 1, and for the High Conversion scheme, while it is not necessary for the Medium conversion refinery with Scheme 2.
- Only Kero Sweetening has been considered in this medium conversion refineries.
- The Visbreaker unit inclusion is confirmed to reduce fuel oil viscosity and to achieve limited conversion into distillates.
- In the High conversion refinery, the asphalt thermal input is adequate to cover the whole refinery utilities balance (steam, power, and hydrogen).

3.5.1 BRAZIL – Medium conversion refinery - Scheme 1

Table 47: Overall Material Balance – Medium Conversion Refinery Scheme 1 - BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
Medium Conversion Refinery - 150,000 BPSD
Rev. 0 - January 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, $/t	Sales, kt/y	Revenues, 10^6 $/y
LPG Product	519	0.0	0.0
Unl. Premium (96) BRAZIL	710	846	600.6
Unl. Premium (92) BRAZIL	703	363	254.9
Jet Fuel A1	694	720	499.7
Diesel	653	2471	1613.4
Marine Diesel	623	824	513.1
Low Sulphur Fuel	385	0	0.0
Medium Sulphur Fuel	362	0	0
High Sulphur Fuel	313	0	0
Bitumen	308	400	123.2
Sulphur	35	23.7	0.8
	Subtotal	**5646.4**	**3605.6**
RAW MATERIALS	Material Cost, $/t	Purchases, kt/y	Cost, 10^6 $/y
Marlim	479	4617.6	2210.4
Lula Tupi	504	2308.8	1163.2
Peregrino (pure)	431	769.6	331.4
Purchased MTBE	1100	16.9	18.6
Biodiesel	1021	182.8	186.7
Ethanol	579	150.9	87.4
Purchased Natural Gas	529	89.1	47.1
	Subtotal	**8135.7**	**4044.8**
POWER PLANT	Material Cost, $/unit	Consumptions, unit/y	Revenues, 10^6 $/y
High Sulphur Fuel Oil to Power Plant (kt/y)	-	2119.7	-
Electrical Power exported to refinery (kWh/y)	-	1.47E+09	-
Electrical Power sold on the market (kWh/y)	0.13	6.26E+09	814.2
	Subtotal	**-**	**814.2**
		kt/y	
Fuels and Losses		**2489.3**	
Gross Margin, 10^6 $/Y		**375.0**	

Table 48: Process Units and Operating Capacity – Medium Conversion Refinery Scheme 1 - BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
Medium Conversion Refinery - 150,000 BPSD
Rev. 0 - January 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	150000	150000	100%
Vacuum Distillation Unit	BPSD	110000 (1)	88069	80%
Naphtha Hydrotreater	BPSD	18500	16632	90%
Light Naphtha Isomerization	BPSD	5000	4284	86%
Heavy Naphtha Catalytic Reforming	BPSD	21000	18733	89%
Kero MEROX Unit	BPSD	20000	17929	90%
Diesel Hydrotreater	BPSD	22000	19810	90%
Hydrocracker	BPSD	43000	38568	90%
Steam Reformer	Nm3/h	90000	66191	74%
Visbreaker	BPSD	50000	38568	77%
Bitumen Oxidation	t/d	1300	1143	88%
Sulphur Recovery Unit	t/d Sulphur	105 (2)	68	64%

Notes
1) VDU design capacity set to manage the operation with Peregrino Blend
2) Three Claus trains in parallel

Table 49: Main Utilities Balance – Medium Conversion Refinery Scheme 1 - BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
Medium Conversion Refinery - 150,000 BPSD
Rev. 0 - January 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	POWER MW	HP STEAM tons/h	MP STEAM tons/h	LP STEAM tons/h	COOLING WATER (2) m3/h
MAIN PROCESS UNITS	343.4	39.4	-45	67	132	12596
BASE LOAD		13.5	9	15	15	
POWER PLANT	2469	-921.2	39	-55	-1025	
COOLING WATER SYSTEM refinery		13.2				
COOLING WATER SYSTEM power plant		21.3				124626
CO2 CAPTURE		88			875	63953
TOTAL	**2813**	**-746**	**0**	**0**	**0**	**201505**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	18.0	151.5	6%
PURCHASED NATURAL GAS	10.6	89.1	4%
HIGH SULPHUR FUEL OIL (3)	252.3	2119.7	90%
TOTAL	**281.0**	**2360.3**	**100%**

CO2 EMISSIONS (after CO2 capture)

	t/h			
From FG/NG combustion (CDU/VDU furnaces)	3.7			
From FG/NG combustion (other sources)	41.4			
SMR (feed only)	1.1			
From HSFO combustion	80.7			
TOTAL	**126.9**	*corresponding to*	***1065.9***	*kt/y*
			135.5	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) HSFO is burnt in power plant

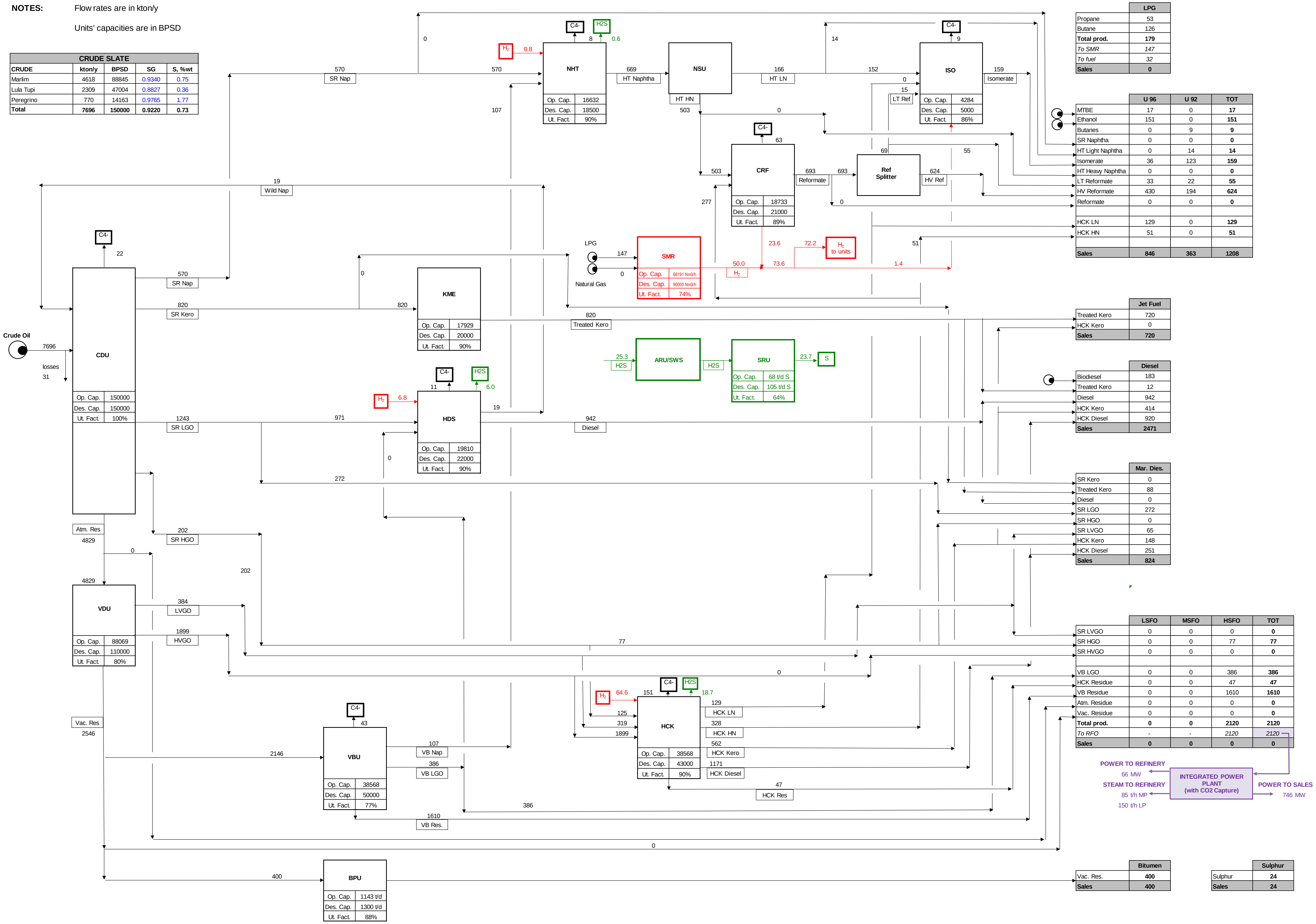
BRAZIL - Medium Conversion Refinery - 150,000 BPSD
Rev. 1 - December 2019

BLOCK FLOW DIAGRAM

NOTES: Flow rates are in kton/y

Units' capacities are in BPSD

CRUDE SLATE				
CRUDE	kton/y	BPSD	SG	S, %wt
Marlim	4618	88845	0.9340	0.75
Lula Tupi	2309	47004	0.8827	0.36
Peregrino	770	14163	0.9765	1.77
Total	7696	150000	0.9220	0.73



	LPG
Propane	53
Butane	126
Total prod.	179
To SMR	147
To fuel	32
Sales	0

	U 96	U 92	TOT
MTBE	17	0	17
Ethanol	151	0	151
Butanes	0	9	9
SR Naphtha	0	0	0
HT Light Naphtha	0	14	14
Isomerate	36	123	159
HT Heavy Naphtha	0	0	0
LT Reformate	33	22	55
HV Reformate	430	194	624
Reformate	0	0	0
HCK LN	129	0	129
HCK HN	51	0	51
Sales	846	363	1208

	Jet Fuel
Treated Kero	720
HCK Kero	0
Sales	720

	Diesel
Biodiesel	183
Treated Kero	12
Diesel	942
HCK Kero	414
HCK Diesel	920
Sales	2471

	Mar. Dies.
SR Kero	0
Treated Kero	88
Diesel	0
SR LGO	272
SR HGO	0
SR LVGO	65
HCK Kero	148
HCK Diesel	251
Sales	824

	LSFO	MSFO	HSFO	TOT
SR LVGO	0	0	0	0
SR HGO	0	0	77	77
SR HVGO	0	0	0	0
VB LGO	0	0	386	386
HCK Residue	0	0	47	47
VB Residue	0	0	1610	1610
Atm. Residue	0	0	0	0
Vac. Residue	0	0	0	0
Total prod.	0	0	2120	2120
To RFO	-	-	2120	2120
Sales	0	0	0	0

	Bitumen
Vac. Res.	400
Sales	400

	Sulphur
Sulphur	24
Sales	24

Figure 53: BRAZIL – Medium Conversion Refinery Scheme 1- Block flow diagram

3.5.2 BRAZIL – Medium conversion refinery - Scheme 2

Table 50: Overall Material Balance – Medium Conversion Refinery Scheme 2 - BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
Medium Conversion Refinery - 250,000 BPSD
Rev. 0 - January 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, \$/t	Sales, kt/y	Revenues, 10^6 \$/y
LPG Product	519	109.3	56.7
Unl. Premium (96) BRAZIL	710	1486	1054.8
Unl. Premium (92) BRAZIL	703	637	447.6
Jet Fuel A1	694	1200	832.8
Diesel	653	3611	2357.7
Marine Diesel	623	1204	749.8
Low Sulphur Fuel	385	0	0.0
Medium Sulphur Fuel	362	0	0
High Sulphur Fuel	313	0	0
Bitumen	308	400	123.2
Sulphur	35	39.0	1.4
Propylene	866	88.1	76.3
	Subtotal	**8772.7**	**5700.2**
RAW MATERIALS	Material Cost, \$/t	Purchases, kt/y	Cost, 10^6 \$/y
Marlim	479	7695.9	3684.0
Lula Tupi	504	3848.0	1938.6
Peregrino (pure)	431	1282.7	552.3
Purchased MTBE	1100	0.0	0.0
Biodiesel	1021	263.7	269.2
Ethanol	579	233.5	135.2
Purchased Natural Gas	529	0.0	0.0
	Subtotal	**13323.7**	**6579.3**
POWER PLANT	Material Cost, \$/unit	Consumptions, unit/y	Revenues, 10^6 \$/y
High Sulphur Fuel Oil to Power Plant (kt/y)	-	3923.2	-
Electrical Power exported to refinery (kWh/y)	-	2.58E+09	-
Electrical Power sold on the market (kWh/y)	0.13	1.16E+10	1510.0
	Subtotal	**-**	**1510.0**
		kt/y	
Fuels and Losses		**4551.0**	
Gross Margin, 10^6 \$/Y	**630.9**		

Table 51: Process Units and Operating Capacity – Medium Conversion Refinery Scheme 2 - BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
Medium Conversion Refinery - 250,000 BPSD
Rev. 0 - January 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	250000	250000	100%
Vacuum Distillation Unit	BPSD	180000 (1)	146782	82%
Naphtha Hydrotreater	BPSD	32000	28755	90%
Heavy Naphtha Catalytic Reforming	BPSD	33000	29154	88%
Kero MEROX Unit	BPSD	33000	30005	91%
Diesel Hydrotreater	BPSD	48000	43393	90%
Vacuum Gasoil Hydrotreater	BPSD	31000	27995	90%
Hydrocracker	BPSD	55000	47911	87%
Fluid Catalytic Cracking Unit	BPSD	30000	26820	89%
FCC Gasoline Post-Treatment Unit	BPSD	12000	10127	84%
Steam Reformer	Nm3/h	125000	90288	72%
Visbreaker	BPSD	80000	69072	86%
Bitumen Oxidation	t/d	1300	1143	88%
Sulphur Recovery Unit	t/d Sulphur	180 (2)	111	62%

Notes

1) VDU design capacity set to manage the operation with Peregrino Blend

Table 52: Main Utilities Balance – Medium Conversion Refinery Scheme 2 - BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
Medium Conversion Refinery - 250,000 BPSD
Rev. 0 - January 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	POWER MW	HP STEAM tons/h	MP STEAM tons/h	LP STEAM tons/h	COOLING WATER (2) m3/h
MAIN PROCESS UNITS	606.9	59.7	-59	141	204	25663
BASE LOAD		22.5	15	30	30	
POWER PLANT	4570	-1690.1	44	-171	-1847	231132
COOLING WATER SYSTEM refinery		25.1				
COOLING WATER SYSTEM power plant		39.6				
CO2 CAPTURE		160			1613	117715
TOTAL	**5177**	**-1383**	**0**	**0**	**0**	**377510**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	51.7	434.5	10%
FCC COKE	0.2	1.5	0%
HIGH SULPHUR FUEL OIL (3)	467.0	3923.2	90%
TOTAL	**519.0**	**4359.4**	**100%**

CO2 EMISSIONS (after CO2 capture)

	t/h			
From FG/NG combustion (CDU/VDU furnaces)	6.2			
From FG/NG/FCC coke combustion (other sources)	90.5			
SMR (feed only)	1.5			
From LSFO combustion	149.5			
TOTAL	**247.7**	*corresponding to*	***2080.4***	*kt/y*
			162.2	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) HSFO is burnt in power plant

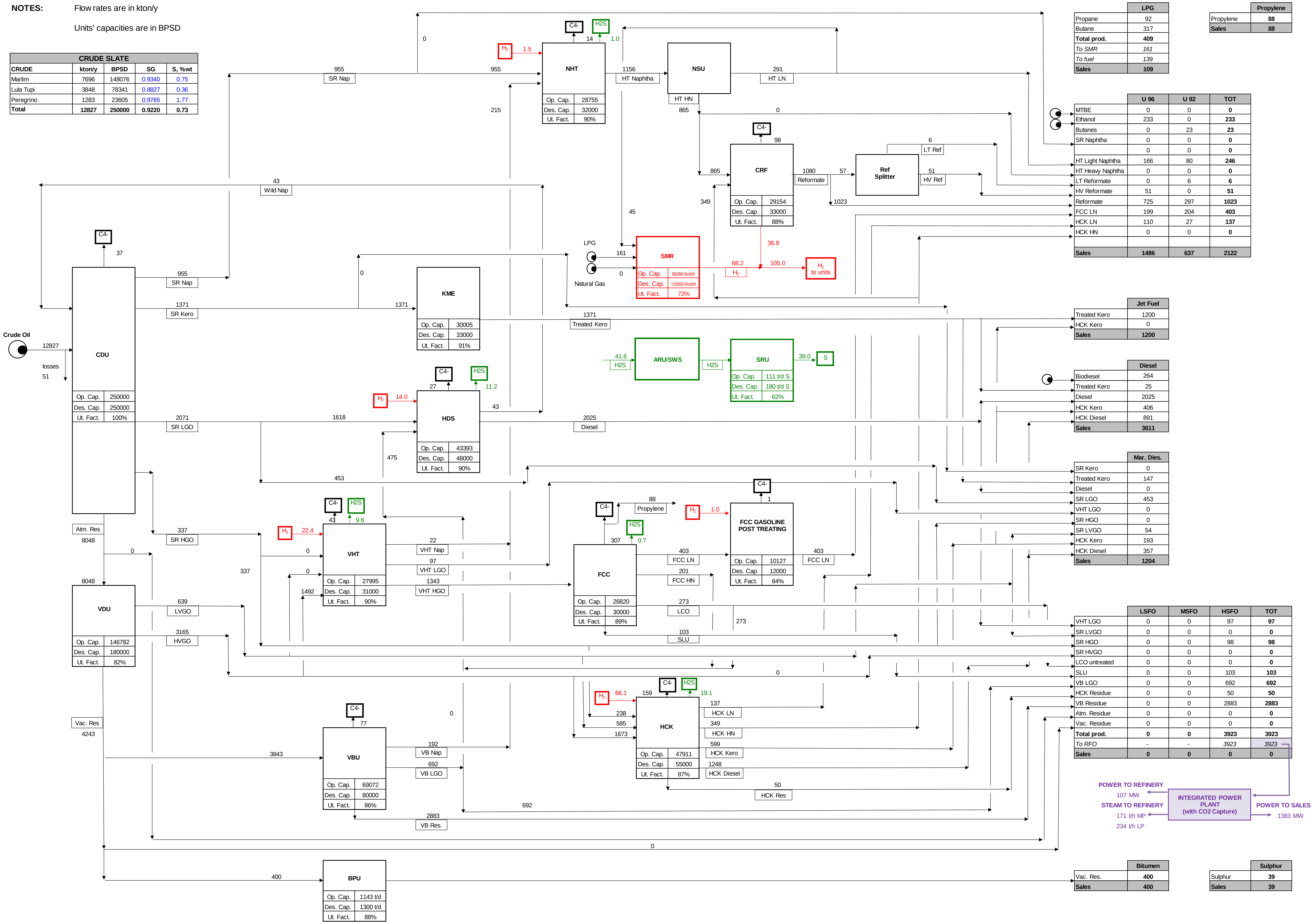
BRAZIL - Medium Conversion Refinery - 250,000 BPSD
Rev. 1 - December 2019

BLOCK FLOW DIAGRAM

NOTES: Flow rates are in kton/y

Units' capacities are in BPSD

CRUDE SLATE				
CRUDE	kton/y	BPSD	SG	S, %wt
Marlim	7696	148076	0.9340	0.75
Lula Tupi	3848	78341	0.8827	0.36
Peregrino	1283	23605	0.9765	1.77
Total	**12827**	**250000**	**0.9220**	**0.73**



	LPG
Propane	92
Butane	317
Total prod.	**409**
To SMR	*161*
To fuel	*139*
Sales	**109**

	Propylene
Propylene	88
Sales	**88**

	U 96	U 92	TOT
MTBE	0	0	**0**
Ethanol	233	0	**233**
Butanes	0	23	**23**
SR Naphtha	0	0	**0**
	0	0	**0**
HT Light Naphtha	166	80	**246**
HT Heavy Naphtha	0	0	**0**
LT Reformate	0	6	**6**
HV Reformate	51	0	**51**
Reformate	725	297	**1023**
FCC LN	199	204	**403**
HCK LN	110	27	**137**
HCK HN	0	0	**0**
Sales	**1486**	**637**	**2122**

	Jet Fuel
Treated Kero	1200
HCK Kero	0
Sales	**1200**

	Diesel
Biodiesel	264
Treated Kero	25
Diesel	2025
HCK Kero	406
HCK Diesel	891
Sales	**3611**

	Mar. Dies.
SR Kero	0
Treated Kero	147
Diesel	0
SR LGO	453
VHT LGO	0
SR HGO	0
SR LVGO	54
HCK Kero	193
HCK Diesel	357
Sales	**1204**

	LSFO	MSFO	HSFO	TOT
VHT LGO	0	0	97	**97**
SR LVGO	0	0	0	**0**
SR HGO	0	0	98	**98**
SR HVGO	0	0	0	**0**
LCO untreated	0	0	0	**0**
SLU	0	0	103	**103**
VB LGO	0	0	692	**692**
HCK Residue	0	0	50	**50**
VB Residue	0	0	2883	**2883**
Atm. Residue	0	0	0	**0**
Vac. Residue	0	0	0	**0**
Total prod.	**0**	**0**	**3923**	**3923**
To RFO	-	-	*3923*	*3923*
Sales	**0**	**0**	**0**	**0**

	Bitumen
Vac. Res.	400
Sales	**400**

	Sulphur
Sulphur	39
Sales	**39**

Figure 54: BRAZIL – Medium Conversion Refinery Scheme 2- Block flow diagram

3.5.3 BRAZIL – High conversion refinery

Table 53: Overall Material Balance – High Conversion Refinery- BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
High Conversion Refinery - 300,000 BPSD
Rev. 1 - January 2019

OVERALL MATERIAL BALANCE

PRODUCTS	Product Price, $/t	Sales, kt/y	Annual Revenues, 10^6 $/y
LPG Product	519	595,4	309,0
Unl. Premium (96) BRAZIL	710	2030	1441,0
Unl. Premium (92) BRAZIL	703	870	611,5
Jet Fuel A1	694	1200	832,8
Diesel	653	5503	3593,3
Marine Diesel	623	1834	1142,7
Low Sulphur Fuel	385	388	149,5
Medium Sulphur Fuel	362	0	0
High Sulphur Fuel	313	0	0
Bitumen	308	400	123
Sulphur	35	133,6	4,7
Propylene	866	180,7	156,5
	Subtotal	**13134,4**	**8364,2**
RAW MATERIALS	Material Cost, $/t	Purchases, kt/y	Cost, 10^6 $/y
Marlim	479	9235,1	4420,8
Lula Tupi	504	4617,6	2326,3
Peregrino (pure)	431	1539,2	662,8
Biodiesel	1021	400,5	409,0
Ethanol	579	338,2	195,8
Purchased Natural Gas	529	150,8	79,8
	Subtotal	**16281,4**	**8094,5**
IGCC COMPLEX	Material Cost, $/unit	Consumptions, unit/y	Cost, 10^6 $/y
Pitch to Gasification Complex (kt/y)		2655,2	
Electrical Power exported to refinery (kWh/y)	-	4,52E+05	
Electrical Power sold on the market (kWh/y)	0,13	3,97E+09	516,0
	Subtotal	**-**	**516,0**
		kt/y	
Fuels and Losses		**3147,0**	
Gross Margin, 10^6 $/Y		**785,7**	

Table 54: Process Units and Operating Capacity – High Conversion Refinery - BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
High Conversion Refinery - 300,000 BPSD
Rev. 1 - January 2019

PROCESS UNITS OPERATING AND DESIGN CAPACITY

UNIT	Unit of measure	Design Capacity	Operating Capacity	Average Utilization
Crude Distillation Unit	BPSD	300000 (2)	300000	100%
Vacuum Distillation Unit	BPSD	240000 (1,2)	176139	73%
Naphtha Hydrotreater	BPSD	33000	30033	91%
Light Naphtha Isomerization	BPSD	10000	7200	72%
Heavy Naphtha Catalytic Reforming	BPSD	35000	31496	90%
Kero Merox	BPSD	13000	11339	87%
Kero Hydrotreater	BPSD	28000	25502	91%
Diesel Hydrotreater	BPSD	80000 (2)	72225	90%
VGO Hydrotreater	BPSD	65000	60153	93%
Fluid Catalytic Cracker	BPSD	60000	55000	92%
FCC Gasoline Post-Treatment Unit	BPSD	23000	20769	90%
Hydrocracker	BPSD	70000	64269	92%
Solvent Deasphalting	BPSD	100000 (2)	90237	90%
IGCC Complex	t/d	8500	7586	89%
Sulphur Recovery Unit	t/d Sulphur	360 (3)	229	64%

Notes
1) VDU design capacity set to manage the operation with Maya Blend
2) Two units in parallel
3) Three Claus trains in parallel.

Table 55: Main Utilities Balance – High Conversion Refinery - BRAZIL

Clean refinery and the role of electricity generation
Refinery Balances

BRAZIL
High Conversion Refinery - 300,000 BPSD
Rev. 1 - January 2019

MAIN UTILITY BALANCE

	FUEL Gcal/h	POWER MW	HP STEAM tons/h	MP STEAM tons/h	LP STEAM tons/h	COOLING WATER (2) m3/h
MAIN PROCESS UNITS	837.6	84.5	38.8	222	128	34089
BASE LOAD		22.5	15	30	30	
POST-COMBUSTION CO2 CAPTURE		1.7	0.0	0.0	77.1	0.0
IGCC COMPLEX (note 1)	2895	-588.0	-54	-252	-235	*100000 (4)*
COOLING WATER SYSTEM (REF)		6.8				-34089
TOTAL	**3732**	**-473**	**0**	**0**	**0**	**0**

FUEL MIX COMPOSITION

	t/h	kt/y	wt%
REFINERY FUEL GAS	41.1	345.4	11%
NATURAL GAS to fuel system	18.0	150.8	5%
FCC Coke	13.3	111.5	3%
Pitch to IGCC (note 3)	316.1	2655.2	81%
TOTAL	**388.5**	**3263.0**	

CO2 EMISSIONS (after CO2 capture)

	t/h			
From FG/NG combustion (CDU/VDU furnaces)	7.4			
From FG/NG/FCC coke combustion (other sources)	136.5			
From IGCC	99.3			
TOTAL	**243.1**	*corresponding to*	***2042.1***	*kt/y*
			132.7	*kg CO2 / t crude*

Notes
1) (-) indicates productions
2) 10°C temperature increase has been considered
3) Part of pitch fed to IGCC is converted to hydrogen and is not to be considered as "fuel"
4) 85000 m3/h as once-through sea cooling water + 15000 m3/h as closed loop cooling water

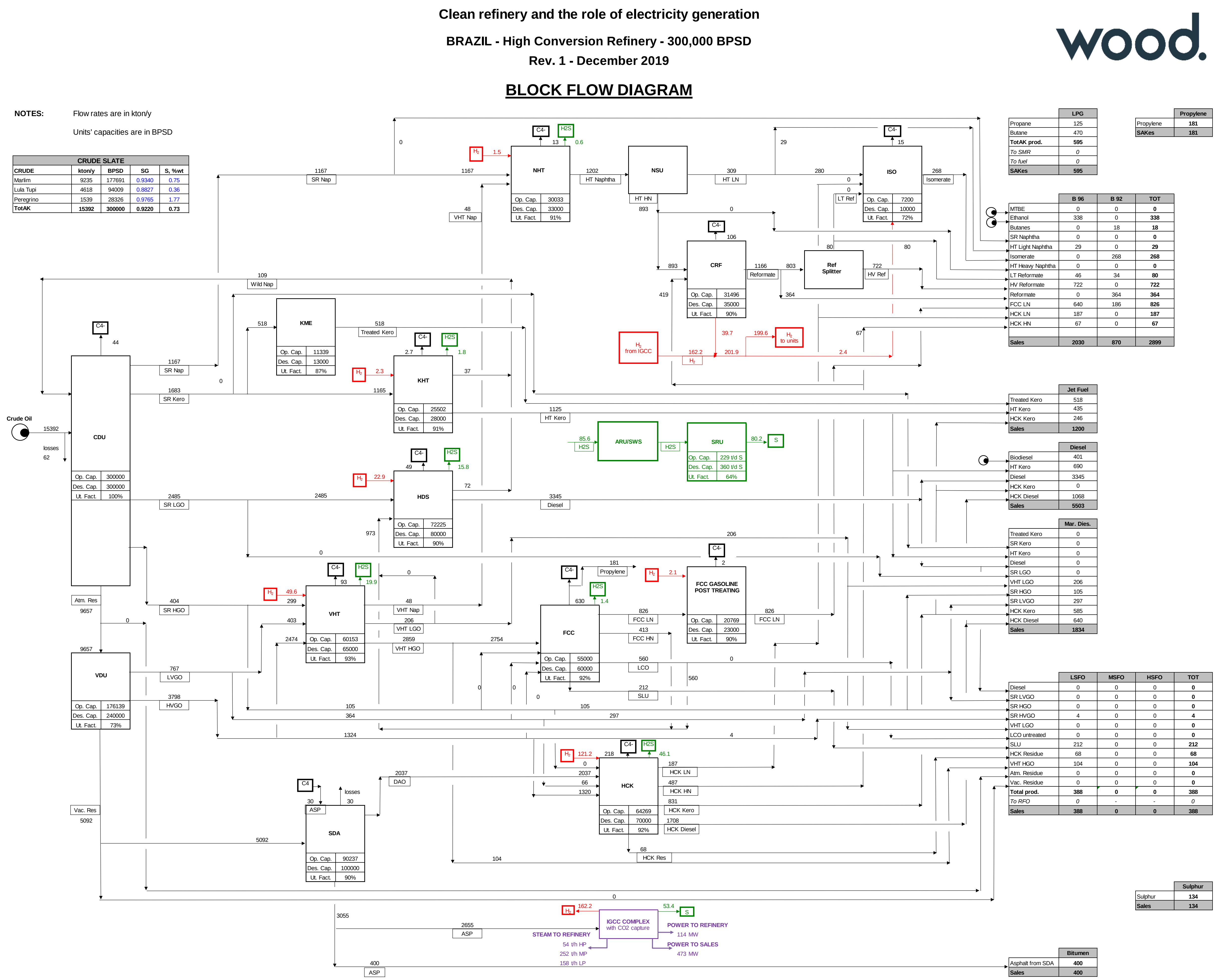


Figure 55: BRAZIL – High Conversion Refinery- Block flow diagram

3.6 Task 3 - Refinery layouts

The refinery layouts for the nine cases have been developed based on the processing schemes and units' capacities defined as a result of the modelling optimisation.

The layouts have been conceived starting from real examples (real sites) in a Wood in-house database.

The following main areas/blocks are shown on the layouts:

- Process units' block (normally located in a central area of the plot);
- Power Plant and Utility block (located in a lateral position with respect to process units);
- Storage tank areas, all around the process units block. Different tank sizes are shown for crude oil, finished products, intermediate products;
- Main pipe-racks connecting the various process units and utility blocks;
- Jetties, railway and truck loading facilities for sending/receiving products;
- Flare and Waste Water Treatment facilities, which are very demanding in terms of plot area.

Layouts of the nine refinery complexes are included in Attachment 6.3.

3.7 Task 3 – CO_2 re-use options

Wood has included in the study an ammonia production unit and a urea production unit to valorise the captured carbon dioxide and part of the syngas produced in the gasification. A Methanol production option is also explored. The cases under study are India HC1 and Brazil HC1, where an IGCC complex is envisaged.

The selected approach is to modify the IGCC configuration described in this report, in order to reduce the amount of captured CO_2 to storage. The principles of the modification are the following:

- Guarantee hydrogen, steam and electric energy demand to the refinery;
- Utilize the excess syngas for urea or methanol production (final products to sale), reducing the electric power export and considering suitable sizes of ammonia and methanol units.

3.7.1 *Ammonia and Urea Production*

The simplified scheme for urea production is shown in Figure 58. The clean syngas from the AGR has the same quality as per the base case design. This flowrate is split into:

- syngas for ammonia and urea production through PSA unit;
- syngas for refinery hydrogen production through PSA unit;
- syngas for steam production (for refinery) and electric energy production (for refinery and power export).

The basis of this study is the definition of a suitable ammonia and urea plant size. The commercial maximum size is 2,500 t/day of NH3 (covered by one train). The conversion of hydrogen to NH_3 in the ammonia production unit is high, due to the low amount of inert N_2 inside the stream of syngas that allows a very limited purge. All the produced NH_3 is then converted into urea that is sold on the market.

A mass and energy balance has been performed in order to find a suitable size for ammonia and urea plants. The selection of plant size is driven by the residual amount of electric energy that can be exported into the grid. In the selected configuration the production of electric energy toward the grid is very limited due to:

- high energy consumption of H_2/N_2 gas compressor;
- energy consumption in ammonia and urea blocks;
- reduced syngas available in the power island.

Moreover, in this configuration, in case of an upset of the power island, electric energy shall be imported from the grid.

The high-level energy balance is shown in Figure 56 for India HC1 and Figure 57 for Brazil HC1.

Table 56 – Ammonia and Urea Plant Size

	Ammonia Plant Size [t/day]	Urea Plant Size [t/day]
INDIA HC1	1,700	3,000
BRAZIL HC1	2,200	3,880

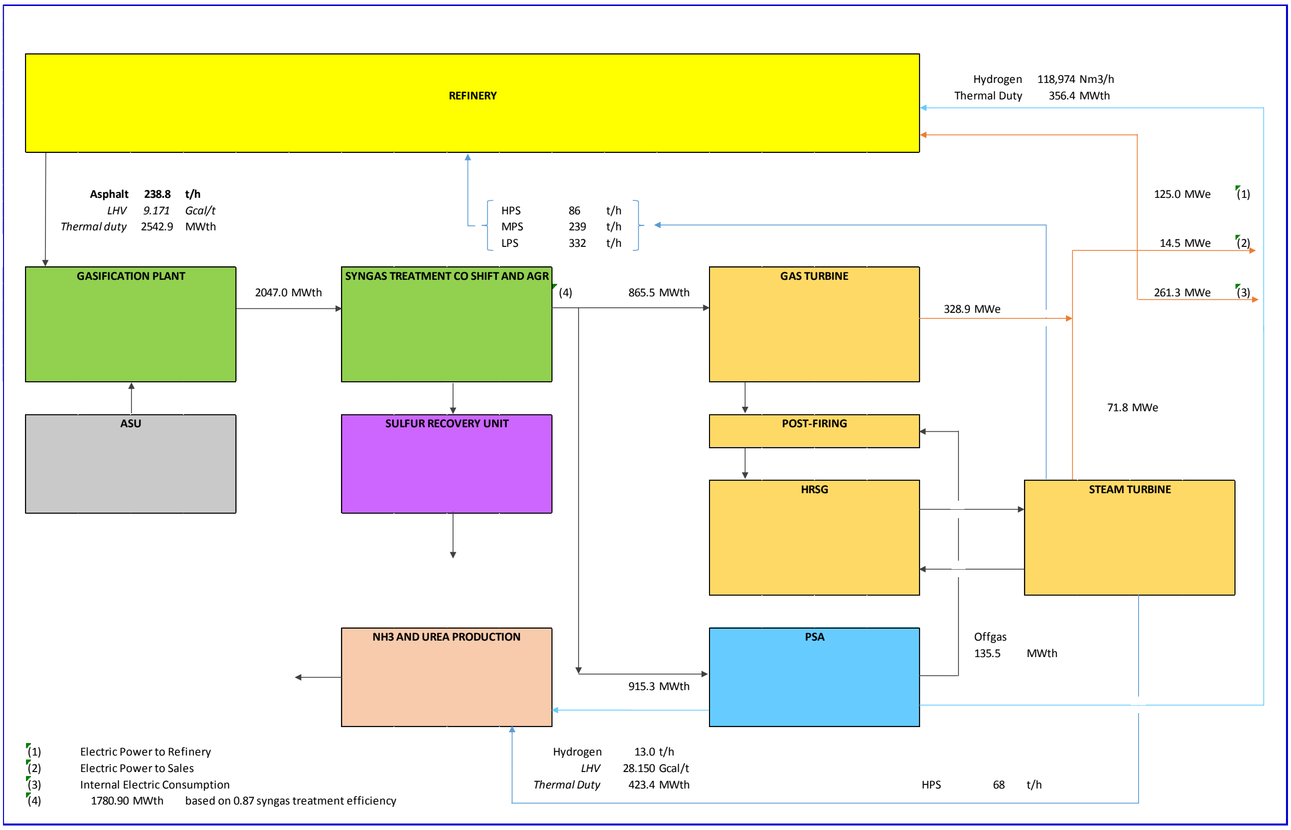


Figure 56 – Integrated Ammonia and Urea Energy Balance – India HC1

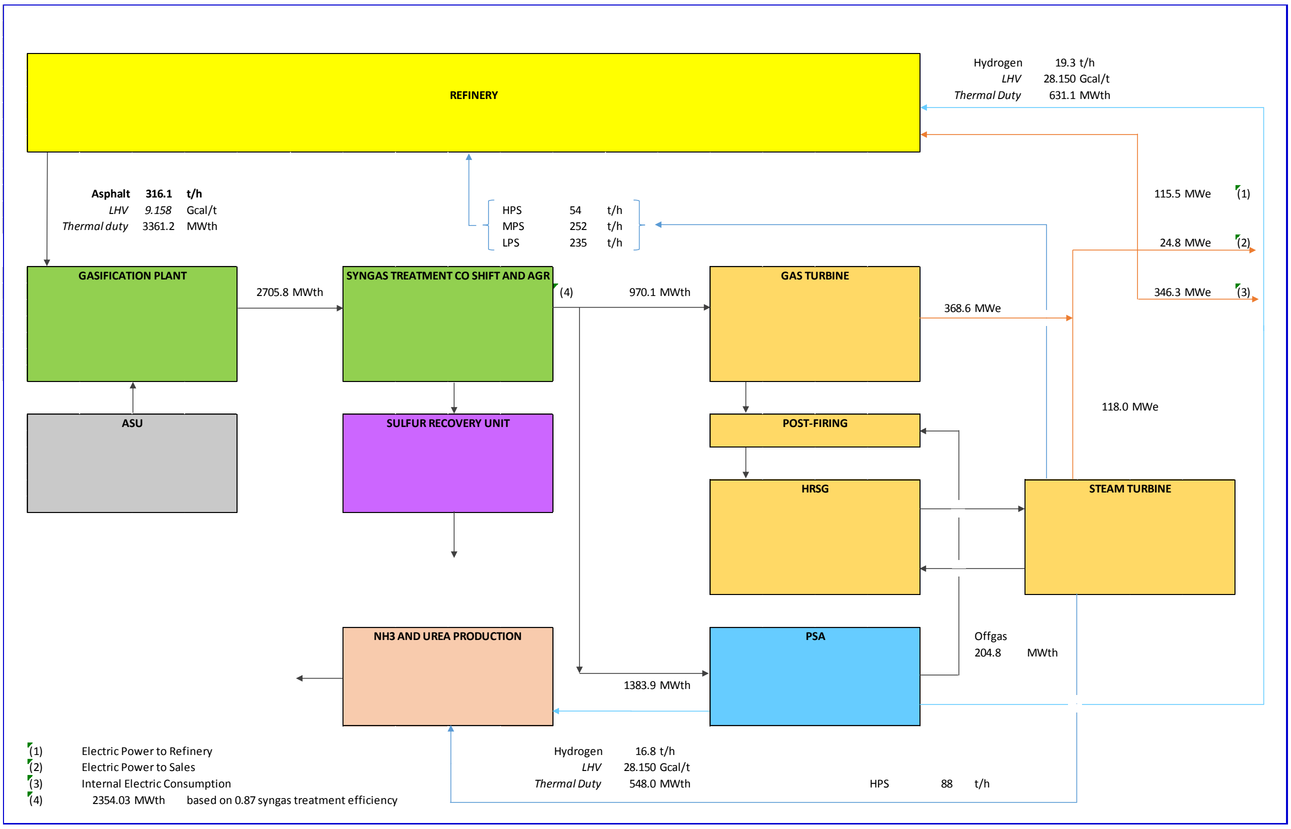


Figure 57 – Integrated Ammonia and Urea Energy Balance – Brazil HC1

By using part of the CO_2 as feed to the urea production unit, the CO_2 balance is modified as shown in Table 57.

Table 57 - CO_2 Balance - Urea Case

	Base Case - CO_2 to storage [t/h]	Urea Case - CO_2 to storage [t/h]	Urea Case - CO_2 to Urea Synthesis [t/h]
INDIA HC1	747.3	655.6	91.7
BRAZIL HC1	959.8	841.2	118.6

A higher amount of CO_2 could be sent to the urea synthesis, with a consequent reduction of the power island size. In this configuration, electric energy is imported from the grid.

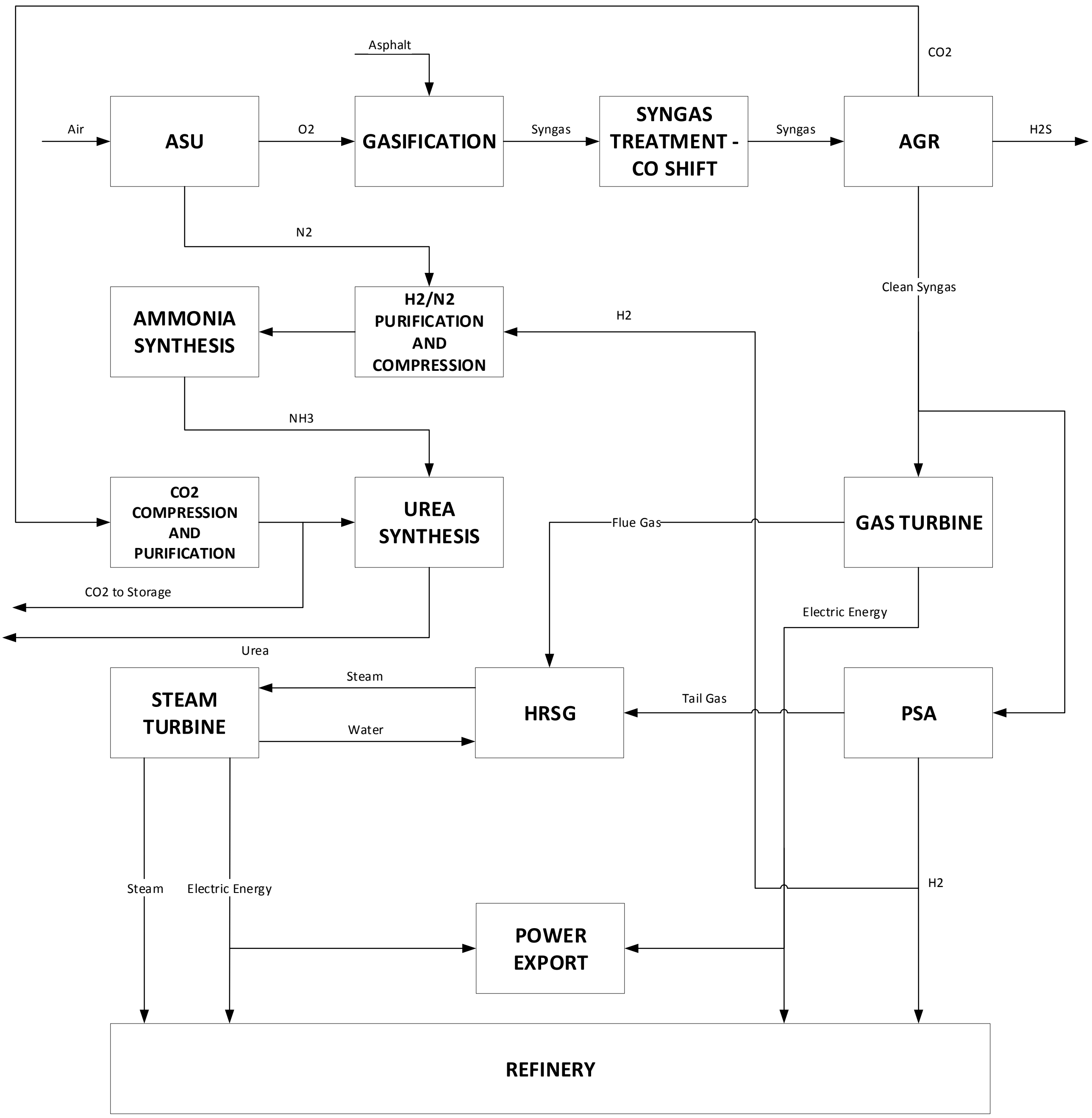


Figure 58 - Urea Case BFD

3.7.2 Methanol Production

The simplified scheme for methanol production is shown in Figure 59. The clean syngas from the AGR has the same quality as per the base case design. This flowrate is split into:

- syngas purification for methanol production;
- syngas for refinery hydrogen production through a PSA unit;
- syngas for steam production (for refinery) and electric energy production (for refinery and power export).

The clean syngas from the AGR is not suitable for methanol synthesis. For this reason, part of it is mixed with a portion of non-shifted syngas, in order to get the following specifications (typical for methanol synthesis):

- $M=(H_2-CO_2)/(CO+CO_2) = 2$ (molar basis)
- $CO_2 = 2.5 – 3.5$ %v

It is possible to reach this specification with a split of about 22% of non-shifted syngas. The resulting CO_2 is 3.02 %v.

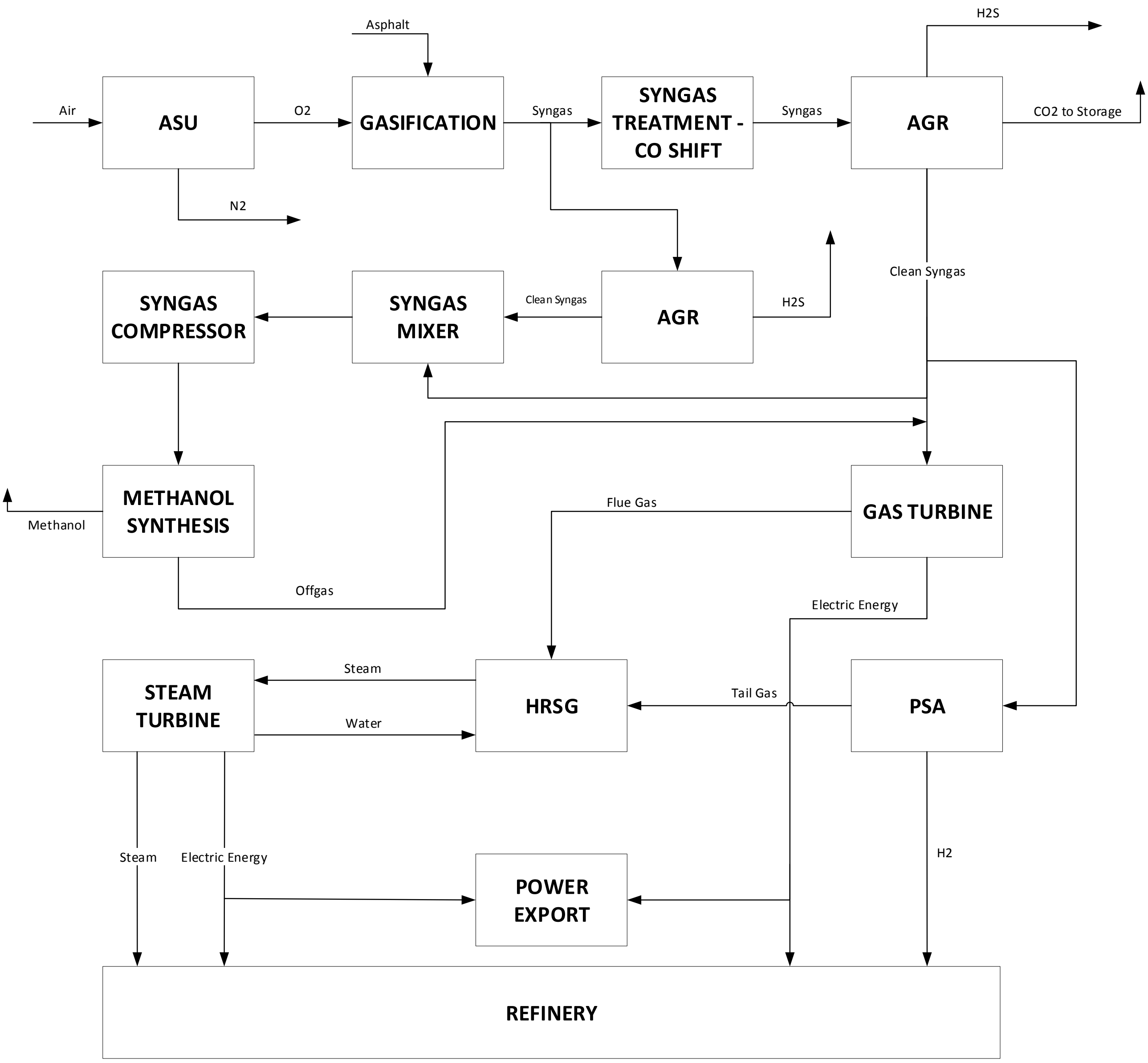


Figure 59 - Methanol Case BFD

The basis of this study is the definition of a suitable methanol plant size. The commercial maximum size is 5,000 t/day of methanol. On the other hand, it is necessary to send to the GT cycle enough syngas in order to sustain the energy internal consumption of the entire refinery complex. For this reason, the exported electric energy toward the grid in the selected configuration is very limited due to:

- high energy consumption of syngas compressor;
- energy consumption in methanol block;
- reduced syngas available in the power island.

The high-level energy balance is shown in Figure 60 for India HC1 and Figure 61 for Brazil HC1

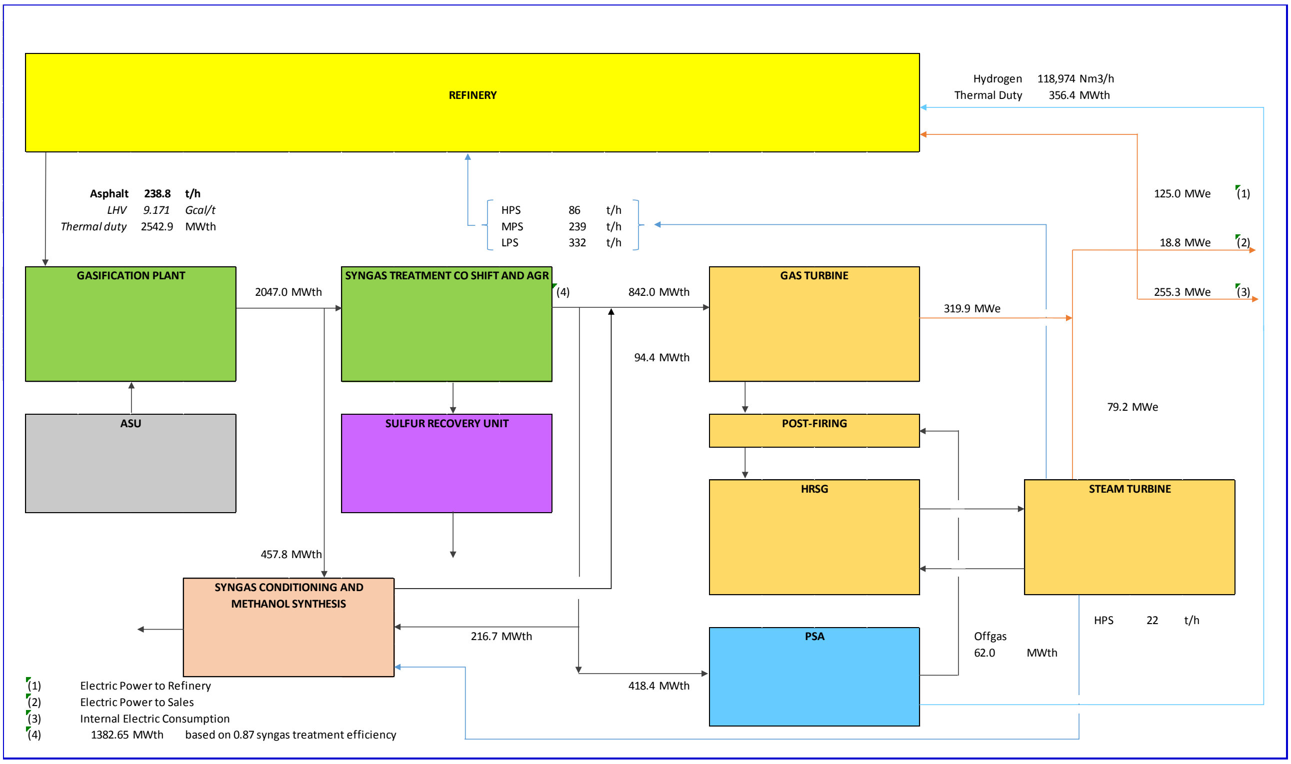


Figure 60 – Integrated Methanol Energy Balance – India HC1

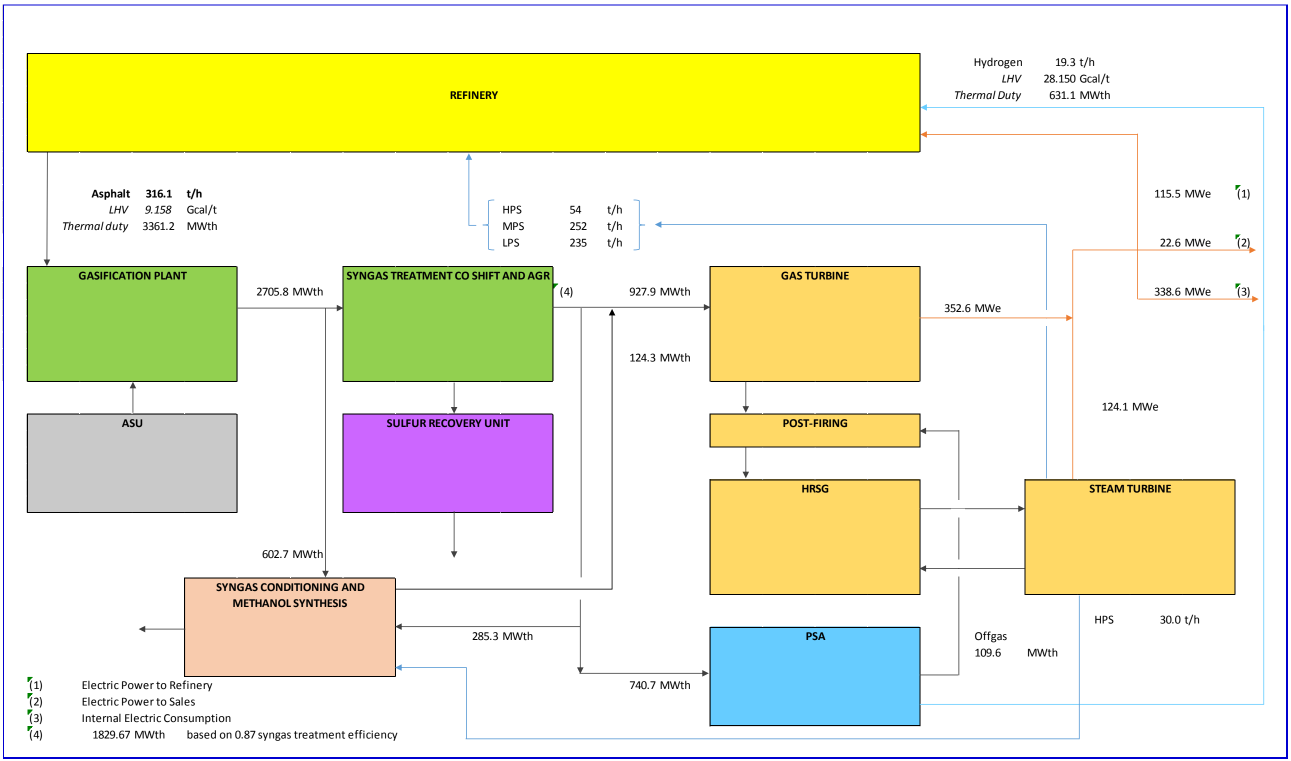


Figure 61 – Integrated Methanol Energy Balance – Brazil HC1

The resulting methanol plant sizes are shown in Table 58:

Table 58 - Methanol Plant Size

	Methanol Plant Size [ton/day]
INDIA HC1	2,300
BRAZIL HC1	3,000

Most of the syngas is transformed in methanol, being the conversion factor about 85%. The inert gas contained in the syngas (N_2, CO_2, Argon etc) are purged in the off gas stream, containing also H_2 and CH_4 whose thermal content can be recovered in the gas turbine.

By using part of the syngas (containing CO and CO_2) for methanol production, the CO_2 Balance is modified as shown in Table 59:

Table 59 - CO_2 Balance - Methanol Case

	Base Case - CO_2 to storage [t/h]	Methanol Case - CO_2 to storage [t/h]
INDIA HC1	747.3	526.3
BRAZIL HC1	959.8	667.2

4 Task 4 – Financial Performance

This section reports the basis, methodology and results of the economic analysis performed on the nine refinery configurations described in the previous Task 3.

4.1 Investment Cost Estimation

4.1.1 Methodology

The cost for the main units has been estimated on a pro-rate capacity basis starting from the in-house database for similar units, populated with cost data from previous Projects. The capacity factored estimate is an AACE (Association for the Advancement of Cost Engineering) recommended practice and is proved to be a reliable method in the preparation of Class 4 and 5 estimates.

$$\text{Cost}_{actual} = \left(\frac{\text{Capacity}_{actual}}{\text{Capacity}_{ref}}\right)^{\text{exp}} \times \text{Cost}_{ref}$$

Where:

- $\text{Cost}_{\text{actual}}$ is the cost of the plant under evaluation;
- Cost_{ref} is the cost of the reference plant;
- $\text{Capacity}_{\text{actual}}$ and $\text{Capacity}_{\text{ref}}$ are the respective capacities of the plants;
- exp is the exponent, which typically varies between 0.5 and 0.85, depending on plant type and size.

Location factors and cost indexes are also considered. Location Factors and Cost Indexes have been applied to the factored costs to properly reflect the plant location and to actualize the cost of the reference plants. Numerically, location factors and cost indexes are multiplied by the result of the above formula.

Location factors take into account:

- materials;
- labour cost;
- labour productivity.

Such factors, typically referred to the USGC (US Gulf Coast) base, have been combined to reflect impact on costs due to the different locations. The estimated location factors are the following:

- India location factor: 0.93;
- Nigeria location factor: 1.31;
- Brazil location: 0.96.

The location factor for India and Brazil is almost equal to the reference location. In contrast, the Nigeria location factor is more than 30% higher. This factor takes into account the limited number of contractors available in Nigeria. For this reason, foreign contractors are required with an associated cost impact. Moreover, the location factor accounts for the limited number of factories to supply materials, which need to be imported from abroad, and safety and security issues associated with this country.

Cost Indexes relate the plant costs at a specific time and are typically applied in adjusting process plant construction costs from one period to another. The Reference Plant costs have been updated by making use of the Chemical Engineering Cost Index (CEPCI).

The estimate is in current currency. All the documentation relevant to TIC estimation for all the cases is attached at the end of this report (Attachment 6.4).

These tables provide the details of the estimate, divided by areas, i.e. Process Units, Power Units, CO_2 Capture Units, Utilities and Offsite and Solid Handling. In particular, the investment cost for Utilities, Offsite and Solid Handling is evaluated as a percentage of the investment cost for the other units:

- Process Utility Units: 25% of TIC of Process units;
- Process Off-Sites Units: 35% of TIC of Process units;
- Power Utility and Offsite Units: 18% of TIC of Power units for Cogeneration Power Plant; 15% of TIC of Power units for IGCC complex;
- Power Solid Handling Units: 7% of TIC of Power units for petcoke Cogeneration Power Plant; 3% of TIC of Power units for fuel oil Cogeneration Power Plant; 4% of TIC of Power units for IGCC complex.

The estimate excludes the following:

- The cost of land
- The cost covering process licensors fee such as technology fee, PDP preparation, royalties and the like
- The cost relevant to the local authorities permitting fee's
- The commissioning and start-up cost
- The cost associated to the utilities generation and consumption during the commissioning stage
- The cost of catalyst and chemicals and lubricants
- The local taxes of any kind
- Custom Duties
- All risk insurance
- Financial cost
- Capital and start-up spare parts
- Interest during construction
- Owner Cost

Further to the investment cost (TIC), other CAPEX is estimated as follows:

- Catalyst and Chemical Cost: typically assumed equal to 3% of TIC of Process Units.
- License fees, Royalties and Engineering fees: typically assumed equal to 3% of TIC of Process Units and 3% of TIC of IGCC, if present.
- Spare Parts: typically assumed equal to 2% of total TIC.
- Start-up expenses: typically assumed equal to 2.5% of total TIC. It includes the cost of utilities during start-up, consumable spare-parts, cost for re-processing the off-spec products, assistance of Licensors and Vendors, etc.
- Other expenses: typically assumed equal to 1.5% of total TIC. It includes the other cost items excluded from the TIC (previously indicated as TIC exclusions) and not listed in this bulleted list, evaluated on a statistical basis.

4.1.1.1 Power Plant Analysis for TIC estimation

TIC estimation for power plant required a deeper analysis with respect to the concepts presented in the previous section. The basis for the definition of the power plant configuration is to guarantee all the electric energy and steam for the refinery, in case of shut down of one main component of the power island. Moreover, adequate sparing facilities are foreseen in the Power Plant to guarantee the required operating factor.

The different power plant configurations are described here below:

- Cogeneration Power Plant – fuel oil feedstock:
    - Conventional steam boiler + steam turbine (boiler island, DeNOx, FGD, Steam Cycle, CO2 Amine Absorption if applicable);
    - 3x50% trains configuration for high capacity, 2x100% trains configuration for low capacity cogeneration power plants (less than 150 MWe, i.e. Nigerian cases). Low capacity cogeneration power plants are considered as a utility of the refinery. Based on this, a different approach for the estimation is envisaged (no split of the cost in the different section, TIC considered on the basis of the produced electric power).
- Cogeneration Power Plant – petcoke feedstock:
    - Circulating Fluidized Bed (CFB) boiler + steam turbine (boiler island, DeNOx, Steam Cycle, CO_2 Amine Absorption);
    - 2x100% trains configuration.
- Integrated Gasification Combined Cycle (IGCC) – pitch feedstock:
    - Dedicated schemes and sparing philosophy have been worked out for India and Brazil cases, depending on the feed rate, hydrogen demand, steam and power demand;
    - See dedicated schemes (Sections 4.1.1.1.1 and 4.1.1.1.2) for details.

4.1.1.1.1 India IGCC Complex (HC1)

The IGCC scheme envisaged for India HC1 is showed in Figure 62. The asphalt flowrate to the gasification section is equal to about 240 t/h. There is a constraint on the maximum capacity of a single gasification train (about 80-90 t/h), confirmed by a major gasification Licensor. For this reason, three parallel trains have been envisaged.

To satisfy the refinery electric power and steam demand in case of the shut-down of one gasifier, the proposed gasifiers configuration is 3x40% trains, allowing an extra capacity. The other process sections are designed to treat the extra capacity of the gasification section.

The other critical element is the gas turbine: to satisfy the refinery electric power and steam demand in case of a shut-down of one gas turbine, a configuration 3x40% train is envisaged. The HRSG (Heat Recovery Steam Generator) has the same configuration of the gas turbine.

In both the cases (one gasifier shut down or one gas turbine shut down), it is still possible to export to the grid more than 60% of the normal export.

All the other units are designed according to general criteria of a typical IGCC complex.

wood.

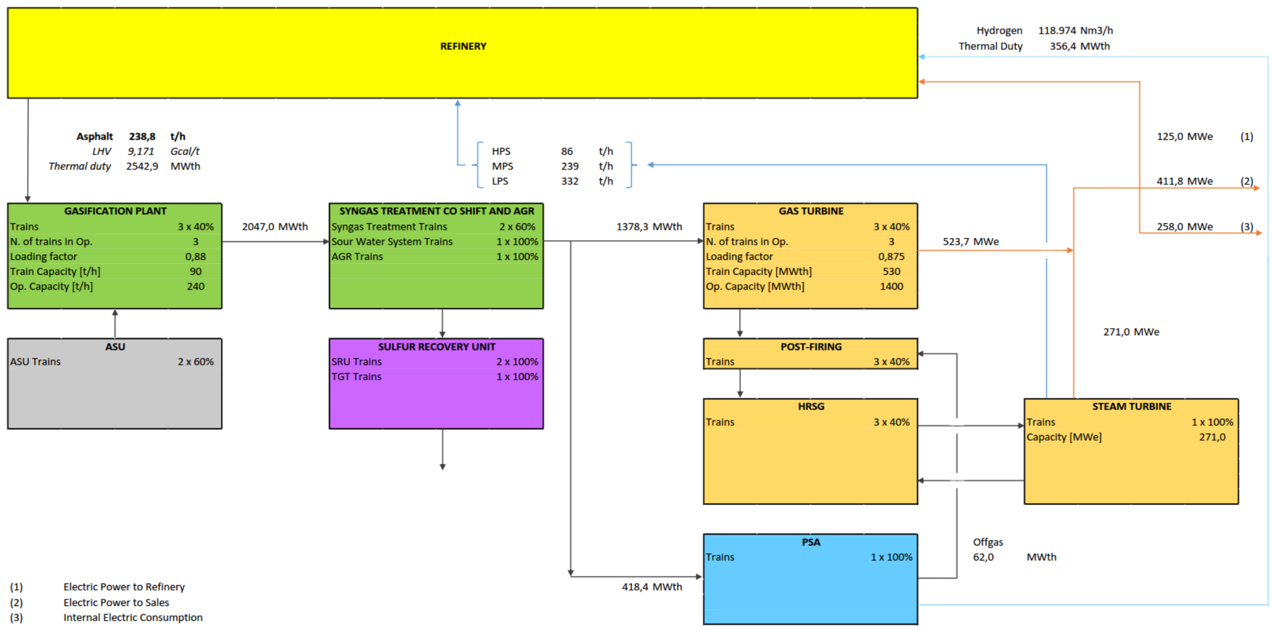


Figure 62 - IGCC Complex India HC1

4.1.1.1.2 Brazil IGCC Complex (HC1)

The IGCC scheme envisaged for Brazil HC1 is showed in Figure 63. The asphalt flowrate to the gasification section is equal to 316 t/h. Based on the maximum possible capacity of the single gasifier train, a configuration of 4x25% train is selected (about 80 t/h each gasifier). This configuration guarantees the refinery electric power and steam demand in case of the shut-down of one gasifier, even if no extra capacity is provided. The same scenario is also guaranteed for the gas turbine configuration (3x33%).

In both the cases (gasifier shut down or gas turbine shut down), it is still possible to export to the grid more than 50% of the normal export.

All the other units are designed according to general criteria of a typical IGCC complex.

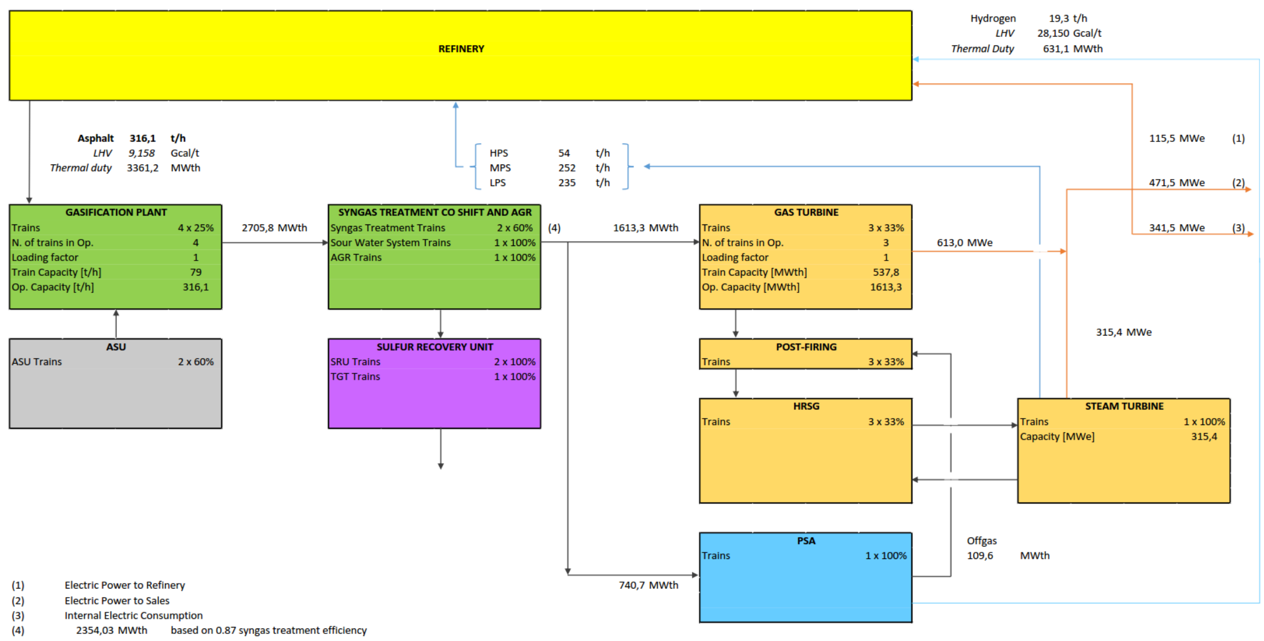


Figure 63 - IGCC Complex Brazil HC1

4.1.1.2 CO_2 Compression and Purification Analysis for TIC estimation

A configuration with 2x50% trains is envisaged. CO_2 is collected from all the sources from refinery and power plant through a common header and compressed by a four stage compressor from 2 bar to75 bar. No spare capacity has been envisaged: in the event of compressor shut-down, it is accepted that CO_2 is partially vented to atmosphere for a short period.

4.1.2 TIC results - India

In Table 60 the Total Investment Cost (TIC) is shown for the three Indian cases, split in Refinery, Power units and CO_2 Capture:

Table 60 - India Total Investment Cost

	MC1	HC1	HC2
TIC Refinery [MM USD]	*3,339*	*6,277*	*7,388*
TIC Power Units [MM USD]	*2,214*	*2,455*	*1,354*
TIC CO_2 Capture [MM USD]	*0*	*305*	*533*
TIC Total [MM USD]	**5,553**	**9,037**	**9,275**

All the data are taken from Attachment 6.4.

It is worth noting that in Table 60 the portion of TIC for CO_2 capture relevant to power units is reported in the row "TIC CO_2 capture", while in Attachment 6.4 it is included in the cost for power units.

Based on TIC estimation, all the CAPEX contributions can be calculated as percentage of the TIC (Table 61):

Table 61 - CAPEX India

	MC1	HC1	HC2
Total Units Investment Cost [MM USD]	5,553	9,037	9,275
Catalyst Costs (first batch) [MM USD]	*63*	*118*	*139*
Process License Fees, Royalties, Engineering Fees [MM USD]	*63*	*118*	*139*
IGCC License Fees, Royalties, Engineering Fees [MM USD]	*0*	*66*	*0*
Spare Parts [MM USD]	*111*	*181*	*185*
Start-up Expenses [MM USD]	*139*	*226*	*232*
Other Expenses [MM USD]	*83*	*136*	*139*
Total Other Investment Costs [MM USD]	458	843	834
Total CAPEX [MM USD]	**6,011**	**9,880**	**10,108**

4.1.3 TIC results - Brazil

Table 62 summarizes the Total Investment Cost (TIC) for the three Brazilian cases, split into Refinery, Power units and CO_2 Capture.

Table 62 - Brazil Total Investment Cost

	MC1	MC2	HC1
TIC Refinery [MM USD]	*2,609*	*4,416*	*5,780*
TIC Power Units [MM USD]	*2,371*	*3,367*	*2,862*
TIC CO_2 Capture [MM USD]	*805*	*1102*	*372*
TIC Total [MM USD]	5,785	8,885	9,014

All the data are taken from Attachment 6.4.

It is worth noting that in Table 60 the portion of TIC for CO_2 capture relevant to power units is reported in the row "TIC CO_2 capture", while in Attachment 6.4 it is included in the cost for power units.

Based on TIC estimation, all the CAPEX contributions can be calculated as a percentage of the TIC (Table 63):

Table 63 - CAPEX Brazil

	MC1	MC2	HC1
Total Units Investment Cost [MM USD]	5,785	8,885	9,014
Catalyst Costs (first batch) [MM USD]	*49*	*83*	*108*
Process License Fees, Royalties, Engineering Fees [MM USD]	*49*	*83*	*108*
IGCC License Fees, Royalties, Engineering Fees [MM USD]	*0*	*0*	*77*
Spare Parts [MM USD]	*116*	*178*	*180*
Start-up Expenses [MM USD]	*145*	*222*	*225*
Other Expenses [MM USD]	*87*	*133*	*135*
Total Other Investment Costs [MM USD]	445	699	834
Total CAPEX [MM USD]	**6,230**	**9,584**	**9,848**

4.1.4 TIC results - Nigeria

Table 64 summarizes the Total Investment Cost (TIC) for the three Nigerian cases, split in Refinery, Power units and CO_2 Capture:

Table 64 - Nigeria Total Investment Cost

	LC1	MC1	HC1
TIC Refinery [MM USD]	*2,536*	*3,707*	*3,707*
TIC Power Units [MM USD]	*146*	*194*	*605*
TIC CO_2 Capture [MM USD]	*0*	*0*	*240*
TIC Total [MM USD]	**2,682**	**3,901**	**4,552**

All the data are taken from Attachment 6.4.

It is worth noting that in Table 64 the portion of TIC for CO_2 capture relevant to power units is reported in the row "TIC CO_2 capture", while in Attachment 6.4 it is included in the cost for power units.

Based on TIC estimation, all the CAPEX contributions can be calculated as a percentage of the TIC (Table 65):

Table 65 - CAPEX Nigeria

	LC1	MC1	HC1
Total Units Investment Cost [MM USD]	2,682	3,901	4,552
Catalyst Costs (first batch) [MM USD]	*48*	*70*	*70*
Process License Fees, Royalties, Engineering Fees [MM USD]	*48*	*70*	*70*
IGCC License Fees, Royalties, Engineering Fees [MM USD]	*0*	*0*	*0*
Spare Parts [MM USD]	*54*	*78*	*91*
Start-up Expenses [MM USD]	*67*	*98*	*114*
Other Expenses [MM USD]	*40*	*59*	*68*
Total Other Investment Costs [MM USD]	256	373	412
Total CAPEX [MM USD]	**2,937**	**4,274**	**4,964**

•

4.2 Operating & Maintenance Costs

4.2.1 Methodology

Operating costs are divided in two types:

- Variable operating costs, proportional to the operating throughput
- Fixed operating costs, independent of the operating throughput.

Main variable operating costs (raw materials, main utilities) are already accounted for in the refinery balances. Additionally, the following fixed operating costs are considered.

- Maintenance (Materials and Contractor Costs)
  - Refinery: 3% of Process Units Total Investment Cost (TIC), plus 1% of Utilities & Offsite Units TIC
  - IGCC: 2.5% of TIC including utilities and offsites
  - Cogeneration Power Plant (ST + Boiler) including utilities and offsites: 1.5% of TIC.
- Chemicals and Catalyst: estimated as 1% of Total Investment Cost.
- Plant Insurance: typically estimated as 0.5% of Total Investment Cost.
- Labour (Own and Contracted Personnel): the labour cost is estimated by multiplying the number of workers times an average yearly salary (assumed for each Country). The number of workers is estimated with the in-house database for similar plants. The database is based on a typical European refinery. The following productivity factors for average skilled operators have been considered to determine the equivalent local staff:
  - India: 1.8
  - Nigeria: 1.8
  - Brazil: 1.5

  A percentage (based on % of local staff) of foreign staff has been envisaged, to assist and train the local staff in operating the refinery, at least during the first 10-15 years from the first start-up:

  - India: 10%
  - Nigeria: 35%
  - Brazil: 20%

  The following average local annual salaries are considered:
  - India: 20,000 USD
  - Nigeria: 20,000 USD
  - Brazil: 30,000 USD

  The estimated annual salary for foreign staff is equal to 120,000 USD.

Based on the above data, the resulting labour cost estimation for all the nine cases is shown in the following Table 66:

Table 66 - Labour Cost Estimation Results

Size	India	Nigeria	Brazil
Power integrated simple Hydro-skimming refinery Low to medium size	-	150000 bpd EU staff: 370 Nigeria staff (*): 910 Annual cost (MMUSD/y): 49	-
Power integrated Medium conversion refinery Medium to Large – Size 1	250000 bpd HCU Scheme EU staff: 680 India staff (*): 1350 Annual cost (MMUSD/y): 39	200000 bpd FCC Scheme EU staff: 540 Nigeria staff (*): 1310 Annual cost (MMUSD/y): 70	150000 bpd HCU Scheme EU staff: 600 Brazil staff (*): 1080 Annual cost (MMUSD/y): 49
Power integrated Medium conversion refinery Medium to Large – Size 2	-	-	250000 bpd HCU + FCC Scheme EU staff: 670 Brazil staff (*): 1220 Annual cost (MMUSD/y): 55
Power integrated bottom of the barrel solution Medium to very large size	400000 bpd Scheme 1 HCU+FCC Scheme EU staff: 810 India staff (*): 1610 Annual cost (MMUSD/y): 47	200000 bpd FCC Scheme EU staff: 540 Nigeria staff (*): 1310 Annual cost (MMUSD/y): 70	300000 bpd HCU + FCC Scheme EU staff: 810 Brazil staff (*): 1470 Annual cost (MMUSD/y): 66
Power integrated bottom of the barrel solution Medium to very large size	400000 bpd Scheme 2 HCU+FCC Scheme EU staff: 680 India staff (*): 1360 Annual cost (MMUSD/y): 39	-	-

Other fixed operating costs could be accounted for Land Rental, Environmental Tax, Administration Expenses, etc. They are however quite site-specific and very difficult to be generalized for reference cases.

4.2.2 O&M - India

The resulting OPEX costs (MM$/y) for each term are shown in Table 67:

Table 67 - OPEX India

	MC1	HC1	HC2
Manpower [MM$/y]	39	47	39
Catalyst and Chemicals [MM$/y]	56	90	93
Plant Insurance [MM$/y]	28	45	46
Maintenance Process Units [MM$/y]	63	118	139
Maintenance Utility&Offsite Process Units [MM$/y]	13	24	28
Maintenance Power Units [MM$/y]	33	69	28
Total OPEX [MM$/y]	**231**	**393**	**373**

4.2.3 O&M - Brazil

The resulting OPEX costs (MM$/y) for each term are shown in Table 68:

Table 68 - OPEX Brazil

	MC1	MC1	MC1
Manpower [MM$/y]	49	55	66
Catalyst and Chemicals [MM$/y]	58	89	90
Plant Insurance [MM$/y]	29	44	45
Maintenance Process Units [MM$/y]	49	83	108
Maintenance Utility&Offsite Process Units [MM$/y]	10	17	22
Maintenance Power Units [MM$/y]	48	67	81
Total OPEX [MM$/y]	**242**	**354**	**412**

4.2.4 O&M - Nigeria

The resulting OPEX costs (MM$/y) for each term are shown in Table 69:

Table 69 - OPEX Nigeria

	LC1	MC1	HC1
Manpower [MM$/y]	49	70	70
Catalyst and Chemicals [MM$/y]	27	39	46
Plant Insurance [MM$/y]	13	20	23
Maintenance Process Units [MM$/y]	48	70	70
Maintenance Utility&Offsite Process Units [MM$/y]	10	14	14
Maintenance Power Units [MM$/y]	2	3	13
Total OPEX [MM$/y]	**148**	**215**	**235**

4.3 Financial modelling

4.3.1 *Methodology and Assumptions*

The financial analysis is based on the calculation of the financial parameters Net Present Value (NPV) and Internal Rate of Return (IRR). Therefore, the financial analysis is a high-level economical evaluation only, while the rigorous project profitability for the specific cases is beyond the scope of the present study.

The following assumptions have been considered:

- Discount rate 8%
- Economic lifetime of 25 years
- Start of the project 2019
- Start of construction 2021
- Four years of engineering, with the following curve (typical): year 1 (15%), year 2 (25%), year 3 (30%), year 4 (30%)
- Four years of construction, with the following curve of capital expenditure (typical): year 1 (5%), year 2 (25%), year 3 (45%), year 4 (25%)
- Project 100% financed on equity
- Effect of inflation not considered
- Operating factor of 80% in the start-up year and then, for the following years:
    - 35 days of operation lost every four years, resulting in 90% operating factor
    - 7 days of operation lost in the remaining years, resulting in 98% operating factor
- Based on several market analyses available to Wood (confidential), an increase of middle distillates price equal to 5 USD/ton/y from the current market price has been assumed. On the other side, the fuel oil price has been penalized by 5 USD/ton/y (low sulphur fuel oil (LSFO), medium sulphur fuel oil (MSFO), high sulphur fuel oil (HSFO). The price of the other products and raw materials is kept unchanged. The price trends of middle distillates and fuel oil are shown in Figure 64:

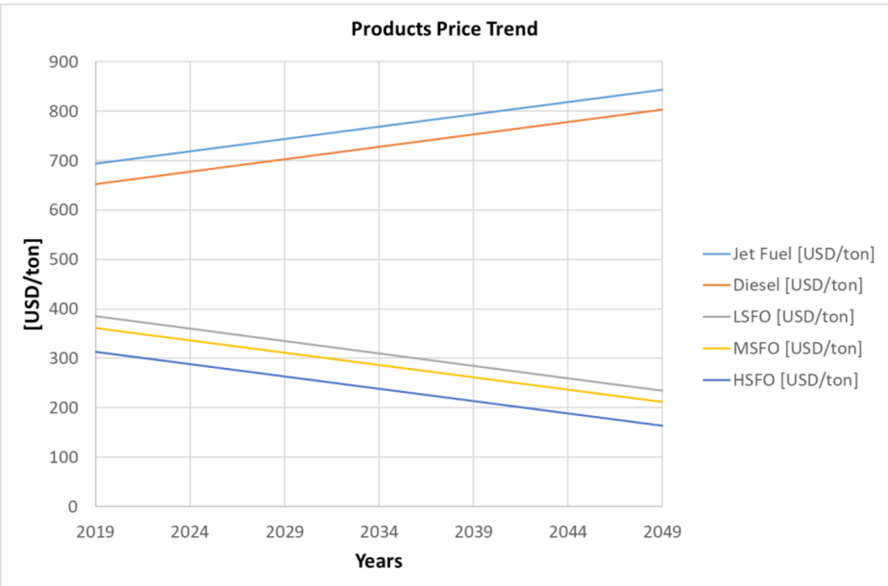


Figure 64 - Products Price Trend

All the documentation related to the calculation of the NPV and IRR (i.e. cash flow analysis) is shown in Attachment 6.5 for the nine base case configurations. For each configuration, the document is divided in:

- Financial analysis assumptions, already discussed above in this section;
- Summary of the CAPEX estimations;
- Summary of the fixed OPEX estimations;
- Costs and revenues analysis, i.e. the costs related to feedstock, utilities, fixed OPEX, and the revenues from selling products and electric energy (if applicable);
- Cash flow analysis, whose outputs are calculated from standard NPV and IRR techniques. These financial parameters are determined using dedicated excel functions.

4.3.2 *Financial Modelling - India*

The financial performance is summarized in Table 70:

Table 70 - Financial Performances INDIA

	Refinery Configuration	NPV [MM USD]	IRR
MC1	250 kBPD, HCU, FO boiler	895	10%
HC1	400 kBPD, HCU+FCC, SDA+IGCC	6,567	16%
HC2	400 kBPD, HCU+FCC, SDA+DCU+CFB	8,949	18%

4.3.1 *Financial Modelling - Brazil*

The financial performance is summarized in Table 71:

Table 71 - Financial Performances BRAZIL

	Refinery Configuration	NPV [MM USD]	IRR
MC1	150 kBPD, HCU, FO boiler	-1,972	3%
MC2	250 kBPD, HCU+FCC, FO boiler	-2,615	4%
HC1	300 kBPD, HCU+FCC, SDA+IGCC	-1,505	6%

The scope of this section is informative only. A critical discussion of the results is performed in Chapter 5 Task 5 – Analysis and Conclusions. It is worth mentioning that a negative value of NPV is linked with an IRR lower than 8% (value of the discount rate). It means that the investment is not profitable since the return of the investment is lower than the discount rate.

4.3.2 *Financial Modelling - Nigeria*

The financial performance is summarized in Table 72:

Table 72 - Financial Performances NIGERIA

	Refinery Configuration	NPV [MM USD]	IRR
LC1	150 kBPD, Hydroskimming, FO boiler	-454	6%
MC1	200 kBPD, FCC, FO boiler	1,045	11%
HC1	200 kBPD, FCC, FO boiler	506	9%

It is worth mentioning that a negative value of NPV is linked with an IRR lower than 8% (value of the discount rate). It means that the investment is not profitable since the return of the investment is lower than the discount rate.

5 Task 5 – Analysis and Conclusions

5.1 Comparison of Alternative Process Schemes

The scope of this section is to compare alternative process schemes, based on technical and economic criteria.

Technical criteria are the following:

- Plant complexity;
- Efficiency/conversion;
- Export of electricity;
- Environmental impact: gaseous emissions, liquid effluent, water usage;
- Environmental impact: CO_2 emission;
- Operating flexibility;
- Plot plan requirements.

On the other hand, the economic comparison is performed at three different levels:

- CAPEX parameters;
- OPEX parameters;
- Financial parameters.

5.1.1 India

5.1.1.1 Technical Comparison

The products' yields of the three configurations studied for India are compared in Figure 65, defined as a percentage on crude oil feed.

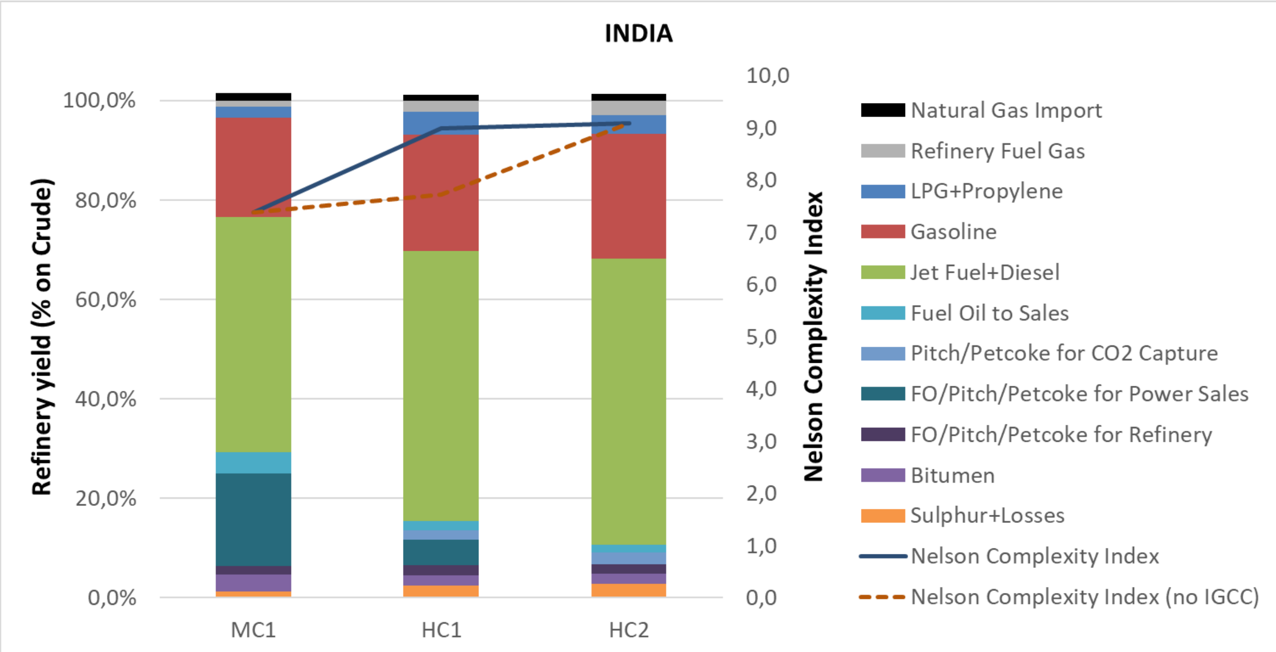


Figure 65 - Refinery Yield INDIA

It is worth highlighting that from the Medium Conversion refinery (MC1) to the High Conversion refineries (HC1 and HC2) the yield in black -unconverted- products (fuel oil, asphalt-pitch, bitumen) decreases while the naphtha and gasoil productions increase. This is due to the presence, in the most complex schemes, of the bottom-of the-barrel conversion units (SDA, DCU and IGCC), that convert the heavy residues to lighter and more valuable products.

The degree of complexity is defined through the Nelson Complexity Index, which associates a complexity factor to each refinery unit. The detailed definition of the Nelson Complexity Index is the following:

$$\frac{\sum \mathit{Unit\ Complexity\ Capacity}}{\mathit{CDU\ Complexity\ Capacity}}$$

An IGCC complex, which is sometimes considered as a "separate" entity with respect to the rest of the refinery, can contribute as well to the definition of Nelson Complexity Index, as shown in Figure 65.

It can be noted that the Nelson Complexity Indexes of High Conversion schemes HC1 (SDA+IGCC) and HC2 (SDA+DCU) are practically equivalent.

To close the refinery fuel gas balance, an import of natural gas from the grid is needed to feed the refinery process heaters. In Figure 65 this import is shown as an increment above 100%, since all the other products, including the fuels used for power and steam productions, are generated from crude oil.

From Figure 65, it is possible to isolate certain contributions to separately illustrate some specific effects. Figure 66 shows the refinery conversion, that is the percentage of distillates, LPG and eventually propylene obtained from crude oil. The conversion is clearly increasing from MC1 to HC2, passing from approx. 70% to 85%.

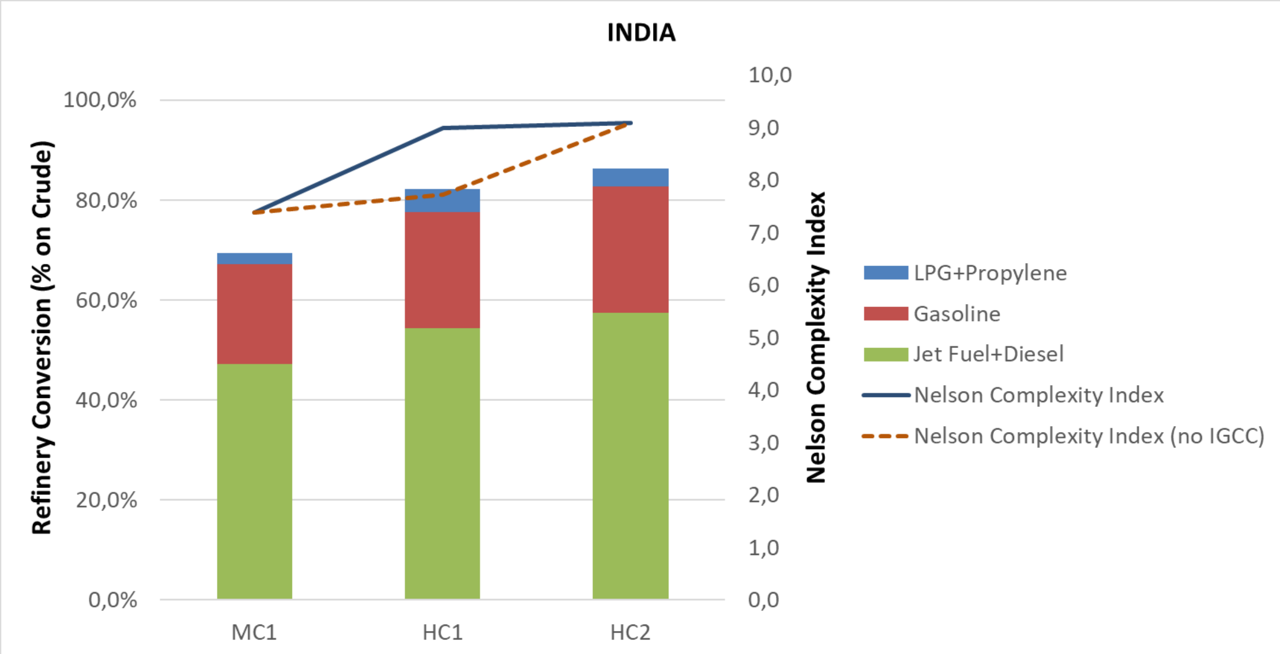


Figure 66 – Refinery Conversion INDIA

The total amount of fuels used for refinery operation and power generation is shown in Figure 67.

In this chart, the fuel oil/pitch/petcoke contribution is divided into different terms, based on the final destination of the produced electric energy/steam. Part of the energy/steam is used to sustain the refinery operation, part to sustain CO_2 capture facilities, and only the remaining part of fuel is used for electric power export.

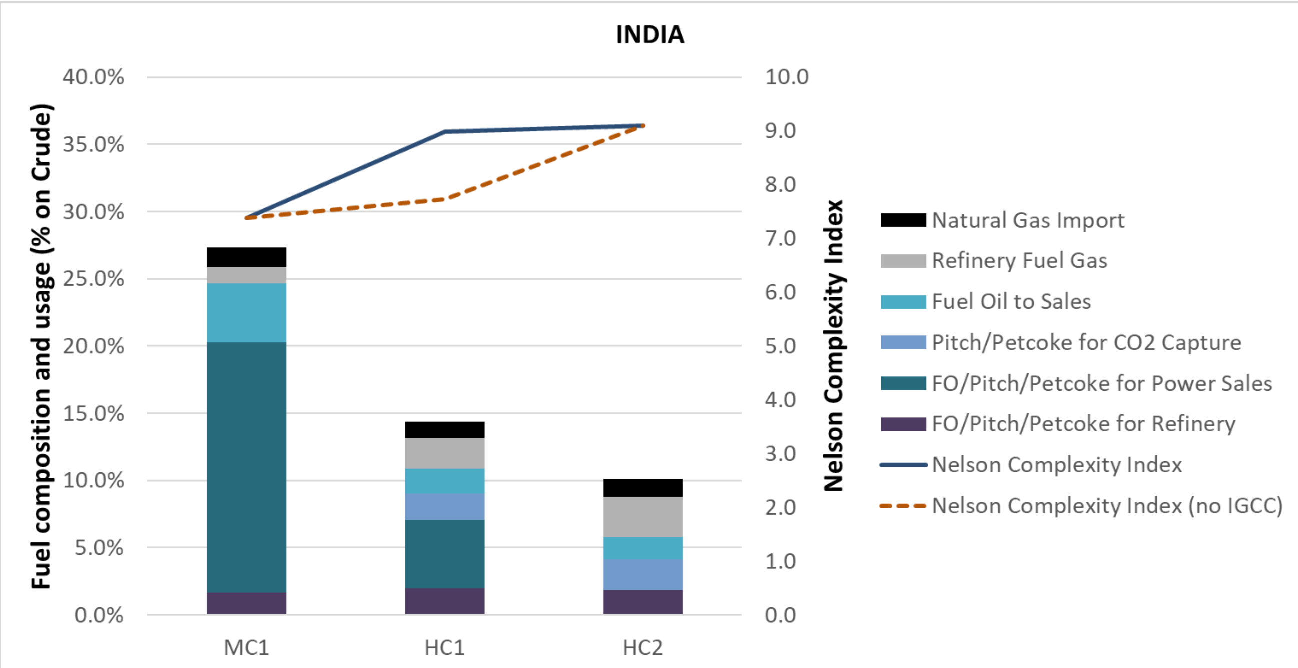


Figure 67 – Fuel composition and usage

It can be observed that the amount of fuels needed for the refinery operation (Natural gas import + Refinery fuel gas + FO/Pitch/Petcoke for Refinery) is increasing with the complexity of the schemes, since the conversion units and the downstream treating units require an additional amount of energy on top of the “base” units.

The level of CO_2 emissions is shown in Figure 68:

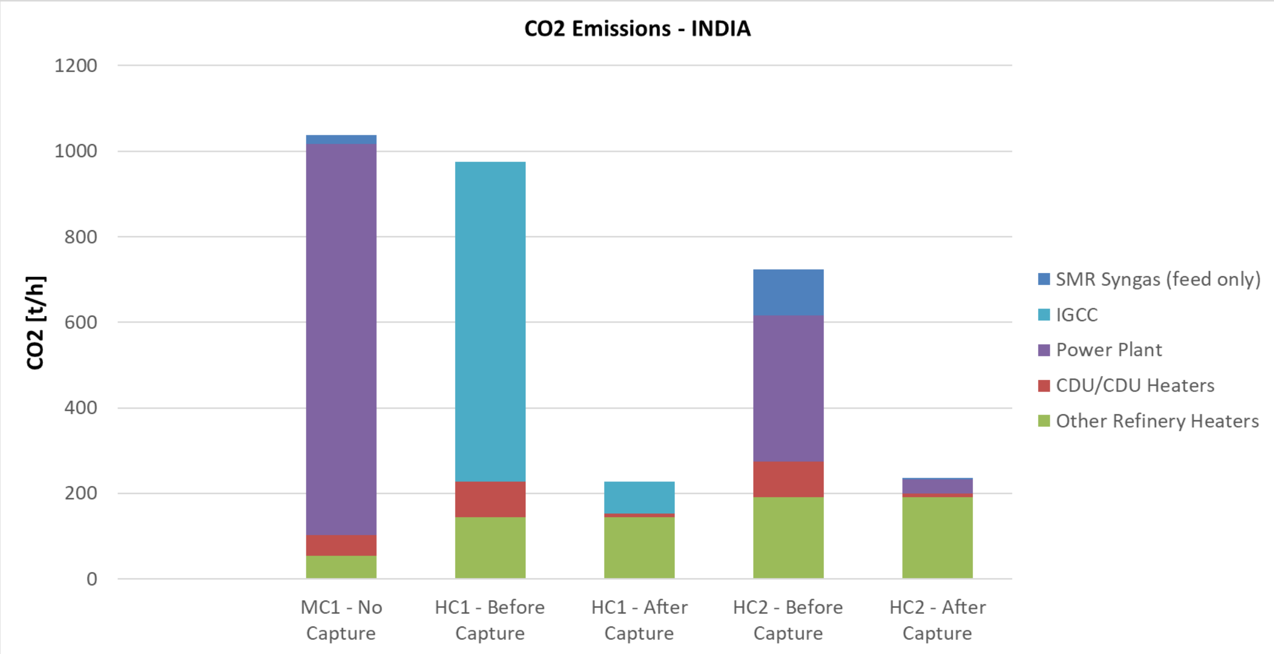


Figure 68 - CO2 Emissions INDIA

The greatest contribution is related to the emissions in power plant/IGCC complex. The *"MC1 – No Capture"* emissions are higher with respect to the other two correspondent cases: this is due to the fact that in the medium conversion scheme more fuel oil is burnt rather than converted in valuable products (also observable in Figure 67).

It should be noted that CO_2 is captured only in HC1 and HC2 configuration. The more sensible reduction is achieved by recovering CO_2 in the power plant/IGCC, which are the main emitters of the complex, followed by the Steam Reformer for hydrogen production.

5.1.1.2 Economical Comparison

The selected parameter for CAPEX comparison is the total investment cost per unit of crude processed in a day, expressed in BPSD (Barrel Per Stream Day). This specific parameter allows a fair comparison to be made between refinery schemes with different capacities. The results are shown in Figure 69:

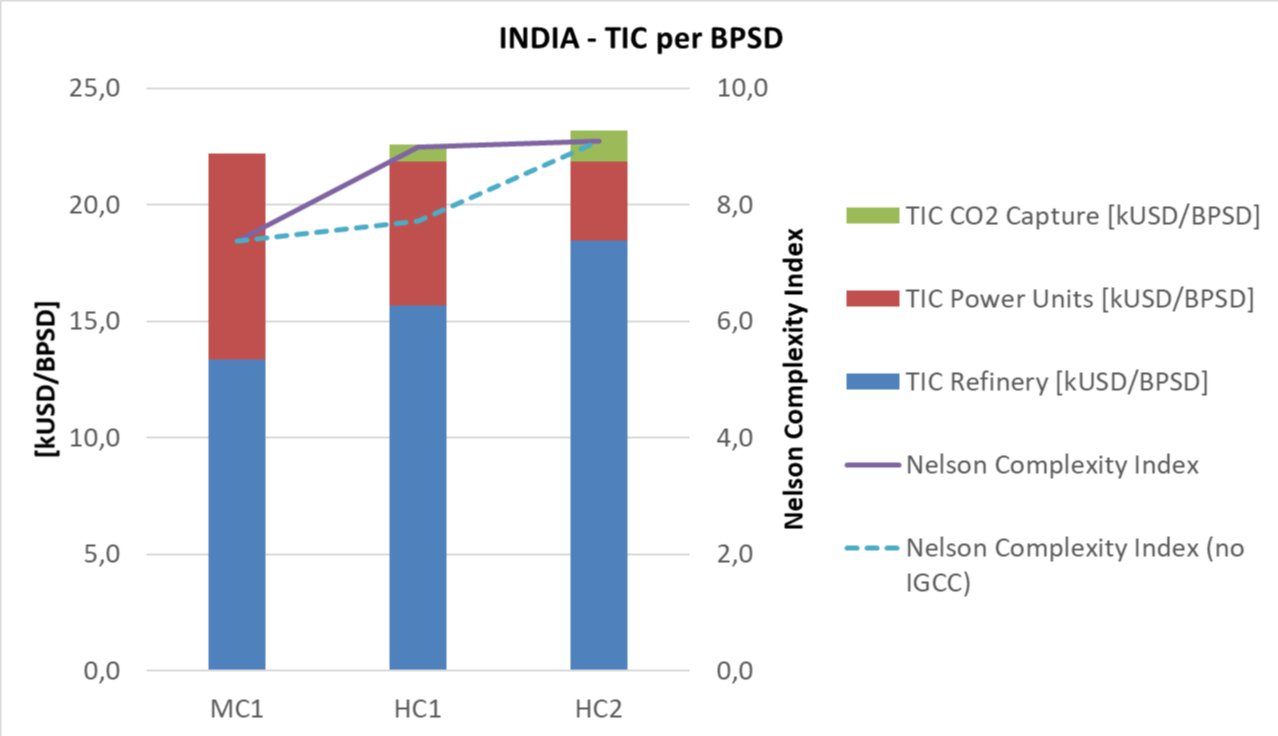


Figure 69 - TIC per BPSD INDIA

The TIC per BPSD slightly increases from MC1 to HC2, in line with the increased refinery complexity, which is monitored through the Nelson Complexity Index. The increase of the specific investment cost is however very marginal, because of the two main opposite effects:

- the economy of scale is in favour of HC1 and HC2;
- the contribution of power unit TIC decreases from MC1 to HC2, due to the decreasing capacity of the power plant with respect of crude oil intake. Indeed, in the HC2 configuration no electric power export is foreseen, since the power island size is just enough to saturate the power/steam demand of the refinery.

The specific investment cost for CO_2 capture facilities is limited when compared with the cost of the Refinery and Power units. However, CO_2 capture also has a negative impact on refinery margins (by reducing the export of energy, since part of the power output is “used” to satisfy the demand of the CO_2 capture units). In other terms, as shown in Figure 67, about 2% of crude oil in HC1 and 2.3% in HC2 is used for CO_2 capture, without producing any margin.

The negative impact of the CO_2 capture on the financial performance of the refinery complex should therefore be counterbalanced by incentives (in the short term) or by carbon emission abatement policies (that in the medium-long term will force the markets to react, by re-shaping the differential prices between oil distillates and crude oil).

Specific revenues and OPEX (per crude oil barrel) of the different cases are reported in Figure 70. This results in a specific gross margin which increases from MC1 to HC2. In MC1 case, the electric power revenues are a significant component of the final gross margin, in contrast to the HC1 and HC2 cases.

In these two latter cases, the specific size of power production units is smaller and on top of this, the CO_2 capture facilities absorb a substantial amount of electric power/steam that cannot be sold. A sensitivity analysis on the presence of CO_2 capture facilities is made in Section 5.2.

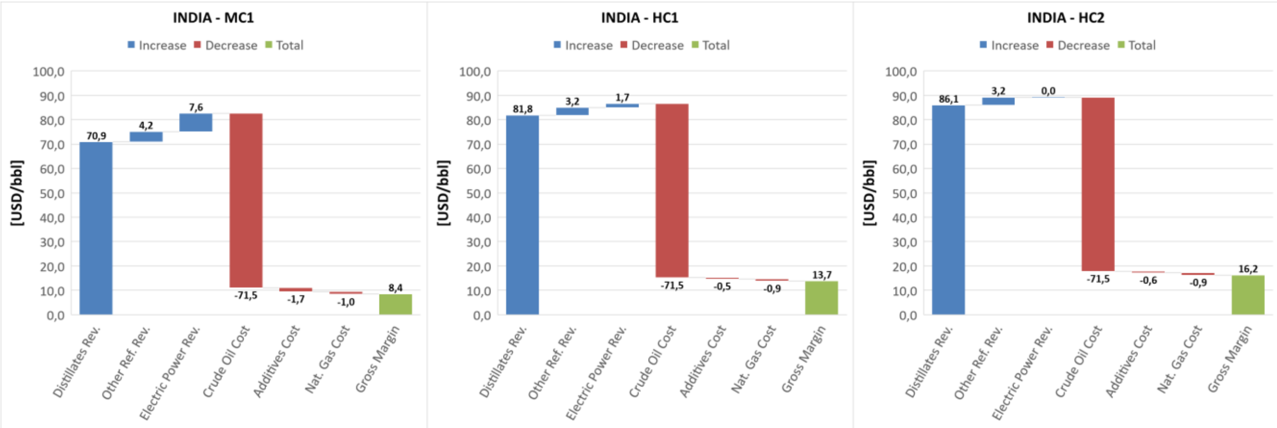


Figure 70 - OPEX INDIA

An economic comparison is completed at the end of the technical analysis based on the financial indicators of different refinery configurations. Figure 71 shows the cumulative discounted cash flow for the three different cases. The curves are extracted from the data in Attachment 6.5. taking 2024 as start-up year, the figure shows the number of years of operation needed to reach the return of the investment point, i.e. cumulative discounted cash flow equal to zero. The end point of each curve (value on the y-axis in year 2049) is equal to the Net Present Value.

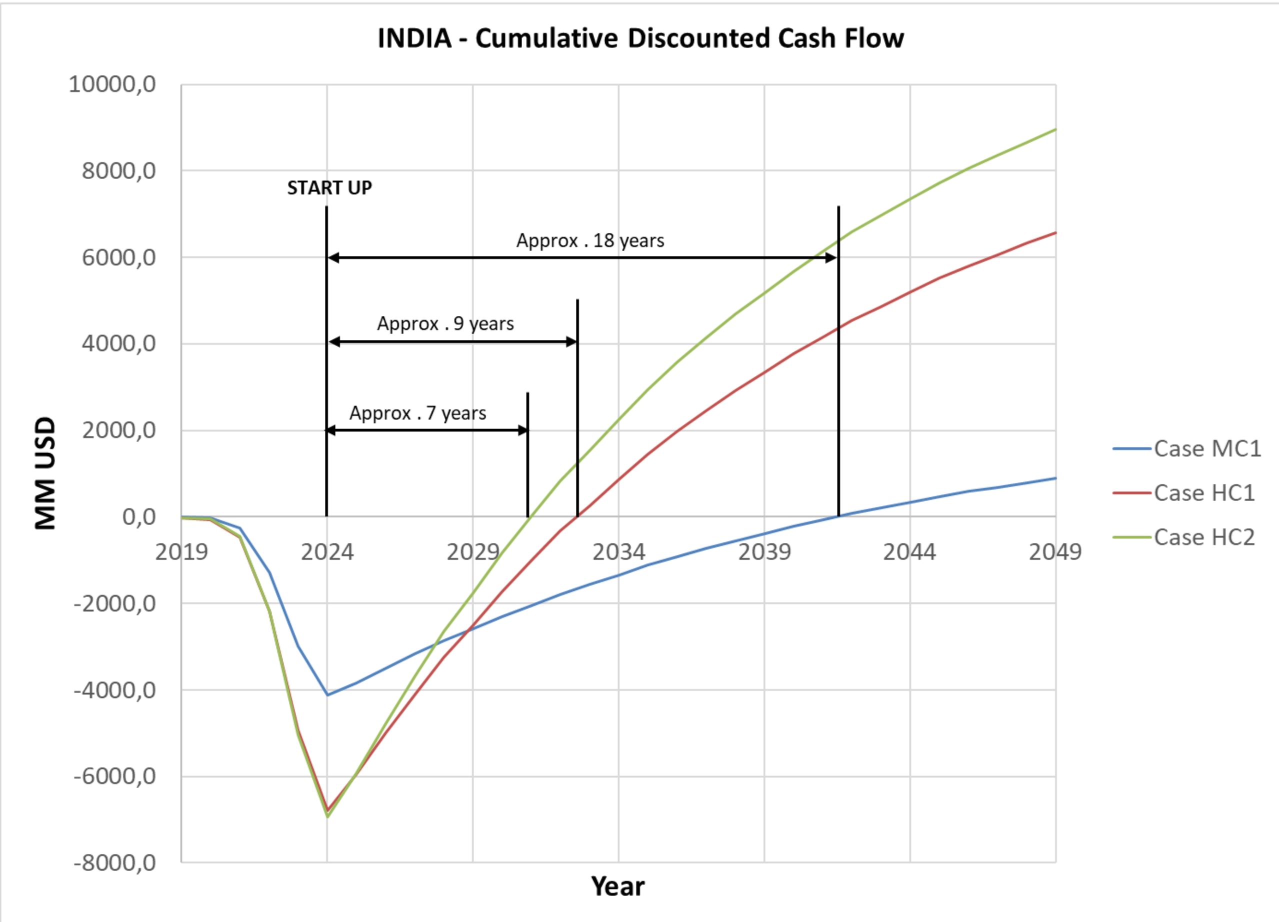


Figure 71 - Cumulative Discounted Cash Flow INDIA

5.1.2 Brazil

5.1.2.1 Technical Comparison

In this section, the same charts previously described for India are reported for the three Brazilian configurations.

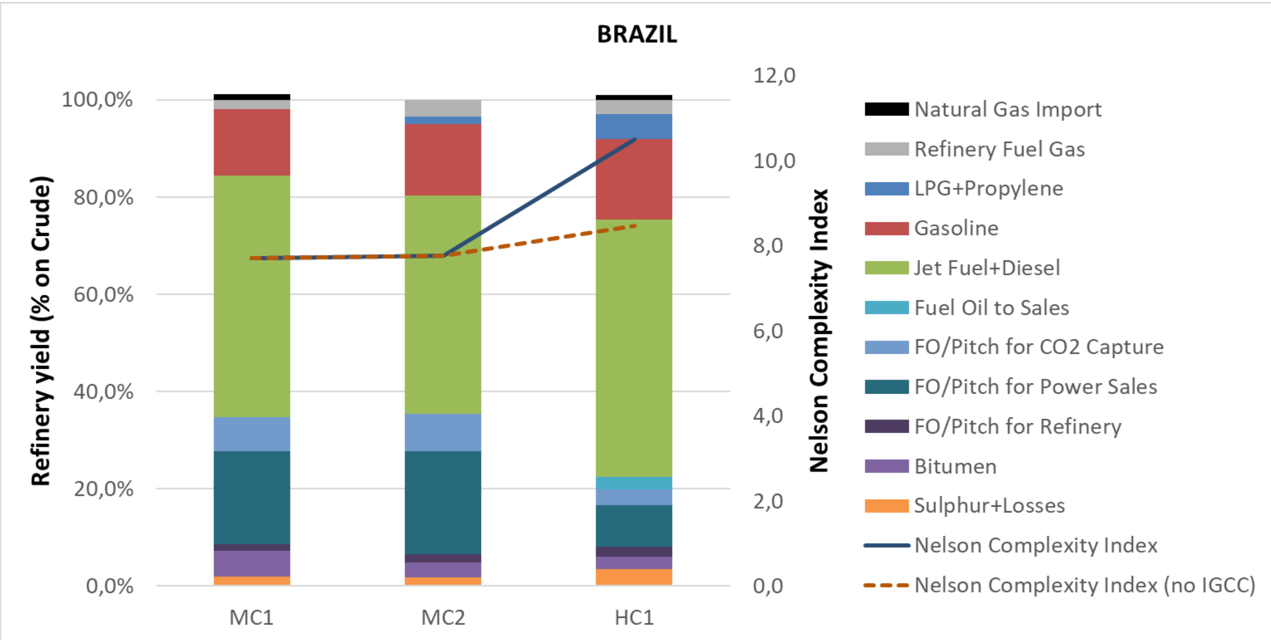


Figure 72 - Refinery Yield BRAZIL

As shown in Figure 73, the conversion in MC1 (configuration based on HCU) and MC2 (configuration based on HCU+FCC in parallel) is practically equivalent, as well as the Nelson Complexity Index. However, in MC2, due to the presence of the FCC unit, more gasoline is produced, as well as offgas, LPG and propylene, reducing the production of the middle distillates (Jet + Diesel). In HC1 case, the conversion is higher due to the presence of the SDA unit.

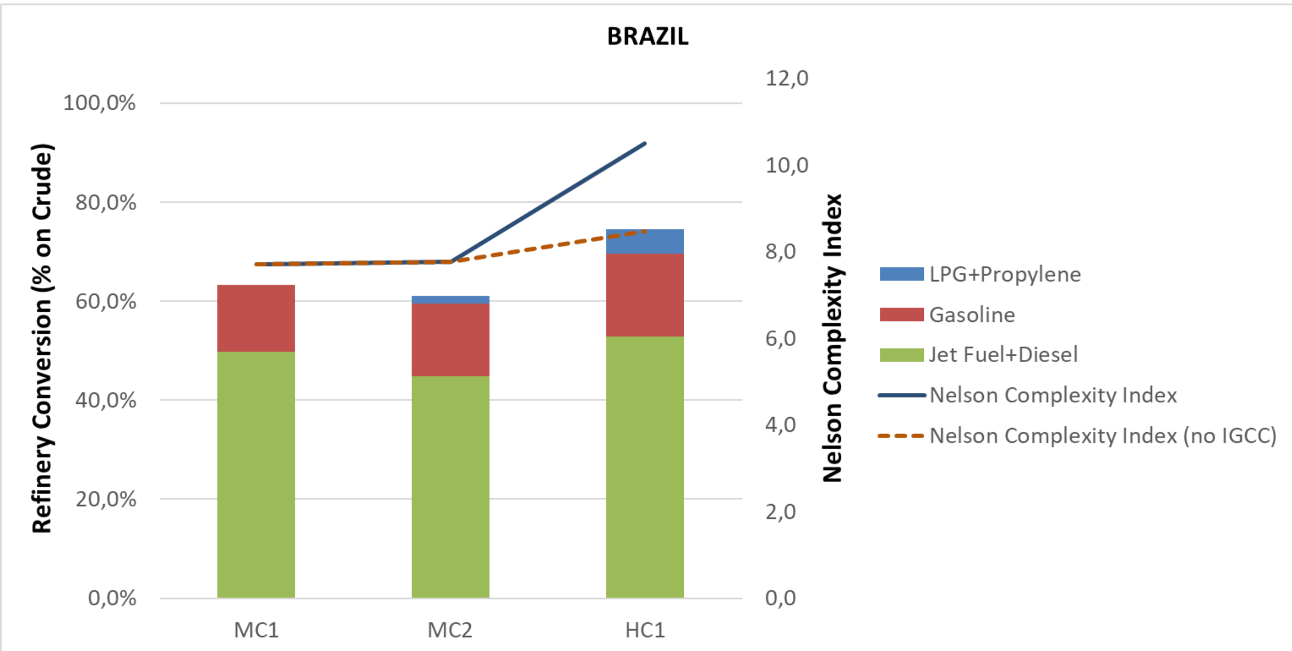


Figure 73 - Refinery Conversion BRAZIL

The fuel composition and usage are shown in Figure 74. It can be noted that there is a greater percentage of fuel oil available for power sales in MC2 with respect to MC1, despite the two schemes have the same bottom-of-the barrel configuration (bitumen production plus fuel oil production through Visbreaking Unit VBU). This is due to the fact that a fixed quantity of bitumen production of 400 kton/y was considered for both refineries. The impact on mass balance of the small refinery MC1 (150,000 BPSD) is more evident than on the one of the medium-scale MC2 (250,000 BPSD). Once the bitumen to sales amount (400 kt/y) has been subtracted, more fuel oil is produced through VBU unit in MC2.

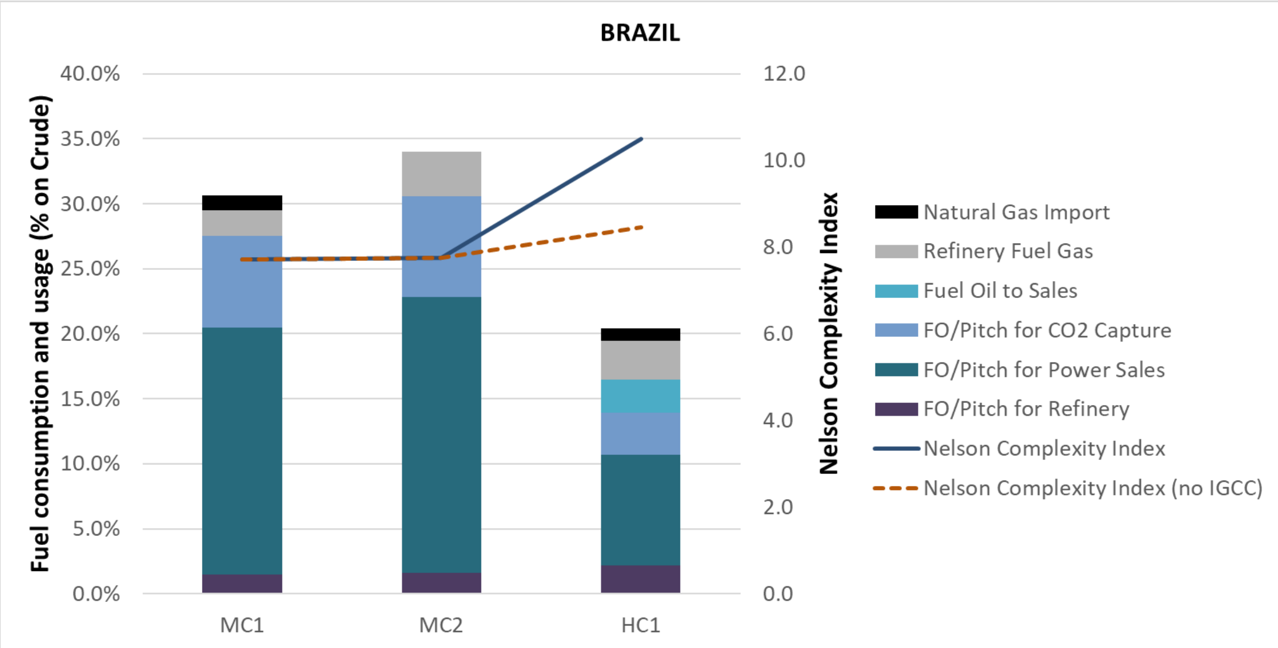


Figure 74 - Fuel composition and usage

The resultant CO_2 emissions are shown in Figure 75. In all the three cases a CO_2 capture system is foreseen.

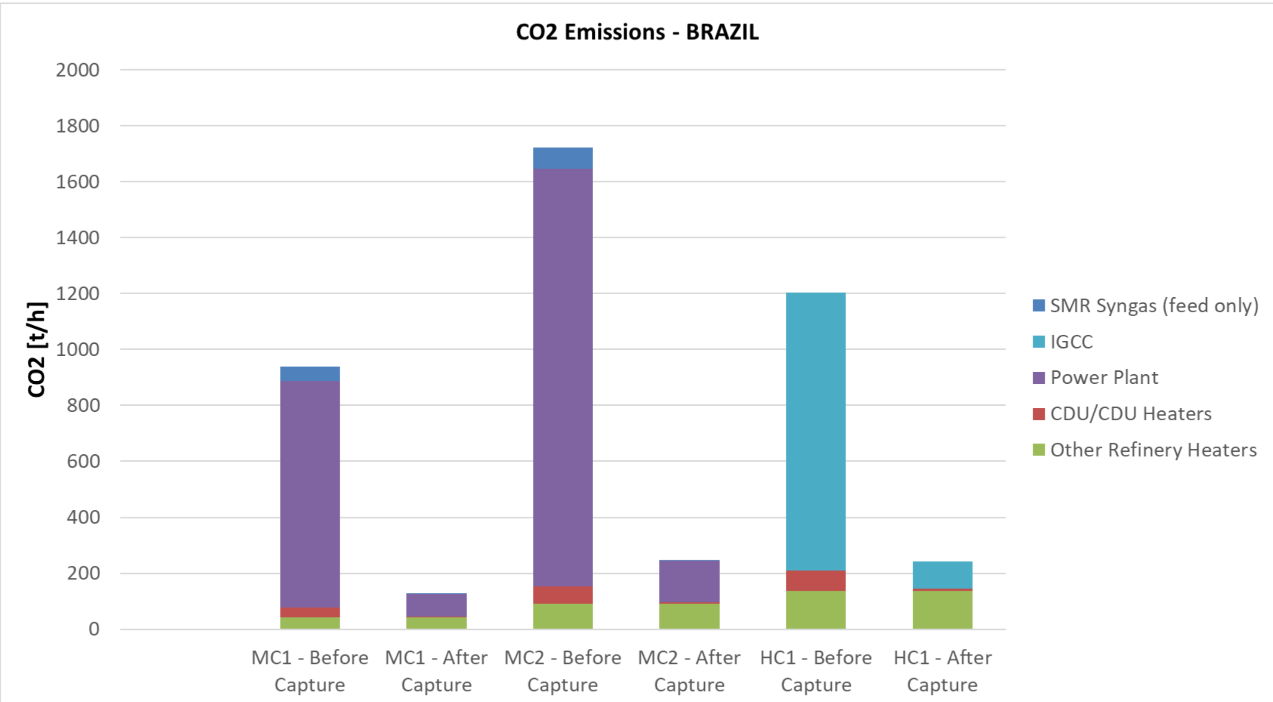


Figure 75 - CO_2 Emissions BRAZIL

5.1.2.2 Economic Comparison

The Total Investment Cost per unit of capacity (TIC per BPSD) is shown in Figure 76. This specific parameter allows a fair comparison to be made between refinery schemes with different capacities. The TIC per BPSD decreases from MC1 to HC1, although the complexity of the refinery, reflected by the Nelson Complexity Index, increases.

As a matter of fact, the additional investment needed for the conversion units is more than counterbalanced by:

- the economy of scale, which is in favour of the larger installations;
- the contribution of power unit TIC decreasing from MC1 to HC1.

It can be noted that in the configuration HC1 the CO_2 capture facilities require relatively low specific CAPEX. This is because the CO_2 recovery from the syngas produced in an IGCC is less capital intensive than post-combustion CO_2 capture: reference can be made to the paper "CO_2 Capture at Coal Based Power and H2 Plants", published as IEA GHG Technical Review 2014-3.

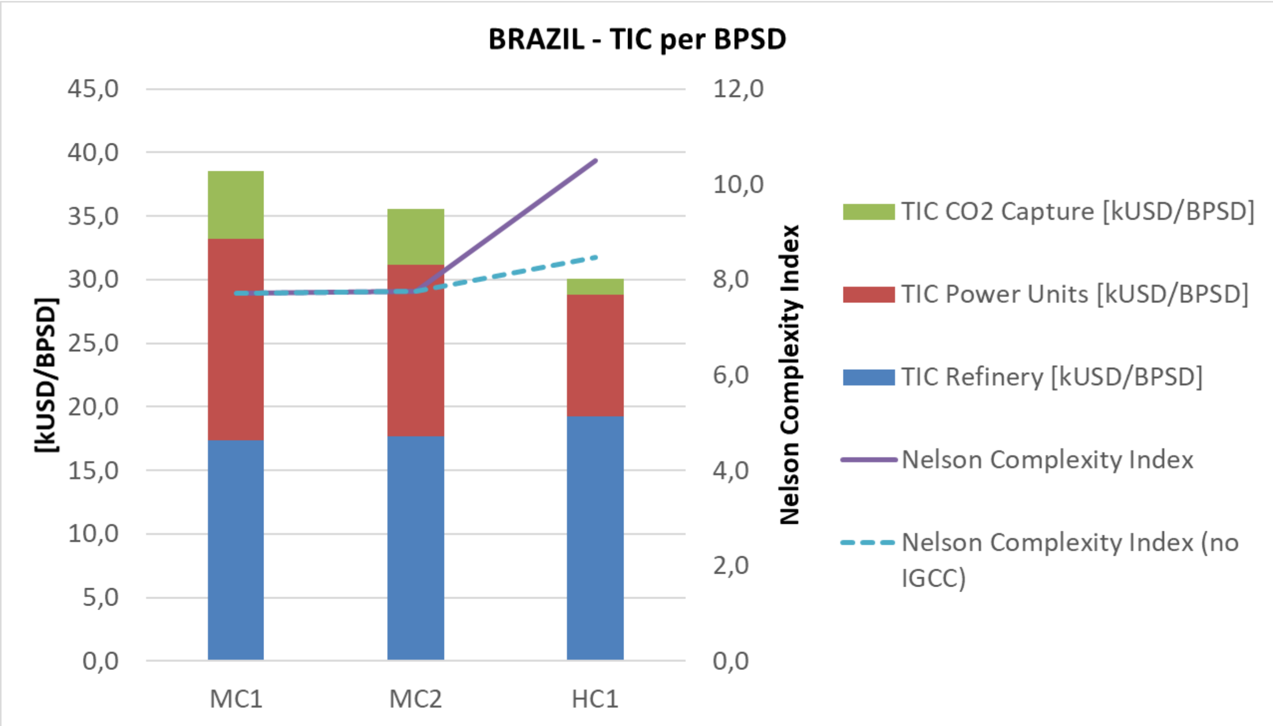


Figure 76 - TIC per BPSD BRAZIL

Revenues and OPEX analysis is shown in Figure 77, where the gross margin is calculated by subtracting the operating costs from the revenues.

The contribution of revenues from power export is important, except for case HC1 where the power export is limited.

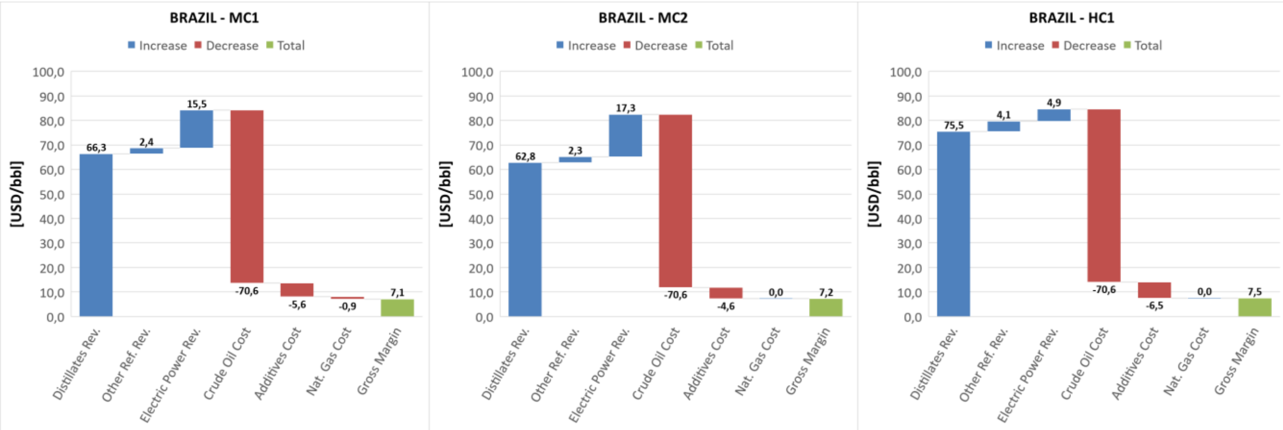


Figure 77 - OPEX BRAZIL

The cumulative discounted cash flow is plotted in Figure 78. The curves are extracted from the data in Attachment 6.5. As expected, none of the three cases shows a return of investment point within the refinery design life of 25 years (i.e. cumulative discounted cash flow remains below zero in all the plant life) In fact, Brazil cases are very penalized by:

- the assumed crude cost (based on an international parity base market) in relation to the product prices (related to local market: refinery gate price determined from the price at the gasoline station minus taxes and transportation costs);
- the relatively high TIC estimated, driven by the location factors for materials supply and construction costs.

In other words, new refineries in Brazil could result in a profitable investment only by considering some incentives for crude supply (in the form of subsidies to buy the local crude oils or in the form of crude oil export taxes).

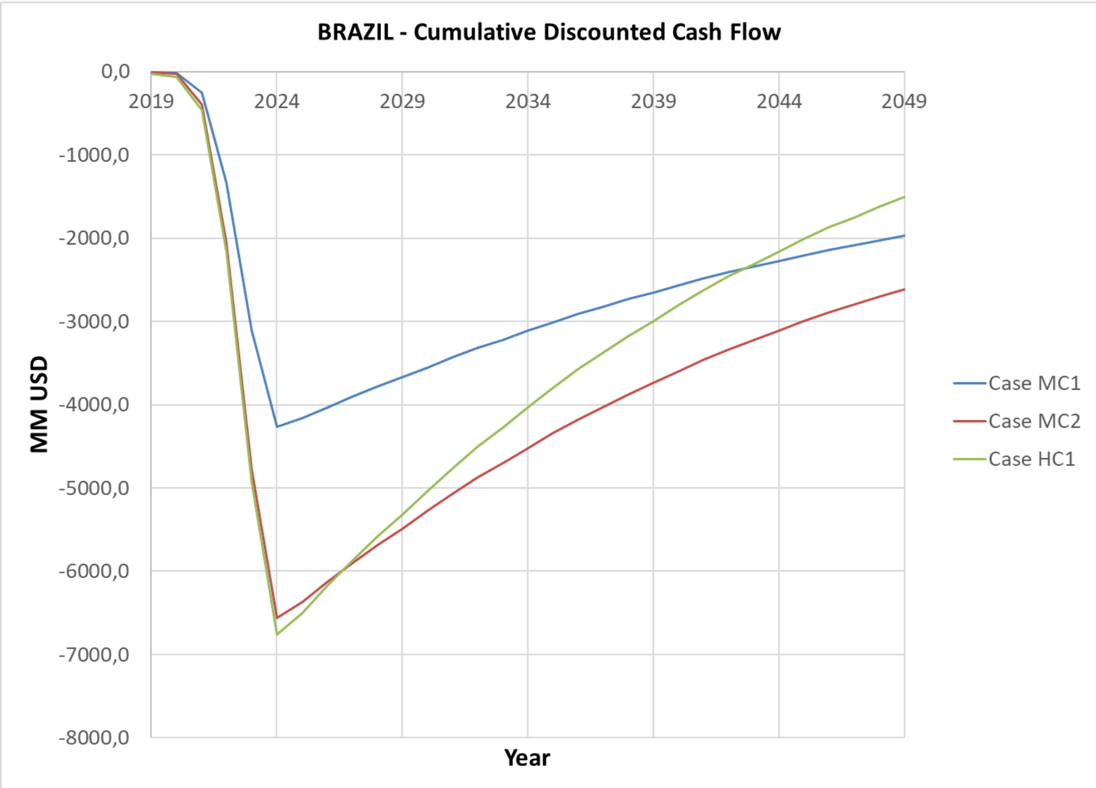


Figure 78 - Cumulative Discounted Cash Flow BRAZIL

5.1.3 *Nigeria*

5.1.3.1 Technical Comparison

Refinery product distributions and Nelson Complexity Index for the three Nigerian refineries are shown in Figure 79.

It has to be remarked that the refinery scheme of MC1 and HC1 is the same, as it appears evident from the chart.

The only difference between the two cases is the destination of the excess low sulphur fuel oil, as shown Figure 81: in Case HC1 the excess of low sulphur fuel oil is not sold on the market but instead burnt in a boiler to produce electricity. In this case (HC1), CO_2 capture is envisaged (as shown in Figure 78) and about half of the fuel oil is used to sustain the consumptions of the CO_2 facilities.

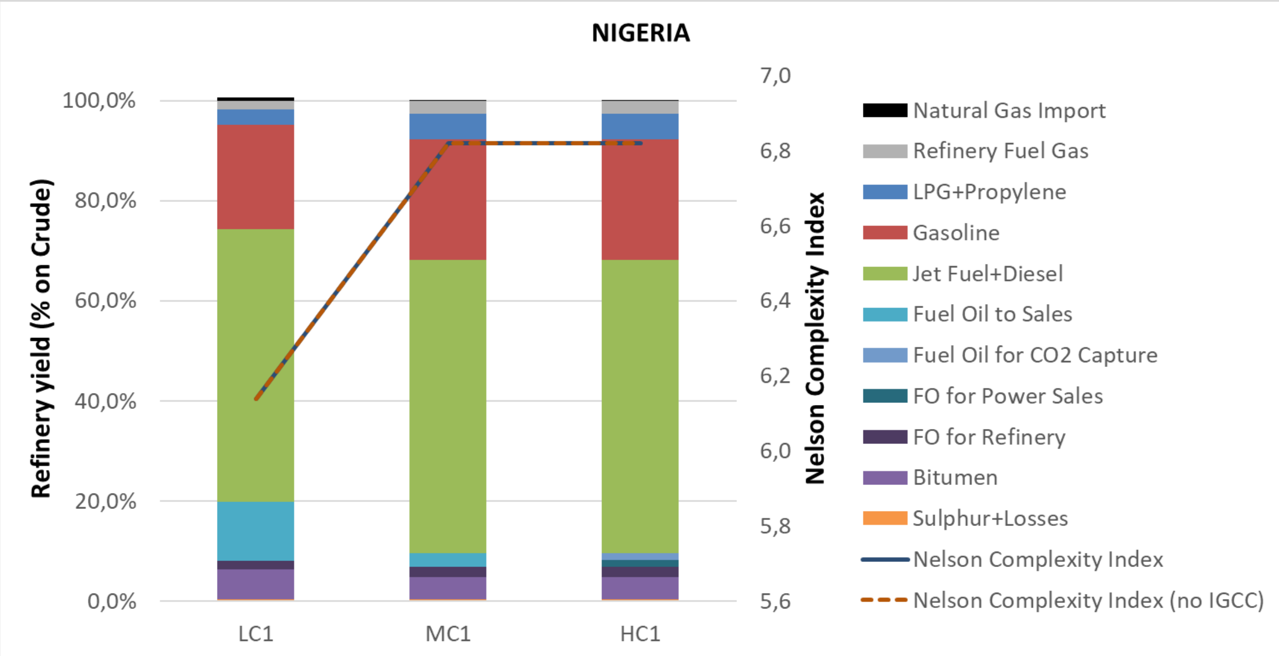


Figure 79 - Refinery Yield NIGERIA

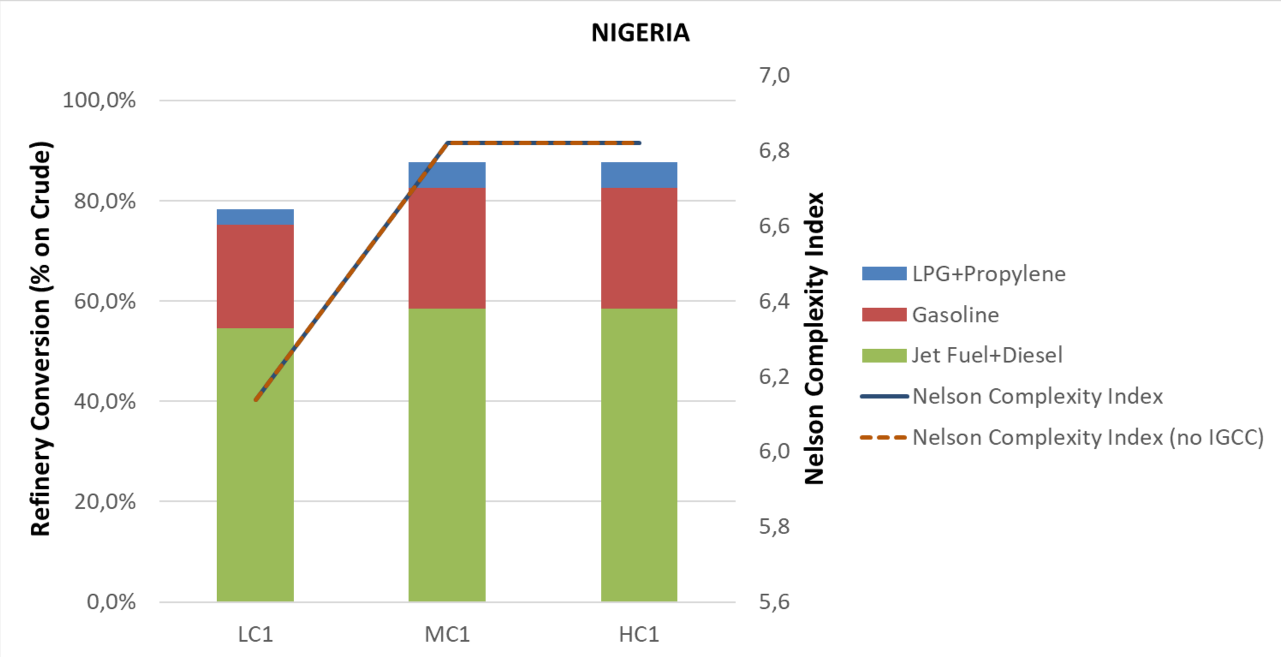


Figure 80 - Refinery Conversion NIGERIA

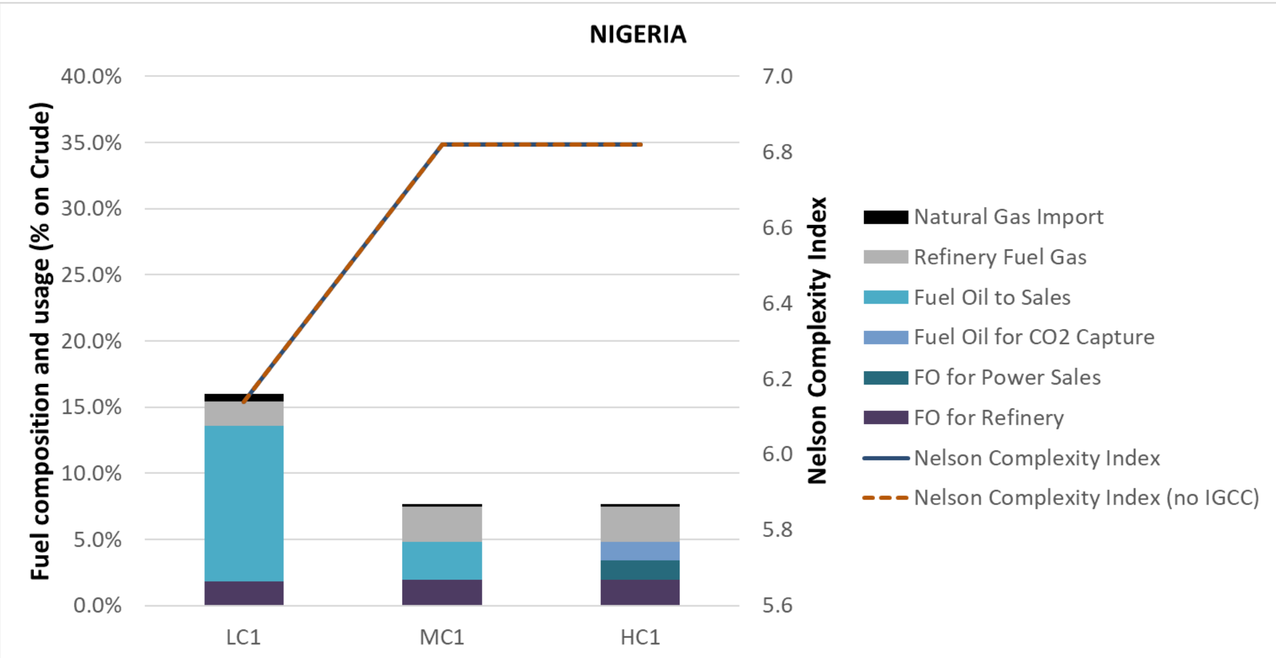


Figure 81 – Fuel composition and usage NIGERIA

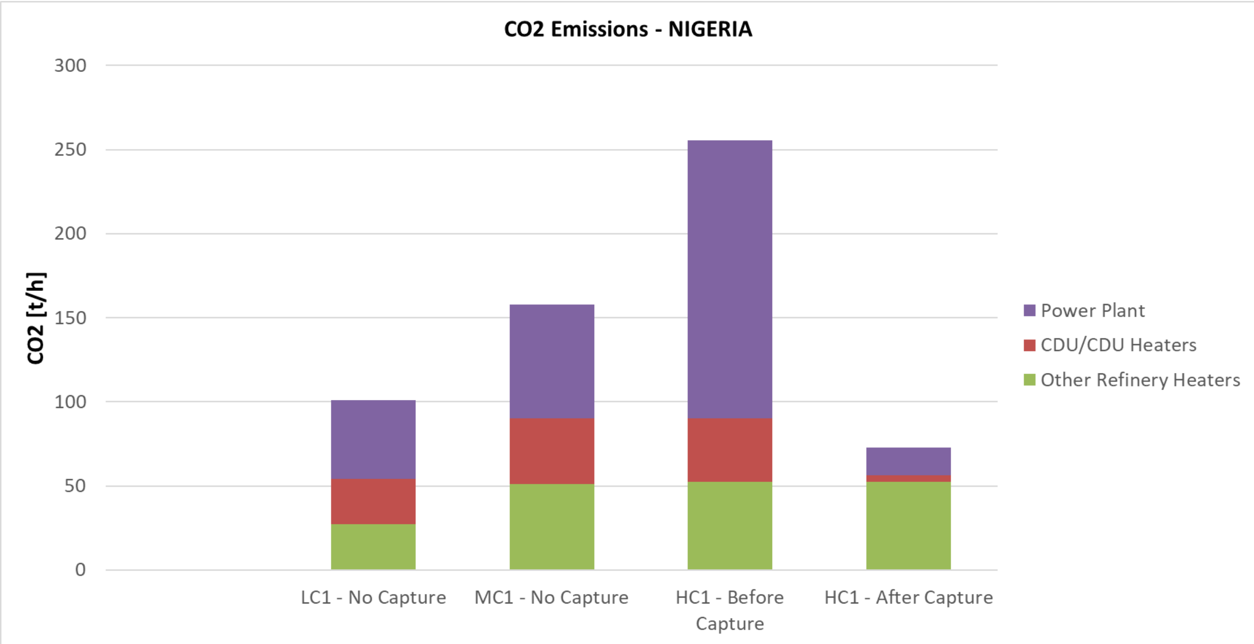


Figure 82 - CO2 Emissions NIGERIA

5.1.3.2 Economical Comparison

Comparison among the three cases on CAPEX (expressed as TIC per BPSD of crude oil) and OPEX (specific revenues and operating costs) are shown in Figure 83 and Figure 84 respectively.

The refinery configuration increases in the complexity and in the associated TIC from LC1 to MC1.

For Nigeria cases, the effect of the economy of scale is not sufficient to counterbalance the additional conversion units, also because the capacity of the Medium Conversion and High Conversion cases (200,000 BPSD) is only marginally higher than the capacity considered for the Low Conversion case (150,000 BPSD).

HC1 is equal to MC1 in terms of complexity but requires more CAPEX, due to the bigger power island burning fuel oil and the relevant CO_2 capture facilities.

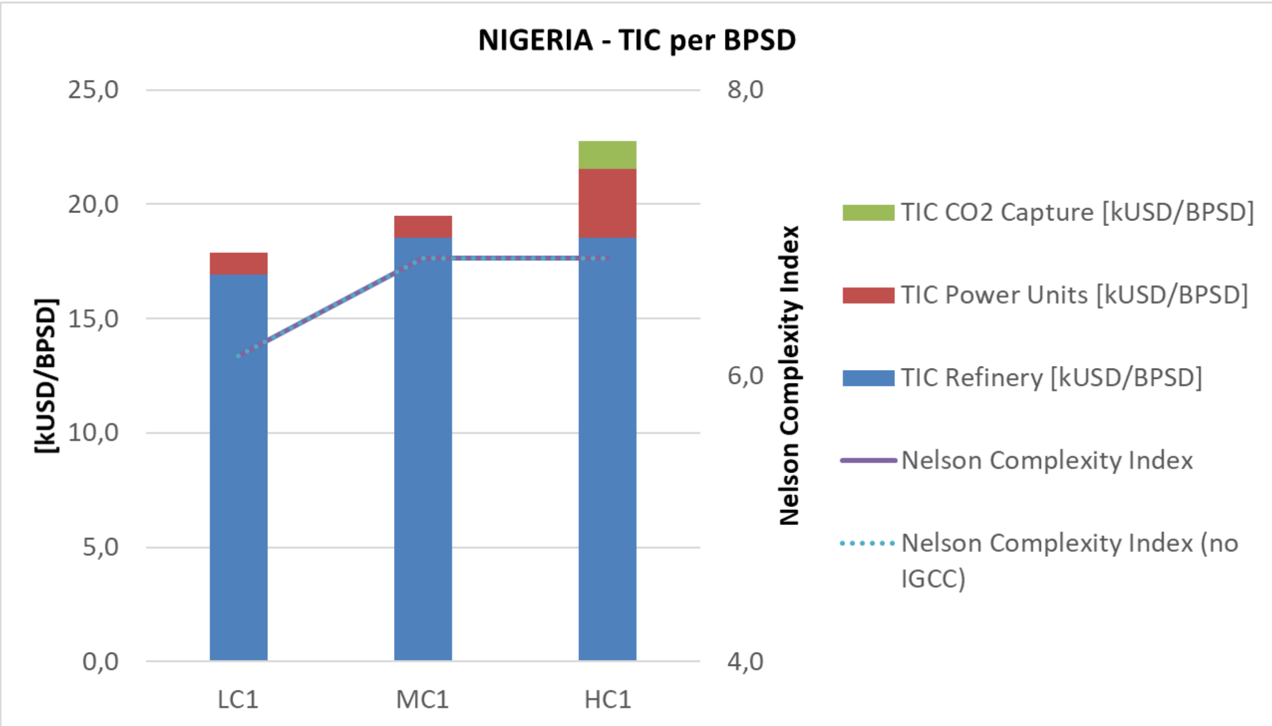


Figure 83 - TIC per BPSD NIGERIA

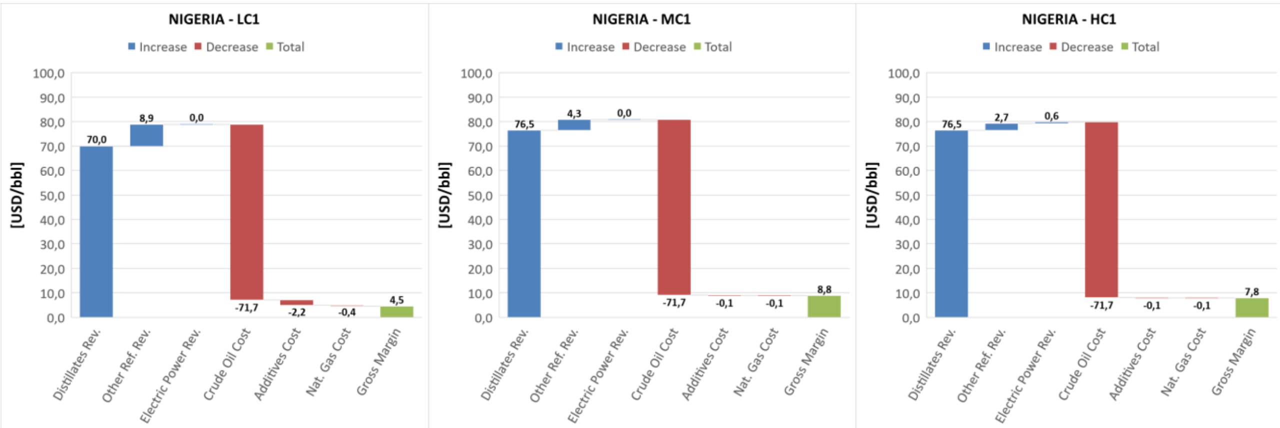


Figure 84 - OPEX NIGERIA

From Figure 84 Case HC1, it is evident that the revenues related to exported electric power, which is very low, are negligible with respect to the total gross margin.

The cumulative discounted cash flow is plotted in Figure 85. The curves are extracted from the data in Attachment 6.5. The hydro-skimming configuration (LC1) is not profitable, since the payout time would exceed the plant design life of 25 years. The best configuration, in term of financial performances, is MC1, where approximately 16 years are needed to re-pay the initial investment. The introduction of a bigger power island, and CO_2 capture facilities, create two combined negative effects on the financial performance in the case of HC1, as shown by the green curve (vs red curve of case MC1) of Figure Figure 85. In other words, it is more profitable to sell LSFO rather than burning it and selling the corresponding electric energy

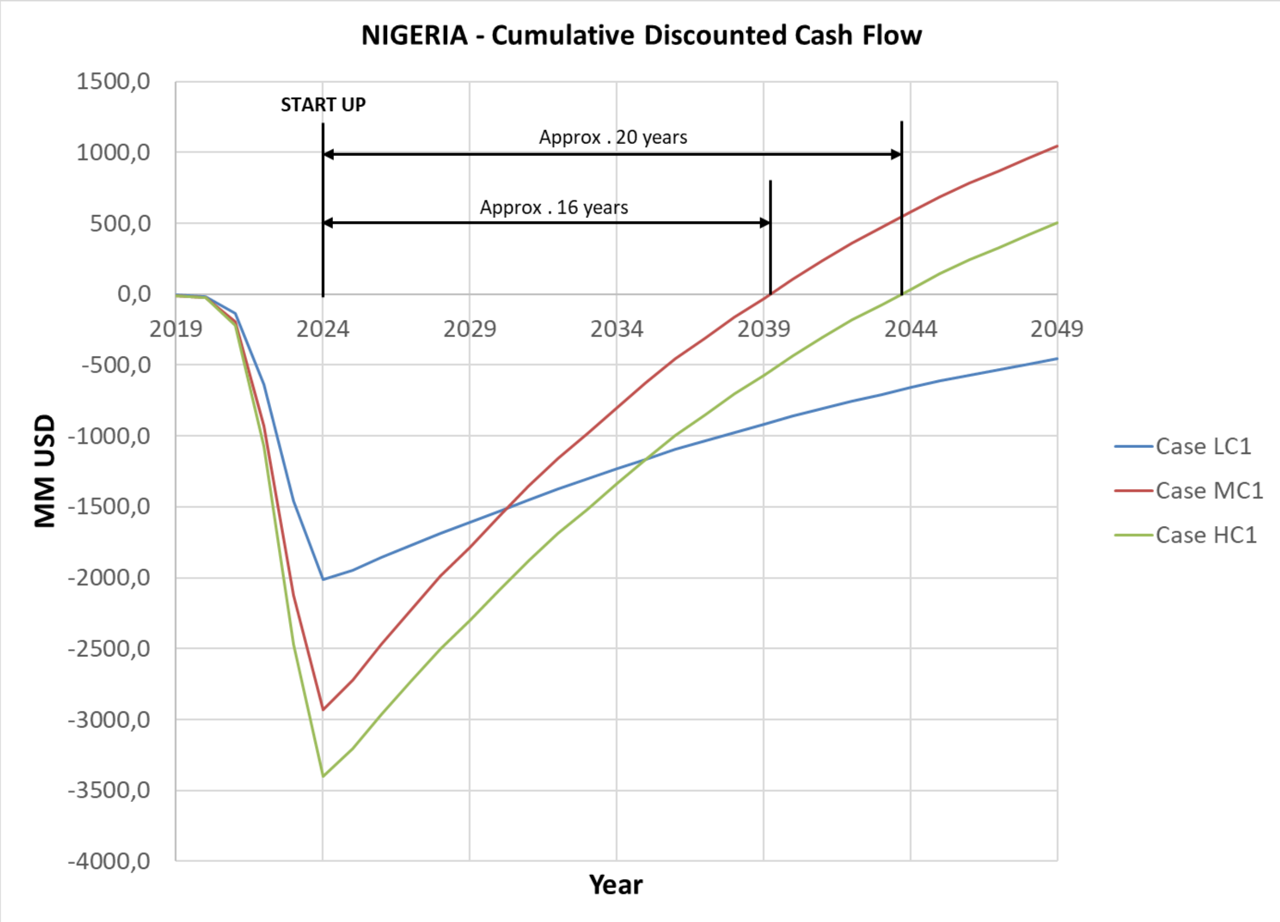


Figure 85 - Cumulative Discounted Cash Flow NIGERIA

5.2 Effect of CO2 Capture on Economic performance

The basic aim of this study is the techno-economic analysis of a conceptual clean refinery, including CO_2 capture. However, CO_2 capture means costs and loss of profitability. Therefore, to promote clean refineries with a lower carbon footprint, policies should be introduced based on subsidies that compensate for the extra costs of CO_2 capture (e.g. incentives for crude supply, tax reduction, etc.). Alternatively, CO_2 emitted to atmosphere should be charged as a cost to be paid by the emitter.

If carbon emissions are taken into account, a fairer comparison is for the plants with CO_2 capture to be preferentially favored or plants without CO_2 capture penalized, so that they compete in the market on more equitable basis.

Carbon emissions can be taken into account either by assuming preferential integration of CO_2-capture or by assuming plants without CO_2 capture are penalized so that they compete in the market on more equitable basis.

The CO_2 avoidance cost has been evaluated for the six out of nine refinery configurations where CO_2 capture is envisaged, including compression and purification facilities.

This evaluation has been based on the IRR parameter and made in two steps:

- As a first step, the IRR of each of the six configurations is calculated by assuming no CO_2 capture units (Reference Case, without Carbon Capture). This approach allows a reduction of the TIC and of the electric energy and LP steam consumption. The resultant electric power could be sold on the market, improving the financial performance.

- As a second step, the CO_2 emission price is calculated assuming the configuration with CO_2 capture is as profitable as the Reference case (i.e. the case has the same IRR).

5.2.1 India

The calculated IRR for Indian configurations is shown in Table 73.

Table 73 – CO Capture Scenarios INDIA

	Refinery Configuration	Base Case (with CC)	Reference Case (w/o CC)
HC1	400 kBPD, HCU+FCC, SDA+DCU+CFB	18%	20%
HC2	400 kBPD, HCU+FCC, SDA+IGCC	16%	17%

In HC2 the delta IRR between the two cases is lower than HC1, due the different bottom of the barrel configuration. In HC1, in fact, the CO_2 capture facilities are integrated in the IGCC scheme (pre-combustion capture) with lower cost impact and energy consumption than the post-combustion capture applied in HC2.

The base cases have been modified considering the sale of CO_2 (reference cases). The required selling price of CO_2 to get the same IRR of *"Reference Cases"* are:

- For HC1, **79 USD/ton**
- For HC2, **32 USD/ton**

As expected, CO_2 capture has less impact on the IGCC configuration, i.e. it requires less valorisation of the CO_2.

5.2.2 Brazil

The results for Brazilian configurations are shown in Table 74:

Table 74 - CO_2 Capture Scenarios BRAZIL

	Refinery Configuration	Base Case (with CC)	Reference Case (w/o CC)
MC1	150 kBPD, HCU, FO boiler	3%	10%
MC2	250 kBPD, HCU+FCC, FO boiler	4%	12%
HC1	300 kBPD, HCU+FCC, SDA+IGCC	6%	8%

As shown in Indian configuration, this kind of sensitivity has less impact on IGCC configuration for the same reasons discussed in Section 5.2.1. Moreover, it is observable that variance is greater in MC2 than MC1, since more fuel oil is directed to the power island (bigger units) and so CO_2 capture TIC and consumption are greater. Moreover, the variance in Brazilian cases is higher with respect to the Indian one for the same reasons.

The base cases have been modified considering the sale of CO_2 (reference cases). The required selling price of CO_2 to get the same IRR of *"Reference Case"* are:

- For MC1, **72 USD/ton**
- For MC2, **68 USD/ton**

- For HC1, **35 USD/ton**

It is possible to see the same price trends for CO2 as in the Indian cases.

5.2.3 Nigeria

CO_2 capture units are only envisaged in one Nigerian refinery scheme (HC1). The results are shown in Table 75:

Table 75 - CO_2 Capture Scenarios NIGERIA

	Refinery Configuration	**Base Case (with CC)**	**Reference Case (w/o CC)**
HC1	200 kBPD, FCC, FO boiler	9%	11%

The increase of the IRR is in line with the Indian case HC2, indeed the power islands have the same order of magnitude of the capacity.

The required price of CO_2 to get the same IRR of "Reference Case" is **53 USD/ton**.

5.3 Sensitivity Analysis on key parameters

The financial performance of the nine refineries has been re-evaluated by running some sensitivity cases, to see the effects of the main economical parameters.

5.3.1 Sensitivity on Total Investment Cost (TIC) and Electricity Price

This sensitivity is performed considering two different scenarios:

- Variance of the total investment cost;
- Variance of the electricity selling price.

A range of ±20% is considered in both the scenarios. The output variable is the IRR.

The variance of TIC (which depends on the accuracy of the cost estimation, i.e. ±30% at this stage) causes a different value of cumulative cash flow at start-up year.

On the contrary, a variance of the electricity selling price causes a different cash flow on a yearly basis.

5.3.1.1 India

The sensitivity analysis results are summarized in Figure 86.

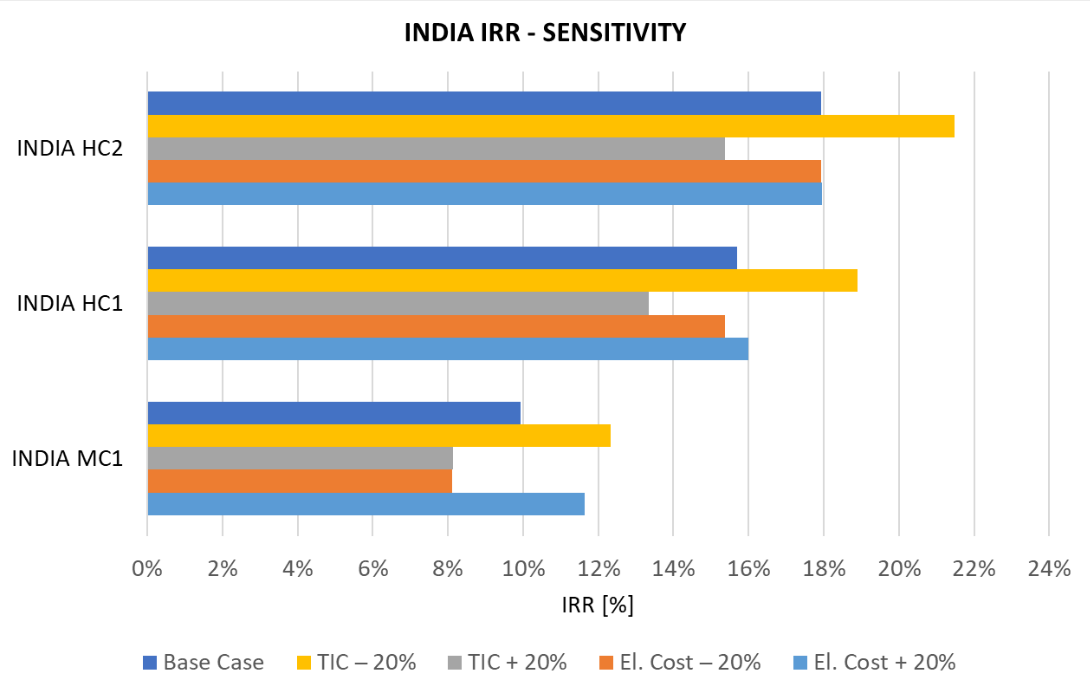


Figure 86 - TIC and Electricity Price Sensitivity - INDIA

A different representation of the above results is shown in Figure 87 showing how IRR changes with the modification of the selected parameters. The vertical black line represents the IRR of the base case.:

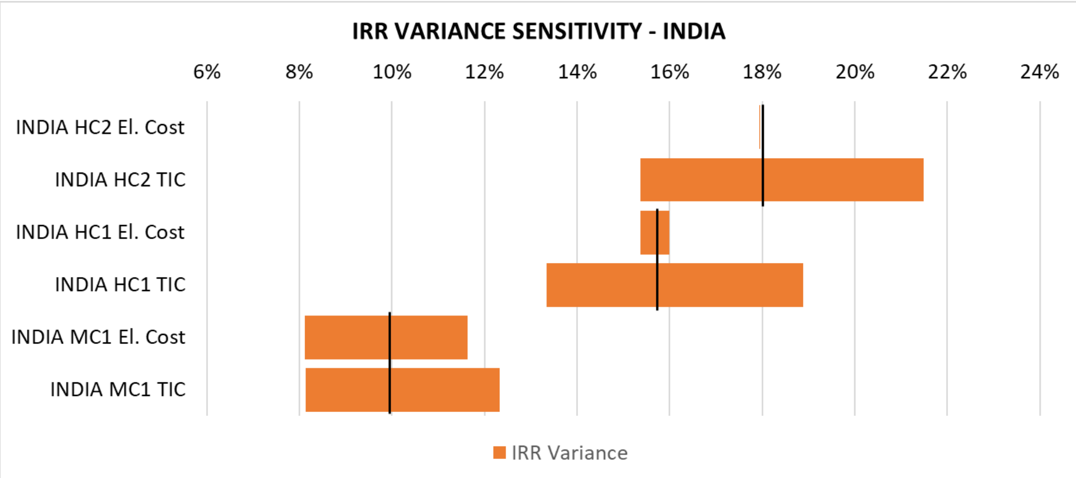


Figure 87 - Variance TIC and Electricity Price Sensitivity - INDIA

The HC2 case is insensitive to the electricity cost variance because no electric power export is foreseen. In HC1 and MC1 cases the IRR variance is proportional to the amount of electricity that is exported to the grid.

5.3.1.2 Brazil

The sensitivity analysis results are summarized in Figure 88. The table shows for each case the IRR value.

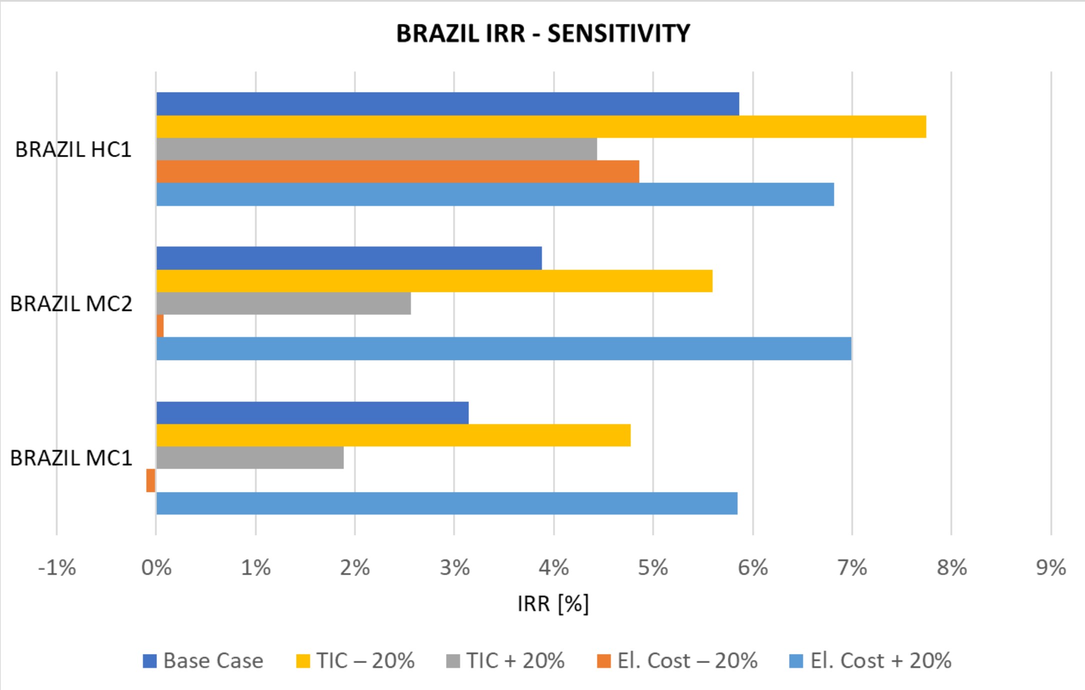


Figure 88 - TIC and Electricity Price Sensitivity - BRAZIL

The most interesting cases are relevant to electricity cost variance. All three Brazilian cases foresee an important contribution of the power export to the revenues, and on the resultant financial performances. Moreover, the selected price of electricity selected for Brazil is 0.13 USD/kW, which is in contrast to India and Nigeria which have electricity prices of 0.07 USD/kW. These combined conditions cause a huge variation in the resultant IRR. In case MC1 the IRR at the lowest electricity price even assumes a negative value.

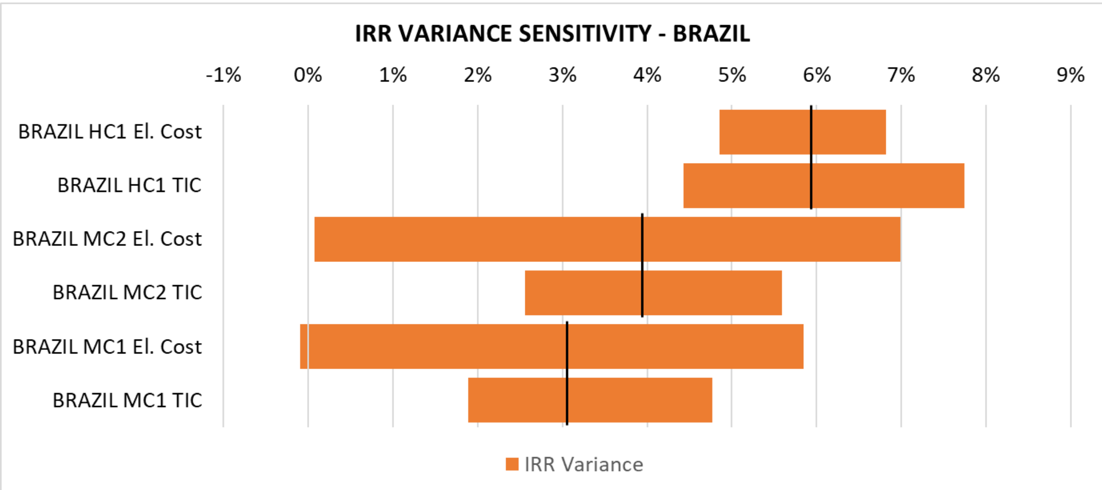


Figure 89 - Variance TIC and Electricity Price Sensitivity - BRAZIL

5.3.1.3 Nigeria

The sensitivity analysis results are summarized in Figure 90. The table shows for each case the IRR value.

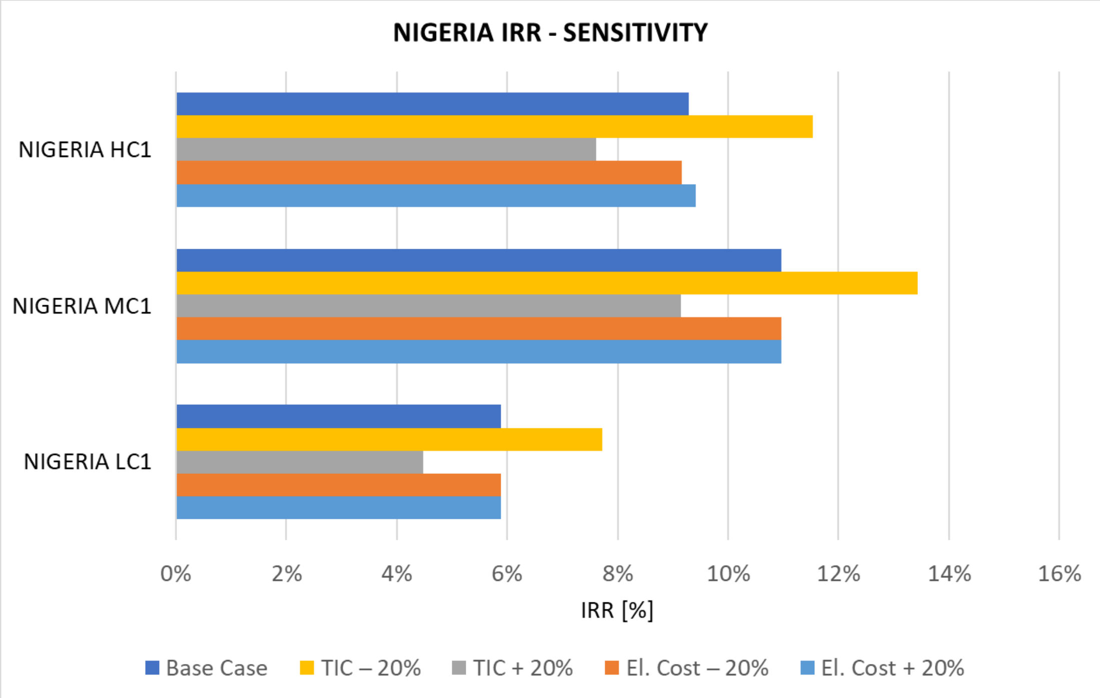


Figure 90 - TIC and Electricity Price Sensitivity - NIGERIA

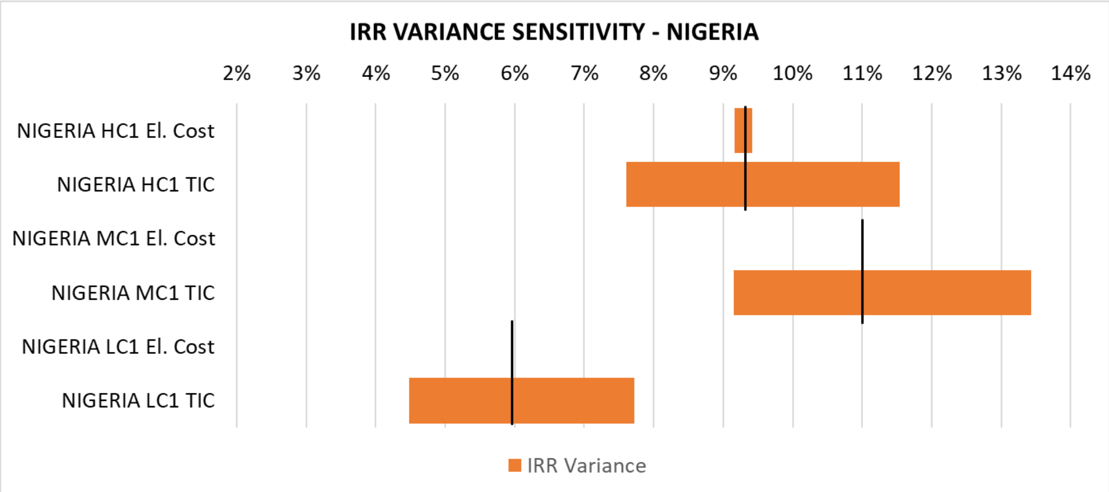


Figure 91 - Variance TIC and Electricity Price Sensitivity - BRAZIL

Only a small or null variance is observable related to electricity selling price, since Nigeria crude is very light and only a small amount of excess low sulphur fuel oil is sent to the power island in case HC1.

5.3.2 *Sensitivity on Reduction of Crude Oil Price*

In all cases, the base case crude oil price has been evaluated on an international parity market.

For some of the countries, this assumption has a negative impact on the economic analysis results of the modelled refineries. It should be noted that the price of locally produced crude is very similar to the price paid by the international competitors. The only benefit for the local refineries is represented by the lower transportation cost.

If there were some incentives for promoting the use of local crude for processing, there would be a positive effect on the IRR. The incentives could attract more investors to participate in the new refinery business.

A sensitivity analysis has been made by considering a crude price reduction of 5-10 USD/ton (corresponding to approx.1-2 USD/barrel), which is deemed a reasonable range for possible incentives or discounts for long-term supply agreements.

5.3.2.1 India

The results of the sensitivity analysis for the three Indian configurations are shown in Figure 92. The trend in all the cases is almost linear.

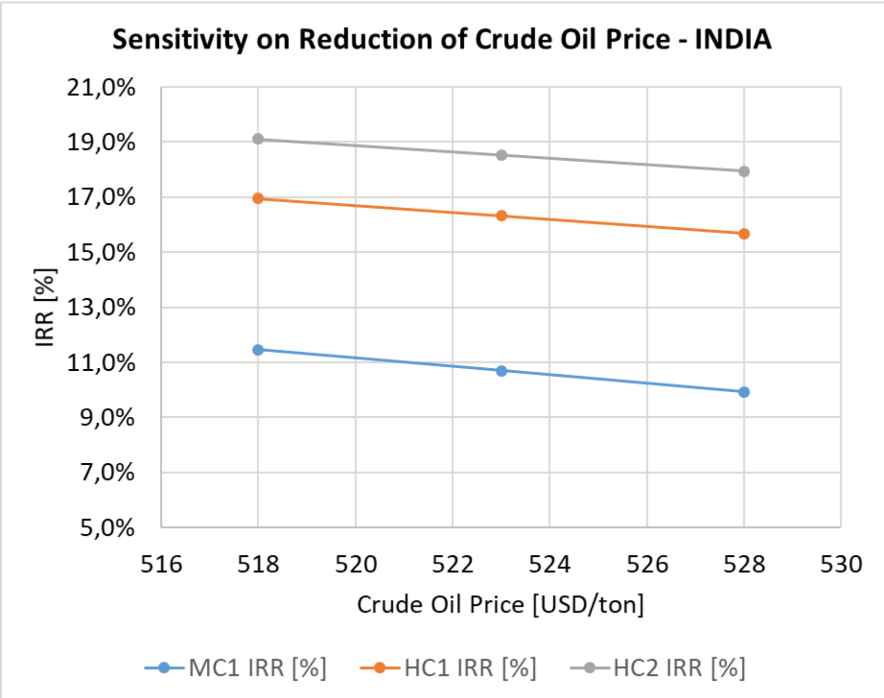


Figure 92 - Sensitivity on Reduction of Crude Oil Price - INDIA

Table 76 - Crude Oil Sensitivity - INDIA

Refinery Configuration	Delta IRR - 5 USD/ton	Delta IRR - 10 USD/ton
MC1 - 250kBPD, HCU, FO boiler	0.7%	1.3%
HC1 - 400kBPD, HCU+FCC, SDA+IGCC	0.7%	1.4%
HC2 - 400 kBPD, HCU+FCC, SDA+DCU+CFB	0.7%	1.4%

The trend is such that increasing the complexity of the refinery, the delta IRR (difference between Sensitivity Case and Base Case) decreases.

5.3.2.2 Brazil

The results of the sensitivity analysis for the three Brazilian configurations are shown in Figure 93. The trend in all the cases is almost linear.

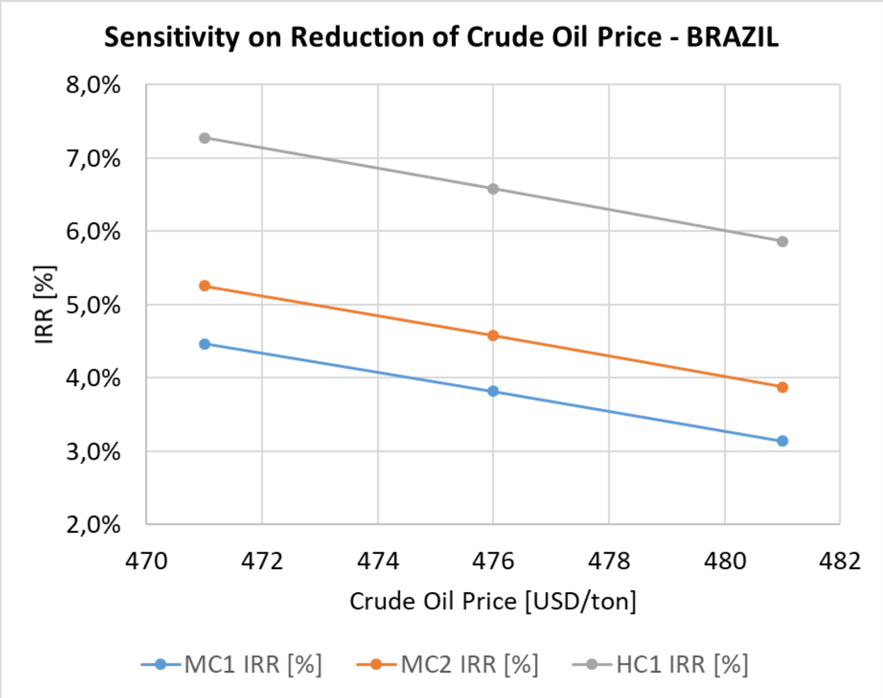


Figure 93 - Sensitivity on Reduction of Crude Oil Price - BRAZIL

Table 77 - Crude Oil Sensitivity - BRAZIL

Refinery Configuration	Delta IRR - 5 USD/ton	Delta IRR - 10 USD/ton
150kBPD, HCU, FO boiler	0.7%	1.3%
250kBPD, HCU+FCC, FO boiler	0.7%	1.4%
300 kBPD, HCU+FCC, SDA+IGCC	0.7%	1.4%

5.3.2.3 Nigeria

The results of the sensitivity analysis for the three Nigerian configurations are shown in Figure 94. The trend in all the cases is almost linear.

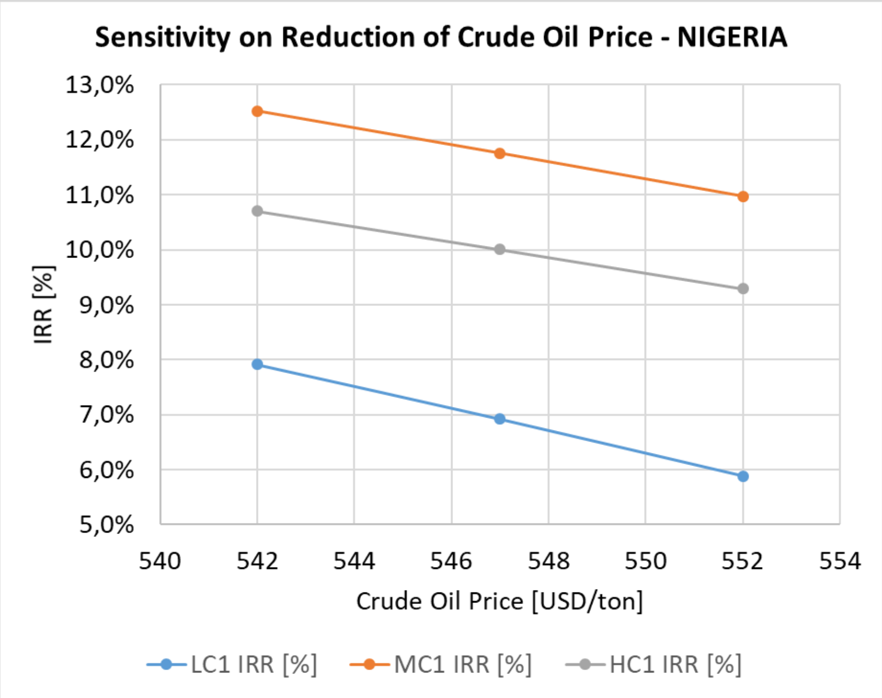


Figure 94 - Sensitivity on Reduction of Crude Oil Price - NIGERIA

Table 78 - Crude Oil Sensitivity - NIGERIA

Refinery Configuration	Delta IRR - 5 USD/ton	Delta IRR - 10 USD/ton
150kBPD, Hydroskimming, FO boiler	1.0%	2.0%
200kBPD, FCC, FO boiler	0.8%	1.5%
200 kBPD, FCC, FO boiler	0.7%	1.4%

5.4 Recommendations for Optimum Configurations

The results of this Study show that, in all Countries, the most favourable scheme is the one with High Conversion, capable of creating the highest added-value from each single barrel of crude oils.

In a mature market like the refining one, the key-drivers that still make a new refinery a profitable investment are:

- Access to infrastructures;
- Secure crude supply.
- Medium-to-large capacity;
- Complexity, flexibility and fit-for-purpose configuration, able to convert the crude oil into the products that the markets require;
- Energy efficiency;

In developing economies investment in new refineries, especially integrated with Power Production Plants, offers strategic energy independency as well as social development in the surrounding areas. They could also stimulate employment and conducive conditions for the development of other industries.

The economic results of this Study, which are based on international parity basis prices for crude oils, and on the current structure of prices for the automotive fuels in the selected Countries, should only be regarded as indicative. The financial indicators would be significantly impacted by any form of incentive that the Governments could be put in place for strategical and social purposes.

CO_2 capture is a fundamental measure to meet the challenge of greenhouse gas reduction targets. For this reason, in this study, CO_2 capture is regarded as embedded in the concept of a clean refinery.

However, CO_2 capture means additional costs and loss of profitability, evident from the economic results of the study. Therefore, to promote clean refineries with a lower carbon footprint, and allow them to compete in the market on a fair basis, policies should be introduced based on subsidies that compensate for the extra costs for CO_2 capture or, alternatively, penalties for the CO_2 emitted to atmosphere.

It is important to emphasise that including the CO_2 capture in a new refinery complex enables the integration of the CO_2 capture systems to be optimised with the rest of the plant leading to a significant reduction in CAPEX and OPEX compared with a retrofit scheme. The main reduction factors are:

- CAPEX: saving in utility and interconnecting facilities, synergy in the engineering and construction phases.
- OPEX: optimization of heat integration, saving in O&M staff.

5.5 Project Implementation Plan

Subsequent phases are needed for the implementation of a large-scale project like the construction of a new refinery.

In this section, only the main phases needed to build the inside-battery-limits (ISBL) facilities are described. Several parallel or precedent projects would also be needed to create all the infrastructures that allows the refinery construction and operation (roads, railways, terminals, electrical supply, raw water supply, houses, etc.).

The high-level implementation schedule for the ISBL portion is represented in Figure 95.

Based on Wood experience, around 30 months are needed in front of Engineering, Procurement and Construction (EPC) Phase Start to:

- define the configuration of the Plant, through a Market Study followed by a Detailed Feasibility Study,
- perform the basic design and front-end design (FEED) activities,
- produce a Class II Cost estimate (+/-10%), which is typically a condition for the Final Investment Decision (FID),

- obtain part of the capital through financing,
- select the Engineering, Procurement and Construction (EPC) Contractor through a competitive bid.

The duration of a detailed EPC phase has been set to 54 months for the most complex schemes. It could be somewhat shorter (in the range 42-48 months) for the simplest configurations.

Six months after the mechanical completion has been achieved commissioning and start-up can begin.

The overall schedule for Project implementation is based on a statistic duration of the various phases for similar projects (in terms of size and complexity), as per Wood experience. However, there are examples of projects in which fast-track strategies are put in place to shorten the schedule, e.g. partial overlapping of FEED and EPC phases (by proceeding with the bidding phase during the FEED and awarding the orders at the start of the EPC for the so-called "Long Lead" items), roll-over from FEED to EPC phase with the same Contractor (avoiding the EPC bidding phase), etc.

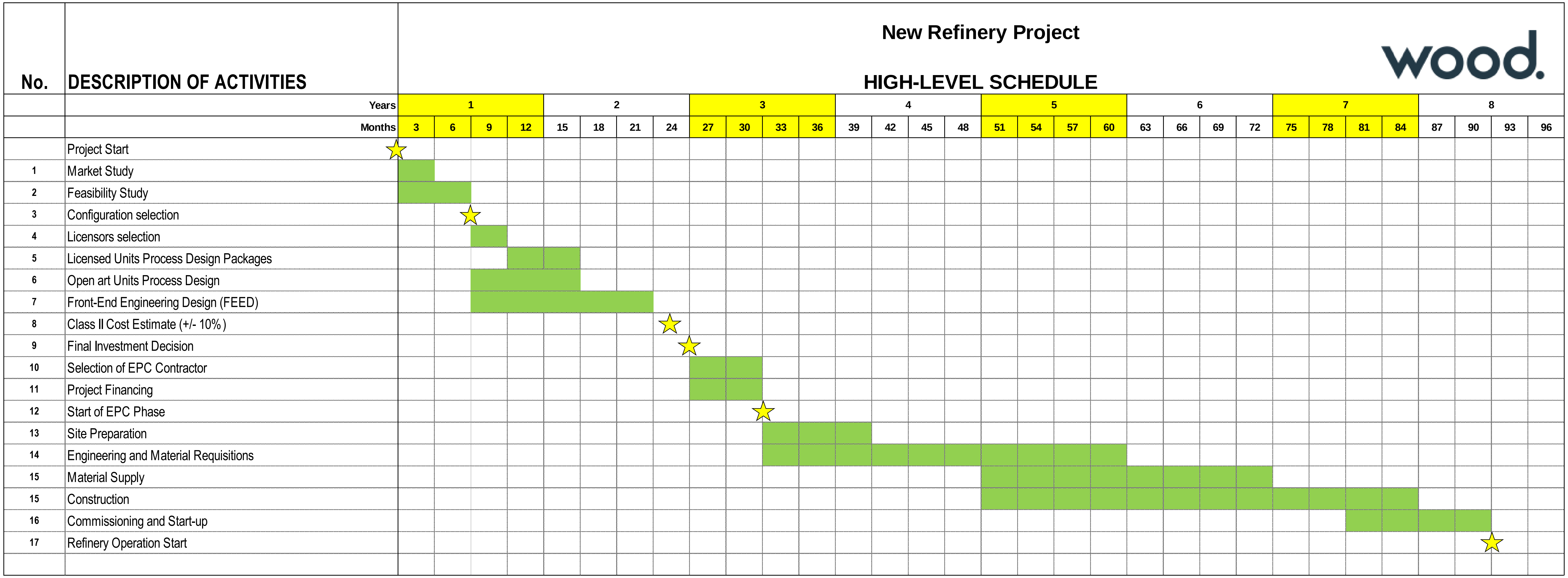


Figure 95: New Refinery Project Implementation Schedule

6 Attachments

6.1 Crude Data Grids

6.2 Summary Reports

6.3 Refinery Layouts

6.4 Total Investment Cost Sheets

6.5 Financial Analysis – Base Cases

Evaluating technology options to mitigate greenhouse gas emissions

IEA Greenhouse Gas R&D Programme

Pure Offices, Cheltenham Office Park, Hatherley Lane,
Cheltenham, Glos. GL51 6SH, UK

Tel: +44 1242 802911

mail@ieaghg.org
www.ieaghg.org