A MULTI-REGIONAL OPTIMIZATION MODEL FOR THE BRAZILIAN OIL REFINING INDUSTRY

Fernanda Pires Domingues Cardoso Guedes

Tese de Doutorado apresentada ao Programa de Pós-Graduação em Planejamento Energético, COPPE, da Universidade Federal do Rio de Janeiro, como parte dos requisitos necessários à obtenção do título de Doutor em Planejamento Energético.

Orientador(es): Alexandre Salem Szklo

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Ao Leon.

"Nosso céu tem mais estrelas,
Nossas várzeas têm mais flores,
Nossos bosques têm mais vida,
Nossa vida mais amores."

- Gonçalves Dias

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A MULTI-REGIONAL OPTIMIZATION MODEL FOR THE BRAZILIAN OIL REFINING INDUSTRY

Fernanda Pires Domingues Cardoso Guedes

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Orientadores: Alexandre Salem Szklo
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Programa: Planejamento Energético

Esta tese desenvolve e aplica o modelo de otimização multirregional para a indústria brasileira de refino de petróleo, chamado ORION - Oil Refining Industry Optimization and syNergies, que pode servir de base para outros modelos de cunho nacional ou regional. Para testar a confiabilidade do modelo, foram construídos três cenários de demanda por derivados de petróleo entre 2015 e 2040, o Shadow, o Cloudy e o Shiny. Para cada um, o modelo foi executado sob uma estrutura multirregional e uniregional, conforme duas opções de especificações de óleo combustível, à luz do regulamento da Organização Marítima Internacional (IMO) para reduzir as emissões de óxidos de enxofre (SOx) dos navios. Os cenários mais rigorosos - com os maiores crescimentos de demanda por derivados - apresentaram expansões de capacidade de novas refinarias entre 0.3 e 0.4 milhões de barris por dia (Mbbl/d). Já os cenários com maiores quedas na demanda por derivados não apresentaram expansões de capacidade de processamento. Além disso, mostraram a redução média nos custos totais do sistema de US$ 101 bilhões. Quanto aos cenários de especificação de enxofre, a regulamentação da IMO a partir de 2020 indica a necessidade de maiores capacidades de unidades de hidrotratamento de instáveis, seja através de investimentos em capacidades adicionais ou aumentando o fator de utilização de unidades existentes.

Abstract of Thesis presented to COPPE/UFRJ as a partial fulfillment of the requirements for the degree of Doctor of Science (D.Sc.)

A MULTI-REGIONAL OPTIMIZATION MODEL FOR THE BRAZILIAN OIL REFINING INDUSTRY

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This thesis develops and applies a multi-regional optimization model for the Brazilian oil refining industry, the ORION model – Oil Refining Industry Optimization and syNergies, which could also provide the basis for other regional or national models. Aiming to test the model's reliability, three different scenario in terms of oil products demands between 2015 and 2040 were constructed, the Shadow, Cloudy and Shiny, and, for each one, the model was run under a multi-regional and a single-regional framework, considering two options of heavy fuel oil specifications, in light of the IMO - International Maritime Organization regulation to reduce sulfur oxides (SOx) emissions from ships. The most stringent scenarios in terms of oil products demands - with the highest demand growths - presented between 0.3 and 0.4 million of barrels per day (Mb/d) of greenfield refining capacity expansions. On the other hand, the scenario with the largest decrease in demand for oil derivatives did not show greenfield refining capacity expansions. Moreover, it presented an average reduction on total system's costs of 101 billion US$. As for sulfur specification scenarios, the IMO regulation from 2020 onwards leaded to higher unstable hydrotreatment capacities (HDTI), either through investments in additional capacities or increasing already existing units´ utilization factor.

Summary

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List of Acronyms

ADU – Atmospheric distillation unit

AF - Africa

AGO – Atmospheric gasoil

AIM - Asia-Pacific Integrated Modeling

ALK – Alkylation unit

ANEEL – Agência Nacional de Energia Elétrica

ANP – Agência Nacional do Petróleo, Gás Natural e Biocombustíveis

AP - Asia-Pacific

API – American Petroleum Institute

ATR – Atmospheric residue

BP – British Petroleum

CA – Central America

CAESAR – Carbon and Energy Strategy Analysis for Refineries

CAPADU - Atmospheric distillation unit capacity

CAPEX – Capital Expenditure

CBA – Cost benefit analysis

CEPCI - Chemical Engineering Plant Cost Index

CGE – Computable general equilibrium

CH_4 - Methane

CIF - Cost, Insurance, and Freight

CO – Carbon monoxide

CO_2 – Carbon dioxide

COFFEE – COmputable Framework For Energy and the Environment

COG – Cogeneration unit

COK – Delayed coking unit

COPPE – Instituto Alberto Luiz Coimbra de Pós-Graduação e Pesquisa de Engenharia

DOSP – Deasphalted oil

DSP – Deasphalting unit

ECAs - Emission Control Areas

EPE – Empresa de Pesquisa Energética

EPPA – Emissions Prediction and Policy Analysis

EPRI – Electric Power Research Institute

ETBE - Ethyl tert-butyl ether

ETSAP - Energy Technology Systems Analysis Program

EY – Ernst & Young

FCC – Fluid catalytic cracking unit

FOB – Free-on-board

FOM – Fixed Operation and Maintenance Cost

GAMS – General Algebraic Modeling System

GCAM - Global Change Assessment Model

GHG – Greenhouse gas emissions

GTL – Gas to liquids

H_2 - Dihydrogen

H_2O – Hydrogen oxide

H_2SO_4 – Sulfuric acid

HCC – Hydrocracking unit

HDSG – Gasoline hydrodesulfurization unit

HDT – Hydrotreatment unit

HDTD – Diesel hydrotreating unit

HDTI - Instable products hydrotreating unit

HDTK – Kerosene hydrotreating unit

HDTN - Naphtha hydrotreating unit

HF – Hydrofluoric acid

HGO – Heavy gasoil

HGU – Hydrogeneration unit

HP Steam – High-pressure steam

HSRN – Heavy straight run naphtha

HVGO – Heavy vacuum gasoil

IAM – Integrated Assessment Model

IEA – International Energy Agency

IFP – *Institut Français du Pétrole*

IIASA - International Institute for Applied Systems Analysis

IMAGE - Integrated Model to Assess the Global Environment

IMO - International Maritime Organization

IPCC - Intergovernmental Panel on Climate Change

IPP – Import parity price

ISBL - Inside Battery Limits

LCAOST - Life Cycle Analysis of Oil Sands Technologies

LCO – Light cycle oil

LGO – Light gasoil

LP – Linear Programming

LP Steam – Low-pressure steam

LSRN – Light straight run naphtha

LVGO – Light vacuum gasoil

MagPIE - Model of Agricultural Production and its Impact on the Environment

MCTIC - Ministério da Ciência, Tecnologia, Inovações e Comunicações

ME – Middle East

MERGE - Model for Evaluating the Regional and Global Effects of GHG Reduction Policies

MESSAGE - Model for Energy Supply Strategy Alternatives and their General Environmental Impact

MIT - Massachusetts Institute of Technology

MP Steam – Medium-pressure steam

MTBE - Methyl tertiary-butyl ether

NE_D – Northeast demand region

NE_S – Northeast supply region

NIES - National Institute for Environmental Studies

NPGU – Natural Gas Processing Unit

O&M – Operation and Maintenance Cost

OPEX – Operating Expenses

ORION – Oil Refinery Industry Optimization and syNergies

OSBL – Outside Batter Limits

OURSE – Oil is Used in Refineries to Supply Energy

PBL - *Planbureau voor de Leefomgeving* (Netherlands Environmental Assessment Agency)

PIK - Potsdam Institute for Climate Impact Research

PNE – Plano Nacional de Energia

PNLP - Plano Nacional de Logística Portuária

PNNL - Pacific Northwest National Laboratory

POLES - Prospective Outlook on Long-term Energy Systems

PRELIM - Petroleum Refinery Life Cycle Inventory Model

REDSP – Deasphalted residue

REF – Catalytic reforming unit

REMIND - Regional Model of Investments and Development

RFCC – Resid fluid catalytic cracking unit

RITE - Research Institute of Innovative Technology for the Earth

RJMG_D – Rio de Janeiro/Minas Gerais demand region

RJMG_S – Rio de Janeiro/Minas Gerais supply region

SLO – Slurry oil

SO_x – Sulfur oxide

S_D – South demand region

S_S – South supply region

SP_D – São Paulo demand region

SP_S – São Paulo supply region

TIAM – TIMES Integrated Assessment Model

TIMER - The IMage Energy Regional model

TIMES - The Integrated MARKAL-EFOM System

ULSFO – Ultra Low Sulfur Oil

USA – United States of America

USD – United States Dollar

VDU – Vacuum distillation unit

VOM – Variable Operation and Maintenance Cost

WE – Western Europe

WTI – West Texas Intermediate

1. Introduction

The worldwide oil refining industry has been facing numerous challenges in recent years. Oil's prices volatility (HERRERA *et al*., 2018), more stringent fuel specifications, rigorous environmental regulations (SZKLO and SCHAEFFER, 2007), and changing oil products demand patterns (IEA, 2019) can be considered as the main ones.

Crude oil prices have been extreme volatile in the last two decades due to factors such as wars and political instability, economic and financial slowdown, excessive speculation[1], terrorist attacks and natural disasters (KAUFMANN and ULMAN, 2009; CIFARELLI and PALADINO, 2010; KILIAN and MURPHY, 2011; SILVERIO and SZKLO, 2012; ZAVADSKA *et al*., 2018). In the specific case of the oil refining sector, the influences of this volatility can occur through investment decisions, adjustment of oil derivatives' prices (ASCHE *et al*., 2003), changes in refineries' utilization factors (KAUFMANN *et al*., 2008) and changes in oil refining gross margins, which are the difference between the revenue obtained from the sale of the derivatives and the cost of the petroleum processed in a refinery.

Alongside, global and regional targets in the context of the transition to a cleaner energy system with lower greenhouse gas emissions (RIBEIRO *et al*., 2013; IEA, 2018), less presence of fossil-based fuels (BRADSHAW and JANNUZZI, 2019), increasing demand for ultra-specified oil products (CASTELO BRANCO *et al*., 2011; ICCT, 2012; OPEC, 2017) and the formulation of oil products with non-oil components (biofuels) having almost no contaminant content levels (SZKLO and SCHAEFFER, 2007; CE DELFT, 2013; WEC, 2016), are leading refining companies to re-think their refining processes and production profile (IHS MARKIT, 2018).

For the coming decades, it is foreseen that mobility systems will be different from what currently exists, with the presence of several key mobility trends, such as transport electrification, shared mobility, autonomous steering, and new concepts as the MaaS – Mobility as a Service, which facilitates the access to transport services through a digital platform with integrated public transport and shared car pricing (MOUNCE

[1] In the long term, there is little theory that would argue that speculation can influence price. However, in the short term, if expectations slow to respond, thus delaying any significant supply-side response, and demand is relatively inelastic, the prospect of speculative pressures influencing price must be considered (MEDLOCK III *et al*., 2013; FATTOUH, KILIAN and MAHADEVA, 2012).

and NELSON 2019; DELOITTE, 2017; MCKINSEY & COMPANY, 2018; O'CONNOR, 2010). These new trends have a strong impact on the demand for oil products, notably light and medium distillates, as gasoline and diesel. Thus, an increase in the yield of other products, and a reduction in the output of traditional refined products are expected (IEA, 2018). According to IHS MARKIT (2018), seeking a deepen integration with petrochemical operations, and gathering a higher conversion of crude oil into chemical products can be an attractive option for refiners.

In the specific case of the Brazilian oil refining industry, the process' adaptation to new trends has been occurring for some years. With the ramp-up of medium-to-heavy crude oils production in Brazilian offshore basins in the 1980s and 1990s (HALLACK *et al*., 2017), refining schemes of existing refineries, which were mainly focused on gasoline production and designed for light oil processing, were modified to convert the heaviest fractions of crudes into medium cuts and meet the more stringent specifications – e.g., by adding delayed coking units and severe hydrotreatment processes (PERISSÉ, 2007; SZKLO and SCHAEFFER, 2007; SZKLO *et al*., 2012). For instance, the introduction of the specification of diesel S10 (10 ppm of sulfur) in the Brazilian market (BONFÁ, 2011) boosted the investments in medium distillate hydrotreating units. Likewise, in 2012, through the creation of PROMEGA (Medium and Gasoline Production Program), Petrobras modified its oil refining park in order to increase the production of diesel, jet fuel and gasoline through capacities expansions and efficiency improvements of process units, reducing by-product imports and increasing its profit margin (EPE, 2011; PETROBRAS, 2013; PETROBRAS, 2014).

Still, it is worthwhile mentioning the uncertainties faced by the Brazilian oil refining industry, associated to the evolution of energy demand and supply over the past and in the future decades. These uncertainties mainly concern the balance between biofuel and petroleum products for the automotive sector, the development of the domestic crude oil supply and the process of market opening, in which the prices of oil products are being defined according to the international market (Import Parity Price - IPP[2]), with the objective of attracting investors, and thus meeting the partnership policy currently being sought in the sector (PETROBRAS, 2018).

[2] Based on the parity with the international market, which includes costs such as chartering vessels, internal transport costs, and port charges (PETROBRAS, 2016).

On the demand side, for the transportation sector, there are explicit aspects that suggest a late transition in the Brazilian automotive industry, such as the high purchase price of hybrid or electric vehicles; the need for adaptations and improvements in the supply infrastructure for electric vehicles; and lack of governmental incentives for the dissemination of hybrid and electric vehicular technologies. However, there is the commitment to meet the demand for fuels with more restrictive specifications, as previously mentioned, as well as a strong presence of biofuels[3] – especially ethanol - in the transport sector's energy system (EPE, 2018a).

On the supply side, the development of the pre-salt crude oil fields provides an increasing crude oil production (SZKLO *et al*. (2006, 2007); DE SANTANNA PIZARRO *et al*., 2012; SARAIVA *et al*., 2013; SAUER and RODRIGUES, 2016) which growths up from 34 Mt in 1990 to 142.7 Mt in 2017. This stands for 3.2% of the worldwide crude oil supply.

In sum, Brazil is a major oil producer, with newly discovered wells (pre-salt area) - which have great production potential - and a refining park undergoing a process transformation to be able to receive the pre-salt oil (light-to-medium oil), as well as investing in hydrotreating units in order to meet fuels stringent specifications. The country has also been, in the last years, importing oil products in ascendant order, reducing, therefore, the refineries' utilization factors and increasing its refining margin uncertainty (ANP, 2018a; BP, 2018).

In this context, Petrobras, a state-owned company that currently owns 99% (ninety nine percent) of the market share of the refining and logistics sectors in Brazil

[3] In 1975, pursuing the first oil crisis, the National Fuel Alcohol Program (ProÁlcool) was introduced, in Brazil, creating conditions for large-scale development of the sugar and ethanol industry (FAO, 2008). During the same time, the Pró-Óleo, a biodiesel program was also brought in (MAGALHÃES *et al.*, 1991; ROSILLO-CALLE and CORTEZ, 1998; POUSA *et al*., 2007). The arguments for both programs were the same: reduce country's dependence on imported fuels and stimulate rural development (CARDOSO *et al*., 2019). Nonetheless, unlike ethanol politics, the biodiesel program failed to create a similar political alliance between state agencies and non-state industries of oleaginous crops (STATTMAN, 2019). The beginning of the growth of biodiesel production in the country dates from 2004, with the National Program of Production and Use of Biodiesel (PNPB), which established minimum biodiesel to diesel blending requirements (MELO, 2018). The most recent biofuel policy, RenovaBio was introduced in 2016, aiming to outline a joint strategy to recognize the strategic role of all types of biofuels in the Brazilian energy matrix, both for energy security and for mitigating greenhouse gas emission reductions (MME, 2019).

has stated its new objective, which consists of the repositioning of the national refining sector by dividing the refining park into four geographical blocks, as well as by selling eight of its seventeen refineries. The idea is that only refineries of the southeast would remain under Petrobras management (PETROBRAS, 2019). The plan for the sale of refineries is part of a large Petrobras divestment package.

Given these challenges, which are short to long-term in nature and involve the discussion of how the oil refining industry is flexible, as well as the focus on the Brazilian problem of refining regionalization and the refiners' strategies, the main purpose of this thesis is to develop a multi-regional model for the Brazilian oil refining industry, with a medium to long-term analysis, in an open-source modeling language, which allows the dialogue with international consolidated models associated with both the entire energy system - the so-called Integrated Assessment Models (ANDERSON and JEWELL, 2019) - and the world oil refining (models focused only on the petroleum process).

1.1. Objectives

The main purpose of this research is the development of the ORION (Oil Refining Industry Optimization and syNergies) model, which consists in a multi-regional linear programming optimization model for the Brazilian oil refining industry, in an open-source modeling language, capable of analyzing the evolution of this industry, in the medium and long terms, providing, this way, a tool to help experts and decision makers. The model is developed to address the main identified challenges for the country´s refining industry in the next years and to be able to be linked to other models´ structures for either representing Brazil in the world oil refining industry or representing the country´s oil refining in the country´s energy system as whole.

The programming language used in the construction of this model was the GAMS - General Algebraic Modeling System associated with the CPLEX solver.

Aiming to test the model’s reliability, three different scenarios were developed in terms of oil products demands: the Shadow scenario, based on the evolvement of the current oil refining industry and the energy and transport systems, without changes in current policies; the Cloudy scenario, which takes into account the announced policies and targets both for oil refining and for the energy and transportation systems as a

whole, envisaging the mobility in the transport system for the next few years; and the Shiny scenario, being the most disruptive among the three scenarios, since it considers an accelerated energy transition to reach the goals associated to climate change, clean energy and clean air. For each one, the model is run under a multi-regional and a single-regional framework, in order to analyze, in each case, whether there is an advantage or not in having a regional model. In addition, for each case previously mentioned, two options of heavy fuel oil specifications were taken into account, in light of the IMO's regulations to reduce sulfur oxides (SOx) emissions from ships.

Moreover, as the ORION output, at a regional level, depends on the foreign trade flows and these flows are related to the international market prices, a nested optimization approach was also carried out. Thus, a worldwide multi-regional model OURSE (Oil is Used in Refineries to Supply Energy) (LANTZ *et al*., 2005) was run, for each previously defined scenario, in order to provide marginal values associated to the oil products demand constraints, which are used in the Brazilian model.

The OURSE model is also used to assist the validation of variables of the ORION model, such as investment costs, O&M costs and logistics costs.

Finally, it is worth mentioning that the methodological procedure and the methods followed in this research could well be applied in other countries, and, even more important, the model developed by this thesis can be connected to existing national or global models, as was done in the present study in the case of OURSE, aiming to obtain more accurate results, and/or to give more detail to less detailed models.

The following section discusses the state of the art of oil refining optimization models, showing the relevance of the model developed by the present research, as well as its possible applications.

1.2. Background: Oil refining expansion optimization models

Mathematical optimization techniques have been involved in refining operations through the years, including crude selection and evaluation, process configurations, derivatives' production, and products logistics planning (HASSAN *et al*., 2011). Likewise, according to BODINGTON and BAKER (1990), since 1947, with the invention of the Simplex algorithm by Dantzig, many computational mathematical models have been implemented to solve specific subjects of a refining process.

In the literature, a series of works have developed optimization models for the refining sector, using linear, non-linear and mixed integer programming, with the aim of improving the output of production processes (LAN, 2008; LAN *et al*., 2008; MENEZES *et al*., 2013; CASTILLO and MAHALEC, 2014; KANCIJAN *et al*., 2015), integrating refining and petrochemical plants (LI *et al*., 2006; GOMES, 2011; KETABCHI *et al*., 2018), optimizing refineries' greenhouse gas emissions (GHG) (DIKSHIT *et al*., 2005; HADIDI *et al*., 2016), analyzing market scenarios (PINTO *et al*., 2000), optimizing market trades (COELHO and SZKLO, 2015), integrating oil supply chains (GUAJARDO *et al*., 2013; FERNANDES *et al*., 2014), netback pricing crude oils in marginal refineries´ schemes (OHARA, 2014; DUQUE, 2017; ARAGÃO, 2018), and absorbing the uncertainty in risk assessment (GUPTA and GROSSMANN, 2014) or in oil refineries´ operation to deal with changes in derivatives markets (BARROS and SZKLO, 2015; DUQUE, 2017).

Specifically in terms of linear programming models, a significant contribution was made by LANTZ *et al*. (2005), with the development of the OURSE (Oil is Used in Refineries to Supply Energy) model, which is a world-wide aggregated refining model designed to simulate the world oil product supply for the POLES (Prospective Outlook for the Long-term Energy System) model. It includes a representative refinery for nine different regions of the world (Z1 - North and Central America, Z2 - Latin America, Z3 - North Europe, Z4 - South Europe and Turkey, Z5 - Former Soviet Union (CIS), Z6 – Africa, Z7 - Middle East, Z8 – China and Z9 - Other Asia), being designed to operate over the period 1997-2030. It comprises all the relevant techno-economic characteristics of the oil refining industry (such as technical processes, investment and operating costs, and pollutant emission factors). The OURSE model was used for several studies concerning the global trends of the refining industry (SAINT-ANTONIN & MARION, 2011), the CO_2 emissions (TEHRANI & SAINT-ANTONIN, 2008) or some regional applications (BENYOUCEF and LANTZ, 2012).

Another important mathematical model is the PRELIM (Petroleum Refinery Life Cycle Inventory Model) developed by the LCAOST - Life Cycle Assessment of Oil Sands Technologies research group of the University of Calgary (BERGERSON *et al*., 2017). The model is a mass- and energy-based, process unit-level tool for estimating the energy use and greenhouse gas (GHG) emissions associated with processing a variety of crude oils within a range of configurations in a refinery. Although not being an optimization model, PRELIM is a complex Excel spreadsheet simulation tool presenting

eleven refinery configurations constructed to reflect current operating refineries in North America, and containing a crude assay inventory with 144 crude oil types. Each crude is characterized according to its qualities as the crude distillation curve, sulfur content, API gravity, carbon residue content, and hydrogen content. The crude is also divided into nine fractions, each associated with a specific cut temperature. Already, PRELIM employs a systems level approach and refinery linear modeling methods which ensures wide applicability in assessing energy use and environmental impacts for processing crudes of different quality, and allows for incorporation of model results into Well-To-Wheel analyses (BERGERSON *et al.*, 2017).

In the context of simulation tools, it is also worth mentioning also the CAESAR – Carbon and Energy Strategy Analysis for Refineries, performed within excels' visual basic model which was originally described in TOLMASQUIM and SZKLO (2000), later being used by the Brazilian Government in its Long-Term Energy Plan 2030 (EPE, 2007), and updated by GUEDES (2015), VÁSQUEZ-ARROYO (2018), MAGALAR (2018) and GUEDES *et al*., (2019). The model relies on refining schemes, including energy and mass balances for eighteen process units. For each unit capacities are determined, as well as the processed feedstock, specific utilities consumption (steam, fuel and hydrogen) and specific water consumption. The outputs of the tool consist of the final energy consumption, CO_2 emissions, oil products output, and refineries´ water consumption and withdrawals (GUEDES *et al*., 2019). Although being a simulation tool, the model comprises a small optimization module, which selects the best emissions mitigation technologies when subjected to CO_2 taxes scenarios.

Lastly, there are the Integrated Assessment models (IAMs), which are widely used techniques for knowledge production to assess costs of future energy pathways and economic effects of energy/climate policies (ELLENBECK and LILLIESTAM, 2019). According to VAN VUUREN (2015), there are numerous types of IAMs, ranging from small cost benefit analysis (CBA) models to complex models able to identify underlying processes of interaction. Usually climate change and air pollution are the focus of IAMs (ROCHEDO, 2016), however, these models are capable of survey diverse impacts, such as water quality, water scarcity, depletion of non-renewable resources and overexploitation of renewable resources (PBL, 2016).

IAMs generally include oil refining processes in their frameworks, but not in very detailed manner, contemplating few crude oil options and final products, poor or none flexibility, and, in most cases with single process configurations. Table 1-1

summarizes the main current IAMs, with their respective characteristics with respect to the oil refining modules, as well as the main existing oil refining models.

Table 1-1 - IAMs and oil refining models

Model		Institute	Country	Model type	Crude oil options	Refinery configuration	Final products	Reference
IAMs	AIM/CGE	NIES	Japan	General equilibrium/Recursive Dynamic	Crude oil	Single	Oil products	FUJINO (2002)
	GCAM	PNNL	USA	General equilibrium/Recursive Dynamic	Oil (conv.,unconv.)	Single	Refined liquids end use/ Refined liquids industrial	CALVIN *et al.* (2019)
	IMAGE-TIMER	PBL	Netherlands	General equilibrium/Recursive Dynamic	Crude Oil	Single	Light liquid fuels/Heavy liquid fuels	PBL (2017)
	MESSAGE-Globiom	IIASA	Austria	General equilibrium/Intertemporal optimization	Crude oil	Multiple[1]	Gasoline, fuel oil (light/heavy)	IIASA (2016)
	REMIND-MagPIE	PIK	Germany	General equilibrium/Intertemporal optimization	Crude oil	Single	Liquid fuels	KRIEGLER and LUCHT (2015)

	TIAM-TIMES	ETSAP	France	Partial equilibrium/Intertemporal optimization	Crude oil	Single	Liquefied petroleum products (LPG), gasoline, naphtha, diesel, kerosene, heavy fuel oil	LOULOU *et al*. (2016)
	MERGE	EPRI	USA	General equilibrium/Intertemporal optimization	10 crude oils	Single	Oil products	MANNE and RICHELS (2004)
	DNE21+	RITE	Japan	Partial equilibrium/Intertemporal optimization	Oil (conv.,unconv.)	Single	Liquid fuels (gasoline, light oil products, heavy oil products)	RITE (2009)
	COFFEE	COPPE	Brazil	General equilibrium/Intertemporal optimization	Crude oil	Multiple[2]	Refinery gases, LPG, naphtha, gasoline, gasoil, diesel, FCC coke, petroleum coke, heavy products	ROCHEDO (2016)
	EPPA	MIT	USA	General equilibrium/Recursive Dynamic	Crude oil, oil shale, oil sands	Multiple[3]	Refinery gases, gasoline, diesel, heavy fuel oil, petroleum coke, and other products[4]	CHOUMERT *et al*. (2006)

Refining Models	OURSE	IFP	France	Linear programming (LP) model	8crude oils	Single[5]	Liquefied petroleum products (LPG), gasoline and naphtha, middle distillates and heavy distillates	LANTZ *et al*. (2012)
	PRELIM	Univeristy of Calgary	Canada	Linear programming (LP) model	112 crude oils	Multiple[6]	Blended gasoline, jet-A/AVTUR, ULSD[7], fuel oil, coke, hydrocracking residue, liquid heavy ends, liquefied petroleum gas (LPG)	BERGERSON *et al*. (2017)
	CAESAR	COPPE	Brazil	Linear programming (LP) model	6 crude oils	Multiple[8]	Liquefied petroleum products (LPG), gasoline and naphtha, middle distillates and heavy distillates	GUEDES *et al*., (2019)

[1]Simple refinery/Complex Refinery

[2]Mega-refinery with possible gasoline/diesel refinery expansions, and with gasoline/diesel campaigns

[3]Topping, hydroskimming and cracking refineries

[5]Deep conversion refineries (regionalized)

[6]This category comprises a wide variety of products, from the high-value naphtha fraction, whose price is often closely related to gasoline's, to the lower value bitumen or waxes

[7]Hydroskimming, coking (medium conversion with FCC, with gasoil HCC, or with both; deep conversion with FCC, with gasoil HCC or with both), hydrocracking (medium conversion with FCC, with gasoil HCC, or with both; deep conversion with FCC, with gasoil HCC or with both)

[6]Ultra-low sulfur diesel

[8]Naphtha, diesel and kerosene refinery campaigns

Hence, it is verified the important contribution associated with the development of a multi-regional expansion oil refining model for Brazil, in an open source language, which can be replicated in other countries, as well as contribute to a better detailing of the oil refining segment in IAMs.

1.3. Thesis Outline

This thesis consists of six chapters, including this one. Chapter 2 presents the current Brazilian oil refining industry featuring the typical refining schemes of national refineries, recent investments and decisions, the evolution of its production profile, the types of oil consumed in recent years, as well as its trajectory of exports and imports of oil derivatives. Chapter 3 exposes the methodology followed by this thesis, first detailing the GAMS (General Algebraic Modeling System) tool, then presenting the OURSE (Oil is Used in Refineries to Supply Energy) model and the nested optimization approach performed by the study, and finally presenting the ORION (Oil Refining Industry Optimization and syNergies) model framework. Chapter 4 describes the case study, i.e., the data inserted in the model for its base year (year for which the calibration stage is carried out). In the same chapter the scenarios performed in the ORION and OURSE models are depicted. In Chapter 5 the results are presented according to the scenarios analyzed. Finally, Chapter 6 presents the conclusion and final considerations of the work.

2. The Brazilian oil refining industry

The Brazilian oil refining industry consists of seventeen refineries in operation, with a total installed nominal capacity of 2.4 million of barrels per day (Mb/d) (ANP, 2018a). Most of them are under control of Petrobras and, in the last years, the national refining park has undergone a period of expansion, especially with the start-up of the first train of Abreu e Lima Refinery (RNEST), in December 2014. In addition, investments were made in conversion and hydrotreatment units for the adequacy of the existing refining plants, in order to increase the production of higher value-added oil products (EPE, 2017).

Since 2018, Petrobras, a state-owned company that currently owns 99% (ninety nine percent) of the market share of the refining and logistics sectors in Brazil, has undergone a process of market opening, in which the prices of oil products are being defined according to the international market (Import Parity Price - IPP), with the objective of attracting investors, and thus meeting the partnership policy currently being sought in the sector (PETROBRAS, 2018). In this context the company has stated its new objective, which concerns in breaking the refinery park in 4 geographical blocks (South, Northeast, Rio de Janeiro-Minas Gerais and São Paulo), and selling eight of its seventeen refineries. The idea is that only refineries of the southeast would remain under Petrobras management (PETROBRAS, 2019). The plan for the sale of refineries is part of a large Petrobras divestment package. According to ANP (2018a), this plan is an exclusive decision of the company that may represent the most rapid step towards creating an open market, with a lower risk of interference or the adoption of anti-competitive practices, which will allow the attraction of new investments and the reduction of dependence on imports (ANP, 2018a).

Table 2-1 shows the capacity, localization, and start-up year of Brazilian refineries per geographical block, Figure 2-1 illustrates their localizations, and Figure 2-2 presents the logistics infrastructure of crude oil and oil derivatives in Brazil.

Table 2-1 - Brazilian refineries as of December, 2017

Refinery	Start of operation	Nominal Capacity (10^3bbl/d)
South Region		
REFAP- Refinaria Alberto Pasqualini S.A.	1968	220
REPAR- Refinaria Pesidente Getúlio Vargas	1977	214
Riograndense- Refinaria de Petróleo Riograndense S.A.	1937	17
Total		**451**
São Paulo Region		
REPLAN- Refinaria de Paulínia	1972	434
REVAP- Refinaria Henrique Lage	1980	252
RPBC- Refinaria Presidente Bernardes	1955	170
RECAP- Refinaria de Capuava	1954	63
Univen- Univen Refinaria de Petróleo Ltda.	2007	5
Total		**924**
Rio_Minas Region		
REGAP- Refinaria Gabriel Passos	1968	166
REDUC- Refinaria Duque de Caxias	1961	252
Manguinhos- Refinaria de Petróleos de Manguinhos S.A.	1954	14
Total		**432**
North_Northeast Region		
RLAM- Refinaria Landulpho Alves	1950	377
RNEST- Refinaria Abreu e Lima	2014	115
REMAN- Refinaria Isaac Sabbá	1956	46
RPCC- Refinaria Potiguar Clara Camarão	2000	45
Lubnor- Lubrificantes e Derivados de Petróleo do Nordeste	1966	10
Daxoil- Dax Oil Refino S.A.	2008	2
Total		**595**
Total Regions		**2402**

Source: ANP (2018b)

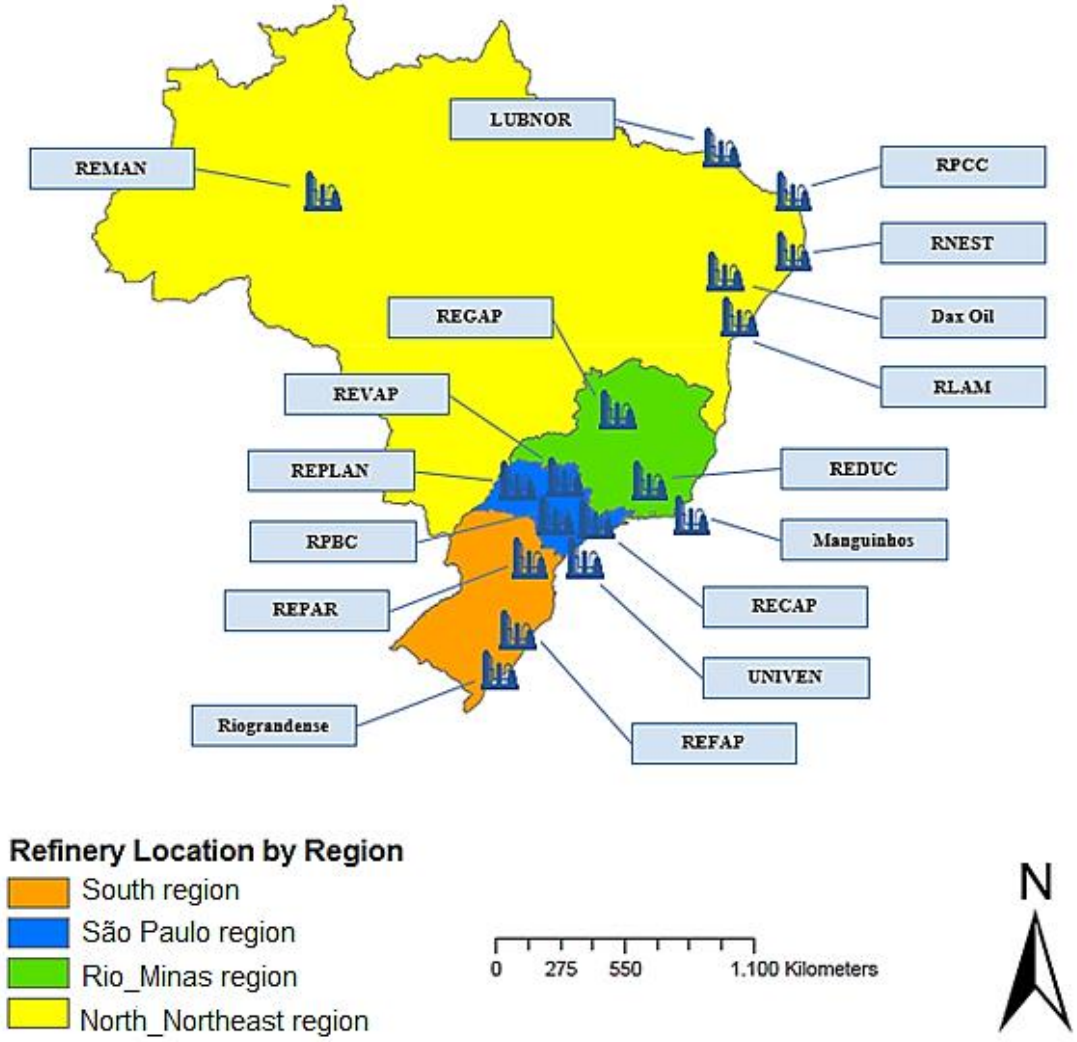


Figure 2-1 – Localization of Brazilian refineries

Figure 2-2 - Brazilian logistics infrastructure of crude oil and oil derivatives

Source: ANP (2018b)

The São Paulo region plus the Rio_Minas region, which comprise the Brazilian southeastern region have the largest installed refining capacity in the country, also comprising an important network of pipelines, allowing the movement of derivatives between refineries, terminals and bases, and supplying not only the regions itself, but also a good part of the other regions (ANP, 2018b). The South region is one of the most balanced regions, that is, where consumption and demand remain close. As it is a region further away from the country's main oil-deficit areas, and far from international supply points (such as the Gulf of Mexico), refineries in the South tend to operate within their regional boundaries (EPE, 2018a). The North_Northeast region is a deficient region in terms of derivatives supply, since the production of its refineries is unable to meet its demand. Thus, most of the derivatives consumed in this region come from the region of Sao Paulo and Rio_Minas (EPE, 2018a). Although not represented in the geographical blocks, since it has no refineries, the Midwest region has its oil derivatives demand supplied basically by the São Paulo region (EPE, 2018a).

Despite the large refining capacity, the Brazilian refining industry has been presenting a declining in its processed load (utilization factor[4]) since 2014. While in 2013 the utilization factor was approximately 98%, in 2017 it reached 76% (ANP, 2018b). This fall can be explained because of Petrobras' pricing policy, as mentioned previously, which has made export of crude oil and import of derivatives more advantageous than the processing of domestic oil and the production of derivatives in Brazilian oil refineries (FGV ENERGIA, 2017).

Figure 2-3 presents the processed load and the refining capacity of Brazilian refining park from 2008 to 2017.

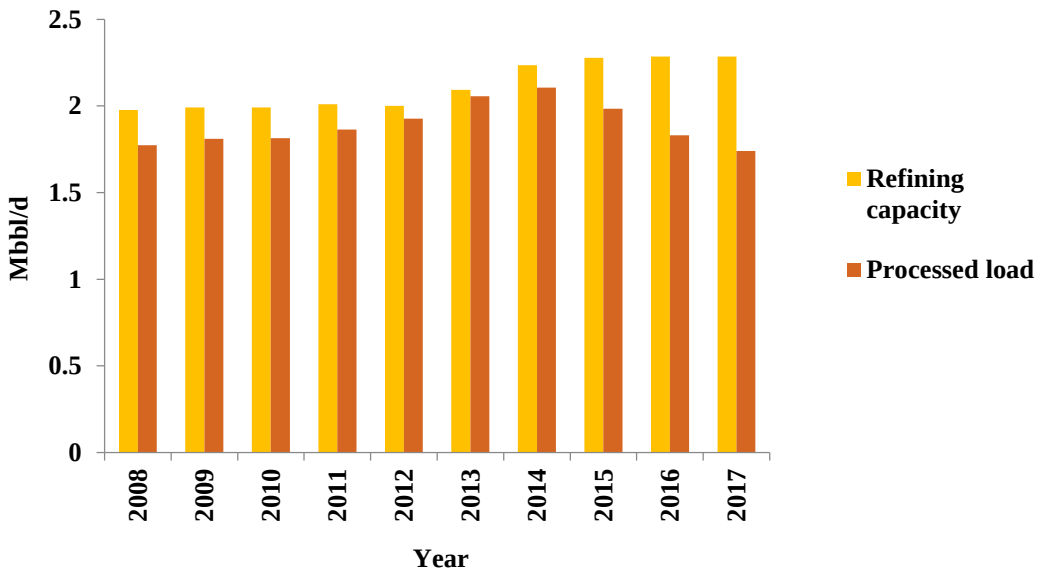


Figure 2-3 - Processed load and refining capacity of Brazilian refining industry (2008-2017)

Source: ANP (2018b)

In addition, as shown by Figure 2-4, in 2017, 91.9% of the total oil processed were of domestic origin and 8.1% were imported (ANP, 2018b), being this the highest ratio domestic/imported oil in the last 10 years.

[4] Utilization Factor, in this case, is the ratio between the usage time for which a process unit has been functional to the total time for which it could be used. Since for its calculation, only the ADU is considered, it does not directly grasp the complexity of the refinery. Nervetheless, when their more complex downstream units are fully utilized, refineries operate as simple refineries.

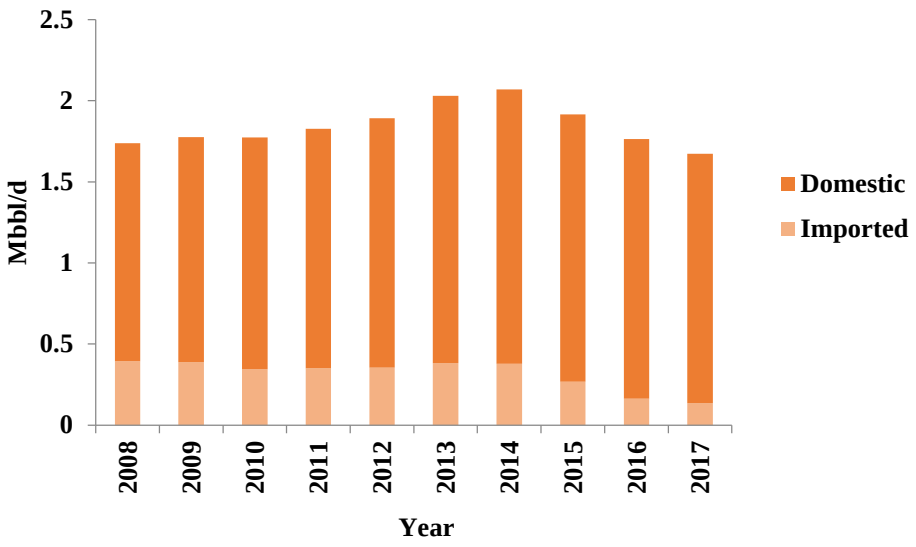
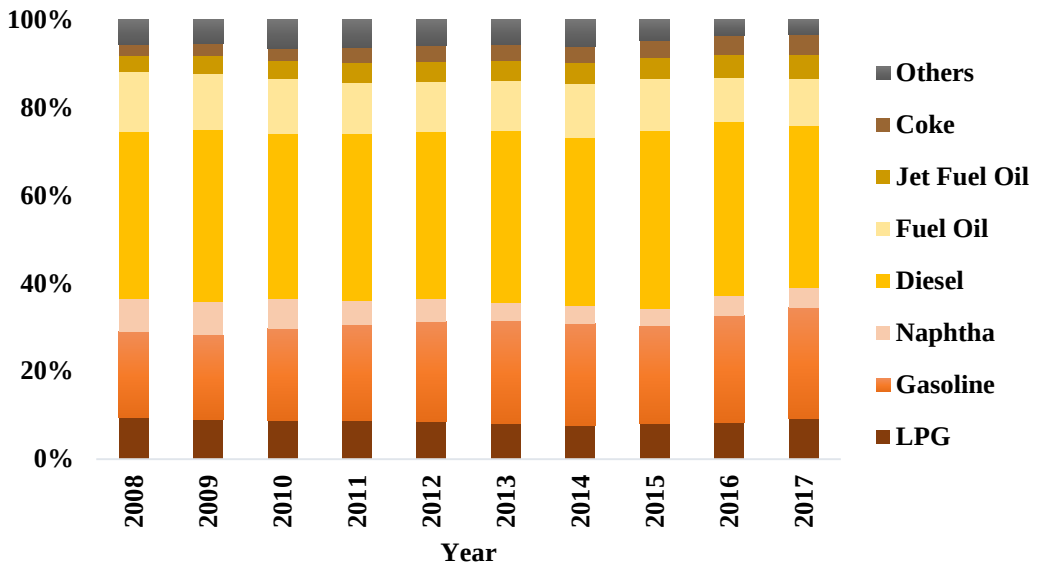


Figure 2-4 - Nature of processed load (2008 – 2017)

Source: ANP (2018b)

Most Brazilian refineries were built before the 1980s with the main objective of meeting the demand for gasoline and fuel oil in major urban centers of Brazil (also close to the country´s coast). Considering the imported light crude oil processed at this time, these refineries were equipped with FCC units (SZKLO and SCHAEFFER, 2007). However, due to the increasing diesel demand after the 1980s (BORBA *et al*., 2017), as well as the ramp-up of medium-to-heavy crude oils production in Brazilian offshore basins in the 1980s and 1990s (HALLACK *et al*., 2017), the refining schemes of existing refineries were partially modified to convert the heaviest fractions of crudes into medium cuts – e.g., by adding delayed coking units and severe hydrotreatment processes (SZKLO and SCHAEFFER, 2007; SZKLO *et al*., 2012). Through the PROMEGA (Medium and Gasoline Production Program), created in 2012, Petrobras modified its oil refining park in order to increase its heavy oil processing capacity and meet the demand for gasoline and diesel with more restrictive specifications. The largest share of investments since then was for the addition and improvement of hydrotreatment units (EPE, 2015; PETROBRAS, 2013).

Figure 2-5 displays the Brazilian refining industry's profile production evolution from 2008 to 2017.



[1]Although diesel is not separated by quality level, it is important to note that there has been a significant effort in recent years to maintain its production and meet increasingly restricted specifications.

Figure 2-5 - Brazilian refining industry's profile production evolution (2008-2017)

Source: ANP (2018b)

From Figure 2-5 it can be observed that gasoline production has gained participation in the last ten years, going from 19.5% in 2008 to 25.2% in 2017. Petrochemical naphtha share, in turn, reached 4.5% in 2017, approximately half of its production in 2008. In relation to diesel, it had been increasing its share until 2015, but in the last two years it lost space, representing, in 2017, 36.8% of total production. Finally, in the same downward trend of diesel comes fuel oil, which had a share of 10.6% in 2017, against 13.8% in 2008. Such fluctuations can be explained by both technical, political and economic factors, especially in gasoline and diesel's cases.

In the last two decades, the Brazilian fuel market was marked by two different phases. The first one, between 2000 and 2007, is represented by favorable national and global economic conditions, such as low interest rates, credit expansion, and income increase (RODRIGUES *et al*., 2018). During this time, oil products prices in Brazil were free to float according to international market prices (CAVALCANTI *et al*., 2012).

The second phase, that is, from 2008 until now, is characterized by a global economic and financial crisis, which hit the Brazilian market and caused a slowdown in the economy (RODRIGUES *et al*., 2018). Thereafter, Petrobras, having a dominant position in the fuel market, became a price-setter (CAVALCANTI *et al*., 2012).

Between 2008 and 2014, the practice of controlling and delaying the transfer of international gasoline prices to the domestic market was practiced, thus keeping gasoline domestic prices below parity prices on the international market, in order to reduce inflation rates. In the third quarter of 2012, for instance, the price of gasoline in Brazil was 19% below the world price. This fact benefited the production of gasoline, although part of the consumption was imported (NUÑEZ and ONAL, 2016).

Importing transportation fuels at higher world prices and selling in the domestic market at subsidized prices resulted in substantial losses (NUÑEZ and ONAL, 2016). Hence, in 2016, when a new president was appointed to Petrobras, the fuel price policy started to be guided by the company's interests, without government influence. In the same year the price of fuels began to follow the trend of the international market - international parity price (IPP) - based not only on the price of crude oil, but also on costs such as ship freight, internal transportation costs and port taxes, as well as a margin for compensate the risks inherent in the operation, such as exchange rate and price volatility, port rates, profit and taxes. This new practice would end the fuel price subsidy, a policy adopted by previous governments.

However, in 2017, seeing that it was unable to keep up with the increasing volatility of the exchange rate and the price of oil and oil products, Petrobras announced that there would be a higher frequency of price adjustments (PETROBRAS, 2017). Then, the company began to make frequent price alterations, sometimes with even daily periodicity. This culminated in a Brazilian trucker strike that, after much negotiation, managed to stabilize fuel prices at that moment.

Currently, diesel and gasoline pricing policies continue to be based on international markets and prices may vary according to market conditions and external environment analysis (PETROBRAS, 2018). In other words, policies such as the international parity price (PPI), margins to compensate for the risks inherent to the operation, level of market share and derivative protection mechanisms are maintained (PETROBRAS, 2019).

In short, between 2011-2015 oil products´ prices were controlled to curb inflation. This also caused an increasing demand for gasoline and raised the average gasoline yield of Brazilian refineries (to the detriment of naphtha). Then, prices followed the international parity. Nevertheless, this has hampered diesel production and resulted in truckers' strikes, which, in turn, still continue to threaten the Brazilian economy due to constant fluctuations in diesel prices.

In the case of diesel, the drop in its production can also be explained by its increasingly restricted specifications. In 2009, the ANP – National Petroleum Agency increased diesel's sulfur specification, thus the previously allowed concentration of 500 ppm (S500) has been reduced to 50 ppm (S50) outside metropolitan areas, and to 10 ppm (S10) inside metropolitan areas[5] (Rio de Janeiro, São Paulo, Curitiba, Recife, Fortaleza and Belém) (BORBA et al., 2017). In this way, Brazilian refineries faced some difficulties to meet these new specifications requisites, which led to an increase of high-quality diesel's imports (see Figure 6). Investments in severe hydrotreating units, capable of producing diesel S50 were made in the last years, however, regarding the production of diesel S10, the maximum output that could be reached was of 12,960 thousand m^3 per year (BONFÁ and SZKLO, 2011).

In such a way, although Brazil is a net petroleum exporter, its balance for the main derivatives is negative, especially for naphtha, gasoline, and diesel, as presented by Table 2-2**.** Moreover, imports of most of the derivatives have shown a significant increase in the last 10 years. The main exporting countries to Brazil were the United States (LPG, gasoline, jet fuel oil, diesel and petroleum coke) and Algeria (naphtha) (ANP, 2018b).

According to BORBA *et al*. (2017), there are two factors that can cooperate to reduce Brazil's foreign dependence: the recently discovered pre-salt fields, which are expected to produce better quality crude oils; and the improvement of refining processes infrastructure to process domestic crude oils.

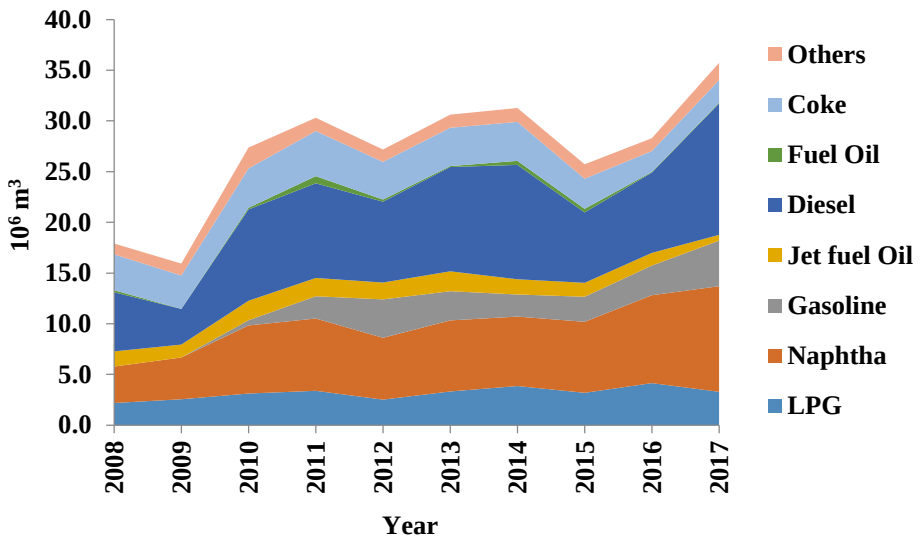
[5] The lower allowed concentration in metropolitan areas aims to improve local air quality (BORBA *et al*., 2017).

Table 2-2 - Imports and exports balances

Product	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Imports (10^6 m^3)									
LPG	2.2	2.6	3.1	3.4	2.5	3.3	3.9	3.2	4.1	3.3
Naphtha	3.6	4.1	6.7	7.1	6.1	7.0	6.8	7.0	8.7	10.4
Gasoline	0.0	0.0	0.5	2.2	3.8	2.9	2.2	2.5	2.9	4.5
Jet fuel Oil	1.5	1.3	1.9	1.8	1.7	2.0	1.5	1.4	1.2	0.6
Diesel	5.8	3.5	9.0	9.3	8.0	10.3	11.3	6.9	7.9	13.0
Fuel Oil	0.2	0.0	0.2	0.7	0.2	0.1	0.4	0.4	0.1	0.1
Coke	3.5	3.3	3.9	4.4	3.7	3.8	3.8	3.0	2.1	2.2
Others[1]	1.1	1.2	2.1	1.3	1.2	1.3	1.4	1.4	1.3	1.7
	Exports (10^6 m^3)									
LPG	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
Naphtha	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gasoline	2.6	2.5	0.8	0.3	0.1	0.3	0.4	0.6	0.7	0.5
Jet fuel Oil	1.9	2.0	2.3	2.6	2.8	2.8	3.0	3.0	2.7	2.8
Diesel	0.7	1.2	0.7	0.6	0.3	0.4	0.4	0.1	0.5	0.5
Fuel Oil	9.7	8.5	9.2	9.1	10.7	9.1	8.6	8.5	6.6	7.1
Coke	1.0	0.8	0.8	0.8	0.9	1.3	1.5	1.3	1.3	1.5
Others[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Balances[2] (10^6 m^3)									
LPG	-2.2	-2.5	-3.1	-3.3	-2.5	-3.2	-3.8	-3.2	-4.1	-3.3
Naphtha	-3.5	-4.1	-6.7	-7.1	-6.1	-7.0	-6.8	-7.0	-8.7	-10.4
Gasoline	2.6	2.5	0.3	-1.9	-3.7	-2.5	-1.8	-1.9	-2.2	-4.0
Jet fuel Oil	0.4	0.7	0.4	0.8	1.1	0.8	1.5	1.6	1.4	2.2
Diesel	-5.2	-2.3	-8.3	-8.7	-7.7	-9.9	-10.9	-6.9	-7.4	-12.5
Fuel Oil	9.5	8.5	9.0	8.4	10.5	9.0	8.2	8.1	6.5	7.1
Coke	-2.6	-2.5	-3.1	-3.7	-2.8	-2.5	-2.4	-1.6	-0.8	-0.7
Others[1]	-1.1	-1.2	-2.1	-1.3	-1.2	-1.3	-1.4	-1.4	-1.3	-1.7

[1]Others include asphalt, lubricating oil, paraffin, solvent and other non-energy products.
[2] Balance = Exports - Imports.

Source: EPE (2017)

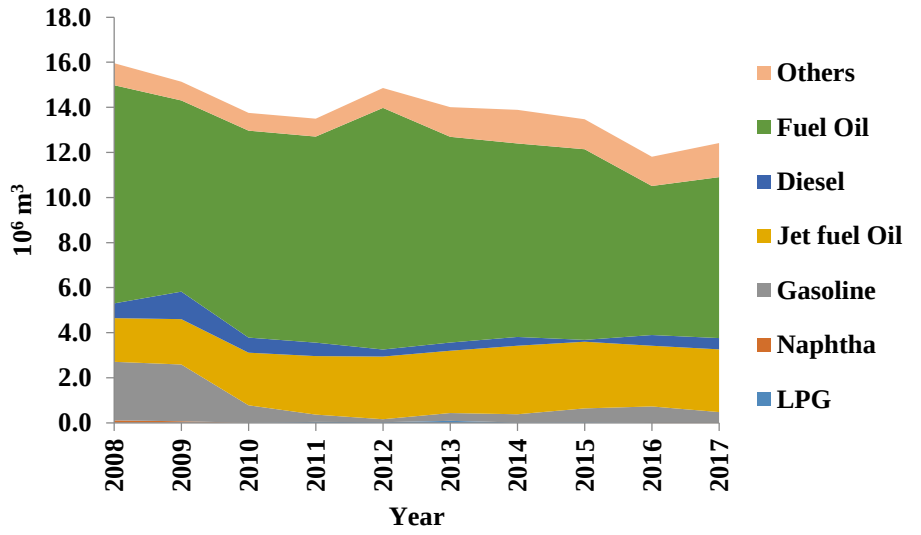


[1]Others include asphalt, lubricating oil, paraffin, solvent and other non-energy products.

Figure 2-6 – Brazilian oil products' imports (2008-2017)

Source: ANP (2018b)

Regarding Brazilian derivatives exports (Figure 2-7), it is worth noting the Brazilian excess production of fuel oil, which serves mainly the bunker market for foreign ships (EPE, 2017). By country, the largest current importers of Brazilian derivatives are Singapore (fuel oil) and the United States (unfinished gasoline, jet fuel oil, fuel oil, petroleum coke) (ANP, 2018b).



[1]Others include coke, asphalt, lubricating oil, paraffin, solvent and other non-energy products.
[2]Fuel oil include marine fuel oil (bunker)

Figure 2-7 – Brazilian oil products' exports (2008-2017)

Source: ANP (2018b)

The following section presents and details the typical existent oil refining schemes in Brazilian refineries.

2.1. Typical Refining Schemes of National Refineries

The structure of a refinery is complex, depending on the characteristics of the oil to be processed, the capacities of the units, the production profile of the derivatives, the specification for these products and the choice of technologies to be used (SCHAEFFER et al., 2009). Also, it can be classified as a Hydroskimming, Cracking, Coking/ Hydrocracking and Hycon configuration, as detailed in Table 2-3.

Table 2-3 - Refining schemes

Configuration	Description
Topping	ADU+ VDU
Hydroskimming	ADU + Isomerization + REF + Treatment units
Cracking	Hydroskimming configuration +VDU + FCC+ Alkylation
Hydrocracking	Cracking configuration + HCC + HGU
Coking	Hydroskimming configuration + VDU + Delayed Coking
Coking/ Hydrocracking	Hydroskimming configuration + VDU + HCC + Delayed Coking + HGU

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; ALK – Alkylation unit; REF – Catalytic Reforming unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; COK – Delayed Coking unit; DSP – Deasphalting unit; HDTs – Hydrotreatment units; HGU – Hydrogeneration unit; COG – Cogeneration unit

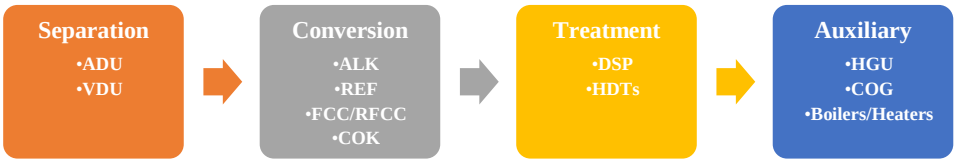
Source: SZKLO *et al*. (2012)

Brazilian refining schemes can be mostly classified between the Cracking and Coking/Hydrocracking configurations (OIL & GAS JOURNAL, 2018). The former optimizes the production of gasoline with the presence of FCC and alkylation units, while the latter focuses on the production of diesel with the delayed coking unit as well as the production of petroleum coke, maximizing, at the same time, the production of gasoline and high quality medium distillates, such as diesel, with the presence of the hydrocracking unit (SZKLO *et al*., 2012). There are, however, no hydrocracking units in operation in the country's current refining park, and thus the main conversion unit involves FCC (of gasoils and residues) and delayed coking units (processing atmospheric distillation residues and vacuum distillation residues). According to GUEDES *et al*. (2019), although the Brazilian refinery system, on average, focuses on

diesel optimization, single refineries can present a different feature - e.g. focusing on lube oils, or petrochemicals.

Regarding the steps of a refining scheme, they consist of separation, conversion, treatment and auxiliary steps (MAGALAR, 2018).

Figure 2-8 illustrates the main process units present in each mentioned step.



ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; ALK – Alkylation unit; REF – Catalytic Reforming unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; COK – Delayed Coking unit; DSP – Deasphalting unit; HDTs – Hydrotreatment units; HGU – Hydrogeneration unit; COG – Cogeneration unit

Figure 2-8 – Steps of a refining scheme

Source: Based on MAGALAR (2018)

The typical existing process units in Brazilian refineries are briefly described below.

2.1.1. Atmospheric and Vacuum distillation

Refining of crude is usually composed of two stages of distillation: the atmospheric distillation unit and the vacuum distillation unit[6] (OSUOLALE, 2017).

The atmospheric distillation unit is the most important within a refinery. In this process a vertical distillation tower at atmospheric pressure[7] is used to vaporize the cargo and fractionate it in different cuts through several different condensing temperatures, so that each of the following units have their input loads according to their specificities (GARY and HANDWERK, 2001; MEYERS, 2004). The lighter fractions condense and are collected at the top of the distillation column while the heavier fractions are collected at the bottom.

[6] RNEST, the most recent refinery of the Brazilian refining park, has only the first stage (ADU), being the atmospheric residue sent straitght to the delayed coking unit.

[7] The pressure varies as cargo's fractions volatilize and condense along the column, but, there is no vacuum in it.

The straight-run fractions produced consist of liquefied petroleum gases, light and heavy naphtha, kerosene, diesel, atmospheric gasoil, and atmospheric residue. Such products may be treated as finished products, except for the atmospheric residue, or can be mixed with other streams and routed for downstream process units (SZKLO *et al*., 2012).

The atmospheric residue, which could not be vaporized under the existing operating conditions of pressure and temperature, is further fed to the vacuum distillation unit, which operates at subatmospheric pressures (KAES, 2000).

In this unit, the vacuum is used to separate the heaviest part of the crude oil, since at the atmospheric pressure, the high temperatures required to vaporize them may cause thermal cracking, product discoloration and inlays in the equipment, due to coke formation (GARY and HANDWERK, 2001). In this stage, light and heavy vacuum gas oil and vacuum residue are produced. The vacuum gasoils can go to the catalytic cracking unit or straight to heavy fuel oil pool, and the vacuum residue can proceed to the delayed coking unit, in order to be transformed in higher value products.

2.1.2. Alkylation

The alkylation reaction can be described as a combination of isobutanes and light olefins, in the presence of an acid catalyst (H_2SO_4 or HF) at low temperatures (MEYERS, 2001). The obtained alkylate consists of branched hydrocarbons that have a high octane number (IVASHKINA *et al*., 2019).

This reaction produces high octane gasoline from the light naphtha cut produced in the atmospheric distillation unit. In a context of increasingly restricted fuel specifications, there is a growing demand for alkylation units (IVASHKINA *et al*., 2019).

2.1.3. Catalytic reforming

Catalytic reforming is one of the most important processes for high-octane gasoline manufacture and aromatic hydrocarbons production (IVANCHINA *et al*., 2015).

The process is based on the principle of changing the structure of chemical bonds in the hydrocarbon aromatic structure, and it is extremely dependent on the selectivity and conversion capacity of the catalysts selected (SCHAEFFER *et al*., 2012).

Larger molecules are broken into smaller to insert complex structures that have a higher octane number (KANCIJAN *et al*., 2015).

In addition to promoting the octane increase, this unit is responsible for producing hydrogen, which can be sent to other refinery units, such as the HDT and HCC (SCHAEFFER *et al*., 2012).

2.1.4. Propane deasphalting

The propane deasphalting process separates oil from carbon rich components, resins, and asphaltenes making possible to convert it to lube stock, or into feedstock for other secondary processing facilities (SPEIGHT, 2011).

The load is initially sent to an extractor, where the separation of the deasphalted oil and the asphalt is promoted, then the mixture is heated, in order to vaporize the solvent, to promote the separation of the solvent by flash and return it to the extractor, and finally the product is purified in a stripper (SCHAEFFER *et al*., 2012).

The deasphalted oil is normally used as a feedstock for a fluid catalytic cracking unit or for a hydrocracking unit (SPEIGHT, 2011).

2.1.5. Fluid catalytic cracking (FCC)

The Fluid catalytic cracking (FCC) process is used to convert heavy cuts of hydrocarbons in lighter hydrocarbons, of higher economic value, in the presence of catalysts. Their input is usually composed of heavy and light gas oils from distillation, coking and deasphalting units. In the specific case of Brazil, in addition to the FCC units there are the RFCC (Residue catalytic cracking) units, which have as input the atmospheric residue produced by the atmospheric distillation unit (SZKLO *et al*., 2012).

According to GUAN *et al*. (2019) the process is composed of three steps: reaction, product separation, and catalyst regeneration. Firstly the load is pre-heated. Then, this charge contacts the heated catalyst and is sequentially atomized with steam to increase cracking and vaporization. Reactions, for the most part, occur in the reactor. The reaction products then proceed to the fractionator, in which the fractions of interest are separated and collected. The catalyst does not proceed to the fractionator but is sent to the regenerator so that the coke deposited on it is burned in the presence of air (SZKLO *et al*., 2012).

Although the FCC unit consumes a large amount of energy in the form of fuel, electricity and steam to regenerate the catalyst, preheat the charge, fractionate the products and inject air into the regenerator, it produces large amounts of hot combustion gases that when recovered, can generate heat (SZKLO *et al*., 2012).

2.1.6. Hydrocracking (HCC)

The catalytic hydrocracking unit (HCC) is one of the most versatile processes in a refinery, as it is capable of converting vacuum gas oils, light recycle oils from FCC, heavy coking gas oils, deasphalted oils, among other heavy by-products, into light products (SZKLO *et al*., 2012).

According to GARY and HANDWERK (2001), the process in a HCC unit occurs as follows: the incoming charge is fed into a reactor through a furnace along with hydrogen and recycle gas (high hydrogen content). The effluent exiting the reactor passes through heat exchangers and is directed to a high-pressure separator where the hydrogen-rich gases are separated and sent back to the first stage of the process. The liquid product is separated and sent to a distillation column in which light fractions are produced and where the bottom products are used to feed the second stage of the process. The load sent to the second stage is mixed with hydrogen and sent to a second reactor, where temperatures and pressures capable of converting from 50 to 70% of the volume are maintained.

Unlike the FCC unit, the HCC is not a net energy producer. However, since the hydrogenation reaction is exothermic, the unit requires less energy than the FCC. In addition, the process requires large amounts of hydrogen (SZKLO *et al*., 2012).

2.1.7. Delayed coking

Delayed coking (DCU) is essentially a non-catalytic thermal cracking process, in which the load, which is usually a vacuum residue, is transformed in gasoils, naphtha, fuel gases and petroleum coke (SZKLO *et al*., 2012).

Generally, a DCU is composed of a coking furnace, two coke drums, a main fractionator and heat exchanger networks (LIMA *et al*., 2016). The load is initially fed into the fractionator, in which the light fractions are removed and the heavy ones are condensed and directed to the furnace. Thereafter, the mixture proceeds to one of the coke drums where there is coke formation and then the load flows to the parallel drum

which is initially empty. When the second drum is completely filled, steam is injected to remove the gaseous hydrocarbons impregnated into the solid residue, which are directed to the fractionator and then the coke produced is removed (GARY and HANDWERK, 2001).

Since different residual feedstocks can be handled by this unit, it is known as a highly flexible process, which, besides increasing the yield of light fractions, has environmental and economic advantages, because it does not produce bottom products which require tankage and cutter stock (LIMA *et al*., 2016).

2.1.8. Hydrotreatment units (HDTs)

Hydrotreatment units mainly aim at removing, through catalytic hydrogenation reactions, sulfur, oxygenated, nitrogenous and organometallic compounds from the oil, which can deactivate catalysts in units such as FCC, HCC and catalytic reforming, (SZKLO *et al*., 2012).

The hydrotreatment reactions differ according to a set of operational variables that define the severity of the unit. The severity, in turn, determine the specification of the final product, and, the greater the severity, the greater the consumption of hydrogen (SZKLO *et al*., 2012). Mild-HDTs are usually employed for sulfur and olefins removal while severe HDTs remove larger concentrations of sulfur, aromatic rings and nitrogen (STANISLAU *et al*., 2010).

Just as they treat the input and output streams for the FCC and/or HCC units, they are used to meet the increasingly stringent specifications of petroleum derivatives.

2.1.9. Hydrogen generation unit (HGU)

In a refinery there are two ways to produce hydrogen. The first one is through the catalytic reforming unit, as previously mentioned, and the second with the hydrogen generation units.

Besides the production of hydrogen via power-to-gas (SILVA, 2017), the hydrogen production processes are the steam reforming of natural gas (including its variant called auto-thermal reforming) or of light oil fractions, and the partial oxidation of heavy fractions of hydrocarbons (GARY and HANDWERK, 2001). However, the most common process in oil refineries around the world, and especially in Brazil is the steam reforming (SZKLO *et al*., 2012). Moreover, according to GARY and

HANDWERK (2001), natural gas is the most common reagent used in hydrogen generation units, since it fulfills all the requirements for the reformer's feed and presents low cost.

The main chemical reactions that make up the stages of the steam reforming process are presented below:

Reform:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \quad (1)$$

Shift conversion:

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (2)$$

Methanation:

$$CO + 3H_2 \rightarrow CH_4 + H_2O \quad (3)$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \quad (4)$$

2.1.10. Cogeneration

The cogeneration process consists of the combined production of thermal and electrical energy. The engine produces firstly electrical power while thermal energy of the exhaust gases is converted into steam in the heat recovery boiler (NAJJAR, 2000).

The most common cogeneration plants in refineries consist of a gas turbine equipped with a heat recovery steam generator and a set of back-pressure steam turbines. Electricity is produced through both the gas turbine and the steam turbines while steam is made available to the refinery processes at the required pressure and temperature level (CONCAWE, 2012).

The next chapter presents the methodology followed by this thesis, by, firstly, introducing the GAMS tool, used to develop the ORION model, and, then, detailing the model framework.

3. Methods

The methodology followed by this study consists, firstly, in the development of the ORION (Oil Refining Industry Optimization and syNergies) framework in GAMS – General Algebraic Modeling System[8], with the calibration of the base year in order to characterize the Brazilian oil refining system and define from what conformation it will evolve. Then, the scenarios definition step is performed, and the required database - oil products demands, sulfur constraints, crude oil prices etc. - for each chosen scenario is collected. As already mentioned, three different scenarios were developed in terms of oil products demands: the Shadow scenario, based on the evolvement of the current oil refining industry and the energy and transport systems, without changes in current policies; the Cloudy scenario, which takes into account the announced policies and targets both for oil refining and for the energy and transportation systems as a whole, envisaging the mobility in the transport system for the next few years; and the Shiny scenario, being the most disruptive among the three scenarios, since it considers an accelerated energy transition to reach the goals associated to climate change, clean energy and clean air. For each one, the model is run under a multi-regional and a single-regional framework, in order to analyze, in each case, whether there is an advantage or not in having a regional model. In addition, for each case previously mentioned, two options of heavy fuel oil specifications were taken into account, in light of the IMO's regulations to reduce sulfur oxides (SOx) emissions from ships. Thus, a total of twelve different results are obtained, four for each of the three scenarios mentioned above, as illustrated by Figure 3-1.

[8] The solver used to perform the optimization step is CPLEX, which is well adapted for large scale linear programming models.

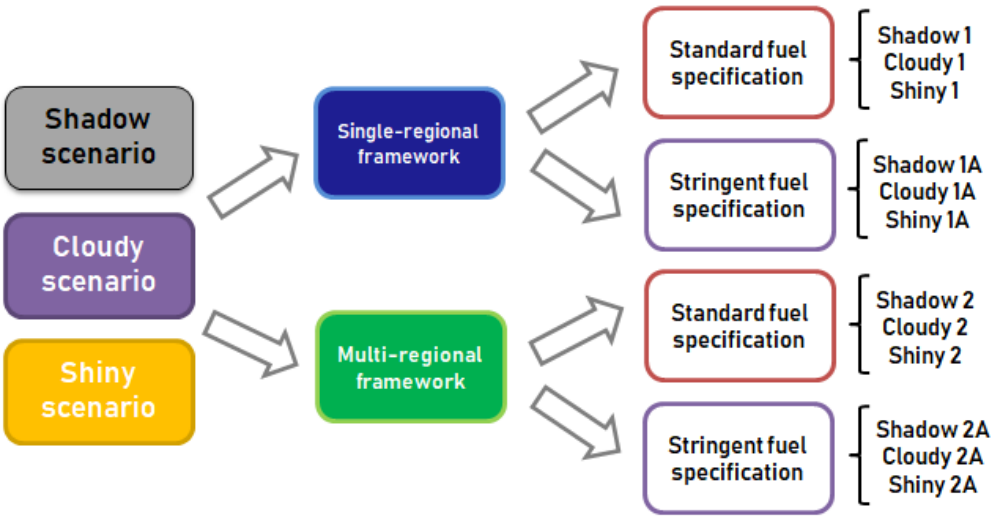


Figure 3-1 - ORION model's scenarios

As the ORION results depend on foreign trade flows (imports/exports of oil products), and these flows are related to the international market prices, a nested optimization approach was carried out. Thus, a worldwide multi-regional model, OURSE (Oil is Used in Refineries to Supply Energy) (LANTZ *et al.*, 2005) is run for each previously defined scenario, in order to provide marginal values associated to the products demand constraints, which are used in the Brazilian model as CIF prices for imports and FOB prices for exports. Once these values are defined, the ORION is run for all the defined scenarios, and for each one, both the multi-regional and the single-regional configurations are run, in order to test the relevance of having a multi-regional model. Finally, the results are obtained and analyzed. As already mentioned, the main objective of the present study is the development of a consistent and calibrated optimization model for the Brazilian oil refining industry, an open-source tool that will help specialists and actors of the petroleum refining sector to make decisions and strategize about the paths that can be taken in the coming years. Figure 3-2 summarizes the step-by-step of the followed methodology.

The definition and runs of scenarios in the model serve to test its reliability, as well as analyze possible future events, regarding the national and global energy and refining systems.

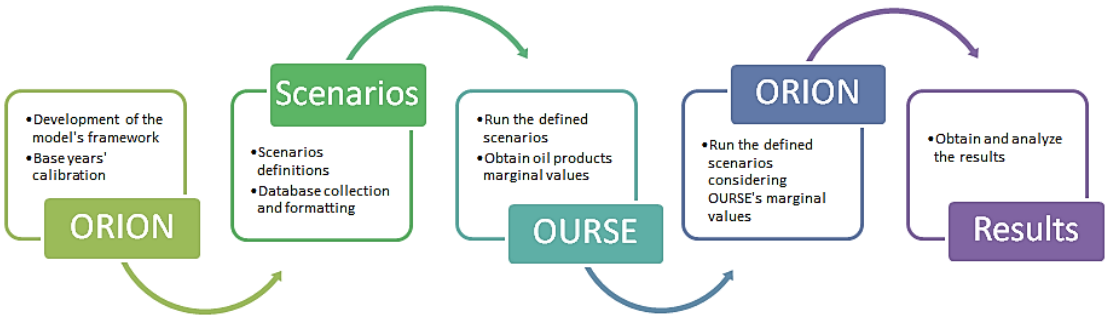


Figure 3-2 – Methodological procedure

The use of a linear programming (LP) model for refineries represents a relevant tool, with a reasonable level of precision, to deal with several process units, with different yields depending on the type of feed and the mode of operation employed, various final products, whose specifications vary from region to region of the world, and distinguished demands for liquid fuels.

Besides, its solution consists of two parts: the primal and the dual solution. The primal solution gives the optimal values of primal decision variables (REMME *et al.*, 2009) including, in the case of the present study, the set of investments in additional units; the operating capacities levels; the crude oil consumption; the imports, exports and national trades of petroleum products; the flows between processing units; the processing units utilities consumption; and the refineries total CO_2 emissions. The dual solution, in turn, is related to the marginal or opportunity costs assigned to each outcome of the primal problem (REMME *et al.*, 2009). In short, the dual values are associated to the equations of the primal problem, and the reduced costs (slack variables of the dual problem) are associated to the variables of the primal problem.

The following section briefly describes the GAMS tool. Section 3.2. depicts the nested optimization approach performed by this study, presenting in more detail the OURSE model and how it was used in order to provide the necessary information to ORION. The model framework is presented on Section 3.3.

3.1. GAMS - General Algebraic Modeling System

GAMS – General Algebraic Modeling System is a high-level modeling system used for mathematical programming problems (MCCARL *et al.*, 2014). It was

developed in order to provide a high-level language for the compact representation of large and complex models, to allow changes in model specifications in a simply and safe way, to avoid ambiguous statements of algebraic relationships, and to permit model descriptions which are independent of solution algorithms (ROSENTHAL, 2007).

GAMS offer an open architecture in which each user can use his word processor or editor of choice. Linear, nonlinear, mixed integer, mixed integer nonlinear optimizations and mixed complementarity problems can be accommodated (ROSENTHAL, 2007).

According to MCCARL *et al*. (2014), GAMS can be used to model at least three different approaches: solving an optimization problem; solving an economic based general equilibrium problem; and solving a nonlinear equations system.

The structure of the model consists of a GAMS input file, where the user can detail the sets (indices of a problem), variables, data (through parameters, tables and scalar), equations (equalities and inequalities), and call the model's solver[9]; and a GAMS output file comprising a compilation output, an execution output, an output produced by a solve statement, and an error reporting. The compilation output is the output produced during the initial check of the program being composed of an *echo print* of the model (consists of a list of the input with the lines numbers added), an explanation of any errors detected, and the maps (Symbol Cross Reference[10], Symbol Listing[11], Unique Element Listing[12]). The execution output is the output that comes from the "display"[13] statement. It is generated while GAMS is performing the data manipulation. The output produced by a solve statement comprises all output produced as a result of a solve. It consists of an equation listing, a column listing, the model statistics (provides details on the size and nonlinearity of the model), the solve summary (presents results as the solver status and model status for the problem, the value of the objective function, the number of iterations used by the solver, among other information), the solver report (displays diagnostic messages if the model detects

[9] GAMS has over fifty options of solver for mathematical programming models (GAMS, 2019).

[10] Lists the symbols (identifiers) from the model in alphabetical order, identifies them as to type, shows the line numbers where the symbols appear, and classifies each appearance (GAMS, 2019).

[11] Groups all identifiers alphabetically by type and list them with their explanatory texts (GAMS, 2019).

[12] Groups all unique elements first in entry order and then in sorted order with their explanatory texts (GAMS, 2019).

[13] Used to request the display of a result.

something unusual), the solution listing (each individual equation and variable is listed with four types of information: the lower bound, the level value, the upper bound and the marginal value), the report summary (presents the number of rows or columns that have been marked as infeasible, unbounded or non-optimal), and the file summary (gives the names of the input and output disk files). Finally, if any error is detected during the modeling process, it will be stopped, and the error will be presented by the error reporting. It is worthwhile mentioning that a model will never be solved after an error detection. Thus, it is essential to fix the error and repeat the run.

GAMS's application is pretty diverse. In its library, it is possible to find numerous problems applications which cover mathematics, finance, statistics, macro and micro economics, agricultural economics, economic development, applied general equilibrium, engineering, chemical engineering, international trades, and others.

3.2. The OURSE model and the nested optimization approach

As formerly briefly presented, the OURSE (Oil is Used in Refineries to Supply Energy) model is a linear programming (LP) world-wide aggregated refining model designed to simulate the world oil product supply for the POLES (Prospective Outlook for the Long-term Energy System) model. Also being written in GAMS language, it includes a representative refinery for nine different regions of the world (Z1 - North and Central America, Z2 - Latin America, Z3 - North Europe, Z4 - South Europe and Turkey, Z5 - Former Soviet Union (CIS), Z6 – Africa, Z7 - Middle East, Z8 – China and Z9 - Other Asia) as shown in Figure 3-3, and is designed to operate over the period 1997-2030. It comprises all the relevant techno-economic characteristics of the oil refining industry (such as technical processes, investment and operating costs, and pollutant emission factors), besides allowing the blending of biomass based derivatives (alcohol and ester) as well as GTL (gas to liquid) products.

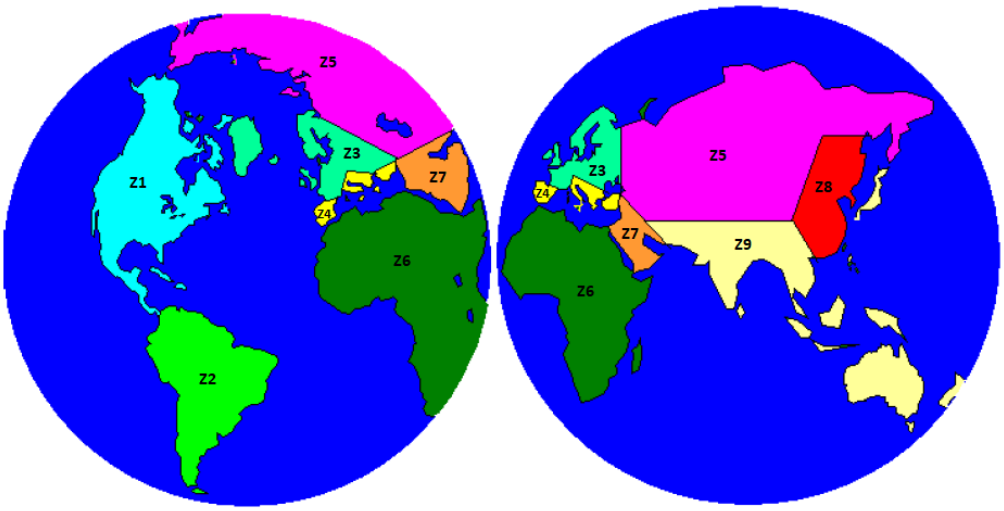


Figure 3-3 - OURSE model regions

Source: Based on LANTZ *et al*. (2012)

The main inputs of the model are the oil product demand in terms of both quantities and specifications (LPG, gasoline[14], naphtha, kerosene, jet fuel oil, heating fuel oil, heavy fuel oil – with sulfur contents of 1% and 3.5% - bitumen, petroleum coke, and marine bunkers[15]), the crude oil availability (through nine representative crude oil types), the CO_2 emissions restrictions and taxes. Regarding the outputs, the main ones consist in the refineries throughput (activity level), the products blending, the products trades, the investments (technology dynamic of the refining processes), the marginal costs of oil products (supply prices), and the pollutant emissions (LANTZ *et al*., 2012).

The refining scheme considered by the model consists of a representative deep-conversion refinery, comprising an atmospheric distillation unit, a vacuum distillation unit, a catalytic reforming unit, a gas oil hydrodesulfurization unit, a MTBE unit as well as an ETBE, a catalytic cracker and four types of hydrocracker, alkylation and isomerization units, a visbreaking and delayed coking units (LANTZ *et al*., 2012).

The objective function consists in minimizing the refining costs (processing and investment cost), the supply costs (imported crude oil price), the delivery costs of the oil products to the consumption areas and pollution permits.

[14] Five types of gasoline are described, depending upon octane numbers and lead contents.

[15] Several qualities of marine bunker fuels are considered in the OURSE model, in order to apply the rules of the International Maritime Organization (IMO) with a lower sulfur content for these fuels.

As mentioned earlier, the OURSE model is used in this study through a nested optimization approach. As stated by SINHA *et al*. (2018), a nested, or bilevel optimization can be defined as a mathematical program, where an optimization problem contains another optimization problem as a constraint, having each of them their own objectives and constraints. The main problem is called the upper-level problem or the leader and the nested problem is called the lower-level problem or the follower. The mathematical formulation with one leader and one follower can be stated as follows (GAMS, 2019):

$$\boldsymbol{Min}_{x \in X, y} \quad \boldsymbol{f}(\boldsymbol{x}, \boldsymbol{y}) \tag{5}$$

$$s.t \quad h(x, y) \leq 0$$

$$y \; solves$$

$$\boldsymbol{Min}_{y} \quad \boldsymbol{g}(\boldsymbol{x}, \boldsymbol{y}) \tag{6}$$

$$s.t \quad k(x, y) \leq 0$$

Where:
x are the upper-level variables
y are the lower-level variables
f is the upper-level objective function
g is the lower-level objective function
h are the upper-level constraints
k are the lower-level constraints

The nested approach of this study has two steps: (i) the OURSE model (upper-level problem) is run for predefined world-wide oil product demand scenarios, providing dual values associated to these products; (ii) the ORION model (lower-level) is run, considering the dual values given by OURSE as international products prices (CIF prices for imports and FOB prices for exports) in its objective function. These interactions are organized in a way that assures proper data exchange between both models as well as short computation time.

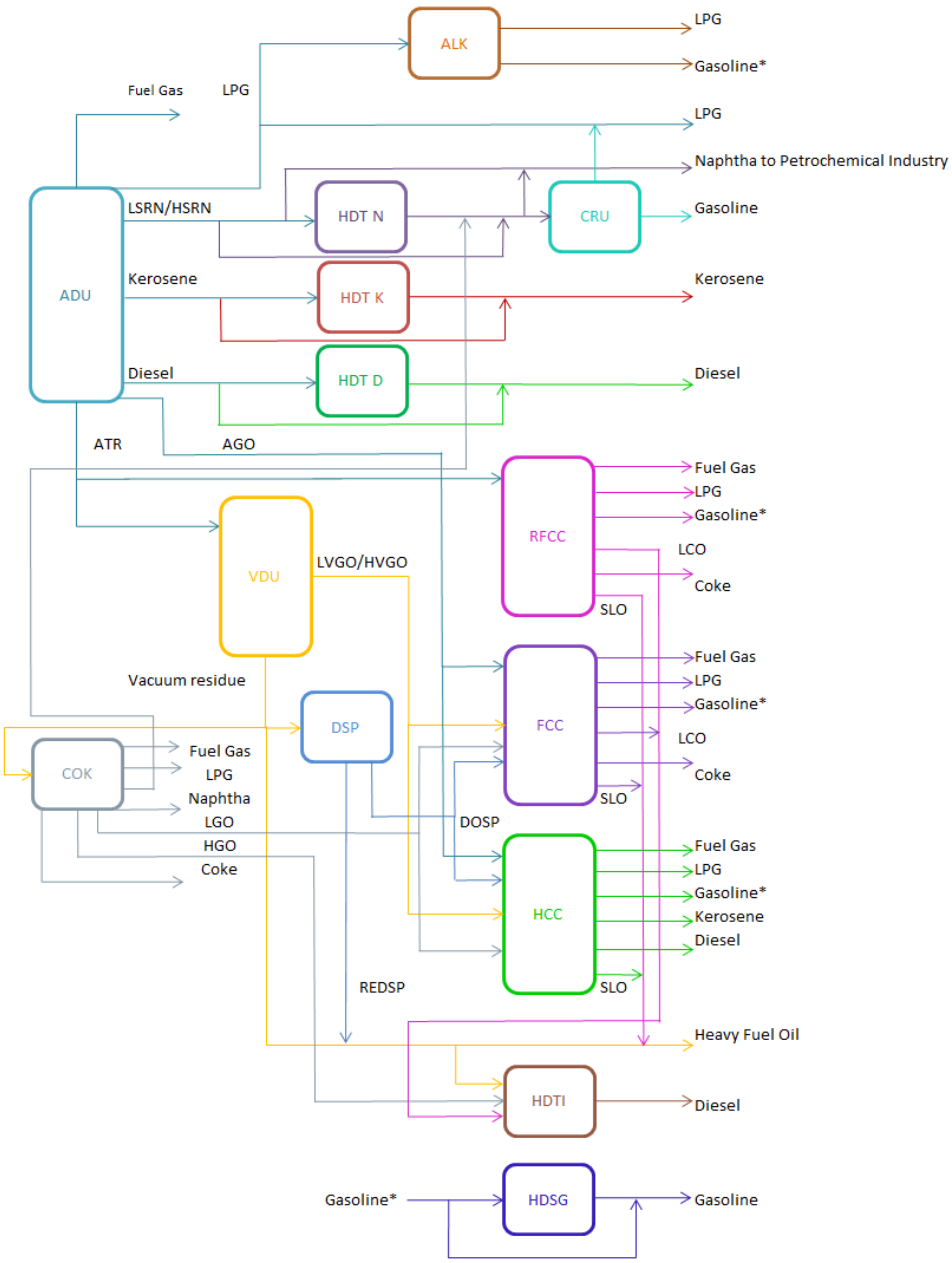
The following section presents the framework of the model developed by this study.

3.3. ORION Model Framework

The optimization model developed by the present study portrays the Brazilian oil refining system organized into four geographical logistical blocks (South, Northeast, Rio de Janeiro-Minas Gerais and São Paulo), given the connections between markets, refineries and terminals (MENDES *et al*., 2018) (see Figure 2-2 and Table 4-1). Also, it considers six international regions (United States, Central America, Western Europe, Middle East, Africa and Asia-Pacific) with which the model allows exchanges (imports/exports) of crude oil and petroleum products. By aggregating refineries into logistic regions defined by a single representative refinery, the model does not consider the exchange of intermediate products among regions, but only final products

The final products represented in the model are liquefied petroleum gases (LPG), naphtha, gasoline, jet fuel oil, kerosene, diesel oil, heavy fuel oil, heating fuel oil and coke. The demand for these products are exogenous data, and, for the base year, the source of these data is the ANP – National Petroleum Agency (ANP, 2018a), as will be further detailed. As the model is designed to operate over the period 2015-2040, through five-year periods (t0 to t5), the products' demand for the following years are based on scenarios that will be described in Chapter 4.

A total of fourteen process units are considered, as detailed in Figure 3-4, and in addition to these, the hydrogen generation and cogeneration units. Investments in new additional capacities are allowed from 2020 (period t1).



ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; ALK – Alkylation unit; CR – Catalytic Reforming unit; COK – Delayed Coking unit; HDSG – Gasoline Hydrodesulfurization unit; HDTN – Naphtha hydrotreating unit; HDTK – Kerosene hydrotreating unit; HDTD – Diesel hydrotreating unit; HDTI – Instable products hydrotreating unit; UGH – Hydrogeneration unit; LPG – Liquefied petroleum gas; LSRN – Light straight run naphtha; HSRN – Heavy straight run naphtha; AGO – Atmospheric gasoil; ATR – Atmospheric residue; LVGO – Light vacuum gasoil; HVGO – Heavy vacuum gasoil; LGO – Light gasoil; HGO – Heavy gasoil; DOSP – Deasphalted oil; REDSP – Deasphalted residue; LCO – Light cycle oil; SLO – Slurry oil

Figure 3-4 – Model's oil refining basic scheme

The main inputs and outputs of the model are illustrated by Figure 3-5.

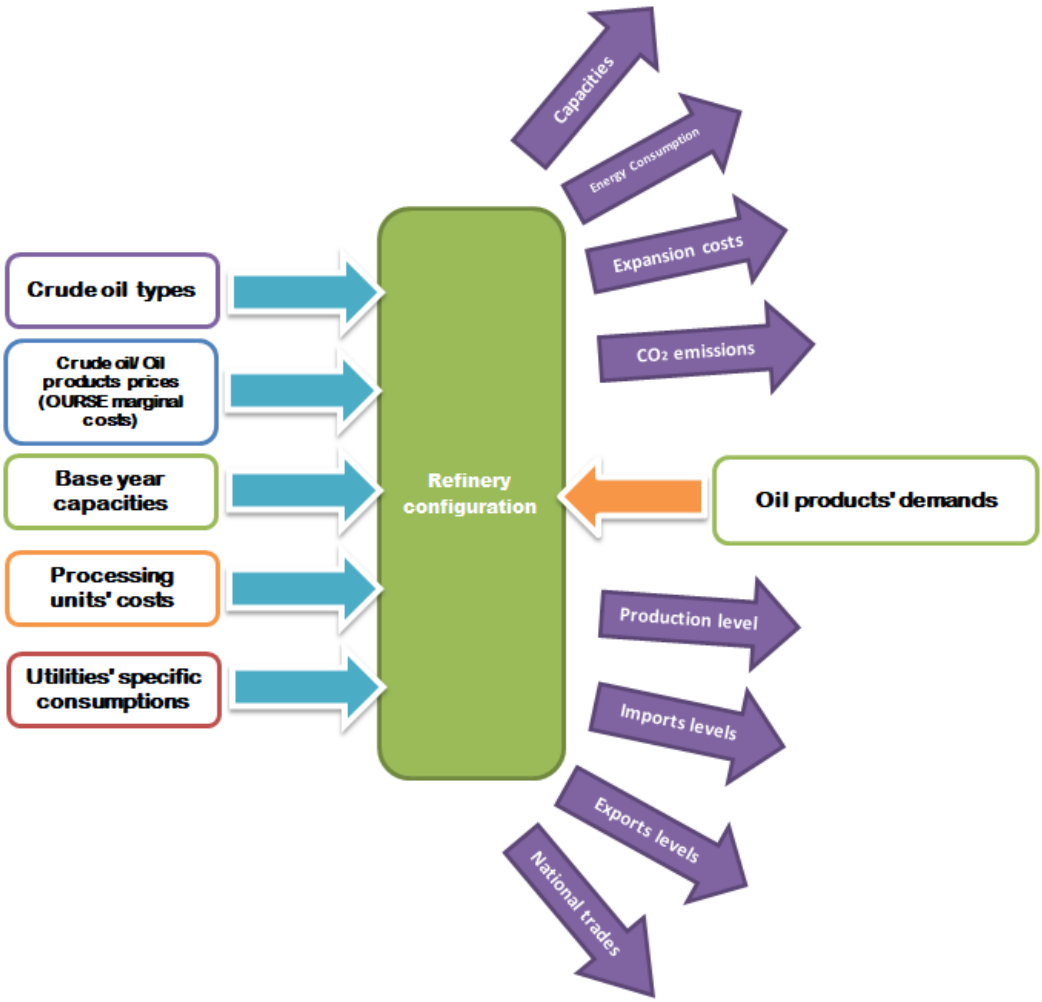


Figure 3-5 – Basic model's inputs and outputs

The equations considered in the model are described below.

Balances of intermediate products

The equations for the intermediate products balance the input quantities with the output quantities for each product. These equations express that inputs of a given processing unit, multiplied by the yields of each intermediate product is equal to the sum of intermediates produced. For the atmospheric and vacuum distillation units, the yields of the intermediates vary according to the type of oil processed. For the other processing units, the yields of a given product is the same, regardless of the crude used.

$$\alpha_{i,j} * \sum_k IN_{k,j,s,t} = X_{i,j,s,t} \quad (7)$$

Where, $\alpha_{i,j}$ is the yield of the intermediate product i in the processing unit j, $IN_{k,j,s,t}$ is the quantity of input feed k in the processing unit j; $X_{i,j,s,t}$ is the quantity of intermediate i produced by the processing unit j; and the indexes s ant t represent the region of supply s and the period t.

The flow diagram below displays, for a processing unit, the input feed (IN_0) and the yields ($\alpha_1, \alpha_2 \ldots$) in intermediate products ($X_1, X_2 \ldots$).

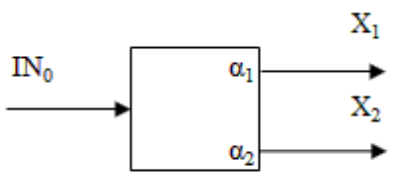


Figure 3-6 - Flow diagram: balance of intermediate products

Balance of intermediate products streams

The equations for the intermediate products streams balance the streams produced by a processing unit with their respective destinations.

$$\boldsymbol{X_{i,j,s,t} = \sum P_{i,j,s,t}} \quad \textbf{(8)}$$

Where, for a given region of supply s and period t, $X_{i,j,s,t}$ is the quantity of intermediate i produced by the processing unit j, and $P_{i,j,s,t}$ is the quantity of intermediate i routed to another processing unit j.

The flow diagram below displays, for a processing unit, the input feed (IN_0), the yields (α_1, $\alpha_2 \ldots$) in intermediate products (X_1, $X_2 \ldots$), and the possible destinations of them ($P_{1,1}$, $P_{1,2}$, $P_{1,3}$, $P_{2,1}$, $P_{2,2}$, $P_{2,3} \ldots$).

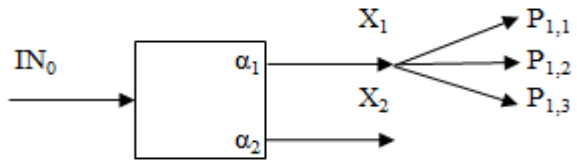


Figure 3-7 - Flow diagram: balance of intermediate products streams

Pool of final products

The pools of final products are given by the sum of the intermediate products produced by each processing unit. The final products considered by the model are LPG, Naphtha, Gasoline, Kerosene, Diesel, Jet Fuel Oil, Fuel Oil, Heating Fuel Oil and Coke.

$$\boldsymbol{Y_{n,s,t}} = \sum_{i,j} \boldsymbol{X_{i,j,s,t}} \quad \textbf{(9)}$$

Where, in the region of supply s, and period t, $Y_{n,s,t}$ is the quantity of final product n, and $X_{i,j,s,t}$ is the quantity of intermediate product i produced by the processing unit j.

Products demand equations

The products demand equations imply that supply (production, national trades and imports) must be greater or equal to demand (demand and exports).

$$\sum_s \boldsymbol{NT_{n,s,d,t}} + \sum_o \boldsymbol{Imp_{n,o,d,t}} - \sum_o \boldsymbol{Exp_{n.s,o,t}} \geq \boldsymbol{Dem_{n,d,t}} \quad \textbf{(10)}$$

$$\sum_s \boldsymbol{NT_{n,s,d,t}} - \boldsymbol{Y_{n,s,t}} \leq \boldsymbol{0} \quad \textbf{(11)}$$

Where, for a given period t, $NT_{n,s,d,t}$ are the domestic transportation of product n, from region of supply s to region of demand d, $Imp_{n,o,d,t}$ are the imports of product n, from the region oversea o to the region demand d, $Exp_{n,s.o,t}$ are the exports of product n, from region of supply s to region oversea, $Dem_{n,d,t}$ is the demand of product n in the region of demand d, and $Y_{n,s,t}$ is the quantity of product n produced in the region of supply s.

Bounds on imports and exports

Imports and exports are restricted by the capacity of Brazilian harbors. Thus, for a given region and period, the sum of imports and exports of oil products are limited to the total capacity of the harbor. In this case, oil products were classified in light (LPG, naphtha and gasoline), medium (kerosene, jet fuel oil, diesel and fuel oil) and heavy products (petroleum coke), the same classification used to define harbors' capacities and its bounds. The harbor's capacity was not defined by region of the model, but as a total of all regions by products' classification, being a task of the model to decide the appropriate import/export region, according to its choices. It should be mentioned that the model allows the expansion of harbors capacity for periods starting from t_1.

$$\sum_{o,d} \boldsymbol{Imp_{p,o,d,t}} + \sum_{s,o} \boldsymbol{Exp_{p,s,o,t}} \leq \boldsymbol{CapHarbor_{p,t}} \quad \textbf{(12)}$$

$$\boldsymbol{CapHarbor_{p,t}} = \boldsymbol{CapHarbor_{p,t-1}} + \boldsymbol{AddCapHarbor_{p,t}} \quad \textbf{(13)}$$

Where, for a given period t and a product classification p (Light – LPG, naphtha, gasoline/ Medium – kerosene, jet fuel oil, diesel, heating fuel oil and heavy fuel oil/ Heavy - coke), $Imp_{p,o,d,t}$ is the quantity imported, from the oversea region o to the region of demand d, $Exp_{p,s,o,t}$ is the quantity exported, from the supply region s to the oversea region o, $CapHarbor_{p,t}$ is the harbor capacity, $CapHarbor_{p,t-1}$ is the harbor capacity in the period t-1; $AddCapHarbor_{p,t}$ is possible harbor additional capacity to be implemented.

Products qualities specifications

Since some final products must meet some technical quality specifications such as density, sulfur content, octane number for gasoline, and cetane number for diesel, the model describes these specifications in terms of linear equations. It means that, the sum of the quantity of each intermediate product that is part of the pool of a given final product, multiplied by its characteristic in question, must be lower or equal to the total amount of final product, multiplied by its required technical specification.

$$\sum_{i} \boldsymbol{X_{i,s,t}} * \boldsymbol{\theta_n} \leq \boldsymbol{Y_{n,s,t}} * \boldsymbol{\beta_n} \quad \textbf{(14)}$$

Where $X_{i,s,t}$ is the quantity of the intermediate product i, θ is the characteristic in question of the intermediate product n, $Y_{n,s,t}$ is the production of final product n, β is the required technical specification for the product n, and the indexes s and t represent the region of supply s and the period t.

The specifications considered in the model are the sulfur content and density of gasoline, jet fuel oil, diesel and fuel oil, gasoline octane number and diesel cetane number.

Capacities balances and constraints

The capacity level of a processing unit is equal to the sum of the input flows in the given unit. For the base year (period t_0) this capacity level is limited by the maximum capacity available multiplied by a capacity factor. For the projection periods (t_1, t_2, t_3, t_4 and t_5) this capacity is equal to the capacity level of the previous period, plus a possible additional capacity in the current period, if the model deems necessary, multiplied by a capacity factor defined for additional capacities.

$$\boldsymbol{Cap_{j,s,t} = \sum_k IN_{k,j,s,t}} \quad \textbf{(15)}$$

$$\boldsymbol{Cap_{j,s,t0} \leq CF_{j,s,t} * MaxCap_{j,s,t0}} \quad \textbf{(16)}$$

$$\boldsymbol{Cap_{j,s,t} = Cap_{j,s,t-1} + (CFAdd_{j,s,t} * AddCap_{j,s,t})} \quad \textbf{(17)}$$

Where, given a region of supply s and a period t, $Cap_{j,s,t}$ is the level capacity of the process unit j, $IN_{k,j,s,t}$ is the quantity of input feed k in the processing unit j, $CF_{j,s}$ is the capacity factor of the process unit j, $CFAdd_{j,s,t}$ is the capacity factor for additional capacities of the process unit j, and $AddCap_{j,s,t}$ is the possible additional capacity of the process unit j. Considering the region of supply s and period t_0, $MaxCap_{j,s,t0}$ is the maximum capacity of the process unit j. Finally, for a region of supply s and period t-1, $Cap_{j,s,t-1}$ is the level capacity of the process unit j.

Utilities consumptions

The utilities consumption represents the demand for steam, fuel and electricity of each processing unit. They also include the demand for hydrogen in hydrotreating and hydrocracking units.

Steam

For the steam balance, three different types of steam are considered: high, low and medium pressure steam. Firstly, the model perform the total energy balances per region and period, considering the specific consumptions per unit and obtaining their total demands. Then, the model details the high pressure (HP) steam balance. The HP demand can be supplied by cogeneration units or boilers. The HP surplus is, then, used to supply the medium pressure (MP) steam demand. Therefore, the demand for MP steam can be met firstly by the surplus of HP steam - if it exists – and secondly by cogeneration units and boilers. Finally, the surplus of MP steam can be used to supply low pressure (LP) steam.

The following equations show, respectively, the total energy balances for steam, the balances of high, medium and low pressure steam, the balance of cogeneration units, and the balance of boilers.

a) <u>Total energy balances:</u>

$$\boldsymbol{Dem_{HP,s,t} = \sum_j SC_{HP,j,s,t} \cdot Cap_{j,s,t}} \quad \textbf{(18)}$$

$$\boldsymbol{Dem_{MP,s,t} = \sum_j SC_{MP,j,s,t} \cdot Cap_{j,s,t}} \quad \textbf{(19)}$$

$$\boldsymbol{Dem_{LP,s,t} = \sum_j SC_{LP,j,s,t} \cdot Cap_{j,s,t}} \quad \textbf{(20)}$$

Where, given a region of supply s and a period t, $DEM_{HP,s,t}$, $DEM_{MP,s,t}$ and $DEM_{LP,s,t}$ are the total demands for high, medium and low pressure steam, $SC_{HP,j,st}$, $SC_{MP,j,s,t}$ and $SC_{LP,j,s,t}$ are the specific consumptions of high, medium and low pressure steam, respectively, in the process unit j, and $Cap_{j,s,t}$ is the level capacity of the process unit j.

b) **<u>High pressure steam energy balance:</u>**

$$\boldsymbol{Sup_{HP,s,t} - Dem_{HP,s,t} = 0} \quad \textbf{(21)}$$

$$\boldsymbol{\left(Prod_{HP,s,t} - Exce_{HP,s,t}\right) - Dem_{HP,s,t} = 0} \quad \textbf{(22)}$$

$$\boldsymbol{Prod_{HP,s,t} \geq 0} \quad \textbf{(23)}$$

$$\boldsymbol{Exce_{HP,s,t} \geq 0} \quad \textbf{(24)}$$

Where, considering a region of supply s and a period t, $Sup_{HP,s,t}$ is the supply of high pressure steam, $DEM_{HP,s,t}$, is the total demand for high steam, $Prod_{HP,s,t}$ is the production of high pressure steam, and $Exce_{HP,s,t}$ is the excess of high pressure steam.

c) **<u>Medium pressure steam energy balance:</u>**

$$\boldsymbol{Sup_{MP,s,t} - Dem_{MP,s,t} = 0} \quad \textbf{(25)}$$

$$\boldsymbol{\left(Prod_{MP,s,t} + Exce_{HP,s,t} - Exce_{MP,s,t}\right) - Dem_{MP,s,t} = 0} \quad \textbf{(26)}$$

$$\boldsymbol{Prod_{MP,s,t} \geq 0} \quad \textbf{(27)}$$

$$\boldsymbol{Exce_{MP,s,t} \geq 0} \quad \textbf{(28)}$$

Where, for a region of supply s and a period t, $Sup_{MP,s,t}$ is the supply of medium pressure steam, $DEM_{MP,s,t}$, is the total demand for medium steam, $Prod_{MP,s,t}$ is the production of medium pressure steam, and $Exce_{MP,s,t}$ is the excess of medium pressure steam.

d) **Low pressure steam energy balance:**

$$\boldsymbol{Sup_{LP,s,t} - Dem_{LP,s,t} \geq 0} \quad \textbf{(29)}$$

$$\boldsymbol{\left(Prod_{LP,s,t} + Exce_{MP,s,t}\right) - Dem_{LP,s,t} \geq 0} \quad \textbf{(30)}$$

$$\boldsymbol{Prod_{LP,s,t} \geq 0} \quad \textbf{(31)}$$

Where $Sup_{LP,s,t}$ is the supply of low pressure steam, $DEM_{LP,s,t}$, is the total demand for low steam, and $Prod_{LP,s,t}$ is the production of low pressure steam in the region of supply s and period t.

e) **Balance of cogeneration units:**

$$\boldsymbol{ElecProd_{s,t} \leq 8.76 * Cap_{COG,s,t}} \quad \textbf{(32)}$$

$$\boldsymbol{NGCOG_{s,t} = \frac{1}{ElecEff * TurbineEff} * ElecProd_{s,t}} \quad \textbf{(33)}$$

$$\boldsymbol{SteamCOG_{HP,s,t} = \frac{SteamProdEff}{ElecEff} * ElecProd_{s,t}} \quad \textbf{(34)}$$

Where, considering a region of supply s and a period t, $ElecProd_{s,t}$ is the electricity production, $Cap_{COG,s,t,}$ is the capacity of the cogeneration unit, $NGCCOG_{s,t}$ is the quantity of natural gas used by the cogeneration units, ElecEff is the efficiency of electricity production, TurbineEff is the efficiency of the turbine, $SteamCOG_{HP,s,t}$ is the amount of steam produced by the cogeneration, and SteamProdEff is the steam production efficiency.

f) **Balance of boilers:**

$$\boldsymbol{SteamBOILER_{HP,s,t} = BoilerEff * FuelBOILER_{s,t}} \quad \textbf{(35)}$$

Where, considering a region of supply s and a period t, $SteamBOILER_{HP,s,t}$ is the high-pressure steam produced by the boilers, BoilerEff is the boilers' efficiency, and $FuelBOILER_{s,t}$ is the amount of fuel consumed by the boilers to produce steam.

Fuel

The fuel balance associated with furnaces is calculated in a mass balance, considering the specific consumptions per unit, in each region, for each period. In order to meet the demand for fuel, the model has the option of choosing between natural gas (with an associated purchase cost), fuel oil and refinery gas (the latter being produced by the refining process itself). Unless for the case of the FCC and RFCC units, where the fuel considered is the FCC and RFCC petcoke, respectively.

$$\boldsymbol{Fuel_{s,t} = \sum_j SCFuel_{j,s,t} \cdot Cap_{j,s,t}} \quad \textbf{(36)}$$

$$\boldsymbol{Fuel_{s,t} = Fuel_{NG,s,t} + Fuel_{FO,s,t} + Fuel_{FG,s,t}} \quad \textbf{(37)}$$

$$\boldsymbol{Fuel_{FO,s,t} \leq Y_{FO,s,t} - Dem_{FO,d,t}} \quad \textbf{(38)}$$

$$\boldsymbol{Fuel_{FG,s,t} \leq Y_{FG,s,t}} \quad \textbf{(39)}$$

$$\boldsymbol{Fuel_{CK,s,t} = \sum_j SCFuel_{j,s,t} \cdot Cap_{j,s,t}} \quad \textbf{(40)}$$

$$\boldsymbol{Fuel_{CK,s,t} \leq Y_{CK,s,t} - Dem_{CK,d,t}} \quad \textbf{(41)}$$

Where, considering the regions of supply s and demand d, and a period t, $Fuel_{s,t}$ is the demand for fuel, $SCFuel_{j,s,t}$ is the specific fuel consumption in the process unit j, $Cap_{j,s,t}$ is the level capacity of the process unit j, $Fuel_{NG,s,t}$ is the quantity of natural gas used to meet fuel demand, $Fuel_{FO,s,t}$ is the quantity of fuel oil used to meet fuel demand, $Fuel_{FG,s,t}$ is the quantity of fuel gas used to meet fuel demand, $Y_{FO,s,t}$ is the production of fuel oil, $Dem_{FO,d,t}$ is the demand for fuel oil, $Y_{FG,s,t}$ is the production of fuel gas,

$Fuel_{CK,s,t}$ is the quantity of coke used to meet fuel demand, $SCFuel_{j,s,t}$ is the specific fuel consumption in the process unit j (in this case FCC/ RFCC), $Cap_{k,s,t}$ is the level capacity of the process unit j (FCC/RFCC), $Y_{CK,s,t}$ is the production of coke and $Dem_{CK,s,t}$ is the demand for coke.

Electricity

For the electricity balance, the estimates derive from the specific consumption of each unit, in each region and for a period, in an energy basis. To meet the demand for electricity, cogeneration units are considered, and, if necessary, the electricity is purchased from the grid.

$$\boldsymbol{ElecDem_{s,t} = \sum_j SCElec_{j,s,t} \cdot Cap_{j,s,t}} \quad \textbf{(42)}$$

$$\boldsymbol{\left(ElecGRID_{s,t} + ElecProd_{s,t}\right) - ElecDem_{s,t} \geq 0} \quad \textbf{(43)}$$

Where, in a region of supply s and in a period t, $ElecDem_{s,t}$ is electricity demand, $SCElec_{j,s,t}$ is the specific consumption of electricity of the process unit j, $Cap_{j,s,t}$ is the level capacity of the process unit j, $ElecGRID_{s,t}$ is the electricity purchased from the grid, and $ElecProd_{s,t}$ is the electricity production.

Hydrogen

The hydrogen balance is performed considering the specific consumption of each unit, in each region and for a period. The demand is met by the hydrogen produced in catalytic reforming units and hydrogen generation units (through the process of steam reforming with natural gas).

$$\boldsymbol{DemH2_{s,t} = \sum_j SCH2_{j,s,t} \cdot Cap_{j,s,t}} \quad \textbf{(44)}$$

$$\boldsymbol{ProdH2_{s,t} \geq DemH2_{s,t}} \quad \textbf{(45)}$$

$$\boldsymbol{ProdH2_{s,t} \leq \left(Cap_{HGU,s,t} * YH2_{HGU}\right) + \left(Cap_{CR,s,t} * PRODH2_{CR}\right)} \quad \textbf{(46)}$$

Where, considering a region of supply s and a period t, $DemH2_{s,t}$ is the hydrogen demand, $Cap_{j,s,t}$ is the level capacity of the process unit j, $SCH2_{j,s,t}$ is the hydrogen specific consumption of the process unit j, $ProdH2_{s,t}$ is the hydrogen production, $YH2_{HGU}$ is the production factor of hydrogen of the hydrogen generation unit, and $PRODH2_{CR}$ is the production facto of hydrogen of the catalytic reforming unit.

CO_2 emissions

As previously mentioned, the model considers accounts for the CO_2 emissions from the each refinery block, which comes mainly from the burning of fuel (natural gas, fuel oil and refinery fuel) to produce steam, electricity and heat, the grid electricity, and the production of hydrogen with natural gas. Therefore, the total CO_2 emissions are equal to the sum of the quantity consumed of each fuel multiplied for its emission factor (IPCC, 2006). For the grid electricity, the emission factor considered is the Brazilian National Interconnected System one (MCTIC, 2018).

$$\boldsymbol{CO_2\ emissions_{s,t} = \sum_{fuel} Fuel_{s,t} * EF_{fuel}} \quad \textbf{(47)}$$

Where, in a region of supply s and period t, $CO2emissions_{s,t}$ are the total CO_2 emissions, $X_{fuel,s,t}$ is the amount of fuel consumed, and EF_{fuel} is the fuel emission factor.

Objective Function

The model´s objective function consists in minimizing the total cost for supplying liquid fuels demand (in present value, i.e., considering all costs for 2015), which includes the crude oil purchase cost, the fuel and electricity purchase costs to meet refinery's utilities demand, the refining costs (processing costs of installed and eventually additional units, and the investment costs of additional units), the oil products imports costs, the national trades of oil products costs, and the CO_2 emissions costs .

$$\boldsymbol{Min\ (Z) = OPC + FPC + COGC + CAPEX + OPEX + IMP + NTRAD + CO2C + Harbor\ Exp\ Cost - EXP} \quad \textbf{(48)}$$

Where OPC is the oil purchase cost, FPC the fuel purchase cost, COGC the cost of cogeneration, CAPEX the capital cost, OPEX the operations and maintenance costs, IMP the imports costs, NTRAD the national trades costs, CO_2 the cost of CO_2 emissions, Harbor ExpCost the harbor capacity expansion cost and EXP the exports revenues.

Each of these elements are detailed below.

Oil purchase cost

Oil purchase cost is defined based on the price of each crude oil blend considered in the model, as well as its import freight price, and the quantity processed by the refinery in each region and in each period of analysis.

$$\boldsymbol{OPC} = \sum_{oil,s,t}\left(\mathbf{1}+\frac{\mathbf{1}}{\boldsymbol{CRF}}\right) * \frac{(\boldsymbol{Price_{oil,t}} + \boldsymbol{Freight\ Price_{oil,o,s,t}}) * \boldsymbol{X_{oil,s,t}}}{(\mathbf{1}+\boldsymbol{r})^{t-t0}} \quad \textbf{(49)}$$

$$\boldsymbol{CRF} = \frac{\boldsymbol{r} * (\mathbf{1}+\boldsymbol{r})^{n}}{((\mathbf{1}+\boldsymbol{r})^{n}-\mathbf{1})} \quad \textbf{(50)}$$

Where OPC is the total oil purchasing cost, $Price_{oil,t}$ is the oil price of the representative oil (1,2 or 3) in the period t, Freight $Price_{oil,o,s,t}$ is the freight price of the representative oil (1,2 or 3), from the oversea region o to the supply region s in the period t, $X_{oil,s,t}$ is the quantity of crude oil processed by the refinery in the region of supply s in the period t, CRF is the capital recovery factor, r is the discount rate, and n is amount of years between periods (in the present study, n corresponds to five years) .

The prices for each type of crude blend inputted in the model are defined according to a crude oil reference price, taking into account the impact of differences in qualities over oil price differentials. The qualities considered for the price estimation in the present study were the °API and the sulfur level. Equation's parameters are based on LIMA *et al*. (2012), which obtained such results through a dynamic panel with a sample of 90 streams over the period of January 2009 to December 2010. Thus, each additional unity of °API results in a premium of around US$0,002 per dollar of Brent, and each percent increase of sulfur discount of US$ 0,056 per dollar of Brent.

$$\boldsymbol{Price_{oil,t} = \left(0.002 * \Delta^{\circ}\ API_{oil,ref} - 0.056 * \Delta Sulphur_{oil,ref}\right) * Price_{ref,t}} \quad \textbf{(51)}$$

Where, considering a period t, $Price_{oil,t}$ is the crude oil blend price, $\Delta°API_{oil,ref}$ is the °API differential between crude oil blend and the reference oil, $\Delta Sulfur_{oil,ref}$ is the sulfur level differential between crude oil blend and the reference oil, and $Price_{ref,t}$ is the oil reference price.

Fuel Purchase Cost

This cost refers to the cost of purchasing fuels used to meet the energy demand of the refineries. The fuels considered in the model are natural gas, refinery gas, fuel oil and petroleum coke (this last one only in the FCC and RFCC units). The option to purchase electricity from the grid was made available to the model.

$$\boldsymbol{FPC = \sum_{s,t}\left(1+\frac{1}{CRF}\right) * \frac{(NGPrice_t * NG_{s,t}) + (FOPrice_t * FO_{s,t}) + (FGPrice_t * FG_{s,t}) + (CokePrice_t * Coke_{s,t}) + (ElecGridPrice_t * ElecGrid_{s,t}}{(1+r)^{t-t0}}} \quad \textbf{(52)}$$

Where, considering a region of supply s and a period t, FPC is the total fuel purchase cost, $NGPrice_t$ is the natural gas price, $NG_{s,t}$ is the quantity of natural gas consumed, $FOPrice_t$ is the fuel oil price, $FO_{s,t}$ is the quantity of fuel oil consumed, $FGPrice_t$ is the fuel gas price, $FG_{s,t}$ is the quantity of fuel gas consumed, $CokePrice_t$ is the petroleum coke, $Coke_{s,t}$ is the quantity of petroleum coke consumed, $ElecGridPrice_t$ is the grid electricity price, $ElecGrid_{s,t}$ is the quantity of grid electricity consumed, CRF is the capital recovery factor, and r is the discount rate.

It is important to reinforce that the quantity of natural gas consumed and considered in the **Equation 52** does not take into account the natural gas used in cogeneration units, since this one is directly introduced in the cogeneration cost.

Refining Costs

Refining costs include variable operating costs, fixed running costs and capital charges. The first category includes chemical products and catalysts. The second concerns to labour, maintenance, taxes, insurance and administrative expenditures. Lastly, the capital charges are related to new investments, which are composed by the ISBL investments (inside battery limits) – that include civil works, piping located within the unit area, electrical installations, instrumentation etc – and the OSBL investments (outside battery limits), i.e. anything outside the refining units, such as product lines, administrative installations and storage facilities. For the present study, and based on MAPLES (2000), TAVARES et al. (2006), and COELHO (2015) it was considered that ISBL = OSBL.

As the model is forecasted until 2040, reference values were considered for both operating and investment costs and brought to the year 2015, which is the base year, through the net present value method.

$$\boldsymbol{CAPEX} = \sum_{j,s,t} \frac{(ISBL_j + OSBL_j) * AddCap_{j,s,t}}{(1+r)^{t-t0}} \quad \textbf{(53)}$$

$$\boldsymbol{OPEX} = \sum_{j,s,t} \left(1 + \frac{1}{CRF}\right) * \frac{(VOM_j + FOM_j) * AddCap_{j,s,t}}{(1+r)^{t-t0}} \quad \textbf{(54)}$$

Where, in a region of supply s and in a period t, CAPEX is the investment cost of adding a new process unit capacity, $ISBL_j$ is the inside battery limits costs of a process unit j, $OSBL_j$ is the outside battery limits costs of a process unit j, $AddCapc_{j,s,t}$ is the additional capacity of the process unit j, r is the discount rate, OPEX is the operation and maintenance costs, VOM_j is the variable operating costs of the process unit j, FOM_j is the fixed operating cost of the process unit j; and CRF is the capital recovery factor.

Cogeneration Costs

Cogeneration costs include the operating and maintenance costs of existing units, the costs of investing in new units, the operating and maintenance costs of new units (if any), and the cost of natural gas used as fuel, all of them brought to present value.

$$COGC = \sum_{s,t} CAPEXCOG_{s,t} + OPEXCOGEx_{s,t} + OPEXCOGNew_{s,t} + NGCOGC_{s,t} \quad (55)$$

$$CAPEXCOG_{s,t} = \frac{(ISBL_{COG}+OSBL_{COG})*AddCap_{COG,s,t}}{(1+r)^{t-t0}} \quad (56)$$

$$OPEXCOGEx_{s,t} = \left(1+\frac{1}{CRF}\right)*\frac{(VOM_{COG}+FOM_{COG})*Cap_{COG,s,t}}{(1+r)^{t-t0}} \quad (57)$$

$$OPEXCOGNew_{s,t} = \left(1+\frac{1}{CRF}\right)*\frac{(VOM_{COG}+FOM_{COG})*AddCap_{COG,s,t}}{(1+r)^{t-t0}} \quad (58)$$

$$NGCOGC_{s,t} = \left(1+\frac{1}{CRF}\right)*\frac{NGCOG_{s,t}*NGPrice_{t}}{(1+r)^{t-t0}} \quad (59)$$

Where, in a region of supply s and in a period t, COGC is the cogeneration cost, CAPEXCOGs,t is the investment cost of adding a new cogeneration unit capacity, $ISBL_{COG}$ is the inside battery limits costs of the cogeneration unit, $OSBL_{COG}$ is the outside battery limits costs of the cogeneration unit, $AddCap_{COG}$,s,t is the cogeneration unit additional capacity, r is the discount rate, OPEXCOGExs,t is the operation and maintenance costs of the existing cogeneration units, VOM_{COG} is the variable operating costs of the cogeneration unit, FOM_{COG} is the fixed operating cost of the cogeneration unit, OPEXCOGNews,t is the operation and maintenance costs of the new cogeneration units, $NGCOGC_{s,t}$ is the cost of natural gas used as fuel in the cogeneration units, $NGCOG_{s,t}$ is the quantity of natural gas consumed in the cogeneration units, CRF is the capacity recovery factor, and r is the discount rate

Imports of petroleum products costs

The imports costs consider the FOB (Free-on-board) prices of each oil product imported and the freight costs related to the transportation of each of them.

$$IMP = \sum_{n,o,d,t}\left(1+\frac{1}{CRF}\right)*\frac{(FOBPrice_{n,t}+FreightPrice_{n,o,d,t})*imp_{n,o,d,t}}{(1+r)^{t-t0}} \quad (60)$$

Where, in a region of demand d, a period t, and an oversea region o, IMP are the imports costs, $FOBPrice_{n,t}$ is the Free-on-board price of the product imported n, $FreightPrice_{n,o,d,t}$ is the freight price of importing the product n, and $imp_{n,o,d,t}$ is the quantity imported of the product n, CRF is capital recovery factor, and r is the discount rate.

National trades costs

These costs represent the national trades between Brazilian regions, which mean the cost of transportation of a given petroleum product from one region to another in the national level.

$$\boldsymbol{NTRAD} = \sum_{n,d,s,t}\left(1+\frac{1}{CRF}\right) * \frac{FreightPrice_{n,d,s,t} * NT_{n,d,s,t}}{(1+r)^{t-t0}} \quad \textbf{(61)}$$

Where, for the regions of supply and demand s and d, and the period t, $NTRAD_{s,t}$ are the national trades costs, $FreightPrice_{n,d,s,t}$ is the freight price for the product n, $ND_{n,s,d,t}$ is the amount transported of the product n, CRF is the capital recovery factor, and r is the discount rate.

CO_2 emissions costs

The CO_2 emissions costs are based on a possible CO_2 taxation, which establishes values to be paid for a given quantity of CO_2 emitted, and on the amount of CO_2 emissions in each region and period.

$$\boldsymbol{CO2C} = \sum_{s,t}\left(1+\frac{1}{CRF}\right) * \frac{Price_{CO2,t} * CO_2\ emissions_{s,t}}{(1+r)^{t-t0}} \quad \textbf{(62)}$$

Where, given a region of supply s and a period t, $CO_2C_{s,t}$ are the CO_2 emissions costs, $Price_{CO2,t}$ is the CO_2 taxation price applied, $CO_2emissions_{s,t}$ are the quantities of CO_2 emitted, CRF is the capital recovery factor, and r is the discount rate.

Exports of petroleum products revenues

The exports revenues consider only the FOB (Free-on-board) prices of each oil product exported.

$$\boldsymbol{EXP} = \sum_{\boldsymbol{n,o,s,t}} \left(\mathbf{1} + \frac{\mathbf{1}}{\boldsymbol{CRF}}\right) * \frac{\boldsymbol{FOB\ Price_{n,t} * exp_{n,o,s,t}}}{(\mathbf{1}+\boldsymbol{r})^{\boldsymbol{t-t0}}} \quad \textbf{(63)}$$

Where $EXP_{s,t}$ are the exports revenues, FOB $Price_{n,t}$ is the Free-on-board price of the product exported n, $exp_{n,s,o,t}$ is the quantity exported of the product n, from the supply region s to the oversea region o, in the period t, CRF is the capital recovery factor, and r is the discount rate.

Harbors expansions costs

As previously mentioned, the model allows the expansion of harbors capacity. The additional capacity, in turn, have an associated CAPEX for periods beyond the base year, that is, for periods starting from t_1.

$$\boldsymbol{Harbor\ ExpCost} = \sum_{\boldsymbol{p,t}} \boldsymbol{AddCapHarbor_{p,t}} * \boldsymbol{CAPEX\ Harbor_{p,t}} \quad \textbf{(64)}$$

$$\boldsymbol{CAPEX\ Harbor_{p,t}} = \sum \frac{\boldsymbol{CostExpHarbor * AddCapHarbor_{p,t}}}{(\mathbf{1}+\boldsymbol{r})^{\boldsymbol{t-t0}}} \quad \textbf{(65)}$$

Where, for a given period t and a product classification p, Harbor $ExpCost_{p,t}$ is the harbor expansion cost, CAPEX $Harbor_{p,t}$ is the levelized investment cost associated to the additional harbor capacity, CostExpHarbor is the cost of expanding the harbor capacity; and r is the discount rate.

4. Case study

The present chapter presents the data inserted in the model. As previously mentioned, the reference year of the model is 2015 (or period t0), period for which the calibration[16] stage was carried out.

Processing units capacities

Processing units capacities for 2015 are based on data published by ANP (2018a), as presented in Table 4-1. As previously mentioned, a total of fourteen process units are considered, and in addition to these, the hydrogen generation and cogeneration units.

[16] Process of adjusting the parameters of the model, with the objective of obtaining, within the margins of uncertainties, a representation of the model that is in agreement with observed values, thus establishing the credibility of the model, demonstrating its ability to replicate the real standards.

Table 4-1 – Processing units capacities as of December, 2017

	Capacities (million tonnes/year)														
Refinery	**ADU**	**VDU**	**DSP**	**FCC**	**RFCC**	**ALK**	**REF**	**COK**	**HDSG**	**HDTN**	**HDTK**	**HDTD**	**HDTU**	**UGH(Mm^3/year)**	**COG (MW)**
	SOUTH														
REFAP	10.57	1.98		1.12	2.44			0.86	1.65			1.98	3.80	675.00	
RIOGRANDENSE	0.89	0.36		0.17											
REPAR	10.90	4.96	1.68	3.47			0.33	1.65	1.65	0.99		1.98	1.98	701.25	
TOTAL	**22.37**	**7.30**	**1.68**	**4.76**	**2.44**	**0.00**	**0.33**	**2.51**	**3.30**	**0.99**	**0.00**	**3.96**	**5.78**	**1376.25**	**123.90**
	NORTH/NORTHEAST														
RLAM	14.70	6.61		1.98	4.63				3.37				0.33	510.00	
REMAN	2.51	0.36		0.20			0.26		0.50				0.83	150.00	
RPCC	1.98														
RNEST	6.05							3.93		0.99			4.29	1125.00	
LUBNOR	0.43														
DAXOIL	0.10														
TOTAL	**25.77**	**6.97**	**0.00**	**2.18**	**4.63**	**0.00**	**0.26**	**3.93**	**3.87**	**0.99**	**0.00**	**0.00**	**5.45**	**1785.00**	**68.90**
	RIO DE JANEIRO/MINAS GERAIS														
REDUC	12.72	6.01	2.25	2.48			0.63	1.65	1.65	0.66	0.59	0.99	3.96	850.12	
REGAP	7.93	4.63		2.25				1.26	1.45	1.09	1.19	0.86	2.74	671.25	
MANGUINHOS	0.76	0.31													
TOTAL	**21.41**	**10.95**	**2.25**	**4.72**	**0.00**	**0.00**	**0.63**	**2.91**	**3.11**	**1.75**	**1.78**	**1.85**	**6.71**	**1521.37**	**120.50**
	SÃO PAULO														
REPLAN	21.80	10.24		5.29			0.99	4.13	2.91	2.18			7.27	1406.25	
REVAP	13.22	6.61	2.25	4.63			0.50	1.65	2.31	0.99	1.98	2.15	2.25	611.25	
RPBC	8.92	4.26		3.30		0.33	0.83	1.39	1.98	0.86			5.29	1076.25	
RECAP	2.81				1.02				0.66				1.32	206.25	
UNIVEN	0.46	0.19													
TOTAL	**47.21**	**21.30**	**2.25**	**13.22**	**1.02**	**0.33**	**2.31**	**7.17**	**7.86**	**4.03**	**1.98**	**2.15**	**16.12**	**3300.00**	**216.80**
TOTAL BRAZIL	**116.75**	**46.52**	**6.18**	**24.88**	**8.09**	**0.33**	**3.54**	**16.52**	**18.14**	**7.76**	**3.77**	**7.96**	**34.06**	**7982.63**	**530.10**

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; ALK – Alkylation unit; CR – Catalytic Reforming unit; COK – Delayed Coking unit; HDSG – Gasoline Hydrodesulfurization unit; HDTN – Naphtha hydrotreating unit; HDTK – Kerosene hydrotreating unit; HDTD – Diesel hydrotreating unit; HDTI – Instable products hydrotreating unit; UGH – Hydrogeneration unit

Source: ANP (2018a); ANEEL (2018)

Crude oils, campaigns and yields

Currently, different crude oils are processed by Brazilian refineries. However, as the size of a LP model is approximately proportional to the number of crude oils considered (LANTZ *et al*., 2012), the representation of feedstocks in details does not compensate the modeling process effort. Thus, the crude oil supply has been reduced to three representative crude oil blends that might include a largest set of crude oil streams (Table 4-2). The first one is a blend from African crude oils, the second a blend from Middle Eastern crude oils, and the third a blend from Brazilian crude oils. The blends were made using data from PRELIM - Petroleum Refinery Life Cycle Inventory Model, developed by the Life Cycle Analysis of Oil Sands Technologies research group of the University of Calgary (BERGERSON *et al*., 2017). Therefore, it was possible to obtain the °API, sulfur content and density of each considered crude oil blend **(**Table 4-3**),** as well as the yields of each intermediate product in the atmospheric distillation unit, for each campaign[17] comprised by the model, i.e., diesel and naphtha campaigns (Table 4-4), and also the yields of the vacuum distillation unit (Table 4-5).

Table 4-2 - Crude oil blends

Crude	Blend	°API	Sulfur (%wt)	Density (kg/m³)
Crude 1	African[1]	47.88	0.08	788.1
Crude 2	Middle East[2]	33.40	1.63	857.8
Crude 3	Brazilian[3]	26.9	0.44	892.5

[1]Represented by Agbami crude oil, an extra light, low sulfur crude oil produced in Agbami field in Nigeria (EQUINOR, 2019); [2]Represented by the Arab Light, a medium-gravity, high-sulfur crude oil produced by Saudi Arabia (MCCKINSEY & COMPANY, 2019); [3]Represented by the Brazilian oil Marlim, a heavy-gravity and high-sulfur crude oil, and the the Brazilian Oil Lula, a medium-gravity and low-sulfur crude oil (BARROS and SZKLO, 2015).

Source: BERGERSON *et al*. (2017); BARROS and SZKLO (2015)

[17] Campaign, in this case, means to maximize the production of a given product in the atmospheric distillation unit, through typical yields (GUEDES, 2015).

Table 4-3 - Yields of the Atmospheric Distillation Unit (mass basis)

Product	Crude 1	Crude 2	Crude 3
Diesel campaing			
Fuel Gas	0.04%	0.06%	0.03%
LPG	3.00%	1.83%	0.27%
LSR Naphtha	11.96%	5.00%	3.00%
HSR Naphtha	11.00%	5.00%	3.00%
SR Kerosene	4.00%	2.00%	1.00%
SR Diesel	32.00%	34.00%	36.73%
Atmospheric Gasoil	21.00%	25.00%	26.00%
Atmospheric Residue	17.00%	27.11%	29.97%
Product	**Crude 1**	**Crude 2**	**Crude 3**
Naphtha campaing			
Fuel Gas	0.04%	0.06%	0.03%
LPG	3.00%	2.00%	1.50%
LSR Naphtha	17.00%	12.00%	9.00%
HSR Naphtha	14.80%	11.94%	10.00%
SR Kerosene	5.00%	4.00%	3.00%
SR Diesel	28.00%	30.00%	34.03%
Atmospheric Gasoil	17.16%	18.00%	16.50%
Atmospheric Residue	15.00%	22.00%	25.94%

Source: MEYERS (2004); GARY & HANDWERK (2001); BARROS and SZKLO (2015); BERGERSON *et al*. (2017)

Table 4-4 - Yields of the Vacuum Distillation Unit (mass basis)

Product	Crude 1	Crude 2	Crude 3
LVGO	37.57%	17.68%	30.10%
HVGO	18.78%	26.22%	34.95%
Vacuum Residue	43.65%	56.10%	34.95%

Source: MEYERS (2004); GARY & HANDWERK (2001); BARROS and SZKLO (2015); BERGERSON *et al*. (2017)

For the other processing units, the model adopted fixed average yields, according to the technical and scientific literatures.

Table 4-5 - Yields of other units (mass basis)

Product	FCC	RFCC	HCC	ALK	REF	COK
Fuel Gas	3.0%	3.0%	0.4%			5.0%
LPG	14.0%	17.0%	3.8%	17.0%	15.0%	4.0%
Naphtha						7.0%
Gasoline	50.0%	45.0%	20.0%	83.0%	85.0%	
Kerosene			25.0%			
Diesel			37.0%			
Light Cycle Oil	17.0%	18.0%				
Light Gasoil						40.0%
Heavy Gasoil						14.0%
Slurry Oil	12.0%	13.0%	13.8%			
Coke	4.0%	4.0%				30.0%

Source: MEYERS (2004); GARY & HANDWERK (2001); BARROS and SZKLO (2015); BERGERSON *et al*. (2017)

Products Demands

As mentioned before, the final products represented in the model are liquefied petroleum gases (LPG), naphtha, gasoline, jet fuel oil, kerosene, diesel oil, heavy fuel oil and heating fuel oil. The demand for these products are exogenous, and, for the base year, the source of these data is ANP (2018a) and IEA (2017). Also, as the model is designed to operate over the period 2015-2040, the products' demand for the following years are based on scenarios that will be described in Chapter 4. Table 4-6 presents the demands for 2015.

Table 4-6 - Oil products demands – 2015

Oil Product (Mtonnes/year)	Region				
	S_D	NE_D	RJMG_D	SP_D	Total
LPG	1.35	2.90	1.35	1.87	7.46
Naphtha	1.95	3.38	1.56	2.08	8.98
Gasoline	4.84	8.39	3.93	5.29	22.46
Kerosene	0.0004	0.0019	0.0013	0.0025	0.01
Diesel	9.66	10.86	7.38	18.78	46.67
Jet fuel oil	0.41	1.83	1.22	2.44	5.89
Fuel oil	2.62	3.03	2.48	5.51	13.64
Heating fuel oil	0.30	0.30	0.30	0.61	1.52
Coke	0.90	1.91	0.90	1.20	4.92

Source: ANP (2018a); IEA(2017)

Products Specifications

The specifications considerer were the density ranges for gasoline and diesel, maximum sulfur content for gasoline, diesel, jet fuel oil and heavy fuel oil, and minimum octane/cetane numbers for gasoline and diesel, respectively - see Table 4-7, Table 4-8 and Table 4-9.

Table 4-7 - Density ranges

Oil product	Density range (g/cm³)
Gasoline	0.720 – 0.750
Diesel	0.835 – 0.845

Source: SPEIGHT (2011)

Table 4-8 - Maximum sulfur content

Oil product	Maximum sulfur content (ppm)
Gasoline	50
Diesel	10
Jet Fuel oil	600
Fuel oil	25000

Source: ANP (2018b)

Table 4-9 – Minimum octane and cetane numbers

Oil product	Minimum octane/cetane numbers
Gasoline	87
Diesel	48

Source: ANP (2018b)

Utilities consumptions

From the literature, it was possible to estimate the typical consumption of utilities of each refinery process unit – see Table 4-10. Although there are variations in the consumption of utilities for the same unit, depending on the supplier of the technology, local characteristics or even different design considerations, the values used seek to represent a typical unit.

Table 4-10 - Utilities consumptions

Utilities	Unit	ADU	VDU	DSP	FCC	RFCC	ALK	REF	DCU	HDSG	HDTN	HDTK	HDTD	HDTI	HGU
HP Steam	MJ/ton	0.00	0.00	0.00	-328.81	-369.91	0.00	-320.59	0.00	61.65	61.65	82.20	82.20	102.75	-0.08
MP Steam	MJ/ton	222.67	167.01	0.00	404.86	0.00	1821.89	0.00	-372.47	0.00	0.00	0.00	0.00	0.00	-
LP Steam	MJ/ton	0.00	0.00	79.37	-71.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
Electricity	kWh/ton	4.41	7.00	14.71	64.71	7.35	22.06	73.53	26.47	14.71	14.71	22.06	22.06	44.12	8.09
Fuel	MJ/ton	933.82	636.76	772.06	2705.88	2705.88	1161.76	2808.82	926.47	772.06	772.06	1161.76	1161.76	1551.47	18.38
Hydrogen	m^3/ton	0.00	0.00	0.00	0.00	0.00	0.00	-352.94	0.00	29.41	51.47	125.00	250.00	310.7	-1.47

Source: HYDROCARBON PROCESSING (2008); MEYERS (2004); GARY and HANDWERK (2001); STANISLAUS *et al*. (2010)

CO_2 Emissions

Total CO_2 emissions are equal to the sum of the quantity consumed of each fuel multiplied for its emission factor (IPCC, 2006). For the grid electricity, the emission factor considered is the Brazilian National Interconnected System one (MCTIC, 2018).

Table 4-11 - CO_2 emission factors

Fuel	Emission Factor (tCO_2/TJ)
Natural Gas	56.1
Fuel Gas	57.6
Fuel Oil	77.4
Coke	97.5
Electricity*	0.2553

*tCO_2/MWh

Source: IPCC (2006) and MCTIC (2018)

Crude Oil Prices

The prices for each type of crude blend represented by the model are defined according to a reference price. The two most commonly used benchmark prices in the world are WTI and Brent. In the present study, the reference price relates to Brent. For the base year, the reference price is based on ARGUS (2018), and consists of a FOB (Free on board) price in 2015 (Table 4-12).

Table 4-12 - Reference crude oil FOB price - 2015

Crude oil	FOB price (US$/bbl)
Brent	53.46

Source: ARGUS (2018)

Oil Products Prices

The prices considered for the petroleum products, in the base year, were obtained in ARGUS (2018), and refer to FOB (Free on board) prices in 2015. For imported products, the freight costs, which will be presented later in this section, must also be taken into account.

Table 4-13 - Oil products FOB prices – 2015

Product	Prices (US$/t)
LPG	214.8
Naphtha	451.7
Gasoline	528.7
Kerosene	506.9
Diesel	493.5
Jet fuel oil	506.9
Fuel oil	431.3
Heating fuel oil	431.3
Coke	56.1

Source: ARGUS (2018)

Fuel Prices

Fuel prices refer to fuels used to meet the energy demand of the refinery. They include natural gas, refinery gas, fuel oil and petroleum coke. Nevertheless, refinery gas, as well as fuel oil and petroleum coke have a zero associated cost, as those are by-products of the refinery itself. Thus, only the costs associated with the purchase of natural gas and electricity from the grid were considered.

Table 4-14 - Fuel prices - 2015

Product	Price	Unit
Natural gas	15.00	US$/MMBtu
Electricity	0.22	US$/kWh

Source: OIL & GAS JOURNAL (2015); ANEEL(2017)

Refining Costs

The refining costs considered in this study are based on LANTZ *et al*. (2012). As mentioned before, the capital charges related to new investments, are composed by the ISBL investments (inside battery limits) and the OSBL investments (outside battery limits). For the O&M costs, they are roughly 4% of the value of the investment (LANTZ *et al*., 2012) and, in addition, they can be separated into fixed (FOM) and variables (VOM) costs. In the present study, it was considered that each of these costs represents 50% of the total value of O&M cost.

Given that the database for ISBL and OSBL costs dates of 2008, it was necessary to update it to the base year of the model, that is, 2015, using the CEPCI

(Chemical Engineering Plant Cost Index). The cost update is performed through the relation:

$$\boldsymbol{Cost_{2015} = Cost_{2008} * \frac{CEPCI_{2015}}{CEPCI_{2008}}} \quad \textbf{(66)}$$

For 2015 average CEPCI was 556.8 and for 2008 it was 575.4 (CHEMICAL ENGINEERING ONLINE, 2018).

Table 4-15 - Investment and O&M costs

Process unit	Investment Cost (2015 US$/t)	O&M Cost (2015 US$/t)	VOM (2015 US$/t)	FOM (2015 US$/t)
ADU	74.42	2.98	1.49	1.49
VDU	41.70	1.67	0.83	0.83
DSP	61.77	2.47	1.24	1.24
NAHDT	56.56	2.26	1.13	1.13
REF	114.36	4.57	2.29	2.29
KEHDT	56.56	2.26	1.13	1.13
DIHDT	56.56	2.26	1.13	1.13
FCC	189.40	7.58	3.79	3.79
RFCC	189.40	7.58	3.79	3.79
HCC	253.00	10.12	5.06	5.06
HDS	83.31	3.33	1.67	1.67
ALK	446.45	17.86	8.93	8.93
COK	208.31	8.33	4.17	4.17
UGH[1]	0.19	0.01	0.004	0.004
HDTI	142.86	5.71	2.86	2.86
COG[2]	0.97	0.04	0.02	0.02

[1]UGH costs in US$/Nm^3

[2]Cogeneration costs in 10^6 US$/MW

Source: Based on LANTZ *et al*. (2012) and ROCHEDO *et al*. (2016)

As the model is forecasted until 2040, reference values were considered for both operating and investment costs and brought to the year 2015, which is the base year, through the net present value method. The discount rate used was 10% per year, a standard value for the refining industry (OLIVEIRA, 2016).

Freight Prices

The freight costs used in the model are divided into national and international freight costs. The first concerns the cost of transportation of petroleum products between the national regions of the model (national trades costs), and the second concerns the freight of importing those products. For national trades, costs are based on data obtained in COELHO (2015). With regard to international freight, they are based on LANTZ *et al*. (2012), with an update to 2015 USD. As the costs presented by COELHO (2015) were in US$/m³.km, it was necessary to estimate the distances between national regions (Table 4-16), to finally obtain the values showed in Table 4-17.

Table 4-16 - Estimated distances between Brazilian regions

Region	Distances (km)			
	S_D	**NE_D**	**RJMG_D**	**SP_D**
S_S	-	2700	1200	700
NE_S	2700	-	1600	2000
RJMG_S	1200	1600	-	400
SP_S	700	2000	400	-

Source: Based on Google Earth

Table 4-17 - National trades freight costs

Region	Freigh costs (US$/t)			
	S_D	**NE_D**	**RJMG_D**	**SP_D**
S_S	0.00	18.00	8.00	4.70
NE_S	18.00	0.00	10.70	13.30
RJMG_S	8.00	10.70	0.00	2.70
SP_S	4.70	13.30	2.70	0.00

Source: Based on COELHO (2015)

Table 4-18 - Imports freight costs

Oversea region	USA	CA	WE	AF	ME	AP
Freight cost (US$/t)	20.05	20.05	33.45	25.62	40.47	45.37

Source: Based on LANTZ et al. (2012)

For the purposes of simplifying the calculation of national freight, it was only considered the pipeline modal, although there are other modes of transportation in Brazil, such as maritime, road and rail (CNT, 2018). In addition, the freight cost was kept the same for all petroleum products. Regarding the imports freight costs, they refer

to shipping costs, from the oversea regions of the model, to the national demand regions. Again, for the sake of simplification, the costs of an oversea region are the same, regardless of the Brazilian demand region.

Harbors Capacities

Harbors capacities are restricted in the base year (t0) according to the highest observed value of imports plus exports, of each oil product classification, in the last ten years, based on ANP (2018a) (Table 4-19). For the projection years, the model was given the option of investing in new harbors capacities, under a maximum bound, as previous explained, thus increasing the imports and exports if necessary. Table 4-20 presents the maximum bound and the cost for expanding the harbor capacity. These values were calculated based on data reported by SCHAEFFER *et al*. (2017) and PNLP (2015) of expected investment portfolio and capacity gains in tha Brazilian harbor system. As a premise of this study, they remained constant throughout the horizon of analysis.

Table 4-19 - Harbors capacities

Oil products classification	Installed Capacity - 2015 (Mtonnes/year)
Light[1]	11.5
Medium[2]	24.0
Heavy[3]	7.5

[1]LPG, naphtha and gasoline; [2]Kerosene, diesel, jet fuel oil and fuel oil; [3]Petroleum coke

Source: ANP (2018a)

Table 4-20 - Maximum bound and cost for harbor capacity expansion

Maximum bound for capacity expansion (Mt/year)	1.3
Harbor capacity cost expansion (US$/t/year)	65

Source: Based on SCHAEFFER et al. (2017) and PNLP (2015)

The next section will present and describe the scenarios considered by this study.

4.1. Scenarios description

This section describes the oil products demand scenarios considered in this thesis, both for the OURSE model as for the ORION model, explaining their main premises. Then, the fuel specification cases considered in each demand scenario are discussed, through the explanation of the IMO's regulations to reduce sulfur oxides (SOx) emissions from ships, and the road liquid fuels specifications. Lastly, the crude oil price scenario considered is presented. The time period considered is from 2015 to 2040, being 2015 the base year, i.e., the calibrated year in the model. Time horizon is divided in 5-year time periods.

As previously explained, the ORION results depend on foreign trade flows (imports/exports of oil products), and these flows are related to the international market prices, thus a nested optimization approach was carried out. The worldwide multi-regional model, OURSE (Oil is Used in Refineries to Supply Energy) (LANTZ *et al*., 2012) is run for each previously defined scenario, in order to provide marginal values associated to the products demand constraints. The behavior of such marginal values in the analysis horizon is used by the ORION model to calculate oil products prices (CIF prices for imports and FOB prices for exports).

Again, it is important to mention that the construction and simulation of scenarios is not the main objective of this thesis, which actually consists in the development of the ORION model. However, to test the model's reliability it is necessary to perform rounds based on scenarios. Nevertheless, it is relevant to understand that other scenarios can be run using the model, which is a flexible and friendly tool.

4.1.1. Demand scenarios

As previously presented, the demand scenarios considered both for the OURSE model as for the ORION model consist of three scenarios in terms of oil products demands: the Shadow, Cloudy and Shiny scenarios. The description and meaning of each scenario is given below:

- **Shadow scenario:** Shadow in the dictionary means a dark area, caused by light being blocked by an obstacle. And this is exactly what this scenario means, a trajectory based on the current configuration of the oil refining industry and the energy and

transport systems, which has the possibility of improving, but there are no changes during the analysis period, i.e. the evolvement towards the sustainability is blocked by the lack of application of public policies and technological improvement.

❖ **Cloudy scenario:** This scenario takes into account the announced policies and targets both for oil refining and for the energy and transportation systems as a whole, envisaging the mobility in the transport system for the next few years. However, it still presents considerable demand for fossil fuels and can be considered as a slow path to the energy transition. It is like a cloudy sky. It is known that behind the clouds it is possible to see the sun and a clear sky, but the clouds are still there, hindering the passage of sunlight and the lightening of the day.

❖ **Shiny scenario:** This is the most disruptive among the three scenarios, since it considers an accelerated energy transition to reach the goals associated to climate change, clean energy and clean air. The name Shiny is based on exactly this fact, because achieving these goals involves the possibility of overcoming the global challenge of global climate change, and such fact represents success, with the accomplishment of something brilliant.

All the demand scenarios were constructed based on the evolution of final energy consumption by sector of the scenarios "Current Policies"[18], "New Policies"[19] and "Sustainable Development"[20] of the World Energy Outlook studies developed by the International Energy Agency (IEA, 2016; 2017; 2018) and, in the Brazilian case, i.e.

[18] The Current Policies scenario of IEA considers the impact only of the policies and measures firmly enshrined in legislation by the year of publication of the study. It assumes that only the lower level of ambition is attained (IEA, 2016; 2017; 2018).

[19] The New Policies scenario of IEA takes into account no only the policies and measures that are already in place, but it also the the aims, targets and intentions that have been announced. It provides a sense of the direction in which the most recent policy ambitions could take the energy sector (IEA, 2016; 2017; 2018).

[20] The Sustainable Development scenario of IEA setts out a pathway to achieve the objectives of depicted by the Sustainable Development Goals (SDGs) of the United Nations. It is also fully aligned with the goal of the Paris Agreement to hold the increase in the global average temperature to well below 2 °C above pre-industrial levels (IEA, 2017; 2018).

for the demand scenarios applied in the ORION model and the OURSE's Z2 (Latin America), premises about the evolution of final energy consumption in the Brazilian transportation sector of the study "Cenários de Demanda para o PNE 2050" published by the Empresa de Pesquisa Energética (EPE, 2018b) were also taken into account.

4.1.1.1. OURSE model

As already mentioned, the demand scenarios built for the OURSE model were based on the evolution of final energy consumption by sector of the scenarios "Current Policies", "New Policies" and "Sustainable Development" of the World Energy Outlook (WEO) studies developed by the International Energy Agency (IEA, 2016; 2017; 2018), considering the detailed regions in the OURSE model (Z1 - North and Central America, Z2 - Latin America, Z3 - North Europe, Z4 - South Europe and Turkey, Z5 - Former Soviet Union (CIS), Z6 – Africa, Z7 - Middle East, Z8 – China and Z9 - Other Asia). For OURSE's Z2 (Latin America), premises about the evolution of final energy consumption in the Brazilian transportation sector of the study "Cenários de Demanda para o PNE 2050" published by the Empresa de Pesquisa Energética (EPE, 2018b) were also taken into account.

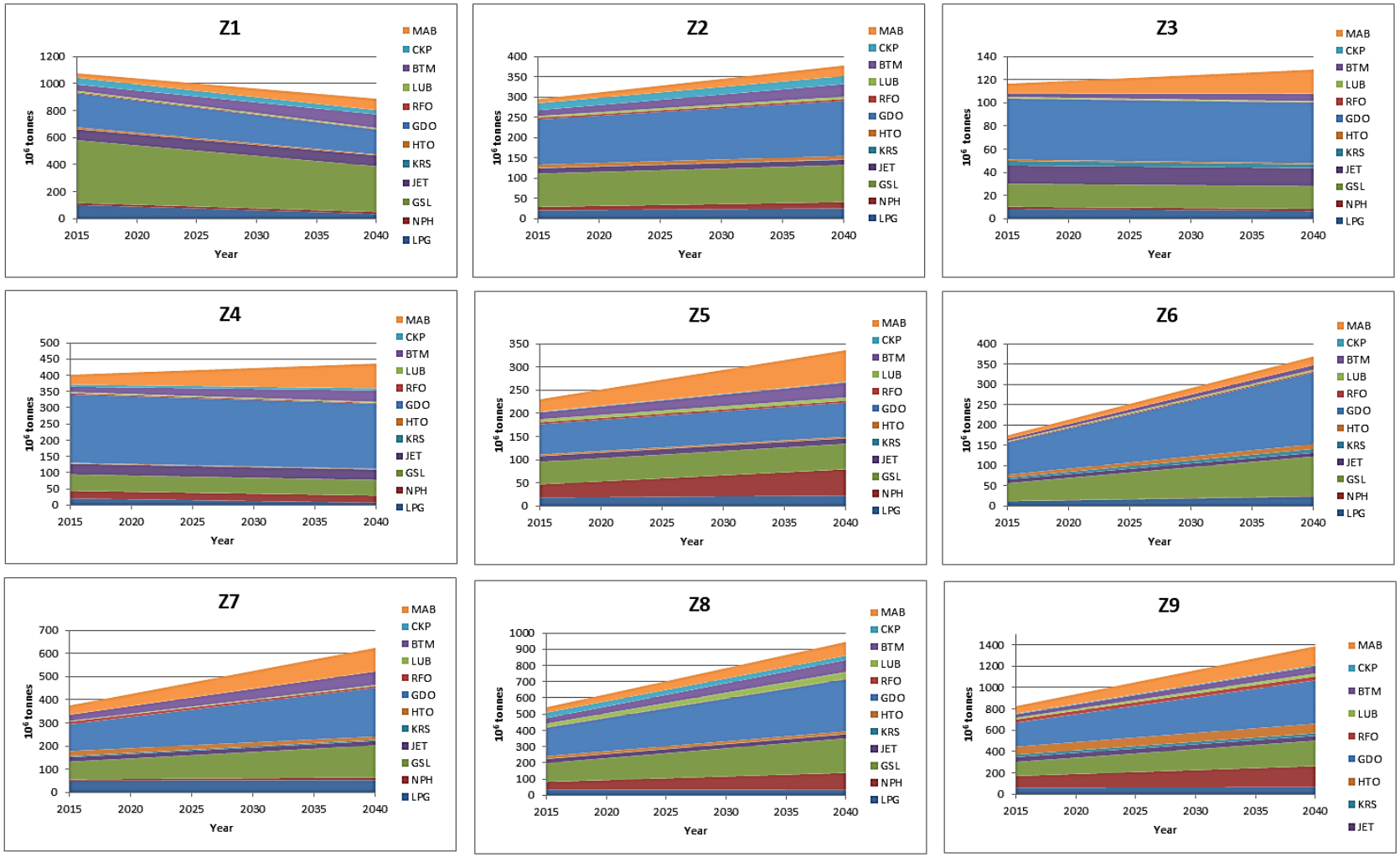
The scenarios were developed through the use of regional energy demand growth rates projections by sector published in the World Energy Outlook studies (WEO) (IEA, 2016; 2017; 2018). Since WEO does not present detailed projections by fuel (eg LPG, gasoline, diesel etc) but by "family" of fuel (eg oil, gas, biofuel etc), some assumptions were made so that the detailed projections could be constructed and applied in this study.

The oil derivatives considered in the OURSE model are LPG, naphtha, gasoline jet fuel oil, other kerosene, heating oil, diesel oil (gasoil), heavy fuel oil, lubricants, bitumen, petroleum coke and marine bunkers. The sectors of the WEO studies considered were industry, transports, buildings and petrochemical feedstocks. For jet fuel oil, marine bunkers and bitumen, no sectors were considered, since the WEO presents scenarios for these fuels specifically. Table 4-21 presents the analogies made to develop the demand scenarios used in this study.

Table 4-21 – Analogies made with WEO and PNE 2050 database to create OURSE demand scenarios

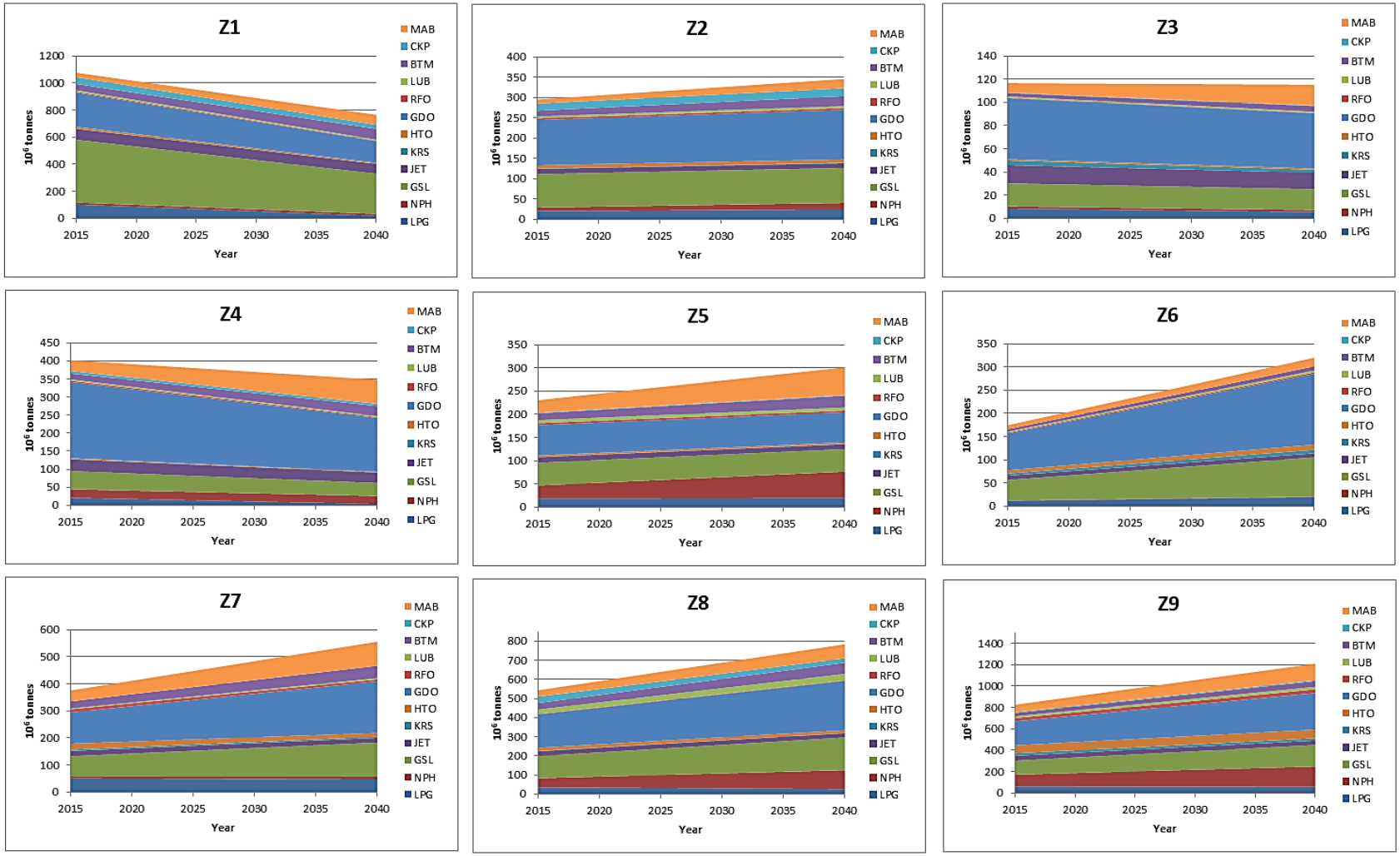
LPG	The demand grows as the demand for oil in the "buildings" sector
Gasoline and diesel	The demands grow as the demand foi oil in the "transports" sector/ For Zone 2 they grow according to the oil demand growth published in EPE (2017), considering the share between gasoline and diesel
Fuel oil and heating fuel oil	The demands grow as the demand for oil in the "industry" sector
Kerosene	The demand grows as the demand for oil in the "buildings" sector
Naphtha	The demand grows as the demand for "petrochemial feedstock"
Petroleum coke	The demand grows as the demand for coal in the "industry" sector
Jet fuel oil and marine bunkers	The demands grow as the demand for aviation fuel and marine bunkers
Bitumen	The demand grows as the demand for bitumen

Figure 4-1**,** Figure 4-2 and Figure 4-3 present the oil products demands projections, for each OURSE region, in each scenario performed. Tables showing the data considered in the construction of such graphs are in Annex II.



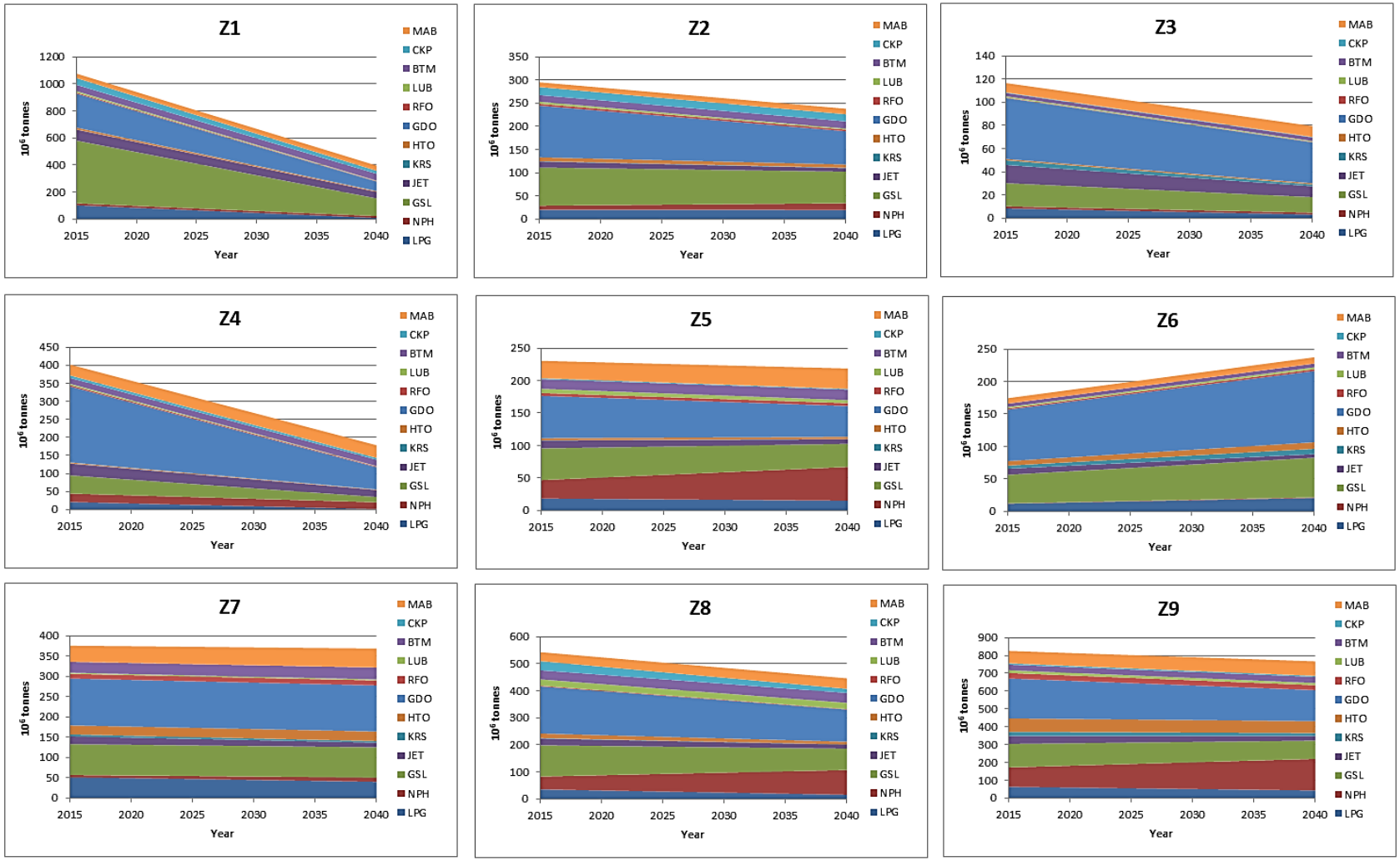
Z1 - North and Central America, Z2 - Latin America, Z3 - North Europe, Z4 - South Europe and Turkey, Z5 - Former Soviet Union (CIS), Z6 – Africa, Z7 - Middle East, Z8 – China, Z9 - Other Asia

Figure 4-1 - Oil products demands graphs - Shadow scenario - OURSE model



Z1 - North and Central America, Z2 - Latin America, Z3 - North Europe, Z4 - South Europe and Turkey, Z5 - Former Soviet Union (CIS), Z6 – Africa, Z7 - Middle East, Z8 – China, Z9 - Other Asia

Figure 4-2 - Oil products demands graphs - Cloudy scenario - OURSE model



Z1 - North and Central America, Z2 - Latin America, Z3 - North Europe, Z4 - South Europe and Turkey, Z5 - Former Soviet Union (CIS), Z6 – Africa, Z7 - Middle East, Z8 – China, Z9 - Other Asia

Figure 4-3 - Oil products demands graphs - Shiny scenario - OURSE model

4.1.1.2. ORION model

For the ORION model, the demand scenarios were also built based on the evolution of final energy consumption by sector of the scenarios “Current Policies”, “New Policies” and “Sustainable Development” of the World Energy Outlook (WEO) studies developed by the International Energy Agency (IEA, 2016; 2017; 2018) and, in gasoline’s and diesel’s cases premises about the evolution of final energy consumption in the Brazilian transportation sector of the study “Cenários de Demanda para o PNE 2050” published by the Empresa de Pesquisa Energética (EPE, 2018b) were also taken into account.

As for the OURSE model, the scenarios were developed through the use of regional energy demand growth rates projections by sector published in the World Energy Outlook studies (WEO) (IEA, 2016; 2017; 2018). Since WEO does not present detailed projections by fuel (eg LPG, gasoline, diesel etc) but by "family" of fuel (eg oil, gas, biofuel etc), some assumptions were made so that the detailed projections could be constructed and applied in this study.

The oil derivatives considered in the ORION model are LPG, naphtha, gasoline kerosene, diesel, jet fuel oil, fuel oil, heating fuel oil and petroleum coke. The sectors of the WEO studies considered were industry, transports, buildings and petrochemical feedstocks. For jet fuel oil no sectors were considered, since the WEO presents scenarios for this fuel specifically. present the analogies made to develop the demand scenarios used in this study.

Table 4-22 - Analogies made with WEO and PNE 2050 database to create ORION demand scenarios

LPG	The demand grows as the demand for oil in the "buildings" sector
Gasoline and diesel	The demands grow according to the oil demand growth published in EPE (2017), considering the share between gasoline and diesel
Fuel oil and heating fuel oil	The demands grow as the demand for oil in the "industry" sector
Kerosene	The demand grows as the demand for oil in the "buildings" sector
Naphtha	The demand grows as the demand for "petrochemial feedstock"
Petroleum coke	The demand grows as the demand for coal in the "industry" sector
Jet fuel oil	The demand grows as the demand for aviation fuel

Figure 4-4, Figure 4-5 and Figure 4-6 show the oil products demand projections considered in each scenario performed. The tables showing the data considered in the construction of such graphs are in Annex III.

Although the graphs and tables show the evolution of demand throughout Brazil, i.e., not being separated by region of the model, for modeling purposes the growth rates of demand were applied in each region, based on the demands (Table 4-6) for 2015 (period t0) previously presented. In this study such rates are the same for all regions, however, the ORION model has the ability, as mentioned, to apply different rates for each region considered.

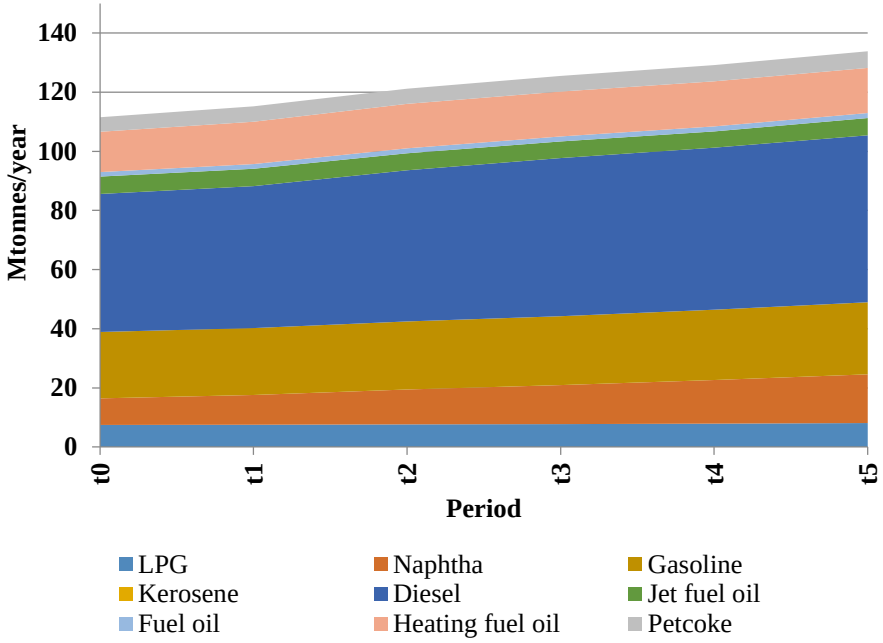


Figure 4-4 - Oil products demands - Shadow scenario

Source: Based on IEA (2016; 2017; 2018) and EPE (2018b)

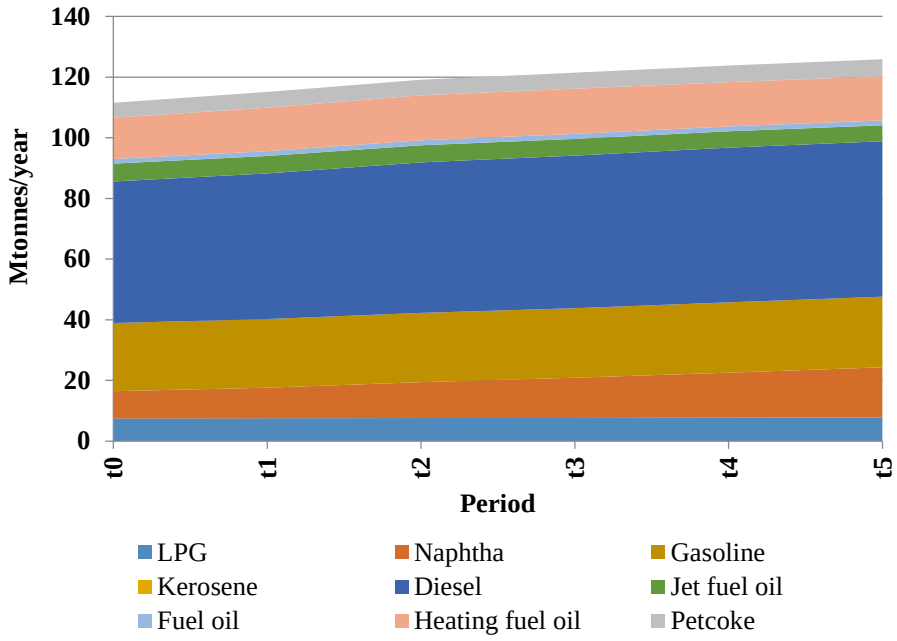


Figure 4-5 - Oil products demands - Cloudy scenario

Source: Based on IEA (2016; 2017; 2018) and EPE (2018b)

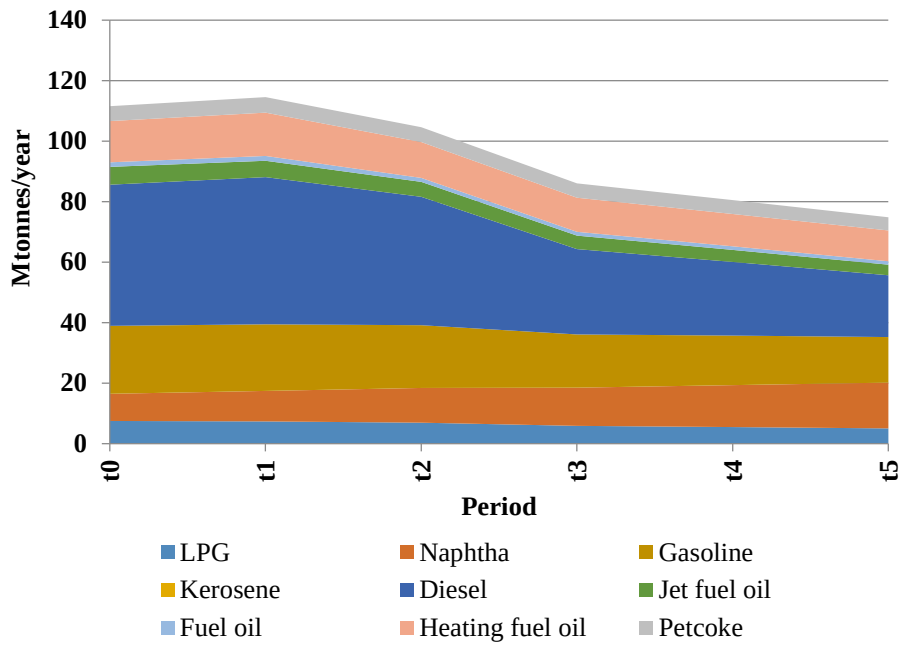


Figure 4-6 - Oil products demands - Shiny scenario

Source: Based on IEA (2016; 2017; 2018) and EPE (2018b)

As can be noticed, the Shadow scenario presents a demand growth to practically all products by t5 compared to t0. Thus, from a total product demand of 111.5 Mtonnes

in t0, a quantity of 133.2 Mton is reached in t5. This represents an overall growth of approximately 19%. Specifically for gasoline, diesel, fuel oil and petcoke, which are the most representative fuels in t0, the demand growths are of 8.5%, 21%, 7.7% and 14.5%, respectively. For naphtha, this growth is of 83%, passing from 9.0 Mtonnes in t0 to 16.5 Mtonnes in t5. For LPG the increase is of 8.5%, with demands of 7.5 Mtonnes in t0 and 8.1 in t5. Finally, the only product presenting a decrease is the jet fuel oil, with its demand reduced by approximately 1% by 2040 compared to t0. As this is a baseline scenario, it was already expected that the growth in products demand would be considerable.

The Cloudy scenario, while still showing growth in demand for almost all products, has a lower overall growth rate than the Shadow scenario, though not much. From a total product demand of 111.5 Mtonnes in t0, a quantity of 125.9 Mtonnes is reached in t5, with an overall growth of approximately 12.8%. The most significant differences from the Shadow scenario are in the growing demand per product, which are generally smaller. For instance, for LPG, gasoline, diesel, fuel oil and petcoke, the demand growths are respectively of 3.6%, 3.6%, 9.8%, 6.7% and 13.6%. However, in naphtha case the demand growth is a little higher than in the Shadow scenario, reaching about 84.7% between t0 and t5. Lastly, for jet fuel oil the downward trend continues, and even stronger than in the Shadow scenario, with a decrease rate of 10.7% in t5 compared to t0.

The third and most disruptive scenario, the Shiny, reacts completely differently from the previous two ones, as expected. The first difference is in the overall growth rate between t0 and t5. While the first two scenarios did not have much difference between their rates, the Shiny scenario presents a rate over 40% lower. Hence, from a total product demand of 111.5 Mtonnes in t0, a quantity of 76.6 Mtonnes is reached in t5, i.e. a decrease of 31.3%. The differences are even stronger when it comes to the product's analysis. In this case, almost all products demands decline between t0 and t5, with the exception of naphtha, which present an increase of 65,8%. LPG and gasoline show a decrease of 32.9%, diesel of 56.2%, jet fuel oil of 40.5%, fuel oil of 13.4%, and petcoke of 11.3%.

As mentioned earlier, for each demand scenario constructed the model is run both with a multi-regional as with a single-regional framework, and with two options of heavy fuel oil specifications in light of the IMO's regulations to reduce sulfur oxides (SOx) emissions from ships. This means, in terms of modeling, that the model will be

run considering Brazil as a single region, having a large fictional refinery, which is represented by the sum of capacity of all Brazilian refineries, being able to import and export from oversea regions, but having no trades internally; as well as a multi-regional country, considering the four regions previously presented (South, Northeast, Rio de Janeiro-Minas Gerais and São Paulo), where each one has a fictional refinery that is represented by the sum of capacity of the refineries present in the specified region, and which can trade with each other as well as import and export from/to oversea regions. Regarding the heavy fuel oil specification, two different maximum sulfur limits allowed in the heavy fuel oil pool are used, the first one of 3.5% and the second one of 0.5%, thus totaling four different runs for each of the built demand scenarios.

For each demand scenario presented, the ORION model is run both with a multi-regional as with a single-regional framework, in order to analyze, in each case, whether there is an advantage or not in having a regional model. In addition, for each case previously mentioned, two options of heavy fuel oil specifications were taken into account, in light of the IMO's regulations to reduce sulfur oxides (SOx) emissions from ships, as will be further explained. Thus, a total of twelve different results are obtained, four for each of the three scenarios mentioned above.

4.1.2. Oil products specification

4.1.2.1. IMO's specification

The IMO – the International Maritime Organization is a specialized agency of the United Nations responsible for the safety and security of shipping and the prevention of marine and atmospheric pollution by ships (IMO, 2019a). IMO's regulations to reduce sulfur oxides (SOx) emissions from ships first came into force in 2005, under the terms of IMO's MARPOL Annex VI of the International Convention for the Prevention of Pollution from Ships (IMO, 2019b) . At that time the maximum value for sulfur content of marine fuels used for vessels operating in Emission Control Areas (ECAs) was reduced from 1% weight basis to 0.1% weight basis. Since then, the limits on sulfur oxides have been progressively tightened (IMO, 2019b)

In 2016 the IMO announced it was going ahead with a global sulfur cap on marine fuels (PLATTS, 2016). From 1 January 2020, the limit for sulfur in fuel oil used on board ships operating outside ECAs will be reduced from 3.5% to 0.50% weight basis (Figure 4-7).

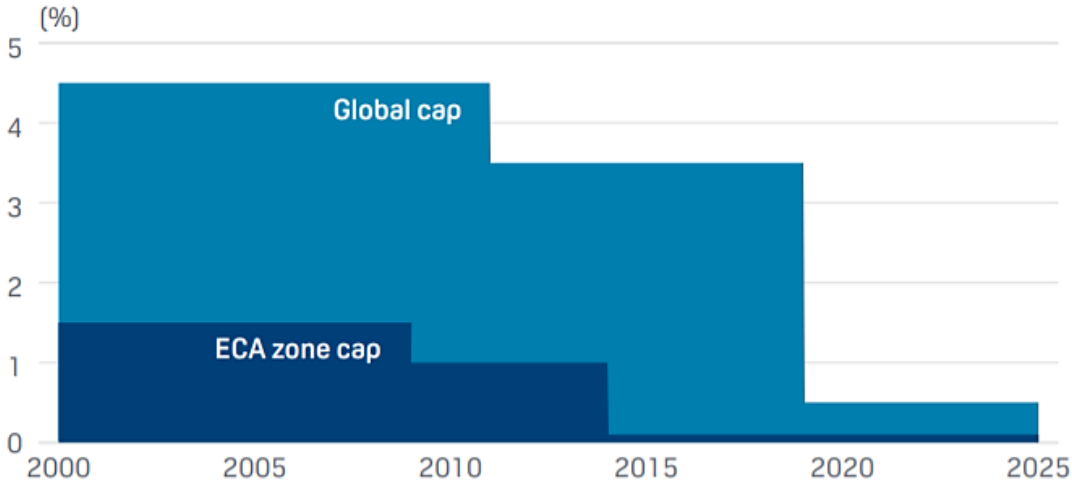


Figure 4-7 - MARPOL Annex VI sulfur limits

Source : IMO (2019a)

The IMO's decision will have an impact not only in the shipping sector, but also crude production, bunker suppliers and refineries. Moreover, it will positively affect the health of millions of people through reduced SOx and PM (particulate matter) emissions and a better air quality.

Shipping options comprise the use of exhaust gas cleaning systems, known as scrubbers, which will enable the continued use of high-sulfur bunker fuel from 2020, through the removal of sulfur and other unwanted chemicals by spraying alkaline water into a vessel's exhaust; the burning of LNG instead of heavy fuel oil (HFO); or simply the switch to burning ultra-low sulfur oil (ULSFO) (SEATRADE, 2017).

With regard to the oil refining sector, this new specification will undoubtedly have serious implications in terms of refinery configuration and operations. Simple refineries that produce a substantial share of their crude run into heavy fuel oil may face margins pressure, while complex refineries may potentially boost margins with a larger production of low-sulfur products (LIANG, 2018). Possible modifications consist of upgrading fuel oil residues to gasoil grades; reduction of residue production through changes to a sweeter crude slate; residue destruction, stopping the production of fuel oil; and desulfurization of residual fuel oil blends with low sulfur gasoils, through investments in new process units as hydrotreaters and hydrocrackers (PLATTS, 2016).

Moreover, these modifications, particularly the ones related to the use of low sulfur gasoils in marine fuel blends might well affect the international prices of

distillates, by increasing their demand, and indirectly influence the operation of refineries that aim to maximize the production of diesel and jet fuel.

4.1.2.2. Road liquid fuels

The implementation of increasingly stringent road liquid fuel specifications has been taking place in recent years in many countries. Motivated by the reduction of pollutant emissions, it results in the continuous improvement of fuel quality by reviewing various parameters of the specifications, with emphasis on the sulfur content (BONFÁ,2011).

In Brazil, the organ responsible for establishing and inspecting fuel quality is the ANP – Agência Nacional do Petróleo, Gás Natural e Biocombustíveis. The establishment of fuel specifications differ according to the fuel, being gasoline and diesel the main road liquid fuels in the country, as well as are modified according to legislative requirements. Regarding the inspection, it is supported by the Fuel Quality Monitoring Program, established in 1998 with the objective of providing fuel compliance indicators to the specifications established by the ANP, thus acting as an element for inducing quality assurance actions by companies or market institutions, and guiding the inspection actions of the ANP itself (ANP, 2018b).

The gasoline types sold in the country are gasoline A, without ethanol, sold by gasoline producers and importers, and gasoline C, with the addition of anhydrous fuel ethanol by the distributors, sold to the dealer and then to the final consumer (ANP, 2019a). Since 2015, the mandatory percentage of anhydrous fuel ethanol addition to gasoline, established by the CIMA - Conselho Interministerial do Açúcar e do Álcool, is 27% in Regular gasoline C, and 25% in Premium gasoline C (BRASIL, 2015). With respect to the maximum sulfur content allowed, it has been modified four times since 1998, with 2014 being the last date, when a maximum content of 1200 mg/kg (or ppm) was set for gasoline A and 50 mg/kg (or ppm) for gasoline C (ANP, 2019a). In addition to the sulfur content, gasoline in Brazil is also specified by its octane number, expressed in Anti-Knock Index (AKI) through the MON (Motor octane number) or Motor - ASTM D270 method, which evaluates the resistance of gasoline to detonation when the engine is at full load and at high rotation. The minimum octane number is 87 units measured by the AKI for Regular gasoline C, and 91 units for Premium gasoline C (PETROBRAS, 2019b).

With regard to diesel, since the creation of the National Program of Production and Use of Biodiesel (PNPB) in 2004, the addition of biodiesel to diesel came into force (MELO, 2018). Between 2005 and 2007, the addition of 2% was voluntary. The obligation came in 2008, with the same 2% (B2), throughout the national territory. With the maturation of the Brazilian market, this percentage was successively expanded by the CNPE – Conselho Nacional de Política Energética to the current percentage of 11.0%[21] (ANP, 2019b). Considering the maximum sulfur content, the ANP regulation has been encouraging over the years its gradual decrease. Currently, for road use, diesel types S10 (10 mg/kg or 10 ppm), suitable for the new emission control technologies of new diesel engines manufactured from 2012, and S500 (500 mg/kg or 500 ppm), proper for the huge fleet of diesel vehicles manufactured before January 1, 2012, are in force (PETROBRAS, 2019c). Besides the sulfur content, cetane number is also a key parameter to ensure better diesel engine performance. It is related to the time between fuel injection and the start of combustion. The lower the cetane number, the shorter the ignition delay and the better the combustion quality (ANP, 2019d). Currently, the minimum cetane number set for S-10 diesel is 48 and for S-500 diesel is 42 (PETROBRAS, 2019c).

Although not considered directly in the model developed by the present study, it is important to highlight the existing national specifications for ethanol, which can be found in the Brazilian market in two ways: as anhydrous ethanol, being a mixture component in the formation of gasoline C; or as hydrous ethanol, marketed nationwide as a finished fuel, which may be a substitute for gasoline, as it can be used on the same engine type (otto cycle) (ANP, 2019e). The main specifications for this fuel are related to the ethanol content, which should be at least 98% (v/v) for anhydrous ethanol and 94.5% (v/v) for hydrous ethanol; the alcoholic strength of at least 99.3% (m/m) for anhydrous ethanol, and between 92.5% and 94.5% (m/m) for hydrous ethanol; the water content, which should be a maximum of 0.7% (m/m) for anhydrous ethanol and 7.5% (m/m) for hydrous ethanol; and the methanol content of maximum 0.5% (v/v) for both ethanol types (BRASIL, 2018).

For model simulation purposes, road liquid fuels (gasoline and diesel) specifications had their values considered in the base period (Products Specifications

[21] Since September 2019, the minimum percentage of biodiesel to be added to diesel sold in the country has increased from 10% to 11% (ANP, 2019c).

section) maintained during the analysis horizon. The same applies to jet fuel oil, although it is not a road liquid fuel.

4.1.3. Crude oil price scenario

This section describes the crude oil price scenario considered for all scenarios analyzed. As formerly presented, the prices for each type of crude blend represented by the model are defined according to a reference price. In the present study, the reference price relates to Brent. For the base year (period t0), as previously shown, the reference price is based on ARGUS (2018), and consists of a FOB (Free on board) price in 2015 of 53.46 US$/bbl. For the projection periods (t1 to t5), the reference price was calculated based on IEA oil prices scenarios (IEA, 2016; 2018), more specifically on oil prices growths.

Table 4-23 - Reference crude oil FOB price scenario

FOB price (US$/bbl)					
t0	**t1**	**t2**	**t3**	**t4**	**t5**
53.46	82.81	92.24	100.63	110.06	117.40

Source: Based on IEA (2016; 2018)

Regarding the prices of fuel (utilities consumption), refining costs, freight prices, harbors expansions prices, as well as CO_2 emissions factors they have constant values throughout the time horizon, based on the values presented in the Case study section. In this context, it is important to reinforce that coupling the ORION model to an IAM could improve such assumptions by varying them over time (which is what actually happens) since IAMs typically have in-depth detail of values such as fuel prices, technology costs and greenhouse gas (GHG) emission factors.

The following chapter describes the results obtained with the ORION model simulations.

5. Results

This chapter comprises the presentation and analysis of the results obtained with the model´s simulations performed in this study. It is worth noting that these results are not forecasts, but rather projections of the possible pathways the Brazilian oil refining sector might follow, in view of the assumptions adopted. First, the results of the OURSE model are presented, that is, the marginal values of oil products in Z2 – Latin America, for each scenario previously described, and the oil products imports and exports of the Z2[22]. Then, the ORION model results by scenario are detailed in terms of set of investments in additional units, operating capacities levels, crude oil consumption, imports, exports and national trades of petroleum products, flows between processing units, processing units utilities consumption, and total CO_2 emissions.

5.1. OURSE model results – Marginal values and oil products imports and exports of Z2 - Latin America

The results of the OURSE model include the marginal values of oil products between 2015 and 2040, the correspondent growth rates between periods, the final price values to be considered for each period of the ORION model and the oil products imports and exports of (and from) Z2 (Latin America).

The marginal values (slack variables of the dual problem) are associated to the variables of the primal problem, as previously explained in Chapter 3. Thus, it is always important to pay attention to the dual values associated to the saturated constraints of a problem, especially to the dual values of the demand equations. Nevertheless, these values can be difficult to interpret when they are associated to products in small quantity as can be seen from the results obtained in the present study.

[22] The results concerning the imports and exports of the Z2 – Latin America are detailed in order to verify the consistency of the results obtained in the national model ORION with trade between regions as obtained in the world model OURSE.

5.1.1. Marginal Values

5.1.1.1. Shadow scenario

The marginal values obtained for the Shadow scenario are presented in Table 5-1.

Table 5-1 - Marginal values OURSE model - Shadow scenario

Marginal values (USD/t)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	669	800	800	800	800	800
Naphtha	466	530	754	816	861	875
Gasoline	505	569	826	875	893	901
Kerosene	478	521	675	739	816	879
Diesel	455	515	754	838	956	1035
Jet fuel oil	478	521	675	739	816	879
Fuel oil	343	412	611	664	736	784
Heating fuel oil	444	488	723	809	930	1008
Petcoke	300	300	300	774	871	961

The marginal values for LPG and petcoke exhibit abnormal behaviors. In the case of LPG, it remains constant from 2020, and in the case of petcoke it shows a high growth between the periods of 2025 and 2030. This can be explained by two factors. The first concerns exactly what was already mentioned before, ie it is difficult to interpret the marginal values when they are associated to products in small quantity, as LPG and petcoke when compared to other oil produtcs. The second involves the characterization of such products in the OURSE model. Prices included in the OURSE model for both LPG and petcoke are fixed throughout the model analysis horizon, and based on supplies from other sectors. In the case of LPG its price is fixed according to natural gas prices, and in the case of petcoke, its prices are based on Tar Sands from Canada. Thus, their values were disregarded for the calculation of growth rates. In turn, in ORION it was considered that the LPG and petcoke international price evolution would follow gasoline's and fuel oil's marginal values growth tendencies.

In addition, it is important to note the high growth in fuel oil and diesel values during the period of analysis, of respectively 127% and 128% in 2040 compared to 2015. This can be explained by a higher fuel oil specification, since OURSE takes into account the IMO specification of 0.5% sulfur content from 2020 for marine bunker fuel, and also by a stringent specification for diesel. Another reason for that could be the switch of use of some intermediate streams to produce diesel, as well as marine

bunkers. Consequently, the fuel oil is obtained by using also some intermediate compounds, which have become more expensive.

Finally, such results reflect the demand scenarios applied to the model, thus, possible large increases or decreases can be understood as a consequence of the demand evolutions considered. Table 5-2 presents the calculated marginal values growth rates for the Shadow scenario. Table 5-3 and Figure 5-1 both present the evolution of oil products' prices to be considered in the ORION model.

Table 5-2 - Calculated marginal values growth rates - Shadow scenario

Growth rates (%)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	-	13%	64%	73%	77%	79%
Naphtha	-	14%	62%	75%	85%	88%
Gasoline	-	13%	64%	73%	77%	79%
Kerosene	-	9%	41%	55%	71%	84%
Diesel	-	13%	66%	84%	110%	127%
Jet fuel oil	-	9%	41%	55%	71%	84%
Fuel oil	-	20%	78%	93%	114%	128%
Heating fuel oil	-	10%	63%	82%	109%	127%
Petcoke	-	20%	78%	93%	114%	128%

Table 5-3 - Oil products' prices to be considered in the ORION model - Shadow scenario

Oil products' prices (USD/t)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	215	242	352	372	380	383
Naphtha	452	513	731	791	835	848
Gasoline	529	596	866	916	935	944
Kerosene	507	553	716	784	866	933
Diesel	493	558	817	909	1037	1123
Jet fuel oil	507	553	716	784	866	933
Fuel oil	431	517	768	834	924	985
Heating fuel oil	431	473	702	785	902	978
Petcoke	56	67	100	108	120	128

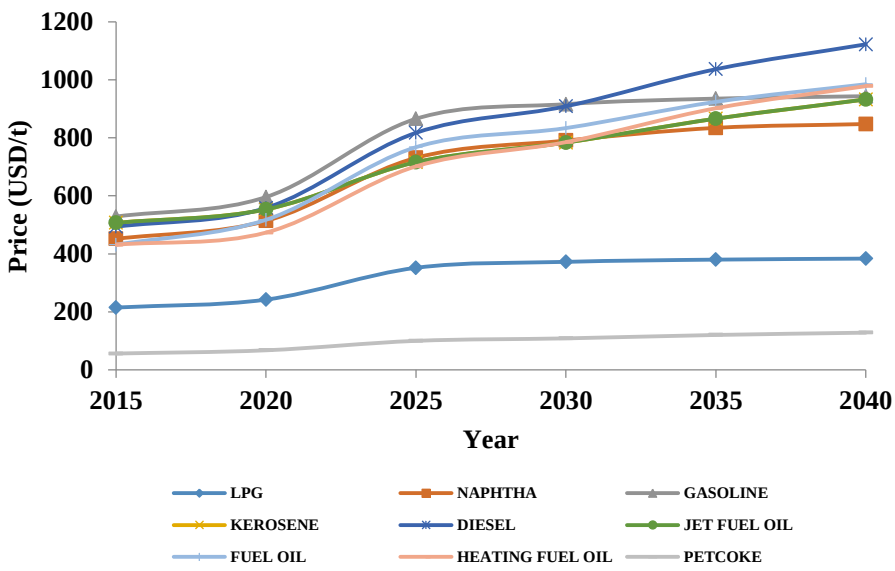


Figure 5-1 - Oil products prices - Shadow scenario

5.1.1.2. Cloudy scenario

The marginal values obtained for the Cloudy scenario are presented in Table 5-4.

Table 5-4 - Marginal values OURSE model - Cloudy scenario

Marginal values (USD/t)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	669	800	800	800	800	800
Naphtha	466	531	752	814	858	872
Gasoline	505	566	821	874	891	899
Kerosene	478	519	663	712	802	844
Diesel	455	510	741	806	927	985
Jet fuel oil	478	519	663	712	802	844
Fuel oil	343	408	605	655	722	760
Heating fuel oil	444	484	710	777	897	955
Petcoke	300	300	300	460	867	955

As in the Shadow scenario case, the marginal values for LPG and petcoke exhibit abnormal behaviors. Again, in the case of LPG it remains constant, and in the case of petcoke it shows a high growth between the periods of 2025 and 2030. As already pinpointed, this can be explained by the same two factors as before. Thus, these values were again disregarded for the calculation of growth rates. Once more, it was considered that for LPG the growth follows gasoline's marginal values growth tendency, and for petcoke, the growth follows fuel oil's growth tendency.

Also, although smaller than in the Shadow scenario, the results show a high growth in fuel oil and diesel values during the period of analysis, of 121% and 116% respectively. Again, it can be explained by a higher fuel specification, and also by a switch of use of some intermediate streams, which can be more expensive, to produce the final products. Nevertheless, the overall growth is lower than in the case of the Shadow scenario, which is a consequence of the scenario demand that, although not so far from the Shadow scenario, already present some reduction in demand for most oil derivatives.

Table 5-5 presents the calculated marginal values growth rates for the Cloudy scenario. Table 5-6 and Figure 5-2 both present the evolution of oil products' prices to be considered in the ORION model.

Table 5-5 - Calculated marginal values growth rates - Cloudy scenario

Growth rates (%)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	-	12%	63%	73%	77%	78%
Naphtha	-	14%	61%	75%	84%	87%
Gasoline	-	12%	63%	73%	77%	78%
Kerosene	-	9%	39%	49%	68%	77%
Diesel	-	12%	63%	77%	104%	116%
Jet fuel oil	-	9%	39%	49%	68%	77%
Fuel oil	-	19%	76%	91%	110%	121%
Heating fuel oil	-	9%	60%	75%	102%	115%
Petcoke	-	19%	76%	91%	110%	121%

Table 5-6 - Oil products' prices to be considered in the ORION model - Cloudy scenario

Oil products' prices (USD/t)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	215	241	350	372	379	382
Naphtha	452	515	729	789	831	845
Gasoline	529	593	860	916	934	941
Kerosene	507	551	703	755	851	895
Diesel	493	553	804	874	1005	1068
Jet fuel oil	507	551	703	755	851	895
Fuel oil	431	512	760	823	907	955
Heating fuel oil	431	470	689	754	871	927
Petcoke	56	67	99	107	118	124

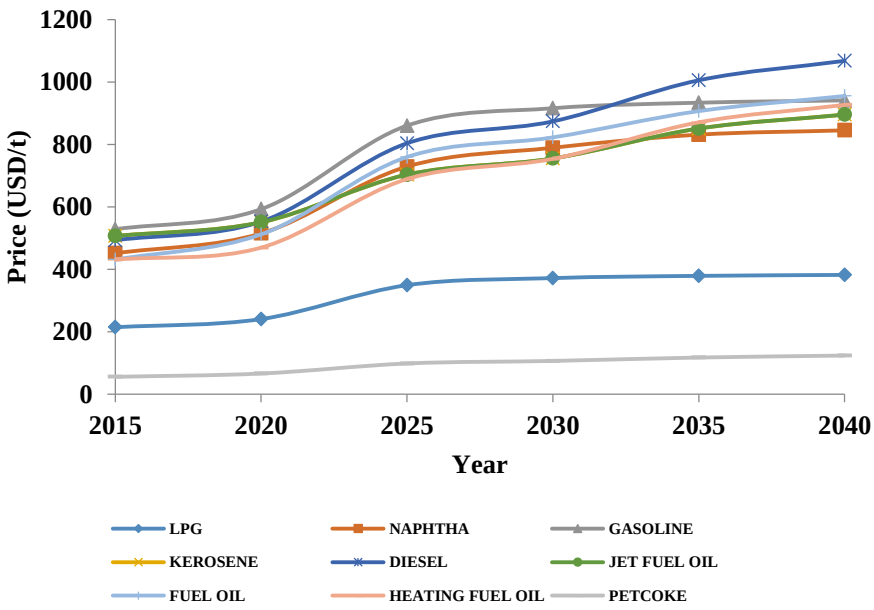


Figure 5-2 - Oil products prices - Cloudy scenario

5.1.1.3. Shiny scenario

The marginal values obtained for the Shiny scenario are presented in Table 5-7.

Table 5-7 - Marginal values OURSE model - Shiny scenario

Marginal values (USD/t)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	669	800	800	800	800	800
Naphtha	465	519	752	794	834	916
Gasoline	504	559	827	864	889	905
Kerosene	477	507	619	653	689	701
Diesel	455	499	686	722	773	780
Jet fuel oil	477	507	619	653	689	701
Fuel oil	343	399	593	634	687	698
Heating fuel oil	444	472	657	697	747	756
Petcoke	300	300	300	300	300	300

As in the Shadow and Cloudy scenarios cases, the marginal values for LPG and petcoke exhibit abnormal behaviors. Again, in the case of LPG it remains constant, and in the case of petcoke it shows a high growth between the periods of 2025 and 2030. As before, these values were again disregarded for the calculation of growth rates and the same assumptions were considered for estimation their growth rates.

Also, as for the previous scenarios the results show a high growth – but considerably smaller than in the two preceding cases, which is a consequence of the demand scenario considered, that, in this case presents a huge reduction in demand for

most oil derivatives. Specifically for fuel oil and diesel, the marginal values show a growth of, respectively, 103% and 71%.

Table 5-8 presents the calculated marginal values growth rates for the Cloudy scenario. Table 5-9 and Figure 5-3 both present the evolution of oil products' prices to be considered in the ORION model.

Table 5-8 - Calculated marginal values growth rates - Shiny scenario

Growth rates (%)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	-	11%	64%	71%	76%	79%
Naphtha	-	11%	61%	70%	79%	97%
Gasoline	-	11%	64%	71%	76%	79%
Kerosene	-	6%	30%	37%	44%	47%
Diesel	-	10%	51%	59%	70%	71%
Jet fuel oil	-	6%	30%	37%	44%	47%
Fuel oil	-	16%	73%	85%	100%	103%
Heating fuel oil	-	6%	48%	57%	68%	70%
Petcoke	-	16%	73%	85%	100%	103%

Table 5-9 - Oil products' prices to be considered in the ORION model - Shiny scenario

Oil products' prices (USD/t)						
Product	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
LPG	215	238	352	368	378	385
Naphtha	452	503	729	770	809	888
Gasoline	529	586	866	905	931	947
Kerosene	507	538	657	693	731	743
Diesel	493	541	744	783	839	846
Jet fuel oil	507	538	657	693	731	743
Fuel oil	431	501	745	797	864	877
Heating fuel oil	431	458	638	677	725	734
Petcoke	56	65	97	104	112	114

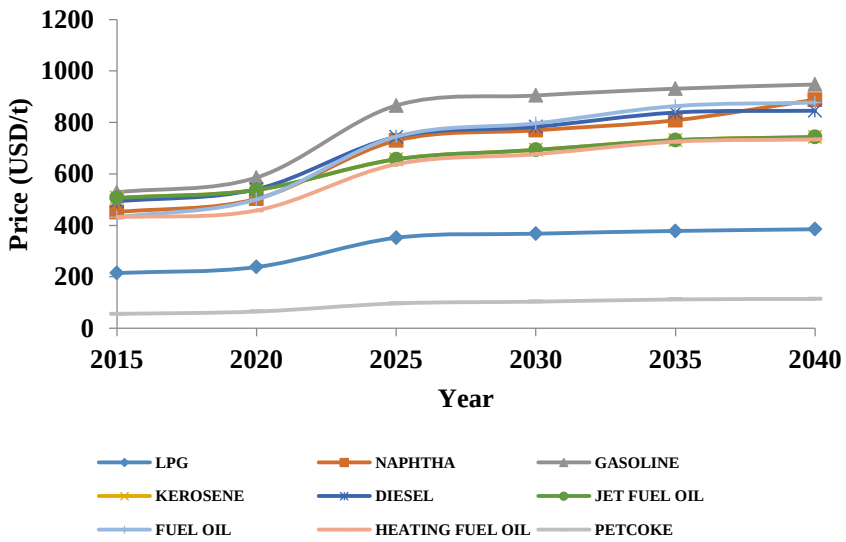


Figure 5-3 - Oil products prices - Shiny scenario

5.1.2. Oil products imports and exports of Z2 – Latin America

This section presents the results of imports and exports of oil products of Z2, for each of the scenarios considered (Shadow, Cloudy and Shiny), between 2015 and 2040 (see Table 5-10). At the end of Chapter 5, in the Discussion section, these figures are compared to the results obtained in the ORION model for fuel imports to (and exports from) Brazil, to check the consistency of the proposed nested optimization. Since Brazil represents approximately 50% of Z2 in terms of oil products trades in the OURSE model, it is assumed that imports and exports flows for Brazil should be capped by this limit.

Table 5-10 - Oil products imports and exports of OURSE's Z2 - Latin America

Mtonnes/year	2015	2020	2025	2030	2035	2040
	Shadow					
Imports	23.67	27.75	32.15	36.20	39.83	43.47
Exports	3.81	13.96	8.82	4.64	20.10	35.24
Total	**27.48**	**41.71**	**40.97**	**40.84**	**59.93**	**78.71**
	Cloudy					
Imports	23.67	26.39	29.02	31.82	33.99	36.17
Exports	3.81	17.75	16.47	2.77	22.44	18.26
Total	**27.48**	**44.14**	**45.50**	**34.59**	**56.43**	**54.43**
	Shiny					
Imports	23.67	22.98	22.31	21.95	26.68	28.85
Exports	3.81	8.49	10.12	15.07	24.50	20.33
Total	**27.48**	**31.47**	**32.43**	**37.02**	**51.18**	**49.18**

In 2015, the total flows of Z2, in all scenarios, are of 27.48 Mtonnes/year, being 23.67 Mtonnes/year of imports and 3.81 Mtonnes/year of exports. Considering that Brazil represents 50% of the Z2 in the OURSE model, its total flow would be about 13.7 Mtonnes/year, being 11.8 Mtonnes/year of imports and 1.9 Mtonnes/year of exports.

Total imports and exports growth between 2015 and 2040 reached 186% or 51.2 Mtonnes/year for the Shadow scenario; 98% or 26.9 Mtonnes/year for the Cloudy scenario; and 79% or 21.7 Mtonnes/year for the Shiny scenario. In addition, it is worth noticing that exports gain space in the total international flow over time. While in 2015 they represent about 14% of total Z2' international flows, in 2040 they are almost 45% for the Shadow scenario, 34% for the Cloudy scenario, and 41% for the Shiny scenario.

The next section presents the ORION model results.

5.2. ORION model results

Following the methodology procedure of this study (Figure 3-2), using the results of marginal values for oil derivatives obtained from the OURSE model, the Shadow, Cloudy and Shiny scenarios were run in the ORION model, according to the step-by-step presented by Figure 3-1. The results obtained in the ORION model consist of crude oil consumption by type of crude and by campaign available in the model, oil derivatives production, oil derivatives imports and exports, oil derivatives national trades (for the multi-regional cases), capacity levels of processing units, utilities consumption, CO_2 emissions, costs - refining processing costs (crude oil purchase cost, fuel purchase cost, O&M costs, imports costs) and investments costs (refining and harbors expansions costs) - and exports revenues. For the runs of the multi-regional scenarios, all these results were also obtained by region of the model.

5.2.1. Shadow scenarios

The Shadow scenario is run for the four cases presented in Figure 3-1, that is the multi-regional case without (Shadow 1) and with (Shadow 1A) heavy fuel oil specifications from t1, in light of the IMO's regulations to reduce sulfur oxides (SOx)

emissions from ships fuel, and the single-regional case without (Shadow 2) and with (Shadow 2A) the heavy fuel oil specification.

Crude oil consumption

The results for crude oil consumption are presented, firstly by type of crude oil (crude 1, crude 2, crude 3) and campaign (diesel – crude 1d, crude 2d, crude 3d; naphtha – crude 1n, crude 2n, crude 3n) in each period of time (t0, t1, t2, t3, t4 and t5). Then, for the Shadow 1 and Shadow 1A scenarios, which are multi-regional cases, the results of crude oil consumption are presented by type of crude oil (crude 1, crude 2, crude 3), campaign (diesel and naphtha) and region of the model (S_S, NE_S, RJMG_S, SP_S).

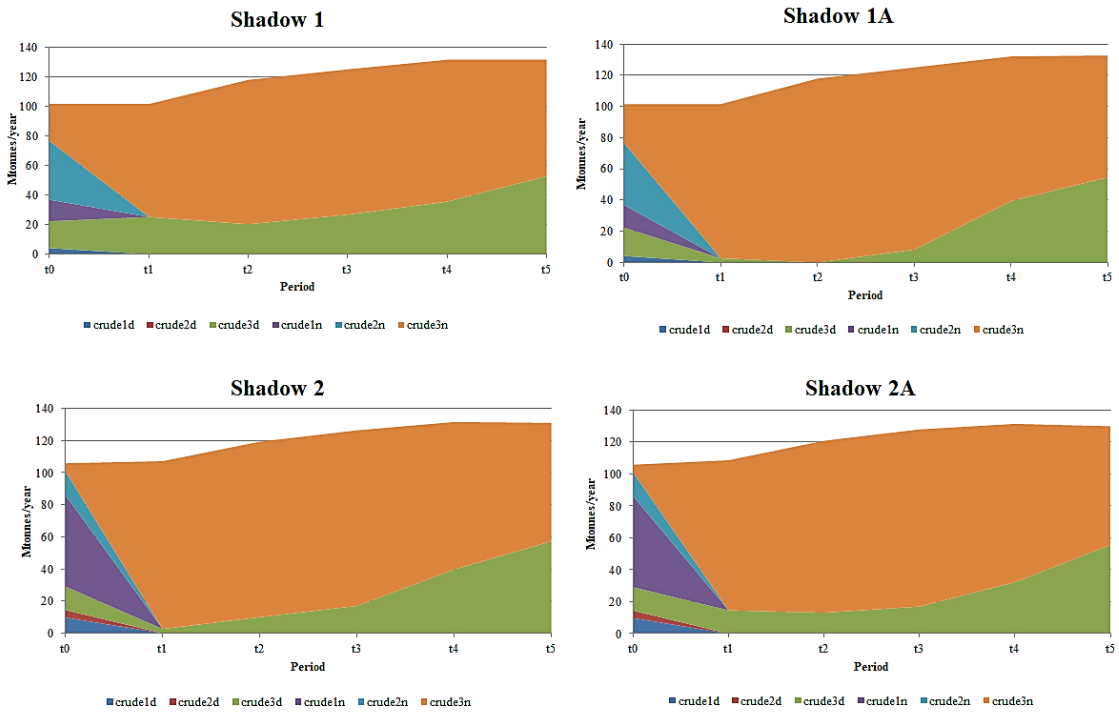


Figure 5-4 - Crude oil consumption by type of crude oil and campaign - Shadow scenarios

From Figure 5-4 it is possible to note that the consumption of crude oil grows over the time horizon, in all scenarios, which naturally derives from the demand scenario considered (the demand growths for all oil derivatives). This is also part of the ORION model response, that consisted, as will be shown later, on the increase of the refining capacity operation, either through greater utilization of the existing refining processing units capacities, or through investments in additional greenfield capacities. At t0, the total crude oil consumption reaches 101.7 Mtonnes/year for Shadow 1 and

Shadow 1A scenarios, and of 105.9 Mtonnes/year for Shadow 2 and Shadow 2A scenarios. At t5, Shadow 1 presents a total consumption of 131.6 Mtonnes/year, Shadow 1A of 132.8 Mtonnes/year, Shadow 2 of 129.2 Mtonnes/year and Shadow 2A of 131.0 Mtonnes/year, which represent respectives growths of 29.5%, 30.7%, 22.7% and 23.7%.

As can be seen, the total consumption of crude oil at t0 is higher in the Shadow 2 and Shadow 2A scenarios. This may be influenced by their single-regional structure, requires the processing of more crude oil to meet the national oil derivatives demand. However, at t4 and t5 their total crude oil consumption is lower than those of Shadow 1 and Shadow 1A. This is a consequence of the lower investments in additional atmospheric distillation units[23] capacities in Shadow 2 and Shadow 2A, as will be shown later.

Regarding the crude oil consumption profile, in all cases, from t1 onwards, the model's results indicate the preference towards crude 3, with naphtha and diesel campaigns. The results are in line with expectations, since crude 3 is the cheapest option for the model, as it is an oil produced in the national territory, which theoretically has a lower price, given its characteristics (lower °API, higher density, medium sulfur content), than the other two crudes, as well as a lower freight cost. Moreover, as will be shown, the refining production profile in all scenarios is aimed at medium/heavy distillates, further justifying its use, and also the use of a diesel campaign. In addition, given that there is a growth in gasoline production, it can be justified the use of naphtha campaign, which has higher yields in light distillates, compared to the diesel campaign - but still has most of its production destinated to medium/heavy products. The choice for crude 3 is in line with the increasing consumption trend, in the last years, of domestic crude oil by Brazilian refineries, as published by ANP (2018b) (Figure 2-4).

Also, at period t0 the Shadow 1 and Shadow 1A scenarios show, in addition to the consumption of crude 3 with naphtha and diesel campaigns, the consumption of crude 1 with naphtha and diesel campaigns, and crude 2 with naphtha campaign; and Shadow 2 and Shadow 2A scenarios present the consumption of crude 1 and 2, both with naphtha and diesel campaigns. This result demonstrates a good model calibration capability, in all scenarios, and a good optimizing capability, since, despite choosing to

[23] The total crude oil consumption refers exactly to the level capacity of the atmospheric distillation unit (CAPADU), the primary unit within a refinery, which fractionates the crudes into different cuts.

use only crude 3 from t1, it identifies different possibilities of crudes and campaigns in the base year, fitting quite well real Brazilian data.

Concerning the differences between Shadow 1 and Shadow 1A, and Shadow 2 and Shadow 2A, by the application of a lower sulfur content for fuel oil in "A" scenarios, Shadow 1 and Shadow 2 scenarios have a higher presence of crude 3 with diesel campaign than the Shadow 1A and 2A, which may be influenced by the level of fuel oil production. As Shadow 1A and Shadow 2A scenarios show a lower fuel oil production from t1 than Shadow 1 and Shadow 2, respectively, their total crude oil consumption have lower quantities of crude 3 with diesel campaign, which, as already explained, is more focused on medium/heavy distillates than the naphtha campaign.

Figure 5-5 and Figure 5-6 present the crude oil consumption per type of crude, campaign and per region of the model for Shadow 1 and Shadow 1A (multi-regional scenarios).

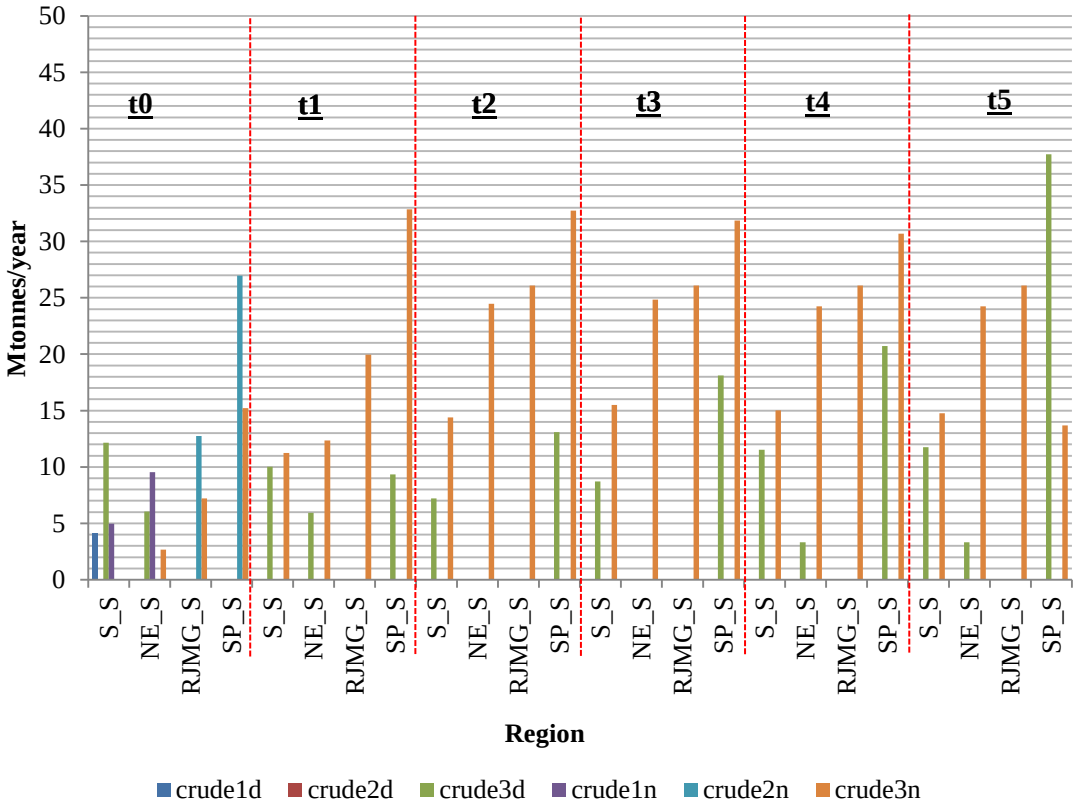


Figure 5-5 - Crude oil consumption by type of crude oil, campaign and region - Shadow 1

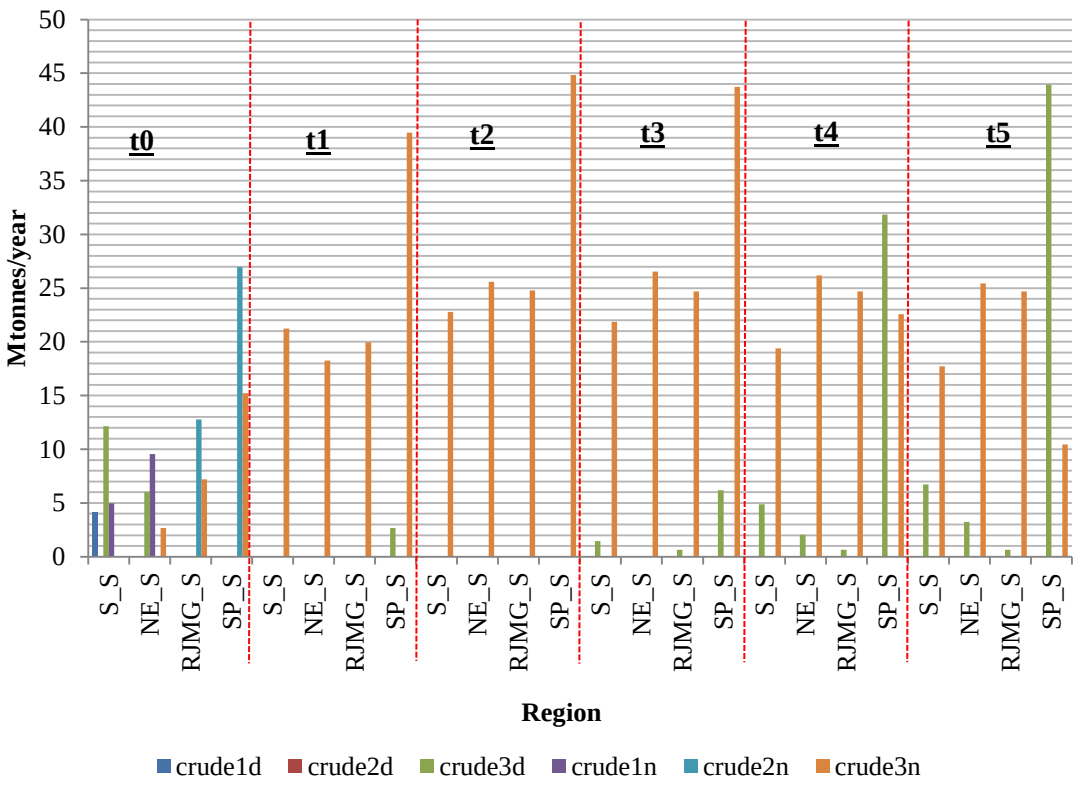


Figure 5-6 - Crude oil consumption by type of crude oil, campaign and region - Shadow 1A

In both scenarios the region with the highest oil consumption is the SP_S region, which makes sense due to its higher refining capacity among all regions, as will be presented in Processing units capacities section. After SP_S region, at t0 and t1, the second most oil-consuming region is the S_S region, and, from t2 ownwards NE_S becomes the second most oil-consuming region. Although S_S region has lower refinig capacity than NE_S region, as will be presented, as well as lower demand for derivatives, it receives fewer trades from other regions than NE_S region, at periods t0 and t1, as will be shown in the National Trades section, which ultimately forces higher production of derivatives and a consequent higher consumption of crude oil in this region.

Concerning the types of crudes and campaigns in each region, both scenarios present the same profile consumption at t0, ie, S_S region shows a consumption of crude 1 with naphtha and diesel campaigns, and of crude 3 with diesel campaign; NE_S region have a consumption of crude 1 with naphtha campaign, and crude 3 with diesel and naphtha campaigns; RJMG_S region presents a consumption of crude 2 and 3 with naphtha campaign; and SP_S region shows a huge consumption of crude 2 with naphtha campaign, and also a consumption of crude 3 with naphtha campaign. These results are

a consequence of the scenario of demand for derivatives by region, and are related to results of production of derivatives by region, national trades and imports/exports by region. As an example, the demand for naphtha, gasoline and LPG is higher in NE_S region than in other regions, which leads to higher consumption of crude 1 (light crude oil) with naphtha campaign at t0 in this region. On the other hand SP_S region presents a higher demand for diesel, jet fuel and fuel oil than other regions, and the second largest demand for light derivatives (LPG, naphtha and gasoline), which justifies the use of crude 3 with diesel campaign (focused on the production of medium/heavy distillates), and also the use of crude 2 with naphtha campaign (medium crude oil, but with a campaign geared towards light/medium distillates).

Finally, in both scenarios, from period t1 onwards, all regions (except for SP_S region at t4 in Shadow 1, and at t4 and t5 in Shadow 1A) have higher consumption of crude 3 with naphtha campaign, but also some consumption of crude 3 with diesel campaign, which balances the production of light, medium and heavy oil derivatives. A basic message here is that the regionalized model better used the possibilities to optimize its output, through different campains and crudes consumption among regions, for the same period of time.

The following section presents the oil derivatives production for the Shadow scenarios.

Oil derivatives production

The results for each Shadow scenario concerning their oil derivatives production by time period are presented below. For the Shadow 1 and Shadow 1A scenarios, which are multi-regional cases, the results are also presented by region of the model (S_S, NE_S, RJMG_S, SP_S).

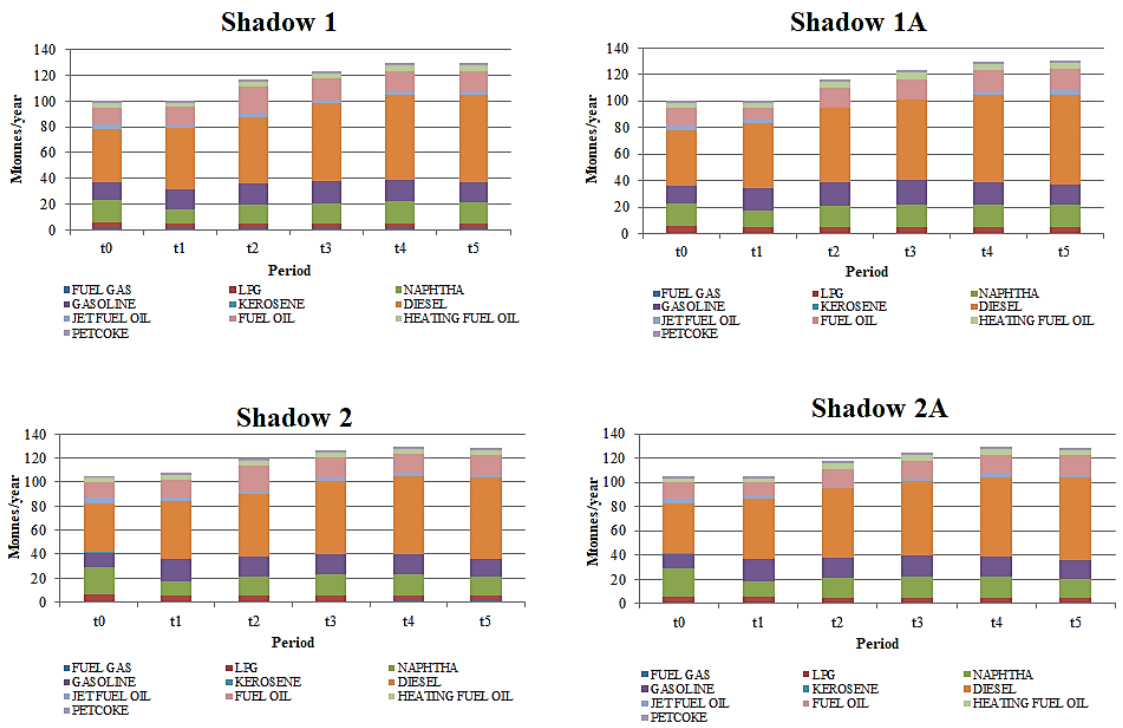


Figure 5-7 - Oil derivatives production - Shadow scenarios

In Shadow 1 and Shadow 2 scenarios, diesel is the main output, followed by fuel oil, gasoline and naphtha (see Table 5-11, Table 5-12, Table 5-13 and Table 5-14), what is in line with data published by ANP (2018b). In Shadow 1A and Shadow 2A, the largest production also refers to diesel, however, fuel oil production is lower from t1, due to the application of the IMO regulation, making gasoline the second largest oil derivative produced, followed by naphtha.

Despite this lower production of fuel oil in Shadow 1A and Shadow 2A scenarios, it is still sufficient (except at t1[24]), even under stringent sulfur specification, to meet the national demand. In order to achieve this sulfur condition, investments in additional unstable hydrotreatment units (HDT I) are made, as will be shown later.

As regards LPG production, although the Shadow scenario presents a growth in demand for this oil derivative, the optimization of ORION model reduces its production

[24] At period t1 the production of fuel oil considerably reduces in these two scenarios, which is a short-term response of the model for the application of IMO regulation in this period. At t1, there is no time for investing in conversion and/or treatment units, and, then, imports of fuel oil were needed to cope with demand. However, from t2, as it is detailed in the main text, the production is resumed, thus meeting the demand for this oil derivative, and imports cease.

throughout the time horizon, thus giving space for a higher production of other derivatives, as naphtha, for example, then meeting its demand mainly through imports[25].

The smallest production shares (see Table 5-11, Table 5-12, Table 5-13 and Table 5-14), in all scenarios, correspond to fuel gas, kerosene, petcoke and jet fuel oil.

Table 5-11 - Oil derivatives production share - Shadow 1

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
LPG	4.8%	3.7%	3.4%	3.3%	3.2%	3.1%
Naphtha	17.1%	11.5%	12.3%	12.7%	13.0%	12.5%
Gasoline	13.4%	15.3%	14.4%	13.7%	12.9%	11.9%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	41.0%	46.4%	43.7%	48.1%	49.7%	51.5%
Jet fuel oil	3.3%	2.5%	1.7%	2.0%	2.4%	2.2%
Fuel oil	13.4%	13.9%	18.1%	13.6%	12.0%	12.2%
Heating fuel oil	3.6%	3.1%	3.1%	3.1%	3.1%	3.1%
Petcoke	1.5%	1.6%	1.4%	1.5%	1.5%	1.5%

Table 5-12 - Oil derivatives production share - Shadow 1A

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.7%	0.8%	0.7%	0.7%	0.7%	0.7%
LPG	4.8%	3.9%	3.6%	3.5%	3.3%	3.2%
Naphtha	17.3%	13.2%	13.7%	13.9%	13.0%	12.6%
Gasoline	13.5%	16.9%	15.6%	14.7%	13.0%	12.1%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	41.5%	48.5%	48.1%	49.1%	50.3%	51.9%
Jet fuel oil	3.4%	2.9%	0.0%	0.6%	2.4%	2.2%
Fuel oil	13.6%	8.6%	13.0%	12.3%	12.2%	12.2%
Heating fuel oil	3.6%	3.7%	3.8%	3.7%	3.6%	3.6%
Petcoke	1.6%	1.6%	1.5%	1.5%	1.5%	1.6%

[25] It is possible that this deficit demand for LPG will come from Natural Gas Processing Units (NGPU) in Brazil, instead of from imports, but the ORION model does not do this analysis yet. This is precisely indicated as a possible model enhancement in future studies.

Table 5-13 - Oil derivatives production share - Shadow 2

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.6%	0.8%	0.7%	0.7%	0.7%	0.7%
LPG	5.1%	4.1%	3.4%	3.4%	3.2%	3.1%
Naphtha	21.9%	11.3%	13.6%	13.9%	13.6%	12.4%
Gasoline	11.7%	17.3%	14.4%	13.9%	12.9%	12.0%
Kerosene	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	39.3%	45.3%	43.3%	48.2%	50.4%	52.7%
Jet fuel oil	3.9%	2.6%	2.0%	2.1%	2.3%	2.0%
Fuel oil	12.9%	13.9%	18.1%	13.2%	12.2%	12.5%
Heating fuel oil	3.2%	3.2%	3.0%	3.2%	3.2%	3.1%
Petcoke	1.4%	1.7%	1.5%	1.5%	1.5%	1.5%

Table 5-14 - Oil derivatives production share - Shadow 2A

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.6%	0.8%	0.7%	0.7%	0.7%	0.7%
LPG	5.1%	4.6%	3.5%	3.4%	3.3%	3.1%
Naphtha	21.9%	12.3%	13.8%	14.0%	13.4%	12.3%
Gasoline	11.7%	17.6%	14.7%	13.9%	12.6%	12.0%
Kerosene	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	39.3%	47.2%	48.4%	49.3%	50.4%	52.4%
Jet fuel oil	3.9%	2.8%	0.9%	1.3%	2.2%	2.0%
Fuel oil	12.9%	9.4%	12.8%	12.2%	12.2%	12.4%
Heating fuel oil	3.2%	3.7%	3.7%	3.6%	3.6%	3.6%
Petcoke	1.4%	1.7%	1.5%	1.5%	1.6%	1.5%

Concerning specifically the multi-regional cases (Shadow 1 and Shadow 1A), Table 5-15 and Table 5-16 present, respectively, their oil derivatives production per period and region of the model. As can be seen, the production of oil derivatives by region follows the same trend as crude oil consumption by region, where SP_S region presents the largest oil derivatives production, for almost all products, folowed by the S_S, NE_S and RJMG_S regions, with variations depending on the oil derivative and the period. As for the crude oil consumption this is a consistent result, since SP_S region has the highest refining capacity among all regions, and, although S_S region has lower capacity than NE_S region, as well as lower demand for derivatives, it receives fewer trades from other regions – and also imports - than NE_S region, as will be still shown, which ultimately forces higher production of oil derivatives in this region.

These results are in line with oil derivatives production by refinery data published by ANP (2018a), which shows that São Paulo's refineries are responsible for most oil derivatives production, mainly LPG (38%), gasoline (48%), diesel (48%), jet fuel oil (52%) and petcoke (56%). For naphtha and fuel oil, according to ANP (2018a), the main producers are refineries from Rio de Janeiro and Northeast, respectively. However, in the case of fuel oil, the S_S region is, in almost every period, the second largest producer after SP_S. In this sense it is important to understand that the results of the model are a consequence, in addition to the production capacity per region, of the demand of oil derivatives per region, national trades between regions and imports by region.

Table 5-15 - Oil derivatives production per period and region - Shadow 1

Oil product (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
Fuel gas	0.15	0.10	0.13	0.37	0.15	0.12	0.13	0.36	0.15	0.15	0.17	0.32	0.17	0.15	0.17	0.35	0.18	0.17	0.17	0.36	0.18	0.17	0.17	0.38
LPG	0.89	0.75	0.88	2.32	0.62	0.56	0.59	1.94	0.67	0.79	0.82	1.69	0.78	0.80	0.82	1.74	0.89	0.90	0.82	1.66	0.89	0.90	0.73	1.57
Naphtha	3.26	3.81	4.04	6.24	2.49	2.47	3.37	3.32	2.57	4.32	3.98	3.63	2.87	4.38	3.98	4.62	3.17	4.43	3.98	5.49	3.14	4.43	4.66	4.25
Gasoline	2.06	1.43	2.07	8.03	2.46	2.16	2.44	8.53	2.79	2.95	3.55	7.68	3.12	2.99	3.55	7.45	3.25	3.33	3.55	6.83	3.25	3.33	2.98	6.08
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel	9.02	7.83	7.93	16.92	9.89	8.48	9.10	19.64	10.22	11.51	8.66	21.22	12.37	11.72	13.41	22.72	13.83	12.88	13.41	25.33	13.84	12.88	14.61	26.42
Jet fuel oil	0.53	0.62	0.71	1.51	0.43	0.42	0.59	1.05	0.20	0.00	0.77	1.09	0.54	0.02	0.77	1.12	0.55	0.74	0.77	1.11	0.55	0.75	0.77	0.77
Fuel oil	4.23	2.70	2.98	3.73	4.01	3.01	2.60	4.52	3.75	3.40	6.82	7.33	2.91	3.37	1.76	8.95	3.04	3.52	1.76	7.53	3.07	3.52	0.54	8.86
Heating fuel oil	0.57	0.63	0.72	1.72	0.62	0.53	0.60	1.41	0.66	0.69	0.69	1.57	0.77	0.70	0.88	1.59	0.81	0.79	0.88	1.63	0.81	0.79	0.87	1.57
Petcoke	0.31	0.21	0.26	0.78	0.31	0.28	0.27	0.78	0.31	0.37	0.36	0.65	0.37	0.38	0.36	0.74	0.43	0.43	0.36	0.76	0.43	0.43	0.36	0.80

Table 5-16 - Oil derivatives production per period and region - Shadow 1A

Oil product (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
Fuel gas	0.15	0.10	0.13	0.37	0.14	0.12	0.13	0.37	0.14	0.16	0.17	0.30	0.15	0.16	0.17	0.34	0.16	0.18	0.17	0.39	0.16	0.18	0.17	0.40
LPG	0.89	0.75	0.88	2.32	0.71	0.56	0.72	1.92	0.88	0.83	0.88	1.64	0.90	0.86	0.90	1.67	0.85	0.92	0.71	1.78	0.81	0.93	0.71	1.67
Naphtha	3.26	3.81	4.04	6.24	3.08	3.24	2.31	4.53	2.96	4.45	2.99	5.50	2.87	4.63	3.01	6.54	3.21	4.71	4.43	4.48	3.43	4.63	4.44	3.97
Gasoline	2.06	1.43	2.07	8.03	3.05	2.16	3.33	8.34	3.64	3.13	4.04	7.29	3.70	3.24	4.10	7.10	3.31	3.41	2.89	7.29	2.98	3.47	2.89	6.44
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel	9.02	7.83	7.93	16.92	10.03	10.50	8.87	19.08	10.68	12.01	12.24	20.92	11.17	12.57	12.61	24.00	11.45	12.88	11.87	29.20	11.80	13.27	11.85	30.84
Jet fuel oil	0.53	0.62	0.71	1.51	0.62	0.54	0.58	1.18	0.04	0.00	0.00	0.01	0.00	0.00	0.00	0.76	0.62	0.79	0.73	0.97	0.59	0.78	0.73	0.74
Fuel oil	4.23	2.70	2.98	3.73	2.19	0.00	2.60	3.76	2.89	3.34	2.74	6.08	2.91	3.37	2.76	6.14	3.04	3.52	2.88	6.41	3.07	3.55	2.91	6.46
Heating fuel oil	0.57	0.63	0.72	1.72	0.77	0.61	0.78	1.50	0.84	0.85	0.97	1.72	0.86	0.89	0.99	1.84	0.85	0.94	0.87	2.06	0.83	0.96	0.87	2.03
Petcoke	0.31	0.21	0.26	0.78	0.30	0.27	0.27	0.79	0.35	0.39	0.34	0.63	0.36	0.40	0.35	0.71	0.38	0.43	0.35	0.83	0.39	0.44	0.35	0.85

Oil derivatives imports and exports

As explained in the methodological part of the present study, the imports and exports characterized in the ORION model concern only oil derivatives. The results for each Shadow scenario concerning their oil derivaties imports and exports by time period are presented below. For the Shadow 1 and Shadow 1A scenarios, which are multi-regionals, the results are also presented by region of the model (S_S, NE_S, RJMG_S, SP_S).

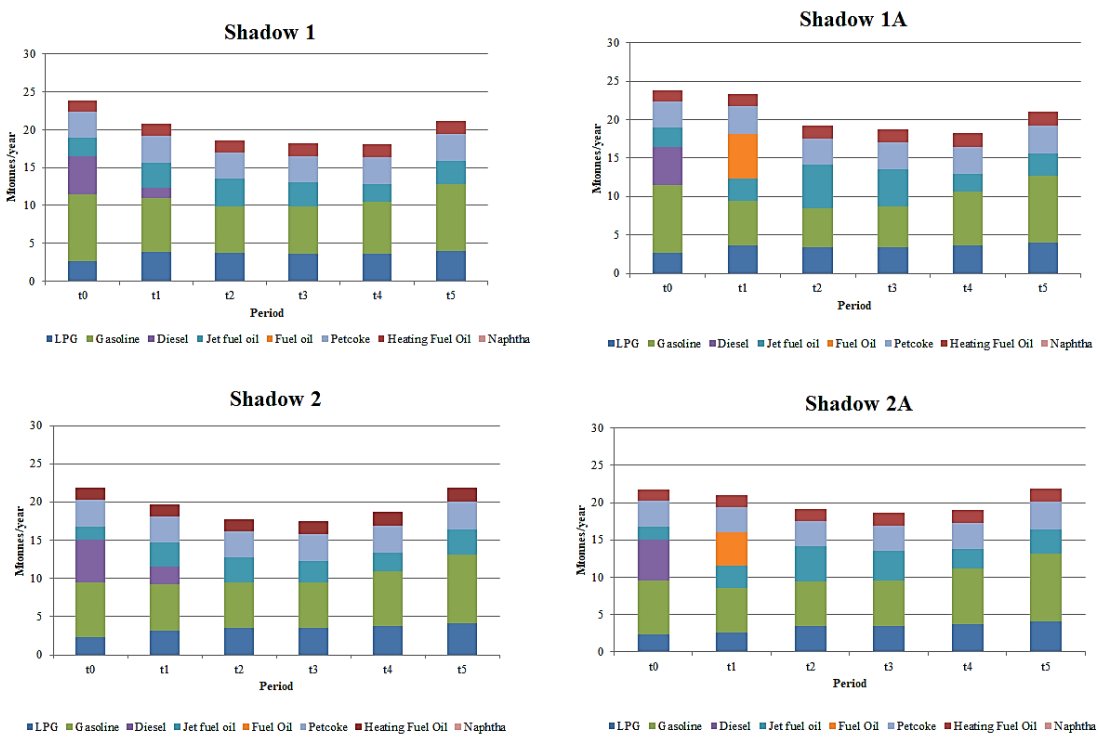


Figure 5-8 - Oil derivatives imports - Shadow scenarios

The first evidence to be analyzed regarding oil derivatives imports is that all scenarios have the same profile of total imports over the time horizon, that is, they show a decrease between t0 and t4, and an increase at t5. These results are an effect of the growth in the production of oil derivatives, between t0 and t4, caused both by the increase of the refining utilization factor and the investments in additional processing units; and of the drop in most oil derivatives production in t5, except diesel. Since the capacity levels of the processing units remain practically constant between t4 and t5[26],

[26] Although the model has the possibility of investing in CAPADU in period t5 to increase the total production of oil derivatives, avoiding the increase of imports it is more interesting for it to maintain the

as will be shown later, this growth in imports of oil derivatives can be explained exactly by the increase in diesel production over all time periods. Given that the diesel prices originated from the OURSE model, and implemented in the ORION model are very high at the end of the analysis horizon, the model reaches its optimum solution by outputting diesel surpluses, with the aim of exporting them, at the expenses of importing larger quantities of other products, such as gasoline.

The total imports at t0 are of 23.8 Mtonnes/year in Shadow 1 and Shadow 1A scenarios, and of 21.8 Mtonnes/year in Shadow 2 and Shadow 2A scenarios. As the latters scenarios present a higher total oil derivative production in this period, it was expected that their imports would be lower.

The most imported oil derivative in all scenarios is gasoline, followed by LPG, petcoke and jet fuel oil. As regards fuel oil, it is imported only at t1, in Shadow 1A and Shadow 2A scenarios, which can be understood as a model's short-term response to the implementation of the IMO regulation in this period. From t2 onwards it is no longer imported, and all the fuel oil demanded is produced - even under higher sulfur specifications – through investments in HDTI units. Still, in Shadow 1 and Shadow 2 scenarios there are exports of fuel oil at periods t2 and t3, which is an outcome of the profile production of oil derivatives (geared towards medium/heavy distillates), that, in turn, can be influenced by oil derivatives prices given by the OURSE model, which are expensive for medium distillates and can lead to excessive export-oriented production.

Concerning diesel, there are imports of 4.97 Mtonnes/year at t0 in Shadow 1 and Shadow 1A scenarios, and of 5.52 Mtonnes/year in Shadow 2 and Shadow 2A scenarios. These results are in accordance with ANP (2018) diesel imports data for 2015, of 5.8 Mtonnes/year (or 6,940.1 thousand m^3/year). Still, in the Shadow 1, there are imports of 1.5 Mtonnes/year at t1. However, as shown by Figure 5-9, from t2 onwards it starts to be exported, varying from scenario to scenario the period in which exports start. At period t5 its exports are of 10.7 Mtonnes/year in Shadow 1 and Shadow 1A scenarios, and of 10.4 Mtonnes/year in Shadow 2 and Shadow 2A scenarios. As previously explained, the diesel prices generated by the OURSE model, and implemented in the ORION model are very high for diesel at the end of the horizon of

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capacity levels reached in t4 and increase imports of certain oil derivatives. This occurs exactly because is the last period of analysis. As the model does not verify oil derivatives demands after this period, the optimization tends not to choose for more investments.

analysis. Thus, the model find the best solution to produce diesel surpluses. In addition, it is worth mentioning that the national trades that occur in the Shadow 1 and Shadow 1A scenarios have no physical constrains but only associated transportation costs. This may have leaded the model to meet the demand for diesel of certain regions without the need for imports.

In the case of naphtha, although Brazil is a net importer the model exports naphtha from t0 on Shadow 1 and Shadow 1A, and from t1 on Shadow 2 and Shadow 2A. In addition to the high prices generated by the OURSE model for this oil derivative – which leads the model to produce surpluses in order to export - the model has imports and exports limits given by classification of oil derivatives (light, medium, heavy), that may leave it on the threshold of choosing to produce or import LPG, naphtha and gasoline, for example, since they are all classificated as light derivatives. The same applies to other oil derivatives, as diesel, kerosene, jet fuel oil, fuel oil and heating fuel oil, which are classificated as medium derivatives. Regarding petcoke, it is the only heavy oil derivative in the model, thus it does not present threshold results.

Nevertheless, as can be seen, total oil derivatives exports are smaller than imports, in all scenarios and time periods. This indicates that Brazil will keep its current position as a net importer of almost all oil derivatives. Specifically for gasoline and LPG the results corroborate the data published by ANP (2017), which show that Brazil has been a net importer of these fuels in recent years. However, as mentioned before, the increasing production and processing of natural gas in Brazil might output additional volumes of LPG and gasoline (mostly the former), which are not accounted now in ORION.

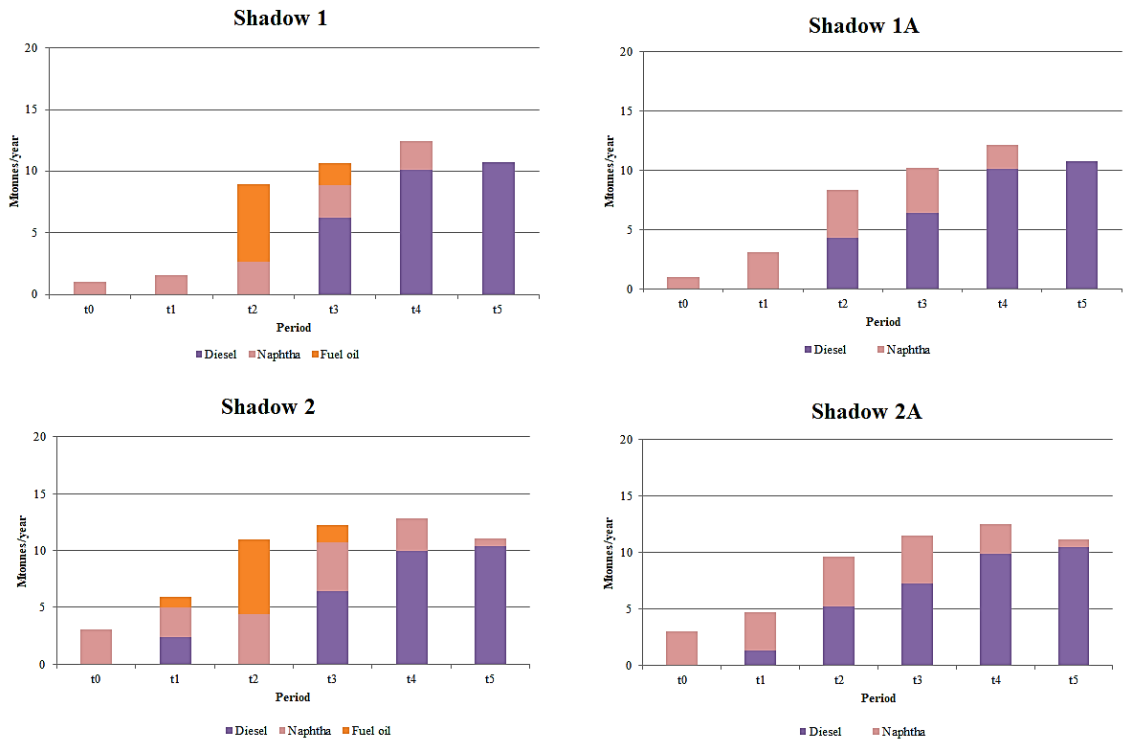

Figure 5-9 - Oil derivatives exports - Shadow scenarios

For the Shadow 1 and Shadow 1A scenarios, which have a multi-regional framework, Table 5-17 and Table 5-18 present the results of oil derivatives imports and exports by region of the model (S_D, NE_D, RJMG_D, SP_D). They show that in both scenarios, on average, the region that imports the most is the NE_S region, followed by the SP_D, S_S, and RJMG_D regions; and the major exporting region is SP_S, followed by RJMG_S, S_S and NE_S.

According to Aliceweb/MDIC (2017) the Brazilian Northeast region plays an important role in foreign trade of fuels, as the largest amounts of gasoline and LPG are imported from the harbors of São Luís, in Maranhão, and Suape, in Pernambuco. Still, the other three Brazilian harbors of relevance are the harbors of Santos (in São Paulo), of Rio de Janeiro and of Paranaguá (in the South). Such evidence reaffirms the reliability of the ORION model. Even though the results obtained are not exactly in accordance with the literature data, they have congruence.

Table 5-17 - Oil derivatives imports and exports per period and region - Shadow 1

Region	Imp/Exp (Mtonnes/year)	LPG						Naphtha						Gasoline						Kerosene						Diesel						Jet fuel oil						Fuel oil						Heating fuel oil						Petcoke					
		t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5
S_D	Imports	0.45	0.74	0.72	0.62	0.54	0.58	-	-	-	-	-	-	1.91	0.77	0.43	0.50	1.29	2.02	-	-	-	-	-	-	0.63	-	-	-	-	-	-	-	0.19	-	-	-	-	-	-	-	-	-	0.30	0.32	0.33	0.34	0.35	0.35	0.59	0.65	0.63	0.61	0.58	0.60
	Exports	-	-	-	-	-	-	-	0.30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.20	2.38	2.04	-	-	-	-	-	-	-	-	0.86	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NE_D	Imports	2.15	2.37	2.19	2.22	2.18	2.26	-	-	-	-	-	-	6.97	6.31	5.68	5.74	5.57	5.80	-	-	-	-	-	-	3.04	1.37	-	-	-	-	1.21	1.40	1.78	1.72	0.96	1.06	-	0.17	-	-	-	-	0.30	0.32	0.33	0.34	0.35	0.35	1.70	1.74	1.62	1.68	1.70	1.76
	Exports	-	-	-	-	-	-	0.43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RJMG_D	Imports	0.02	0.72	0.56	0.58	0.61	0.73	-	0.29	-	-	-	-	-	-	-	-	-	0.98	-	-	-	-	-	-	-	-	-	-	-	-	0.51	0.63	0.42	0.40	0.37	0.44	-	-	-	-	-	-	0.30	0.32	0.33	0.34	0.35	0.35	0.64	0.68	0.58	0.61	0.65	0.68
	Exports	-	-	-	-	-	-	-	-	1.80	1.09	0.28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.03	4.67	5.20	-	-	-	-	-	-	-	-	4.09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SP_D	Imports	-	-	0.23	0.20	0.32	0.46	-	0.99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.30	-	-	-	-	-	0.80	1.36	1.29	1.06	0.99	1.49	-	-	-	-	-	-	0.60	0.63	0.67	0.67	0.70	0.71	0.42	0.50	0.60	0.56	0.58	0.58
	Exports	-	-	-	-	-	-	0.57	-	0.90	1.56	2.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.99	3.07	3.49	-	-	-	-	-	-	-	-	1.25	1.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	Imports	2.62	3.83	3.70	3.62	3.65	4.03	-	1.58	-	-	-	-	8.88	7.08	6.11	6.24	6.86	8.80	-	-	-	-	-	-	4.97	1.37	-	-	-	-	2.52	3.39	3.68	3.18	2.32	2.99	-	0.17	-	-	-	-	1.50	1.59	1.66	1.69	1.75	1.76	3.35	3.57	3.43	3.46	3.51	3.62
	Exports	-	-	-	-	-	-	1.00	0.77	2.70	2.65	2.31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.22	10.12	10.73	-	-	-	-	-	-	-	-	6.25	1.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 5-18 - Oil derivatives imports and exports per period and region - Shadow 1A

Region	Imp/Exp (Mtonnes/year)	LPG						Naphtha						Gasoline						Kerosene						Diesel						Jet fuel oil						Fuel oil						Heating fuel oil						Petcoke					
		t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5
S_D	Imports	0.45	0.65	0.51	0.51	0.58	0.66	-	-	-	-	-	-	1.91	-	-	-	1.43	2.29	-	-	-	-	-	-	0.63	-	-	-	-	-	-	-	0.35	0.39	-	-	-	0.56	-	-	-	-	0.30	0.32	0.33	0.34	0.35	0.35	0.59	0.66	0.60	0.62	0.63	0.65
	Exports	-	-	-	-	-	-	-	0.89	0.39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NE_D	Imports	2.15	2.37	2.15	2.15	2.16	2.22	-	-	-	-	-	-	6.97	5.79	4.97	5.22	5.50	5.66	-	-	-	-	-	-	3.04	-	-	-	-	-	1.21	1.29	1.78	1.75	0.92	1.03	-	3.18	-	-	-	-	0.30	0.32	0.33	0.34	0.35	0.35	1.70	1.75	1.60	1.65	1.70	1.74
	Exports	-	-	-	-	-	-	0.43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RJMG_D	Imports	0.02	0.60	0.50	0.50	0.72	0.76	-	-	-	-	-	-	-	-	-	-	-	0.71	-	-	-	-	-	-	-	-	-	-	-	-	0.51	0.63	1.19	1.16	0.41	0.47	-	-	-	-	-	-	0.30	0.32	0.33	0.34	0.35	0.35	0.64	0.68	0.60	0.63	0.66	0.69
	Exports	-	-	-	-	-	-	-	-	0.94	0.37	1.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.09	4.07	3.13	2.84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SP_D	Imports	-	-	0.28	0.27	0.20	0.36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.30	-	-	-	-	-	0.80	1.03	2.36	1.57	1.06	1.49	-	2.03	-	-	-	-	0.60	0.63	0.67	0.67	0.70	0.71	0.42	0.49	0.62	0.58	0.52	0.53
	Exports	-	-	-	-	-	-	0.57	2.20	2.76	3.48	1.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.15	2.27	6.93	7.90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	Imports	2.62	3.62	3.44	3.43	3.66	4.00	-	-	-	-	-	-	8.88	5.79	4.97	5.22	6.93	8.66	-	-	-	-	-	-	4.97	-	-	-	-	-	2.52	2.95	5.68	4.87	2.39	2.99	-	5.77	-	-	-	-	1.50	1.59	1.66	1.69	1.75	1.76	3.35	3.58	3.42	3.48	3.51	3.61
	Exports	-	-	-	-	-	-	1.00	3.09	4.09	3.85	2.08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.24	6.34	10.06	10.74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

National trades

The national trades concern the trades of oil derivatives between Brazilian regions of supply (S_S, NE_S, RJMG_S, SP_S) and demand (S_D, NE_D, RJMG_D, SP_D) in Shadow 1 and Shadow 1A scenarios, which are the multi-regional cases.

Regarding the Shadow 1, in almost all time periods the LPG is traded from SP_S to RJMG_D. For naphtha, the trades are mostly from RJMG_S to NE_D, with some trades from SP_S to S_D in the two last periods (t4 and t5). Concerning gasoline, the trades are usually from SP_S to S_D and RJMG_D. For diesel from RJMG_S to NE_D and from SP_D to S_S. For jet fuel oil they are always from S_S to SP_D. For fuel oil from RJMG_S to NE_D and SP_D at period t0, from SP_S to RJMG_D at t3, t4 and t5, and from SP_S to NE_D at t5. As regards kerosene, heating fuel oil and petcoke, there are no trades between regions for the scenario in question.

In the Shadow 1A the trades are very similar to the previous case, in terms of origin and destination for each product, except for fuel oil and diesel, whose trades cease to exist from t2.

These results, for both scenarios, reflect the demand shares for products applied in each region, which were kept the same throughout the analysis horizon, as well as the production capacity of each product in each region, according to the existing processing units. For example, oil products demands are very high in the NE_S region, which, despite having considerable production capacity, is unable to meet these demands. For this reason, it is an importing region, both in terms of international imports, and in terms of trades from other regions of the model. Anoter example is the RJMG_S region, that sends naphtha to NE_D in the two scenarios analyzed, which is a consequence of this region's production profile and also its lower demand for naphtha than in the NE_D region.

Lastly, it worth mentioning that national trades may find bottlenecks that were not specified in the model (tanking capacity, mode of transport), which could limit trades between regions, leading to higher/lower production of oil derivatives per region, and lower/higher oil derivatives imports. However, these level of detail was beyond the scope of this thesis.

Table D-1 and Table D-2 in Annex D present the results of national trades by product, period and region of the model, for these scenarios.

Processing units capacities

The results for processing units capacities relate to both capacity levels[27] in each period of time as well as additional capacities, if any. Figure 5-10 exhibits the capacities levels for each processing unit considered in the models' refining scheme, for each Shadow case, in each time period.

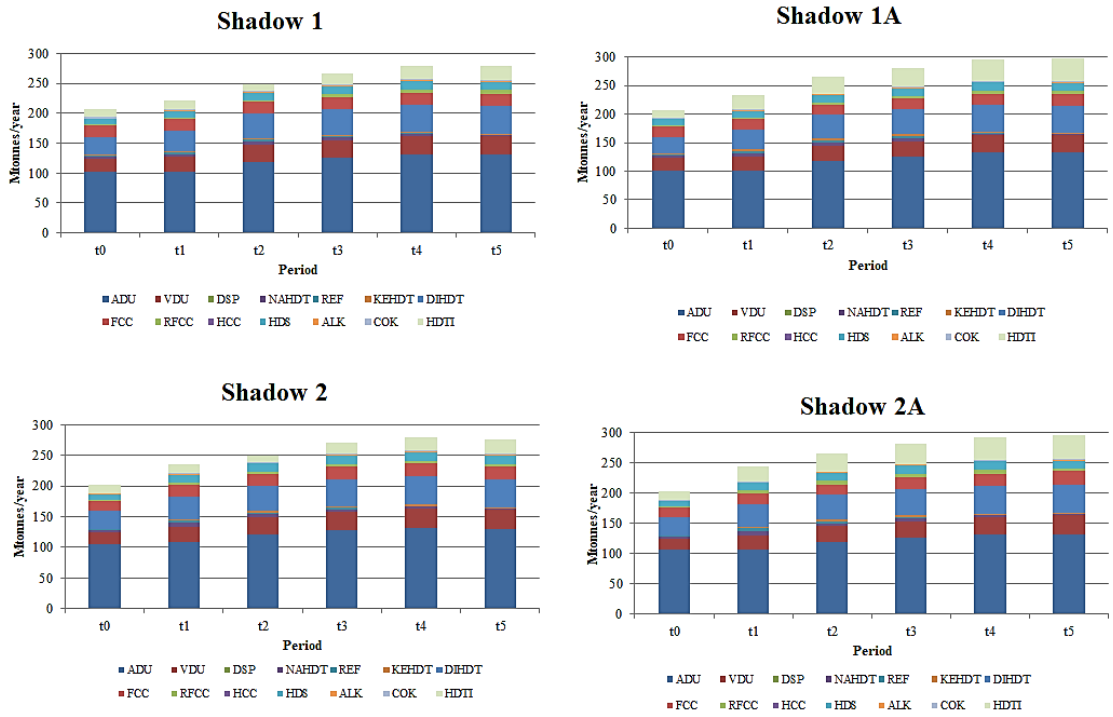

Figure 5-10 - Processing units level capacities - Shadow scenarios[28]

The results above corroborate the information presented in section 2.1., which shows that Brazilian refining schemes are mostly classified between the Cracking and Coking/Hydrocracking configurations (OIL & GAS JOURNAL, 2018), with the presence mainly of FCC and also delayed coking units (COK), but with no presence of hydrocracking units (HCC). Additionally, they confirm some results previously shown, more specifically the ones related to the crude oil consumption, since these values, in each scenario, refer exactly to the level capacities of the atmospheric distillation unit

[27] The capacity level corresponds to the level of utilization of the processing unit, which is different from the existing maximum capacity.

[28] Results concerning the capacities of the hydrogeneration unit (CAPUGH) and cogeneration unit (CAPCOG) are not represented in the graphs, given that they have units of measurement other than Mtonnes/year. The resulting values for these processing units can be found in Annex D.

(CAPADU), the primary unit within a refinery, which fractionate the crudes into different cuts. At period t0 (model's calibration period), the capacities were limited to the maximum available capacity (Table 4-1), which for the atmospheric distillation unit is of 116.75 Mtonnes/year. Thus, at this period, Shadow 1 and Shadow 1A scenarios presented a CAPADU level of 101.7 Mtonnes/year, and Shadow 2 and Shadow 2A of 105.9 Mtonnes/year, with respective utilization factors[29] of 87.1% and 90.7%. When analyzing the real utilization factor of the Brazilian refining industry in 2015 (ANP, 2018b), of 86.8%, it can be seen that the values found by the ORION model were quite realistic, especially in Shadow 1 and Shadow 1A scenarios. In this sense, as previously explained for the total crude oil consumption results, the higher CAPADU level at t0 in the Shadow 2 and Shadow 2A scenarios may be related to their single-regional structure, with no possibility of trades between regions - since there is only one region - which requires the processing of more crude oil to meet the national oil derivatives demand, and consequently higher levels of CAPADU.

By analyzing the capacity results over time, it is worth noticing that in all scenarios there is a tendency of growth. These capacities increases occur either through investments in additional capacities or through increasing refining utilization factor, ie, through raising the use of existing capacities.

In this context it is important to detail some simulations performed for the Shadow 1 scenario, as well as certain bounds on investments in additional processing units capacities that had to be added to the model before reaching the final results presented in this thesis. Actually, two simulations were run for Shadow 1 scenario before the one that generated the results detailed in this thesis. In the first simulation, the model was free to invest in additional units capacities (no bound on investment for each period). This has resulted in huge investments in additional processing units capacities, specifically CAPADU (about 42 Mtonnes/year of total ADU additional capacity), with the purpose of exporting all excess production[30], which corresponded

[29] Utilization Factor is the ratio between the usage time for which a process unit has been functional to the total time for which it could be used. Since for its calculation, only the ADU is considered, it does not directly grasp the complexity of the refinery. Nervetheless, when their more complex downstream units are fully utilized, refineries operate as simple refineries.

[30] It is important to mention that for this same simulation attempts were made to reduce the import/export limits in order to solve the problem of excessive exports, however, the model ends up investing even more in additional processing capacities, because it simply reduced the import of oil derivatives.

principally to diesel, naphtha and fuel oil. Moreover, investments occurred mainly in period t2 (approximately 36 Monnes/year of additional CAPADU only in this period), and doubled the atmospheric distillation capacities in the South and São Paulo regions. It is understood that this result is a consequence of the high prices of oil derivatives generated by the OURSE model, mainly for diesel and fuel oil, which induces the model to maximize oil derivatives production in order to export, thus reducing the total system cost by increasing its revenues. Also, the investments only at period t2 are understandable since the ORION, exactly for being an optimization model, has the tendency, when making an investment, to invest everything at once than gradually invest in each period. However, such results are beyond the Brazilian (and even other country´s) reality, first by the amount of additional ADU capacity, that corresponds to 0.84 million of barrels per day (Mb/d), approximately 1/3 of the current total Brazilian refining capacity, and second by the period in which all this additional capacity is implemented, as period t2 starts in the year 2030, that is, 10 years from now.

In order to solve the problem of overinvestment in additional processing units capacities, it was decided to add to the model a bound on investment of additional capacity for each period of time. Thus, a second simulation was carried out, considering a maximum possible investment in CAPADU, per time period, of 12.7 Mtonnes/year, which corresponds to 250 thousand of barrels per day (kb/d), a more reasonable value regarding possible expansions of the Brazilian refining park. The results showed a choice for additional CAPADU investments of exactly 12.7 Mtonnes/year at periods t2 and t3, that is, a total investment of 25.4 Mtonnes/year, or 0.5 million of barrels per day (Mb/d). Although this result is closer to the Brazilian refining industry's expansion forecasts - IEA (2019) indicates that by 2040 the total Brazilian refining capacity will be increased by 0.3 million of barrels per day (Mb/d) – it may still be too optimistic given the recent record of the country´s refining industry.

Therefore, considering the construction of the second train of RNEST – Refinaria Abreu e Lima (115 thousand of barrels per day) and the first train of COMPERJ – Complexo Petroquimico do Rio de Janeiro (165 thousand barrels per day) (PETROBRAS, 2019d) in more than 10 years, it was concluded that the best maximum limit of investments in additional CAPADU per period (5 years) would be 7.5 Mtonnes/year, or 150 thousand of barrels per day. Under this new constraint, the model presents a total investment in additional CAPADU of 21.8 Mtonnes/year, or 0.4 million of barrels per day (Mb/d), spread over periods t2, t3 and t4. Being this a more realistic

result, the constraint of investments in additional CAPADU were replicated for all Shadow scenarios.

Hence, regarding ADU capacity levels, in Shadow 1 they rise from 101.7 Mtonnes/year to 131.6 Mtonnes/year; in Shadow 1A from 101.7 Mtonnes/year to 132.4 Mtonnes/year; in Shadow 2 from 105.9 Mtonnes/year to 131.0 Mtonnes/year; and in Shadow 2A from 105.9 Mtonnes/year to 129.9 Mtonnes/year.

Despite the trend of capacity increases, there is a capacity reduction of REF and NAHDT units, between t3 and t5 for Shadow 1 and Shadow 1A, and between t2 and t5 for Shadow 2 and Shadow 2A . This can be explained by the gasoline profile production per period, which follows the same trend of REF and NAHDT units capacities in each scenario.

The largests capacities increases in all scenarios relate to the atmospheric distillation (ADU), vacuum distillation (VDU), diesel hydrotreating (DIHDT) and unstable hydrotreating units (HDTI). This confirms the results regarding the refining profile, which show a focus on diesel production. Still, the growth of HDTI units capacitites in Shadow 1A and Shadow 2A scenarios is higher than in Shadow 1 and Shadow 2, what is explained by the application of the IMO sulfur specification in the first two cases. While in Shadow 1 and Shadow 2 this growth occurs mostly through the increased use of existing capacities, in Shadow 1A and Shadow 2A it takes place mainly through investments in additional units, indicating that tighter specification for maritime bunker fuels requires new HDT capacity to adjust the quality of fuel oils.

For the Shadow 1 and Shadow 1A scenarios, which are multi-regional cases, Table 5-19 and Table 5-20 present the results of processing units capacities per period and region of the model. It can be seen that, on average, in both scenarios the region with the highest processing unit level capacity is the SP_S region, which makes sense due to its higher maximum refining capacity (47.2 Mtonnes/year), at t0, and to its results of regional investments in additional processing units capacities. After SP_S region, the second region with the highest processing units level capacities is the S_S region, followed by the RJMG_S region, in the first two periods and, from period t2 to t5 the second region becomes RJMG_S, followed by NE_S. Although S_S region has lower maximum ADU available capacity (22.37 Mtonnes/year) than NE_S region (25.77 Mtonnes/year) at t0 and t1, as well as lower demand for derivatives, it receives fewer trades from other regions than NE_S region, as shown in the National Trades section, which ultimately forces higher production of derivatives and consequent higher

capacity levels in this region at periods t0 and t1. Regarding the increase in capacities of RJMG_S and NE_S regions from t2, they are due to investments in additional units capacities.

Table 5-19 - Processing units level capacties - Shadow 1

Processing unit capacity level (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
ADU	21.25	18.27	19.96	42.18	21.25	18.27	19.96	42.18	21.60	24.48	26.10	45.84	24.24	24.83	26.10	49.95	26.53	27.55	26.10	51.42	26.53	27.55	26.10	51.42
VDU	5.09	3.29	4.67	8.91	5.92	4.24	5.11	10.35	5.89	4.37	6.70	12.42	5.74	4.43	6.70	12.72	5.06	5.01	6.70	13.20	5.06	5.01	6.70	13.89
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	-	0.10	0.38	3.48	0.24	0.23	0.42	3.48	0.60	0.33	0.98	3.37	0.60	0.34	0.98	2.51	0.37	0.38	0.98	1.58	0.37	0.38	0.30	0.62
REF	-	-	0.17	2.19	-	-	0.17	2.51	0.31	-	0.60	2.51	0.26	-	0.60	1.69	-	-	0.60	0.85	-	-	-	-
KEHDT	-	-	0.51	1.08	0.31	0.30	0.51	1.08	0.44	0.73	0.55	0.78	0.39	0.74	0.55	0.80	0.40	0.53	0.55	0.79	0.39	0.53	0.55	0.55
DIHDT	6.61	5.18	5.56	11.54	7.50	5.84	6.76	14.33	7.54	8.33	8.88	15.95	8.49	8.45	8.88	17.49	9.34	9.47	8.88	18.06	9.35	9.47	8.88	18.52
FCC	4.05	2.07	3.39	9.16	4.05	2.84	3.49	9.16	4.03	2.84	4.58	8.50	3.86	2.88	4.58	8.63	3.29	3.26	4.58	8.96	3.29	3.26	4.58	9.43
RFCC	-	0.65	-	0.97	-	0.74	0.07	0.97	-	1.98	0.07	-	0.90	2.01	0.07	0.97	2.29	2.27	0.07	0.97	2.29	2.27	0.07	0.97
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	2.02	1.33	1.70	5.28	2.19	1.93	2.03	5.46	2.22	2.62	2.65	4.70	2.55	2.66	2.65	5.20	2.89	2.97	2.65	5.36	2.89	2.97	2.65	5.41
ALK	-	-	-	0.31	0.20	0.20	0.30	0.52	0.24	0.37	0.39	0.53	0.26	0.37	0.39	0.53	0.26	0.37	0.39	0.52	0.25	0.37	0.39	0.31
COK	0.50	0.14	0.42	0.96	0.50	0.22	0.42	0.96	0.50	-	0.55	1.05	0.32	-	0.55	0.89	-	-	0.55	0.93	-	-	0.55	0.99
HDTI	2.64	2.85	2.57	5.81	2.64	2.85	2.57	5.81	2.64	2.74	-	5.81	4.20	2.85	4.88	5.81	4.85	3.74	4.88	7.92	4.85	3.74	6.10	8.58

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit

Table 5-20 - Processing units level capacties - Shadow 1A

Processing unit capacity level (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
ADU	21.25	18.27	19.96	42.18	21.25	18.27	19.96	42.16	22.79	25.58	24.79	44.85	23.31	26.55	25.32	49.93	24.28	28.22	25.32	54.39	24.45	28.68	25.32	54.39
VDU	5.09	3.29	4.67	8.91	5.04	3.78	5.17	10.08	4.07	4.57	6.42	10.66	4.20	4.74	6.58	12.23	4.47	5.10	6.58	14.42	4.55	5.21	6.58	14.91
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	-	0.10	0.38	3.48	0.96	0.23	1.48	3.13	1.37	0.41	1.72	3.03	1.37	0.41	1.72	2.15	0.77	0.39	0.29	1.71	0.34	0.39	0.29	0.65
REF	-	-	0.17	2.19	0.62	-	1.11	2.19	0.94	0.06	1.27	2.19	0.93	0.04	1.26	1.37	0.38	-	-	0.94	-	-	-	-
KEHDT	-	-	0.51	1.08	0.45	0.39	0.51	1.08	0.67	0.77	0.74	1.34	0.67	0.80	0.75	1.14	0.44	0.57	0.52	0.70	0.42	0.56	0.52	0.53
DIHDT	6.61	5.18	5.56	11.54	7.23	6.22	6.79	14.42	7.76	8.70	8.44	15.26	7.97	9.04	8.63	17.16	8.39	9.66	8.63	19.37	8.50	9.85	8.63	19.70
FCC	4.05	2.07	3.39	9.16	3.41	2.52	3.53	9.23	2.65	2.97	4.39	7.22	2.73	3.08	4.50	8.30	2.91	3.31	4.50	9.80	2.96	3.39	4.50	10.13
RFCC	-	0.65	-	0.97	0.47	0.96	0.01	0.97	1.84	2.07	0.01	0.97	1.90	2.15	0.01	0.97	2.02	2.31	0.01	0.97	2.06	2.36	0.01	0.97
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	2.02	1.33	1.70	5.28	2.19	1.92	2.03	5.56	2.44	2.74	2.52	4.62	2.51	2.85	2.57	5.16	2.62	3.03	2.57	5.70	2.65	3.09	2.57	5.74
ALK	-	-	-	0.31	0.32	0.27	0.30	0.60	0.34	0.38	0.37	0.67	0.33	0.40	0.37	0.67	0.30	0.40	0.37	0.42	0.28	0.39	0.37	0.28
COK	0.50	0.14	0.42	0.96	0.34	0.14	0.43	0.97	-	-	0.54	0.72	-	-	0.55	0.85	-	-	0.55	1.03	-	-	0.55	1.08
HDTI	2.64	2.85	2.57	5.81	5.30	4.55	4.97	9.00	5.52	6.28	6.18	11.10	5.80	6.52	6.38	13.15	6.47	7.16	6.50	17.14	6.75	7.41	6.50	18.56

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit

The additional capacities are presented in Table 5-21, Table 5-22, Table 5-23 and Table 5-24 for the Shadow 1 and Shadow 1A per period and region of the model, and for Shadow 2 and Shadow 2A per period considered.

As it can be seen, the main investments in additional capacities after the distillation unit (ADU) are for the diesel hydrotreating units (DIHDT) in Shadow 1 and Shadow 2 scenarios, and for the unstable hydrotrating units (HDTI) in Shadow 1A and Shadow 2A scenarios.

In Shadow 1 and Shadow 1A, the investments in additional capacities per region vary by period, which can be understood to be a consequence of the processing units capacities already existing in each region, as well as the regional demand scenario considered, the imports/exports, and national trades results. Moreover, it can be seen that in the case of REF and NAHDT units, even if they have a total capacity reduction at the end of analysis horizon, there are investments in the first periods.

The regions with the largest investments in ADU additional capacities are SP_S and RJMG_S. In this sense, it is important to note that São Paulo's refining production attends the oil derivative demand of the midwest region of the country. Thus, in the disaggregation of the model, the refining expansion in SP_S could also involve this region.

Finally, it is worth mentioning that the results of investments in additional processing units capacities, as well as the periods when they occur do not take into account the overruns costs and delays that might happen during the construction of new refineries or new refining units, which facilitates the choice of the model of maximizing investments and choosing periods close to the base year to conceive them. Nevertheless, the average overrun cost of refining projects can reach approximately 70% of the approved budget (EY, 2014; KÖBERLE *et al*., 2018; SILVÉRIO, 2018), while the percentage of refining projects that present overrun costs in the world reaches 62% (EY, 2014). In addition, KÔBERLE *et al*. (2018) estimate a 10-year delay for refining projects in Brazil.

Table 5-21 - Processing units additional capacties - Shadow 1

Additional Capacity (Mtonnes/year)	t1					t2					t3					t4					t5				
	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total
ADU	-	-	-	-	-	0.36	-	6.06	1.05	7.47	2.79	0.37	-	4.32	7.48	2.41	2.87	-	1.55	6.83	-	-	-	-	-
VDU	0.87	1.00	0.46	1.51	3.84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	0.26	0.14	0.04	-	0.44	0.38	0.11	0.58	-	1.07	-	-	-	-	-	-	0.04	-	-	0.04	-	-	-	-	-
REF	-	-	-	0.34	0.34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KEHDT	0.32	0.32	-	-	0.64	0.14	0.46	-	-	0.60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIHDT	0.94	0.70	1.26	2.93	5.83	0.04	2.62	2.24	1.71	6.61	0.99	0.12	-	1.61	2.72	0.90	1.07	-	0.60	2.57	0.01	-	-	0.48	0.49
FCC	-	0.81	0.10	-	0.91	-	-	-	-	-	-	0.04	-	-	0.04	-	0.40	-	-	0.40	-	-	-	-	-
RFCC	-	0.10	0.07	-	0.17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	0.17	0.63	0.35	0.18	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALK	0.21	0.21	0.32	0.22	0.96	0.04	0.17	0.10	0.01	0.32	0.02	0.01	-	-	0.03	-	-	-	-	-	-	-	-	-	-
COK	-	0.08	-	-	0.08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UGH[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDTI	-	-	-	-	-	-	-	-	-	-	1.64	-	2.42	-	4.06	0.68	0.94	-	2.22	3.84	-	-	1.29	0.70	1.99

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen geration unit

[1]Mm^3/year

Table 5-22 - Processing units additional capacities - Shadow 1A

Additional Capacity (Mtonnes/year)	t1					t2					t3					t4					t5				
	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total
ADU	-	-	-	-	-	1.62	1.16	4.69	-	7.47	0.55	1.02	0.55	5.35	7.47	1.01	1.76	-	4.70	7.47	0.18	0.48	-	-	0.66
VDU	0.44	0.52	0.52	1.23	2.71	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	1.01	0.15	1.16	-	2.32	0.43	0.19	0.25	-	0.87	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REF	0.66	-	0.99	-	1.65	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KEHDT	0.47	0.41	-	-	0.88	0.23	0.40	-	-	0.63	-	0.03	-	-	0.03	-	-	-	-	-	-	-	-	-	-
DIHDT	0.65	1.10	1.30	3.03	6.08	0.55	2.62	1.73	0.89	5.79	0.23	0.35	0.20	2.00	2.78	0.44	0.66	-	2.33	3.43	0.11	0.20	-	0.34	0.65
FCC	-	0.47	0.02	-	0.49	-	0.48	-	-	0.48	-	0.12	-	-	0.12	-	0.24	-	-	0.24	-	0.08	-	-	0.08
RFCC	-	0.33	0.01	-	0.34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	0.29	0.63	0.28	0.26	1.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALK	0.34	0.29	0.32	0.30	1.25	0.02	0.12	0.08	0.08	0.30	-	0.02	-	-	0.02	-	-	-	-	-	-	-	-	-	-
COK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UGH[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	128.94	128.94	172.43	-	1.50	518.98	692.91
HDTI	2.80	1.79	2.52	3.36	10.47	0.23	1.82	1.27	2.20	5.52	0.30	0.25	0.21	2.16	2.92	0.70	0.68	0.12	4.21	5.71	0.29	0.26	-	1.49	2.04

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Table 5-23 - Processing units additional capacties - Shadow 2

Additional Capacity (Mtonnes/year)	t1	t2	t3	t4	t5
ADU	-	7.47	7.47	3.65	-
VDU	6.67	-	-	-	-
DSP	-	-	-	-	-
NAHDT	3.51	0.69	-	-	-
REF	2.19	0.19	-	-	-
KEHDT	1.75	0.45	0.05	-	-
DIHDT	7.79	5.44	2.65	1.68	0.14
FCC	3.06	-	0.34	0.44	0.15
RFCC	2.14	-	-	-	-
HCC	-	-	-	-	-
HDS	3.46	-	-	-	-
ALK	1.13	0.28	0.06	0.05	-
COK	-	-	-	-	-
UGH[1]	-	-	-	-	-
HDTI	-	-	3.90	3.73	2.23

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Table 5-24 - Processing units additional capacties - Shadow 2A

Additional Capacity (Mtonnes/year)	t1	t2	t3	t4	t5
ADU	-	7.48	7.48	5.45	-
VDU	5.74	-	-	-	-
DSP	-	-	-	-	-
NAHDT	3.95	0.67	-	-	-
REF	2.62	-	-	-	-
KEHDT	1.84	0.31	-	0.07	-
DIHDT	8.05	4.56	2.74	2.50	0.32
FCC	3.07	0.06	0.17	0.41	0.11
RFCC	2.13	-	-	-	-
HCC	-	-	-	-	-
HDS	3.17	-	-	-	-
ALK	0.80	0.62	0.02	0.05	-
COK	-	-	-	-	-
UGH[1]	-	-	-	524.62	209.52
HDTI	11.65	5.85	2.74	4.10	2.31

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Utilities consumption and CO_2 emissions

Utilities consumption and CO_2 emissions concern, respectively, the consumption of steam (low, medium and high pressure), fuel (natural gas, fuel oil, fuel gas and coke), electricity and hydrogen by the processing units, and the CO_2 emissions related to the burning of fuel and the grid - if the model opts to buy electricity instead of producing it.

As explained before, the high pressure (HP) steam demand can be supplied by cogeneration units or boilers. The HP surplus is, then, used to supply the medium pressure (MP) steam demand. Therefore, the demand for MP steam can be met firstly by the surplus of HP steam - if it exists – and secondly by cogeneration units and boilers. Finally, the surplus of MP steam can be used to supply low pressure (LP) steam. The fuel option given to the model for steam production was natural gas, both for cogeneration and boilers. In addition to steam, cogeneration produce electricity. Natural gas can also be used to produce hydrogen in the hydrogenation units through the steam reforming process.

Table 5-25, Table 5-26, Table 5-27 and Table 5-28 detail the results of utilities consumption and CO_2 emissions for the Shadow scenarios.

Table 5-25 - Utilities consumption and CO_2 emissions - Shadow 1

Steam	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Low-pressure (LP) steam consumption (10^6 MJ)	-1333.18	-1395.22	-1424.64	-1424.82	-1434.49	-1468.30
Medium-pressure (MP) steam consumption (10^6 MJ)	30020.40	31983.32	36351.69	38105.24	39687.66	39471.22
High-pressure (HP) steam consumption (10^6 MJ)	-1926.89	-1662.42	-1538.58	-1356.52	-1473.92	-1516.49
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	8511.91	6850.64	6315.81	13876.55	5236.69	12715.86
Natural gas - HP steam production (10^6 MJ)	0.00	2489.79	7404.60	0.00	10363.42	2579.54
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	147794.04	128534.76	146956.68	159517.08	166634.64	164541.24
Fuel gas (10^6 MJ)	7536.24	38518.56	39774.60	41868.00	44380.08	45217.44
Coke (10^6 MJ)	55265.76	57777.84	59452.56	64895.40	69919.56	71175.60
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3551.16	3840.01	4077.78	4397.69	4567.37	4557.38
Electricity production (GWh)	3551.16	3810.48	3941.45	4248.39	4248.39	4248.39
Electricity grid (GWh)	0.00	29.53	136.33	149.30	318.98	308.99
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	39577.40	42467.48	43927.05	47347.89	47347.89	47347.89
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3810.75	4186.24	4254.64	5186.11	5723.11	5887.40
Hydrogen consumption (10^6 m^3)	3810.75	4186.24	4254.64	5186.11	5723.11	5887.40
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	60591.07	66561.20	67648.72	82459.32	90996.89	93609.58
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	108680.38	115879.33	117891.58	143683.76	143581.46	153673.32
Fuel oil (10^6 MJ)	147794.04	128534.76	146956.68	159517.08	166634.64	164541.24
Fuel gas (10^6 MJ)	7536.24	38518.56	39774.60	41868.00	44380.08	45217.44
Coke (10^6 MJ)	55265.76	57777.84	59452.56	64895.40	69919.56	71175.60
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	24.72	24.13	26.18	28.82	30.52	30.63

Table 5-26 - Utilities consumption and CO_2 emissions - Shadow 1A

Steam	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Low-pressure (LP) steam consumption (10^6 MJ)	-1333.18	-1335.12	-1230.55	-1329.25	-1465.15	-1498.16
Medium-pressure (MP) steam consumption (10^6 MJ)	30020.40	32226.61	36018.03	38112.31	39891.50	39880.95
High-pressure (HP) steam consumption (10^6 MJ)	-1926.89	-466.36	261.90	237.25	137.74	101.91
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	8511.91	8826.17	13325.05	11034.88	15436.91	10655.39
Natural gas - HP steam production (10^6 MJ)	0.00	0.00	0.00	4725.03	2299.10	7026.03
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	147794.04	148631.40	177939.00	185893.92	191755.44	190499.40
Fuel gas (10^6 MJ)	7536.24	38099.88	38099.88	40611.96	43961.40	45636.12
Coke (10^6 MJ)	55265.76	57359.16	60289.92	64058.04	70338.24	71594.28
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3551.16	4342.00	4775.47	5028.21	5297.89	5310.28
Electricity production (GWh)	3551.16	4129.96	4248.39	4248.39	4248.39	4248.39
Electricity grid (GWh)	0.00	212.05	527.10	779.83	1049.50	1061.90
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	39577.40	46027.95	47347.89	47347.89	47347.89	47347.89
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3810.75	5528.91	6581.37	7033.17	7717.14	7907.80
Hydrogen consumption (10^6 m^3)	3810.75	5528.91	6581.37	7033.17	7717.14	7907.80
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	60591.07	87909.54	104644.04	111827.43	122702.38	125733.98
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	108680.38	142763.66	165316.97	170210.19	185487.17	183737.25
Fuel oil (10^6 MJ)	147794.04	148631.40	177939.00	185893.92	191755.44	190499.40
Fuel gas (10^6 MJ)	7536.24	38099.88	38099.88	40611.96	43961.40	45636.12
Coke (10^6 MJ)	55265.76	57359.16	60289.92	64058.04	70338.24	71594.28
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	24.72	26.98	30.80	32.51	34.49	34.74

Table 5-27 - Utilities consumption and CO_2 emissions - Shadow 2

Steam	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Low-pressure (LP) steam consumption (10^6 MJ)	-1134.67	-1342.51	-1330.27	-1418.34	-1511.13	-1280.00
Medium-pressure (MP) steam consumption (10^6 MJ)	30042.89	33805.30	36876.47	39018.23	39987.82	21909.92
High-pressure (HP) steam consumption (10^6 MJ)	-1592.61	-2146.90	-1871.60	-1394.55	-1291.15	-5160.50
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	2832.25	8518.55	10049.84	7594.96	16168.25	15373.20
Natural gas - HP steam production (10^6 MJ)	7883.93	1487.82	5001.08	7610.06	0.00	0.00
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	133977.60	139001.76	146538.00	162866.52	167053.32	163285.20
Fuel gas (10^6 MJ)	17584.56	40611.96	39774.60	42705.36	43961.40	44380.08
Coke (10^6 MJ)	50241.60	63639.36	61964.64	66151.44	68244.84	69919.56
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3292.92	4026.83	3973.62	4435.65	4619.43	4559.86
Electricity production (GWh)	3292.92	3941.82	3781.54	4205.10	4248.39	4187.93
Electricity grid (GWh)	0.00	85.01	192.09	230.55	371.04	371.94
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	36699.27	43931.24	42144.99	46865.48	47347.89	46674.07
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3621.10	4355.64	4224.37	5230.39	5675.79	5848.19
Hydrogen consumption (10^6 m^3)	3621.10	4355.64	4224.37	5230.39	5675.79	5848.19
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	57575.47	91798.26	106749.64	113621.25	121512.34	125083.52
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	97106.99	144248.04	158944.47	168081.69	185028.48	187130.79
Fuel oil (10^6 MJ)	133977.60	139001.76	146538.00	162866.52	167053.32	163285.20
Fuel gas (10^6 MJ)	17584.56	40611.96	39774.60	42705.36	43961.40	44380.08
Coke (10^6 MJ)	50241.60	63639.36	61964.64	66151.44	68244.84	69919.56
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	22.78	25.81	26.32	29.22	30.38	30.34

Table 5-28 - Utilities consumption and CO_2 emissions - Shadow 2A

Steam	t0	t1	t2	t3	t4	t5
Low-pressure (LP) steam consumption (10^6 MJ)	-1134.67	-1280.61	-1206.45	-1289.39	-1356.76	-1574.85
Medium-pressure (MP) steam consumption (10^6 MJ)	30042.89	32642.99	36068.94	38129.59	39306.82	39629.26
High-pressure (HP) steam consumption (10^6 MJ)	-1592.61	-1044.78	64.73	8.07	-132.48	326.59
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	2832.25	7692.32	9404.97	15510.62	14411.22	17649.64
Natural gas - HP steam production (10^6 MJ)	7883.93	364.00	3747.99	0.00	2319.01	0.00
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	133977.60	155748.96	176264.28	183800.52	187568.64	189243.36
Fuel gas (10^6 MJ)	17584.56	39774.60	38518.56	41030.64	43124.04	45636.12
Coke (10^6 MJ)	50241.60	63639.36	62383.32	66570.12	71175.60	69919.56
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3292.92	4472.64	4722.23	4952.32	5108.95	5361.08
Electricity production (GWh)	3292.92	4213.78	4248.39	4248.39	4248.39	4248.39
Electricity grid (GWh)	0.00	258.87	473.84	703.94	860.57	1112.70
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	36699.27	46962.12	47347.89	47347.89	47347.89	47347.89
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3621.10	5773.48	6713.81	7145.98	7642.28	7866.88
Hydrogen consumption (10^6 m^3)	3621.10	5773.48	6713.81	7145.98	7642.28	7866.88
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	57575.47	69254.63	67167.37	83163.20	90245.14	92986.25
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	97106.99	123909.07	123920.22	146021.71	152004.24	157983.77
Fuel oil (10^6 MJ)	133977.60	155748.96	176264.28	183800.52	187568.64	189243.36
Fuel gas (10^6 MJ)	17584.56	39774.60	38518.56	41030.64	43124.04	45636.12
Coke (10^6 MJ)	50241.60	63639.36	62383.32	66570.12	71175.60	69919.56
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	22.78	28.45	30.97	32.64	34.05	34.48

The results show, in all scenarios, an increase in utility consumption, which is a consequence of the increased capacity of processing units. In Shadow 1A and Shadow 2A, the increase are even more significant, due to the higher presence of HDTI units, which demand large amounts of steam, electricity and hydrogen.

With respect to the electricity, the options given to the model were to produce electricity through existing cogeneration units, invest in additional cogeneration capacities as well as buy the electricity from the grid. From the results it is possible to see that, in all scenarios, the model first produces electricity with the existing

cogeneration capacity, and when it reaches the maximum capacity, it buys electricity from the grid, since it is a cheaper option than investing in additional cogeneration capacities.

Regarding CO_2 emissions, since no environmental constraints have been applied to the model, such as carbon taxes or CO_2 caps, and as utilities consumptions increase in all scenarios, they also grow. Neverthless, the option of taxing as well as limiting CO_2 emissions is available in the ORION model and could well be tested in other scenario exercises. Moreover, precisely because of the lack of environmental constraints, and given that the model has the objective of minimizing cost, the cheapest fuels were chosen, although they are the most polluting in terms of emissions, such as the fuel oil produced by the refining process itself, with no associated purchase price, as well as the coke produced and consumed at the FCC and RFCC units.

Although Shadow 1 and Shadow 1A present a lower crude oil consumption, lower total oil derivatives production and a lower ADU capacity level at t0, their CO_2 emissions are slightly higher at this period than those of Shadow 2 and Shadow 2A scenarios. This can be explained by greater capacity levels of FCC, which consumes high amounts of coke, and of HDS which has high hydrogen consumption - what, in turn, increases the hydrogen production in the hydrogen generating units, and consequently increases the total consumption of natural gas.

Finally, the CO_2 emission values obtained for t0, in all scenarios, are in accordance with Petrobras estimates (PETROBRAS, 2017), which state that the Brazilian refining CO_2 emissions have varied, in recent years, between 23 and 25 Mtonnes/year.

Costs

As formerly presented, the model´s objective function consists in minimizing the total cost for supplying liquid fuels demand (in present value, i.e., considering all costs for 2015), which includes the crude oil purchase cost, the fuel and electricity purchase costs to meet refinery's utilities demand, the national trades costs, the oil products imports costs, the national trades of oil products costs, the refining costs (processing costs of installed and eventually additional units), the investment costs in additional processing units capacities, the investments costs in harbor capacity expansion, and the revenues related to oil products exports. Table 5-29 details the total costs, ie, the

resulting values for the objective function. Figure 5-11 gives the share, in each scenario, of the cost elements considered.

Table 5-29 - Total costs (Z) - Shadow scenarios

Scenario	Total Cost (Z) - 10^9 US$
Shadow 1	743.26
Shadow 1A	749.42
Shadow 2	764.53
Shadow 2A	770.71

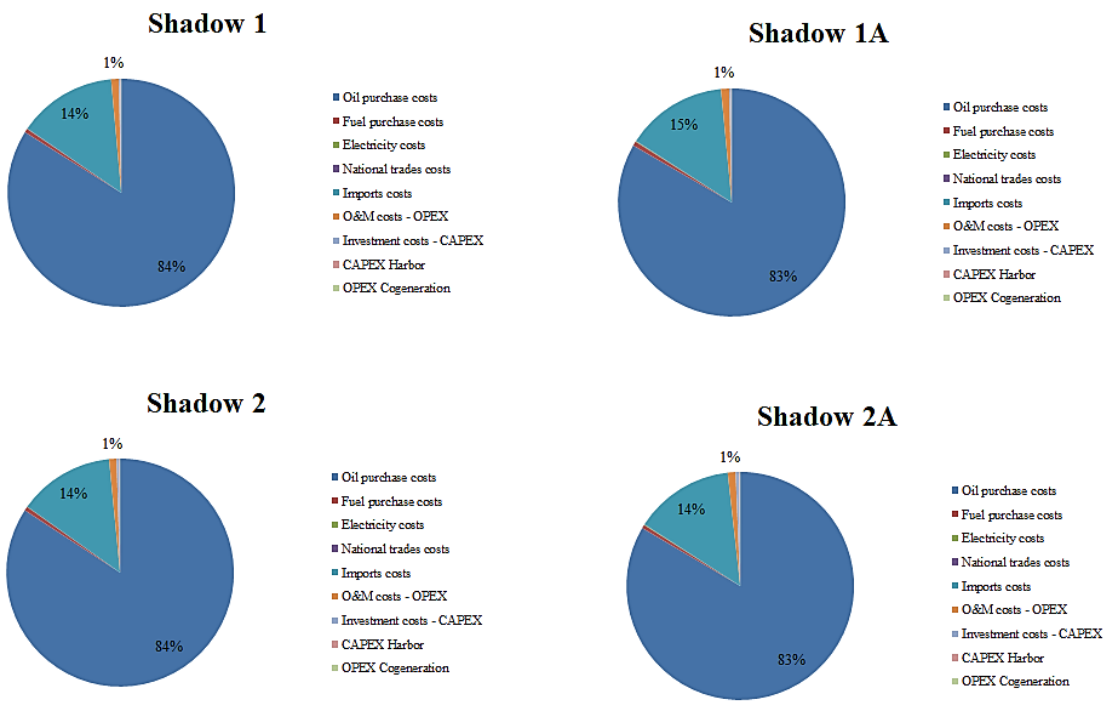

Figure 5-11 - Costs elements shares - Shadow scenarios

According to the results, Shadow 2 and Shadow 2A scenarios are more expensive than Shadow 1 and 1A scenarios, respectively. Despite having more exports, which increases the exports revenues, and less imports, Shadow 2 and 2A have higher crude oil consumption levels, as well as higher capacities for almost all processing units between t0 and t3. As the oil purchase costs account for more than 80% of total costs, and as the processing units OPEX costs are part of the highest cost shares (although they represent 1% of the total), it was expected that Shadow 2 and 2A scenarios would have a higher total cost than Shadow 1 and Shadow 1A scenarios.

Comparing Shadow 1A and Shadow 2A, with Shadow 1 and Shadow 2 scenarios, respectively, the firsts are more expensive. Besides having higher processing units capacities, higher consumption of natural gas and electricity (which have

associated costs), these scenarios have significant investments in HDTI additional capacities, as previously mentioned, which increases the total cost of the system.

In all scenarios, the largest share of the total cost relates to the purchase of crude oil, as already mentioned, followed by import costs and OPEX costs. In Shadow 1 and Shadow 2, the oil purchase costs represent between 84% of the total refining system cost. In Shadow 1A and Shadow 2A it represents 83%. Given that imports are higher in the last two scenarios, there is a decrease in the share of oil purchase costs and an increase in the share of imports costs, when comparing to the first two scenarios.

Lastly, although the costs of investing in a processing unit (CAPEX) are known to be higher than its O&M costs (OPEX), the OPEX share of the total system cost is higher, since it is an annualized cost. In addition, OPEX costs are associated with all processing units, whether existing or additional ones, while CAPEX are associated only with additional capacities. Hence, the OPEX total system cost share is expected to be higher.

The following section presents the results for the Cloudy scenarios.

5.2.2. Cloudy scenarios

As for the Shadow scenarios, the Cloudy scenarios are first run for the four cases presented in Figure 3-1, that is the multi-regional case without (Cloudy 1) and with (Cloudy 1A) heavy fuel oil specifications from t1, in light of the IMO's regulations to reduce sulfur oxides (SOx) emissions from ships fuel, and the single-regional case without (Cloudy 2) and with (Cloudy 2A) the heavy fuel oil specification.

Given that the oil derivatives demand of Cloudy scenarios is very similar to that of the Shadow scenario, with a total reduction at t5 of only 6%, and with a very close demand profile across all periods, the results obtained resemble to the Shadow's ones. The only differences between them relate to quantities. The behavior of the results is exactly the same. This fact confirms the robustness of the ORION model. Given that a very small change was made in the demand scenario, it was expected that the results would not show significant differences.

Therefore, this section details only part of the results, that is, the oil derivatives production, the oil derivatives imports and exports, the processing units capacities and the costs. Nevertheless, the remainder results can be found in Annex D.

Oil derivatives production

The results for each Cloudy scenario concerning their oil derivatives production by time period are presented below. For the Cloudy 1 and Cloudy 1A scenarios, which are multi-regional cases, the results are also presented by region of the model (S_S, NE_S, RJMG_S, SP_S).

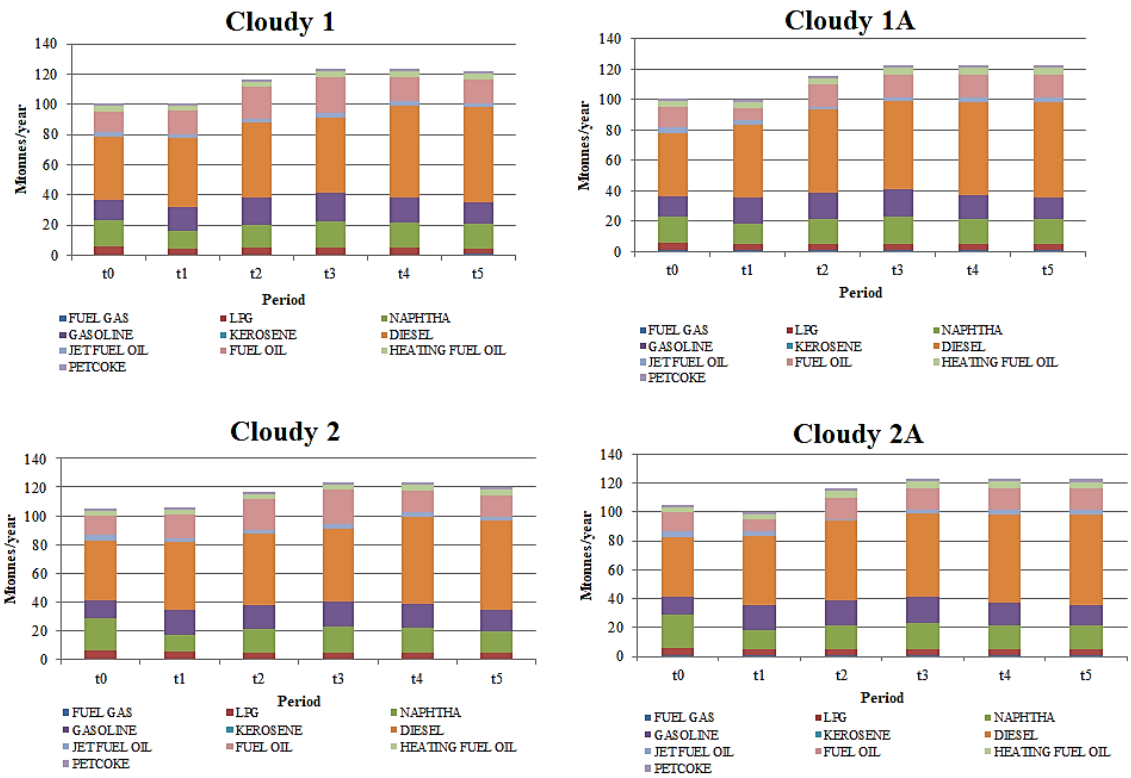

Figure 5-12 - Oil derivatives production - Cloudy scenarios

As may be observed in Figure 5-12, the results, in terms of production profile, are very close to the Shadow scenarios' ones, with slight modifications in the amount produced of each oil derivative. Hence, while Shadow 1 presents a total production of 131.6 Mtonnes/year in period t5, and Shadow 1A a production of 132.8 Mtonnes/year, Cloudy 1 shows a total production of 123.5 Mtonnes/year and Cloudy 1A a production of 124.9 Mtonnes/year in the same period, which represent reductions of 6.2% and 5.9%, respectively. Similarly, Shadow 2 has a total production of 129.9 Mtonnes/year and Shadow 2A a production of 131.0 Mtonnes/year in period t5, while Cloudy 2 presents a total production of 121.9 Mtonnes/year, and Cloudy 2A a production of 124.9

Mtonnes/year. The corresponding reductions in these cases are 6.1% and 5.0% respectively.

The largest production in Cloudy 1 and 2 scenarios concerns to diesel, followed by fuel oil, naphtha and gasoline (see Figure D-5 in Annex D). However, as in the Shadow scenarios, although gasoline although gasoline has one of the largest production shares, its total production reduces between t0 and t5. In Cloudy 1A and Cloudy 2A, the largest production also regards to diesel, however, fuel oil production is lower from t1, due to the application of the IMO regulation, making naphtha the second largest oil derivative produced, followed by gasoline.

As for the Shadow 1A and Shadow 2A, despite this lower production of fuel oil in Cloudy 1A and Cloudy 2A scenarios, it is still sufficient (except at t1[31]), even under stringent sulfur specification, to meet the national demand. In order to achieve this sulfur condition, investments in additional unstable hydrotreatment units (HDT I) are made, as will be shown later.

As regards LPG production, the ORION model still reduces its production throughout the time horizon, thus giving space for a higher production of other derivatives.

The most visible difference regarding the production of oil derivatives between the Shadow and Cloudy scenarios regards to diesel. Cloudy 1 and Cloudy 2 present a reduction on the production of this oil derivative of 6.5% and 6.9%, and Cloudy 1A and Cloudy 2A of 4.0% and 4.6%, respectively. It is understood that the smallest reduction in scenarios "A" is because they have lower production of fuel oil (IMO regulation), which gives space for the maintenance of a higher production of diesel.

Like in Shadow scenarios, the smallest production shares (see Figure D-5 in Annex D), in all scenarios, correspond to fuel gas, kerosene, petcoke and jet fuel oil.

Finally, regarding the multi-regional cases (Cloudy 1 and Cloudy 1A), the results look like those of Shadow 1 and Shadow 1A, with respect to the oil derivatives production profile per period and region of the model. Table D-3 and Table D-4 in Annex D detail these results. Once again, the SP_S region presents the largest oil derivatives production, for almost all products, folowed by the S_S, NE_S and RJMG_S

[31] Again, at period t1 the production of fuel oil considerably reduces in these two scenarios, which is considered to be a short-term response of the model, given the application of IMO regulation in this period, and which leads to imports of fuel oil. However, from t2, the production is resumed, thus meeting the demand for this oil derivative, and imports cease.

regions, with variations depending on the oil derivative and the period. As previously explained, this is a consistent result, since SP_S region has the highest refining capacity among all regions, and, although S_S region has lower capacity than NE_S region, as well as lower demand for derivatives, it receives fewer trades from other regions – and also imports - than NE_S region, as will be still shown, which ultimately forces higher production of oil derivatives in this region.

Oil derivatives imports and exports

The results for each Cloudy scenario concerning their oil derivaties imports by time period are presented in Figure 5-13. Table D-5 and Table D-6 in Annex D exhibit the imports tin Cloudy 1 and Cloudy 1A (multi-regional frameworks) per period and region of the model (S_S, NE_S, RJMG_S, SP_S).

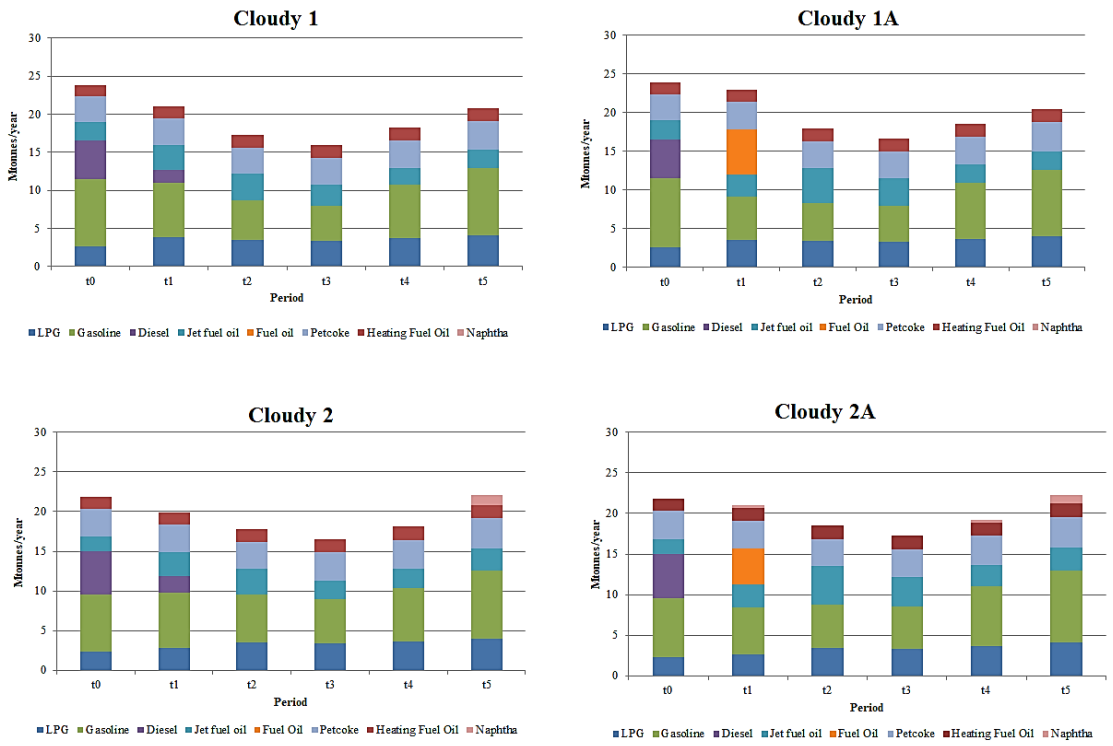

Figure 5-13 - Oil derivatives imports - Cloudy scenarios

From Figure 5-13 it can be observed that, as for the results of oil derivatives production, the oil derivatives imports results resemble those of Shadow scenarios, with small differences in terms of total imports amounts, and imports quantites per oil derivative. While Shadow 1 presents total oil derivatives imports of 21.2 Mtonnes/year in period t5, and Shadow 1A of 21.0 Mtonnes/year, Cloudy 1 shows total imports of

20.8 Mtonnes/year and Cloudy 1A of 20.4 Mtonnes/year in the same period, which represent reductions of 1.8% and 2.9%, respectively. Similarly, Shadow 2 and Shadow 2A have total oil derivatives imports of 21.9 Mtonnes/year in period t5, while Cloudy 2 show total imports of 22.1 Mtonnes/year, and Cloudy 2A of 22.3 Mtonnes/year. The corresponding reductions in these cases are 1.0% and 1.8% respectively.

The most imported oil derivative in Cloudy scenarios is still gasoline, followed by petcoke, LPG and jet fuel oil, but less so than in Shadow scenarios. As regards fuel oil, it is again imported only at t1, in Cloudy 1A and Cloudy 2A scenarios, which can be understood as a model's short-term response given the implementation of the IMO regulation in this period. From t2 onwards it is no longer imported, and all the fuel oil demanded is produced - even under higher sulfur specifications – through investments in HDTI units.

As regards fuel oil, once again in all scenarios, even in the ones considering the IMO specification, imports only occur at t0 and t1. After that, the model's result show a production all the fuel oil demanded, as a consequence of the high price attributed to it (OURSE results), which, in turn, makes it more advantageous to produce the oil derivate, even if it is necessary to invest in hydrotreating units to meet its stringent specifications. Still, in Cloudy 1 and Cloudy 2 scenarios there are exports of fuel oil at periods t1, t2 and t3, which is an outcome of the profile production of oil derivatives (geared towards medium/heavy distillates), that, in turn, can be influenced by oil derivatives prices given by the OURSE model, which are expensive for medium distillates and can lead to excessive export-oriented production.

Concerning diesel, as for the Shadow scenarios, there are imports of 4.97 Mtonnes/year at t0 in Cloudy 1 and Cloudy 1A scenarios, and of 5.52 Mtonnes/year in Cloudy 2 and Cloudy 2A scenarios. As t0 is the calibration period of the model, its results are the same for all scenarios. Again, these results are in accordance with ANP (2018) diesel imports data for 2015, of 5.8 Mtonnes/year (or 6,940.1 thousand m^3/year). Still, in Cloudy 1 and Cloudy 2 there are imports of 1.7 Mtonnes/year and 2 Mtonnes/year at period t1. However, as shown by Figure 5-14, from t2 onwards it starts to be exported, varying from scenario to scenario the period in which exports start. At period t5 its exports are of 11.4 Mtonnes/year in Cloudy 1 and Cloudy 1A scenarios, and of 11.0 Mtonnes/year in Cloudy 2 and Cloudy 2A scenarios. Although exports of diesel in Cloudy scenarios are higher at period t5, total imports from all periods, for this oil derivative specifically, are lower in Cloudy 1 and Cloudy 2 scenarios, since diesel

begins to be exported at a later period of time than in Shadow 1 and Shadow 2 scenarios, respectively.

As previously explained, the diesel prices generated by the OURSE model, and implemented in the ORION model are very high for diesel at the end of the analysis horizon, thus, it is interesting for the model to produce diesel surpluses, with the aim of exporting them. In addition, it is worth mentioning the national trades that occur in the Cloudy 1 and Cloudy 1A scenarios, which have no limitations within the model, but only associated transportation costs, and which may lead the model to meet the demand for diesel of certain regions without the need for imports.

As regards naphtha, the same occurs in Shadow and Cloudy scenarios, that is, although Brazil is a net importer the model exports naphtha from t0 in Cloudy 1 and Cloudy 1A, and from t1 in Cloudy 2 and Cloudy 2A. In addition to the high prices generated by the OURSE model for this oil derivative – which leads the model to produce surpluses in order to export - the model has imports and exports limits given by classification of oil derivatives (light, medium, heavy), that may leave it on the threshold of choosing to produce or import LPG, naphtha and gasoline, for example, since they are classificated as light derivatives. The same applies to other oil derivatives, as diesel, kerosene, jet fuel oil, fuel oil and heating fuel oil, which are classificated as medium derivatives. Regarding petcoke, it is the only heavy oil derivative in the model, thus it does not present threshold results.

Figure 5-14 presents the oil derivatives exports for the Cloudy scenarios.

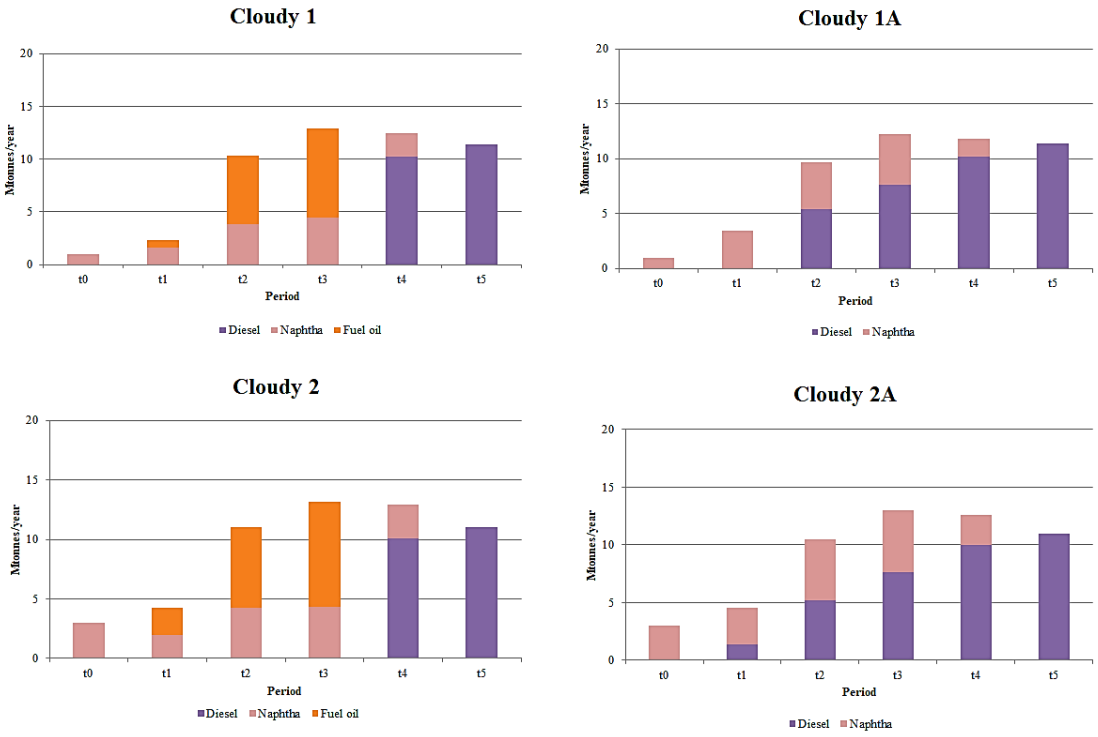

Figure 5-14 - Oil derivatives exports - Cloudy scenarios

As can be seen, oil derivatives exports in Cloudy scenarios follow the same trend of exports of Shadow scenarios, that is, the two oil derivatives exported in Cloudy 1 and Cloudy 2 are diesel, naphtha, and fuel oil, and in Cloudy 1A and Cloudy 2A, diesel and naphtha. Nonetheless, in Cloudy scenarios the total exported quantities are slightly greater than in Shadow scenarios (except for diesel, as already presented). These results are consistent, as the demands for oil derivatives are slightly lower in these cases, and the oil derivatives production and imports results have not shown significant change from the Shadow scenarios.

Thus, the total sum of exports of all periods are of 50.4 Mtonnes in Cloudy 1, 49.6 Mtonnes in Cloudy 1A, 55.39 Mtonnes in Cloudy 2 and 54.4 Mtonnes in Cloudy 2A. The same values for Shadow1, Shadow 1A, Shadow 2 and Shadow 2A are, respectively, 45.3 Mtonnes, 45.5 Mtonnes, 52.9 Mtonnes and 49.2 Mtonnes.

Regarding the multi-regional cases (Cloudy 1 and Cloudy 1A), the results look like those of Shadow 1 and Shadow 1A, with respect to the oil imports/exports per period and region of the model. As already mentioned, Table D-5 and Table D-6 in Annex D detail these results. In sum, the results by region follow the same regional logic as the results for Shadow scenarios, differing only in imported/exported quantities, as previously presented. Thus, on average, the region that imports the most is the NE_D

region, followed by the SP_D, S_S and RJMG_D regions; and the major exporting region is still SP_S, followed by RJMG_S, S_S and NE_S.

Processing units capacities

The results for processing units capacities relate to both capacity levels in each period of time as well as additional capacities, if any. Figure 5-15 exhibits the capacities levels for each processing unit considered in the models' refining scheme, for each Cloudy case, in each time period.

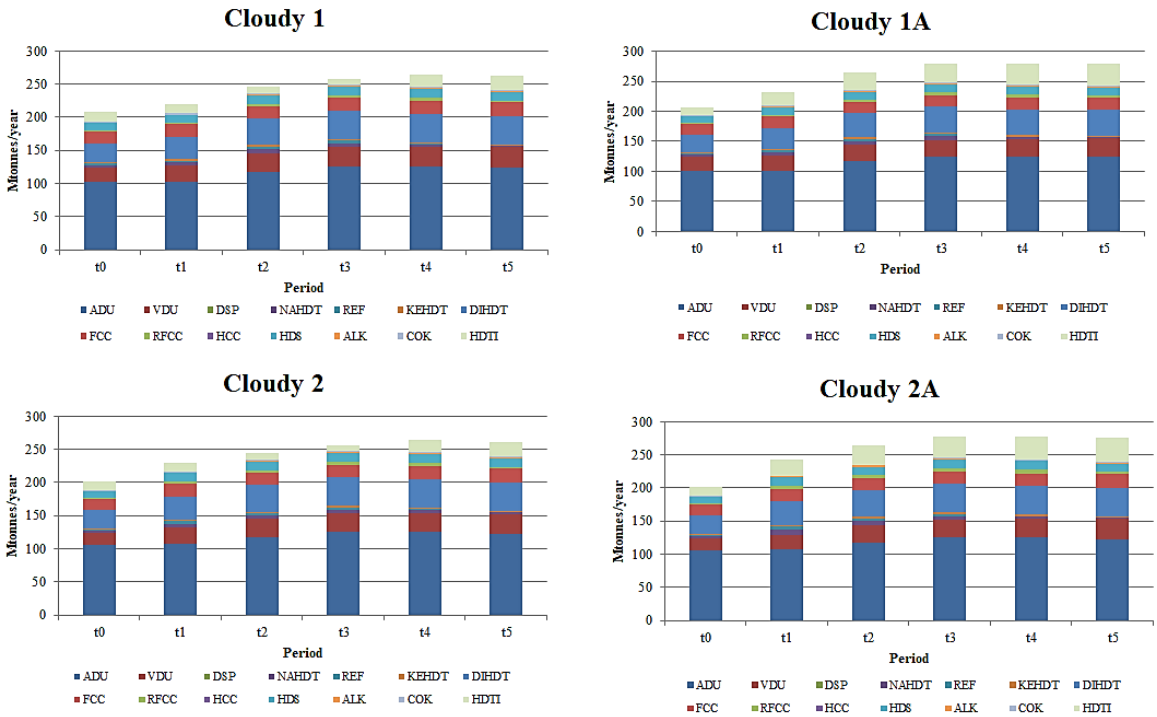

Figure 5-15 - Processing units level capacities - Cloudy scenarios[32]

As observed, at period t0, the capacities in all scenarios are exactly the same as those of Shadow scenarios. As this is the base period, it was already expected to have this result. Thus, at t0, the utilization factor of Cloudy scenarios continue to be 87.1% for Cloudy 1 and Cloudy 1A, and 90.7% for Cloudy 2 and Cloudy 2A.

Regardig the capacity levels over time, once again, all scenarios present a tendency of growth. Still, these capacities increases occur either through investments in

[32]Results concerning the capacities of the hydrogeneration unit (CAPUGH) and cogeneration unit (CAPCOG) are not represented in the graphs, given that they have units of measurement other than Mtonnes/year. The resulting values for these processing units can be found in Annex D.

additional capacities or through increasing refining utilization factor, ie, through raising the use of existing capacities.

Since the changes of oil derivatives demands between Cloudy and Shadow scenarios is very low, as previously presented, by leaving the model free to invest in additional processing units capacities, it continues to make high investments, although smaller than in the Shadow scenario. In the specific case of the atmospheric distillation unit, by running Cloudy 1 scenario without investments constraints, the model presents a total addition of 33.7 Mtonnes/year of CAPADU, again with the purpose of exporting all excess production, which corresponds principally to diesel, naphtha and fuel oil. Moreover, investments also occur mainly in period t2 (approximately 31.5 Monnes/year of additional CAPADU only in this period), and the atmospheric distillation capacities in the South and São Paulo regions are almost doubled.

Hence, as for the Shadow scenarios, a maximum limit of investments in additional CAPADU, per period, of 7.5 Mtonnes/year - or 150 thousand of barrels per day - was introduced in the model. Under this new constraint, the model presents a total investment in additional CAPADU of 14.94 Mtonnes/year, or 0.3 million of barrels per day (Mb/d), spread over periods t2 and t3. This value is approximately 30% lower than in the Shadow scenario.

Regarding the capacities of all processing units, the largest increases in all scenarios still relate, after the atmospheric distillation (ADU), to the vacuum distillation (VDU), diesel hydrotreating (DIHDT) and unstable hydrotreating units (HDTI). However, as for the ADU, capacity increases occur on a smaller scale in Cloudy scenarios than in Shadow scenarios.

Despite the trend of capacity increases, Cloudy scenarios also show a capacity reduction of REF and NAHDT units, between t4 and t5 for Shadow 1 and Shadow 1A, and between t3 and t5 for Shadow 2 and Shadow 2A . This can be explained by the gasoline profile production per period, which follows the same trend of REF and NAHDT units capacities in each scenario.

Regarding the growth of HDTI units capacitites, as in the Shadow scenarios, the Cloudy 1A and Shadow 2A scenarios present a higher increase than the Cloudy 1 and Cloudy 2, what is explained by the application of the IMO sulfur specification in the first two cases. Therefore, in Cloudy 1A and Cloudy 2A, in addition to increasing the utilization of existing HDTI units capacities, an even greater amount of investment in additional units is made.

For the Cloudy 1 and Cloudy 1A scenarios, which are multi-regional cases, Table D-9 and Table D-10 in Annex D present the results of processing units capacities per period and region of the model. It can once again be seen that, on average, in both scenarios the region with the highest processing unit level capacity is the SP_S region, which makes sense due to its higher maximum refining capacity (47.2 Mtonnes/year) at t0, and to the results of regional investments in additional processing units capacities. After SP_S region, the second region with the highest processing units level capacities is the S_S region, followed by the RJMG_S region in the first two periods and the NE_S region in the last four periods. Although S_S region has lower maximum ADU available capacity (22.37 Mtonnes/year) than NE_S region (25.77 Mtonnes/year) at t0 and t1, as well as lower demand for derivatives, it receives fewer trades from other regions than NE_S region, as shown in the National Trades section, which ultimately forces higher production of derivatives and consequent higher capacity levels in this region at periods t0 and t1. Regarding the increase in capacities of RJMG_S and NE_S regions from t2, they are due to investments in additional units capacities.

In this context, Table 5-30, Table 5-31, Table 5-32 and Table 5-33 present the processing units additional capacities for the Cloudy 1 and Cloudy 1A per period and region of the model, and for Cloudy 2 and Cloudy 2A per period considered.

As it can be seen, the main investments in additional capacities after the distillation unit (ADU) are for the diesel hydrotreating units (DIHDT) in Shadow 1 and Shadow 2 scenarios, and for the unstable hydrotrating units (HDTI) in Shadow 1A and Shadow 2A scenarios. However, as already mentioned, the additional capacities levels are lower in Cloudy than in scenarios.

As for the Shadow scenarios, in Cloudy 1 and in Cloudy 1A the investments in additional capacities per region vary again by period, which can be understood to be a consequence of the processing units capacities already existing in each region, as well as the regional demand scenario considered, the imports/exports, and national trades results. Moreover, it can also be seen that in the case of REF and NAHDT units, even if they have a total capacity reduction at the end of analysis horizon, there are investments in the first periods. The regions with the largest investments in ADU additional capacities are again SP_S and RJMG_S.

Table 5-30 - Processing units additional capacties - Cloudy 1

Additional Capacity (Mtonnes/year)	t1					t2					t3					t4					t5				
	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total
ADU	-	-	-	-	-	-	-	5.18	2.29	7.47	1.96	-	-	5.51	7.47	-	-	-	-	-	-	-	-	-	-
VDU	0.97	0.62	0.53	1.51	3.63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	0.26	0.15	0.03	-	0.44	0.95	0.25	0.62	-	1.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REF	-	-	-	0.38	0.38	0.23	-	-	0.75	0.98	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KEHDT	0.29	0.36	-	-	0.65	0.56	0.77	-	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIHDT	0.98	0.63	0.76	2.58	4.95	0.78	3.32	3.20	4.73	12.03	0.54	-	-	1.84	2.38	0.34	-	-	0.41	0.75	-	-	-	-	-
FCC	-	0.53	-	-	0.53	-	0.81	-	-	0.81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RFCC	-	0.37	-	-	0.37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	0.15	0.64	0.27	0.18	1.24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALK	0.18	0.24	0.32	0.22	0.96	0.28	0.39	0.40	0.40	1.47	0.09	-	-	0.10	0.19	-	-	-	-	-	-	-	-	-	-
COK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UGH[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDTI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.70	-	2.90	1.39	5.99	-	-	1.15	0.46	1.61

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Table 5-31 - Processing units additional capacties - Cloudy 1A

Additional Capacity (Mtonnes/year)	t1					t2					t3					t4					t5				
	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total
ADU	-	-	-	-	-	2.14	1.49	3.84	-	7.47	0.03	0.82	1.34	5.28	7.47	-	-	-	-	-	-	-	-	-	-
VDU	0.56	0.52	0.06	1.14	2.28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	0.34	0.15	1.15	-	1.64	1.08	0.57	0.60	-	2.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REF	0.08	-	0.93	0.14	1.15	0.33	-	-	0.61	0.94	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KEHDT	0.43	0.41	-	-	0.84	0.61	0.60	-	-	1.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIHDT	0.73	1.09	1.29	2.99	6.10	1.38	3.83	2.74	3.92	11.87	0.01	0.28	0.46	1.80	2.55	0.09	-	-	0.86	0.95	-	-	0.02	0.17	0.19
FCC	-	0.47	0.67	-	1.14	-	0.99	-	-	0.99	-	0.09	-	-	0.09	-	-	-	-	-	-	-	0.02	-	0.02
RFCC	-	0.33	0.46	-	0.79	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	0.25	0.63	0.81	0.28	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALK	0.30	0.29	0.31	0.33	1.23	0.37	0.41	0.38	0.38	1.54	-	0.01	0.02	0.08	0.11	-	-	-	-	-	-	-	-	-	-
COK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UGH[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62.29	-	-	289.60	351.89
HDTI	3.22	1.79	2.47	2.35	9.83	3.14	3.68	3.64	5.51	15.97	0.05	0.20	0.34	1.39	1.98	0.38	0.02	0.03	3.67	4.10	0.17	-	0.12	1.07	1.36

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen geration unit

[1]Mm^3/year

Table 5-32 - Processing units additional capacties - Cloudy 2

Additional Capacity (Mtonnes/year)	t1	t2	t3	t4	t5
ADU	-	7.47	7.47	-	-
VDU	6.62	-	-	-	-
DSP	-	-	-	-	-
NAHDT	2.63	3.96	-	-	-
REF	1.47	2.09	-	-	-
KEHDT	1.52	1.37	0.05	-	-
DIHDT	6.48	12.11	2.50	0.46	-
FCC	3.17	0.91	0.37	-	-
RFCC	2.21	-	-	-	-
HCC	-	-	-	-	-
HDS	3.02	-	-	-	-
ALK	0.52	1.40	0.17	-	-
COK	-	-	-	-	-
UGH[1]	-	-	-	-	-
HDTI	-	-	-	5.48	1.98

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen geration unit

[1]Mm^3/year

Table 5-33 - Processing units additional capacties - Cloudy 2A

Additional Capacity (Mtonnes/year)	t1	t2	t3	t4	t5
ADU	-	7.46	7.47	-	-
VDU	5.54	-	-	-	-
DSP	-	-	-	-	-
NAHDT	4.02	4.26	-	-	-
REF	2.66	2.04	-	-	-
KEHDT	1.86	1.32	0.01	-	-
DIHDT	7.97	11.87	2.58	0.82	0.05
FCC	3.21	1.11	0.37	-	-
RFCC	2.24	-	-	-	-
HCC	-	-	-	-	-
HDS	3.31	-	-	-	-
ALK	0.80	1.52	0.09	-	-
COK	-	-	-	-	-
UGH[1]	-	-	-	-	163.66
HDTI	11.26	15.49	2.50	3.64	1.81

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Costs

The last results to be presented for the Cloudy scenarios are the costs. Table 5-34 details the total costs, ie, the resulting values for the objective function. Figure 5-16 gives the share, in each scenario, of the cost elements considered, which are, as previously presented, the crude oil purchase cost, the fuel and electricity purchase costs to meet refinery's utilities demand, the national trades costs, the oil products imports costs, the national trades of oil products costs, the refining costs (processing costs of installed and eventually additional units), the investment costs in additional processing units capacities, the investments costs in harbor capacity expansion, and the revenues related to oil products exports.

Table 5-34 - Total costs (Z) - Cloudy scenarios

Scenario	Total Cost (Z) - 10^9 US$
Cloudy 1	729.47
Cloudy 1A	736.25
Cloudy 2	751.19
Cloudy 2A	757.94

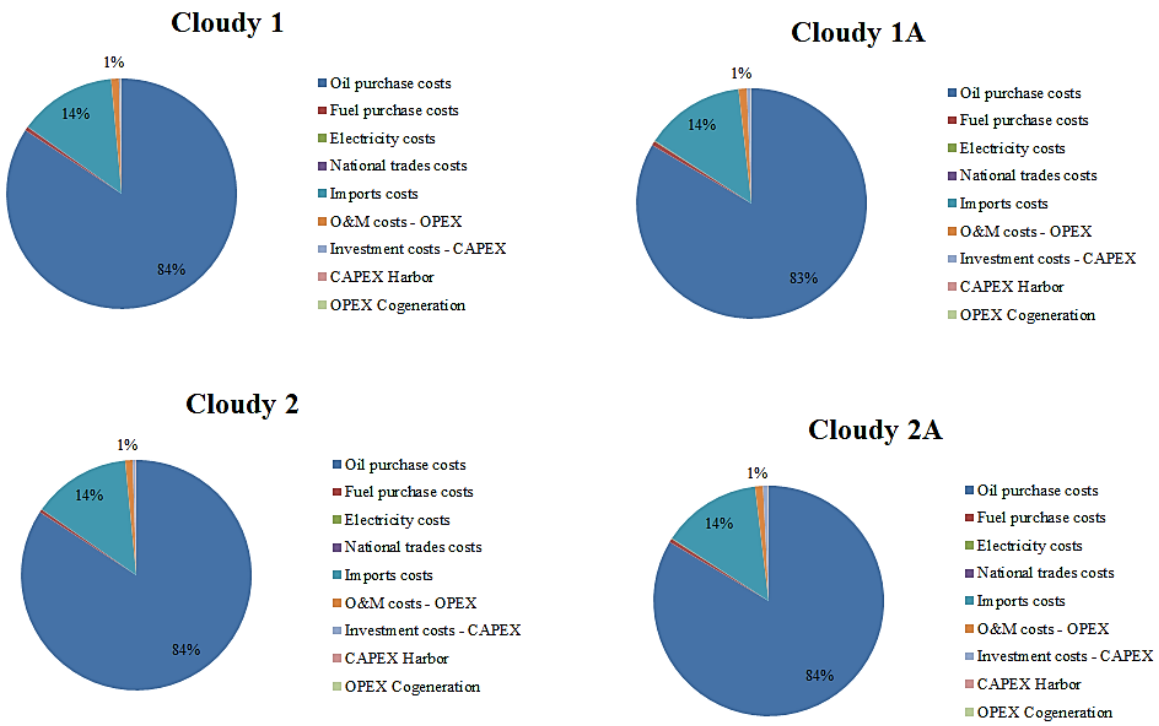

Figure 5-16 - Costs elements shares - Cloudy scenarios

As expected, the total costs are lower in Cloudy scenarios than in Shadow scenarios. Costs variations are on average, for all Cloudy scenarios, of approximately 13.3 billions of dollars less, which represent a reduction of 2%. These differences can be explained for a number of reasons. The first one concerns the crude oil consumption. As the total crude oil consumption is lower in Cloudy scenarios, the crude oil purchase costs are also less expensive. In addition, as capacity levels are lower, OPEX costs are reduced. Concerning imports and exports, as imports are smaller in Cloudy scenarios, their costs are lower than in Shadow scenarios. Another difference is related to CAPEX costs (investments in additional processing units capacities). As in Cloudy scenarios the amounts of additional capacities are lower, the CAPEX costs are diminished. On the other hand, as previously presented, the total exports are higher in Cloudy scenarios, which increases their revenues, and which may explain a smaller reduction in total costs than in the production of oil derivatives, for example, when comparing Cloudy with Shadow scenarios.

Regarding the comparison of Cloudy scenarios between themselves, as for the Shadows, Cloudy 2 and Cloudy 2A scenarios are more expensive than Cloudy 1 and 1A scenarios, respectively. Despite having more exports, which increases the exports revenues, and less imports, Cloudy 2 and 2A have higher crude oil consumption levels, as well as higher capacities for almost all processing units between t0 and t3. As the oil purchase costs account for more than 80% of total costs, and as the processing units OPEX costs are part of the highest cost shares (although they represent 1% of the total), it was expected that Cloudy 2 and 2A scenarios would have a higher total cost than Cloudy 1 and Cloudy 1A scenarios.

Moreover, Cloudy 1A and Cloudy 2A are more expensive than Cloudy 1 and Cloudy 2 scenarios, respectively. Besides having higher processing units capacities, higher consumption of natural gas and electricity (see Annex D), these scenarios have significant investments in HDTI additional capacities, as previously mentioned, which increases the total cost of the system.

Finally, it is important to mention again that although the costs of investing in a processing unit (CAPEX) are known to be higher than its O&M costs (OPEX), the OPEX share of the total system cost is higher, since it is an annualized cost. In addition, OPEX costs are associated with all processing units, whether existing or additional ones, while CAPEX are associated only with additional capacities. Hence, the OPEX total system cost share is expected to be higher.

The next section presents the results for the Shiny scenarios.

5.2.3. Shiny scenarios

The Shiny scenarios, unlike the Cloudy, have a reduction of approximately 44% in the total demand for oil derivatives at period t5, when compared to the Shadow scenarios. Therefore, its results differ considerably from those obtained in the two scenarios presented before.

As in the previous scenarios, the four cases presented in Figure 3-1 are run, that is, the multi-regional case without (Shiny 1) and with (Shiny 1A) heavy fuel oil specifications from t1, in light of the IMO's regulations to reduce sulfur oxides (SOx) emissions from ships fuel, and the single-regional case without (Shiny 2) and with (Shiny 2A) the heavy fuel oil specification.

Crude oil consumption

The results for crude oil consumption are presented, firstly by type of crude oil (crude 1, crude 2, crude 3) and campaign (diesel – crude 1d, crude 2d, crude 3d; naphtha – crude 1n, crude 2n, crude 3n) in each period of time (t0, t1, t2, t3, t4 and t5). Then, for the Shiny 1 and Shiny 1A scenarios, which are multi-regional cases, the results of crude oil consumption are presented by type of crude oil (crude 1, crude 2, crude 3), campaign (diesel and naphtha) and region of the model (S_S, NE_S, RJMG_S, SP_S).

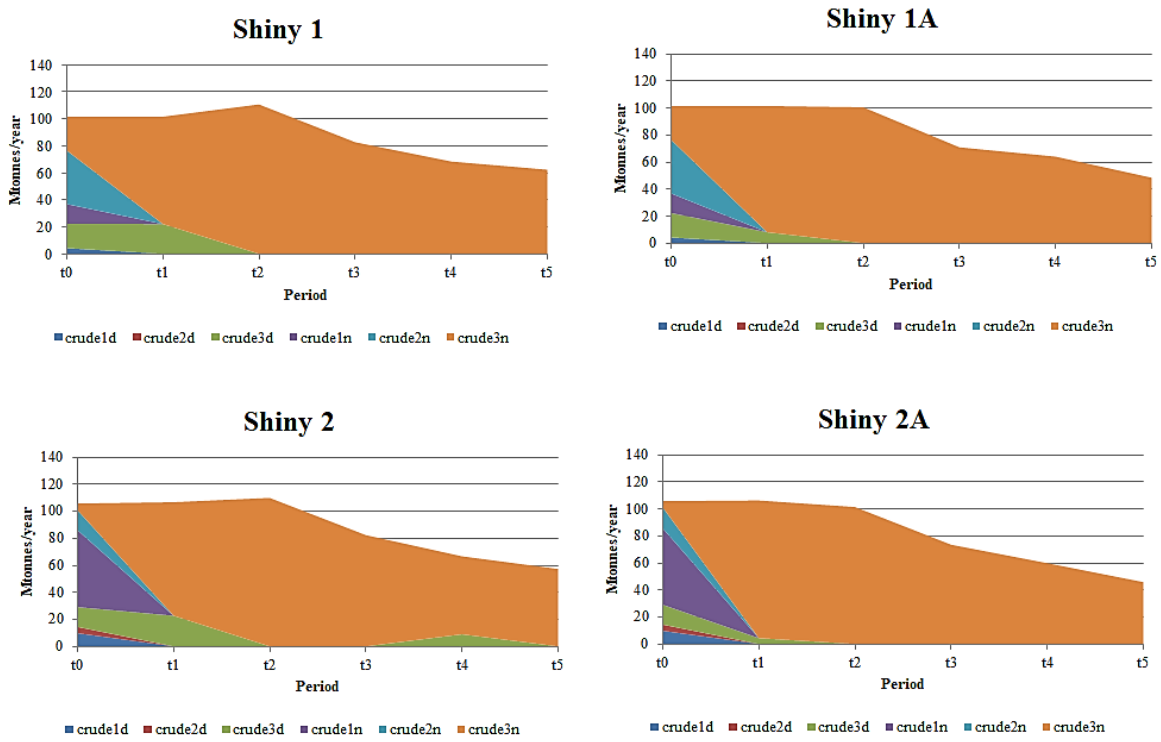

Figure 5-17 - Crude oil consumption by type of crude oil and campaign - Shiny scenarios

From Figure 5-17 it is possible to note that the total consumption of crude oil grows until period t2 in Shiny 1 and Shiny 2 senarios, and until period t1 in Shiny 1A and Shiny 2A, and then undergoes a decrease until the period t5. This trajectory is a consequence of the demand scenario considered, as well as a part of the ORION model response, that consisted, as will be shown later, on the greater utilization of the existing refining processing units capacities in the first periods, followed by the reduction of the refining utilization factor.

Concerning the crude oil consumption profile, in all cases, from t1 onwards, it consists of using only crude 3, with a naphtha and some diesel (in Shiny 2 at period t4) campaigns. As previously explained, crude 3 is the cheapest option for the model. Moreover, as for the Shadow and Cloudy scenarios, the refining production profile in all Shiny scenarios is aimed at medium/heavy distillates, further justifying its use. However, Shiny scenarios presented less presence of crude 3 with diesel campaign than the first two groups of scenarios. This can be explained by the fact that the biggest drop in the production of oil derivatives, as will be shown, when comparing the Shiny scenarios with the two previous ones, concerns diesel.

Despite the similarity in the consumption profile of the three scenarios (Shadow, Cloudy and Shiny), the total amount consumed in the Shiny scenarios is noticeably

lower than in the previous cases. Table 5-35 presents the total crude oil consumption at period t5 for all Shadow, Cloudy and Shiny scenarios. As can be observed, the reductions between Cloudy and Shadow scenarios is not significant – between 5 and 6% depending on the case - however, the differences between Shiny and Shadow scenarios is more than 50% in all cases, which is a result of the oil derivatives demand scenarios considered[33].

Table 5-35 - Total crude oil consumption at period t5 (Mtonnes/year)

Shadow 1	131.6	**Shadow 1A**	132.8	**Shadow 2**	129.9	**Shadow 2A**	131
Cloudy 1	123.5	**Cloudy 1A**	124.9	**Cloudy 2**	121.9	**Cloudy 2A**	124.9
Shiny 1	62.3	**Shiny 1A**	48.4	**Shiny 2**	57.4	**Shiny 2A**	45.9

As in Shadow and Cloudy scenrios, at period t0, the Shiny 1 and Shiny 1A scenarios show, in addition to the consumption of crude 3 with naphtha and diesel campaigns, a consumption of crude 1 with naphtha and diesel campaigns, and crude 2 with naphtha; and Shiny 2 and Shiny 2A show a consumption of crude 1 and 2 both with naphtha and diesel campaigns. Again, this result demonstrates a good model calibration capability, in all scenarios, and a good optimizing ability, since, despite choosing to use only crude 3 from t1, it identifies different possibilities of crudes and campaigns in the base year.

Concerning the differences between Shiny 1 and Shiny 1A, and Shiny 2 and Shiny 2A, the application of a lower sulfur content for fuel oil in A-type scenarios (from 3.5% to 0.5% in light of the IMO specification) did not alter, in this case, the crude oil consumption profile.

Figure 5-18 and Figure 5-19 present the crude oil consumption per type of crude, campaign and per region of the model for Shiny 1 and Shiny 1A (multi-regional scenarios).

[33] This suggests the need to study more carefully the decommissioning of refining units (especially costs), which is not considered in the ORION model.

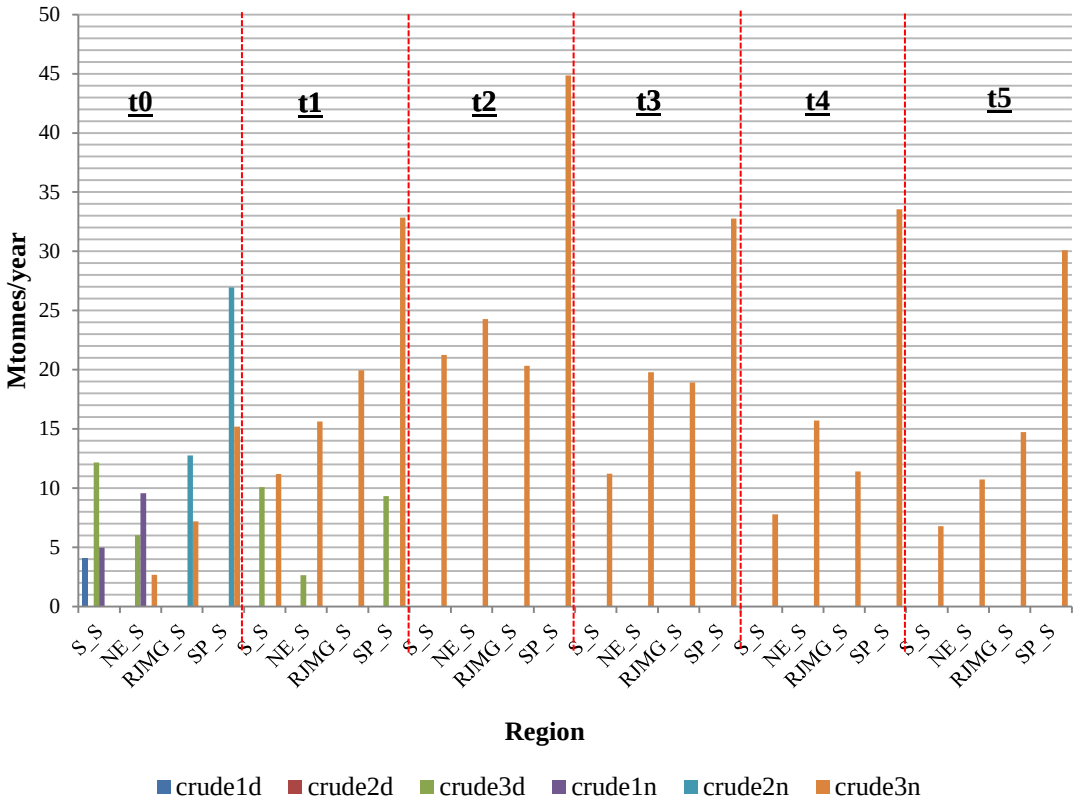

Figure 5-18 - Crude oil consumption by type of crude oil, campaign and region - Shiny 1

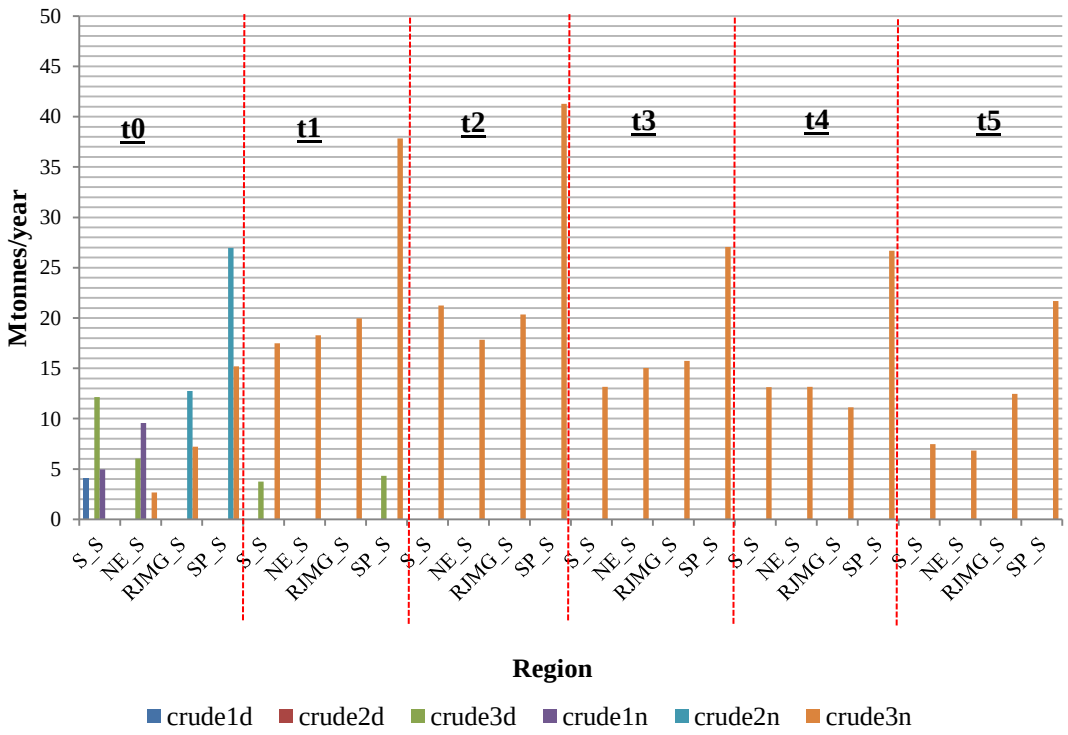

Figure 5-19 - Crude oil consumption by type of crude oil, campaign and region - Shiny 1A

In both scenarios the region with the highest oil consumption is the SP_S region, at all periods, which makes sense due to its higher refining capacity among all regions. After SP_S region, at t0 and t1, the second most oil-consuming region is the S_S region, followed by RJMG_S region. However, between periods t2 and t4, the amount of crude oil consumed in region S_S declines more than in the other regions, becoming NE_S region the second most oil consuming during this period. At period t5, RJMG_S shows a greater crude oil consumption than NE_S and S_S regions. Again, although S_S region has lower refinig capacity than NE_S region, as will be presented, as well as lower demand for derivatives, it receives fewer trades from other regions than NE_S region, at periods t0 and t1, as will be shown in the National Trades section, which ultimately forces higher production of derivatives and a consequent higher consumption of crude oil in this region.

As regards the types of crudes and campaigns in each region, both scenarios present the same profile consumption at t0, ie, S_S region shows a consumption of crude 1 with naphtha and diesel campaigns, and of crude 3 with diesel campaign; NE_S region have a consumption of crude 1 with naphtha campaign, and crude 3 with diesel and naphtha campaigns; RJMG_S region presents a consumption of crude 2 and 3 with naphtha campaign; and SP_S region shows a huge consumption of crude 2 with naphtha campaign, and also a consumption of crude 3 with naphtha campaign. As explained for the Shadow scenarios, these results are a consequence of the scenario of demand for derivatives by region, and are related to results of production of derivatives by region, national trades and imports/exports by region. As an example, the demand for naphtha, gasoline and LPG is higher in NE_S region than in other regions, which leads to higher consumption of crude 1 (light crude oil) with naphtha campaign at t0 in this region. On the other hand SP_S region presents a higher demand for diesel, jet fuel and fuel oil than other regions, and the second largest demand for light derivatives (LPG, naphtha and gasoline), which justifies the use of crude 3 with diesel campaign (focused on the production of medium/heavy distillates), and also the use of crude 2 with naphtha campaign (medium crude oil, but with a campaign geared towoards light/mediul distillates).

Finally, at period t1 both scenarios show the consumption of crude 3 with naphtha (mainly) and diesel campaing, and, in addition, the scenario Shiny 1 shows higher consumption of crude 3 with diesel campaign than Shiny 1A (explained by the

model's short-term response to reduce fuel oil production due to the application of the IMO regulation in the Shiny 1A scenario in this period).

Oil derivaties production

The results for each Shiny scenario concerning their oil derivatives production by time period are presented below. For the Shiny 1 and Shiny 1A scenarios, which are multi-regional cases, the results are also presented by region of the model (S_S, NE_S, RJMG_S, SP_S).

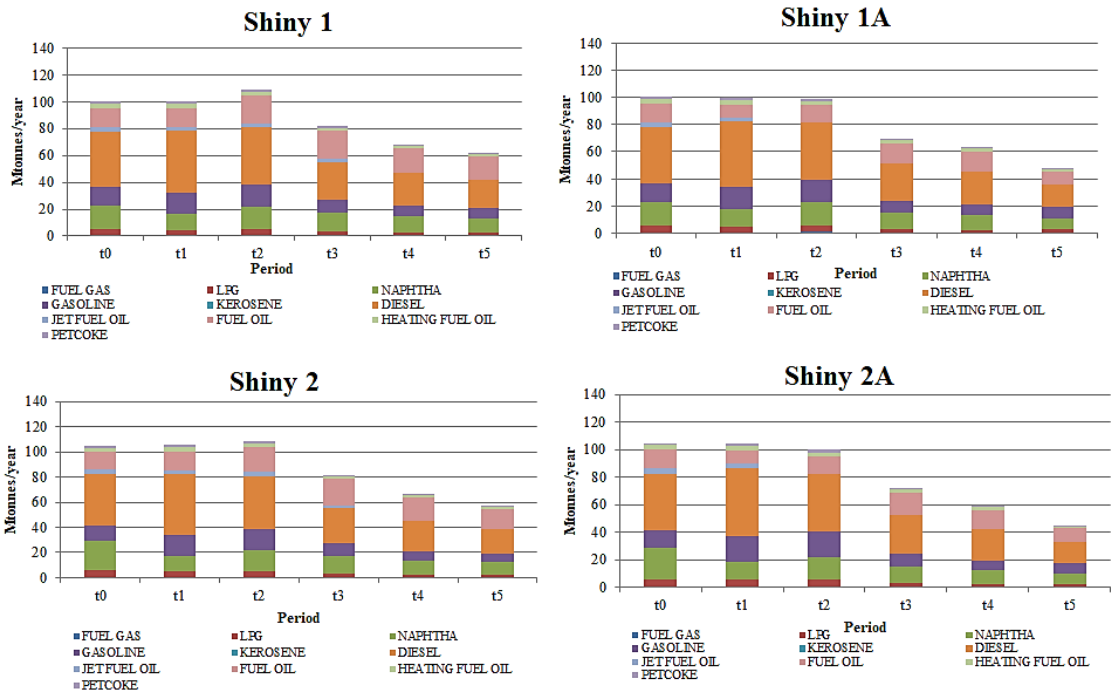

Figure 5-20 - Oil derivatives production - Shiny scenarios

The oil derivatives production results present, as for the crude oil consumption, an increase until period t2 in Shiny 1 and Shiny 2 senarios, and until period t1 in Shiny 1A and Shiny 2A, and then a decrease until the period t5.

Like in Shadow and Cloudy scenarios, all Shiny scenarios have the production focused on diesel, at all time periods, nonetheless its production share decreases over time. Productions of gasoline, fuel oil and naphtha are also significant among all oil derivatives (see Table 5-36, Table 5-37, Table 5-38 and Table 5-39).

In Shiny 1 and Shiny 2, gasoline share also decreases over the time horizon, but not as much as diesel share; naphtha share decreases at period t1, but at period t2 it grows, and remains practically constant between periods t3 and t5; and fuel oil share

considerably increases throughout the analysis period. As regards Shiny 1A and Shiny 2A, gasoline share increases over time, and fuel oil share also increases, but not as much as in Shiny 1 and Shiny 2 scenarios. Such changes can be explained by the implementation of the IMO regulation in Shiny 1A and 2A scenarios, and were not seen in the Shadow/Cloudy 1A and Shadow/Cloudy 2A scenarios. As in the these cases diesel production has always remained very high, the application of IMO regulation has influenced the drop in fuel oil production, while it increased diesel production. Moreover, in Shadow/Cloudy 1 and Shadow/Cloudy 2 cases, there was no growth in fuel oil production due to the high growth in diesel production.

As regards LPG[34], jet fuel oil and petcoke, the ORION model's results show a reduction in their output over the time horizon, meeting their demands mainly through imports.

Table 5-36 - Oil derivatives production share - Shiny 1

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
LPG	4.8%	3.6%	3.7%	2.9%	2.8%	2.8%
Naphtha	17.1%	12.1%	15.3%	17.1%	17.8%	17.8%
Gasoline	13.4%	15.1%	15.0%	12.1%	11.4%	11.6%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	41.0%	45.9%	38.3%	34.1%	35.6%	33.8%
Jet fuel oil	3.3%	2.5%	3.0%	2.9%	0.0%	0.0%
Fuel oil	13.4%	14.1%	18.5%	25.2%	26.9%	28.6%
Heating fuel oil	3.6%	3.1%	2.7%	2.5%	2.5%	2.4%
Petcoke	1.5%	1.6%	1.6%	1.4%	1.4%	1.4%

Table 5-37 - Oil derivatives production share - Shiny 1A

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.7%	0.7%	1.0%	0.7%	0.7%	1.1%
LPG	4.8%	3.7%	4.3%	2.9%	2.8%	4.3%
Naphtha	17.1%	13.0%	17.2%	17.8%	17.9%	17.3%
Gasoline	13.4%	15.9%	16.6%	11.6%	11.4%	17.2%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	41.0%	47.9%	42.2%	39.8%	37.9%	33.3%
Jet fuel oil	3.3%	2.8%	0.0%	0.0%	0.0%	0.0%
Fuel oil	13.4%	9.1%	12.4%	20.8%	22.9%	20.4%
Heating fuel oil	3.6%	3.6%	2.9%	3.4%	3.4%	2.9%
Petcoke	1.5%	1.6%	2.1%	1.4%	1.4%	2.2%

[34] It is possible that LPG will come from Natural Gas Processing Units (NGPU) and not imports, but the ORION model does not do this analysis, which is indicated as a possible model enhancement in future studies.

Table 5-38 - Oil derivatives production share - Shiny 2

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.6%	0.8%	0.7%	0.7%	0.7%	0.6%
LPG	5.0%	4.4%	3.7%	3.1%	2.8%	2.9%
Naphtha	21.6%	10.8%	15.5%	16.7%	16.1%	17.8%
Gasoline	11.6%	16.2%	15.0%	12.6%	11.5%	11.5%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	38.9%	45.3%	38.6%	34.2%	36.5%	33.8%
Jet fuel oil	4.0%	2.5%	2.7%	2.7%	0.0%	0.0%
Fuel oil	12.7%	13.9%	18.3%	25.1%	27.6%	28.6%
Heating fuel oil	3.1%	3.1%	2.7%	2.6%	2.5%	2.4%
Petcoke	1.4%	1.7%	1.7%	1.4%	1.4%	1.4%

Table 5-39 - Oil derivatives production share - Shiny 2A

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.6%	0.8%	1.0%	0.7%	0.7%	1.0%
LPG	5.0%	4.5%	4.7%	3.3%	3.0%	4.2%
Naphtha	21.6%	11.9%	16.0%	16.6%	17.2%	17.3%
Gasoline	11.6%	17.5%	18.1%	13.0%	12.0%	16.6%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	38.9%	46.9%	41.7%	38.3%	37.5%	33.3%
Jet fuel oil	4.0%	2.7%	0.0%	0.0%	0.0%	0.0%
Fuel oil	12.7%	8.8%	11.9%	21.6%	23.2%	21.1%
Heating fuel oil	3.1%	3.6%	2.9%	3.4%	3.5%	2.9%
Petcoke	1.4%	1.7%	2.4%	1.5%	1.4%	2.1%

Concerning the multi-regional cases (Shiny 1 and Shiny 1A), Table 5-40 and Table 5-41 present their oil derivatives production per period and region of the model. As can be seen, as for the oil consumption results by region, SP_S region presents the largest oil derivatives production. After SP_S region, at t0 and t1, the second largest oil derivatives producing region is the S_S, followed by RJMG_S region. However, between periods t2 and t4, the production of oil derivatives by region S_S declines more than in the other regions, becoming NE_S largest oil derivatives producing region during this period. At period t5, RJMG_S shows greater oil derivatives production cthan NE_S and S_S regions.

Table 5-40 - Oil derivatives production per period and region - Shiny 1

Oil product (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
Fuel gas	0.15	0.10	0.14	0.37	0.15	0.12	0.13	0.36	0.19	0.15	0.17	0.30	0.08	0.13	0.13	0.22	0.05	0.11	0.08	0.23	0.05	0.08	0.10	0.20
LPG	0.89	0.75	0.90	2.29	0.62	0.57	0.58	1.89	0.96	0.78	0.71	1.62	0.31	0.60	0.53	1.00	0.22	0.44	0.32	0.94	0.19	0.33	0.41	0.84
Naphtha	3.26	3.82	4.04	6.25	2.49	2.89	3.38	3.50	3.64	4.28	3.48	5.59	2.01	3.51	3.38	5.26	1.39	2.80	2.04	5.99	1.21	1.90	2.63	5.38
Gasoline	2.06	1.43	2.15	7.94	2.46	2.17	2.43	8.30	3.55	2.92	2.89	7.21	1.28	2.33	2.16	4.24	0.89	1.79	1.30	3.82	0.77	1.32	1.68	3.43
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel	9.02	7.83	7.93	16.92	9.89	8.39	8.56	19.75	8.78	9.88	6.71	17.08	4.50	6.57	6.28	10.88	2.81	5.67	3.85	12.03	2.29	3.62	4.97	10.16
Jet fuel oil	0.53	0.62	0.71	1.51	0.43	0.48	0.58	1.05	0.63	0.72	0.60	1.32	0.31	0.58	0.56	0.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil	4.23	2.70	2.87	3.85	4.01	2.60	3.18	4.52	2.27	4.25	4.75	9.19	2.16	5.13	4.99	8.60	2.05	4.14	3.29	8.94	1.95	2.95	4.25	8.68
Heating fuel oil	0.57	0.63	0.72	1.72	0.62	0.53	0.59	1.40	0.51	0.64	0.48	1.38	0.31	0.47	0.46	0.85	0.19	0.39	0.27	0.83	0.16	0.25	0.36	0.73
Petcoke	0.31	0.21	0.27	0.77	0.31	0.27	0.27	0.77	0.46	0.37	0.35	0.63	0.15	0.29	0.26	0.45	0.11	0.21	0.16	0.46	0.09	0.16	0.20	0.41

Table 5-41 - Oil derivatives production per period and region - Shiny 1A

Oil product (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
Fuel gas	0.15	0.10	0.14	0.37	0.15	0.12	0.13	0.36	0.22	0.11	0.17	0.46	0.09	0.10	0.11	0.18	0.09	0.09	0.07	0.18	0.06	0.05	0.16	0.24
LPG	0.89	0.75	0.90	2.29	0.60	0.56	0.72	1.90	1.08	0.58	0.71	1.94	0.37	0.46	0.44	0.81	0.37	0.39	0.31	0.75	0.24	0.19	0.66	0.99
Naphtha	3.26	3.82	4.04	6.25	3.31	3.24	2.35	4.33	3.59	3.14	3.48	7.07	2.35	2.66	2.81	4.81	2.35	2.34	1.99	4.77	1.32	1.22	2.11	3.73
Gasoline	2.06	1.43	2.15	7.94	2.44	2.16	3.30	8.29	4.02	2.15	2.89	7.64	1.50	1.78	1.79	3.16	1.50	1.53	1.27	3.04	0.96	0.78	2.64	3.96
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel	9.02	7.83	7.93	16.92	10.07	10.50	8.87	19.22	8.78	9.25	7.34	17.08	5.84	6.57	5.68	10.13	5.04	5.60	4.01	9.63	2.45	2.23	4.20	7.24
Jet fuel oil	0.53	0.62	0.71	1.51	0.55	0.54	0.58	1.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil	4.23	2.70	2.87	3.85	2.75	0.00	2.60	3.90	2.19	1.46	4.42	4.42	2.16	2.51	3.89	6.24	2.96	2.37	2.75	6.60	1.95	1.92	1.89	4.11
Heating fuel oil	0.57	0.63	0.72	1.72	0.74	0.61	0.78	1.51	0.55	0.59	0.66	1.11	0.45	0.51	0.54	0.92	0.45	0.45	0.38	0.92	0.25	0.24	0.31	0.60
Petcoke	0.31	0.21	0.27	0.77	0.30	0.27	0.27	0.78	0.53	0.27	0.35	0.97	0.18	0.22	0.21	0.39	0.18	0.19	0.15	0.36	0.12	0.09	0.34	0.50

Oil derivatives imports and exports

The results for each Shiny scenario concerning their oil derivaties imports and exports by time period are presented below. For the Shiny 1 and Shiny 1A scenarios, which are multi-regionals, the results are also presented by region of the model (S_S, NE_S, RJMG_S, SP_S).

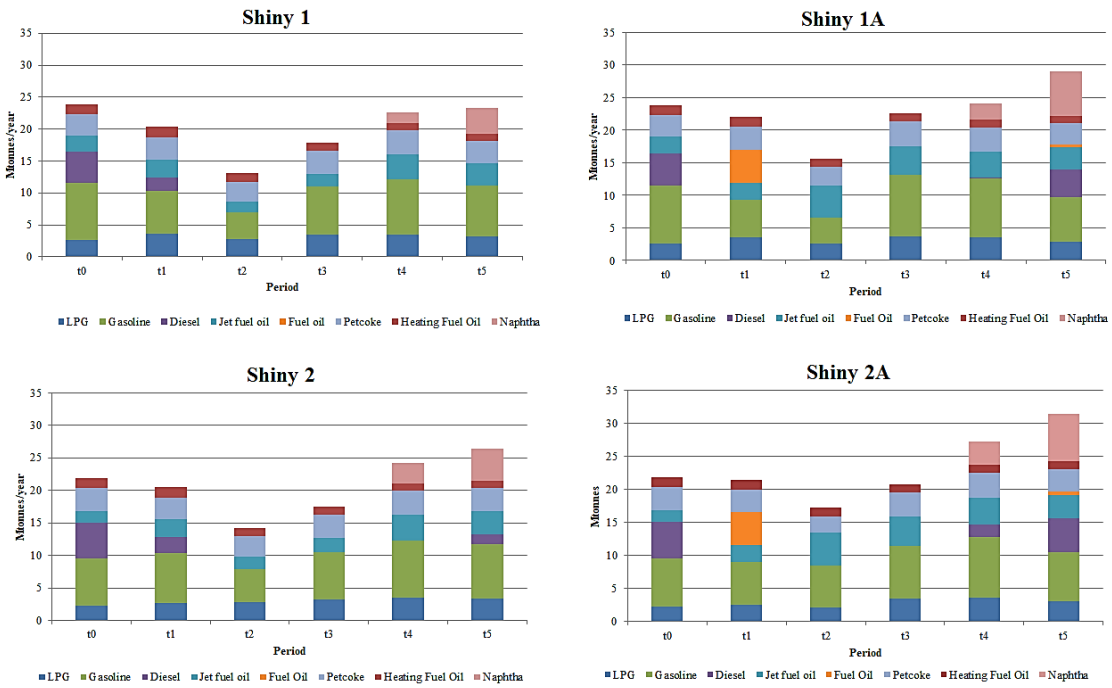

Figure 5-21 - Oil derivatives imports - Shiny scenarios

The oil derivatives imports results show that, despite the downward trend in refining capacity and in the production of oil derivatives previously shown, imports continue to follow the same upward trend in the last analysis periods, and beyond that, at t4 and t5 the total imports of derivatives is even higher than in the Shadow and Cloudy scenarios. The biggest differences in relation to the Shadow and Cloudy scenarios are in the imports of naphtha and diesel in the last periods of time. This is explained by the ORION model choice of drastically reduce the production of most oil derivatives, mainly diesel, and maintain imports in order to meet their demands.

While Shadow 1 presents total oil derivatives imports of 21.2 Mtonnes/year in period t5, and Shadow 1A of 21.0 Mtonnes/year, Shiny 1 shows total imports of 22.3 Mtonnes/year and Shiny 1A of 28.9 Mtonnes/year in the same period. Similarly, Shadow 2 and Shadow 2A have total oil derivatives imports of 21.9 Mtonnes/year in

period t5, while Shiny 2 show total imports of 26.4 Mtonnes/year, and Cloudy 2A of 31.4 Mtonnes/year.

The most imported oil derivative in Shiny scenarios is still gasoline, followed by petcoke, LPG and jet fuel oil. However, in Shiny 1A and Shiny 2A, at periods t4 and t5, the imports of naphtha exceed gasoline imports, and at period t5 diesel becomes the third largest oil derivative imported. As regards fuel oil, it is again imported only at t1, in Shiny 1A and Shiny 2A scenarios, which can be understood as a model's short-term response given the implementation of the IMO regulation in this period. From t2 onwards it is no longer imported, and all the fuel oil demanded is produced - even under higher sulfur specifications – through investments in HDTI units, resulting in surpluses, which are exported (see Figure 5-22).

Concerning exports, it can be noted that total exports are lower in Shiny scenarios than in Shadow and Cloudy scenarios. In addition, diesel is no longer exported, which was expected due to the high drop in its production. Comparing all the scenarios, the total sum of exports of all periods are of 43.8 Mtonnes in Shiny 1, 18.1 Mtonnes in Shiny 1A, 45.9 Mtonnes in Shiny 2, 23.2 Mtonnes in Shiny 2A; 50.4 Mtonnes in Cloudy 1, 49.6 Mtonnes in Cloudy 1A, 55.39 Mtonnes in Cloudy 2 and 54.4 Mtonnes in Cloudy 2A. The same values for Shadow1, Shadow 1A, Shadow 2 and Shadow 2A are, respectively, 45.3 Mtonnes, 45.5 Mtonnes, 52.9 Mtonnes and 49.2 Mtonnes.

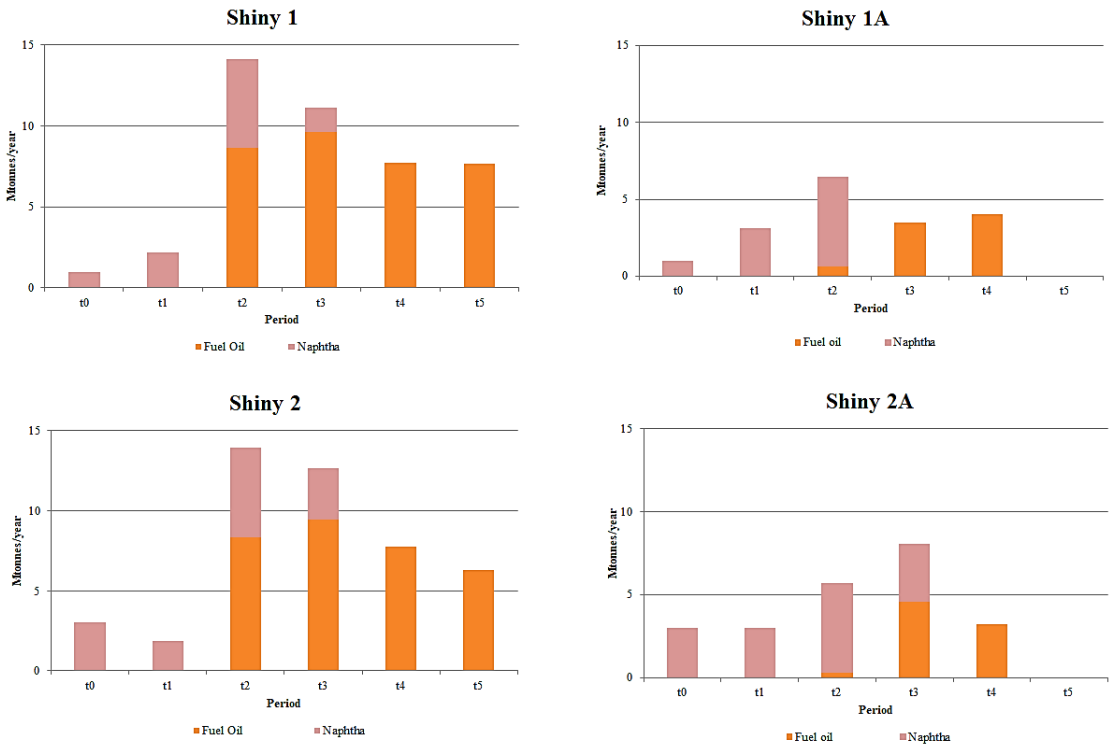

Figure 5-22 - Oil derivatives exports - Shiny scenarios

For the Shiny 1 and Shiny 1A scenarios, which have a multi-regional framework, Table 5-42 and Table 5-43 present the results of oil derivatives imports and exports by region of the model (S_D, NE_D, RJMG_D, SP_D). They show that, on average, the region that imports the most is the NE_D region, followed by the S_D, SP_D and RJMG_D regions; and the major exporting region is still SP_S, followed by RJMG_S, NE_S and S_S.

Table 5-42 - Oil derivatives imports and exports per period and region - Shiny 1

Region	Imp/Exp	LPG						Naphtha						Gasoline						Kerosene						Diesel						Jet fuel oil						Fuel oil						Heating fuel oil						Petcoke					
	(Mtonnes/year)	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5
S_D	Imports	0.45	0.70	0.28	0.74	0.76	0.71	-	-	-	-	-	0.21	1.92	0.60	-	2.51	2.64	2.47	-	-	-	-	-	-	0.63	-	-	-	-	-	-	-	-	-	0.27	0.24	-	-	-	-	-	-	0.30	0.32	0.26	0.25	0.24	0.23	0.59	0.63	0.44	0.72	0.74	0.71
	Exports	-	-	-	-	-	-	0.99	0.30	1.14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NE_D	Imports	2.15	2.28	1.90	1.67	1.68	1.62	-	-	-	-	1.64	3.80	6.97	6.06	4.17	4.24	4.33	4.31	-	-	-	-	-	-	3.04	2.06	-	-	-	-	1.21	1.19	0.82	0.80	1.24	1.09	-	-	-	-	-	-	0.30	0.32	0.26	0.25	0.24	0.23	1.70	1.72	1.53	1.55	1.57	1.53
	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.62	2.62	1.76	0.69	-	-	-	-	-	-	-	-	-	-	-	-
RJMG_D	Imports	0.02	0.67	0.54	0.53	0.66	0.49	-	-	-	-	-	-	-	-	-	0.83	1.57	0.96	-	-	-	-	-	-	-	-	-	-	-	-	0.51	0.53	0.42	0.37	0.82	0.72	-	-	-	-	-	-	0.30	0.32	0.26	0.25	0.24	0.23	0.63	0.67	0.56	0.61	0.69	0.60
	Exports	-	-	-	-	-	-	-	0.72	1.44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.60	2.94	1.35	2.40	-	-	-	-	-	-	-	-	-	-	-	-
SP_D	Imports	-	-	0.10	0.46	0.42	0.41	-	-	-	-	-	-	-	-	-	-	0.04	0.12	-	-	-	-	-	-	1.30	-	-	-	-	-	0.80	1.13	0.43	0.88	1.65	1.45	-	-	-	-	-	-	0.60	0.63	0.53	0.50	0.47	0.45	0.44	0.49	0.57	0.71	0.67	0.66
	Exports	-	-	-	-	-	-	-	1.17	2.93	1.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.40	4.04	4.62	4.56	-	-	-	-	-	-	-	-	-	-	-	-
Total	Imports	2.62	3.65	2.82	3.40	3.52	3.23	-	-	-	-	1.64	4.01	8.89	6.66	4.17	7.58	8.58	7.86	-	-	-	-	-	-	4.97	2.06	-	-	-	-	2.52	2.85	1.67	2.05	3.98	3.50	-	-	-	-	-	-	1.50	1.59	1.31	1.25	1.19	1.14	3.36	3.51	3.10	3.59	3.67	3.50
	Exports	-	-	-	-	-	-	0.99	2.19	5.51	1.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.62	9.60	7.73	7.65	-	-	-	-	-	-	-	-	-	-	-	-

Table 5-43 - Oil derivatives imports and exports per period and region - Shiny 1A

Region	Imp/Exp	LPG						Naphtha						Gasoline						Kerosene						Diesel						Jet fuel oil						Fuel oil						Heating fuel oil						Petcoke					
	(Mtonnes/year)	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5
S_D	Imports	0.45	0.72	0.16	0.69	0.61	0.67	-	-	-	-	-	1.97	1.92	-	-	2.29	2.03	1.88	-	-	-	-	-	-	0.63	-	-	-	-	1.77	-	-	0.34	0.31	0.27	0.24	-	-	-	-	-	-	0.30	0.32	0.26	0.25	0.24	0.23	0.59	0.64	0.37	0.69	0.66	0.68
	Exports	-	-	-	-	-	-	0.99	1.12	1.10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.91	-	-	-	-	-	-	-	-	-	-	-	-	-
NE_D	Imports	2.15	2.28	2.10	1.81	1.73	1.75	-	-	-	-	2.43	4.48	6.97	5.83	4.05	4.79	4.59	4.85	-	-	-	-	-	-	3.04	-	-	-	0.07	2.52	1.21	1.14	1.53	1.38	1.24	1.09	-	3.18	-	-	-	0.31	0.30	0.32	0.26	0.25	0.24	0.23	1.70	1.72	1.63	1.62	1.60	1.60
	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RJMG_D	Imports	0.02	0.53	0.31	0.61	0.67	0.24	-	-	-	-	-	0.31	-	-	-	1.28	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-	0.51	0.53	1.02	0.92	0.82	0.72	-	-	-	-	-	-	0.30	0.32	0.26	0.25	0.24	0.23	0.63	0.67	0.56	0.66	0.69	0.46
	Exports	-	-	-	-	-	-	-	0.04	0.31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.64	1.84	0.81	-	-	-	-	-	-	-	-	-	-	-	-	-
SP_D	Imports	-	-	-	0.65	0.61	0.26	-	-	-	-	-	-	-	-	-	0.98	0.82	-	-	-	-	-	-	-	1.30	-	-	-	-	-	0.80	0.91	2.04	1.84	1.65	1.45	-	1.88	-	-	-	-	0.60	0.63	0.53	0.50	0.47	0.45	0.44	0.48	0.23	0.77	0.76	0.57
	Exports	-	-	-	-	-	-	-	1.99	4.40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.68	2.29	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	Imports	2.62	3.53	2.57	3.76	3.62	2.92	-	-	-	-	2.43	6.76	8.89	5.83	4.05	9.34	9.04	6.73	-	-	-	-	-	-	4.97	-	-	-	0.07	4.29	2.52	2.58	4.93	4.45	3.98	3.50	-	5.06	-	-	-	-	1.50	1.59	1.31	1.25	1.19	1.14	3.36	3.51	2.79	3.74	3.71	3.31
	Exports	-	-	-	-	-	-	0.99	3.15	5.81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.64	3.52	4.01	0.31	-	-	-	-	-	-	-	-	-	-	-	-

National trades

As already explained, the national trades concern the trades of oil derivatives between Brazilian regions of supply (S_S, NE_S, RJMG_S, SP_S) and demand (S_D, NE_D, RJMG_D, SP_D) in Shiny 1 and Shiny 1A scenarios, which are the multi-regional cases.

Analyzing the results, which are presented in Table D-15 and Table D-16 in Annex D, it can be observed that they do not significantly differ from those of Shadow and Cloudy scenarios, in terms of regions between which the trades occur. In fact, the changes are practically related to the traded quantities.

Hence, the results for the Shiny 1 and Shiny 1A show that LPG is mostly traded from SP_S to RJMG_D. For naphtha, the trades are mostly from RJMG_S to NE_D, with some trades from SP_S to S_D at periods t3, t4 and t5, and from SP_S to RJMG_D at t4. Concerning gasoline, the trades are usually from SP_S to S_D and RJMG_D. For diesel from RJMG_S to NE_D and SP_D, and from SP_S to S_D. For jet fuel oil they are always from S_S to SP_D. For fuel oil from RJMG_S to NE_D. As regards kerosene, heating fuel oil and petcoke, there are no trades between regions for the scenario in question.

As pointed out in previous scenarios, these results reflect the demand shares for products applied in each region, which were kept the same throughout the analysis horizon, as well as the production capacity of each product in each region, according to the existing processing units. For instance, oil products demands are very high in the NE_S region, which, despite having considerable production capacity, is unable to meet these demands. For this reason, it is an importing region, both in terms of international imports, and in terms of trades from other regions of the model. Anoter example is the RJMG_S region, that sends naphtha to NE_D in the two scenarios analyzed, which is a consequence of this region's production profile and also its lower demand for naphtha than in the NE_D region.

Processing units capacities

The results for processing units capacities relate to both capacity levels in each period of time as well as additional capacities, if any, as previously explained. Figure

5-23 presents the capacities levels for each processing unit considered in the models' refining scheme, for each Shiny case, in each time period.

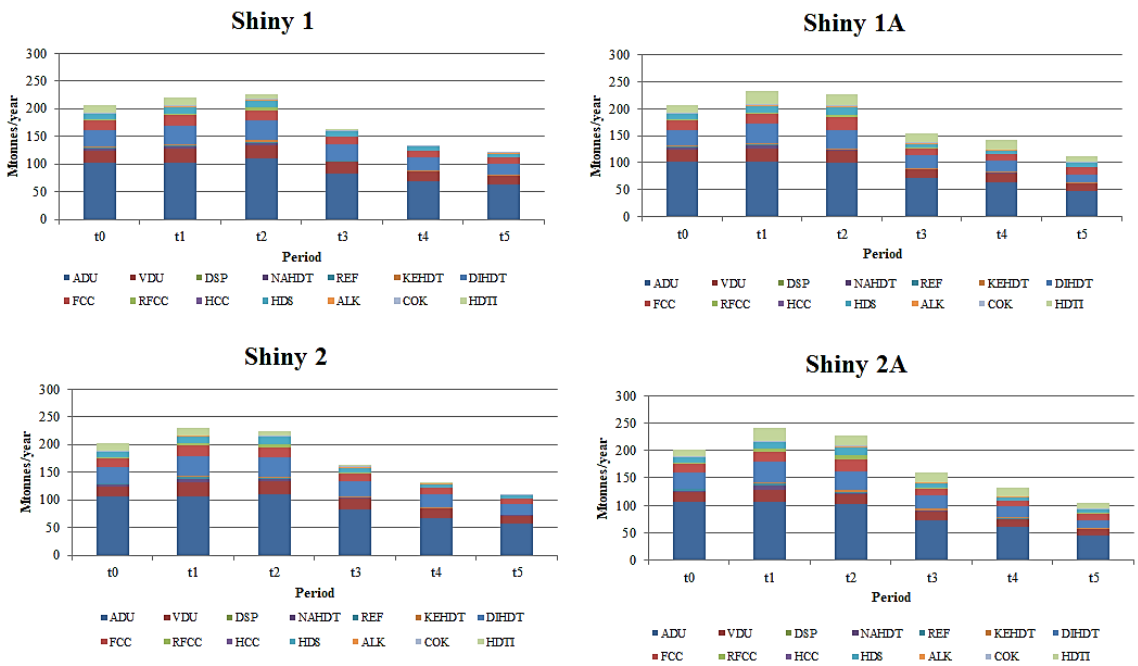

Figure 5-23 - Processing units level capacities - Shiny scenarios[35]

Again, at period t0 the level capacities are the same as the Shadow and Cloudy scenarios, since this is the base period. Thus, at t0, the utilization factor of Shiny scenarios continue to be 87.1% for Shiny 1 and Shiny 1A, and 90.7% for Shiny 2 and Shiny 2A.

Neverthless, when analyzing the level of capacities over time, Shiny scenarios differ from the Shadow and Cloudy. While the two latters present an increase in processing units capacitites throughout the time horizon, Shiny scenarios show an overall increase until period t2 (Shiny 1 and Shiny 2), and until period t1 (Shiny 1A and Shiny 2A), through greater utilization of the existing refining processing units capacities, followed by a capacity decrease, through the reduction of the utilization of existing capacities. Thus, while in Shadow 1 and Cloudy 1 the ADU capacity levels increases, between t0 and t5, by approximately 29.5% and 21.5%, respectively, in Shiny 1 ADU capacity decreases by 38.7%. Similarly, Shadow 1A and Cloudy 1A present,

[35] Results concerning the capacities of the hydrogeneration unit (CAPUGH) and cogeneration unit (CAPCOG) are not represented in the graphs, given that they have units of measurement other than Mtonnes/year. The resulting values for these processing units can be found in Annex D.

respectively, ADU capacity levels increases, between period t0 and t5, of 30.7% and 22.8%. Concerning Shadow 2 and Cloudy 2, and Shadow 2A and Cloudy 2A, the increases are of 23.7%, 15.1%, 22.7% and 15.8%, while Shiny 2 and Shiny 2A present decreases of 45.8% and 56.7%, respectively.

Since the reduction of oil derivatives demands between Shiny and Shadow scenarios is very high, as previously presented, this study left the model free to invest in all additional processing units capacities. As expected, it does not perform investments in additional ADU capacities, but in periods t1 and t2 it invests in other additional processing units capacities, mainly DIHDT, VDU, ALK, and NAHDT. This result can be related to the maintenance of fuel oil production (with VDU), gasoline production (with ALK), and the quality of products such as diesel (with DIHDT) and gasoline (with NAHDT). For Shiny 1A and Shiny 2A, the model still presents investments in additional capacities of HDTI units, at periods t1 and t2. As the last two cases have to meet the IMO sulfur specification for fuel oil from t1, it was expected that their HDTI capacity levels would remain high in the first periods. However, as the fuel oil demand declines over the time horizon, the need for high levels of HDTI units capacities, as occurs in Shadow and Cloudy scenarios is reduced, what explains the capacity decrease between periods t3 and t5.

When analyzing specifically Shiny 1 and Shiny 1A (see Table 5-44 and Table 5-45), which are multi-regionals, in both scenarios the region with the highest capacity levels is the SP_S region. After SP_S region, from t0 to t2, the second region with the highest capacitites is the S_S region, followed by RJMG_S region. However, between periods t3 and t5, the capacity levels in region S_S declines more than in the other regions, resulting, at period t5, in a higher level capacity in RJMG_S region than in S_S region. This derives from the oil derivatives imports/exports and the national trades, as already explained in the crude oil consumption results section.

Table 5-44 - Processing units level capacties - Shiny 1

Processing unit capacity level (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
ADU	21.25	18.27	19.96	42.16	21.25	18.27	19.96	42.16	21.25	24.27	20.34	44.85	11.23	19.80	18.92	32.78	7.78	15.70	11.40	33.55	6.78	10.72	14.73	30.09
VDU	5.09	3.29	4.68	8.91	5.92	3.86	5.18	10.34	3.19	4.33	5.28	10.66	2.91	4.22	4.91	8.50	2.02	4.07	2.96	8.70	1.76	2.78	3.82	7.80
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	-	0.10	0.38	3.30	0.24	0.24	0.41	3.30	0.40	0.33	0.38	2.93	0.13	0.25	0.21	0.97	0.09	0.18	0.13	0.38	0.08	0.13	0.17	0.34
REF	-	-	0.16	2.19	-	-	0.16	2.36	-	-	0.09	2.11	-	-	-	0.53	-	-	-	-	-	-	-	-
KEHDT	-	-	0.51	1.08	0.31	0.35	0.51	1.08	0.45	0.51	0.43	0.95	0.24	0.42	0.40	0.69	0.23	0.47	0.34	1.01	0.20	0.32	0.44	0.90
DIHDT	6.61	5.18	5.56	11.54	7.50	5.76	6.20	14.44	6.72	8.26	6.44	13.88	3.82	6.74	6.44	11.15	2.65	5.34	3.60	11.33	2.14	3.39	4.66	9.51
FCC	4.05	2.07	3.54	9.00	4.05	2.56	3.54	9.00	3.70	2.82	4.48	7.22	1.99	2.82	3.36	5.82	1.38	2.79	2.02	5.96	1.20	2.08	2.62	5.34
RFCC	-	0.65	-	0.97	-	0.99	-	0.97	2.32	1.96	-	0.97	-	0.92	-	-	-	-	-	-	-	-	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	2.02	1.33	1.77	5.20	2.19	1.93	2.03	5.38	3.16	2.60	2.50	4.62	1.14	2.07	1.92	3.33	0.79	1.59	1.16	3.41	0.69	1.18	1.50	3.05
ALK	-	-	-	0.31	0.19	0.24	0.30	0.52	0.32	0.36	0.31	0.67	0.17	0.30	0.28	0.49	0.12	0.24	0.17	0.50	0.10	0.16	0.22	0.45
COK	0.50	0.14	0.44	0.94	0.50	0.14	0.44	0.94	0.05	-	0.55	0.72	0.25	0.19	0.41	0.72	0.17	0.34	0.25	0.73	0.15	0.26	0.32	0.66
HDTI	2.64	2.85	2.57	5.81	2.64	2.85	2.57	5.81	2.29	1.87	0.44	3.63	0.77	-	-	-	-	-	-	-	-	-	-	-

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit

Table 5-45 - Processing units level capacties - Shiny 1A

Processing unit capacity level (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
ADU	21.25	18.27	19.96	42.16	21.25	18.28	19.96	42.16	22.45	19.33	22.04	43.07	13.15	15.04	15.74	27.06	13.14	13.16	11.12	26.67	7.46	6.83	12.47	21.68
VDU	5.09	3.29	4.68	8.91	5.66	3.78	5.18	10.14	3.19	3.18	5.28	9.74	3.41	3.11	4.08	6.05	3.41	3.06	2.88	6.92	1.94	1.77	3.23	5.62
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	-	0.10	0.38	3.30	0.24	0.23	1.45	3.12	0.44	0.24	0.38	0.78	0.15	0.19	0.18	0.33	0.15	0.16	0.13	0.30	0.10	0.08	0.26	0.39
REF	-	-	0.16	2.19	-	-	1.08	2.19	-	-	0.09	-	-	-	-	-	-	-	-	-	-	-	-	-
KEHDT	-	-	0.51	1.08	0.40	0.39	0.51	1.08	0.64	0.53	0.61	1.24	0.39	0.45	0.47	0.81	0.39	0.39	0.33	0.80	0.22	0.20	0.37	0.65
DIHDT	6.61	5.18	5.56	11.54	7.33	6.22	6.79	14.46	7.23	6.07	6.92	14.04	4.48	5.12	5.35	9.21	4.47	4.48	3.78	9.08	2.29	2.09	3.94	6.78
FCC	4.05	2.07	3.54	9.00	3.87	2.52	3.54	9.18	4.52	2.07	4.48	11.68	2.33	2.07	2.79	4.07	2.33	2.07	1.97	4.73	1.52	1.21	4.38	6.50
RFCC	-	0.65	-	0.97	0.01	0.96	-	0.97	2.32	1.44	-	0.97	-	0.79	-	0.97	-	0.35	-	-	-	-	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	2.02	1.33	1.77	5.20	2.17	1.92	2.03	5.52	3.58	1.91	2.50	6.80	1.33	1.58	1.60	2.81	1.33	1.36	1.13	2.71	0.85	0.69	2.35	3.53
ALK	-	-	-	0.31	0.27	0.27	0.30	0.58	0.32	0.27	0.31	0.62	0.20	0.23	0.24	0.41	0.20	0.20	0.17	0.40	0.11	0.10	0.19	0.33
COK	0.50	0.14	0.44	0.94	0.47	0.14	0.44	0.96	0.15	-	0.55	1.27	0.29	0.12	0.34	0.33	0.29	0.19	0.24	0.58	0.19	0.15	0.54	0.80
HDTI	2.64	2.85	2.57	5.81	5.81	4.55	4.98	9.26	3.38	4.38	4.54	6.77	3.34	3.74	3.99	6.77	3.33	3.31	2.82	6.77	2.00	1.97	1.94	4.22

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit

Table 5-46 - Processing units additional capacties - Shiny 1

Additional Capacity (Mtonnes/year)	t1					t2					t3					t4					t5				
	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total
ADU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VDU	0.87	0.60	0.53	1.51	3.51	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	0.26	0.15	0.03	-	0.44	0.42	0.25	-	-	0.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REF	-	-	-	0.18	0.18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KEHDT	0.32	0.37	-	-	0.69	0.47	0.54	-	-	1.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIHDT	0.94	0.61	0.68	3.06	5.29	0.11	3.25	0.93	2.46	6.75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FCC	-	0.52	-	-	0.52	-	0.79	-	-	0.79	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RFCC	-	0.36	-	-	0.36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	0.17	0.64	0.27	0.18	1.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALK	0.21	0.25	0.32	0.21	0.99	0.34	0.38	0.32	0.38	1.42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UGH[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDTI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Table 5-47 - Processing units additional capacties - Shiny 1A

Additional Capacity (Mtonnes/year)	t1					t2					t3					t4					t5				
	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total	S_S	NE_S	RJMG_S	SP_S	Total
ADU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VDU	0.60	0.52	0.53	1.30	2.95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	0.26	0.15	1.12	-	1.53	0.47	0.16	-	-	0.63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REF	-	-	0.96	-	0.96	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KEHDT	0.42	0.41	-	-	0.83	0.67	0.56	-	-	1.23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIHDT	0.76	1.10	1.30	3.07	6.23	0.65	0.94	1.44	2.63	5.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FCC	-	0.47	-	-	0.47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RFCC	-	0.33	-	-	0.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	0.24	0.63	0.27	0.24	1.38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALK	0.29	0.29	0.32	0.28	1.18	0.34	0.28	0.32	0.32	1.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UGH[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDTI	3.34	1.79	2.53	3.62	11.28	0.78	1.61	2.06	1.01	5.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Table 5-48 - Processing units additional capacties - Shiny 2

Additional Capacity (Mtonnes/year)	t1	t2	t3	t4	t5
ADU	-	-	-	-	-
VDU	6.51	-	-	-	-
DSP	-	-	-	-	-
NAHDT	2.66	2.54	-	-	-
REF	1.49	0.77	-	-	-
KEHDT	1.50	1.10	-	-	-
DIHDT	7.86	6.57	-	-	-
FCC	3.08	0.81	-	-	-
RFCC	2.14	-	-	-	-
HCC	-	-	-	-	-
HDS	-	-	-	-	-
ALK	0.57	1.41	-	-	-
COK	-	-	-	-	-
UGH[1]	-	-	-	-	-
HDTI	-	-	-	-	-

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Table 5-49 - Processing units additional capacties - Shiny 2A

Additional Capacity (Mtonnes/year)	t1	t2	t3	t4	t5
ADU	-	-	-	-	-
VDU	5.55	-	-	-	-
DSP	-	-	-	-	-
NAHDT	3.87	2.00	-	-	-
REF	2.53	0.20	-	-	-
KEHDT	1.80	1.40	-	-	-
DIHDT	7.81	5.94	-	-	-
FCC	3.12	-	-	-	-
RFCC	2.17	-	-	-	-
HCC	-	-	-	-	-
HDS	-	-	-	-	-
ALK	0.82	1.28	-	-	-
COK	-	-	-	-	-
UGH[1]	-	-	-	-	-
HDTI	11.52	4.61	-	-	-

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit; UGH – Hydrogen generation unit

[1]Mm^3/year

Utilities consumption and CO_2 emissions

Once again, utilities consumption and CO_2 emissions concern, respectively, the consumption of steam (low, medium and high pressure), fuel (natural gas, fuel oil, fuel gas and coke), electricity and hydrogen by the processing units, and the CO_2 emissions

related to the burning of fuel and the grid - if the model opts to buy electricity instead of producing it.

As previously explained, the high pressure (HP) steam demand can be supplied by cogeneration units or boilers. The HP surplus is, then, used to supply the medium pressure (MP) steam demand.

Table 5-50, Table 5-51, Table 5-52 and Table 5-53 detail the results of utilities consumption and CO_2 emissions for the Shiny scenarios.

Table 5-50 - Utilities consumption and CO_2 emissions - Shiny 1

Steam	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Low-pressure (LP) steam consumption (10^6 MJ)	-1332.57	-1367.79	-1301.37	-998.75	-867.18	-802.25
Medium-pressure (MP) steam consumption (10^6 MJ)	30014.77	31927.08	34571.47	25766.91	21470.36	19615.00
High-pressure (HP) steam consumption (10^6 MJ)	-1935.17	-1658.13	-2952.20	-1783.43	-1464.83	-1481.42
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	3901.86	4597.90	8382.93	2806.99	10138.97	5500.86
Natural gas - HP steam production (10^6 MJ)	4620.69	4903.44	4918.68	7513.61	0.00	3717.72
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	147794.04	127278.72	122673.24	85410.72	68663.52	60708.60
Fuel gas (10^6 MJ)	7536.24	58196.52	48566.88	48148.20	36006.48	36843.84
Coke (10^6 MJ)	55265.76	57359.16	63639.36	40611.96	33075.72	30982.32
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3547.26	3787.15	3546.54	2369.05	1938.71	1753.21
Electricity production (GWh)	3547.26	3778.34	3458.29	2589.68	1938.71	1753.21
Electricity grid (GWh)	0.00	8.81	88.25	0.00	0.00	0.00
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	39533.88	42109.36	38542.39	28861.80	21606.84	19539.34
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3801.35	4150.28	3553.82	1964.48	1529.60	1336.11
Hydrogen consumption (10^6 m^3)	3801.35	4150.28	3553.82	1964.48	1529.60	1336.11
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	60624.12	65872.07	64494.61	64245.38	84969.48	86107.47
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	104059.86	112579.33	111419.94	95914.17	116715.29	111147.67
Fuel oil (10^6 MJ)	147794.04	127278.72	122673.24	85410.72	68663.52	60708.60
Fuel gas (10^6 MJ)	7536.24	58196.52	48566.88	48148.20	36006.48	36843.84
Coke (10^6 MJ)	55265.76	57359.16	63639.36	40611.96	33075.72	30982.32
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	24.70	23.91	23.74	15.84	12.79	11.53

Table 5-51 - Utilities consumption and CO_2 emissions - Shiny 1A

Steam	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Low-pressure (LP) steam consumption (10^6 MJ)	-1332.57	-1364.09	-1624.82	-804.35	-793.22	-971.31
Medium-pressure (MP) steam consumption (10^6 MJ)	30014.77	32220.39	33657.08	21909.38	20034.70	16996.69
High-pressure (HP) steam consumption (10^6 MJ)	-1935.17	-388.15	-3183.47	143.06	283.60	-1564.52
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	3901.86	4482.04	7844.49	1330.23	5159.23	3122.05
Natural gas - HP steam production (10^6 MJ)	4620.69	4441.63	0.00	5879.93	1328.53	0.00
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	147794.04	147794.04	118067.76	98389.80	89178.84	56521.80
Fuel gas (10^6 MJ)	7536.24	57359.16	50241.60	48985.56	33494.40	33913.08
Coke (10^6 MJ)	55265.76	57359.16	74525.04	35587.80	31401.00	36843.84
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3547.26	4347.65	4101.68	2711.03	2520.35	2175.54
Electricity production (GWh)	3547.26	4128.10	4052.96	2711.03	2520.35	2175.54
Electricity grid (GWh)	0.00	219.55	48.72	0.00	0.00	0.00
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	39533.88	46007.28	45169.91	30214.37	28089.02	24246.24
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3801.35	5589.06	4832.71	3842.79	3480.37	2378.59
Hydrogen consumption (10^6 m^3)	3801.35	5589.06	4832.71	3842.79	3480.37	2378.59
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	60624.12	86575.52	104171.40	109822.13	115163.53	116547.11
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	104059.86	137064.84	157185.80	141366.72	148411.78	143915.40
Fuel oil (10^6 MJ)	147794.04	147794.04	118067.76	98389.80	89178.84	56521.80
Fuel gas (10^6 MJ)	7536.24	57359.16	50241.60	48985.56	33494.40	33913.08
Coke (10^6 MJ)	55265.76	57359.16	74525.04	35587.80	31401.00	36843.84
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	24.70	26.97	26.03	17.70	16.05	12.88

Table 5-52 - Utilities consumption and CO_2 emissions - Shiny 2

Steam	t0	t1	t2	t3	t4	t5
Low-pressure (LP) steam consumption (10^6 MJ)	-1134.67	-1343.70	-1314.58	-923.45	-863.57	-674.95
Medium-pressure (MP) steam consumption (10^6 MJ)	30042.89	32438.21	34480.06	25404.27	20833.97	17810.33
High-pressure (HP) steam consumption (10^6 MJ)	-1592.61	-2247.20	-3047.43	-1910.32	-1439.24	-1427.14
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	5312.50	8826.67	13203.64	9281.79	4586.80	2101.74
Natural gas - HP steam production (10^6 MJ)	5403.68	0.00	0.00	2364.05	0.00	3509.18
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	133977.60	134396.28	120998.52	85410.72	67826.16	55684.44
Fuel gas (10^6 MJ)	17584.56	47310.84	39355.92	40193.28	32657.04	33075.72
Coke (10^6 MJ)	50241.60	63639.36	64058.04	41030.64	32657.04	28051.56
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3292.92	3936.21	3530.77	2314.55	1942.18	1550.07
Electricity production (GWh)	3292.92	3862.72	3440.69	2314.55	2638.20	1977.29
Electricity grid (GWh)	0.00	73491763.54	90.08	0.00	0.00	0.00
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	36699.27	43049.64	38346.27	25795.57	29402.51	22036.62
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3621.10	4292.52	3525.20	1974.59	1591.51	1231.70
Hydrogen consumption (10^6 m^3)	3621.10	4292.52	3525.20	1974.59	1591.51	1231.70
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	57575.47	67195.89	64233.97	63982.51	84379.78	85828.31
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	99587.24	119072.20	115783.88	99059.87	118369.08	109966.67
Fuel oil (10^6 MJ)	133977.60	134396.28	120998.52	85410.72	67826.16	55684.44
Fuel gas (10^6 MJ)	17584.56	47310.84	39355.92	40193.28	32657.04	33075.72
Coke (10^6 MJ)	50241.60	63639.36	64058.04	41030.64	32657.04	28051.56
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	22.78	25.31	23.63	15.80	12.90	10.65

Table 5-53 - Utilities consumption and CO_2 emissions - Shiny 2A

Steam	t0	t1	t2	t3	t4	t5
Low-pressure (LP) steam consumption (10^6 MJ)	-1134.67	-1283.94	-1517.23	-760.63	-713.90	-823.40
Medium-pressure (MP) steam consumption (10^6 MJ)	30042.89	32529.68	33319.88	22461.01	18621.98	15670.44
High-pressure (HP) steam consumption (10^6 MJ)	-1592.61	-1110.37	-3727.98	-179.63	226.82	-1377.17
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	5312.50	7493.49	6425.63	3932.49	4529.75	573.08
Natural gas - HP steam production (10^6 MJ)	5403.68	358.87	1222.12	3086.85	1337.18	1360.46
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	133977.60	154074.24	118067.76	101739.24	84573.36	54428.40
Fuel gas (10^6 MJ)	17584.56	47310.84	44798.76	42286.68	33075.72	33494.40
Coke (10^6 MJ)	50241.60	64058.04	78293.16	38937.24	29307.60	33913.08
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3292.92	4453.28	4077.48	2777.64	2360.00	1975.44
Electricity production (GWh)	3292.92	4212.84	3931.32	2777.64	2360.00	2153.63
Electricity grid (GWh)	0.00	240.46	146.17	0.00	0.00	0.00
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	36699.27	46951.62	43814.22	30956.54	26302.05	24002.09
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3621.10	5739.30	4827.65	3971.65	3282.83	2287.70
Hydrogen consumption (10^6 m^3)	3621.10	5739.30	4827.65	3971.65	3282.83	2287.70
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	57575.47	91093.69	102684.89	109215.11	114227.40	115812.38
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	99587.24	145538.80	152924.74	144104.14	145059.21	140387.55
Fuel oil (10^6 MJ)	133977.60	154074.24	118067.76	101739.24	84573.36	54428.40
Fuel gas (10^6 MJ)	17584.56	47310.84	44798.76	42286.68	33075.72	33494.40
Coke (10^6 MJ)	50241.60	64058.04	78293.16	38937.24	29307.60	33913.08
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	22.78	28.33	26.43	18.53	15.11	12.12

The results show, in all scenarios, a decrease in utility consumption, which derives from the reduction of the processing units capacities. In Shiny 1A and Shiny 2A, the decreases are smaller, due to the higher presence, in these cases, of HDTI units, which demand large amounts of steam, electricity and hydrogen.

Regarding CO_2 emissions, since no environmental constraints have been applied to the model, such as carbon taxes or CO_2 caps, they follow the trend of processing units capacities, that is, they show a growth from period t0 to period t2, followed by a reduction beteween period t2 and t5, reaching values of 11.53 Monnes/year and 12.88 Mtonnes/year in Shiny 1 and Shiny 1A scenarios, and of 10.65 Mtonnes/year and 12.11

Mtonnes/year in Shiny 2 and Shiny 2A scenarios. As Shiny 1A and Shiny 2A show higher utilities consumption, their CO_2 emissions are also higher.

Finally, it is important to reinforce that the option of taxing as well as limiting CO_2 emissions is available in the ORION model, but these were not the purposes of the scenarios proposed by the present research. Precisely because of the lack of environmental constraints, and given that the model has the objective of minimizing cost, the cheapest fuels were chosen, although they are the most polluting in terms of emissions, such as the heavy fuel oil produced by the refining process itself, with no associated purchase price, as well as the coke produced and consumed at the FCC and RFCC units. Hence, it is understood that in addition to the reductions already achieved by the Shiny scenarios, it would be possible to further reduce CO_2 emissions if they were taxed, or if emissions limits were added to the ORION model. However, as in the oil sector emissions come mainly from burning of fuels, a smaller market is what really matters.

Costs

The costs results for Shiny scenarios are presented in Table 5-54 concerning the the total costs, ie, the resulting values for the objective function, and in Figure 5-24, which gives the share, in each scenario, of the cost elements considered.

Table 5-54 - Total costs (Z) - Shiny scenarios

Scenario	Total Cost (Z) - 10^9 US$
Shiny 1	642.41
Shiny 1A	648.32
Shiny 2	663.90
Shiny 2A	669.86

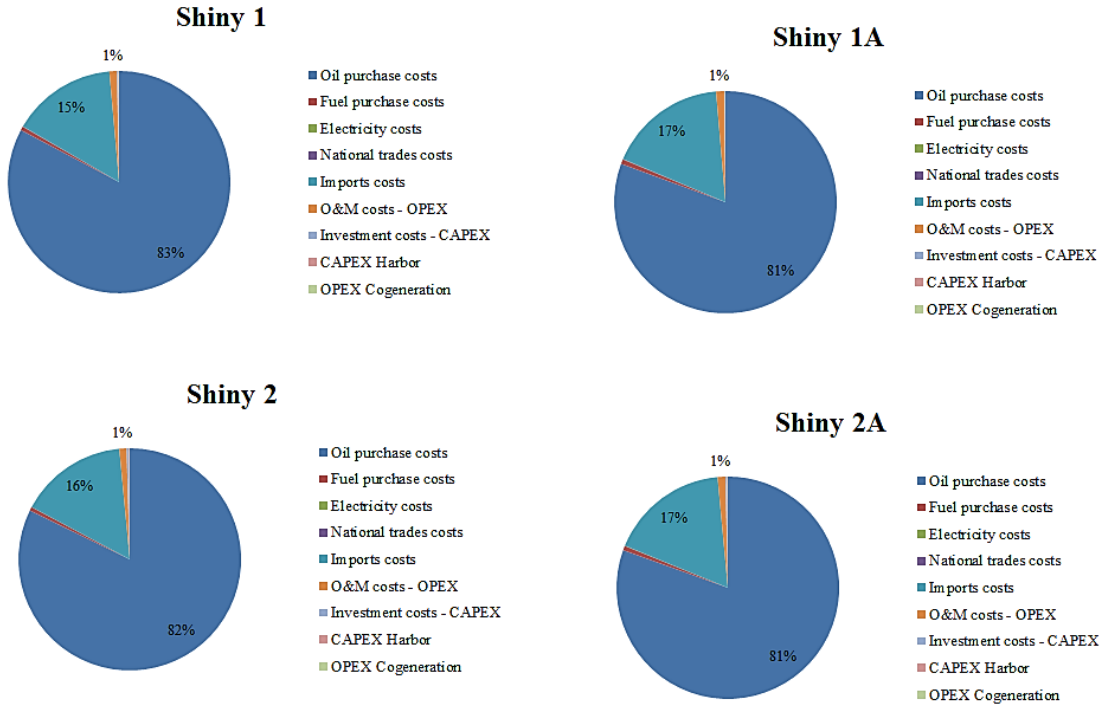

Figure 5-24 - Costs elements shares - Shiny scenarios

As expected, the total costs are lower in Shiny scenarios than in Shadow and Cloudy scenarios. On average, the costs of Shiny scenarios are 101 billion US$ less than the costs of Shadow scenarios, and 88 billion US$ less than the costs of Cloudy scenarios[36]. These differences can be explained by the lower crude oil consumption, lower processing units capacities, lower utilities consumptions, and lower investments in additional processing units capacities. As the total crude oil consumption is lower, the crude oil purchase costs are also less expensive. In addition, as capacity levels are lower, OPEX costs are reduced and so are the fuel purchase costs. Lastly, as in Shiny scenarios the amounts of additional capacities are lower, the CAPEX costs are diminished.

When comparing Shiny scenarios between themselves, as for the Shadow and Cloudy scenarios, Shiny 2 and Shiny 2A scenarios are more expensive than Shiny 1 and 1A scenarios, respectively. In addition to having more imports and less exports, Shiny 2 and Shiny 2A have higher crude oil consumption levels between period t0 and t3. As

[36] Given the large reduction in total costs, it is possible to reflect that such values, plus the positive externalities of electromobility would give a minimum monetary value to change the transport structure in favor of lower consumption of petroleum products.

the oil purchase costs account for more than 80% of total costs, it was expected that Shiny 2 and 2A scenarios would have a higher total cost than Shiny 1 and 1A scenarios.

Still, Shiny 1A and Shiny 2A are more expensive than Shiny 1 and Shiny 2, respectively, which can be explained by the investments in HDTI additional capacities in the first two scenarios, as previously mentioned, which increases the total cost of the system.

As for the Shadow and Cloudy scenarios, the largest share of the total cost relates to the purchase of crude oil, followed by import costs and OPEX costs.

5.3. Discussion of Results

This section presents a general discussion of the results obtained in the present study, which consisted of both the results of the OURSE model and the results of the ORION model.

First, regarding the OURSE model's marginal values results, they presented a high growth during the period of analysis, mainly for diesel and fuel oil, as a consequence of the stringent fuel oil specification (IMO regulation), and of the switch of use of some intermediate streams to produce diesel, as well as marine bunkers[37]. Concerning the differences between the Shadow, Cloudy and Shiny scenarios marginal values, since the oil derivatives demands grow in Shadow and Cloudy scenarios, the marginal values obtained also grow, and the prices to be considered in the ORION model show a higher evolution than in the Shiny scenario case. However, even though the Shiny scenario presents a reduction in demand for most oil derivatives, the marginal values obtained do not show a reduction, but only a smaller evolution over the analyzed time horizon, which results in lower prices to be considered in the ORION model.

With respect to ORION results, they consist of twelve different scenarios results, since three different oil derivatives demand scenarios were considered (Shadow, Cloudy and Shiny), for each one, the model was run under a multi-regional (scenarios 1) and a single-regional framework (scenarios 2) - in order to analyze, in each case, whether there is an advantage or not in having a regional model - and, for each case previously mentioned, two options of heavy fuel oil specifications were taken into account (scenarios 1 and 2, and 1A and 2A) in light of the IMO's regulations to reduce sulfur

[37] Consequently, the fuel oil is obtained by using also some intermediate compounds, which are more expensive.

oxides (SOx) emissions from ships. The ORION results were detailed in terms of crude oil consumption, oil derivatives production, oil derivatives imports and exports, national trades, processing units capacities, utilities consumption and CO_2 emissions ans costs.

Main findings show that, for the model's calibration period, that is, period t0, the single-regional scenarios (scenarios 2) have higher levels of processing capacities (CAPADU), and consequently higher crude oil consumptions[38], higher oil derivative productions, and lower oil derivatives imports. This may be influenced by their single-regional structure, which requires the processing of more crude oil to meet the national oil derivatives demand. Although presenting higher levels for almost all processing units capacities, their CO_2 emissions are slightly lower than the multi-regionals cases (scenarios 1). This can be explained by greater capacity levels of FCC, which consumes high amounts of coke, and of HDS, which has high hydrogen consumption - what, in turn, increases the hydrogen production in the hydrogen generating units, and consequently increases the total consumption of natural gas. In addition, single-regional scenarios presented, on average, total system's costs 3% higher than multi-regional scenarios, which is mainly due to their higher crude oil consumption between periods t0 and t4 - as the crude oil purchase cost have a share of more than 80% of the total cost.

Still for the calibration period, both structures (scenarios 1 and 2) demonstrated imports of diesel, gasoline, petcoke and jet fuel oil. Specifically for diesel, the imports were of 4.97 Mtonnes/year in scenarios 1, and of 5.52 Mtonnes/year in scenarios 2. These results are in accordance with ANP (2018) diesel imports data for 2015, of 5.8 Mtonnes/year (or 6,940.1 thousand m^3/year). However, from t2 onwards it starts to be exported (except in the Shiny scenarios), varying from scenario to scenario the period in which exports start. As previously explained, the diesel prices generated by the OURSE model, and implemented in the ORION model are very high for diesel at the end of the analysis horizon. In addition, the national trades that occur in the multi-regional scenarios have no physical restrictions within the model, but only associated transportation costs. That might have leaded the model to meet the demand for diesel of certain regions without the need for imports. In this sense it is worth noting that part of the divergence between results and reality in t0, and even in t1, comes from

[38] Altough multi-regional scenarios present a lower crude oil consumption, they have, at t0, a more realistic refining utilization factor (87.1%) – when comparing it to the real utilization factor of the Brazilian refining industry in 2015 (86.8%) - than the one obtained in in the single-regional scenarios (91%), which demonstrates a better conversion-distillation adjustment.

simplifications of the model, for example, the detailing of only 3 types of crude oils, the lack of supply of UPGN liquids (LPG and gasoline), and the classification of oil derivatives considered for the detailing of maximum imports and exports (light, medium, heavy).

Relating to scenarios considering and not considering the heavy fuel oil specification, the results point out that the biggest difference between them is in the level capacities of HDTI units (which is used to reduce the sulfur content of the fuel oil pool) and in the investments in their additional capacities. Hence, the scenarios that take into account the IMO regulation feature higher HDTI units capacities, as well as greater investments in additional capacities.

Certain limits on the investments in additional processing units capacities had to be added to the model before reaching the final result presented in this thesis. The results show that the most stringent scenarios in terms of oil products demands, Shadow and Cloudy scenarios, presented between 0.3 and 0.4 million of barrels per day (Mb/d) of greenfield refining capacity expansions, which in multi-regional scenarios are concentrated in SP_S[39] and RJMG_S regions. On the other hand, the scenario with the largest decrease in demand for oil derivatives, the Shiny, did not show greenfield refining capacity expansions. Moreover, it demonstrated that, even without CO_2 emissions constraints, the refining capacity is greatly reduced due to electromobility, and oil production remains in the niches where it has less possibility of substitution, as naphtha (petrochemical industry raw material) and fuel oil (marine bunkers). The Shiny scenarios' average reduction on total system's costs is of 101 billion US$, relative to the Shadow scenario average.

Concerning the imports and exports of OURSE's Z2, which were reported in section 5.1.2., and the ORION model's results of oil derivatives imports and exports, it is possible to observe that, for the base period, ORION imports and exports present a higher level than the values calculated from OURSE results. As previously presented, in 2015, the total flows of Z2, in all scenarios, are of 27.48 Mtonnes/year, being 23.67 Mtonnes/year of imports and 3.81 Mtonnes/year of exports. Considering that Brazil represents around 50% of the Z2 in the OURSE model, its total flows would be about 13.7 Mtonnes/year in this year, being 11.8 Mtonnes/year of imports and 1.9

[39] As São Paulo's refining production attends the oil derivative demand of Brazil's midwest, the refining expansion in SP_S could also involve expansions in this region.

Mtonnes/year of exports. According to ORION results[40], in the base period imports are approximately 23.8 Mtonnes/year and exports are 1 Mtonnes/year, in all scenarios. However, by analyzing both results over the time periods, the differences are reduced, specially for the Shadow scenarios. At period t5, OURSE's Z2 imports plus exports are approximately 78.7 Mtonnes/year in the Shadow scenario. Again, considering a rate of 50% for Brazil, the corresponding flow would be about 39.3 Mtonnes/year. According to ORION results, the Shadow scenarios present total international flows of 31.9 Mtonnes/year, 31.7 Mtonnes/year, 32.9 Mtonnes/year and 33.0 Mtonnes/year for Shadow 1, Shadow 1A, Shadow 2 and Shadow 2A, respectively. These results demonstrate, together with the OURSE marginal costs results, that the nested optimization mechanism between the two models was successful, thus confirming the ability of the ORION model to integrate with global refining models, and Integreated Assessment Models (IAMs)[41].

[40] Although ORION results did not fit results of OURSE trades to Brazil in Z2 at t0, they were coherent with Brazilian oil products trade data in ANP (2018a). Maybe it would be reasonable to review the assumption of Brazil as 50% of trades in OURSE's Z2 region.

[41] By contributing to better detail the oil refining segment.

6. Conclusion

This thesis aimed at developing the ORION (Oil Refining Industry Optimization and syNergies) model, which consists in a multi-regional linear programming optimization model for the Brazilian oil refining industry, in an open-source modeling language, capable of analyzing the evolution of this industry. The programming language used in the construction of this model was the GAMS - General Algebraic Modeling System associated with the CPLEX solver.

The reasons that led to the decision of developing this model consist of the situation that the Brazilian refining industry is currently experiencing, the uncertainties that it has been facing, which are associated to the evolution of energy demand and supply over the past and in the future decades, and, furthermore, lie in the fact that ORION is an open source model, developed in academia, and therefore capable of being used for research purposes both as an independent model and through nested optimization mechanisms with global refining models and Integrated Assessment Models (IAMs).

Brazil is a major oil producer, with newly discovered fields (pre-salt area), which have great production potential, and a refining park undergoing a process of transformation to be able to receive the pre-salt oil (light-to-medium oil), as well as investing in hydrotreating units in order to meet fuels stringent specifications. Nevertheless, the Brazilian oil refining industry has been facing many uncertainties, which concern the balance between biofuel and petroleum products for the automotive sector, the development of the domestic crude oil supply and the process of market opening, in which the prices of oil products are being defined according to the international market (Import Parity Price - IPP), with the objective of attracting investors, and thus meeting the partnership policy currently being sought in the sector. Thus, despite the large existing refining capacity, the country has been, in the last years, importing oil products in ascendant order, reducing, therefore, the refineries' utilization factors and increasing its refining margin uncertainty. Furthermore, Petrobras, a state-owned company that currently owns 99% (ninety nine percent) of the market share of the refining and logistics sectors in Brazil has presented plans for repositioning the national refining sector by dividing the refining park into four geographical blocks, as well as by selling eight of its seventeen refineries.

Given these challenges, which are short to long-term in nature and involve the discussion of how the oil refining industry is flexible, as well as the focus on the Brazilian problem of refining regionalization and the refiners' strategies, it is recognized that the development of the ORION model, in addition to addressing all of the above issues, allows the dialogue with international consolidated models associated with both the entire energy system and the detailed oil refining models (models focused only on the petroleum processes).

The ORION model portrays the Brazilian oil refining system organized into four geographical logistical blocks (South, Northeast, Rio de Janeiro-Minas Gerais and São Paulo), given the connections between markets, refineries and terminals. Also, it considers six international regions (United States, Central America, Western Europe, Middle East, Africa and Asia-Pacific) with which the model allows exchanges (imports/exports) of crude oil and petroleum products.

The final products represented in the model are liquefied petroleum gases (LPG), naphtha, gasoline, jet fuel oil, kerosene, diesel oil, heavy fuel oil, heating fuel oil and coke. In addition, the model is designed to operate over the period 2015-2040, through five-year periods (t0 to t5). A total of fourteen process units are considered, and in addition to these, the hydrogen generation and cogeneration units. Investments in new additional capacities are allowed from 2020 (period t1).

Aiming to test the model's reliability, three different scenarios were developed in terms of oil products demands: the Shadow scenario, based on the evolvement of the current oil refining industry and the energy and transport systems, without changes in current policies; the Cloudy scenario, which takes into account the announced policies and targets both for oil refining and for the energy and transportation systems as a whole, envisaging the mobility in the transport system for the next few years; and the Shiny scenario, being the most disruptive among the three scenarios, since it considers an accelerated energy transition to reach the goals associated to climate change, clean energy and clean air. For each one, the model was run under a multi-regional and a single-regional framework, in order to analyze, in each case, whether there is an advantage or not in having a regional model. In addition, for each case previously mentioned, two options of heavy fuel oil specifications were taken into account, in light of the IMO's regulations to reduce sulfur oxides (SOx) emissions from ships.

Moreover, as the ORION output, at a regional level, depends on the foreign trade flows and these flows are related to the international market prices, a nested

optimization approach was also carried out. Thus, a worldwide multi-regional model OURSE (Oil is Used in Refineries to Supply Energy) was run, for each previously defined scenario, in order to provide marginal values associated to the oil products demand constraints, which are used in the Brazilian model as CIF prices for imports and FOB prices for exports.

As the marginal values given by the OURSE model a high growth during the period of analysis, the prices of oil derivatives considered by the ORION model show also a great evolution, becoming extremely expensive at the end of the time period. Therefore, the optimization of the ORION model, in all scenarios, maximizes the production of some oil derivatives, as diesel, naphtha and fuel foil - but mainly diesel - meeting their demands and exporting its surpluses. On the other hand, the model ends up with low production and high imports levels of other oil derivatives, as LPG, gasoline, jet fuel oil and petcoke. Perhaps if fuel oil and diesel marginal values were lower[42], for example, the ORION model's results would present a production of higher levels of gasoline, and lower levels of diesel (importing some amounts of the latter).

Heavy fuel oil specification in light of the IMO's regulations to reduce sulfur oxides (SOx) emissions from shipsaffected the results, specially related to the need of additional capacity of HDTI units (which is used to reduce the sulfur content of the fuel oil pool). Hence, scenarios that take into account the IMO regulation feature higher hydrotreating need and, therefore, larger investments.

Given the results obtained in this thesis, it can be concluded that it was able, in the base period (period of calibration) to adequately reproduce the Brazilian refining sector, with regard to processing units capacities levels, imports of oil derivatives, trades between regions (in the multi-regional cases), utilities consumption, and CO_2 emissions. Regarding the medium and long-terms, although a restriction regarding investment in additional atmospheric distillation capacities has been added to the model, it is understood that it is within what is expected in terms of expansion of the Brazilian refining park in the coming years.

In this sense, despite the limitations found in the ORION model, which consist of the investment analysis of new refining units - which caused the addition of investments constraints; of the exchanges between regions detailing - that are not

[42] Maybe the addition of micro and mesoregional logistical constraints in the ORION model would also lead to other results.

physically restricted in the model, but only have associated costs; of the lack of possibility of decommissioning process units with associated costs; and of the detailing absence of other sources of oil derivatives, such as NGPUs in the case of LPG, which would reduce its imports, it is verified the important contribution associated to its development, especially as it is a tool that can help experts and decision makers, and which can be connected to global models, as was done in the present study in the case of OURSE, aiming to obtain more accurate results, and/or to give more detail on the oil refining segment to less detailed models, as the Integrated Assessment models (IAMs).

In fact, this was not the focus of this study, but the ORION model could be coupled with global and national IAMs, in a synergic approach between modelling strategies. IAMs typically lack a very good representation of the oil refineries and oil derivatives, as shown before. On the other hand, IAMs provide consistency of all sector of the economy, either from a supply or demand perspective. As such, a coupled platform between an IAM and ORION can become a powerful tool for policy makers and the oil sector.

In this context, propositions for future works consist of analyzing the influence of some variables in the model's results, for example, the oil products prices, since many of the model's results were influenced by the expensive prices given by the OURSE model; test new CAPEX and OPEX of refining processing units, since the costs considered in this thesis, which derived from the OURSE model database, are slightly lower than costs found in the literature for the specific case of Brazil – and, in this case, an option would be to consider a location factor within the costs calculations; analyze new discount rates to calculate the present value of costs; insert a water module to calculate the water consumption of the refining park and the impacts on water availability[43] with, for example, increasing processing units capacities; add possibilities for investments in energy efficiency technologies that reduce CO_2 emissions from the sector[43]; consider the decommissioning option of processing units (idea reinforced when analyzing the Shiny scenario); consider limitations of national trades between the regions of the model; take into account overrun costs and construction delays issues when investing in new processing units; develop and simulate better detailed scenarios, since, the construction and simulation of scenarios was not the main objective of this thesis, which actually consisted in the development of the ORION model; perform

[43] Based on the study developed by GUEDES *et al*. (2019).

scenarios related to climate policies, through CO_2 maximum caps, or using the equation of CO_2 taxation available in the model's structure; analyze refinery integration with advanced biomass loads, as well as the integration with non-energy products industry (petrochemical, lubricants); detail the international regions considered in the model, thus being able to better understand the role of the Brazilian refining industry in a world context; and, finally, integrate the ORION model with international consolidated models associated with the entire energy system, such as IAMs.

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8. Annex A – ORION model definitions: sets, variables and equations

A.I) Model sets

Set ***t*** 'periods of analysis'

t0 2015-2019
t1 2020-2024
t2 2025-2029
t3 2030-2034
t4 2035-2039
t5 2040-2044

Set ***dores***
S_S South
NE_S Northeast
RJMG_S Rio_Minas
SP_S São paulo

Set ***dored***

S_D South
NE_D Northeast
RJMG_D Rio_Minas
SP_D São paulo

Set ***oversea***

USA United States of America
CA Central America
WE Western Europe
AF Africa
ME Middle East
AP Asia Pacific

Set ***j*** 'all variables'

***process units**

ADU atmospheric distillation unit
VDU vacuum distillation unit
KEHDT kerosene hydrotreatment unit
NAHDT naphtha hydrotreatment unit
DIHDT diesel hydrotreatment unit
DSP desasphalting unit
REF catalytic reforming unit
ALK alkylation unit
FCC fluid catalytic cracking unit
RFCC resid fluid catalytic cracking unit
HCC hydrocracking unit
COK delayed coking unit
HDS gasoline hydrodessulfurization unit
HDTI unstable hydrotreatment unit
HGU hydrogen generation unit
COG cogeneration unit

***fuels**

NG natural gas
NGUGH natural gas - UGH
FG fuel gas
FO fuel oil

FCOK coke
ELECGRID electricity from the GRID

***crudes**

totcrude total quantity of crude processed
cruderef reference crude (Brent)

crude1 quantity of crude 1 treated
crude2 quantity of crude 2 treated
crude3 quantity of crude 3 treated

crude1d quantity of crude 1 treated with diesel campaign
crude2d quantity of crude 2 treated with diesel campaign
crude3d quantity of crude 3 treated with diesel campaign

crude1n quantity of crude 1 treated with naphtha campaign
crude2n quantity of crude 2 treated with naphtha campaign
crude3n quantity of crude 3 treated with naphtha campaign

***Atmospheric distillation unit**

1FGAS quantity of fuel gas produced by the atmospheric distillation unit with crude 1
2FGAS quantity of fuel gas produced by the atmospheric distillation unit with crude 2
3FGAS quantity of fuel gas produced by the atmospheric distillation unit with crude 3
1LPG quantity of LPG produced by the atmospheric distillation unit with crude 1
2LPG quantity of LPG produced by the atmospheric distillation unit with crude 2
3LPG quantity of LPG produced by the atmospheric distillation unit with crude 3
1LSRNA quantity of light straight run naphtha produced by the adu unit with crude 1
2LSRNA quantity of light straight run naphtha produced by the adu unit with crude 2
3LSRNA quantity of light straight run naphtha produced by the adu unit with crude 3
1HSRNA quantity of heavy straight run naphtha produced by the adu unit with crude 1
2HSRNA quantity of heavy straight run naphtha produced by the adu unit with crude 2
3HSRNA quantity of heavy straight run naphtha produced by the adu unit with crude 3
1SRKE quantity of straight run kerosene produced by the adu unit with crude 1
2SRKE quantity of straight run kerosene produced by the adu unit with crude 2
3SRKE quantity of straight run kerosene produced by the adu unit with crude 3
1SRDI quantity of straight run diesel produced by the adu unit with crude 1
2SRDI quantity of straight run diesel produced by the adu unit with crude 2
3SRDI quantity of straight run diesel produced by the adu unit with crude 3
1AGO quantity of atmospheric gasoil produced by the adu unit with crude 1
2AGO quantity of atmospheric gasoil produced by the adu unit with crude 2
3AGO quantity of atmospheric gasoil produced by the adu unit with crude 3
1ATR quantity of atmospheric residue produced by the adu unit with crude 1
2ATR quantity of atmospheric residue produced by the adu unit with crude 2
3ATR quantity of atmospheric residue produced by the adu unit with crude 3
1AGOFUELOIL quantity of atomspheric gasoil sent to fuel oil pool with crude 1
2AGOFUELOIL quantity of atomspheric gasoil sent to fuel oil pool with crude 2
3AGOFUELOIL quantity of atomspheric gasoil sent to fuel oil pool with crude 3

***Vacuum distillation unit**

1ATRVDU quantity of atmospheric residue fed to the vacuum distillation unit with crude 1
2ATRVDU quantity of atmospheric residue fed to the vacuum distillation unit with crude 2
3ATRVDU quantity of atmospheric residue fed to the vacuum distillation unit with crude 3
1LVGO quantity of light vacuum gasoil produced by the vacuum distillation unit with crude 1
2LVGO quantity of light vacuum gasoil produced by the vacuum distillation unit with crude 2
3LVGO quantity of light vacuum gasoil produced by the vacuum distillation unit with crude 3
1HVGO quantity of heavy vacuum gasoil produced by the vacuum distillation unit with crude 1
2HVGO quantity of heavy vacuum gasoil produced by the vacuum distillation unit with crude 2
3HVGO quantity of heavy vacuum gasoil produced by the vacuum distillation unit with crude 3
1VRES quantity of vacuum residue produced by the vacuum distillation unit with crude 1
2VRES quantity of vacuum residue produced by the vacuum distillation unit with crude 2
3VRES quantity of vacuum residue produced by the vacuum distillation unit with crude 3
1LVGOFCC quantity of light vacuum gasoil produced by the vacuum distillation unit and sent to the FCC unit with crude 1

2LVGOFCC quantity of light vacuum gasoil produced by the vacuum distillation unit and sent to the FCC unit with crude 2
3LVGOFCC quantity of light vacuum gasoil produced by the vacuum distillation unit and sent to the FCC unit with crude 3
1HVGOFCC quantity of heavy vacuum gasoil produced by the vacuum distillation unit and sent to the FCC unit with crude 1
2HVGOFCC quantity of heavy vacuum gasoil produced by the vacuum distillation unit and sent to the FCC unit with crude 2
3HVGOFCC quantity of heavy vacuum gasoil produced by the vacuum distillation unit and sent to the FCC unit with crude 3
1LVGOHCC quantity of light vacuum gasoil produced by the vacuum distillation unit and sent to the HCC unit with crude 1
2LVGOHCC quantity of light vacuum gasoil produced by the vacuum distillation unit and sent to the HCC unit with crude 2
3LVGOHCC quantity of light vacuum gasoil produced by the vacuum distillation unit and sent to the HCC unit with crude 3
1HVGOHCC quantity of heavy vacuum gasoil produced by the vacuum distillation unit and sent to the HCC unit with crude 1
2HVGOHCC quantity of heavy vacuum gasoil produced by the vacuum distillation unit and sent to the HCC unit with crude 2
3HVGOHCC quantity of heavy vacuum gasoil produced by the vacuum distillation unit and sent to the HCC unit with crude 3
1VRESFOP quantity of vacuum residue produced by the vacuum distillation unit and sent to fuel oil pool with crude 1
2VRESFOP quantity of vacuum residue produced by the vacuum distillation unit and sent to fuel oil pool with crude 2
3VRESFOP quantity of vacuum residue produced by the vacuum distillation unit and sent to fuel oil pool with crude 3

***Deasphalting unit**

1VRESDSP quantity of vacuum residue produced by the vacuum distillation unit and sent to desasphalting unit with crude 1
2VRESDSP quantity of vacuum residue produced by the vacuum distillation unit and sent to desasphalting unit with crude 2
3VRESDSP quantity of vacuum residue produced by the vacuum distillation unit and sent to desasphalting unit with crude 3
1DODSP quantity of desasphalted oil produced by the desasphalting unit with crude 1
2DODSP quantity of desasphalted oil produced by the desasphalting unit with crude 2
3DODSP quantity of desasphalted oil produced by the desasphalting unit with crude 3
1REDSP quantity of desasphalted residue produced by the desasphalting unit with crude 1
2REDSP quantity of desasphalted residue produced by the desasphalting unit with crude 2
3REDSP quantity of desasphalted residue produced by the desasphalting unit with crude 3

***Kerosene Hydrotreating unit**

1SRKEHDT quantity of straight run kerosene fed to the kerosene hidrotreating unit with crude 1
2SRKEHDT quantity of straight run kerosene fed to the kerosene hidrotreating unit with crude 2
3SRKEHDT quantity of straight run kerosene fed to the kerosene hidrotreating unit with crude 3
1SRKEBY quantity of straight run kerosene that bypasses the kerosene hidrotreating unit with crude 1
2SRKEBY quantity of straight run kerosene that bypasses the kerosene hidrotreating unit with crude 2
3SRKEBY quantity of straight run kerosene that bypasses the kerosene hidrotreating unit with crude 3
1KEHDT quantity of kerosene produced by the kerosene hydrotreating unit with crude 1
2KEHDT quantity of kerosene produced by the kerosene hydrotreating unit with crude 2
3KEHDT quantity of kerosene produced by the kerosene hydrotreating unit with crude 3
1SUKEHDT quantity of sulfur produced by the kerosene hydrotreating unit with crude 1
2SUKEHDT quantity of sulfur produced by the kerosene hydrotreating unit with crude 2
3SUKEHDT quantity of sulfur produced by the kerosene hydrotreating unit with crude 3
1KEJFP quantity of kerosene produced by the kerosene hydrotreating unit sent to the jet fuel oil pool with crude 1
2KEJFP quantity of kerosene produced by the kerosene hydrotreating unit sent to the jet fuel oil pool with crude 2
3KEJFP quantity of kerosene produced by the kerosene hydrotreating unit sent to the jet fuel oil pool with crude 3
1KEDIP quantity of kerosene produced by the kerosene hydrotreating unit sent to the diesel pool with crude 1
2KEDIP quantity of kerosene produced by the kerosene hydrotreating unit sent to the diesel pool with crude 2
3KEDIP quantity of kerosene produced by the kerosene hydrotreating unit sent to the diesel pool with crude 3
1KEKEP quantity of kerosene produced by the kerosene hydrotreating unit sent to the kerosene pool with crude 1
2KEKEP quantity of kerosene produced by the kerosene hydrotreating unit sent to the kerosene pool with crude 2

3KEKEP quantity of kerosene produced by the kerosene hydrotreating unit sent to the kerosene pool with crude 3
1KEBYJFP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the jet fuel oil pool with crude 1
2KEBYJFP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the jet fuel oil pool with crude 2
3KEBYJFP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the jet fuel oil pool with crude 3
1KEBYDIP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the diesel pool with crude 1
2KEBYDIP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the diesel pool with crude 2
3KEBYDIP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the diesel pool with crude 3
1KEBYKEP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the kerosene pool with crude 1
2KEBYKEP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the kerosene pool with crude 2
3KEBYKEP quantity of kerosene that bypasses the kerosene hydrotreating unit sent to the kerosene pool with crude 3

*__Diesel hydrotreating unit__

1SRDIHDT quantity of straight run diesel fed to the diesel hidrotreating unit with crude 1
2SRDIHDT quantity of straight run diesel fed to the diesel hidrotreating unit with crude 2
3SRDIHDT quantity of straight run diesel fed to the diesel hidrotreating unit with crude 3
1SRDIBY quantity of straight run diesel that bypasses the diesel hidrotreating unit with crude 1
2SRDIBY quantity of straight run diesel that bypasses the diesel hidrotreating unit with crude 2
3SRDIBY quantity of straight run diesel that bypasses the diesel hidrotreating unit with crude 3
1DIHDT quantity of diesel produced by the diesel hydrotreating unit with crude 1
2DIHDT quantity of diesel produced by the diesel hydrotreating unit with crude 2
3DIHDT quantity of diesel produced by the diesel hydrotreating unit with crude 3
1SUDIHDT quantity of sulfur produced by the diesel hydrotreating unit with crude 1
2SUDIHDT quantity of sulfur produced by the diesel hydrotreating unit with crude 2
3SUDIHDT quantity of sulfur produced by the diesel hydrotreating unit with crude 3
1DIDIP quantity of diesel produced by the diesel hydrotreating unit sent to the diesel pool with crude 1
2DIDIP quantity of diesel produced by the diesel hydrotreating unit sent to the diesel pool with crude 2
3DIDIP quantity of diesel produced by the diesel hydrotreating unit sent to the diesel pool with crude 3
1DIBYDIP quantity of diesel that bypasses the diesel hydrotreating unit sent to the diesel pool with crude 1
2DIBYDIP quantity of diesel that bypasses the diesel hydrotreating unit sent to the diesel pool with crude 2
3DIBYDIP quantity of diesel that bypasses the diesel hydrotreating unit sent to the diesel pool with crude 3
1SRDIBYHTFO quantity of straigh run diesel that bypasses the diesel hydrotreating unit and is sent to the heating fuel oil pool with crude 1
2SRDIBYHTFO quantity of straigh run diesel that bypasses the diesel hydrotreating unit and is sent to the heating fuel oil pool with crude 2
3SRDIBYHTFO quantity of straigh run diesel that bypasses the diesel hydrotreating unit and is sent to the heating fuel oil pool with crude 3

__*Fluid Catalytic Cracking Unit__

1AGOFCC quantity of atmospheric gasoil fed to the FCC unit with crude 1
2AGOFCC quantity of atmospheric gasoil fed to the FCC unit with crude 2
3AGOFCC quantity of atmospheric gasoil fed to the FCC unit with crude 3
1DODSPFCC quantity of desasphalted oil produced by the desasphalting unit and fed to the FCC unit with crude 1
2DODSPFCC quantity of desasphalted oil produced by the desasphalting unit and fed to the FCC unit with crude 2
3DODSPFCC quantity of desasphalted oil produced by the desasphalting unit and fed to the FCC unitwith crude 3
1INFCC input stream of the fcc unit with crude 1
2INFCC input stream of the fcc unit with crude 2
3INFCC input stream of the fcc unit with crude 3
1FGASFCC quantity of fuel gas produced by the FCC unit with crude 1
2FGASFCC quantity of fuel gas produced by the FCC unit with crude 2
3FGASFCC quantity of fuel gas produced by the FCC unit with crude 3
1LPGFCC quantity of butane produced by the FCC unit with crude 1
2LPGFCC quantity of butane produced by the FCC unit with crude 2
3LPGFCC quantity of butane produced by the FCC unit with crude 3
1GASFCC quantity of gasoline produced by the FCC unit with crude 1
2GASFCC quantity of gasoline produced by the FCC unit with crude 2
3GASFCC quantity of gasoline produced by the FCC unit with crude 3
1LCOFCC quantity of light cycle oil produced by the FCC unit with crude 1
2LCOFCC quantity of light cycle oil produced by the FCC unit with crude 2
3LCOFCC quantity of light cycle oil produced by the FCC unit with crude 3
1COKFCC quantity of coke produced by the FCC unit with crude 1
2COKFCC quantity of coke produced by the FCC unit with crude 2

3COKFCC quantity of coke produced by the FCC unit with crude 3
1SLOFCC quantity of slurry oil produced by the FCC unit with crude 1
2SLOFCC quantity of slurry oil produced by the FCC unit with crude 2
3SLOFCC quantity of slurry oil produced by the FCC unit with crude 3

***Resid Catalytic Cracking Unit**

1ATRRFCC quantity of atmospheric residue fed to the RFCC unit with crude 1
2ATRRFCC quantity of atmospheric residue fed to the RFCC unit with crude 2
3ATRRFCC quantity of atmospheric residue fed to the RFCC unit with crude 3
1INRFCC input stream of the RFCC unit with crude 1
2INRFCC input stream of the RFCC unit with crude 2
3INRFCC input stream of the RFCC unit with crude 3
1FGASRFCC quantity of fuel gas produced by the RFCC unit with crude 1
2FGASRFCC quantity of fuel gas produced by the RFCC unit with crude 2
3FGASRFCC quantity of fuel gas produced by the RFCC unit with crude 3
1LPGRFCC quantity of butane produced by the RFCC unit with crude 1
2LPGRFCC quantity of butane produced by the RFCC unit with crude 2
3LPGRFCC quantity of butane produced by the RFCC unit with crude 3
1GASRFCC quantity of gasoline produced by the RFCC unit with crude 1
2GASRFCC quantity of gasoline produced by the RFCC unit with crude 2
3GASRFCC quantity of gasoline produced by the RFCC unit with crude 3
1LCORFCC quantity of light cycle oil produced by the RFCC unit with crude 1
2LCORFCC quantity of light cycle oil produced by the RFCC unit with crude 2
3LCORFCC quantity of light cycle oil produced by the RFCC unit with crude 3
1COKRFCC quantity of coke produced by the RFCC unit with crude 1
2COKRFCC quantity of coke produced by the RFCC unit with crude 2
3COKRFCC quantity of coke produced by the RFCC unit with crude 3
1SLORFCC quantity of slurry oil produced by the RFCC unit with crude 1
2SLORFCC quantity of slurry oil produced by the RFCC unit with crude 2
3SLORFCC quantity of slurry oil produced by the RFCC unit with crude 3

***HCC unit**

1INHCC input steam of the HCC unit with crude 1
2INHCC input steam of the HCC unit with crude 2
3INHCC input steam of the HCC unit with crude 3
1AGOHCC quantity of AGO sent to the HCC unit with crude 1
2AGOHCC quantity of AGO sent to the HCC unit with crude 2
3AGOHCC quantity of AGO sent to the HCC unit with crude 3
1DODSPHCC quantity of oil distillate from DSP unit sent to HCC unit with crude 1
2DODSPHCC quantity of oil distillate from DSP unit sent to HCC unit with crude 2
3DODSPHCC quantity of oil distillate from DSP unit sent to HCC unit with crude 3
1FGASHCC quantity of fuel gas produced by the HCC unit with crude 1
2FGASHCC quantity of fuel gas produced by the HCC unit with crude 2
3FGASHCC quantity of fuel gas produced by the HCC unit with crude 3
1LPGHCC quantity of butane produced by the HCC unit with crude 1
2LPGHCC quantity of butane produced by the HCC unit with crude 2
3LPGHCC quantity of butane produced by the HCC unit with crude 3
1GASHCC quantity of gasoline produced by the HCC unit with crude 1
2GASHCC quantity of gasoline produced by the HCC unit with crude 2
3GASHCC quantity of gasoline produced by the HCC unit with crude 3
1KEHCC quantity of kerosene produced by the HCC unit with crude 1
2KEHCC quantity of kerosene produced by the HCC unit with crude 2
3KEHCC quantity of kerosene produced by the HCC unit with crude 3
1DIHCC quantity of diesel produced by the HCC unit with crude 1
2DIHCC quantity of diesel produced by the HCC unit with crude 2
3DIHCC quantity of diesel produced by the HCC unit with crude 3
1SLOHCC quantity of slurry oil produced by the HCC unit with crude 1
2SLOHCC quantity of slurry oil produced by the HCC unit with crude 2
3SLOHCC quantity of slurry oil produced by the HCC unit with crude 3
1KEHCCKE quantity of kerosene produced by the HCC unit with crude 1
2KEHCCKE quantity of kerosene produced by the HCC unit with crude 2
3KEHCCKE quantity of kerosene produced by the HCC unit with crude 3
1KEHCCJFP quantity of kerosene produced by the HCC unit with crude 1
2KEHCCJFP quantity of kerosene produced by the HCC unit with crude 2
3KEHCCJFP quantity of kerosene produced by the HCC unit with crude 3

***Naphtha Hydrotreating Unit**

1LSRNAHDT quantity of LSR naphtha fed to the naphtha hydrotreating unit with crude 1
2LSRNAHDT quantity of LSR naphtha fed to the naphtha hydrotreating unit with crude 2
3LSRNAHDT quantity of LSR naphtha fed to the naphtha hydrotreating unit with crude 3
1HSRNAHDT quantity of HSR naphtha fed to the naphtha hydrotreating unit with crude 1
2HSRNAHDT quantity of HSR naphtha fed to the naphtha hydrotreating unit with crude 2
3HSRNAHDT quantity of HSR naphtha fed to the naphtha hydrotreating unit with crude 3
1NACOKHDT quantity of coker naphtha fed to the naphtha hydrotreating unit with crude 1
2NACOKHDT quantity of coker naphtha fed to the naphtha hydrotreating unit with crude 2
3NACOKHDT quantity of coker naphtha fed to the naphtha hydrotreating unit with crude 3
1LSRNABYHDT quantity of LSR naphtha that bypasses the naphtha hidrotreating unit with crude 1
2LSRNABYHDT quantity of LSR naphtha that bypasses the naphtha hidrotreating unit with crude 2
3LSRNABYHDT quantity of LSR naphtha that bypasses the naphtha hidrotreating unit with crude 3
1HSRNABYHDT quantity of HSR naphtha that bypasses the naphtha hidrotreating unit with crude 1
2HSRNABYHDT quantity of HSR naphtha that bypasses the naphtha hidrotreating unit with crude 2
3HSRNABYHDT quantity of HSR naphtha that bypasses the naphtha hidrotreating unit with crude 3
1NACOKBYHDT quantity of coker naphtha that bypasses the naphtha hidrotreating unit with crude 1
2NACOKBYHDT quantity of coker naphtha that bypasses the naphtha hidrotreating unit with crude 2
3NACOKBYHDT quantity of coker naphtha that bypasses the naphtha hidrotreating unit with crude 3
1LSRNAPRODHDT quantity of LSR naphtha produced by the hydrotreating unit with crude 1
2LSRNAPRODHDT quantity of LSR naphtha produced by the hydrotreating unit with crude 2
3LSRNAPRODHDT quantity of LSR naphtha produced by the hydrotreating unit with crude 3
1HSRNAPRODHDT quantity of HSR naphtha produced by the hydrotreating unit with crude 1
2HSRNAPRODHDT quantity of HSR naphtha produced by the hydrotreating unit with crude 2
3HSRNAPRODHDT quantity of HSR naphtha produced by the hydrotreating unit with crude 3
1NACOKPRODHDT quantity of coker naphtha produced by the hydrotreating unit with crude 1
2NACOKPRODHDT quantity of coker naphtha produced by the hydrotreating unit with crude 2
3NACOKPRODHDT quantity of coker naphtha produced by the hydrotreating unit with crude 3
1NAPET quantity of naphtha sent to the petrochemical industry with crude 1
2NAPET quantity of naphtha sent to the petrochemical industry with crude 2
3NAPET quantity of naphtha sent to the petrochemical industry with crude 3
1SULSRNAHDT quantity of sulfur produced by the hydrotreating unit of the LSR Naphtha crude 1
2SULSRNAHDT quantity of sulfur produced by the hydrotreating unit of the LSR Naphtha crude 2
3SULSRNAHDT quantity of sulfur produced by the hydrotreating unit of the LSR Naphtha crude 3
1SULHSRNAHDT quantity of sulfur produced by the hydrotreating unit of the HSR Naphtha crude 1
2SULHSRNAHDT quantity of sulfur produced by the hydrotreating unit of the HSR Naphtha crude 2
3SULHSRNAHDT quantity of sulfur produced by the hydrotreating unit of the HSR Naphtha crude 3
1LSRNAPROD quantity of heavy straight run naphtha produced with crude 1
2LSRNAPROD quantity of heavy straight run naphtha produced with crude 2
3LSRNAPROD quantity of heavy straight run naphtha produced with crude 3

***Catalytic Reforming Unit**

1INREF catalytic refoming unit input feed with crude 1
2INREF catalytic refoming unit input feed with crude 2
3INREF catalytic refoming unit input feed with crude 3
1BYREF catalytic reforming unit bypass with crude 1
2BYREF catalytic reforming unit bypass with crude 2
3BYREF catalytic reforming unit bypass with crude 3
1HSRNAPROD quantity of heavy straight run naphtha produced and bypassed by the hdt naphtha unit with crude 1
2HSRNAPROD quantity of heavy straight run naphtha produced and bypassed by the hdt naphtha unit with crude 1
3HSRNAPROD quantity of heavy straight run naphtha produced and bypassed by the hdt naphtha unit with crude 1
1HSRNAREF quantity of heavy straight run naphtha fed do the reforming unit with crude 1
2HSRNAREF quantity of heavy straight run naphtha fed do the reforming unit with crude 2
3HSRNAREF quantity of heavy straight run naphtha fed do the reforming unit with crude 3
1HSRNABYREF quantity of heavy straight run naphtha that bypasses the reforming unit with crude 1
2HSRNABYREF quantity of heavy straight run naphtha that bypasses the reforming unit with crude 1
3HSRNABYREF quantity of heavy straight run naphtha that bypasses the reforming unit with crude 1
1HSRNAPET quantity of heavy straight run naphtha sent to the petrochemical industry with crude 1
2HSRNAPET quantity of heavy straight run naphtha sent to the petrochemical industry with crude 2
3HSRNAPET quantity of heavy straight run naphtha sent to the petrochemical industry with crude 3
1HSRNAGAS quantity of heavy straight run naphtha sent to the gasoline pool with crude 1
2HSRNAGAS quantity of heavy straight run naphtha sent to the gasoline pool with crude 2
3HSRNAGAS quantity of heavy straight run naphtha sent to the gasoline pool with crude 3

1REFGAS quantity of gasoline produced by the reforming unit with crude 1
2REFGAS quantity of gasoline produced by the reforming unit with crude 2
3REFGAS quantity of gasoline produced by the reforming unit with crude 3
1LPGREF quantity of LPG produced by the reforming unit with crude 1
2LPGREF quantity of LPG produced by the reforming unit with crude 1
3LPGREF quantity of LPG produced by the reforming unit with crude 1

***Gasoline Hydrodessulfurization unit**

1GASHDS quantity of gasoline directed to the gasoline hydrodessulfurization unit with crude 1
2GASHDS quantity of gasoline directed to the gasoline hydrodessulfurization unit with crude 1
3GASHDS quantity of gasoline directed to the gasoline hydrodessulfurization unit with crude 1
1GASBYHDS quantity of gasoline that bypasses the gasoline hydrodessulfurization unit with crude 1
2GASBYHDS quantity of gasoline that bypasses the gasoline hydrodessulfurization unit with crude 2
3GASBYHDS quantity of gasoline that bypasses the gasoline hydrodessulfurization unit with crude 3
1GASHDSPROD quantity of gasoline produced by the hydrodessulfurization unit with crude 1
2GASHDSPROD quantity of gasoline produced by the hydrodessulfurization unit with crude 2
3GASHDSPROD quantity of gasoline produced by the hydrodessulfurization unit with crude 3
1SULHDSPROD quantity of sulfur produced by the hydrodessulfurization unit with crude 1
2SULHDSPROD quantity of sulfur produced by the hydrodessulfurization unit with crude 2
3SULHDSPROD quantity of sulfur produced by the hydrodessulfurization unit with crude 3

***Alkylation unit**

1LPGALKADU quantity of lpg produced by the adu fed to the alkylation unit with crude 1
2LPGALKADU quantity of lpg produced by the adu fed to the alkylation unit with crude 2
3LPGALKADU quantity of lpg produced by the adu fed to the alkylation unit with crude 3
1LPGBYALKADU quantity of lpg produced by the adu that bypasses the alkylation unit with crude 1
2LPGBYALKADU quantity of lpg produced by the adu that bypasses the alkylation unit with crude 2
3LPGBYALKADU quantity of lpg produced by the adu that bypasses the alkylation unit with crude 3
1INSTALK quantity of input stream on the alkylation unit with crude 1
2INSTALK quantity of input stream on the alkylation unit with crude 2
3INSTALK quantity of input stream on the alkylation unit with crude 3
1GASALK quantity of gasoline produced by the alkylation unit with crude 1
2GASALK quantity of gasoline produced by the alkylation unit with crude 2
3GASALK quantity of gasoline produced by the alkylation unit with crude 3
1LPGALK quantity of LPG produced by the alkylation unit with crude 1
2LPGALK quantity of LPG produced by the alkylation unit with crude 2
3LPGALK quantity of LPG produced by the alkylation unit with crude 3

***Delayed coking unit**

1VRESCOK quantity of vacuum residue fed to the coking unit with crude 1
2VRESCOK quantity of vacuum residue fed to the coking unit with crude 2
3VRESCOK quantity of vacuum residue fed to the coking unit with crude 3
1FGASCOK quantity of fuel gas produced by the coking unit with crude 1
2FGASCOK quantity of fuel gas produced by the coking unit with crude 2
3FGASCOK quantity of fuel gas produced by the coking unit with crude 3
1LPGCOK quantity of LPG produced by the coking unit with crude 1
2LPGCOK quantity of LPG produced by the coking unit with crude 2
3LPGCOK quantity of LPG produced by the coking unit with crude 3
1NACOK quantity of naphtha produced by the coking unit with crude 1
2NACOK quantity of naphtha produced by the coking unit with crude 2
3NACOK quantity of naphtha produced by the coking unit with crude 3
1LGOCOK quantity of light gasoil produced by the coking unit with crude 1
2LGOCOK quantity of light gasoil produced by the coking unit with crude 2
3LGOCOK quantity of light gasoil produced by the coking unit with crude 3
1HGOCOK quantity of heavy gasoil produced by the coking unit with crude 1
2HGOCOK quantity of heavy gasoil produced by the coking unit with crude 2
3HGOCOK quantity of heavy gasoil produced by the coking unit with crude 3
1LGOCOKFCC quantity of light gasoil produced by the coking unit and sent to the FCC with crude 1
2LGOCOKFCC quantity of light gasoil produced by the coking unit and sent to the FCC with crude 2
3LGOCOKFCC quantity of light gasoil produced by the coking unit and sent to the FCC with crude 3
1LGOCOKHCC quantity of light gasoil produced by the coking unit and sent to the HCC with crude 1
2LGOCOKHCC quantity of light gasoil produced by the coking unit and sent to the HCC with crude 2

3LGOCOKHCC quantity of light gasoil produced by the coking unit and sent to the HCC with crude 3
1COKCOK quantity of coke produced by the coking unit with crude 1
2COKCOK quantity of coke produced by the coking unit with crude 2
3COKCOK quantity of coke produced by the coking unit with crude 3
1NACOKREF quantity of naphtha produced and sent to the reforming unit with crude 1
2NACOKREF quantity of naphtha produced and sent to the reforming unit with crude 2
3NACOKREF quantity of naphtha produced and sent to the reforming unit with crude 3

***HDT I unit**

1HGOCOKHDTI quantity of heavy gasoil produced by the coking unit and sent to HDT I with crude 1
2HGOCOKHDTI quantity of heavy gasoil produced by the coking unit and sent to HDT I with crude 2
3HGOCOKHDTI quantity of heavy gasoil produced by the coking unit and sent to HDT I with crude 3
1HGOCOKBYHDTI quantity of heavy gasoil produced by the coking unit that bypasses the HDT I with crude 1
2HGOCOKBYHDTI quantity of heavy gasoil produced by the coking unit that bypasses the HDT I with crude 2
3HGOCOKBYHDTI quantity of heavy gasoil produced by the coking unit that bypasses the HDT I with crude 3
1LCOFCCHDTI quantity of light cycle oil produced by the FCC unit and sent to the HDT I with crude 1
2LCOFCCHDTI quantity of light cycle oil produced by the FCC unit and sent to the HDT I with crude 2
3LCOFCCHDTI quantity of light cycle oil produced by the FCC unit and sent to the HDT I with crude 3
1LCOFCCBYHDTI quantity of light cycle oil produced by the FCC unit that bypasses the HDT I with crude 1
2LCOFCCBYHDTI quantity of light cycle oil produced by the FCC unit that bypasses the HDT I with crude 2
3LCOFCCBYHDTI quantity of light cycle oil produced by the FCC unit that bypasses the HDT I with crude 3
1LCORFCCHDTI quantity of light cycle oil produced by the RFCC unit and sent to the HDT I with crude 1
2LCORFCCHDTI quantity of light cycle oil produced by the RFCC unit and sent to the HDT I with crude 2
3LCORFCCHDTI quantity of light cycle oil produced by the RFCC unit and sent to the HDT I with crude 3
1LCORFCCBYHDTI quantity of light cycle oil produced by the RFCC unit that bypasses the HDT I with crude 1
2LCORFCCBYHDTI quantity of light cycle oil produced by the RFCC unit that bypasses the HDT I with crude 2
3LCORFCCBYHDTI quantity of light cycle oil produced by the RFCC unit that bypasses the HDT I with crude 3
1HDTIINFEED input feed of the HDT I with crude 1
2HDTIINFEED input feed of the HDT I with crude 2
3HDTIINFEED input feed of the HDT I with crude 3
1HDTIPROD product of the HDTI with crude 1
2HDTIPROD product of the HDTI with crude 2
3HDTIPROD product of the HDTI with crude 3
1SUHDTI quantity of sulfur produced by the HDT I with crude 1
2SUHDTI quantity of sulfur produced by the HDT I with crude 2
3SUHDTI quantity of sulfur produced by the HDT I with crude 3
1DIHDTI quantity of diesel produced by the HDT I with crude 1
2DIHDTI quantity of diesel produced by the HDT I with crude 2
3DIHDTI quantity of diesel produced by the HDT I with crude 3
1DIBYHDTI quantity of diesel that bypassses HDT I with crude 1
2DIBYHDTI quantity of diesel that bypassses HDT I with crude 2
3DIBYHDTI quantity of diesel that bypassses HDT I with crude 3
1FUELOILHDTI quantity of heavy fuel oil sent to the HDT I with crude 1
2FUELOILHDTI quantity of heavy fuel oil sent to the HDT I with crude 2
3FUELOILHDTI quantity of heavy fuel oil sent to the HDT I with crude 3
1FUELOILBYHDTI quantity of heavy fuel oil that bypasses the HDT I with crude 1
2FUELOILBYHDTI quantity of heavy fuel oil that bypasses the HDT I with crude 2
3FUELOILBYHDTI quantity of heavy fuel oil that bypasses the HDT I with crude 3
1HEATFOHDTI quantity of heating fuel oil sent to the HDT I with crude 1
2HEATFOHDTI quantity of heating fuel oil sent to the HDT I with crude 2
3HEATFOHDTI quantity of heating fuel oil sent to the HDT I with crude 3
1HEATFOBYHDTI quantity of heating fuel oil that bypasses the HDT I with crude 1
2HEATFOBYHDTI quantity of heating fuel oil that bypasses the HDT I with crude 2
3HEATFOBYHDTI quantity of heating fuel oil that bypasses the HDT I with crude 3

*** Products**

FGAS_1 quantity of fuel gas produced with crude 1
FGAS_2 quantity of fuel gas produced with crude 2
FGAS_3 quantity of fuel gas produced with crude 3
LPG_1 quantity of liquified petroleum gas produced with crude 1
LPG_2 quantity of liquified petroleum gas produced with crude 2
LPG_3 quantity of liquified petroleum gas produced with crude 3
NAPHTHA_1 quantity of naphtha produced with crude 1
NAPHTHA_2 quantity of naphtha produced with crude 2
NAPHTHA_3 quantity of naphtha produced with crude 3

GASOLINE_1 quantity of gasoline produced with crude 1
GASOLINE_2 quantity of gasoline produced with crude 2
GASOLINE_3 quantity of gasoline produced with crude 3
KEROS_1 quantity of kerosene produced with crude 1
KEROS_2 quantity of kerosene produced with crude 2
KEROS_3 quantity of kerosene produced with crude 3
DIESEL_1 quantity of diesel produced with crude 1
DIESEL_2 quantity of diesel produced with crude 2
DIESEL_3 quantity of diesel produced with crude 3
JETFUELOIL_1 quantity of jet fuel produced with crude 1
JETFUELOIL_2 quantity of jet fuel produced with crude 2
JETFUELOIL_3 quantity of jet fuel produced with crude 3
FUELOIL_1 quantity of fuel oil produced with crude 1
FUELOIL_2 quantity of fuel oil produced with crude 2
FUELOIL_3 quantity of fuel oil produced with crude 3
HEATFUELOIL_1 quantity of heating fuel oil produced with crude 1
HEATFUELOIL_2 quantity of heating fuel oil produced with crude 2
HEATFUELOIL_3 quantity of heating fuel oil produced with crude 3
COKE_1 quantity of coke produced with crude 1
COKE_2 quantity of coke produced with crude 2
COKE_3 quantity of coke produced with crude 3
SULFUR_1 quantity of sulfur produced with crude 1
SULFUR_2 quantity of sulfur produced with crude 2
SULFUR_3 quantity of sulfur produced with crude 3

***Final products**

FGAS total quantity of fuel gas produced
LPG total quantity of lpg produced
NAPHTHA total quantity of naphtha produced
GASOLINE total quantity of gasoline produced
KEROS total quantity of kerosene produced
DIESEL total quantity of diesel produced
JETFUELOIL total quantity of jet fuel oil produced
FUELOIL total quantity of fuel oil produced
HEATFUELOIL total quantity of heating fuel oil produced
COKE total quantity of coke produced
SULFUR total quantity of sulfur produced

***Final products in volume**

GASOLINEVOL total quantity of gasoline produced in volume term
DIESELVOL total quantity of diesel produced in volume term

***Imports**

imp_lpg import of liquified petroleum gas
imp_naphtha import of naphtha
imp_gasoline import of gasoline
imp_keros import of kerosene
imp_diesel import of diesel
imp_jetfueloil import of jetfueloil
imp_fueloil import of fuel oil
imp_heatfueloil import of heating fuel oil
imp_coke import of coke

***Exports**

exp_lpg export of liquified petroleum gas
exp_naphtha export of naphtha
exp_gasoline export of gasoline
exp_keros export of kerosene
exp_diesel export of diesel
exp_jetfueloil export of jetfueloil
exp_fueloil export of fuel oil

exp_heatfueloil export of heating fuel oil
exp_coke export of coke

***Fuel purchase**

purch_ng purchase of natural gas to meet the demand for utilities within the process units
purch_elec purchase of electricity
purch_fo purchase of fuel oil
purch_fgas purchase of fuel gas

***Emissions**

co2emissions CO2 total emissions
co2emission_ng CO2 emission due to the combustion of natural gas to meet refinery energy demand
co2emission_ago CO2 emission due to the combustion of atmospheric gasoil to meet refinery energy demand

***Units level capacities**

CAPADU level capacity of atmospheric distillation unit
CAPVDU level capacity of vacuum distillation unit
CAPDSP level capacity of desasphalting unit
CAPNAHDT level capacity of naphtha hydrotreating unit
CAPREF level capacity of reforming unit
CAPKEHDT level capcity of kerosene hydrotreating unit
CAPDIHDT level capacity of diesel hydrotreating unit
CAPFCC level capacity of the FCC unit
CAPRFCC level capacity of the RFCC unit
CAPHCC level capacity of the HCC unit
CAPHDS level capacity of the HDS gasoline unit
CAPALK level capacity of alkylation unit
CAPCOK level capacity of the coking unit
CAPUGH level capacity of hydrogeneration unit
CAPHDTI level capacity of HDT I
CAPCOG maximum electricity generation capacity of cogeneration unit

***Additional capacities**

ADDCAPADU additional atmospheric distillation unit capacity
ADDCAPVDU additional vacuum distillation unit capacity
ADDCAPDSP additional desasphalting unit capacity
ADDCAPNAHDT additional naphtha hydrotreating unit capacity
ADDCAPREF additional catalytic refoming unit capacity
ADDCAPKEHDT additional kerosene hydrotreating unit capacity
ADDCAPDIHDT additional diesel hydrotreating unit capacity
ADDCAPFCC additional fluid catalytic cracking unit capacity
ADDCAPRFCC additional resid catalytic cracking unit capacity
ADDCAPHCC additional catalytic hydrocracking unit capcity
ADDCAPHDS additional gasoline desulfurisation unit capacity
ADDCAPALK additional alkylation unit capacity
ADDCAPCOK additional coking unit capacity
ADDCAPUGH additional hydrogeneration unit capacity
ADDCAPHDTI additional HDT I capacity
ADDCAPCOG additional cogeneration capacity

***Additional Harbors Capacities**

ADDHARBORLIGHT additional harbor capacity for light products
ADDHARBORMED additional harbor capacity for medium products
ADDHARBORHEAVY additional harbor capacity for heavy products

***Products classification**

LIGHTPROD light products
MEDIUMPROD medium products
HEAVYPROD heavy products

set ***i*** 'all balances'

***Atmospheric distillation unit**

1BALTOPFGAS balance of fuel gas in the adu with crude 1
2BALTOPFGAS balance of fuel gas in the adu with crude 2
3BALTOPFGAS balance of fuel gas in the adu with crude 3
1BALTOPLPG balance of liquified petroleum gas in the adu with crude 1
2BALTOPLPG balance of liquified petroleum gas in the adu with crude 2
3BALTOPLPG balance of liquified petroleum gas in the adu with crude 3
1BALTOPLSRNA balance light straight run naphtha in the adu with crude 1
2BALTOPLSRNA balance light straight run naphtha in the adu with crude 2
3BALTOPLSRNA balance light straight run naphtha in the adu with crude 3
1BALTOPHSRNA balance heavy straight run naphtha in the adu with crude 1
2BALTOPHSRNA balance heavy straight run naphtha in the adu with crude 2
3BALTOPHSRNA balance heavy straight run naphtha in the adu with crude 3
1BALTOPSRKE balance of straight run kerosene in the adu with crude 1
2BALTOPSRKE balance of straight run kerosene in the adu with crude 2
3BALTOPSRKE balance of straight run kerosene in the adu with crude 3
1BALTOPSRDI balance of straight run diesel in the adu with crude 1
2BALTOPSRDI balance of straight run diesel in the adu with crude 2
3BALTOPSRDI balance of straight run diesel in the adu with crude 3
1BALTOPAGO balance of atmospheric gasoil in the adu with crude 1
2BALTOPAGO balance of atmospheric gasoil in the adu with crude 2
3BALTOPAGO balance of atmospheric gasoil in the adu with crude 3
1BALTOPATR balance of atmospheric residue in the adu with crude 1
2BALTOPATR balance of atmospheric residue in the adu with crude 2
3BALTOPATR balance of atmospheric residue in the adu with crude 3
1BALATR balance of the atmospheric residue produced with crude 1
2BALATR balance of the atmospheric residue produced with crude 1
3BALATR balance of the atmospheric residue produced with crude 1
1BALAGO balance of atmospheric gasoil with crude 1
2BALAGO balance of atmospheric gasoil with crude 2
3BALAGO balance of atmospheric gasoil with crude 3

***Vacuum distillation unit**

1BALLVGO balance of lvgo in the vacuum distillation unit with crude 1
2BALLVGO balance of lvgo in the vacuum distillation unit with crude 2
3BALLVGO balance of lvgo in the vacuum distillation unit with crude 3
1BALHVGO balance of hvgo in the vacuum distillation unit with crude 1
2BALHVGO balance of hvgo in the vacuum distillation unit with crude 2
3BALHVGO balance of hvgo in the vacuum distillation unit with crude 3
1BALVRES balance of vacuum residue in the vacuum distillation unit with crude 1
2BALVRES balance of vacuum residue in the vacuum distillation unit with crude 2
3BALVRES balance of vacuum residue in the vacuum distillation unit with crude
1BALLVGOPROD balance of the lvgo produced by the vacuum distillation unit with crude 1
2BALLVGOPROD balance of the lvgo produced by the vacuum distillation unit with crude 2
3BALLVGOPROD balance of the lvgo produced by the vacuum distillation unit with crude 3
1BALHVGOPROD balance of the hvgo produced by the vacuum distillation unit with crude 1
2BALHVGOPROD balance of the hvgo produced by the vacuum distillation unit with crude 2
3BALHVGOPROD balance of the hvgo produced by the vacuum distillation unit with crude 3
1BALVRESPROD balance of the vacuum residue produced by the vacuum distillation unit with crude 1
2BALVRESPROD balance of the vacuum residue produced by the vacuum distillation unit with crude 2
3BALVRESPROD balance of the vacuum residue produced by the vacuum distillation unit with crude 3

***Deasphalting unit**

1BALDODSP balance of the desasphalted gasoil in the de desasphalting unit with crude 1
2BALDODSP balance of the desasphalted gasoil in the de desasphalting unit with crude 2
3BALDODSP balance of the desasphalted gasoil in the de desasphalting unit with crude 3
1BALREDSP balance of the desasphalted residue in the desasphalting unit with crude 1
2BALREDSP balance of the desasphalted residue in the desasphalting unit with crude 2
3BALREDSP balance of the desasphalted residue in the desasphalting unit with crude 3

1BALGODSPPROD balance of the gasoil produced by the de desasphalting unit with crude 1
2BALGODSPPROD balance of the gasoil produced by the de desasphalting unit with crude 2
3BALGODSPPROD balance of the gasoil produced by the de desasphalting unit with crude 3
1BALREDSPPROD balance of the residue produced by the desasphalting unit with crude 1
2BALREDSPPROD balance of the residue produced by the desasphalting unit with crude 2
3BALREDSPPROD balance of the residue produced by the desasphalting unit with crude 3

***Naphtha hydrotreater**

1BALLSRNA balance of LSR naphtha with crude 1
2BALLSRNA balance of LSR naphtha with crude 2
3BALLSRNA balance of LSR naphtha with crude 3
1BALHSRNA balance of HSR naphtha with crude 1
2BALHSRNA balance of HSR naphtha with crude 2
3BALHSRNA balance of HSR naphtha with crude 3
1BALLSRNAHDT balance of LSR naphtha in the naphtha hydrotreating unit with crude 1
2BALLSRNAHDT balance of LSR naphtha in the naphtha hydrotreating unit with crude 2
3BALLSRNAHDT balance of LSR naphtha in the naphtha hydrotreating unit with crude 3
1BALHSRNAHDT balance of HSR naphtha in the naphtha hydrotreating unit with crude 1
2BALHSRNAHDT balance of HSR naphtha in the naphtha hydrotreating unit with crude 2
3BALHSRNAHDT balance of HSR naphtha in the naphtha hydrotreating unit with crude 3
1BALNACOKHDT balance of coker naphtha in the naphtha hydrotreating unit with crude 1
2BALNACOKHDT balance of coker naphtha in the naphtha hydrotreating unit with crude 2
3BALNACOKHDT balance of coker naphtha in the naphtha hydrotreating unit with crude 3
1BALSULSRNAHDT balance of sulfur of LSR naphtha in the naphtha hydrotreating unit with crude 1
2BALSULSRNAHDT balance of sulfur of LSR naphtha in the naphtha hydrotreating unit with crude 2
3BALSULSRNAHDT balance of sulfur of LSR naphtha in the naphtha hydrotreating unit with crude 3
1BALSULHSRNAHDT balance of sulfur of HSR naphtha in the naphtha hydrotreating unit with crude 1
2BALSULHSRNAHDT balance of sulfur of HSR naphtha in the naphtha hydrotreating unit with crude 2
3BALSULHSRNAHDT balance of sulfur of HSR naphtha in the naphtha hydrotreating unit with crude 3
1BALSULNACOKHDT balance of sulfur of coker naphtha in the naphtha hydrotreating unit with crude 1
2BALSULNACOKHDT balance of sulfur of coker naphtha in the naphtha hydrotreating unit with crude 2
3BALSULNACOKHDT balance of sulfur of coker naphtha in the naphtha hydrotreating unit with crude 3
1BALNAPET quantity of naphtha sent to the petrochemical industry with crude 1
2BALNAPET quantity of naphtha sent to the petrochemical industry with crude 2
3BALNAPET quantity of naphtha sent to the petrochemical industry with crude 3
1BALLSRNAPROD balance of the light straight run naphtha after the hdt naphtha unit with crude 1
2BALLSRNAPROD balance of the light straight run naphtha after the hdt naphtha unit with crude 2
3BALLSRNAPROD balance of the light straight run naphtha after the hdt naphtha unit with crude 3

***Kerosene Hydrotreater**

1BALSRKE balance of straight run kerosene with crude 1
2BALSRKE balance of straight run kerosene with crude 2
3BALSRKE balance of straight run kerosene with crude 3
1BALKEHDT balance of kerosene in the kerosene hydrotreating unit with crude 1
2BALKEHDT balance of kerosene in the kerosene hydrotreating unit with crude 2
3BALKEHDT balance of kerosene in the kerosene hydrotreating unit with crude 3
1BALSULKEHDT balance of sulfur in the kerosene hydrotreating unit with crude 1
2BALSULKEHDT balance of sulfur in the kerosene hydrotreating unit with crude 2
3BALSULKEHDT balance of sulfur in the kerosene hydrotreating unit with crude 3
1BALKEHDTST balance of hydrotreated kerosene stream with crude 1
2BALKEHDTST balance of hydrotreated kerosene stream with crude 2
3BALKEHDTST balance of hydrotreated kerosene stream with crude 3
1BALKEBYST balance of kerosene bypassed stream with crude 1
2BALKEBYST balance of kerosene bypassed stream with crude 2
3BALKEBYST balance of kerosene bypassed stream with crude 3

***Diesel Hydrotreater**

1BALSRDI balance of straight run diesel with crude 1
2BALSRDI balance of straight run diesel with crude 2
3BALSRDI balance of straight run diesel with crude 3
1BALDIHDT balance of diesel in the diesel hydrotreating unit with crude 1
2BALDIHDT balance of diesel in the diesel hydrotreating unit with crude 2
3BALDIHDT balance of diesel in the diesel hydrotreating unit with crude 3
1BALSULDIHDT balance of sulfur in the diesel hydrotreating unit with crude 1

2BALSULDIHDT balance of sulfur in the diesel hydrotreating unit with crude 2
3BALSULDIHDT balance of sulfur in the diesel hydrotreating unit with crude 3
1BALDIHDTST balance of hydrotreated diesel stream with crude 1
2BALDIHDTST balance of hydrotreated diesel stream with crude 2
3BALDIHDTST balance of hydrotreated diesel stream with crude 3
1BALDIBYST balance of diesel bypassed stream with crude 1
2BALDIBYST balance of diesel bypassed stream with crude 2
3BALDIBYST balance of diesel bypassed stream with crude 3

<u>*Refoming Unit</u>

1BALHSRNAPROD balance of the heavy straight run naphtha after the hdt naphtha unit with crude 1
2BALHSRNAPROD balance of the heavy straight run naphtha after the hdt naphtha unit with crude 2
3BALHSRNAPROD balance of the heavy straight run naphtha after the hdt naphtha unit with crude 3
1BALHSRNAREF balance of the heavy straight run naphtha input stream of the reforming unit with crude 1
2BALHSRNAREF balance of the heavy straight run naphtha input stream of the reforming unit with crude 2
3BALHSRNAREF balance of the heavy straight run naphtha input stream of the reforming unit with crude 3
1BALGASREF balance of the gasoline on the reforming unit with crude 1
2BALGASREF balance of the gasoline on the reforming unit with crude 2
3BALGASREF balance of the gasoline on the reforming unit with crude 3
1BALLPGREF balance of the LPG on the reforming unit with crude 1
2BALLPGREF balance of the LPG on the reforming unit with crude 2
3BALLPGREF balance of the LPG on the reforming unit with crude 3
1BALHSRNAPETGAS balance of heavy straight run naphtha that goes to the petrochemical industry and gasoline pool with crude 1
2BALHSRNAPETGAS balance of heavy straight run naphtha that goes to the petrochemical industry and gasoline pool with crude 2
3BALHSRNAPETGAS balance of heavy straight run naphtha that goes to the petrochemical industry and gasoline pool with crude 3
1BALREFPROC balance of the catalytic reforming unit process with crude 1
2BALREFPROC balance of the catalytic reforming unit process with crude 2
3BALREFPROC balance of the catalytic reforming unit process with crude 3

<u>*FCC Unit</u>

1BALINFCC balance of the input stream of the FCC unit with crude 1
2BALINFCC balance of the input stream of the FCC unit with crude 2
3BALINFCC balance of the input stream of the FCC unit with crude 3
1BALFGASFCC balance of fuel gas in the FCC unit with crude 1
2BALFGASFCC balance of fuel gas in the FCC unit with crude 2
3BALFGASFCC balance of fuel gas in the FCC unit with crude 3
1BALLPGFCC balance of butane in the FCC unit with crude 1
2BALLPGFCC balance of butane in the FCC unit with crude 2
3BALLPGFCC balance of butane in the FCC unit with crude 3
1BALGASFCC balance of gasoline in the FCC unit with crude 1
2BALGASFCC balance of gasoline in the FCC unit with crude 2
3BALGASFCC balance of gasoline in the FCC unit with crude 3
1BALLCOFCC balance of light cycle oil on the FCC unit with crude 1
2BALLCOFCC balance of light cycle oil on the FCC unit with crude 2
3BALLCOFCC balance of light cycle oil on the FCC unit with crude 3
1BALCOKFCC balance of coke on the FCC unit with crude 1
2BALCOKFCC balance of coke on the FCC unit with crude 2
3BALCOKFCC balance of coke on the FCC unit with crude 3
1BALSLOFCC balance of slurry oil on the FCC unit with crude 1
2BALSLOFCC balance of slurry oil on the FCC unit with crude 2
3BALSLOFCC balance of slurry oil on the FCC unit with crude 3

***RFCC Unit**

1BALINRFCC balance of the input stream of the RFCC unit with crude 1
2BALINRFCC balance of the input stream of the RFCC unit with crude 2
3BALINRFCC balance of the input stream of the RFCC unit with crude 3
1BALFGASRFCC balance of fuel gas in the RFCC unit with crude 1
2BALFGASRFCC balance of fuel gas in the RFCC unit with crude 2
3BALFGASRFCC balance of fuel gas in the RFCC unit with crude 3
1BALLPGRFCC balance of butane in the RFCC unit with crude 1
2BALLPGRFCC balance of butane in the RFCC unit with crude 1

3BALLPGRFCC balance of butane in the RFCC unit with crude 1
1BALGASRFCC balance of gasoline in the RFCC unit with crude 1
2BALGASRFCC balance of gasoline in the RFCC unit with crude 2
3BALGASRFCC balance of gasoline in the RFCC unit with crude 3
1BALLCORFCC balance of light cycle oil on the RFCC unit with crude 1
2BALLCORFCC balance of light cycle oil on the RFCC unit with crude 2
3BALLCORFCC balance of light cycle oil on the RFCC unit with crude 3
1BALCOKRFCC balance of coke on the RFCC unit with crude 1
2BALCOKRFCC balance of coke on the RFCC unit with crude 2
3BALCOKRFCC balance of coke on the RFCC unit with crude 3
1BALSLORFCC balance of slurry oil on the RFCC unit with crude 1
2BALSLORFCC balance of slurry oil on the RFCC unit with crude 2
3BALSLORFCC balance of slurry oil on the RFCC unit with crude 3

***HCC Unit**

1BALINHCC balance of the input steam of the HCC unit with crude 1
2BALINHCC balance of the input steam of the HCC unit with crude 2
3BALINHCC balance of the input steam of the HCC unit with crude 3
1BALFGASHCC balance fuel gas in the HCC unit with crude 1
2BALFGASHCC balance fuel gas in the HCC unit with crude 2
3BALFGASHCC balance fuel gas in the HCC unit with crude 3
1BALLPGHCC balance of LPG in the HCC unit with crude 1
2BALLPGHCC balance of LPG in the HCC unit with crude 2
3BALLPGHCC balance of LPG in the HCC unit with crude 3
1BALGASHCC balance of gasoline in the HCC unit with crude 1
2BALGASHCC balance of gasoline in the HCC unit with crude 2
3BALGASHCC balance of gasoline in the HCC unit with crude 3
1BALKEHCC balance of kerosene in the HCC unit with crude 1
2BALKEHCC balance of kerosene in the HCC unit with crude 2
3BALKEHCC balance of kerosene in the HCC unit with crude 3
1BALDIHCC balance of diesel in the HCC unit with crude 1
2BALDIHCC balance of diesel in the HCC unit with crude 2
3BALDIHFCC balance of diesel in the HCC unit with crude 3
1BALSLOHCC balance of slurry oil in the HCC unit with crude 1
2BALSLOHCC balance of slurry oil in the HCC unit with crude 2
3BALSLOHCC balance of slurry oil in the HCC unit with crude 3
1BALKEHCCPROD balance of kerosene produced in the HCC unit with crude 1
2BALKEHCCPROD balance of kerosene produced in the HCC unit with crude 2
3BALKEHCCPROD balance of kerosene produced in the HCC unit with crude 3

***HDS Gasoline**

1BALSTGASHDS balance of the streams directed to the hds unit with crude 1
2BALSTGASHDS balance of the streams directed to the hds unit with crude 1
3BALSTGASHDS balance of the streams directed to the hds unit with crude 1
1BALGASHDS balance of the gasoline in the hds unit with crude 1
2BALGASHDS balance of the gasoline in the hds unit with crude 2
3BALGASHDS balance of the gasoline in the hds unit with crude 3
1BALSULHDS balance of sulfur in the hds unit with crude 1
2BALSULHDS balance of sulfur in the hds unit with crude 2
3BALSULHDS balance of sulfur in the hds unit with crude 3

***LPG Stream**

1BALLPGST balance of the lpg stream produced by the adu with crude 1
2BALLPGST balance of the lpg stream produced by the adu with crude 2
3BALLPGST balance of the lpg stream produced by the adu with crude 3
1BALC4FCCST balance of the butane stream produced by the FCC unit with crude 1
2BALC4FCCST balance of the butane stream produced by the FCC unit with crude 2
3BALC4FCCST balance of the butane stream produced by the FCC unit with crude 3
1BALC4RFCCST balance of the butane stream produced by the RFCC unit with crude 1
2BALC4RFCCST balance of the butane stream produced by the RFCC unit with crude 2
3BALC4RFCCST balance of the butane stream produced by the RFCC unit with crude 3

***Alkylation unit**

1BALSTALK balance of the input stream of the alkylation unit with crude 1
2BALSTALK balance of the input stream of the alkylation unit with crude 2
3BALSTALK balance of the input stream of the alkylation unit with crude 1
1BALGASALK balance of the gasoline in the alkylation unit with crude 1
2BALGASALK balance of the gasoline in the alkylation unit with crude 2
3BALGASALK balance of the gasoline in the alkylation unit with crude 3
1BALLPGALK balance of the LPG in the alkylation unit with crude 1
2BALLPGALK balance of the LPG in the alkylation unit with crude 2
3BALLPGALK balance of the LPG in the alkylation unit with crude 3

***Coking unit**

1BALFGASCOK balance of fuel gas produced by the coking unit with crude 1
2BALFGASCOK balance of fuel gas produced by the coking unit with crude 2
3BALFGASCOK balance of fuel gas produced by the coking unit with crude 3
1BALLPGCOK balance of LPG in the coking unit with crude 1
2BALLPGCOK balance of LPG in the coking unit with crude 2
3BALLPGCOK balance of LPG in the coking unit with crude 3
1BALNACOK balance of naphtha in the coking unit with crude 1
2BALNACOK balance of naphtha in the coking unit with crude 2
3BALNACOK balance of naphtha in the coking unit with crude 3
1BALLGOCOK balance of light gasoil in the coking unit with crude 1
2BALLGOCOK balance of light gasoil in the coking unit with crude 2
3BALLGOCOK balance of light gasoil in the coking unit with crude 3
1BALHGOCOK balance of heavy gasoil in the coking unit with crude 1
2BALHGOCOK balance of heavy gasoil in the coking unit with crude 2
3BALHGOCOK balance of heavy gasoil in the coking unit with crude 3
1BALCOKCOK balance of coke in the coking unit with crude 1
2BALCOKCOK balance of coke in the coking unit with crude 2
3BALCOKCOK balance of coke in the coking unit with crude 3
1BALSTLGOCOK balance of the light gasoil produced by the coking unit with crude 1
2BALSTLGOCOK balance of the light gasoil produced by the coking unit with crude 2
3BALSTLGOCOK balance of the light gasoil produced by the coking unit with crude 3
1BALSTHGOCOK balance of the heavy gasoil produced by the coking unit with crude 1
2BALSTHGOCOK balance of the heavy gasoil produced by the coking unit with crude 2
3BALSTHGOCOK balance of the heavy gasoil produced by the coking unit with crude 3
1BALSTNACOK balance of the naphtha stream produced by the coking unit with crude 1
2BALSTNACOK balance of the naphtha stream produced by the coking unit with crude 2
3BALSTNACOK balance of the naphtha stream produced by the coking unit with crude 3

***HDT I unit**

1BALINHDTI balance of the input stream of the HDT I with crude 1
2BALINHDTI balance of the input stream of the HDT I with crude 2
3BALINHDTI balance of the input stream of the HDT I with crude 3
1BALHDTIPROD balance of the output stream of the HDT I with crude 1
2BALHDTIPROD balance of the output stream of the HDT I with crude 2
3BALHDTIPROD balance of the output stream of the HDT I with crude 3
1BALDIHDTI balance of the diesel produced by the HDT I with crude 1
2BALDIHDTI balance of the diesel produced by the HDT I with crude 2
3BALDIHDTI balance of the diesel produced by the HDT I with crude 3
1BALSULHDTI balance of sulfur in the HDT I unit with crude 1
2BALSULHDTI balance of sulfur in the HDT I unit with crude 2
3BALSULHDTI balance of sulfur in the HDT I unit with crude 3
1BALDIBYHDTI balance of the stream that bypasses the HDT I with crude 1
2BALDIBYHDTI balance of the stream that bypasses the HDT I with crude 2
3BALDIBYHDTI balance of the stream that bypasses the HDT I with crude 3

***Pool balances**

1BALGASP balance of gasoline pool with crude 1
2BALGASP balance of gasoline pool with crude 2
3BALGASP balance of gasoline pool with crude 3
1BALKEP balance of kerosene pool with crude 1
2BALKEP balance of kerosene pool with crude 2

3BALKEP balance of kerosene pool with crude 3
1BALDIP balance of diesel pool with crude 1
2BALDIP balance of diesel pool with crude 2
3BALDIP balance of diesel pool with crude 3
1BALJFP balance of jet fuel oil pool with crude1
2BALJFP balance of jet fuel oil pool with crude2
3BALJFP balance of jet fuel oil pool with crude3

***Capacities balances**

BALCAPADU capacity balance of the atmospheric distillation unit
BALCAPVDU capacity balance of the vacuum distillation unit
BALCAPDSP capacity balance of the desasphalting unit
BALCAPNAHDT capacity balance of the naphtha hydrotreating unit
BALCAPREF capacity balance of the catalytic reforming unit
BALCAPKEHDT capacity balance of the kerosene hydrotreating unit
BALCAPDIHDT capacity balance of the naphtha hydrotreating unit
BALCAPFCC capacity balance of the fluid catalytic cracking unit
BALCAPRFCC capacity balance of the resid catalytic cracking unit
BALCAPHCC capacity balance of the hydrocracking unit
BALCAPHDS capacity balance of the gasoline dessulfurization unit
BALCAPALK capacity balance of the alkylation unit
BALCAPCOK capacity balance of the coking unit
BALCAPUGH capacity balance of the UGH
BALCAPHDTI capacity balance of the HDT I

***Demands**

DEMLPG domestic demand of liquified petroleum gas
DEMNA domestic demand of naphtha
DEMGAS domestic demand of gasoline
DEMKE domestic demand of kerosene
DEMDI domestic demand of diesel
DEMJF domestic demand of jet fuel
DEMHTO domestic demand of heating fuel oil
DEMHFO domestic demand of fuel oil
DEMCOK domestic demand of coke

***Specifications**

MAXSULKEROS Control of Sulfur Max Content in Kerosene Pool
MAXSULDIESEL Control of Sulfur Max Content in Diesel Pool
MAXSULGASOLINE Control os Sulfur Max Content in Gasoline Pool
MAXSULJETFUELOIL Control of Sulfur Max Content in Jet Fuel Oil Pool
MAXSULFUELOIL Control of Sulfur Max Content in Fuel Oil Pool
OCTNUMGASOLINE Control of Gasoline Octane Number
CETNUMDIESEL Control of Diesel Cetane Number
DENSGASOLINE Control of gasoline density
DENSDIESEL Control of diesel density
BALSULHDTNA sulfur balance in the HDTNA unit
BALSULHDTKE sulfur balance in the HDTKE unit
BALSULHDTDI sulfur balance in the HDTI unit
BALSULHDSG sulfur balance in the HDSG unit

***Crude balance/availability**

MAXCRUDE1 maximum availability of crude 1
MAXCRUDE2 maximum availability of crude 2
MAXCRUDE3 maximum availability of crude 3

BALCRUDE balance of crude oil consumption

BALFGASPROD balance of de fuel gas produced

A.II) Model variables

x(j,dores,t)
y(j,t)
w(j,dores,dored,t)
l(j)
m(j,oversea,dored,t)
e(j,dores,oversea,t)
totimports(j,dored,t)
totexports(j,dores,t)
totimpexp(jprodrange,t)
totproduction(dores,t)
totcrude(dores,t)
totcrude1(t)
totcrude2(t)
totcrude3(t)
naturalgashigh(dores,t)
naturalgasmed(dores,t)
naturalgaslow(dores,t)
highsteamprodcog(dores,t)
highsteamprodcog1(dores,t)
lowsteamcons(dores,t)
medsteamcons(dores,t)
highsteamcons(dores,t)
highsteamprod(dores,t)
highsteamexcess(dores,t)
medsteamprod(dores,t)
medsteamexcess(dores,t)
lowsteamprod(dores,t)
lowsteamconsdsp(dores,t)
lowsteamconsfcc(dores,t)
medsteamconsadu(dores,t)
medsteamconsfcc(dores,t)
medsteamconsalk(dores,t)
medsteamconscok(dores,t)
medsteamconshcc(dores,t)
highsteamconshdtk(dores,t)
highsteamconshdtd(dores,t)
highsteamconshdtn(dores,t)
highsteamconsfcc(dores,t)
highsteamconsrfcc(dores,t)
highsteamconsref(dores,t)
highsteamconshdsg(dores,t)
highsteamconshdti(dores,t)
fuelcons(dores,t)
fuelconstotal(t)
fuelconstop(dores,t)
fuelconsvdu(dores,t)
fuelconsdsp(dores,t)
fuelconsnahdt(dores,t)
fuelconsref(dores,t)
fuelconskehdt(dores,t)
fuelconsdihdt(dores,t)
fuelconsfcc(dores,t)
fuelconsrfcc(dores,t)
fuelconshcc(dores,t)
fuelconshds(dores,t)
fuelconsalk(dores,t)
fuelconscok(dores,t)
fuelconsugh(dores,t)
fuelconshdti(dores,t)
eleccons(dores,t)
elecconstotal(t)
elecconstop(dores,t)
elecconsvdu(dores,t)
elecconsdsp(dores,t)
elecconsnahdt(dores,t)

elecconsref(dores,t)
elecconskehdt(dores,t)
elecconsdihdt(dores,t)
elecconsfcc(dores,t)
elecconsrfcc(dores,t)
elecconshcc(dores,t)
elecconshds(dores,t)
elecconsalk(dores,t)
elecconscok(dores,t)
elecconsugh(dores,t)
elecconshdti(dores,t)
elecprod(dores,t)
elecgrid(dores,t)
naturalgascog(dores,t)
hydrogenprod(dores,t)
hydrogencons(dores,t)
hydrogenburn(dores,t)
hydrogenconsnahdt(dores,t)
hydrogenconsref(dores,t)
hydrogenconskehdt(dores,t)
hydrogenconsdihdt(dores,t)
hydrogenconshcc(dores,t)
hydrogenconshds(dores,t)
hydrogenconshdti(dores,t)
hydrogen_ng(dores,t)
hydrogen_naphtha(dores,t)
fuel_fo(dores,t)
fuel_coke(dores,t)
totalng(dores,t)
totalfo(dores,t)
totalfg(dores,t)
fuel_fg(dores,t)
exc_fg(dores,t)
totalcoke(dores,t)
totalelec(dores,t)
CO2emissions(dores,t)
co2emissionscost(dores,t)
oilpurchasecost(t)
opexcost(dores,t)
opexfixcostunit(dores,t)
opexvarcostunit(dores,t)
capexcost(dores,t)
capexcogcost(dores,t)
opexcogcost(dores,t)
fuelpurchasecost(dores,t)
electricitycost(dores,t)
importscost(oversea,dored,t)
exportsincome(dores,oversea,t)
brazregcost(dores,dored,t)
totbrazregcost(dores,t)
totimportscost(dored,t)
totexportsincome(dores,t)
oilpurchasecost1(jcrude,t)
oilpurchasecost2(jcrude,t)
oilpurchasecost3(jcrude,t)
addharborcost(dored,t)
elecprod1(dores,t)
hydrogen_ng1(dores,t)
emissionco2fo(dores,t)
emissionco2ng(dores,t)
emissionco2ngcog(dores,t)
emissionco2ugh(dores,t)
emissionco2fg(dores,t)
emissionco2coke(dores,t)
emissionco2elec(dores,t)
z

A.III) Model equations

totalcost - define objective function

eqoilpurchasecost1(t) - define the cost of purchasing crude oil 1
eqoilpurchasecost2(t) - define the cost of purchasing crude oil 2
eqoilpurchasecost3(t) - define the cost of purchasing crude oil 3
eqoilpurchasecost(t) - define the total cost of purchasing crude oil

eqopexcost(dores,t) - define the total O&M cost of each unit in each region
eqopexfixcost(dores,t) - define the fixed O&M cost of each unit in each region
eqopexvarcost(dores,t) - define the variable O&M cost of each unit in each region

eqcapexcost(dores,t) - define the investment costs of additional units in each region
eqcapexcogcost(dores,t) - define the investment cost in cogeneration units
eqopexcogcost(dores,t) - define the O&M costs of cogeneration units

eqfuelpurchasecost(dores,t) - define the cost of fuel to meet the utilities demand of the refinery in each region
eqelectricitycost(dores,t) - define the cost of electricity
eqimportscost(oversea,dored,t) - define the cost with imports from each region oversa for each region of demand
eqtotimportscost(dored,t -) define the total cost with imports
eqexportsincome(dores,oversea,t) - define the income with exports from each region of supply to each oversea region
eqtotexportsincome(dores,t -) define the total income with exports

eqbrazregcost(dores,dored,t) - define the cost of product's exchange between Brazilian regions
eqtotbrazregcost(dores,t) - define the total cost of products exchange between Brazilian regions per region

eqco2emissionscost(dores,t) - define the cost of co2 emissions

eqaddharborcost(dored,t) - define the cost of harbors expansion

eqrendadu(ibaladu,dores,t) - yields at the atmospheric distillation unit in each region
eqbalatr(ibalatr,dores,t) - balance of the atmospheric residue produced in each region

eqrendvdu (ibalvdu,dores,t) - yields at the vacuum distillation unit in each region
eqlvgo(iballvgo,dores,t) - balance of lvgo produced by the VDU in each region
eqhvgo(ibalhvgo,dores,t) - balance of hvgo produced by the VDU in each region
eqvres(ibalvres,dores,t) - balance of vacuum residue produced by the VDU in each region

eqrenddsp(ibaldsp,dores,t) - yields of the deasphalting unit in each region
eqbalgodsp(ibalgodspprod,dores,t) - balance of the deasphalted gasoil produced in each region

eqsrnaphtha (ibalsrnaphtha,dores,t) - balance of light and heavy straight run naphtha in each region
eqrendnahdt (ibalnahdt,dores,t) - yields at the naphtha hydroteating unit in each region
eqnaphthapet(ibalnapet,dores,t) - balance of naphtha sent to the petrochemical industry in each region

eqstnaref(ibalstnaref,dores,t) - balance of the HSR naphtha input stream on the reforming unit in each region
eqrendref(ibalref,dores,t) - yields at the reforming unit in each region
eqirefproc(ibalrefproc,dores,t) - input stream of the reforming unit

eqsrkeros(ibalsrkeros,dores,t) - balance of straight run kerosene in each region
eqrendkehdt(ibalkehdt,dores,t) - yields at the kerosene hydrotreating unit in each region

eqsrdiesel(ibalsrdiesel,dores,t) - balance of straight run diesel in each region
eqrenddihdt(ibaldihdt,dores,t) - yields at the diesel hydrotreating unit in each region

eqago(ibalagost,dores,t) - balance of the AGO stream in each region
eqinstfcc(ibalinstfcc,dores,t) - balance of the input stream of the FCC unit in each region
eqrendfcc(ibalfcc,dores,t) - yields of the FCC unit in each region

eqinstrfcc(ibalinstrfcc,dores,t) - balance of the input stream of the RFCC unit in each region
eqrendrfcc(ibalrfcc,dores,t) - yields of the RFCC unit in each region

eqinsthcc(ibalinsthcc,dores,t) - balance of the input stream of the HCC unit in each region
eqrendhcc(ibalhcc,dores,t) - yields at the HCC unit in each region
eqstkehcc(ibalkehccprod,dores,t) - balance of the kerosene stream produced by the HCC unit in each region

eqsthds(ibalsthds,dores,t) - balance of the input stream of the HDS gasoline unit in each region
eqrendhds(ibalhds,dores,t) - yields at the HDS gasoline unit in each region

eqstlpg(ibalstlpg,dores,t) - balance of the LPG stream produced by the ADU in each region
eqstalk(ibalstalk,dores,t) - balance of the input stream of the alkylation unit in each region
eqrendalk(ibalalk,dores,t) - yields at the alkylation unit in each region

eqrendcok(ibalcok,dores,t) - yields at the coking unit in each region
eqstlgocok(ibalstlgocok,dores,t) - balance of the light gasoil stream produced by the coking unit in each region
eqsthgocok(ibalsthgocok,dores,t) - balance of the heavy gasoil stream produced by the coking unit in each region
eqstnacok(ibalstnacok,dores,t) - balance of the naphtha stream produced by the coking unit in each region

eqinsthdti(ibalinsthdti,dores,t) - balance of the input stream of the HDT i unit in each region
eqrendhdti(ibalhdti,dores,t) - yields of the HDT i unit in each region
eqstbyhdti(ibalstbyhdti,dores,t) - balance of the HDTI bypass stream
eqprodhdti(ibalhdtiprod,dores,t) - balance of the HDTI products

eqcapmax(jcap,dores) - maximum capacities of the processing units in each region for the base year
eqcapmaxcog(jcapcog,dores) - maximum capacity of cogeneration unit in each region for the base year

eqcapaddt1(jcap,dores) - balance of possible additional capacities in t1
eqcapaddt2(jcap,dores) - balance of possible additional capacities in t2
eqcapaddt3(jcap,dores) - balance of possible additional capacities in t3
eqcapaddt4(jcap,dores) - balance of possible additional capacities in t4
eqcapaddt5(jcap,dores) - balance of possible additional capacities in t5

eqcapaddtcog1(jcapcog,dores) - balance of possible additional cogeneration capacities in t1
eqcapaddtcog2(jcapcog,dores) - balance of possible additional cogeneration capacities in t2
eqcapaddtcog3(jcapcog,dores) - balance of possible additional cogeneration capacities in t3
eqcapaddtcog4(jcapcog,dores) - balance of possible additional cogeneration capacities in t4
eqcapaddtcog5(jcapcog,dores) - balance of possible additional cogeneration capacities in t5

eqbalcap(ibalcap,dores,t) - balance of capacities in each region
eqbrazreg (jprod,dores,t) -balance of transportation of products between Brazilian regions
eqbrazregfo(dores,t) - balance of transportation of products between Brazilian regions for fuel oil

eqbrazregimp (idem,dored,t) - balance of demand and imported products
eqtotimports(jimport,dored,t) - total imports equation
eqtotexports(jexport,dores,t) - total exports equation
eqtotimpexplight(t) - total imports and exports light products
eqtotimpexpmed(t) - total imports and exports medium products
eqtotimpexpheavy(t) - total imports and exports heavy products
eqboundimpexplightt0 - bound imports and exports light products in t0
eqboundimpexpmedt0 - bound imports and exports medium products in t0
eqboundimpexpheavyt0 - bound imports and exports heavy products in t0
eqboundimpexplightt1 - bound imports and exports light products in t1
eqboundimpexpmedt1 - bound imports and exports medium products in t1
eqboundimpexpheavyt1 - bound imports and exports heavy products in t1
eqboundimpexplightt2 - bound imports and exports light products in t2
eqboundimpexpmedt2 - bound imports and exports medium products in t2
eqboundimpexpheavyt2 - bound imports and exports heavy products in t2
eqboundimpexplightt3 - bound imports and exports light products in t3
eqboundimpexpmedt3 - bound imports and exports medium products in t3
eqboundimpexpheavyt3 - bound imports and exports heavy products in t3
eqboundimpexplightt4 - bound imports and exports light products in t4
eqboundimpexpmedt4 - bound imports and exports medium products in t4
eqboundimpexpheavyt4 - bound imports and exports heavy products in t4
eqboundimpexplightt5 - bound imports and exports light products in t5
eqboundimpexpmedt5 - bound imports and exports medium products in t5
eqboundimpexpheavyt5 - bound imports and exports heavy products in t5

eqboundaddharbor(jaddharbor) - bound additional harbor capacity in t0
eqboundaddharbort(jaddharbor,t) - bound additional harbor capacity in t

eqmaxsulkeros (imaxsulkeros,dores,t) - maximum sulfur content in kerosene pool
eqmaxsuldiesel (imaxsuldiesel,dores,t) - maximum sulfur content in diesel pool

eqmaxsuljetfuel (imaxsuljetfuel,dores,t) - maximum sulfur content in jet fuel pool
eqmaxsulgasoline (imaxsulgasoline,dores,t) - maximum sulfur content in gasoline pool
eqmaxsulfueloil(imaxsulfueloil,dores,t) - maximum sulfur content in fuel oil pool

eqoctnumgasoline (ioctnumber,dores,t) – octane number in gasoline pool
eqcetnumdiesel (icetnumber,dores,t) - cetane number diesel

eqprod (jprod,dores,t) - pool of refinery final products
eqpool (intprod,dores,t) - pool of intermediate products

eqkehdtst (ibalkehdtst,dores,t) - balance of HDT K unit output streams
eqkebyhdtst (ibalkebyst,dores,t) - balance of HDT K unit bypassed streams

eqdihdtst (ibaldihdtst,dores,t) - balance of HDT D unit output streams
eqdibyhdtst (ibaldibyst,dores,t) - balance of HDT D unit bypasses streams

balcogcapacity(dores,t) - balance of cogeneration unit capacity
balelecprod(dores,t) - balance of electricity production in the cogeneration unit
baltransformelecprod(dores,t) - electricity equation - transformation units
balnaturalgascog(dores,t) - balance of natural gas consumption by the cogeneration unit
balcogsteam(dores,t) - balance of steam production in the cogeneration unit
balsteamcogunits(dores,t) - units transformation
balelectricity(dores,t) - electricity balance

balsteamhighprod(dores,t) - define the balance of high steam production
balnaturalgashighsteam(dores,t) - define the balance of natural gas used to produce high steam
balsteammedprod(dores,t) - define the balance of medium steam production
balnaturalgasmedsteam(dores,t) - define the balance of natural gas used to produce medium steam
balsteamlowprod(dores,t) - define the balance of low steam production
balnaturalgaslowsteam(dores,t) - define the balance of natural gas used to produce low steam
ballowsteamcons(dores,t) - define the balance of the low steam consumption of each region
balmedsteamcons(dores,t) - define the balance of the medium steam consumption of each region
balhighsteamcons(dores,t) - define the balance of high steam consumption of each region
ballowsteamdsp(dores,t) - define the balance of low steam consumption in the deasphalting unit
ballowsteamfcc(dores,t) - define the balance of low steam consumption in the FCC unit
balmedsteamadu(dores,t) - define the balance of medium steam consumption in the atmospheric distillation unit
balmedsteamfcc(dores,t) - define the balance of medium steam consumption in the FCC unit
balmedsteamalk(dores,t) - define the balance of medium steam consumption in the alkylation unit
balmedsteamcok(dores,t) - define the balance of medium steam consumption in the coking unit
balmedsteamhcc(dores,t) - define the balance of medium steam consumption in the HCC unit
balhighsteamhdtk(dores,t) - define the balance of high steam consumption in the HDT K unit
balhighsteamhdtd(dores,t) - define the balance of high steam consumption in the HDT D unit
balhighsteamhdtn(dores,t) - define the balance of high steam consumption in the HDT N unit
balhighsteamfcc(dores,t) - define the balance of high steam consumption in the FCC unit
balhighsteamrfcc(dores,t) - define the balance of high steam consumption in the RFCC unit
balhighsteamref(dores,t) - define the balance of high steam consumption in the Reforming unit
balhighsteamhdsg(dores,t) - define the balance of high steam consumption in the HDS G unit
balhighsteamhdti(dores,t) - define the balance of high steam consumption in the HDT I unit

balelec(dores,t) - define the balance of electricity on each region
balelectop(dores,t) - define the balance of electricity on topping unit
balelecvdu(dores,t) - define the balance of electricity on the vacuum distillation unit
balelecdsp(dores,t) - define the balance of electricity on the deasphalting unit
balelecnahdt(dores,t) - define the balance of electricity on the naphtha hydrotreating unit
balelecref(dores,t) - define the balance of electricity on the reforming unit
baleleckehdt(dores,t) - define the balance of electricity on the kerosene hydrotreating unit
balelecdihdt(dores,t) - define the balance of electricity on the diesel hydrotreating unit
balelecfcc(dores,t) - define the balance of electricity on FCC unit
balelecrfcc(dores,t) - define the balance of electricity on RFCC unit
balelechcc(dores,t) - define the balance of electricity on HCC unit
balelechds(dores,t) - define the balance of electricity on HDS gasoline unit
balelecalk(dores,t) - define the balance of electricity on alkylation unit
baleleccok(dores,t) - define the balance of electricity on coking unit
balelechdti(dores,t) - define the balance of electricity on HDT I unit

balfuelreg(dores,t) - define the total balance of fuel consumption of each region
balfueltotal(t) - define the total Brazilian balance of fuel consumption

balfuel(dores,t) - define the balance of fuel consumption
balfueltotalfcc(dores,t) - define the total balance of fuel consumption on the FCC unit
balfueltop(dores,t) - define the balance of fuel consumption on the ADU
balfuelvdu(dores,t) - define the balance of fuel consumption on theVDU
balfueldsp(dores,t) - define the balance of fuel consumption on the deasphalting unit
balfuelnahdt(dores,t) - define the balance of fuel consumption on the naphtha hydrotreating unit
balfuelref(dores,t) - define the balance of fuel consumption on the reforming unit
balfuelkehdt(dores,t) - define the balance of fuel consumption on the kerosene hydrotreating unit
balfueldihdt(dores,t) - define the balance of fuel on the diesel hydrotreating unit
balfuelfcc(dores,t) - define the balance of fuel consumption on FC unit
balfuelrfcc(dores,t) - define the balance of fuel consumption on RFCC unit
balfuelhcc(dores,t) - define the balance of fuel consumption on HCC unit
balfuelhds(dores,t) - define the balance of fuel consumption on HDS gasoline unit
balfuelalk(dores,t) - define the balance of fuel consumption on alkylation unit
balfuelcok(dores,t) - define the balance of fuel consumption on coking unit
balfuelugh(dores,t) - define the balance of fuel consumption on UGH
balfuelhdti(dores,t) - define the balance of fuel consumption on HDT I

balngtotal(dores,t) - define the total balance of gas natural consumed
balfototal(dores,t) - define the total balance of fuel oil consumed

boundfo(dores,t) - fuel oil consumption bound
balfgastotal(dores,t) - define the total balance of fuel gas consumed
balexcfuelgas(dores,t) - balance of excess fuel gas
balcoketotal(dores,t) - total balance of coke

balhydrogenugh(dores,t) - define the balance of fuel to meet the demand of hydrogen in the UGH
balfuelconshydrogenugh(dores,t) - define the balance of fuel consumption in the UGH
balhydrogencons(dores,t -) define the total balance of hydrogen

boundhydrogenprod(dores,t) - hydrogen production bound
equnithydrogen(dores,t) - define the conversion of units

balhydrogenconsnahdt(dores,t) - define the balance of hydrogen on the naphtha hydrotreating unit
*balhydrogenconsref(dores,t) - define the balance of hydrogen on the reforming unit
balhydrogenconskehdt(dores,t) - define the balance of hydrogen on the kerosene hydrotreating unit
balhydrogenconsdihdt(dores,t) - define the balance of hydrogen on the diesel hydrotreating unit
balhydrogenconshds(dores,t) - define the balance of hydrogen on the gasoline hydrodesulfurization unit
balhydrogenconshcc(dores,t) - define the balance of hydrogen on the HCC unit
balhydrogenconshdti(dores,t) - define the balance of hydrogen on the HDT I unit

balCO2fo(dores,t) – define the co2emissions of fuel oil consumption
balCO2ng(dores,t) – define the co2emissions of natural gas consumption in boilers
balCO2ngcog(dores,t) – define the co2emissions of natural gas consumption in cogeneration units
balCO2ngugh(dores,t) – define the co2emissions of natural gas consumption in hydrogeneration units
balCO2fg(dores,t) – define the co2emissions of fuel gas consumption
balCO2coke(dores,t) – define the co2emissions of coke consumption
balCO2elec(dores,t) – define the co2emissions of electricity consumption
balCO2(dores,t) - define the total balance of CO2 emissions due to combustion of fuel

eqsumcrudetype1(dores,t) - equation to sum the quantities of crude oil 1 consumed by each campaign
eqsumcrudetype2(dores,t) - equation to sum the quantities of crude oil 2 consumed by each campaign
eqsumcrudetype3(dores,t) - equation to sum the quantities of crude oil 3 consumed by each campaign
eqsumcrude(dores,t) - equation to sum the quantities of crude oil consumed
eqtotcrude(dores,t) - total crude oil equation
eqtotcrude1(t) - total crude 1 equation
eqtotcrude2(t) - total crude 2 equation
eqtotcrude3(t) - total crude 3 equation

eqtransunitgasolinemax(dores,t) - define the transformation of unit of gasoline produced from mass to volume
eqtransunitdiesel(dores,t) - define the transformation of unit of gasoline produced from mass to volume
boundcoke(dores,t) - coke consumption bound
eqtotproduction(dores,t) - total production equation

9. Annex B – OURSE model demand scenarios

B.I) Shadow scenario

Table B-1 - OURSE model oil products demands – Shadow scenario

Z1 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	102.62	89.29	75.96	62.63	49.30	35.97
NPH	14.82	14.76	14.70	14.63	14.57	14.51
GSL	463.98	438.81	413.65	388.48	363.31	338.15
JET	80.99	80.84	80.68	80.53	80.38	80.22
KRS	0.79	0.69	0.59	0.48	0.38	0.28
HTO	14.23	12.92	11.61	10.30	8.99	7.68
GDO	251.05	237.44	223.82	210.20	196.58	182.97
RFO	7.48	6.79	6.10	5.42	4.73	4.04
LUB	10.97	10.38	9.78	9.19	8.59	8.00
BTM	46.12	56.90	67.67	78.44	89.22	99.99
CKP	50.06	46.34	42.63	38.91	35.19	31.47
MAB	33.20	43.50	53.80	64.10	74.40	84.70

Z2 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	20.52	21.53	22.55	23.56	24.58	25.59
NPH	8.56	9.99	11.42	12.85	14.28	15.71
GSL	82.44	84.20	85.96	87.72	89.47	91.23
JET	12.87	12.85	12.82	12.80	12.78	12.75
KRS	0.86	0.90	0.94	0.99	1.03	1.07
HTO	8.19	8.33	8.46	8.60	8.74	8.87
GDO	111.32	116.18	121.04	125.91	130.77	135.63
RFO	4.19	4.26	4.33	4.40	4.47	4.54
LUB	4.41	4.69	4.98	5.27	5.55	5.84
BTM	14.21	17.53	20.85	24.17	27.49	30.81
CKP	17.28	17.78	18.28	18.79	19.29	19.80
MAB	10.23	13.41	16.58	19.75	22.93	26.10

Z3 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	8.50	8.14	7.79	7.44	7.08	6.73
NPH	1.83	1.81	1.79	1.77	1.74	1.72
GSL	19.96	19.92	19.88	19.84	19.80	19.76
JET	15.68	15.65	15.62	15.59	15.56	15.54
KRS	4.03	3.87	3.70	3.53	3.36	3.19
HTO	1.15	1.14	1.13	1.12	1.12	1.11
GDO	52.55	52.45	52.35	52.25	52.15	52.05
RFO	0.42	0.42	0.42	0.41	0.41	0.41
LUB	1.06	1.06	1.05	1.05	1.05	1.05
BTM	2.85	3.52	4.18	4.85	5.51	6.18
CKP	0.46	0.46	0.45	0.45	0.45	0.45
MAB	8.08	10.59	13.10	15.60	18.11	20.62

Z4 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	21.01	18.31	15.62	12.93	10.23	7.54
NPH	23.28	23.04	22.81	22.57	22.33	22.09
GSL	50.64	50.16	49.67	49.18	48.69	48.21
JET	32.56	32.50	32.43	32.37	32.31	32.25
KRS	0.50	0.43	0.37	0.31	0.24	0.18
HTO	2.70	2.53	2.36	2.18	2.01	1.84
GDO	210.48	208.46	206.44	204.41	202.39	200.36
RFO	3.86	3.61	3.36	3.12	2.87	2.62
LUB	3.71	3.67	3.63	3.60	3.56	3.53
BTM	16.11	19.87	23.63	27.40	31.16	34.92
CKP	7.11	6.99	6.87	6.76	6.64	6.52
MAB	30.00	39.31	48.61	57.92	67.23	76.53

Z5 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	18.51	19.38	20.24	21.11	21.98	22.84
NPH	28.38	33.99	39.61	45.22	50.84	56.45
GSL	48.88	50.13	51.39	52.64	53.89	55.14
JET	11.89	11.87	11.84	11.82	11.80	11.77
KRS	0.40	0.42	0.44	0.45	0.47	0.49
HTO	3.44	3.38	3.32	3.26	3.20	3.14
GDO	65.16	66.82	68.49	70.16	71.83	73.49
RFO	4.31	4.24	4.17	4.09	4.02	3.94
LUB	6.54	6.71	6.87	7.04	7.21	7.38
BTM	14.67	18.10	21.52	24.95	28.38	31.80
CKP	1.53	1.53	1.52	1.51	1.51	1.50
MAB	26.83	35.15	43.47	51.80	60.12	68.44

Z6 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	11.94	14.25	16.56	18.87	21.18	23.49
NPH	0.55	0.65	0.76	0.86	0.97	1.07
GSL	44.08	54.82	65.57	76.31	87.05	97.80
JET	9.33	9.31	9.29	9.28	9.26	9.24
KRS	4.68	5.59	6.50	7.40	8.31	9.21
HTO	7.07	8.06	9.06	10.05	11.04	12.04
GDO	79.16	98.46	117.75	137.05	156.34	175.64
RFO	1.90	2.17	2.44	2.71	2.97	3.24
LUB	2.11	2.62	3.13	3.65	4.16	4.67
BTM	5.21	6.43	7.64	8.86	10.08	11.29
CKP	0.00	0.00	0.00	0.00	0.00	0.00
MAB	8.40	11.00	13.61	16.21	18.82	21.43

Z7 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	51.38	51.92	52.46	53.00	53.54	54.08
NPH	5.53	6.60	7.66	8.72	9.79	10.85
GSL	76.04	88.54	101.03	113.53	126.02	138.52
JET	19.06	19.03	18.99	18.95	18.92	18.88
KRS	4.97	5.02	5.08	5.13	5.18	5.23
HTO	22.28	20.73	19.18	17.62	16.07	14.51
GDO	115.30	134.25	153.19	172.14	191.08	210.03
RFO	11.64	10.83	10.01	9.20	8.39	7.58
LUB	2.59	3.02	3.45	3.87	4.30	4.73
BTM	26.72	32.97	39.21	45.45	51.69	57.93
CKP	0.11	0.13	0.14	0.15	0.16	0.18
MAB	39.88	52.25	64.62	76.99	89.36	101.73

Z8 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	35.82	35.34	34.86	34.38	33.90	33.42
NPH	47.29	58.83	70.36	81.90	93.43	104.97
GSL	115.63	135.14	154.66	174.17	193.69	213.20
JET	25.05	25.00	24.95	24.91	24.86	24.81
KRS	1.59	1.57	1.55	1.53	1.50	1.48
HTO	16.97	16.99	17.01	17.03	17.06	17.08
GDO	173.83	203.17	232.51	261.84	291.18	320.52
RFO	3.09	3.10	3.10	3.10	3.11	3.11
LUB	23.06	26.95	30.84	34.74	38.63	42.52
BTM	33.68	41.55	49.41	57.28	65.15	73.02
CKP	33.64	32.29	30.94	29.59	28.24	26.89
MAB	33.25	43.56	53.87	64.19	74.50	84.81

Z9 - Oil products demand (Mtonnes/year) - Shadow Scenario						
Product	2015	2020	2025	2030	2035	2040
LPG	63.28	64.38	65.48	66.58	67.68	68.78
NPH	108.78	126.12	143.45	160.79	178.12	195.46
GSL	131.97	153.35	174.74	196.12	217.51	238.89
JET	44.98	44.90	44.81	44.72	44.64	44.55
KRS	23.06	23.46	23.86	24.26	24.66	25.07
HTO	75.05	77.98	80.91	83.84	86.77	89.70
GDO	223.55	259.78	296.00	332.23	368.46	404.68
RFO	30.99	32.20	33.41	34.62	35.83	37.04
LUB	15.59	18.12	20.64	23.17	25.70	28.22
BTM	30.98	38.21	45.45	52.68	59.92	67.15
CKP	7.72	8.04	8.36	8.68	9.00	9.31
MAB	69.60	91.19	112.78	134.38	155.97	177.56

B.II) Cloudy scenario

Table B-2 - OURSE model oil products demands – Cloudy scenario

Z1 - Oil products demand (Mtonnes/year) - Cloudy Scenario

Products	2015	2020	2025	2030	2035	2040
LPG	102.62	86.00	69.39	52.78	36.17	19.56
NPH	14.82	14.78	14.74	14.71	14.67	14.63
GSL	463.98	430.43	396.89	363.34	329.80	296.25
JET	80.99	79.26	77.54	75.81	74.08	72.35
KRS	0.79	0.66	0.54	0.41	0.28	0.15
HTO	14.23	12.89	11.54	10.20	8.85	7.50
GDO	251.05	232.90	214.75	196.60	178.45	160.30
RFO	7.48	6.77	6.07	5.36	4.65	3.95
LUB	10.97	10.18	9.38	8.59	7.80	7.00
BTM	46.12	52.71	59.31	65.90	72.49	79.08
CKP	50.06	46.20	42.34	38.48	34.62	30.76
MAB	33.20	41.33	49.45	57.58	65.71	73.83

Z2 - Oil products demand (Mtonnes/year) - Cloudy Scenario

	2015	2020	2025	2030	2035	2040
LPG	20.52	21.35	22.19	23.02	23.85	24.69
NPH	8.56	10.01	11.46	12.91	14.36	15.81
GSL	82.44	83.18	83.92	84.66	85.41	86.15
JET	12.87	12.60	12.32	12.05	11.77	11.50
KRS	0.86	0.89	0.93	0.96	1.00	1.03
HTO	8.19	8.30	8.41	8.52	8.63	8.74
GDO	111.32	113.37	115.42	117.47	119.52	121.57
RFO	4.19	4.25	4.30	4.36	4.41	4.47
LUB	4.41	4.53	4.65	4.77	4.89	5.01
BTM	14.21	16.25	18.28	20.31	22.34	24.37
CKP	17.28	17.75	18.22	18.69	19.16	19.64
MAB	10.23	12.74	15.24	17.75	20.25	22.75

Z3 - Oil products demand (Mtonnes/year) - Cloudy Scenario

	2015	2020	2025	2030	2035	2040
LPG	8.50	7.91	7.32	6.74	6.15	5.56
NPH	1.83	1.81	1.79	1.77	1.74	1.72
GSL	19.96	19.57	19.18	18.80	18.41	18.03
JET	15.68	15.35	15.01	14.68	14.35	14.01
KRS	4.03	3.76	3.48	3.20	2.92	2.64
HTO	1.15	1.14	1.13	1.12	1.11	1.10
GDO	52.55	51.54	50.53	49.51	48.50	47.48
RFO	0.42	0.42	0.41	0.41	0.41	0.40
LUB	1.06	1.04	1.02	1.00	0.98	0.96
BTM	2.85	3.26	3.66	4.07	4.48	4.89
CKP	0.46	0.46	0.45	0.45	0.45	0.44
MAB	8.08	10.06	12.04	14.02	16.00	17.97

Z4 - Oil products demand (Mtonnes/year) - Cloudy Scenario

	2015	2020	2025	2030	2035	2040
LPG	21.01	17.56	14.11	10.67	7.22	3.77
NPH	23.28	23.06	22.85	22.63	22.42	22.20
GSL	50.64	47.69	44.74	41.79	38.83	35.88
JET	32.56	31.86	31.17	30.47	29.78	29.09
KRS	0.50	0.42	0.33	0.25	0.17	0.09
HTO	2.70	2.52	2.33	2.14	1.95	1.76
GDO	210.48	198.21	185.94	173.67	161.40	149.13
RFO	3.86	3.59	3.32	3.05	2.79	2.52
LUB	3.71	3.49	3.27	3.06	2.84	2.63
BTM	16.11	18.41	20.71	23.02	25.32	27.62
CKP	7.11	6.96	6.81	6.65	6.50	6.35
MAB	30.00	37.34	44.69	52.03	59.37	66.72

Z5 - Oil products demand (Mtonnes/year) - Cloudy Scenario

	2015	2020	2025	2030	2035	2040
LPG	18.51	18.79	19.06	19.34	19.61	19.88
NPH	28.38	34.04	39.71	45.38	51.05	56.72
GSL	48.88	48.83	48.77	48.72	48.66	48.61
JET	11.89	11.63	11.38	11.13	10.87	10.62
KRS	0.40	0.40	0.41	0.42	0.42	0.43
HTO	3.44	3.40	3.35	3.31	3.27	3.22
GDO	65.16	65.08	65.01	64.94	64.86	64.79
RFO	4.31	4.26	4.21	4.15	4.10	4.05
LUB	6.54	6.53	6.53	6.52	6.51	6.50
BTM	14.67	16.77	18.86	20.96	23.06	25.15
CKP	1.53	1.53	1.53	1.52	1.52	1.51
MAB	26.83	33.40	39.96	46.53	53.09	59.66

Z6 - Oil products demand (Mtonnes/year) - Cloudy Scenario

	2015	2020	2025	2030	2035	2040
LPG	11.94	13.50	15.05	16.61	18.17	19.72
NPH	0.55	0.66	0.76	0.87	0.97	1.08
GSL	44.08	52.21	60.35	68.48	76.62	84.76
JET	9.33	9.13	8.93	8.73	8.53	8.33
KRS	4.68	5.30	5.91	6.52	7.13	7.74
HTO	7.07	7.94	8.81	9.68	10.55	11.42
GDO	79.16	93.77	108.38	123.00	137.61	152.22
RFO	1.90	2.14	2.37	2.61	2.84	3.08
LUB	2.11	2.49	2.88	3.27	3.66	4.05
BTM	5.21	5.95	6.70	7.44	8.19	8.93
CKP	0.00	0.00	0.00	0.00	0.00	0.00
MAB	8.40	10.45	12.51	14.57	16.62	18.68

Z7 - Oil products demand (Mtonnes/year) - Cloudy Scenario

	2015	2020	2025	2030	2035	2040
LPG	51.38	50.47	49.55	48.64	47.73	46.81
NPH	5.53	6.62	7.72	8.81	9.90	11.00
GSL	76.04	85.93	95.81	105.69	115.57	125.46
JET	19.06	18.66	18.25	17.84	17.44	17.03
KRS	4.97	4.88	4.79	4.71	4.62	4.53
HTO	22.28	20.67	19.05	17.43	15.81	14.19
GDO	115.30	130.28	145.27	160.25	175.24	190.22
RFO	11.64	10.79	9.95	9.10	8.26	7.41
LUB	2.59	2.93	3.27	3.61	3.94	4.28
BTM	26.72	30.54	34.36	38.18	42.00	45.82
CKP	0.11	0.13	0.14	0.15	0.16	0.17
MAB	39.88	49.64	59.40	69.16	78.92	88.68

Z8 - Oil products demand (Mtonnes/year) - Cloudy Scenario

	2015	2020	2025	2030	2035	2040
LPG	35.82	33.83	31.84	29.85	27.86	25.87
NPH	47.29	57.60	67.91	78.22	88.52	98.83
GSL	115.63	126.80	137.97	149.14	160.32	171.49
JET	25.05	24.51	23.98	23.45	22.91	22.38
KRS	1.59	1.50	1.41	1.32	1.24	1.15
HTO	16.97	16.50	16.03	15.56	15.08	14.61
GDO	173.83	190.63	207.42	224.21	241.01	257.80
RFO	3.09	3.01	2.92	2.83	2.75	2.66
LUB	23.06	25.29	27.52	29.74	31.97	34.20
BTM	33.68	38.49	43.31	48.12	52.94	57.75
CKP	33.64	31.53	29.42	27.32	25.21	23.10
MAB	33.25	41.38	49.52	57.66	65.79	73.93

Z9 - Oil products demand (Mtonnes/year) - Cloudy Scenario

	2015	2020	2025	2030	2035	2040
LPG	63.28	62.50	61.72	60.94	60.16	59.38
NPH	108.78	124.95	141.11	157.27	173.43	189.59
GSL	131.97	145.79	159.61	173.43	187.26	201.08
JET	44.98	44.02	43.06	42.10	41.14	40.18
KRS	23.06	22.77	22.49	22.21	21.92	21.64
HTO	75.05	76.52	77.98	79.45	80.92	82.39
GDO	223.55	246.97	270.38	293.80	317.21	340.63
RFO	30.99	31.60	32.20	32.81	33.42	34.02
LUB	15.59	17.22	18.86	20.49	22.12	23.76
BTM	30.98	35.40	39.83	44.26	48.69	53.11
CKP	7.72	7.88	8.04	8.21	8.37	8.53
MAB	69.60	86.64	103.67	120.71	137.74	154.78

B.III) Shiny scenario

Table B-3 - OURSE model oil products demands – Shiny scenario

Z1 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	102.62	84.01	65.41	46.81	28.21	9.60
NPH	14.82	14.60	14.39	14.17	13.95	13.73
GSL	463.98	397.28	330.58	263.88	197.18	130.48
JET	80.99	74.43	67.87	61.32	54.76	48.20
KRS	0.79	0.65	0.51	0.36	0.22	0.07
HTO	14.23	12.58	10.94	9.29	7.64	5.99
GDO	251.05	214.96	178.87	142.78	106.69	70.60
RFO	7.48	6.62	5.75	4.88	4.02	3.15
LUB	10.97	9.39	7.82	6.24	4.66	3.09
BTM	46.12	47.00	47.87	48.75	49.62	50.50
CKP	50.06	44.49	38.93	33.36	27.80	22.23
MAB	33.20	34.33	35.46	36.58	37.71	38.83

Z2 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	20.52	20.40	20.28	20.16	20.04	19.93
NPH	8.56	9.73	10.91	12.08	13.25	14.43
GSL	82.44	79.56	76.69	73.81	70.94	68.06
JET	12.87	11.83	10.79	9.75	8.70	7.66
KRS	0.86	0.85	0.85	0.84	0.84	0.83
HTO	8.19	7.97	7.75	7.53	7.31	7.10
GDO	111.32	103.37	95.42	87.47	79.52	71.57
RFO	4.19	4.08	3.97	3.85	3.74	3.63
LUB	4.41	3.94	3.47	3.00	2.53	2.07
BTM	14.21	14.48	14.75	15.02	15.29	15.56
CKP	17.28	16.89	16.50	16.11	15.72	15.33
MAB	10.23	10.58	10.93	11.27	11.62	11.97

Z3 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	8.50	7.44	6.39	5.34	4.29	3.24
NPH	1.83	1.79	1.75	1.72	1.68	1.64
GSL	19.96	18.64	17.32	16.01	14.69	13.38
JET	15.68	14.41	13.14	11.87	10.60	9.33
KRS	4.03	3.54	3.04	2.54	2.04	1.54
HTO	1.15	1.13	1.11	1.09	1.08	1.06
GDO	52.55	49.09	45.62	42.16	38.69	35.23
RFO	0.42	0.41	0.41	0.40	0.39	0.39
LUB	1.06	0.99	0.92	0.85	0.78	0.71
BTM	2.85	2.90	2.96	3.01	3.07	3.12
CKP	0.46	0.45	0.44	0.44	0.43	0.42
MAB	8.08	8.36	8.63	8.91	9.18	9.45

Z4 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	21.01	17.12	13.24	9.35	5.47	1.58
NPH	23.28	22.35	21.42	20.49	19.56	18.63
GSL	50.64	43.48	36.31	29.14	21.97	14.81
JET	32.56	29.92	27.29	24.65	22.01	19.38
KRS	0.50	0.41	0.31	0.22	0.13	0.04
HTO	2.70	2.46	2.22	1.98	1.74	1.50
GDO	210.48	180.70	150.91	121.12	91.33	61.54
RFO	3.86	3.52	3.17	2.83	2.49	2.14
LUB	3.71	3.18	2.66	2.13	1.61	1.08
BTM	16.11	16.41	16.72	17.03	17.33	17.64
CKP	7.11	6.69	6.27	5.85	5.43	5.01
MAB	30.00	31.02	32.04	33.06	34.07	35.09

Z5 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	18.51	17.85	17.19	16.53	15.87	15.21
NPH	28.38	33.08	37.78	42.47	47.17	51.87
GSL	48.88	46.22	43.56	40.89	38.23	35.57
JET	11.89	10.93	9.96	9.00	8.04	7.07
KRS	0.40	0.38	0.37	0.36	0.34	0.33
HTO	3.44	3.44	3.45	3.46	3.46	3.47
GDO	65.16	61.61	58.06	54.51	50.96	47.41
RFO	4.31	4.32	4.33	4.33	4.34	4.35
LUB	6.54	6.18	5.83	5.47	5.11	4.76
BTM	14.67	14.95	15.23	15.50	15.78	16.06
CKP	1.53	1.47	1.41	1.35	1.29	1.23
MAB	26.83	27.74	28.65	29.56	30.47	31.38

Z6 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	11.94	13.69	15.45	17.20	18.95	20.70
NPH	0.55	0.65	0.74	0.84	0.94	1.03
GSL	44.08	47.47	50.87	54.27	57.66	61.06
JET	9.33	8.57	7.82	7.06	6.31	5.55
KRS	4.68	5.37	6.06	6.75	7.43	8.12
HTO	7.07	7.69	8.31	8.93	9.55	10.17
GDO	79.16	85.26	91.36	97.46	103.56	109.66
RFO	1.90	2.07	2.24	2.41	2.57	2.74
LUB	2.11	2.27	2.43	2.59	2.75	2.92
BTM	5.21	5.31	5.41	5.51	5.60	5.70
CKP	0.00	0.00	0.00	0.00	0.00	0.00
MAB	8.40	8.68	8.97	9.25	9.54	9.82

Z7 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	51.38	49.15	46.91	44.68	42.45	40.21
NPH	5.53	6.47	7.41	8.35	9.29	10.23
GSL	76.04	75.82	75.59	75.36	75.13	74.91
JET	19.06	17.52	15.98	14.43	12.89	11.34
KRS	4.97	4.75	4.54	4.32	4.11	3.89
HTO	22.28	22.53	22.77	23.01	23.25	23.49
GDO	115.30	114.96	114.61	114.27	113.92	113.58
RFO	11.64	11.76	11.89	12.02	12.14	12.27
LUB	2.59	2.59	2.58	2.57	2.56	2.56
BTM	26.72	27.23	27.74	28.24	28.75	29.26
CKP	0.11	0.11	0.11	0.11	0.10	0.10
MAB	39.88	41.23	42.59	43.94	45.29	46.65

Z8 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	35.82	31.80	27.79	23.77	19.75	15.74
NPH	47.29	56.16	65.03	73.90	82.77	91.64
GSL	115.63	108.28	100.93	93.58	86.23	78.88
JET	25.05	23.02	20.99	18.96	16.94	14.91
KRS	1.59	1.41	1.23	1.05	0.88	0.70
HTO	16.97	15.61	14.24	12.88	11.51	10.15
GDO	173.83	162.78	151.73	140.68	129.64	118.59
RFO	3.09	2.84	2.60	2.35	2.10	1.85
LUB	23.06	23.06	23.06	23.06	23.06	23.06
BTM	33.68	34.32	34.96	35.60	36.24	36.87
CKP	33.64	29.88	26.13	22.38	18.63	14.87
MAB	33.25	34.37	35.50	36.63	37.76	38.89

Z9 - Oil products demand (Mtonnes/year) - Shiny Scenario	2015	2020	2025	2030	2035	2040
LPG	63.28	59.24	55.21	51.17	47.14	43.10
NPH	108.78	122.37	135.95	149.53	163.11	176.69
GSL	131.97	126.09	120.21	114.34	108.46	102.59
JET	44.98	41.34	37.70	34.05	30.41	26.77
KRS	23.06	21.59	20.12	18.65	17.18	15.71
HTO	75.05	73.44	71.84	70.23	68.62	67.02
GDO	223.55	213.60	203.64	193.69	183.73	173.78
RFO	30.99	30.33	29.67	29.00	28.34	27.67
LUB	15.59	14.90	14.20	13.51	12.81	12.12
BTM	30.98	31.56	32.15	32.74	33.33	33.91
CKP	7.72	7.42	7.13	6.83	6.53	6.23
MAB	69.60	71.96	74.33	76.69	79.05	81.41

10. Annex C – ORION model demand scenarios

C.I) Shadow scenario

Table C-1 - ORION model oil products demands - Shadow

Oil product (Mtonnes/year)	2015	2020	2025	2030	2035	2040
LPG	7.46	7.52	7.65	7.74	7.90	8.10
Naphtha	8.98	10.07	11.80	13.20	14.76	16.48
Gasoline	22.46	22.63	23.01	23.29	23.77	24.37
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01
Diesel	46.67	48.01	51.12	53.49	54.81	56.47
Jet fuel oil	5.89	5.88	5.75	5.62	5.50	5.83
Fuel oil	13.64	14.32	15.05	15.18	15.25	15.24
Heating fuel oil	1.52	1.59	1.67	1.69	1.69	1.69
Petcoke	4.92	5.20	5.12	5.29	5.48	5.63

C.II) Cloudy scenario

Table C-2 - ORION model oil products demands – Cloudy

Oil product (Mtonnes/year)	2015	2020	2025	2030	2035	2040
LPG	7.46	7.52	7.58	7.61	7.70	7.73
Naphtha	8.98	10.07	11.84	13.27	14.85	16.58
Gasoline	22.46	22.63	22.83	22.91	23.18	23.27
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01
Diesel	46.67	48.01	49.62	50.31	51.01	51.26
Jet fuel oil	5.89	5.76	5.64	5.51	5.38	5.26
Fuel oil	13.64	14.32	14.83	14.90	14.60	14.56
Heating fuel oil	1.52	1.59	1.65	1.66	1.62	1.62
Petcoke	4.92	5.20	5.13	5.28	5.46	5.59

C.III) Shiny scenario

Table C-3 - ORION model oil products demands - Shiny

Oil product (Mtonnes/year)	2015	2020	2025	2030	2035	2040
LPG	7.46	7.32	6.89	5.84	5.44	5.00
Naphtha	8.98	10.07	11.48	12.63	13.87	15.13
Gasoline	22.46	22.02	20.75	17.58	16.38	15.06
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01
Diesel	46.67	48.66	42.45	28.22	24.35	20.43
Jet fuel oil	5.89	5.41	4.93	4.46	3.98	3.50
Fuel oil	13.64	14.32	11.85	11.28	10.68	10.18
Heating fuel oil	1.52	1.59	1.32	1.25	1.19	1.13
Petcoke	4.92	5.13	4.90	4.75	4.60	4.36

11. Annex D – ORION model results

D.I) Shadow scenario

National trades

Table D-1 - Oil derivatives national trades - Shadow 1

Products trades (Mtonnes/year)		t0				t1					t2					t3					t4					t5				
LPG	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-
	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-
	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-
	SP_S	-	-	0.45	-	SP_S	-	-	0.06	-	SP_S	-	-	-	-	SP_S	-	-	-	-	SP_S	-	-	-	-	SP_S	-	-	-	-
	Total	-	-	0.45	-	Total	-	-	0.06	-	Total	-	-	-	-	Total	-	-	-	-	Total	-	-	-	-	Total	-	-	-	-
Naphtha	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-
	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-
	RJMG_S	-	-	-	-	RJMG_S	-	1.33	-	-	RJMG_S	-	0.13	-	-	RJMG_S	-	0.59	-	-	RJMG_S	-	1.13	-	-	RJMG_S	-	1.78	-	0.01
	SP_S	-	-	-	-	SP_S	-	-	-	-	SP_S	-	-	-	-	SP_S	-	-	-	-	SP_S	0.04	-	-	-	SP_S	0.44	-	-	-
	Total	-	-	-	-	Total	-	1.33	-	-	Total	-	0.13	-	-	Total	-	0.59	-	-	Total	0.04	1.13	-	-	Total	0.44	1.78	-	0.01
Gasoline	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D	region	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	-	-	-	-	S_S	3.25	-	-	-
	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	-	-	-	NE_S	-	3.33	-	-
	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-	RJMG_S	-	-	-	-	RJMG_S	-	-	2.98	-

	SP_S	0.87	-	1.86	-	**SP_S**	1.65	-	1.53	-	**SP_S**	1.75	-	0.49	-	**SP_S**	1.41	-	0.54	-	**SP_S**	0.59	-	0.62	-	**SP_S**	-	-	0.32	5.76
	Total	0.87	-	1.86	-	**Total**	1.65	-	1.53	-	**Total**	1.75	-	0.49	-	**Total**	1.41	-	0.54	-	**Total**	0.59	-	0.62	-	**Total**	-	-	0.32	-
Kerosene	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Diesel	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	0.55	**RJMG_S**	-	1.44	-	-	**RJMG_S**	-	0.50	-	-	**RJMG_S**	-	0.85	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	0.39	-	-
	SP_S	-	-	-	-	**SP_S**	0.14	-	-	-	**SP_S**	0.46	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.55	**Total**	0.14	1.44	-	-	**Total**	0.46	0.50	-	-	**Total**	-	0.85	-	-	**Total**	-	-	-	-	**Total**	-	0.39	-	-
Jet Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	0.13	**S_S**	-	-	-	0.02	**S_S**	-	-	-	-	**S_S**	-	-	-	0.15	**S_S**	-	-	-	0.17	**S_S**	-	-	-	0.15
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.13	**Total**	-	-	-	0.02	**Total**	-	-	-	-	**Total**	-	-	-	0.15	**Total**	-	-	-	0.17	**Total**	-	-	-	0.15
Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	1.61	**S_S**	-	-	-	1.26	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	0.33	-	0.17	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	1.00	-	**SP_S**	-	-	1.12	-	**SP_S**	-	0.03	2.37	-
	Total	-	0.33	-	1.78	**Total**	-	-	-	1.26	**Total**	-	-	-	-	**Total**	-	-	1.00	-	**Total**	-	-	1.12	-	**Total**	-	0.03	2.37	-

Heating Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Petcoke	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Table D-2 - Oil derivatives national trades - Shadow 1A

Products trades (Mtonnes/year)		**t0**				**t1**					**t2**					**t3**					**t4**					**t5**				
LPG	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	0.45	-	**SP_S**	-	-	0.03	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	0.45	-	**Total**	-	-	0.03	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Naphtha	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-

	RJMG_S	-	-	-	-	**RJMG_S**	-	0.56	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	0.34	-	-	**RJMG_S**	-	0.85	-	-	**RJMG_S**	-	1.57	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	0.15	-	-	-
	Total	-	-	-	-	**Total**	-	0.56	-	-	**Total**	-	-	-	-	**Total**	-	0.34	-	-	**Total**	-	0.85	-	-	**Total**	0.15	1.57	-	-
Gasoline	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	0.27	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	0.87	-	1.86	-	**SP_S**	1.83	0.53	0.64	-	**SP_S**	1.33	0.52	-	-	**SP_S**	1.33	-	0.26	-	**SP_S**	0.40	-	1.28	-	**SP_S**	-	-	0.68	-
	Total	0.87	-	1.86	-	**Total**	1.83	0.53	0.64	-	**Total**	1.33	0.52	-	-	**Total**	1.33	0.27	0.26	-	**Total**	0.40	-	1.28	-	**Total**	-	-	0.68	-
Kerosene	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Diesel	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	0.55	**RJMG_S**	-	0.79	-	0.42	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.55	**Total**	-	0.79	-	0.42	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Jet Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	0.13	**S_S**	-	-	-	0.22	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	0.24	**S_S**	-	-	-	0.19
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-

	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.13	**Total**	-	-	-	0.22	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	0.24	**Total**	-	-	-	0.19
Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	1.61	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	0.33	-	0.17	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	0.33	-	1.78	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Heating Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Petcoke	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Processing units capacities

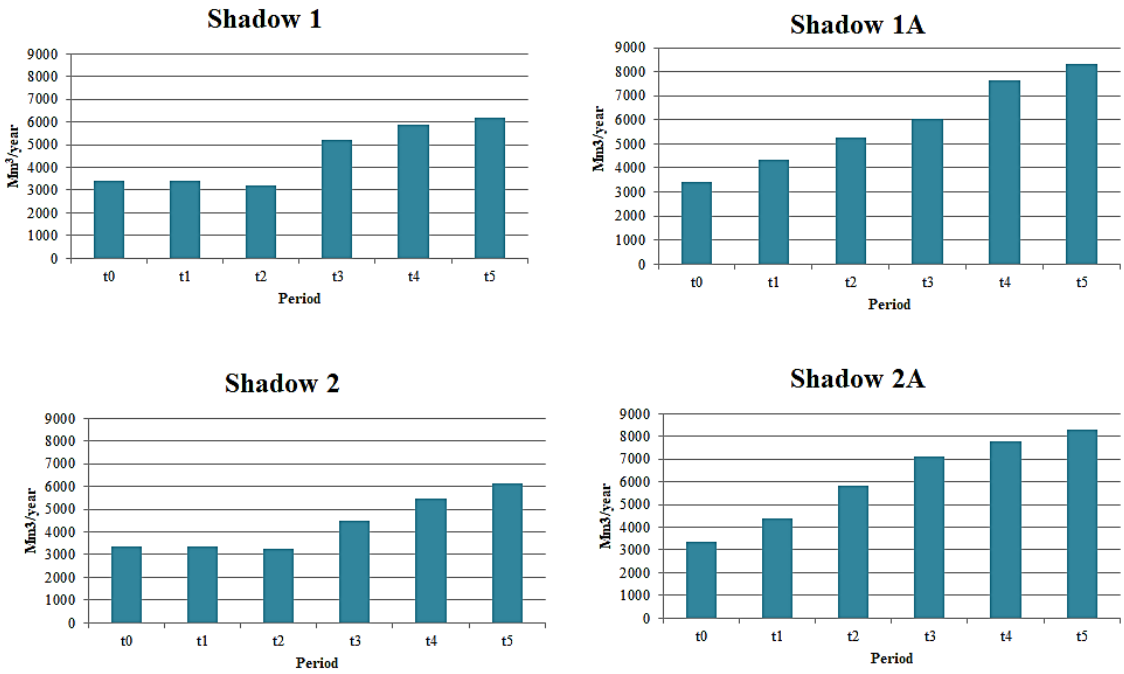

Figure D-1 - UGH level capacities - Shadow scenarios

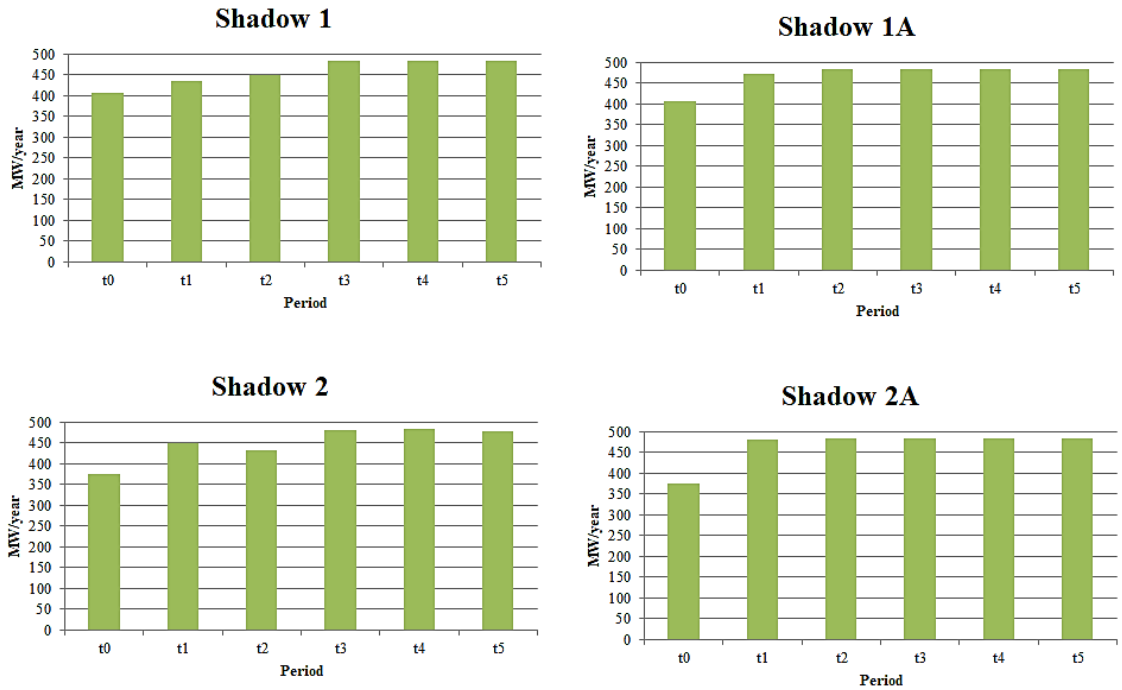

Figure D-2 - Cogeneration level capacities - Shadow scenarios

D.II) Cloudy scenario

Crude oil consumption

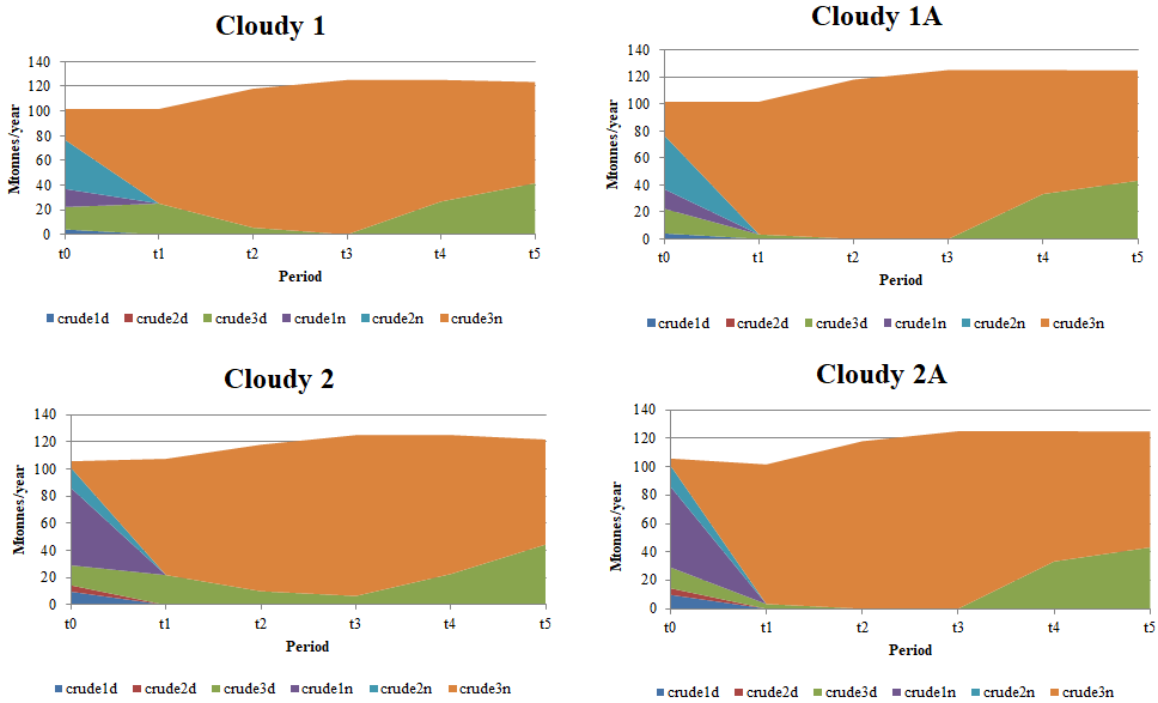

Figure D-3 - Crude oil consumption by type of crude oil and campaign - Cloudy scenarios

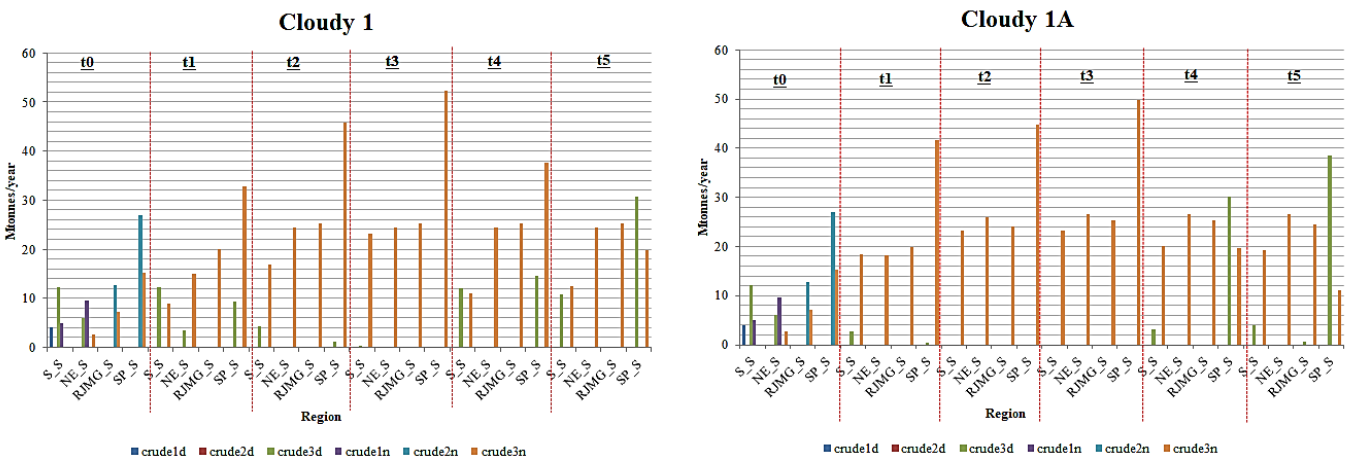

Figure D-4 - Crude oil consumption by type of crude oil, campaign and region - Cloudy 1 and Cloudy 1A

Oil derivatives production

Cloudy 1

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.7%	0.8%	0.7%	0.7%	0.7%	0.7%
LPG	4.8%	3.6%	3.5%	3.4%	3.2%	3.0%
Naphtha	17.1%	11.5%	13.3%	14.2%	13.6%	13.4%
Gasoline	13.4%	15.3%	14.9%	14.6%	12.9%	11.7%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	41.0%	45.5%	42.0%	40.2%	49.0%	50.7%
Jet fuel oil	3.3%	2.4%	1.8%	2.2%	2.5%	2.3%
Fuel oil	13.4%	14.8%	18.0%	19.1%	12.1%	12.3%
Heating fuel oil	3.6%	3.1%	3.0%	3.0%	3.1%	3.1%
Petcoke	1.5%	1.6%	1.4%	1.4%	1.5%	1.5%

Cloudy 1A

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.7%	0.8%	0.7%	0.6%	0.7%	0.7%
LPG	4.8%	3.9%	3.6%	3.5%	3.2%	3.0%
Naphtha	17.1%	13.3%	13.7%	14.3%	13.2%	13.3%
Gasoline	13.4%	16.8%	15.2%	14.6%	12.7%	11.8%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	41.0%	47.2%	46.6%	46.3%	48.9%	50.2%
Jet fuel oil	3.3%	2.9%	0.9%	1.6%	2.4%	2.3%
Fuel oil	13.4%	8.3%	12.6%	12.4%	12.1%	12.1%
Heating fuel oil	3.6%	3.5%	3.7%	3.6%	3.6%	3.5%
Petcoke	1.5%	1.7%	1.4%	1.4%	1.5%	1.5%

Cloudy 2

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.6%	0.8%	0.7%	0.7%	0.7%	0.7%
LPG	5.0%	4.4%	3.4%	3.3%	3.2%	3.0%
Naphtha	21.6%	11.0%	13.6%	14.4%	13.7%	12.6%
Gasoline	11.6%	16.1%	14.3%	13.9%	13.2%	12.1%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	38.9%	43.8%	42.0%	40.2%	48.8%	51.1%
Jet fuel oil	4.0%	2.5%	2.1%	2.5%	2.3%	2.0%
Fuel oil	12.7%	15.3%	18.3%	19.4%	12.2%	12.4%
Heating fuel oil	3.1%	3.0%	3.0%	2.9%	3.1%	3.1%
Petcoke	1.4%	1.7%	1.4%	1.4%	1.5%	1.5%

Cloudy 2A

Oil product	t0	t1	t2	t3	t4	t5
Fuel gas	0.6%	0.8%	0.7%	0.6%	0.7%	0.7%
LPG	5.0%	3.9%	3.6%	3.5%	3.2%	3.0%
Naphtha	21.6%	13.3%	13.7%	14.3%	13.2%	13.3%
Gasoline	11.6%	16.8%	15.2%	14.6%	12.7%	11.8%
Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Diesel	38.9%	47.2%	46.6%	46.3%	48.9%	50.2%
Jet fuel oil	4.0%	2.9%	0.9%	1.6%	2.4%	2.3%
Fuel oil	12.7%	8.3%	12.6%	12.4%	12.1%	12.1%
Heating fuel oil	3.1%	3.5%	3.7%	3.6%	3.6%	3.5%
Petcoke	1.4%	1.7%	1.4%	1.4%	1.5%	1.5%

Figure D-5 - Oil derivatives production share - Cloudy scenarios

Table D-3 - Oil derivatives production per period and region - Cloudy 1

Oil product (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
Fuel gas	0.16	0.10	0.14	0.36	0.16	0.12	0.13	0.36	0.14	0.15	0.17	0.32	0.16	0.15	0.17	0.35	0.16	0.15	0.17	0.36	0.17	0.15	0.17	0.37
LPG	0.90	0.75	0.90	2.28	0.62	0.57	0.58	1.92	0.78	0.79	0.80	1.75	0.73	0.79	0.80	1.93	0.80	0.79	0.80	1.61	0.67	0.79	0.71	1.51
Naphtha	3.26	3.81	4.04	6.25	2.19	2.80	3.38	3.28	2.57	4.32	3.83	4.95	3.52	4.32	3.83	6.10	1.92	4.32	3.83	6.95	2.73	4.32	4.51	5.02
Gasoline	2.09	1.43	2.15	7.91	2.47	2.17	2.43	8.45	3.09	2.95	3.45	8.14	3.15	2.95	3.45	8.73	3.27	2.95	3.45	6.48	2.68	2.95	2.88	5.92
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel	9.02	7.83	7.93	16.92	9.93	8.41	8.63	19.31	10.23	11.01	8.38	20.00	10.41	11.47	8.38	20.05	12.14	10.90	13.58	24.68	12.10	10.90	14.64	24.99
Jet fuel oil	0.53	0.62	0.71	1.51	0.38	0.47	0.59	1.05	0.05	0.00	0.74	1.36	0.51	0.00	0.74	1.52	0.44	0.72	0.74	1.25	0.47	0.72	0.74	0.88
Fuel oil	4.18	2.70	2.87	3.89	4.29	2.68	3.10	5.02	3.13	3.93	6.61	7.63	3.31	3.44	6.61	10.58	2.92	3.29	1.08	7.90	2.91	3.29	0.00	8.95
Heating fuel oil	0.56	0.63	0.72	1.72	0.62	0.53	0.59	1.41	0.65	0.67	0.67	1.59	0.72	0.69	0.67	1.63	0.77	0.69	0.88	1.58	0.73	0.69	0.87	1.52
Petcoke	0.32	0.21	0.27	0.76	0.32	0.28	0.27	0.76	0.33	0.37	0.35	0.64	0.32	0.37	0.35	0.73	0.36	0.37	0.35	0.76	0.34	0.37	0.35	0.76

Table D-4 - Oil derivatives production per period and region - Cloudy 1A

Oil product (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
Fuel gas	0.16	0.10	0.14	0.36	0.15	0.12	0.13	0.40	0.15	0.16	0.16	0.30	0.14	0.17	0.17	0.33	0.15	0.17	0.17	0.36	0.15	0.17	0.17	0.37
LPG	0.90	0.75	0.90	2.28	0.61	0.56	0.74	2.08	0.85	0.87	0.76	1.72	0.85	0.90	0.79	1.80	0.82	0.86	0.76	1.58	0.73	0.86	0.71	1.47
Naphtha	3.26	3.81	4.04	6.25	3.35	3.24	2.31	4.63	3.39	4.29	3.61	4.84	3.40	4.43	3.85	6.23	3.23	4.70	4.11	4.45	3.61	4.70	4.42	3.85
Gasoline	2.09	1.43	2.15	7.91	2.50	2.16	3.35	9.04	3.43	3.35	3.31	7.84	3.40	3.44	3.44	8.00	3.22	3.21	3.22	6.30	2.77	3.21	2.88	5.81
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel	9.02	7.83	7.93	16.92	9.93	10.49	8.81	18.77	10.66	11.55	11.85	20.97	10.60	11.79	12.51	23.02	10.79	11.87	11.85	26.65	10.95	11.93	11.93	27.82
Jet fuel oil	0.53	0.62	0.71	1.51	0.57	0.54	0.59	1.23	0.39	0.70	0.00	0.00	0.38	0.78	0.00	0.78	0.62	0.78	0.74	0.88	0.60	0.78	0.73	0.71
Fuel oil	4.18	2.70	2.87	3.89	2.75	0.00	2.60	3.09	2.85	3.30	2.70	5.99	2.98	3.44	2.82	6.26	2.92	3.38	2.76	6.14	2.91	3.32	2.80	6.12
Heating fuel oil	0.56	0.63	0.72	1.72	0.75	0.61	0.77	1.44	0.82	0.88	0.88	1.77	0.82	0.90	0.92	1.90	0.82	0.88	0.90	1.86	0.79	0.88	0.87	1.86
Petcoke	0.32	0.21	0.27	0.76	0.30	0.27	0.28	0.86	0.36	0.39	0.33	0.63	0.35	0.40	0.35	0.70	0.36	0.40	0.35	0.76	0.35	0.40	0.35	0.76

Oil derivatives imports and exports

Table D-5 - Oil derivatives imports and exports per period and region - Cloudy 1

Region	Imp/Exp (Mtonnes/year)	LPG						Naphtha						Gasoline						Kerosene						Diesel						Jet fuel oil						Fuel oil						Heating fuel oil						Petcoke					
		t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5
S_D	Imports	0.45	0.74	0.59	0.65	0.59	0.73	-	-	-	-	-	-	1.92	0.82	-	-	1.32	2.34	-	-	-	-	-	-	0.63	-	-	-	-	-	-	0.01	0.34	-	-	-	-	-	-	-	-	-	0.30	0.32	0.33	0.34	0.34	0.34	0.59	0.64	0.61	0.65	0.64	0.69
	Exports	-	-	-	-	-	-	0.99	-	-	0.63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.58	1.50	-	-	-	-	-	-	-	0.78	0.28	0.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NE_D	Imports	2.15	2.35	2.16	2.17	2.20	2.22	-	-	-	-	-	-	6.97	6.28	5.20	4.63	5.71	5.75	-	-	-	-	-	-	3.04	1.72	-	-	-	-	1.21	1.32	1.75	1.71	0.95	0.91	-	-	-	-	-	-	0.30	0.32	0.33	0.34	0.34	0.34	1.70	1.74	1.62	1.68	1.75	1.80
	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.64	-	-	-	-	-	-	-	-	-	-	-	-	-
RJMG_D	Imports	0.03	0.74	0.57	0.55	0.59	0.69	-	-	-	-	-	-	-	-	-	-	-	0.76	-	-	-	-	-	-	-	-	-	-	-	-	0.50	0.61	0.42	0.40	0.37	0.34	-	-	-	-	-	-	0.30	0.32	0.33	0.34	0.34	0.34	0.63	0.68	0.60	0.63	0.66	0.68
	Exports	-	-	-	-	-	-	-	0.63	1.63	0.84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.55	5.51	-	-	-	-	-	-	-	-	3.91	3.79	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SP_D	Imports	-	-	0.14	-	0.32	0.43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.30	-	-	-	-	-	0.80	1.33	0.97	0.63	0.91	1.18	-	-	-	-	-	-	0.60	0.63	0.66	0.69	0.67	0.67	0.44	0.51	0.61	0.56	0.57	0.60
	Exports	-	-	-	-	-	-	-	0.95	2.20	3.02	2.17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.16	4.37	-	-	-	-	-	-	-	-	1.64	4.32	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	Imports	2.63	3.83	3.46	3.37	3.70	4.07	-	-	-	-	-	-	8.89	7.10	5.20	4.63	7.03	8.85	-	-	-	-	-	-	4.97	1.72	-	-	-	-	2.51	3.27	3.48	2.74	2.23	2.43	-	-	-	-	-	-	1.50	1.59	1.65	1.71	1.69	1.69	3.36	3.57	3.44	3.52	3.62	3.77
	Exports	-	-	-	-	-	-	0.99	1.58	3.83	4.49	2.17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.29	11.38	-	-	-	-	-	-	-	0.78	6.47	8.44	-	-	-	-	-	-	-	-	-	-	-	-	-

Table D-6 - Oil derivatives imports and exports per period and region - Cloudy 1A

Region	Imp/Exp (Mtonnes/year)	LPG						Naphtha						Gasoline						Kerosene						Diesel						Jet fuel oil						Fuel oil						Heating fuel oil						Petcoke					
		t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5	t0	t1	t2	t3	t4	t5
S_D	Imports	0.45	0.75	0.52	0.53	0.57	0.66	-	-	-	-	-	-	1.92	-	-	-	1.78	2.24	-	-	-	-	-	-	0.63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.30	0.32	0.33	0.34	0.34	0.34	0.59	0.66	0.58	0.62	0.64	0.68
	Exports	-	-	-	-	-	-	0.99	1.16	0.82	0.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.39	0.19	0.24	0.35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NE_D	Imports	2.15	2.36	2.08	2.06	2.13	2.15	-	-	-	-	-	-	6.97	5.58	4.89	4.63	5.45	5.48	-	-	-	-	-	-	3.04	-	-	-	-	-	1.21	1.25	1.05	0.93	0.89	0.85	-	3.18	-	-	-	-	0.30	0.32	0.33	0.34	0.34	0.34	1.70	1.75	1.60	1.64	1.71	1.76
	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RJMG_D	Imports	0.03	0.41	0.61	0.58	0.63	0.69	-	-	-	-	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-	-	-	-	-	-	-	0.50	0.61	1.17	1.14	0.37	0.36	-	-	-	-	-	-	0.30	0.32	0.33	0.34	0.34	0.34	0.63	0.68	0.61	0.63	0.66	0.68
	Exports	-	-	-	-	-	-	-	-	1.37	0.98	0.64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.01	4.56	3.79	3.83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SP_D	Imports	-	-	0.17	0.11	0.35	0.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.30	-	-	-	-	-	0.80	0.98	2.33	1.50	1.10	1.23	-	2.69	-	-	-	-	0.60	0.63	0.66	0.69	0.67	0.67	0.44	0.42	0.63	0.59	0.57	0.61
	Exports	-	-	-	-	-	-	-	2.29	2.09	3.15	1.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.01	2.78	6.13	7.20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	Imports	2.63	3.52	3.38	3.28	3.68	3.96	-	-	-	-	-	-	8.89	5.58	4.89	4.63	7.23	8.59	-	-	-	-	-	-	4.97	-	-	-	-	-	2.51	2.84	4.55	3.57	2.36	2.44	-	5.87	-	-	-	-	1.50	1.59	1.65	1.71	1.69	1.69	3.36	3.51	3.42	3.48	3.58	3.73
	Exports	-	-	-	-	-	-	0.99	3.45	4.28	4.65	1.65	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.41	7.61	10.16	11.38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

National trades

Table D-7 - Oil derivatives national trades - Cloudy 1

		t0				t1					t2					t3					t4					t5				
LPG	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	0.42	-	**SP_S**	-	-	0.04	-	**SP_S**	-	-	-	-	**SP_S**	-	-	0.03	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	0.42	-	**Total**	-	-	0.04	-	**Total**	-	-	-	-	**Total**	-	-	0.03	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Naphtha	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	1.00	-	-	**RJMG_S**	-	0.14	-	-	**RJMG_S**	-	0.68	-	-	**RJMG_S**	-	1.25	-	-	**RJMG_S**	-	1.63	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	1.31	0.02	-	-	**SP_S**	0.87	0.30	-	-
	Total	-	-	-	-	**Total**	-	1.00	-	-	**Total**	-	0.14	-	-	**Total**	-	0.68	-	-	**Total**	1.31	1.27	-	-	**Total**	0.87	1.93	-	-
Gasoline	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	0.83	-	1.79	-	**SP_S**	1.59	-	1.53	-	**SP_S**	1.83	0.39	0.54	-	**SP_S**	1.79	0.98	0.56	-	**SP_S**	0.41	-	0.61	-	**SP_S**	-	-	0.44	-
	Total	0.83	-	1.79	-	**Total**	1.59	-	1.53	-	**Total**	1.83	0.39	0.54	-	**Total**	1.79	0.98	0.56	-	**Total**	0.41	-	0.61	-	**Total**	-	-	0.44	-
Kerosene	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Diesel	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	0.55	**RJMG_S**	-	1.05	-	-	**RJMG_S**	-	0.54	-	-	**RJMG_S**	-	0.24	-	0.19	**RJMG_S**	-	0.97	-	-	**RJMG_S**	-	1.03	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	0.03	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.55	**Total**	-	1.05	-	-	**Total**	0.03	0.54	-	-	**Total**	-	0.24	-	0.19	**Total**	-	0.97	-	-	**Total**	-	1.03	-	-
Jet Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	0.13	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	0.13	**S_S**	-	-	-	0.07	**S_S**	-	-	-	0.11
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.13	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	0.13	**Total**	-	-	-	0.07	**Total**	-	-	-	0.11
Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	1.56	**S_S**	-	-	-	0.77	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	0.33	-	0.06	**RJMG_S**	-	0.50	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	0.08	1.68	-	**SP_S**	-	0.08	2.75	-
	Total	-	0.33	-	1.62	**Total**	-	0.50	-	0.77	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	0.08	1.68	-	**Total**	-	0.08	2.75	-
Heating Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Petcoke	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-

	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Table D-8 - Oil derivatives national trades - Shadow 1A

		t0				**t1**					**t2**					**t3**					**t4**					**t5**				
LPG	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	0.42	-	**SP_S**	-	-	0.20	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	0.42	-	**Total**	-	-	0.20	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Naphtha	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	0.56	-	-	**RJMG_S**	-	0.17	-	-	**RJMG_S**	-	0.57	-	-	**RJMG_S**	-	0.89	-	-	**RJMG_S**	-	1.53	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	0.01	-	-
	Total	-	-	-	-	**Total**	-	0.56	-	-	**Total**	-	0.17	-	-	**Total**	-	0.57	-	-	**Total**	-	0.89	-	-	**Total**	-	1.54	-	-
Gasoline	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	0.83	-	1.79	-	**SP_S**	2.37	0.72	0.61	-	**SP_S**	1.49	0.28	0.69	-	**SP_S**	1.53	0.49	0.57	-	**SP_S**	-	-	0.84	-	**SP_S**	-	-	0.32	-
	Total	0.83	-	1.79	-	**Total**	2.37	0.72	0.61	-	**Total**	1.49	0.28	0.69	-	**Total**	1.53	0.49	0.57	-	**Total**	-	-	0.84	-	**Total**	-	-	0.32	-

Kerosene	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Diesel	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	0.55	**RJMG_S**	-	0.68	-	0.54	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.55	**Total**	-	0.68	-	0.54	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Jet Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	0.13	**S_S**	-	-	-	0.17	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	0.25	**S_S**	-	-	-	0.24
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.13	**Total**	-	-	-	0.17	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	0.25	**Total**	-	-	-	0.24
Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	1.56	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	0.33	-	0.06	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	0.05	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	0.33	-	1.62	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	0.05	-	-

Heating Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Petcoke	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Processing units capacities

Table D-9 - Processing units level capacties - Cloudy 1

Processing unit capacity level (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
ADU	21.25	18.27	19.96	42.17	21.25	18.27	19.96	42.17	21.25	24.48	25.26	47.02	23.11	24.48	25.26	52.25	23.11	24.48	25.26	52.25	23.11	24.48	25.26	50.61
VDU	5.09	3.29	4.68	8.91	6.01	3.87	5.18	10.35	3.95	4.37	6.55	12.25	6.00	4.37	6.55	12.71	5.54	4.37	6.55	13.17	6.43	4.37	6.55	13.91
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	-	0.10	0.38	3.52	0.24	0.24	0.41	3.52	0.90	0.33	0.97	3.83	0.87	0.33	0.97	3.83	0.90	0.33	0.97	1.09	0.26	0.33	0.29	0.59
REF	-	-	0.16	2.19	-	-	0.16	2.56	0.54	-	0.60	2.90	0.54	-	0.60	2.83	0.54	-	0.60	0.41	-	-	-	-
KEHDT	-	-	0.51	1.08	0.27	0.34	0.51	1.08	0.54	0.73	0.53	0.97	0.54	0.73	0.53	1.11	0.32	0.52	0.53	0.90	0.34	0.52	0.53	0.63
DIHDT	6.61	5.18	5.56	11.54	7.55	5.78	6.28	13.99	7.35	8.33	8.60	16.03	7.87	8.33	8.60	17.78	8.19	8.33	8.60	18.18	8.16	8.33	8.60	18.05
FCC	4.11	2.07	3.54	8.94	4.11	2.58	3.54	8.94	2.57	2.84	4.48	8.38	4.10	2.84	4.48	8.64	3.72	2.84	4.48	8.94	4.40	2.84	4.48	9.48
RFCC	-	0.65	-	0.97	-	1.00	-	0.97	1.74	1.98	-	-	-	1.98	-	0.84	0.94	1.98	-	0.97	-	1.98	-	0.46
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	2.06	1.33	1.77	5.17	2.20	1.94	2.03	5.35	2.29	2.62	2.56	4.78	2.35	2.62	2.56	5.36	2.45	2.62	2.56	5.42	2.38	2.62	2.56	5.27
ALK	-	-	-	0.31	0.17	0.23	0.30	0.52	0.27	0.37	0.38	0.69	0.35	0.37	0.38	0.78	0.20	0.37	0.38	0.60	0.21	0.37	0.38	0.38
COK	0.51	0.14	0.44	0.93	0.51	0.14	0.44	0.93	0.01	-	0.55	1.03	0.51	-	0.55	0.91	0.29	-	0.55	0.93	0.54	-	0.55	1.09
HDTI	2.64	2.85	2.57	5.81	2.64	2.85	2.57	5.81	2.64	2.23	-	4.48	2.64	2.70	-	2.75	4.26	2.85	5.33	7.14	4.26	2.85	6.42	7.58

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit

Table D-10 - Processing units level capacties - Cloudy 1A

Processing unit capacity level (Mtonnes/year)	t0				t1				t2				t3				t4				t5			
	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S	S_S	NE_S	RJMG_S	SP_S
ADU	21.25	18.27	19.96	42.17	21.25	18.27	19.93	42.21	23.28	25.90	23.99	44.85	23.31	26.68	25.26	49.87	23.31	26.68	25.26	49.87	23.25	26.68	25.26	49.68
VDU	5.09	3.29	4.68	8.91	5.62	3.78	4.73	10.00	4.13	4.62	6.22	10.66	4.16	4.76	6.55	11.97	4.25	4.76	6.55	13.18	4.82	4.76	6.58	14.44
DSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NAHDT	-	0.10	0.38	3.52	0.33	0.23	1.48	3.33	1.03	0.63	0.95	3.68	1.03	0.63	0.95	3.25	0.79	0.36	0.69	1.11	0.30	0.36	0.29	0.57
REF	-	-	0.16	2.19	0.07	-	1.09	2.32	0.62	0.25	0.60	2.77	0.62	0.24	0.59	2.34	0.41	-	0.35	0.45	-	-	-	-
KEHDT	-	-	0.51	1.08	0.41	0.39	0.51	1.08	0.58	0.57	0.72	1.35	0.58	0.57	0.76	1.26	0.45	0.56	0.53	0.63	0.44	0.56	0.52	0.51
DIHDT	6.61	5.18	5.56	11.54	7.31	6.22	6.78	14.38	7.92	8.81	8.16	15.26	7.93	9.08	8.60	16.97	8.02	9.08	8.60	17.78	8.02	9.08	8.62	17.95
FCC	4.11	2.07	3.54	8.94	3.85	2.52	3.20	10.19	2.74	3.01	4.26	7.22	2.71	3.10	4.48	8.12	2.76	3.10	4.48	8.95	3.20	3.10	4.50	9.88
RFCC	-	0.65	-	0.97	-	0.96	0.44	0.97	1.91	2.09	-	0.97	1.88	2.16	-	0.97	1.92	2.16	-	0.97	1.37	2.16	-	-
HCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HDS	2.06	1.33	1.77	5.17	2.17	1.92	2.05	6.07	2.53	2.78	2.43	4.62	2.50	2.86	2.56	5.13	2.51	2.86	2.56	5.23	2.47	2.86	2.57	5.17
ALK	-	-	-	0.31	0.28	0.27	0.30	0.63	0.35	0.39	0.36	0.67	0.35	0.40	0.38	0.75	0.31	0.40	0.38	0.38	0.30	0.40	0.37	0.27
COK	0.51	0.14	0.44	0.93	0.47	0.14	0.32	1.08	-	-	0.52	0.72	-	-	0.55	0.83	-	-	0.55	0.93	0.15	-	0.55	1.22
HDTI	2.64	2.85	2.57	5.81	5.70	4.55	4.92	8.05	5.63	6.35	6.04	11.04	5.68	6.54	6.36	12.36	6.04	6.56	6.39	15.85	6.20	6.56	6.50	16.87

ADU – Atmospheric distillation unit; VDU – Vacuum distillation unit; DSP – Deasphalting unit; NAHDT - Naphtha hydrotreatment unit; REF – Catalytic Reforming unit; KEHDT – Kerosene hydrotreatment unit; DIHDT – Diesel hydrotreatment unit; FCC – Fluid Catalytic Cracking unit; RFCC – Resid Catalytic Cracking unit; HCC – Hydrocracking unit; HDS – Hydrodesulfurization unit; ALK – Alkylation unit ;COK – Delayed Coking unit; HDTI – Unstable hydrotreatment unit

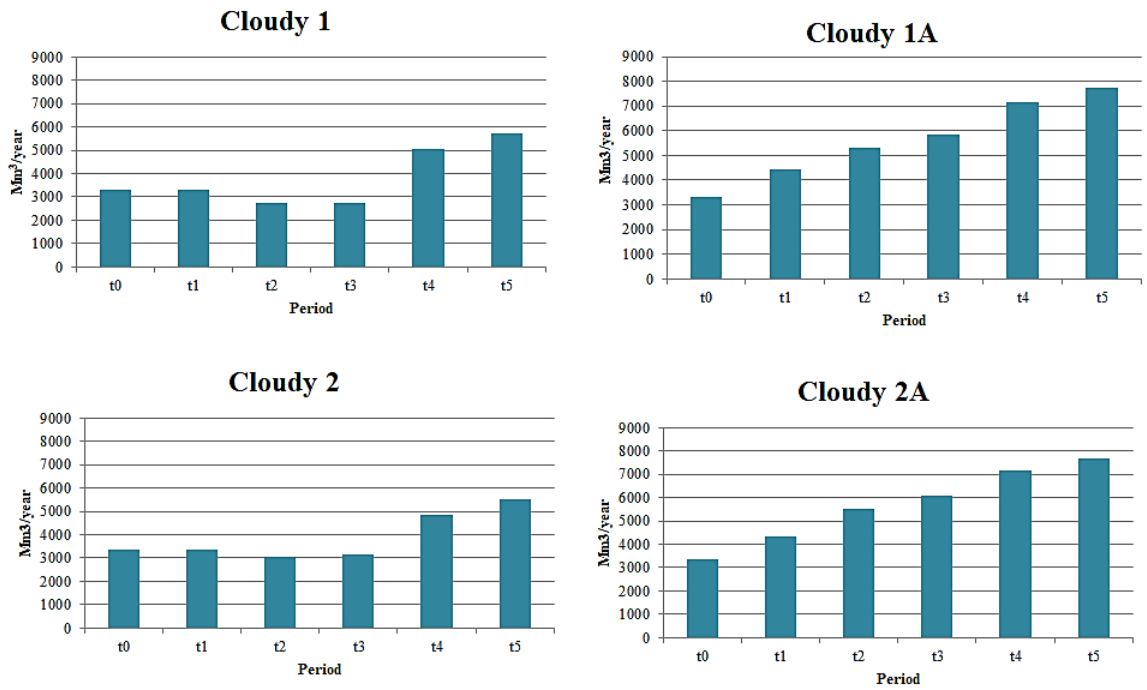

Figure D-6 - UGH level capacities - Cloudy scenarios

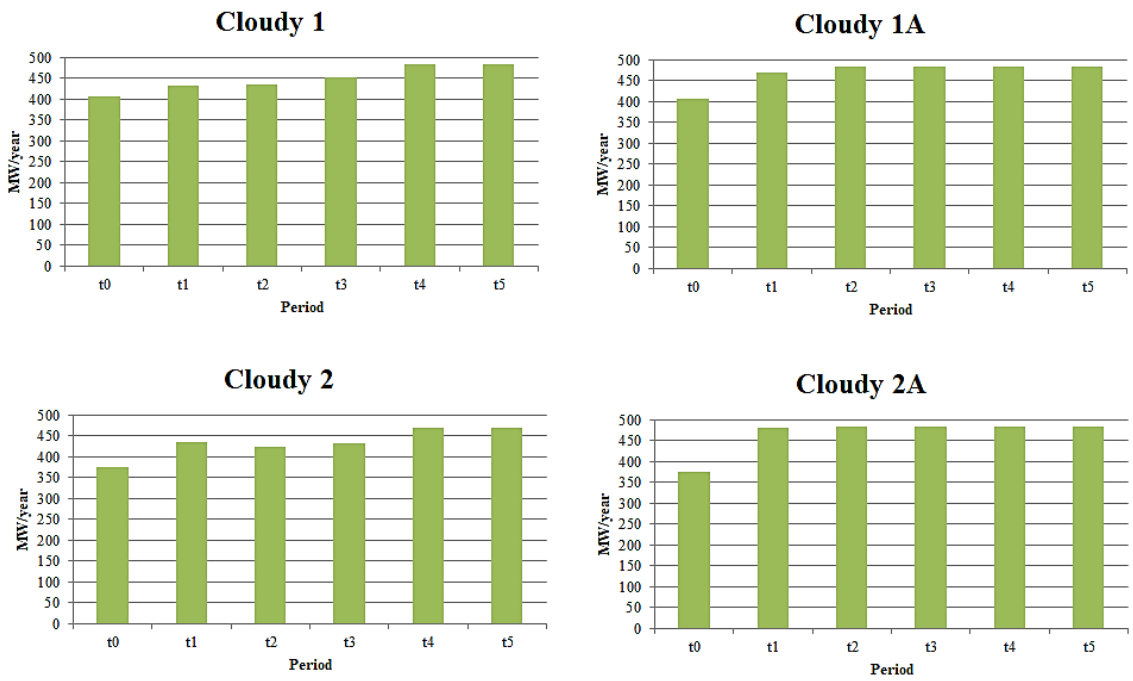

Figure D-7 - Cogeneration level capacities - Cloudy scenarios

Utilities consumption and CO_2 emissions

Table D-11 - Utilities consumption and CO_2 emissions - Cloudy 1

Steam	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Low-pressure (LP) steam consumption (10^6 MJ)	-1332.98	-1369.04	-1305.13	-1432.70	-1427.21	-1514.33
Medium-pressure (MP) steam consumption (10^6 MJ)	30018.66	31869.07	36191.17	38672.02	38117.19	37716.10
High-pressure (HP) steam consumption (10^6 MJ)	-1923.66	-1684.00	-1757.43	-1907.10	-1250.55	-1114.08
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	6615.33	9333.85	5620.00	15834.87	14015.26	11519.49
Natural gas - HP steam production (10^6 MJ)	1899.43	0.00	8524.84	0.00	0.00	2224.51
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	147794.04	127697.40	145281.96	150724.80	158261.04	154492.92
Fuel gas (10^6 MJ)	7954.92	37681.20	38518.56	40611.96	41868.00	42705.36
Coke (10^6 MJ)	55265.76	57359.16	59452.56	62383.32	64476.72	64476.72
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3551.00	3798.07	3928.97	4102.06	4384.66	4378.87
Electricity production (GWh)	3551.00	3788.30	3815.43	3967.75	4220.53	4242.60
Electricity grid (GWh)	0.00	9.78	113.55	134.31	27.86	136.27
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	39575.64	42220.35	42522.65	44220.18	47347.89	47283.31
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3812.84	4142.90	4056.27	4040.59	5343.98	5415.56
Hydrogen consumption (10^6 m^3)	3812.84	4142.90	4056.27	4040.59	5343.98	5415.56
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	60624.12	65872.07	64494.61	64245.38	84969.48	86107.47
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	106815.09	117426.27	112637.26	124300.43	146332.62	144910.27
Fuel oil (10^6 MJ)	147794.04	127697.40	145281.96	150724.80	158261.04	154492.92
Fuel gas (10^6 MJ)	7954.92	37681.20	38518.56	40611.96	41868.00	42705.36
Coke (10^6 MJ)	55265.76	57359.16	59452.56	62383.32	64476.72	64476.72
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	24.72	23.95	25.78	26.72	28.87	28.55

Table D-12 - Utilities consumption and CO_2 emissions - Cloudy 1A

Steam	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Low-pressure (LP) steam consumption (10^6 MJ)	-1332.98	-1411.01	-1230.34	-1314.07	-1377.46	-1476.54
Medium-pressure (MP) steam consumption (10^6 MJ)	30018.66	32598.36	36022.23	38220.18	37795.49	37910.36
High-pressure (HP) steam consumption (10^6 MJ)	-1923.66	-859.21	193.49	197.56	111.13	261.22
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	6615.33	7537.20	9094.79	7267.33	15238.77	15555.15
Natural gas - HP steam production (10^6 MJ)	1899.43	1455.36	4154.71	8572.77	0.00	0.00
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	147794.04	144863.28	176682.96	184219.20	180451.08	178357.68
Fuel gas (10^6 MJ)	7954.92	39774.60	37681.20	40193.28	42286.68	42705.36
Coke (10^6 MJ)	55265.76	60708.60	60289.92	63639.36	65732.76	65732.76
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3551.00	4356.73	4748.70	4980.34	4980.57	5025.99
Electricity production (GWh)	3551.00	4102.28	4248.39	4248.39	4248.39	4247.72
Electricity grid (GWh)	0.00	254.46	500.32	731.95	732.19	778.27
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	39575.64	45719.54	47347.89	47347.89	47347.89	47340.39
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3812.84	5445.01	6551.65	6907.06	7242.99	7330.01
Hydrogen consumption (10^6 m^3)	3812.84	5445.01	6551.65	6907.06	7242.99	7330.01
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	60624.12	86575.52	104171.40	109822.13	115163.53	116547.11
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	106815.09	139832.26	160614.07	164437.34	177750.18	179442.65
Fuel oil (10^6 MJ)	147794.04	144863.28	176682.96	184219.20	180451.08	178357.68
Fuel gas (10^6 MJ)	7954.92	39774.60	37681.20	40193.28	42286.68	42705.36
Coke (10^6 MJ)	55265.76	60708.60	60289.92	63639.36	65732.76	65732.76
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	24.72	26.96	30.68	32.23	32.50	32.46

Table D-13 - Utilities consumption and CO_2 emissions - Cloudy 2

Steam	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Low-pressure (LP) steam consumption (10^6 MJ)	-1134.67	-1349.91	-1297.41	-1399.50	-1407.01	-1492.65
Medium-pressure (MP) steam consumption (10^6 MJ)	30042.89	32569.81	36071.84	38413.91	38117.72	37143.60
High-pressure (HP) steam consumption (10^6 MJ)	-1592.61	-2403.27	-1869.98	-2105.03	-1264.02	-1090.90
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	2832.25	5884.56	14670.05	13755.16	10085.34	6024.90
Natural gas - HP steam production (10^6 MJ)	7883.93	3195.21	0.00	2830.31	4880.45	8020.57
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	133977.60	133140.24	142769.88	146538.00	159517.08	154492.92
Fuel gas (10^6 MJ)	17584.56	40611.96	38518.56	41030.64	41449.32	42286.68
Coke (10^6 MJ)	50241.60	64058.04	60289.92	63220.68	64895.40	63639.36
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3292.92	3915.69	3853.38	3988.54	4375.81	4373.01
Electricity production (GWh)	3292.92	3821.92	3699.95	3781.49	4108.63	4105.45
Electricity grid (GWh)	0.00	93.78	153.44	207.05	267.18	267.57
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	27508.84	27508.84	27508.84	27508.84	27508.84	27508.84
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3621.10	4226.16	4039.86	4024.06	5306.90	5398.01
Hydrogen consumption (10^6 m^3)	3621.10	4226.16	4039.86	4024.06	5306.90	5398.01
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	57575.47	67195.89	64233.97	63982.51	84379.78	85828.31
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	87916.56	100589.29	106412.86	105246.51	121973.96	119362.06
Fuel oil (10^6 MJ)	133977.60	133140.24	142769.88	146538.00	159517.08	154492.92
Fuel gas (10^6 MJ)	17584.56	40611.96	38518.56	41030.64	41449.32	42286.68
Coke (10^6 MJ)	50241.60	64058.04	60289.92	63220.68	64895.40	63639.36
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	22.78	25.20	25.54	26.44	28.83	28.42

Table D-14 - Utilities consumption and CO_2 emissions - Cloudy 2A

Steam	t0	t1	t2	t3	t4	t5
Low-pressure (LP) steam consumption (10^6 MJ)	-1134.67	-1290.76	-1315.94	-1307.46	-1347.54	-1515.77
Medium-pressure (MP) steam consumption (10^6 MJ)	30042.89	32673.51	36421.10	38190.43	37751.91	37354.54
High-pressure (HP) steam consumption (10^6 MJ)	-1592.61	-1161.87	-101.68	49.50	42.40	410.21
Natural Gas - Steam production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - LP steam production (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas - MP steam production (10^6 MJ)	2832.25	4224.29	8093.70	15630.91	8804.13	12260.27
Natural gas - HP steam production (10^6 MJ)	7883.93	3736.72	5277.81	0.00	6302.52	2881.41
Fuel	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	0.00	0.00	0.00	0.00	0.00	0.00
Fuel oil (10^6 MJ)	133977.60	154911.60	172077.48	181707.12	179195.04	177101.64
Fuel gas (10^6 MJ)	17584.56	40193.28	39774.60	40611.96	41868.00	42705.36
Coke (10^6 MJ)	50241.60	64476.72	62383.32	64058.04	65732.76	64058.04
Electricity	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Electricity consumption (GWh)	3292.92	4468.23	4739.70	4905.95	4917.86	5032.78
Electricity production (GWh)	3292.92	4212.84	4248.39	4248.39	4248.39	4238.29
Electricity grid (GWh)	0.00	255.40	491.31	657.55	669.48	794.50
Natural Gas - Electricity production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Electricity production (10^6 MJ)	27508.84	30956.39	30956.39	30956.39	30956.39	30956.39
Hydrogen	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Hydrogen production (10^6 m^3)	3621.10	5729.17	6458.17	6868.88	7184.11	7283.80
Hydrogen consumption (10^6 m^3)	3621.10	5729.17	6458.17	6868.88	7184.11	7283.80
Natural Gas - Hydrogen production	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas - Hydrogen production (10^6 MJ)	57575.47	91093.69	102684.89	109215.11	114227.40	115812.38
Total	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
Natural gas (10^6 MJ)	87916.56	126274.37	141734.98	155802.42	153987.93	159029.04
Fuel oil (10^6 MJ)	133977.60	154911.60	172077.48	181707.12	179195.04	177101.64
Fuel gas (10^6 MJ)	17584.56	40193.28	39774.60	40611.96	41868.00	42705.36
Coke (10^6 MJ)	50241.60	64476.72	62383.32	64058.04	65732.76	64058.04
Emissions	**t0**	**t1**	**t2**	**t3**	**t4**	**t5**
CO_2 emissions (Mtonnes/year)	22.78	28.41	30.51	32.02	32.31	32.11

D.III) Shiny scenario

National trades

Table D-15 - Oil derivatives national trades - Shiny 1

		t0				t1					t2					t3					t4					t5				
LPG	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	0.43	-	**SP_S**	-	-	0.07	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	0.43	-	**Total**	-	-	0.07	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Naphtha	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	0.91	-	-	**RJMG_S**	-	0.04	-	-	**RJMG_S**	-	1.18	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	0.74	0.07	-	-	**SP_S**	1.62	0.78	0.37	-	**SP_S**	1.87	-	-	-
	Total	-	-	-	-	**Total**	-	0.91	-	-	**Total**	-	0.04	-	-	**Total**	0.74	1.25	-	-	**Total**	1.62	0.78	0.37	-	**Total**	1.87	-	-	-
Gasoline	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	0.86	-	1.79	-	**SP_S**	1.68	-	1.42	-	**SP_S**	0.92	0.66	0.74	-	**SP_S**	-	-	0.10	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	0.86	-	1.79	-	**Total**	1.68	-	1.42	-	**Total**	0.92	0.66	0.74	-	**Total**	-	-	0.10	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Kerosene	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Diesel	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	0.55	**RJMG_S**	-	0.87	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	1.82	**RJMG_S**	-	-	-	-	**RJMG_S**	-	1.13	-	-
	SP_S	-	-	-	-	**SP_S**	0.18	-	-	-	**SP_S**	-	-	-	-	**SP_S**	1.34	-	-	-	**SP_S**	2.23	-	-	-	**SP_S**	1.94	-	-	-
	Total	-	-	-	0.55	**Total**	0.18	0.87	-	-	**Total**	-	-	-	-	**Total**	1.34	-	-	1.82	**Total**	2.23	-	-	-	**Total**	1.94	1.13	-	-
Jet Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	0.13	**S_S**	-	-	-	0.06	**S_S**	-	-	-	0.29	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.13	**Total**	-	-	-	0.06	**Total**	-	-	-	0.29	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	1.61	**S_S**	-	-	-	1.27	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	0.33	-	0.06	**RJMG_S**	-	0.58	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	0.33	-	1.67	**Total**	-	0.58	-	1.27	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Heating Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Petcoke	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Table D-16 - Oil derivatives national trades - Shiny 1A

		t0				**t1**					**t2**					**t3**					**t4**					**t5**				
LPG	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**	**region**	**S_D**	**NE_D**	**RJMG_D**	**SP_D**
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	0.43	-	**SP_S**	-	-	0.07	-	**SP_S**	-	-	0.22	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	0.43	-	**Total**	-	-	0.07	-	**Total**	-	-	0.22	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Naphtha	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-

	RJMG_S	-	-	-	-	**RJMG_S**	-	0.56	-	-	**RJMG_S**	-	1.18	-	-	**RJMG_S**	-	0.61	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	0.40	1.48	-	-	**SP_S**	0.67	0.46	0.43	-	**SP_S**	-	-	0.22	-
	Total	-	-	-	-	**Total**	-	0.56	-	-	**Total**	-	1.18	-	-	**Total**	0.40	2.09	-	-	**Total**	0.67	0.46	0.43	-	**Total**	-	-	0.22	-
Gasoline	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	0.86	-	1.79	-	**SP_S**	2.31	0.24	0.55	-	**SP_S**	0.45	1.56	0.74	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	0.41	-	-	-
	Total	0.86	-	1.79	-	**Total**	2.31	0.24	0.55	-	**Total**	0.45	1.56	0.74	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	0.41	-	-	-
Kerosene	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Diesel	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	0.55	**RJMG_S**	-	0.83	-	0.35	**RJMG_S**	-	0.63	-	-	**RJMG_S**	-	-	-	1.22	**RJMG_S**	-	-	-	0.17	**RJMG_S**	-	-	-	0.97
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.55	**Total**	-	0.83	-	0.35	**Total**	-	0.63	-	-	**Total**	-	-	-	1.22	**Total**	-	-	-	0.17	**Total**	-	-	-	0.97
Jet Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	0.13	**S_S**	-	-	-	0.18	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-

	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	0.13	**Total**	-	-	-	0.18	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	1.61	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	0.33	-	0.06	**RJMG_S**	-	-	-	-	**RJMG_S**	-	1.17	-	0.45	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	0.04	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	0.09	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	0.33	-	1.67	**Total**	-	-	-	-	**Total**	0.09	1.17	-	0.45	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	0.04	-	-
Heating Fuel Oil	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-
Petcoke	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D	**region**	S_D	NE_D	RJMG_D	SP_D
	S_S	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-	**S_S**	-	-	-	-
	NE_S	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-	**NE_S**	-	-	-	-
	RJMG_S	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-	**RJMG_S**	-	-	-	-
	SP_S	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-	**SP_S**	-	-	-	-
	Total	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-	**Total**	-	-	-	-

Processing units capacities

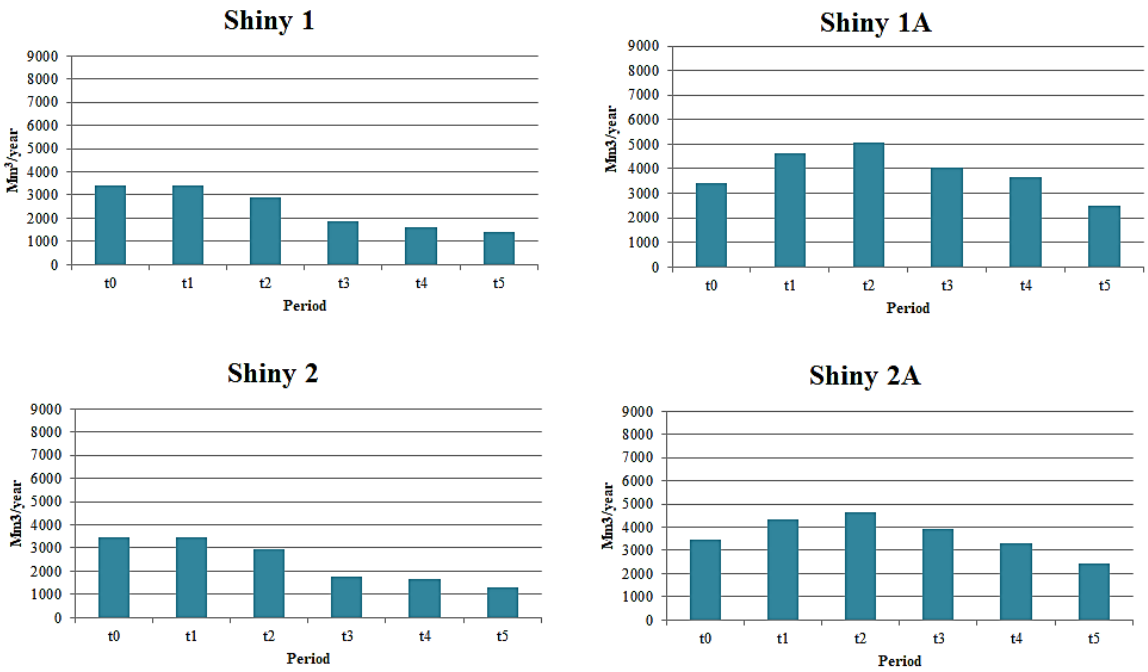

Figure D-8 - UGH level capacities - Shiny scenarios

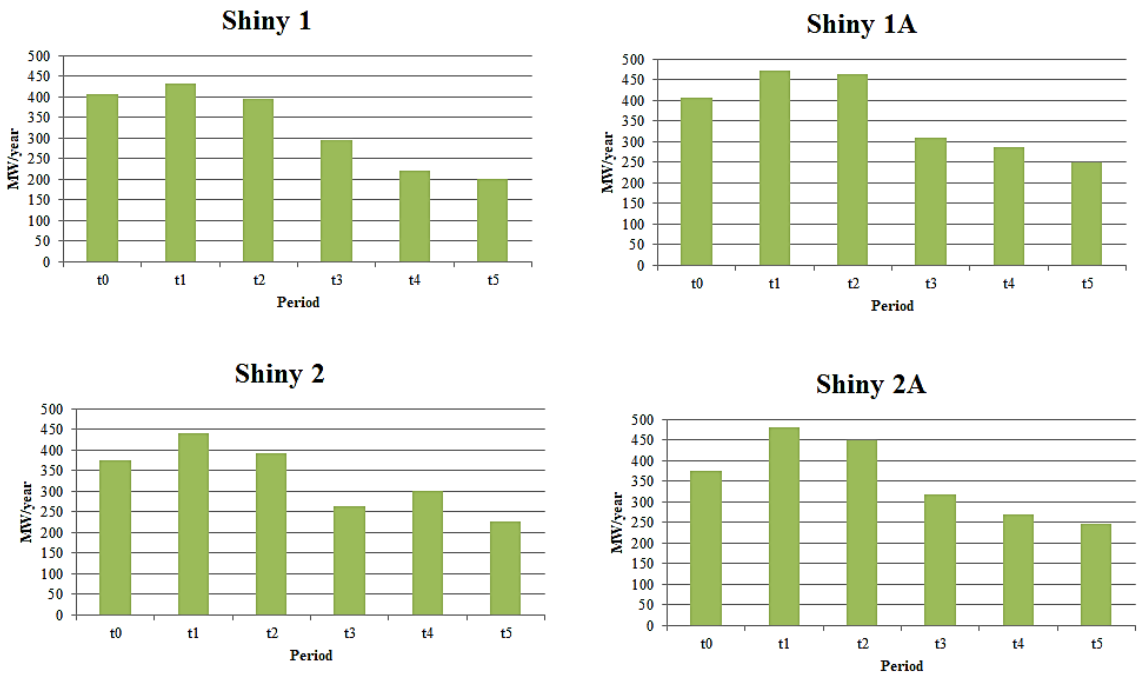

Figure D-9 - Cogeneration level capacities - Shiny scenarios