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Low Hydrology Scenario
for the Brazilian Power Sector 2016–2030

Impact of Climate on Greenhouse Gas Emissions

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Final Report

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Latin America and the Caribbean
Opportunities for all

Low Hydrology Scenario
for the Brazilian Power Sector 2016–2030

Impact of Climate on Greenhouse Gas Emissions

FINAL REPORT

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1st Edition

PREPARED BY PSR CONSULTORIA FOR THE WORLD BANK

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List of contents

Table of figures

List of tables

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The PMR supports countries' efforts to establish post-2020 mitigation scenarios and identify packages of effective and cost-efficient policies—including carbon pricing instruments — to achieve climate change mitigation. Much of this support will facilitate countries' work to prepare the mitigation component for their "intended nationally determined contributions" (iNDCs) under the UNFCCC process. More information about the PMR's post-2020 work can be found on the Policy Work page on our website.

For more information on the Partnership for Market Readiness Program, please visit us at **www.thepmr.org** or write to us at **pmrsecretariat@worldbank.org**.

PREFACE

Publication of the study “Low Hydrology Scenario for the Brazilian Power Sector 2016-2030 - the Impact of Climate on Greenhouse Gas Emissions” represents a milestone in cooperation between the World Bank and the Ministry of Environment, in the studies that provided the technical basis for the elaboration of Brazil´s Intended Nationally Determined Contribution (iNDC), and in the context of the Paris Agreement negotiations.

For a precise analysis of greenhouse gas emissions scenarios covering the period 2020-2025 to reflect Brazil´s determined contribution or, more importantly, the longer period 2020-2030 mirroring the Brazilian indicative contribution up to 2030, it was essential to analyze the low hydrology scenario in the light of the potential impact of climate change on it over the longer term. It was also important to examine the options to mitigate probable adverse effects. These options might involve the increased use of thermoelectric plants in the power matrix, with a consequent increase in the country´s GHG emissions. Low hydrology could therefore make it difficult for Brazil to implement its ambitious iNDC, announced at the UN General Assembly in New York in September 2015 in the run-up to the Paris Agreement.

The main source of electricity generation in Brazil is hydroelectricity, which accounts for 64.7% of installed capacity, and is responsible for supplying over 80% of the country´s electricity in hydrologically normal years, and 60% in unfavorable years. The supply of renewable energy from hydropower sources, together with biofuels - especially sugarcane by-products - accounts for around 42% of the Brazilian energy matrix. This percentage qualifies Brazil as a low-emission energy source country, particularly when compared to the world average (13%) or that of the OECD countries (7%). It is clear that no discussion of a long-term Brazilian emissions scenario would be feasible without a detailed technical study of a low hydrology scenario for the electricity sector.

With the immediate and effective assistance from the World Bank within the framework of the *Partnership for Market Readiness (PMR)*, it was possible to enlist the support of PSR, a distinguished consulting firm with extensive experience in the study of the Brazilian power sector. As a result, we benefited from first-class technical support that enabled Brazil´s iNDC (known as NDC after the Paris Agreement entered into force in November 2016) to be recognized nationally and internationally as one of the most ambitious contributions for achieving the Agreement´s objectives: to limit the increase in the average global temperature by a maximum of 2 degrees Celsius in relation to the pre-industrial era, and to make efforts to ensure that temperatures increase by no more than 1.5 degrees Celsius. We hope that this innovative study, now edited and also available in English, will help practitioners and others in the water, energy and agriculture sectors in Brazil and elsewhere to be increasingly aware of the risk associated with climate change, in particular with regard to its impact on emissions in these sectors.

The Ministry of Environment is proud to have contributed to this study and wishes to record its thanks and appreciation to our partner, the World Bank, for the excellent work which led to the publication of the study.

By engaging in the responsible technical debate on the future of Brazil's greenhouse gas emissions, and consolidating Brazil´s leading role in combating global climate change - especially by working hard towards a low gas emissions future - we hope to continue making a creative and practical contribution to building a better future for all.

EVERTON LUCERO
Secretary for Climate Change and Forests
Ministry of the Environment

ACKNOWLEDGEMENTS

This report, under the direction of Christophe de Gouvello, Senior Energy Specialist and Coordinator of the World Bank's Climate Change agenda, together with Thadeu Abicalil, Senior Water and Sanitation Specialist, was prepared at the request of the Secretariat for Climate Change and Forests (SEMCF) of Brazil´s Ministry of the Environment by the PSR Team comprising Rafael Kelman (coordinator), Pedro Avila, Bernardo Bezerra and Ana Carolina Deveza. Jose Domingos Gonzalez Miguez and Adriano Santhiago de Oliveiro coordinated SEMCF oversight. Special thanks are due to Newton Paciornik for his contribution to the technical review of the intermediate documents.

The World Bank and the Secretariat for Climate Change jointly organized a number of in-house seminars which provided an opportunity for Brazilian and other experts to discuss methodology and preliminary results.

Under the leadership of Antonio Barbalho, Practice Manager for the World Bank's Energy Sector for Latin America, the report received contributions from World Bank reviewers Erwin de Nys, Senior Water and Sanitation Specialist and Program Coordinator, Rikard Liden, Senior Hydropower Specialist, and Thierry David, Senior Water Resources Management Specialist. Thanks are also due to the administrative support team at the World Bank office in Brasilia, in particular to Zélia Brandt de Oliveira and Victor Neves.

This work was carried out with the support of the Partnership for Market Readiness (PMR) program of the World Bank's Climate Change Cross-Cutting Solution Area involving three World Bank areas: the Energy Sector, the Water and Sanitation Sector and the Climate Change Area.

The authors are also grateful to the organizations and entities which generously shared their knowledge and impressions during the preparation of this study. Errors or omissions are the sole responsibility of the authors.

INTRODUCTION

1.1 Background

The main source of power generation in Brazil is hydroelectricity. In 2016 this represents 64.7% of installed capacity and isl responsible for the largest share of Brazil´s energy market, supplying over 80% of the country´s electricity in hydrologically normal or favorable years, and 60% or more in unfavorable years.

1. To facilitate the development of proposals for mitigating emissions through the deployment of economically efficient tools based on a sound analytical study;
2. To contribute to the ongoing work of the UNFCCC; and
3. To promote international contributions to Brazil´s mitigation efforts.

This study, prepared for the World Bank, and the Ministry of Environment (MMA) in the context of the *Partnership for Market Readiness (PMR)*.

Thanks to the large-scale development of renewable energy over the years, especially ethanol and hydroelectricity, Brazil´s energy matrix is relatively "clean" by international standards. Increasing environmental constraints on new hydroelectric power plant developments have however had the following interrelated effects:

- A significant relative reduction in energy storage capacity due to the trend over the last 20 years for building run-of-the-river (ROR) hydroelectric plants, with little or no water storage and limited ability to regulate inflow levels;
- More thermal power plants have therefore been built to offset the seasonal and intermittent supply of renewable energy, resulting in a relative increase of fossil fuel burning plants in the energy matrix, leading to increased GHG emissions;
- Increased vulnerability of Brazil´s power system to climatic variations;

Figure 1 presents the SIN water storage level in relation to the storageable maximum. It can be observed that the years 2014 and 2015 together correspond to the lower storage limits for the greater part of the months concerned. Two reasons possibly account for these extreme values: (i) the impact of climate change on the inflows; and (ii) the unsatisfactory estimation of the storageable volumes in the SIN reservoirs.

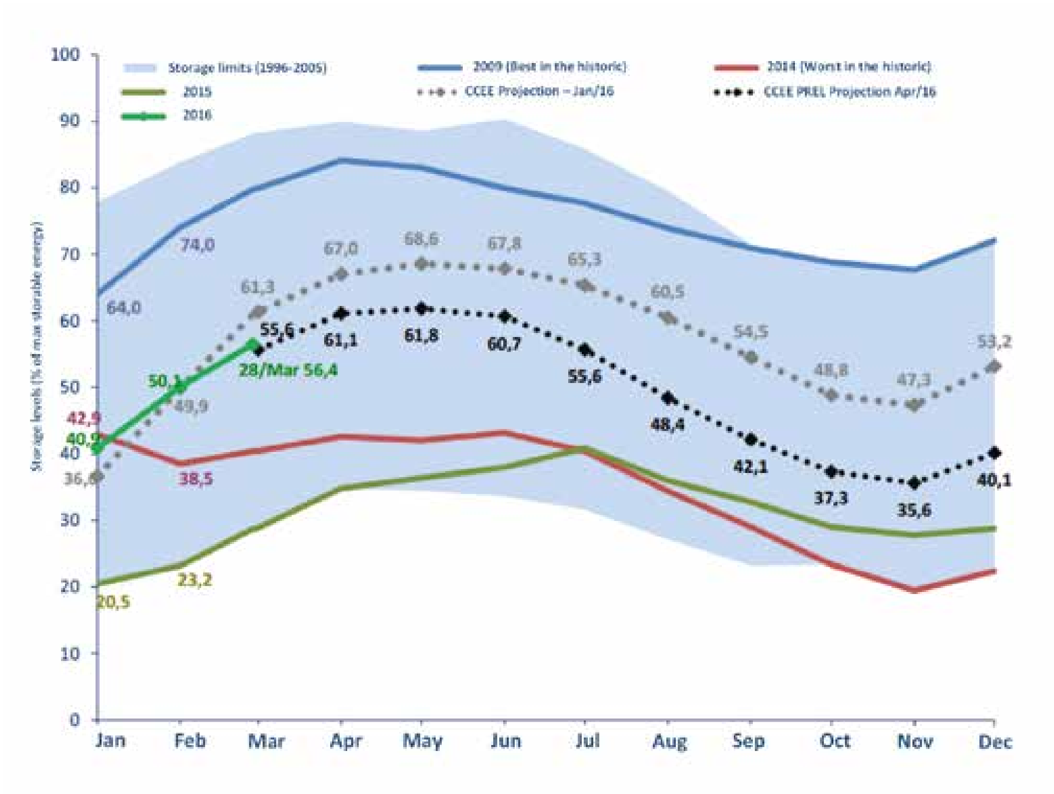


FIGURE 1 - Projection of stored energy (Source: CCEE)

In contrast to the increase in thermal energy production, greenhouse gas emissions from Amazon deforestation have reduced by 80%. According to INPE, the annual deforestation rate in Brazil peaked in 1995 at 30,000 km^2 (equivalent to the size of Belgium), while in 2013 newly-deforested areas amounted to less than 6000 km^2 per year. Although these are still substantial figures, and clearly there is still considerable room for “closing the circle” of deforestation, progress in reducing deforestation has been such that *The Economist* magazine called it the world´s sixth most effective way of reducing greenhouse gas emissions (the *Montreal Protocol* came first).

While deforestation has been reduced, thermal power generation has become a major driver of emissions in Brazil. Figure 2, prepared by PSR, shows the amount of thermal power generated for the Brazilian power grid (National Interconnected System - SIN) since 2011. The vertical axis indicates thermal energy production in average MW. The low hydrology years 2014-2015 cast new light on climate variability impacts on the country´s GHG emissions, while Brazil’s demand for electricity - needed for economic development and the fight against poverty - will continue to grow in the coming decades.

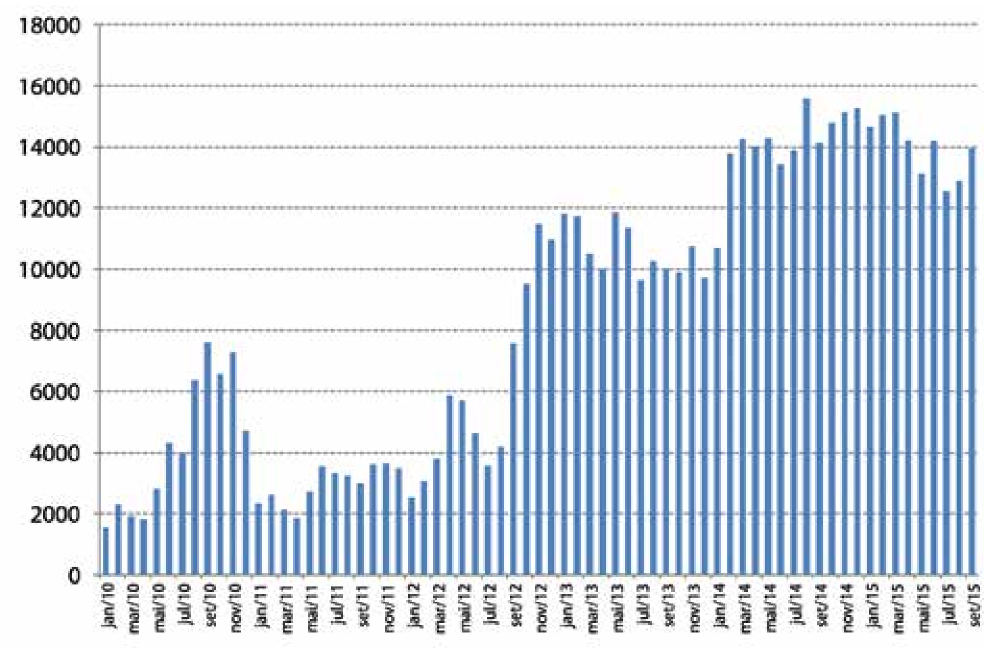


FIGURE 2 - Thermal power generation in the SIN (average MW) (Source: ONS)

The increasing trend in thermal power generation needs to be taken into account when designing strategies to contribute to global climate mitigation efforts.

While the impact of climate change on the output of hydroelectric plants still needs to be understood and scientifically quantified, it is essential to anticipate the consequences of worst-case hydrology scenarios from the standpoint of Brazil´s energy security. It is also vital to consider strategies to protect the country from the risk of increased power sector-related CO_2 emissions. These concerns could become a core aspect of policy recommendations on climate issues and the design of new economic instruments, and are now a new factor in Brazil´s approach to *Nationally Determined Contributions (NDC)*.[1]

1.2 Specific objectives

The World Bank contracted PSR to evaluate the variability of greenhouse gas emissions from the Brazilian power sector due to hydrological fluctuations. It is worth recalling that hydropower is still responsible for the largest share of Brazil´s energy market, supplying over 80% of the country´s electricity in hydrologically normal or favorable years, and 60% or more in unfavorable years.

[1] Mechanism to encourage countries to contribute to GHG reduction, known as *Nationally Determined Contributions* (NDCs).

The study seeks to characterize GHG emissions in Brazil´s National Interconnected System (SIN) over different timescales. The annual variability of emissions is a key indicator. Given that Brazil´s energy system depends largely on hydropower, emissions can vary greatly between favorable and unfavorable hydrologic years.

From the climatic standpoint it is important to evaluate the *cumulative* effect of GHG emissions over an extended time horizon. For this study we chose year 2030 as our evaluation horizon, considering the capacity increase over the years to meet the projected demand for energy. We studied a reference case based initially on the 2014-2023 Ten Year Energy Plan (PDE) of the *Empresa de Pesquisa Energética* (EPE) (Brazilian Energy Planning Agency), with some premises adjusted by PSR, such as delays of certain projects. The projects at the end of the horizon are based on PSR´s best assessment of the evolution of competing energy sources.

Our particular interest was to establish an emissions scenario related to low hydrology conditions that trigger additional energy generation by fossil fuel thermal power plants. We took a probabilistic scenario approach by using aggregate indicators of hydrological conditions and, more specifically, by using probability distribution indicators of the Natural Inflow Energy (ENA) of the SIN. The study employs a *bottom-up* methodology based on the reference case and assumes that future inflows will repeat those of the past (‘stationary inflow hypothesis’).

To complement this hypothesis, we also adopted a top-down methodology, which involved processing the results of general climate circulation models (GCM) by using downscaling techniques to produce data suitable for the hydrological modeling of Brazil´s watersheds.

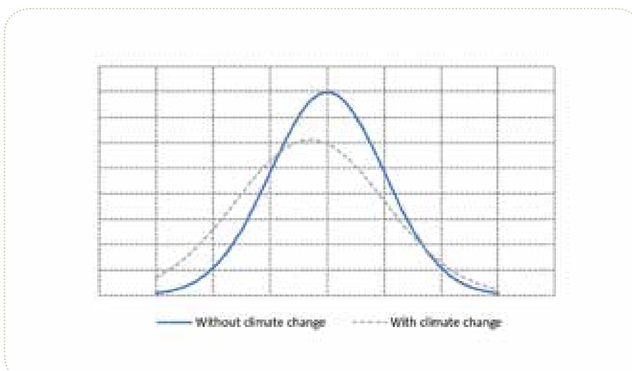
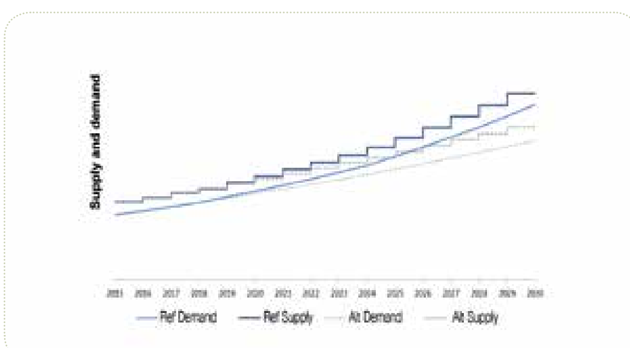
To consider an alternative that could offset the increase in GHG emissions, PSR prepared, in collaboration with COPPE/UFRJ, an alternative generation expansion case involving the replacement of fossil fuels based energy sources by renewables such as wind, solar and biomass. Used together, these sources would meet anticipated demand with the same reliability criteria. In addition to the substitution of energy sources, this scenario also assumed, for the same macroeconomic conditions and expected population growth, a lower demand for electricity that results from the implementation of more robust energy efficiency and distributed generation measures.[2]

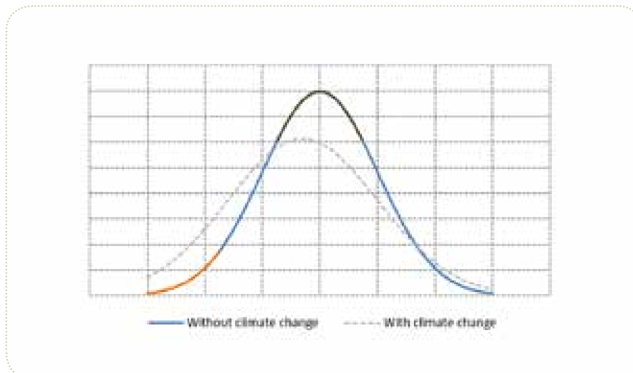
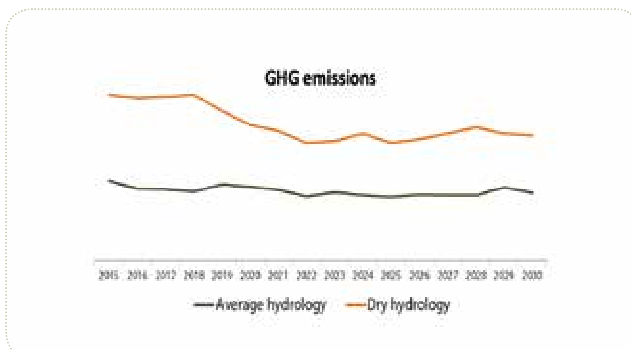
Broadly speaking, this report is aimed at introducing a differentiation between the conventional “climate risk”, which reflects into the variability observed in historical series of water inflows and the new “climate change risk”, which undermines the assumption of stationary inflow according to which future water inflows in reservoirs will statistically repeat those of the past. While the “climate risk” and corresponding uncertainty is already dealt with in the sector planning methods and tools for a few decades, the “climate change risk” has not yet been internalized by the sector in Brazil.

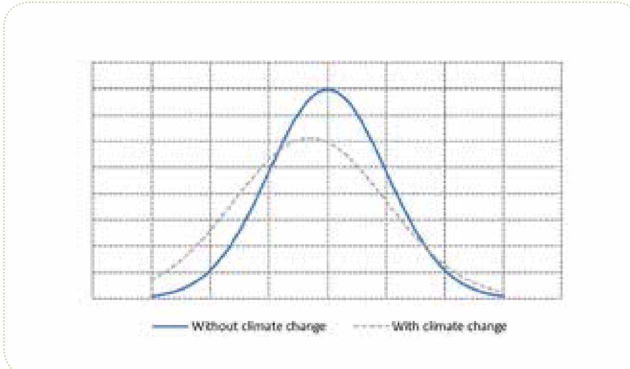
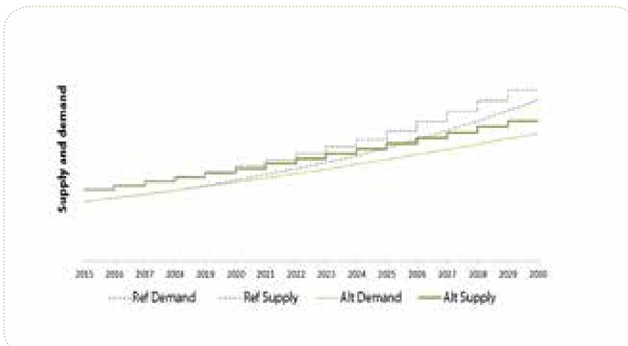
Table 1 below presents the methodology used in each chapter, both in terms of hydrological variability and for preparation of the supply and demand plan. The images are for illustration purposes only.

[2] In addition, a preliminary and exploratory work was conducted to start analyzing the potential impact of increasing competition between the different water uses, in particular in terms of water withdrawals from river basins, mainly for irrigation, in case of a low-hydrology. The results of this preliminary study are presented in a separate Appendix, which can be made available upon request : “Appendix 1: Impact of irrigation growth on GHG emissions of the power sector in case of low-hydrology in Brazil (2015-2030) – A Preliminary Analysis”.

CHART 1 - Case study methodology

CHAP./ SESSION	CASE	HYDROLOGICAL VARIABILITY / EXPANSION OF SUPPLY AND DEMAND
1	-	**OBJECTIVE**: General presentation of study on emissions.
2	Reference	**OBJECTIVE**: To present the assumptions for construction of the PSR expansion plan, comparing expected demand on the one hand (the result of the macroeconomic model) to energy supply associated with existing projects that have already been contracted in energy auctions, and future technologies (related to regional potential).
3	Reference	**OBJECTIVE**: To present variability of results obtained from the simulation of the SIN operation for the reference case. **RESULTS**: Power generation, GHG emissions, operating and marginal costs.
3	Reference	HYDROLOGICAL VARIABILITY  EXPANSION OF SUPPLY AND DEMAND 

CHAP./ SESSION	CASE	HYDROLOGICAL VARIABILITY / EXPANSION OF SUPPLY AND DEMAND
4.1	Reference	**OBJECTIVE**: To characterize “dry” hydrology as a subset of hydrological series simulated in the SDDP for the reference case. **RESULTS**: Accumulated GHG in the SIN may vary 2x in the 2030 timeframe and 4x in a given year depending on the hydrology. HYDROLOGICAL VARIABILITY  EXPANSION OF SUPPLY AND DEMAND 
4.2	Climate change	**OBJECTIVE**: To evaluate the impact of climate change on hydrologic availability (future inflows no longer repeat past inflows) according to a *top-down* approach and its results in the operation of the SIN (GHG emissions, costs, etc.) for demand of the reference case. **MAIN RESULTS**: The scenarios indicate a structural imbalance between supply and demand caused by reduction of water availability in the reference case. SDDP indicates electricity rationing, major increases in operating costs and GHG emissions increasing as the result of thermal power plants being activated at full capacity. There is a need to review the *top-down* approach (regionalization of the global circulation model followed by rainfall/runoff flow modeling). An adaptive measure would involve the need to devise a new expansion plan involving more investment in thermal power plants in order to balance the SIN and therefore offset lower water availability (the new plan, illustrated below, was not used in the study).

CHAP./ SESSION	CASE	HYDROLOGICAL VARIABILITY / EXPANSION OF SUPPLY AND DEMAND
5	**Alternative**	**OBJECTIVE**: To evaluate emissions for the alternative expansion case that considers a reduction of 15% in energy consumption in 2030 due to greater energy efficiency and distributed generation. **RESULTS**: Average accumulated GHG emissions of the SIN reduced by 20%. HYDROLOGICAL VARIABILITY  EXPANSION OF SUPPLY AND DEMAND 
6	**Conclusions**	**OBJECTIVE**: To present the main conclusions of the study by comparing the results of the different cases evaluated.

2 EXPANSION OF SUPPLY AND DEMAND

This chapter outlines the various assumptions used for designing the PSR expansion plan (reference case) related to projected electricity supply and demand. We focus on projects that are already in operation or those contracted in the energy auctions. For the longer term, unspecified technology-based projects are used in the energy simulation.

2.1 Methodology

The Expansion Scenario represents the evolution of the energy generation matrix and major transmission trunks, with energy supply growth requirements quantified to ensure that this scenario is an acceptable framework that meets energy supply quality standards. Figure 3 presents an overview of the methodology:

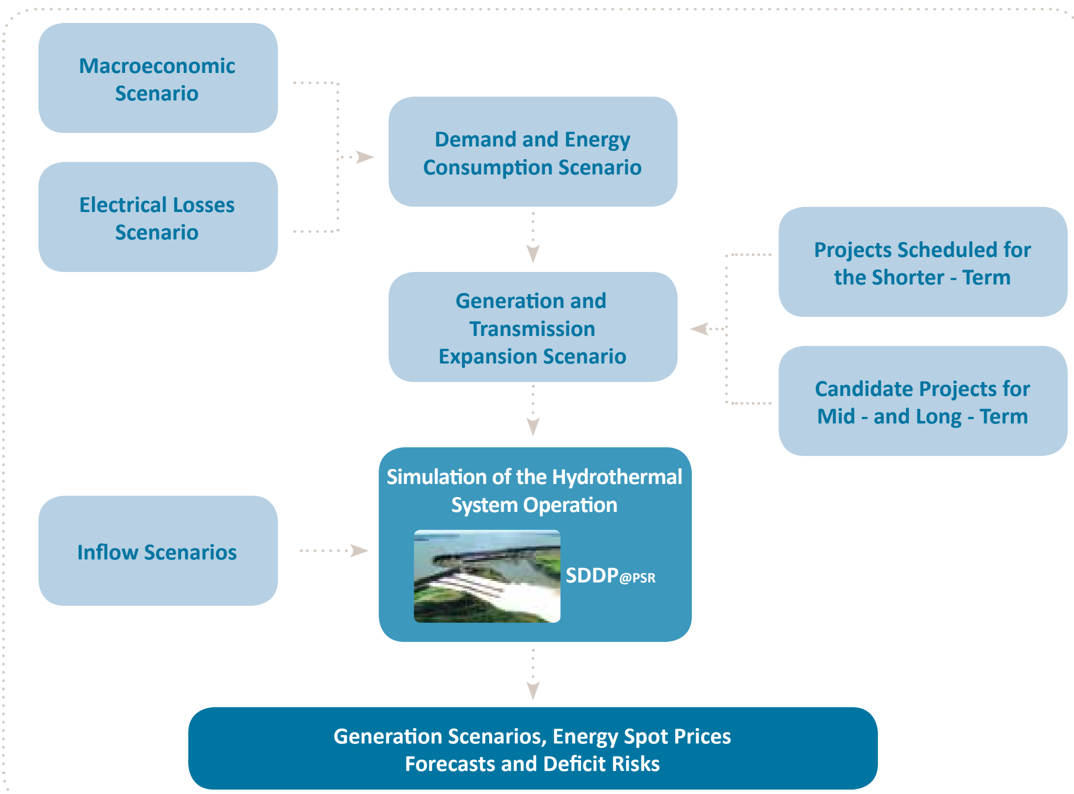


FIGURE 3 - Overview of the methodology

We begin by the macro-economic assumptions that provide the “inputs” needed for an energy market projection.

Water inflows scenarios were generated to determine the Natural Inflow Energy (NIE)[3] that can be used by the hydropower plants of the system. The calculation of these scenarios takes into account the historical series of the natural water inflows. These historical series come from the National System Operator (NSO)[4] data base.

We constructed a supply scenario for this projection that minimizes the sum of investment costs in new projects and operating costs. An energy simulation of the SIN was made using a proprietary stochastic energy dispatch model - SDDP (*Stochastic Dual Dynamic Programming).*

The calculation of SIN greenhouse gases emissions was done by considering the energy output of each thermal plant (MWh) in terms of its individual emission factor (tCO_2/MWh), as follows:

- If $g(j,t,s,k)$ is the thermal output of the thermal plant j, in month t, hydrological scenario s and load level k (MWh).
- The individual plant emissions are $g(j,t,s,k) \cdot \phi(j)$, where $\phi(j)$ is the unitary emission factor of the plant, in tCO_2/ per MWh.
- Total emissions in year y and in each scenario s are represented as:

$$E(y,s) = \sum_{j} \sum_{t \in y} \sum_{k} \phi(j) \cdot g(j,t,s,k)$$

EQUATION 1

2.2 Long term demand projection

Consumption projections were made for residential, industrial, commercial and other sectors, considering the following assumptions:

- A macroeconomic scenario, with the key variable being the GDP growth rate;
- A population growth rate scenario as indicated in Table 1.

[3] In Portuguese: Energia Natural Afluente (ENA).

[4] In Portuguese: Operador Nacional do Systema (ONS).

TABLE 1 - Population growth rates (Source: IBGE)

REGION	2010	2015	2020
North	1,30%	0,97%	0,78%
Northeast	0,86%	0,66%	0,54%
Southeast	0,83%	0,63%	0,52%
Midwest	1,32%	0,98%	0,80%
South	0,73%	0,56%	0,56%
Brazil	**0,90%**	**0,58%**	**0,56%**

- Estimates for the future performance of certain technical parameters such as income-consumption elasticity (based on historical market data) and the level of electrical losses in the system (see Figure 4), together with considerations of the probable future characteristics and profiles of this market.

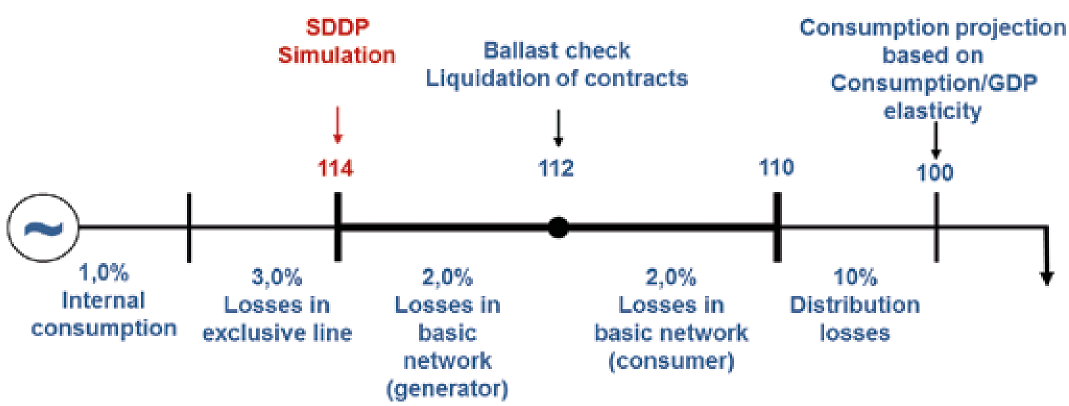


FIGURE 4 - Estimate of future technical parameters and electrical losses

Figure 5 illustrates the demand projection process:

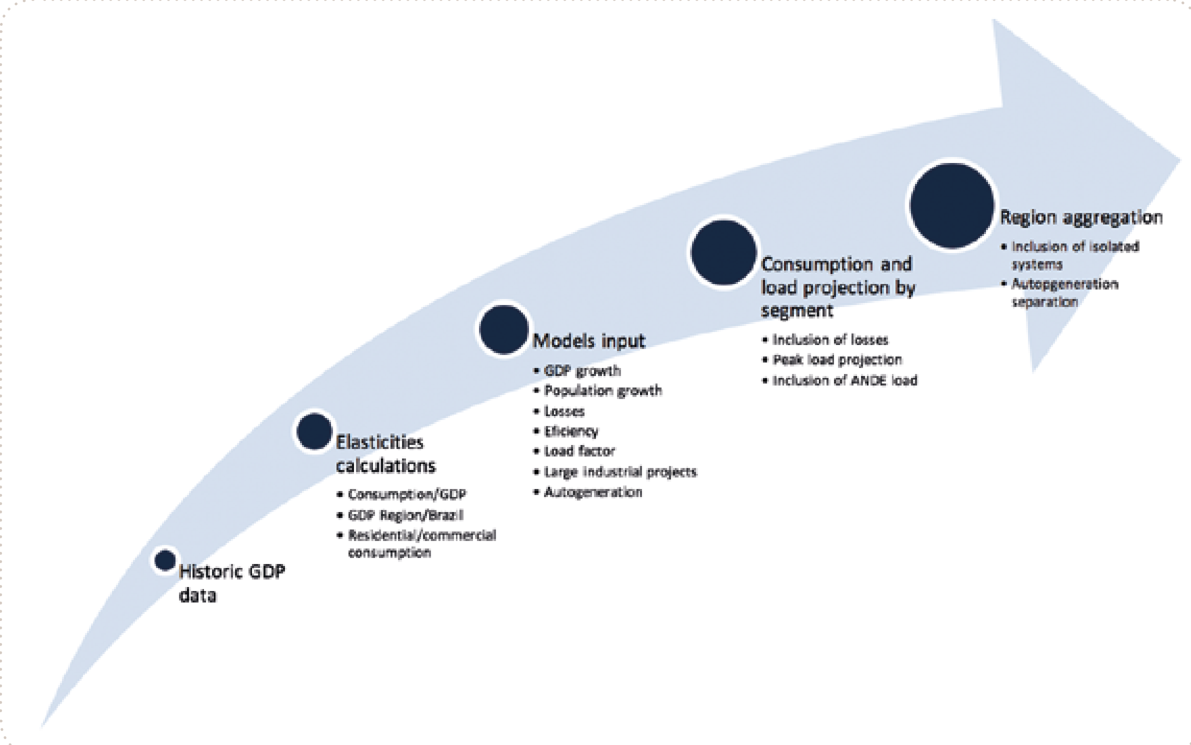


FIGURE 5 - Demand projection process

Based on consumption projections and additional assumptions regarding power loss trajectories, the forecast energy loads[5] for each of the four Interconnected Power Subsystems (North, Northeast, Southeast / Midwest and South) as well as for the entire SIN.

For the horizon 2015-2018, the macroeconomic scenario used in this study is based on estimated national GDP growth[6] according to the Brazil´s Central Bank´s FOCUS report of 31 December 2014. For 2020-2030 we assumed a constant annual GDP growth of 3.5%.

TABLE 2 - GDP growth projection

PERIOD	2016	2017	2018	2019	2020	2021-2025	2026-2030
GDP growth	-2%	1.3%	1.9%	2.1%	2.3%	3.0%	3.5%

[5] Total amount of energy required by the subsystem in a given period. Includes all energy losses between production and consumption.

[6] The values presented in this report for GDP growth projections and GDP / consumption elasticity already take into account the new IBGE methodology. Unlike the forecasts made in September 2015, the figures shown here for 2015 and 2016 are higher. However, the medium and long-term impact is small and does not justify reprocessing the simulations.

Figure 6 shows a consolidated projection for the required energy requirement up to year 2030, including the load from ANDE (Paraguay). In the case of ANDE it is worth noting that from 2023 aluminum plants may be installed in Paraguay under the terms of the Itaipu Treaty. PSR´s scenario envisages this Paraguayan load will translate into energy market growth for Brazil of 6% per annum between 2014 and 2017, 11% per annum in 2018-2023 and 6% per annum in 2024-2030.

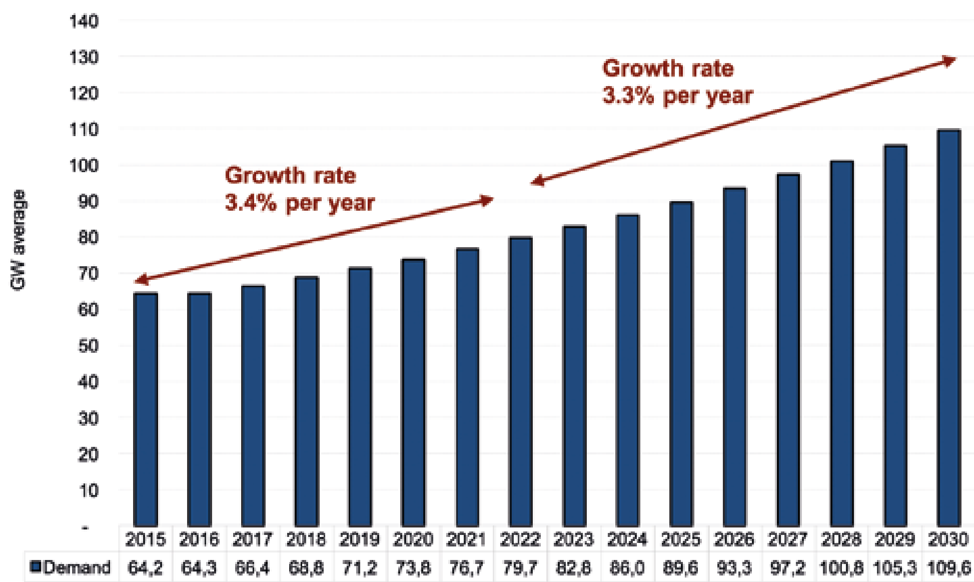


FIGURE 6 - Projected Energy Requirement

2.3 Criteria for expansion of the supply

After preparing the demand projection scenario, the next step was to set a target scenario for the expansion of the electricity supply. This scenario covers power generation projects and transmission interconnections between subsystems.

The Expansion Scenario reflected the growth trend of the Brazilian power sector (given the available expansion options) and was consistent with the previously addressed energy market scenario.

The Expansion Scenario considers the *competitiveness* of the different technologies (in terms of minimum overall cost for consumers) and the *regulatory aspects* of the Brazilian system that influence the expansion of the system.

The three main regulatory issues that influence total supply are:

1. The contractual requirement to meet 100% of demand, with contracts guaranteed by an equal number of physical guaranteed power output certificates (Figure 7);

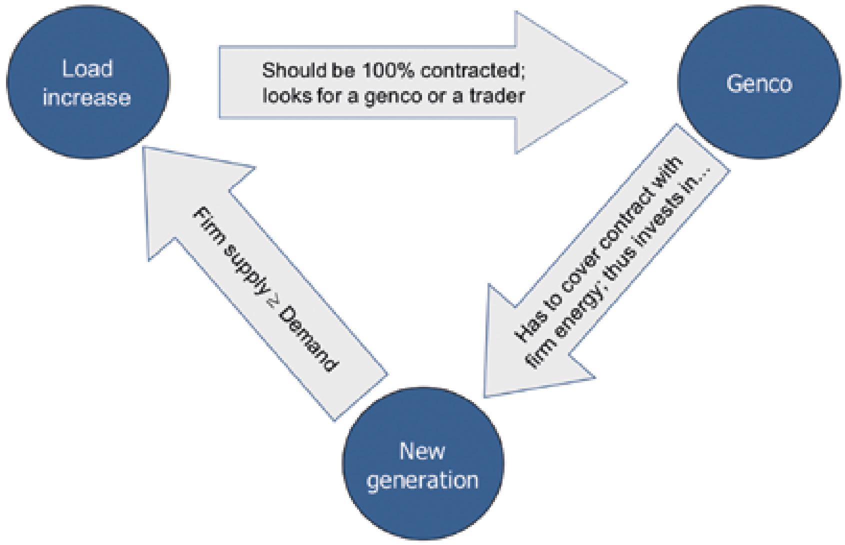


FIGURE 7 - Consequence of the requirement for 100% demand coverage

2. In view of demand growth uncertainties, distributors employ strategies in auctions that generally involve *over-contracting*, which results in increased total energy supply;

3. Reserve energy auctions, recently proposed by the government, can also lead to *over-supply*.

Given the above, we conclude that regulatory aspects (1) and (2) do not justify producing energy over and above market requirements. Over-supply is more easily justified by contracting reserve energy (item 3 above), but this is clearly a policy decision to be taken by government.

Other regulatory issues also affect the "mix" of power generation technologies in the expansion of the system:

- So-called 'structuring' projects such as the plants in Rio Madeira and Belo Monte plant in Xingu, which are determined by the government, with mandatory contracting in the hands of distributors.
- The A-3 and A-5 auctions, with lead times of 3 and 5 years, determine the level of involvement in system expansion of both types of power plants: The longer construction times for Hydropower Plants (HPP) mean that they can only compete in A-5, while thermoelectric plants can compete in both A-3 and A-5 auctions.
- The reserve energy auctions will probably be skewed towards renewable energy sources. This was the case, for example, of the 2008 reserve auction exclusively targeted at biomass plants, and the December 2009 auction, exclusively for wind energy.

Each of these items are discussed below.

2.4 Long-term expansion options

To identify the need for additional generating capacity from 2020 onwards, preparation of the energy supply Expansion Scenario focused on the availability and competitiveness of candidate projects and other system expansion criteria.

Figure 8 shows the options for system expansion from 2020.

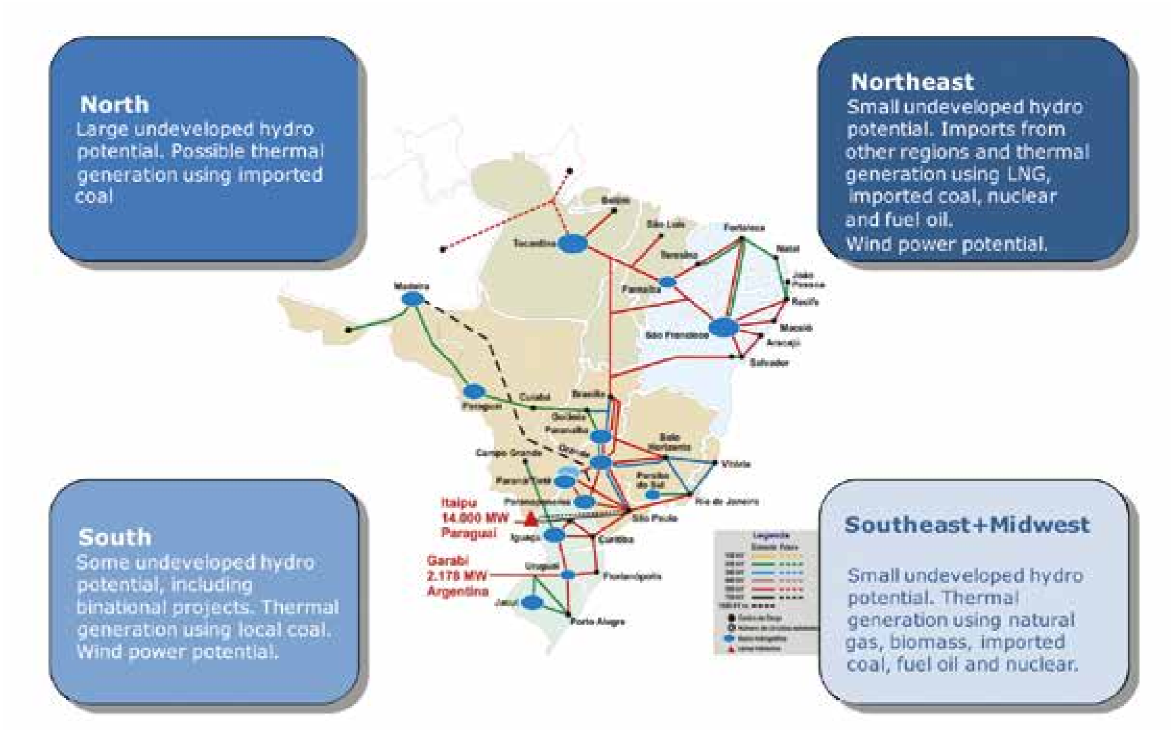


FIGURE 8 - Power generation expansion options

Expanding energy supply is faced with major challenges such as:

- Hydroelectric plants: environmental licensing;
- Gas-fired plants: adverse contractual conditions imposed by PETROBRAS on natural gas supplies for thermal power plants discourages competitors. Brazil has no natural gas policy.
- Renewables:
    - Small Hydropower Plants (SHP): Increasingly difficult to develop good projects; increasing problems with environmental licensing; and new MME/ANEEL regulations (physical guarantee review and expulsion from the Energy Reallocation Mechanism - MRE) deter investors;
    - Cogeneration from sugar cane biomass: bioelectricity should be the most promising energy source (leveraging increased ethanol production), but ethanol-based power output has been less than expected due to low gasoline pricing and network connection problems;
    - There is a substantial window of opportunity for wind power to become the most competitive source of energy to be offered in new auctions, both in terms of volume and price.

Opportunities for each energy source in the Expansion Scenario are discussed below.

2.4.1 Hydroelectric plants

Despite the shortage of inventory surveys and economic feasibility studies on hydroelectric power plants, the studies being prepared by EPE should result in new hydroelectric power generation projects being offered in energy auctions for plants to commence operation starting 2021. The new projects could however face environmental licensing setbacks - definitely the largest obstacle to developing future hydropower generation in Brazil.

Figure 9 shows the new hydroelectric projects in order of priority:

FIGURE 9 - Prioritization of HPPs

Environmental barriers also have to be considered in each project. However the government´s stategic decisions can result in projects being selected that do not conform to the above criteria.

2.4.1.1 CNPE

According to CNPE Resolution No. 03/2011, the following strategic, public interest, structuring power generation projects are to be awarded high priority:

- HPP São Luiz do Tapajós (5,918 MW):
    - Total of 31 turbines, motorization May 2022 to July 2027;
    - Guaranteed power output of 3,264 MW.
- HPP Jatoba (2,336 MW):
    - Total of 40 turbines, motorization January 2024 to July 2028;
    - Guaranteed power output of 1,265 MW.
- HPP Jardim do Ouro (227 MW):
    - Total of 4 turbines, motorization July 2022 to April 2023;
    - Guaranteed power output of 102 MW.
- HPP Chacorão (3,335 MW):
    - Total of 21 turbines, motorization January 2026 to May 2029;
    - Guaranteed power output of 1,728 MW.

2.4.2 Conventional thermal power plants

Even where hydroelectric projects are plentiful and unencumbered by environmental restrictions, expanding energy generation at the lowest cost for consumers involves a "mix" of hydroelectric and thermal power plants to complement one another. Thermal plants contribute to the operational safety of the system by being activated when the hydrology is unfavorable, while during favorable hydrologic periods the hydropower plants come into operation and the thermal plants are shut down, thus saving costs.

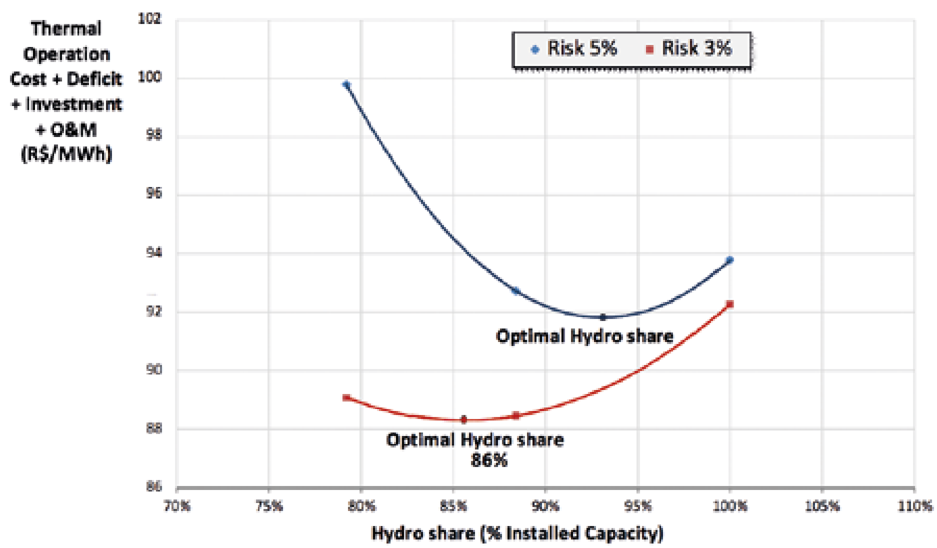


FIGURE 10 - Hydropower linked to risk

A further important feature of "flexible" thermal plants is "dispatchability", measured by their ability to be activated in no particular sequence or "order of priority", whenever unexpected events occur in the system.

As for the different energy supply alternatives, conventional thermoelectric, natural gas, coal and fuel oil plants are the obvious choices.

2.4.2.1 Natural Gas

In systems dominated by hydropower, such as in Brazil, the use of NG thermal generation faces a major challenge: how to reconcile gas price volatility with beneficial returns on gas industry investments. Since it is not economical to build a production and transport infrastructure for a gas-fired plant to remain idle for long periods, the construction of the necessary infrastructure is not viable unless contracts between NG producers and thermal plant operators contain *Take or Pay* and *Ship or Pay* clauses. Such clauses however tend to reduce the economic attractiveness of new natural gas thermal plants.

In this scenario, Liquefied Natural Gas (LNG) emerged as an attractive power generation alternative. Regasification terminals were built at Pecém and in Rio de Janeiro, and strategic projects are planned in Rio Grande do Sul, Bahia and at Suape to enhance supply flexibility and reduce dependence on Bolivian gas imports. Although LNG prices are more volatile, usually tied to international gas spot-price markets such as the *Henry Hub*[7] , contracts can be flexible (e.g. with no *take or pay* clauses). This type of flexible operation is highly attractive to the Brazilian system: given that energy spot prices may be low for much of the time, a flexible plant can meet its contractual obligations by purchasing "cheap" power in the short-term market. In this way the plant can save fuel costs and increase competitiveness when prices rise (compared with a plant with a *take or pay* clause).

LNG contracts normally contain clauses that increase price volatility (*Henry Hub* price indicator, number and size of LNG vessels, advance contracts, etc.). From 2007, contracts offered in the new energy auctions were indexed to regasified NG prices.

This situation changed in early 2011 when the contracts for supplying NG offered at the 2011 A-3 energy auction reverted to *take or pay* clauses. The main reasons for this *volte face* included: (i) the cyclical over-supply of local NG, produced mainly in the Santos and Espírito Santos basins; (ii) onshore NG discoveries in Brazil[8] ; (iii) low international NG prices (*Henry Hub*) due to shale gas development in the United States[9] ; and, finally, (iv) appreciation of the Brazilian currency.

Since late 2011 further changes have taken place due to: (i) a change in the NG regulatory model used in the energy auctions; and (ii) the change in the price of NG. The regulatory change was based on two Government Directives: Ordinance No. 52 of the National Agency for Petroleum, Natural Gas and Biofuels (ANP), published on 29 September 2011, and MME Ordinance No. 514 of 2 September 2011, which state that all NG contracts must be backed by proven NG reserves. PSR believes that further regulatory changes should take place to enable NG based thermal power projects to compete in the next auctions.

[7] The *Henry Hub* is a pricing mechanism for natural gas futures traded on the NY Stock Exchange.

[8] The main onshore gas reserves are located in the Parnaíba and São Francisco basins. Since these are located in regions with low potential for industrial and residential gas consumption, the main anchor for the monetization of the reserves would be inflexible thermoelectric plants.

[9] According to the EIA, the prospective natural gas price for the next ten years was around 7 US$ per MMBTU. EIA´s Energy Outlook 2011 projection points to a mean price of 4.5 US$ per MMBTU.

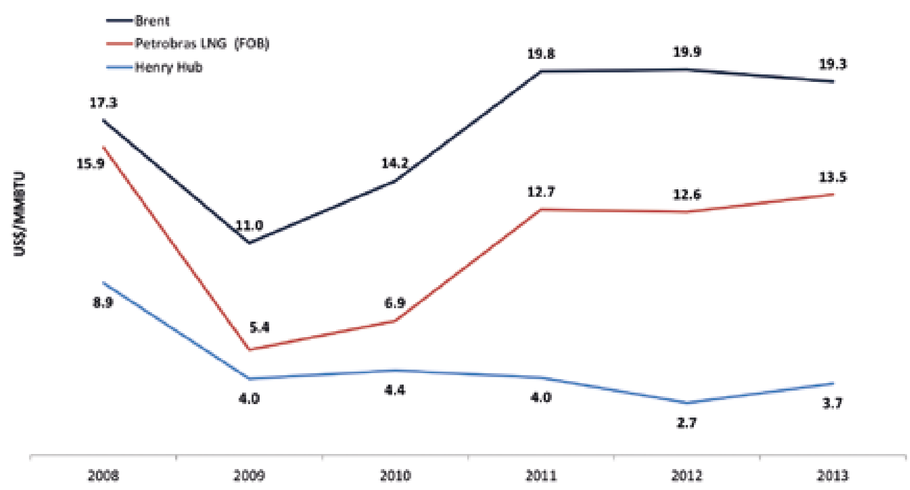


FIGURE 11 - Price evolution of LNG in Brazil

Another issue concerns (i) the shale gas discoveries in the United States and the restrictions on building liquefaction facilities for exporting LNG, both of which had a negative effect on the *Henry Hub* price, and (ii) the Fukushima nuclear disaster, which led to increased gas exports to the Pacific Basin. Since natural gas prices in this area are oil-indexed, LNG price formation migrated from the *Henry Hub* to the North Sea *Brent* crude oil index. Figure 10 compares the FOB prices paid by PETROBRAS for LNG cargoes using the two indices. Since 2011 LNG prices have increased from 5.4 to 13.5 US$ per MMBTU in line with Brent price trends, while the *Henry Hub* index remained at under US$4 per MMBTU.

Given these two barriers for the development of gas-powered plants, PSR considers that the new plants will not win auctions until 2016. It is assumed that NG plants will be auctioned in the 2015 A-5 auction, to start operation in 2020.

For this study, two types of thermal plants were considered in the expansion scenario: gas-fueled plants fulfilling *take or pay* requirements of 50% over the fuel supply contract, and 100% flexible NG plants.

2.4.2.2 Coal

Given that Brazilian coal production is confined to the south of the country, it follows that coal is the predominant choice for thermoelectric expansion in that region. In Brazil´s other regions imported coal can be an interesting alternative, since coal is relatively plentiful globally and can be relied upon as a secure fuel supply. An additional point is that coal is less subject to the geopolitical problems that oil and gas entail.

Concern has been expressed about this energy source in view of the increased coal prices in the international market over the last year, and the levels of CO_2 emissions from coal which have been resisted by environmentalist movements. Although the Brazilian government clearly intends to discourage the development of new coal-fired plants, the latter were nevertheless authorized to participate in the A-5 auction in 2014. This mirrors the government’s concern with the shortage of hydroelectric projects being offered at auction, as well as problems with gas supplies.

The reference case considers coal-based technology as a candidate for the new energy auctions, given that the auctions provide a window of opportunity for developing this energy source in view of the restrictions faced by natural gas.

2.4.2.3 *Fuel Oil*

Given their short construction times (one to three years), fuel oil (FO) power plants are a good alternative during periods of uncertain demand growth. FO projects can be quickly offered in new energy A-3 auctions where developments using other technologies are burdened with lengthy time constraints on construction, or inability to produce the required volumes of energy. The main uncertainty of FO technology concerns oil prices: given the volatility of international oil-linked commodity prices, the price of oil negotiated with local distributors can make sales of the energy produced by FO plants unviable. Furthermore, as with coal, there is mounting concern about FO emissions levels. Since 2007 the government has restricted the participation of fuel oil in the new energy auctions by introducing a cap on the variable unit cost of thermal power plants. This cap was reduced year on year, reaching 146 R$/MWh in 2011 which ruled out participation by these plants in new energy auctions.

The PSR reference case removes this technology as a new supply alternative.

2.4.2.4 *Nuclear*

Brazil's first uranium reserves totaling 9,400 tons were discovered in the mid-1970s. At present the country possesses the world's seventh largest geological reserve of uranium, with a little over 300 thousand tons of U_3O_8 after Australia, Kazakhstan, Russia, South Africa, Canada and the United States. The main producing states are Minas Gerais (4.500t), Bahia (100.770t) and Ceará (142.500t)[10]. With costs of under US$80 per kgU, Brazilian uranium is competitive by international standards (up to US$130 per kgU).

Construction of Brazil's first nuclear power plant, Angra 1 (657 MW), began in 1972 and commercial operation started in 1985. The second plant, Angra 2 (1,350 MW) resulted from the Brazil-Germany Agreement, signed in June 1975. After several interruptions in construction work, the plant finally entered into operation in 2000. Construction of the third plant, Angra 3 (1,350 MW) came to a standstill in 1985 with 30% of investments covering most of the equipment already disbursed. The deadline for completion of the project is estimated at five to six years, and involve an *additional* investment of R$7 billion.

Brazil has mastered the technology of the entire fuel cycle, including the crucial enrichment stage, using the isotopic method for enriching uranium by ultracentrifugation. This stage is the most vital in economic terms since it accounts for virtually half of the investments in the cycle. Meanwhile, from the political and strategic standpoint, given its potential application in the production of nuclear weapons, nuclear power production is subject to international controls and safeguards.

According to the 2030 National Energy Plan, considering that only the reserves costing under US$ 40 per kgU will be developed, there is potential for developing two more nuclear power plants with a total installed capacity of over 4,500 MW. If the proven reserves of 177 thousand tons of U_3O_8, with costs of between 40 and 80 US$ per kgU, are added, it would be possible to construct 15 more nuclear plants, which would give Brazil a potential for installing nuclear power of 17,500 MW.

[10] Source: *Indústrias Nucleares do Brasil* (INB).

The PSR reference case considers that in the time horizon up to 2030 Brazil´s installed nuclear power capacity will increase after Angra 3 is completed (contracted in reserve auction) and when three further plants are installed (two plants of 960 MW average load in the Northeast in 2024 and 2030, and one plant of 960 MW average load in the Southeast in 2028).

2.4.3 Additional Sources

2.4.3.1 Biomass

Cogeneration using sugarcane bagasse is highly attractive from an economic standpoint and it is clear that this process could be another important alternative for expanding supply, mainly focused on the Southeast region. Brazil is a major producer of ethanol from sugarcane. The production of ethanol is self-sufficient given that sugar bagasse is used as fuel in steam turbines to produce electricity, with the excess energy sold automatically to the national grid. With the growth of ethanol production, new fields are being opened up and more efficient boilers installed, resulting in more surplus energy for sale. However, the development of cellulosic ethanol may in the long-term create an opportunity cost for sugarcane bagasse (zero cost at present), that may boost the price of the surplus energy. A similar approach applies to the recent development of processes using enzymes and bacteria to transform sugar into diesel fuel[11].

The recent linkups between oil and bioenergy companies (e.g. Shell and Cosan, and BP’s stake in the *Tropical Energía* plant) reflect the interest of these companies in this type of ethanol and diesel production technology and might threaten the availability of bagasse for energy cogeneration.

2.4.3.2 Wind

Wind power still represents only a small percentage of the electricity produced in Brazil (less than 2 GW), with most of this contracted in the *Alternative Sources Incentive Program* (PROINFA) priced in 2013 at around 330 R$ / MWh. Wind power projects competed for space in the Brazilian power sector at the Reserve Energy Auction held in 2009. After seven energy auctions, wind power prices declined by 69% from the PROINFA level, with contracted wind power capacity increasing seven times (to 8.6 GW by 2016).

Various studies estimate Brazil’s wind power potential at about 60,000 MW average load[12] , to be developed mainly in the Northeast. The states of Ceará and Rio Grande do Norte account for a large part of this potential (12,000 MW). More recently, several states such as São Paulo, Bahia, Alagoas and Rio Grande do Sul, have re-mapped their territories to include new developments in wind power generation using turbines on 100 meter high structures. Meanwhile, the *Center for Electrical Energy Research* (CEPEL) is preparing the new *Atlas Eólico* (Wind Atlas) with measurements of wind data at 100 meters above ground. As a result, the numerical value of Brazil’s potential should increase considerably. One example is the substantial increase of wind power potential in the state of Rio Grande do Sul, which has risen from 16 GW at 50 m height to 115 GW at 100 m.

[11] See http://www.technologyreview.com/energy/24554/

[12] Source: *Atlas de Energia Elétrica do Brasil*, 20th edition, 2005.

It is interesting to note that the regional location of wind farms is fairly complementary to other renewable energy sources, since the majority of undeveloped hydroelectric potential is focused on the North region, while bioelectricity has significant potential in the Southeast and Midwest.

A further point worth mentioning is that the absorption of fluctuations in power generation due to wind variability (a major problem in other countries[13]), does not apply in Brazil, given that hydroelectric reservoirs absorb relatively easily any variation in energy production[14]. A further obstacle in some other countries is the need for long transmission networks, e.g. the "wind corridor" in the center of the United States is thousands of miles from the country´s main load centers. This problem is of less importance in Brazil since wind power installations are generally located near to the coast where the bulk of the population and the majority of electricity consumption are concentrated[15].

Since wind energy is physically viable in Brazil, the challenge is to focus on the costs of wind power compared to other expansion options. The 2010 and 2011 auctions proved to be a breakthrough in this respect, with wind power contracted at around 100 R$/MWh, representing good value when compared to the prices of energy from small hydropower plants (SHP), biomass and natural gas. These wind price levels led to auctions being organized by energy source to make thermal power plants contractually viable, as in the A-5 auctions in 2013 and 2014.

2.4.3.3 Small Hydroelectric Plants (SHP)

Finally, it is worth considering the possibility of installing new Small Hydroelectric Plants (SHP). This technology is already fairly advanced and widely known in the power industry. Over the years it has led to lower installation costs and more efficient equipment. Despite their smaller size, SHP prices compare well with traditional hydroelectric plants and have a number of advantages: (i) the possibility of using an estimated profit tax regime; (ii) greater ease to obtain environmental licensing; (iii) exemption from payment of UBP (use of common good fee); (iv) exemption from R&D and CFUHR (sector charges) overheads; and (v) shorter investment implementation and maintenance time. Moreover, the SHP do not need to bid for concessions: developers need only to obtain ANEEL authorization. According to the ANEEL *Generation Databank* there were 468 SHP in operation in Brazil in September 2015 (4,834 MW), 34 plants under construction (416 MW) and 132 awaiting authorization (1,856 MW). According to the *National Reference Centre for Small Hydroelectric Power Plants* (CERPCH), Brazil has an estimated SHP potential of 12.31 GW[16].

[13] In Germany, for example, thermal plants are needed to compensate for fluctuations in wind power.

[14] The same happens with electricity, where hydroelectric generation offsets the seasonal production pattern coinciding with sugarcane harvest.

[15] Transmission investments in Brazil can be more expensive if, instead of "wind farms" with significant generation capacity located relatively close together, they are more widely dispersed.

[16] Source: CERPCH (July 2012). The figure takes into account the 5.72 GW already awarded by ANEEL.

SHPs are a very attractive proposition for the free market owing to the ANEEL *Regulated Contracting of Incentivized Sources* mechanism which stipulates a reduction in the distribution/transmission tariffs for both operators and consumers. According to Law 9.427 / 1996, alternative sources (SHP, biomass, wind and solar) are eligible for a discount of at least 50% of their transmission and distribution tariffs. The right to this discount is also extended to consumers of this type of energy. These are known as special consumers who must be in Group A[17], with a load of over 0.5 MW. Some Group A consumers can also be considered "special" if they are located in the same submarket, providing they are in contiguous areas or possess the same CNPJ (fiscal) number.

These incentives were created in 1998 but not regulated until after the ANEEL Public Hearing No. 33 which began in 2005 and was concluded in November 2006. As a result of this hearing, ANEEL issued Normative Ruling No. 247 to regulate the sale of electricity from the incentivized generators. Important considerations for the development of this market include: (i) the possibility of combining the energy output from these generators with the production of other generators to offset periods of low production, and (ii) the possibility of selling the incentivized energy through traders with consumer maintaining their discount benefit. The latter advantage presents the incentivized generators and sellers with substantial energy sales opportunities since they will have access to a currently captive market segment that has no way of exiting the captive market unless they purchase energy from incentivized generators[18].

2.4.3.4 Solar

According to INPE´s *Brazilian Solar Energy Atlas (Solar Energy and Wind Resources Assessment Project*), average daily solar radiation in Brazil is between 4.1 and 6.5 kWh per m^2 per day (by contrast, Germany´s best locations receive 3.4 kWh per m2 per day). Figure 11 shows total tilted solar radiation map for Brazil with grid resolution of 10 km x 10 km. The highest solar radiation figures are recorded in the central region, e.g. Tocantins, Piauí and western Bahia. Solar photovoltaic energy (PV) currently accounts for only 0.01% of the total installed energy capacity in Brazil (less than 20 MW).

[17] Group A corresponds to consumers connected to high voltage above 2.3 kV. The tariffs for this vary according to the level of voltage supplied.

[18] In Brazil any new consumer whose demand is greater than 3 MW is potentially 'free', and can choose where to buy energy. To become 'free', existing consumers must meet the minimum demand of 3 MW and be connected at voltage levels equal to or higher than 69 kV.

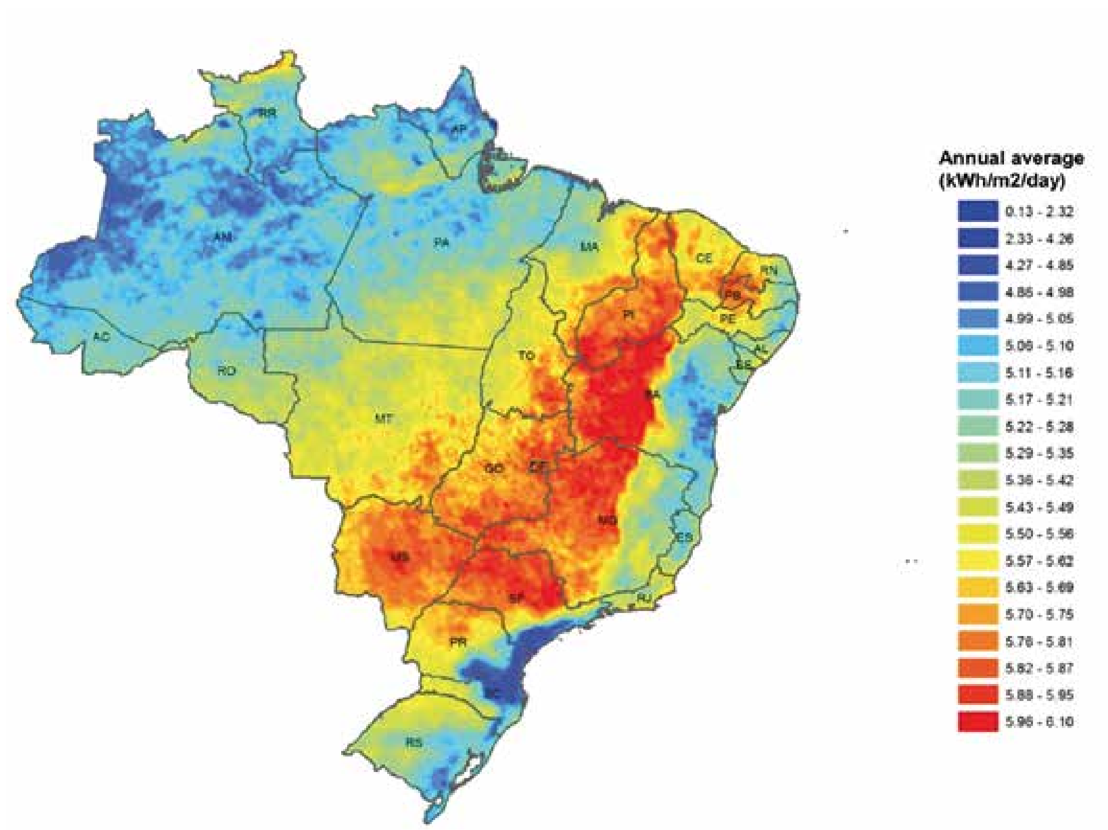


FIGURE 12 - Total tilted solar radiation (Resolution: 10 km x 10 km)

In April 2012, ANEEL issued Normative Resolution 482 on distributed micro- and mini-generation. The main innovation was net metering aimed at resolving the problem of electricity charges for captive consumers. This mechanism enables consumers to supply power to the network and pay only for net energy consumption. This benefits consumers connected to the distribution system who use hydroelectricity, solar, wind, biomass and qualified cogeneration facilities of up to 1 MW. In 2015 this limit was increased to 5 MW, which is the minimum size of projects in electricity auctions. That 5 MW marks the limit between largest distributed generation solar projects and smallest projects that take part in new electricity auctions.

Although PV has no clear advantages over other technologies that can also benefit from net metering, it is widely expected that Resolution 482 will boost the development of roof-mounted solar energy in Brazil (photovoltaic panels). PSR estimates that the levelized cost of a PV system is currently almost equal to the residential tariff. Furthermore, the large amount of solar energy available in densely urbanized areas, concessions granted to distribution companies, and the modularity of photovoltaic panels more suitable for power systems with an output of under 5 MW, also contribute to improving solar energy output.

The expansion scenario considers the development of photovoltaic solar energy as distributed generation in the Southeast from 2022 onwards, attaining 5 GW of installed capacity in 2030.

2.4.4 Summary

The advantages of each subsystem as expansion alternatives are:

- In the North region, available hydroelectric potential could lead to expanded supply;
- In the Southeast regions supply expansion involves development of untapped hydroelectric potential and thermoelectric power plants. A reference standard could be adopted based on a combination of natural gas facilities and steam turbines using sugarcane. PV technologies could also make a contribution;
- In the South region, wind energy could also be considered, in addition to the alternatives for the Southeast region (with the exception of biomass);
- In the Northeast, where the hydroelectric potential is practically exhausted, the only options are to import energy (from the North and/or Southeast), or to rely on local thermal generation (LNG, imported coal and nuclear power) and wind energy. We assume for the Northeast region an expansion based on wind energy, nuclear energy and the importation of energy from other regions of Brazil.

It is important to point out that not all thermal power expansion will be implemented with standard technology, and it is clear that market factors will determine whether the supply expansion described here becomes reality.

2.5 Expansion scenario criteria

The Expansion Scenario is based on a demand projection and the availability and number of candidate projects, considering the prices of competing technologies and compliance with the reliability criteria of the Brazilian power system.

The short-term supply projection is based on the ONS *Monthly Operating Program* (PMO) of January 2015, with adjustments made to the commissioning dates of delayed projects. A thorough review is conducted of ANEEL generation and transmission Inspection Reports.

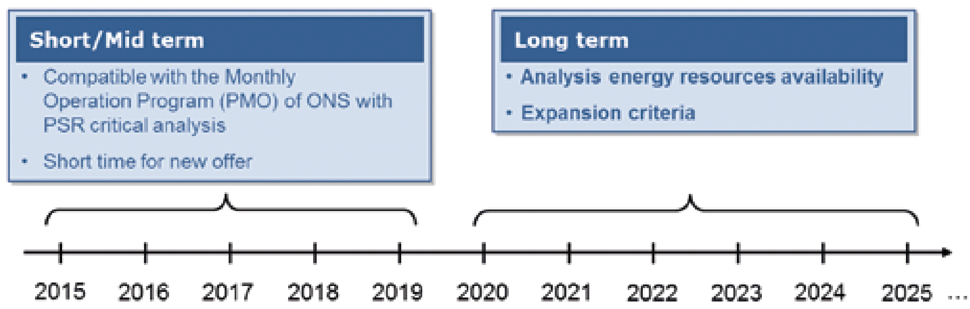


FIGURE 13 - Expansion Scenario

2.5.1 Short and medium term

Short and medium term expansion (2015 to 2019) is consistent with the expansion plans released by the *Monthly Operating Programs* (PMO) of the National System Operator (ONS). This study used the January 2015 PMO data on short/medium term supply expansion.

For 2015-2019 the Expansion Scenario is defined on the basis of the "new energy" auctions, including: the December 2005 auction, the A-3 (July 2006) and A-5 auctions (October 2006), the alternative sources auction held in June 2007, the A-3 and A-5 auctions in July and October 2007 respectively, the 2008 biomass reserve auction, the A-3 and A -5 auctions of September 2008, the 2009 A-3 auction, the 2010 wind reserve auction, the 2010 A-5 auctions (July and December), the reserve energy and alternative sources auctions in 2010 and 2011, the 2011 A-3 and A-5 auctions, the 2012 A-5 auction, the 2013 reserve auction, and the A-3 auction and two A-5 auctions held in 2013.

The December 2014 ANEEL Inspection Report refers to three types of restrictions regarding developers´ compliance with the dates of entry into operation established in the concession agreement of each project:

- "GREEN" supply: no restrictions on entry into operation (environmental licenses up-to-date and civil works initiated);
- "YELLOW" supply: restrictions on entry into operation (works not initiated, delays in obtaining environmental permits, schedule compromised);
- "RED" supply: serious constraints on plants entering into operation (suspension of environmental licensing process, litigation issues, environmental non-compliance, etc.).

If a developer has begun construction of a plant (even behind schedule), and complies with a new agreed schedule, ANEEL considers the plant to be in the "green" supply category, allowing for discrepancies between the registered delays on the status of the plant ("green", "yellow" or "red") and the actual works schedule ("early", "normal" or "delayed").

TABLE 3 - Status of delayed plants

PLANT	TYPE	STATE	POWER (MW)	PHYSICAL GUARANTEE (MW AVERAGE)	STATUS	ANEEL STATUS SCHEDULE	ANEEL STATUS WORKS	FORCASTS FSG/ANEEL	AUCTION SCHEDULE	PMO JANUARY/2015(ONS)	PSR ASSUMPTION
Baixo Iguaçu	Hydro	PR	350	179	Red	Delayed	P	sem prev.	Jan-13	Fev-17	Fev-18
Belo Monte Comp.	Hydro	PA	233	152	Green	Delayed	EC	Mar-16	Mar-15	Mar-16	Sep-16
Colider	Hydro	MT	300	173	Green	Delayed	EC	May-16	Jan-15	Nov-16	Fev-17
Santo Antônio Jari(1)	Hydro	AP/PA	300	196	Green	In advance	EC	Jan-15	Jan-15	Mar-15	Mar-15
Ferreira Gomes(2)	Hydro	AP	252	150	Green	Normal	EC	Dec-14	Jan-15	Apr-15	Apr-15
Teles Pires	Hydro	MT/PA	1820	915	Green	Normal	EC	Jun-15	Apr-16	Oct-15	Jan-16
Belo Monte	Hydro	PA	11000	4419	Green	Delayed	EC	Apr-16	Jan-16	Apr-16	Oct-16
São Roque	Hydro	SC	135	91	Green	Delayed	EC	Jul-16	Jan-16	Jul-16	Jan-17
Cachoeira Caldeirão	Hydro	AP	219	130	Green	Normal	EC	Jan-17	Jan-17	Jan-17	Apr-17
Sinop	Hydro	MT	400	240	Green	Normal	NI	Jan-18	Jan-18	Mar-18	Sep-18
Salto Apiacás	Hydro	MT	45	23	Green	Delayed	EC	Dec-16	Jan-18	Dec-16	Jun-17
São Manoel	Hydro	MT/PA	700	421	Green	Normal	EC	Jan-18	May-18	Jan-18	Jan-19
Angra 3	Thermo	RJ	1405	1262	Green	Delayed	EC	Jan-19	Dec-15	Jan-19	Jan-19
Baixada Fluminense(3)	Thermo	RJ	530	430	Green	Normal	EC	Jan-15	Jan-14	Jan-15	Jan-15
Maranhão III	Thermo	MA	519	471	Green	Delayed	EC	Jul-16	Jan-14	Aug-16	Aug-16
Novo tempo	Thermo	PE	1238	612	-	-	-	-	Jan-19	Jan-19	Jul-19
Rio grande	Thermo	RS	1238	605	-	-	-	-	Jan-19	Jan-19	Jul-19
Pampa sul	Thermo	RS	340	324	-	-	-	-	Jan-19	Jan-19	Jul-19
Acre	Thermo	AC	164	135	-	-	-	-	Jan-19	Jan-19	Jul-19
Costa Rica I	Thermo	MS	164	135	-	-	-	-	Jan-19	Jan-19	Jul-19

(1) UG3 – 123.3MW

(2) UG2 e UG3 – 84 MW each

(3) UG3 – 186 MW

Source: ANEEL Energy Generation Inspection Report, December 2014.

Key:

EC = Plant under construction

NI = Plant where works have not commenced

NA = Plant not monitored by ANEEL

2.5.1.1 Specific HPPs

HPP SANTO ANTÔNIO (3,568 MW)

Total of 50 turbines, became operational in 2012, scheduled for completion in December 2017. Guaranteed power output of 2,424 MW. Work on this plant is behind schedule but progressing. Considered to be "green". 32 turbines (2,286 MW) to enter service by December 2014.

HPP JIRAU (3,750 MW)

Total of 50 turbines, became operational in 2013, scheduled for motorization in December 2017. Guaranteed power output of 2,184 MW average load. Work on the plant is behind schedule but progressing. Considered to be "green". 16 turbines (1,200 MW) commenced operation in December 2014.

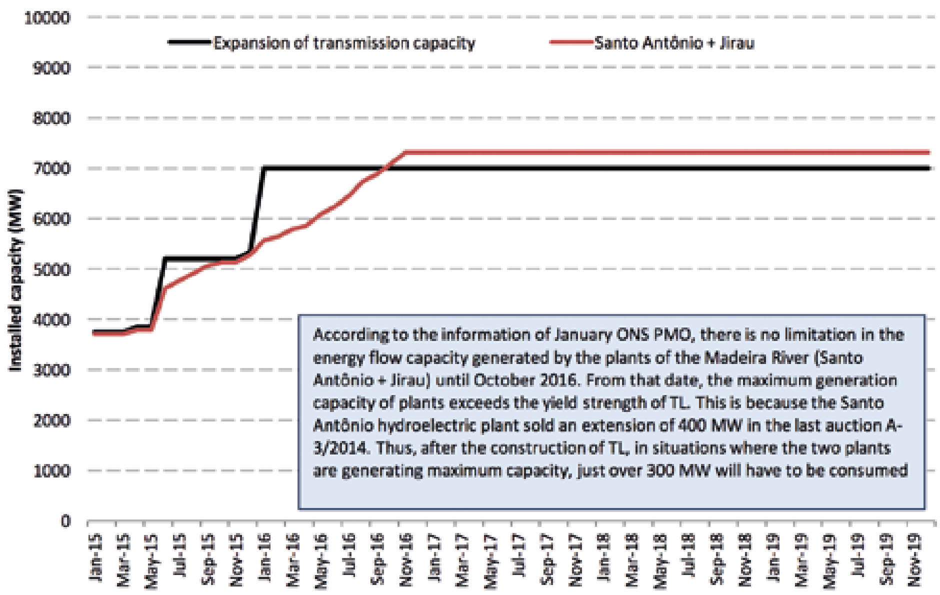


FIGURE 14 - **Effect of the Madeira River TL**

HPP BELO MONTE (11,000 MW):

Total of 18 turbines, with motorization scheduled for October 2016-August 2019. Guaranteed power output of 4,419 MW. Work on the plant is behind schedule but progressing. Considered to be "green". Tenders have been issued for the transmission lines to export energy from the first turbines at Belo Monte and these are expected to enter service in 2016. In June 2014 the Concession Agreement was signed for the construction of the first Direct Current in Ultra High Voltage 800 kV bipolar line in Brazil and tendering launched for the converters for interconnecting Xingu (PA) with Estreito (MG), scheduled to enter service in February 2018. Tenders for the second bipole, Xingu (PA)> Nova Iguaçu (RJ), are still to be launched.

HPP BAIXO IGUAÇU (350 MW):

Total of 3 turbines, due to become operational in March 2017. Guaranteed power output of 179 MW. Baixo Iguaçu HPP faces serious environmental restrictions and still awaits a preliminary license. Work on the plant has not started. The ANEEL Inspection Report rates it "yellow".

HPP TELES PIRES (1820 MW):

Total of 5 turbines, with operation scheduled to start in January 2016. Guaranteed power output of 915 MW average load. Work is progressing on the plant despite being behind schedule. Rated "green" in the ANEEL Inspection Report.

2.5.1.2 Wind Power

As for wind farms already contracted, Figure 15 shows the differences between the scheduled dates for entry into operation: the official date established in the auction, the schedule described in the ONS PMO of January 2015, and PSR´s assumption (based on the ANEEL Inspection Report of December 2014).

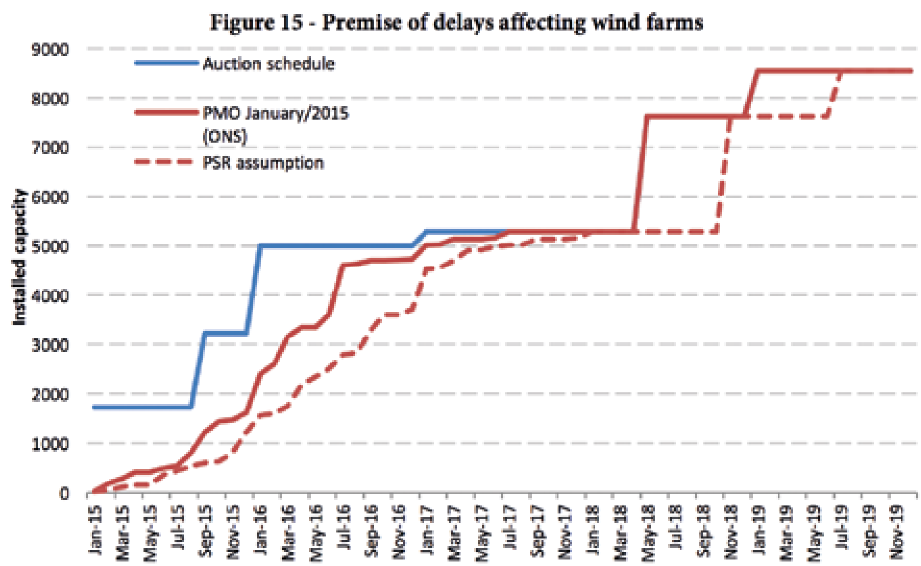
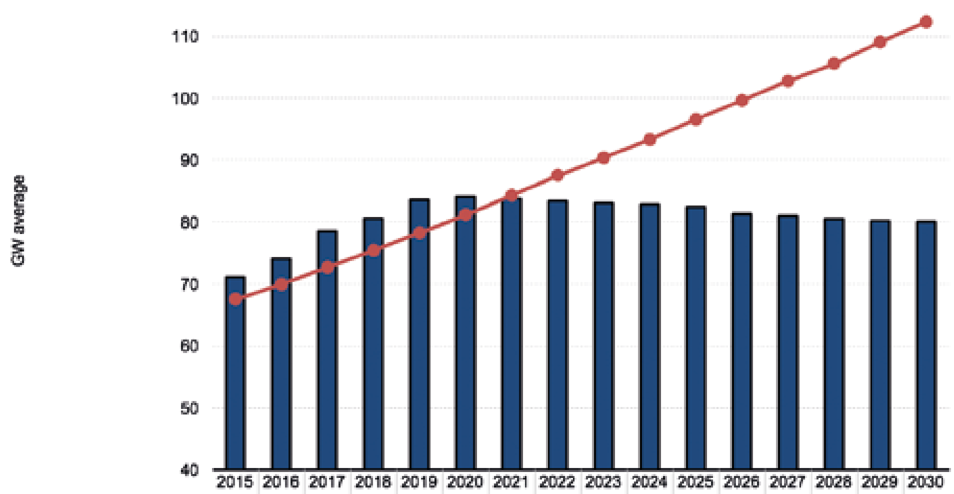


FIGURE 15 - Premise of delays affecting wind farms

2.5.2 Long-term

The Expansion Scenario is adjusted for the long-term horizon (post-2019). The need to increase new supply and meet demand with adequate levels of reliability involves incorporating new hydroelectric, thermoelectric and renewable projects in the Scenario, in line with the criteria established by PSR.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Guaranteed supply	71,1	74,0	78,5	80,6	83,6	84,2	83,8	83,4	83,0	82,9	82,5	81,3	81,0	80,5	80,2	80,0
Supply-Demand	3,6	4,1	5,9	5,2	5,4	3,0	-0,5	-4,1	-7,3	-10,5	-14,1	-18,3	-21,8	-25,1	-28,9	-32,3
Demand	67,5	70,0	72,7	75,4	78,2	81,1	84,3	87,5	90,4	93,3	96,6	99,6	102,8	105,6	109,1	112,3

1 - Dem = Energy requirement, including ANDE demand, Light bombs and Itaipu comsumption.

2 - The guaranteed supply includes power plants in operation and contracted in the new energy auctions.

FIGURE 16 - Space for contracting new supply

2.5.2.1 Inclusion of hydropower plants

The Expansion Scenario considers previously-studied hydropower projects (e.g. by ELETROBRÁS and MME), and those in which private investors have shown interest.

After feasibility studies have been approved, projects need a Preliminary License (LP) to participate in the "new energy" auctions. The licensing process can take up to one year, e.g. a plant with feasibility studies approved in 2014 will only be able to participate in the A-5 auction in 2015. Such delays are common. According to the Ministry of Energy and Mines (MME) seven hydropower projects with a total installed capacity of 905 MW failed to obtain environmental licenses in time and the 2009 A-5 auction was cancelled as a result.

In the Expansion Scenario, determining the dates of entry into operation of a HPP involved considering the progress of the project´s feasibility study and analyzing its environmental situation. Developments in basins that encounter little local resistance, and where environmental licensing is therefore easier to obtain, make it possible to fix a schedule for the plants to enter into service after 2019. On the other hand, dam construction in watersheds such as the Uruguai and Araguaia basins faces greater resistance and results in delays.

In addition to the projects with feasibility studies in progress, the Expansion Scenario considers plants where tenders have been launched for concession agreements but without stipulating firm dates for entry into operation.

These plants participated in the federal auctions held between 1996 and 2002, where successful investors offered the highest payment for UBP (use of Public Good fee). Since these projects cannot participate in the Regulated Market (ACR) "new energy" auctions, the only feasible way forward would be for them to sell energy in the open market. A further possibility would be for the concessions to revert to the government, thereby attracting new investors, which would enable a given project to participate in a new energy auction.

Table 4 lists the dates of entry into operation of these plants in the Expansion Scenario, determined according to the "adjustment" of the scenario for the long term.

TABLE 4 - HPP plants in the long-term horizon

POWER PLANT	TYPE	STATE	POWER (MW)	START OF OPERATION (PSR SCENARIO)
Baú I	UHE	MG	110	Jan-24
Cachoeirinha	UHE	PR	45	Jan-22
Pai Querê	UHE	SC/RS	292	Jun-21
Couto Magalhães	UHE	GO/MT	150	Jul-22
São João	UHE	PR	60	Jan-22
Tijuco Alto	UHE	SP/PR	129	Apr-23

2.5.2.2 *Inclusion of thermal and wind projects*

Thermoelectric projects are inserted by using standard modules of thermoelectric plants allocated in the various submarkets so that, together with the expansion of the HPPs and the main inter-connections, a total power supply is envisaged that can meet projected demand according to supply quality criteria compatible with the commercial and energy characteristics expected of a system with supply/ demand equilibrium. These plants are not immediately identifiable (they were called "generic thermal plants ") and therefore are not specifically linked to future projects. They represent only the "need" for power in the system which should be met with the installation of a thermal power plant.

The modules of "generic" thermoelectric projects considered in the construction of the Expansion Scenario comprise:

- 450 MW modules of natural gas combined cycle plants (in the Southeast submarket);
- 750 MW wind farm modules; and
- 1200 MW nuclear power plant modules.

The 750 MW wind farm module consists of a set of wind farms located in the Northeast and South regions, using fixed generation with a capacity factor of 40% and considering the seasonal fluctuations typical of the Northeast and South based on project data provided in the new energy auctions. A factor of 40% was considered for calculating the guaranteed power output.

For the thermal power plants, the 450 MW module used represents a project with combined cycle technology comprising two 176 MW gas turbines and one 176 MW steam cycle turbine, assuming a power loss of 15% caused by the effects of altitude, temperature and degradation.

Two types of natural gas projects are considered:

- Flexible thermoelectric:
  - Minimum generation = 0%;
  - *City gate* gas price (ex-tax) = 13 US$ / MMBTU (base date 2014);
  - *Brent*-adjusted;
  - CVU = 285 R$ / MWh (base date 2014);
  - GF = 54% of available power (calculated with CMO = CME = 139 R$ / MWh and with CVaR).
- Inflexible thermoelectric:
  - Minimum generation = 70%;
  - *City gate* natural gas price (ex-tax) (ex-tax) = 7 US$ / MMBTU;
  - *Brent*-adjusted;
  - CVU = 160 R$ / MWh (base date 2014);
  - GF = 96% of available power (CMO = CME = 139 R$ / MWh and with CVaR).

Note: Assuming for CVU: ICMS of 5%, PIS / COFINS of 9.25%, distributor margin of 1 R$ / MMBTU, domestic consumption of 2.5%, losses in the core network 2.5%, heat rate 6.8 MMBtu / MWh (PCS), O&M of 6 R$ / MWh, exchange rate according to FOCUS report of February 2014.

The Expansion Scenario considers that the flexible thermal expansion is subject to a reduction in the price of natural gas for the thermoelectric plants, otherwise this source would be displaced by wind energy.

Due to regulatory constraints and natural gas prices, the modules of NG plants will be ready to enter the system from 2021. These projects cover new supply requirements and, depending on fuel availability, could be replaced by coal, biomass or fuel oil.

The inclusion of thermoelectric and wind modules in the Expansion Scenario considers the need for distribution companies to manage demand growth uncertainty. If demand growth were entirely predictable, project construction time would not be important. In this case, the lowest cost solution for the system would be to build the cheapest projects to meet growth in demand. In the case of hydropower plants demand would need to be projected five years in advance.

However, given demand growth uncertainty, a project that requires less construction time will have a greater economic value since it makes system expansion more flexible. In other words, despite having a lower nominal price compared to other sources, the lengthy construction time and low adaptability to changes in demand growth rates mean that HPP power is more expensive for consumers.

Despite thermal and wind plants being nominally more expensive, they can be presented in contracting strategies as a more economically attractive option for final consumers. Given that demand growth uncertainty makes it risky for a distribution company to contract all its energy for five years, it is more prudent to contract part of the energy five years in advance and expect to top up the purchase in the near future. This concept led to the A-3 and A-5 new energy auctions, where energy is contracted 3 and 5 years in advance.

Thermal plants also have the following advantages: on-call capability, peak demand supply ability, dispatchability (energy dispatched at any time), and location near/far load centers (which impact losses in transmission and need for expanding transmission). Although these advantages are not taken directly into consideration in the auction pricing mechanisms, some of them are nevertheless priced indirectly. One example is the current restriction on *take-or-pay* gas-fired power plants, which cannot exceed 50%. This restriction means that flexibility is of value in the auction. A further example is the A-5 auction held in December 2013, which separated the wind and thermal energy products with maximum prices of R$122 per MWh and R$144 per MWh, respectively, meaning that thermal plants have an indirect value advantage of R$22 per MWh.

The Expansion Scenario considers that, due to the above-mentioned advantages, a minimal amount of thermal power could be contracted in a scenario with a supply of hydropower.

In both cases, a reference price for natural gas (indexed to Brent) was considered. For a plant with a 50% *take-or-pay* clause, a 5% premium over Brent (without tax) is considered and 9% premium over Brent (without tax) (without tax) for a fully flexible plant.

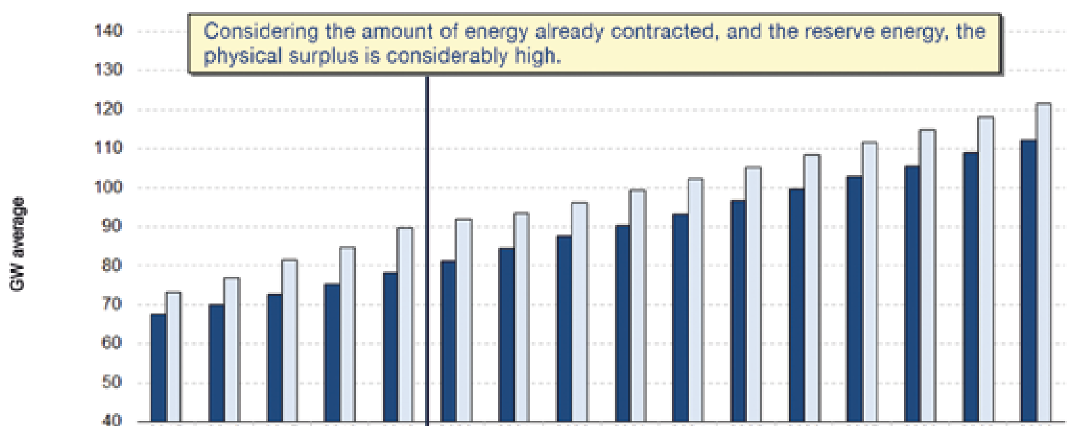
Other aspects of the supply and demand Expansion Scenario are detailed in Annex B.

3 ANALYSIS OF THE REFERENCE CASE

In this chapter we present the variability of the results of the reference case, obtained from the simulation of the SIN operation, for different hydrology scenarios (without climate change).

3.1 Balance between SIN energy supply and demand

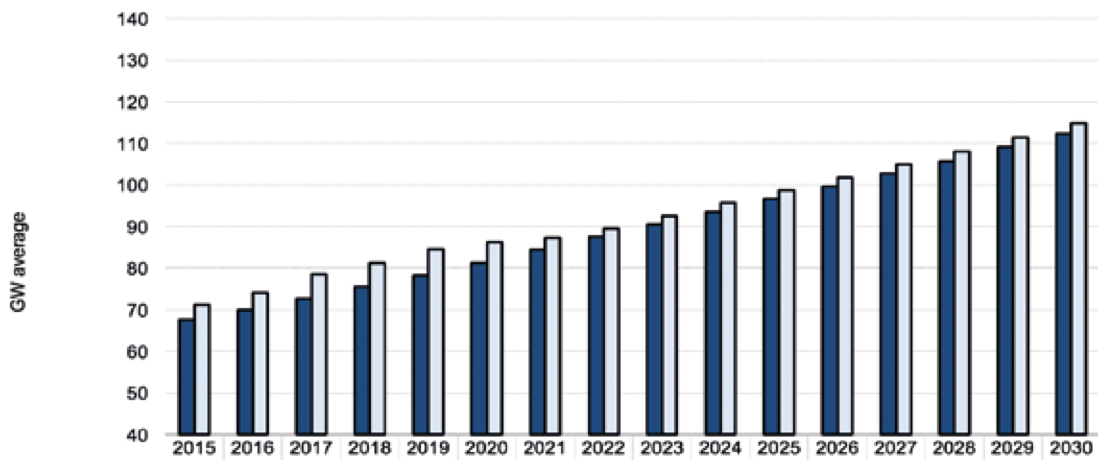
The two figures below show the physical balance of the average annual[19] supply and demand of the reference case with and without reserve energy. Both balances take into account the assumptions for calculating the physical balance.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand	67.5	70.0	72.7	75.4	78.2	81.1	84.3	87.5	90.4	93.3	96.6	99.6	102.8	105.6	109.1	112.3
Firm Energy	73.0	76.8	81.5	84.6	89.7	91.8	93.4	96.1	99.2	102.3	105.3	108.4	111.6	114.7	118.1	121.5
Firm Energy - Demand	5.6	6.8	8.8	9.1	11.5	10.7	9.0	8.6	8.9	9.0	8.7	8.8	8.8	9.2	9.0	9.2
% Demand	8.2%	9.8%	12.1%	12.1%	14.7%	13.2%	10.7%	9.8%	9.8%	9.6%	9.1%	8.8%	8.6%	8.7%	8.2%	8.2%

FIGURE 17 - Physical balance of average annual supply and demand with reserve energy

[19] Energy requirement including ANDE and LIGHT demand and ITAIPU consumption.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
■Demand	67,5	70,0	72,7	75,4	78,2	81,1	84,3	87,5	90,4	93,3	96,6	99,6	102,8	105,6	109,1	112,3
□Firm Energy	71,1	74,0	78,5	81,2	84,5	86,2	87,2	89,5	92,6	95,6	98,6	101,7	104,9	108,1	111,4	114,9
Firm Energy - Demand	3,6	4,1	5,9	5,8	6,3	5,0	2,9	1,9	2,2	2,3	2,1	2,1	2,2	2,5	2,3	2,6
% Demand	5,4%	5,8%	8,1%	7,6%	8,1%	6,2%	3,4%	2,2%	2,4%	2,5%	2,1%	2,1%	2,1%	2,4%	2,1%	2,3%

FIGURE 18 - Physical balance of average annual supply and demand without reserve energy

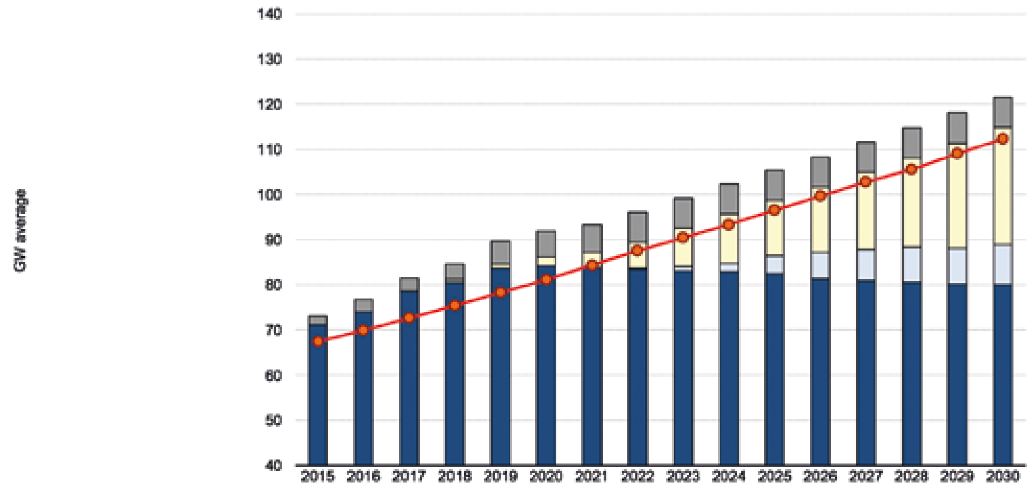
It can be seen from the above that oversupply in the short and medium terms (up to 2019) increases as a result of (a) the low demand growth projection over the 2015-2019 horizon, and (b) entry into operation of the major HPP projects already contracted.

Over the longer term, the excess supply tends to remain at around 2% of demand assuming that the free market contributes only 50% of supply growth, while the remainder is consumed as the result of auctions for existing energy.

Figure 18 shows the same balance, with supply divided into:

- Guaranteed supply: existing and/or already-contracted energy through the "new energy" auctions (including Belo Monte);
- Structuring projects: international projects (Peruvian HPPs and the Garabi HPP);
- Indicative supply: projects that need to contract new supply;
- Reserve energy: includes Angra 3, biomass and wind power.

The following figure indicates the need for new energy supply from 2021. There is a need to contract around a 35 GW average guaranteed power output to meet the growth in demand for new energy by 2030 (excluding Belo Monte, Angra 3 and international projects). It is clear there are opportunities for new investments (See Annex C).

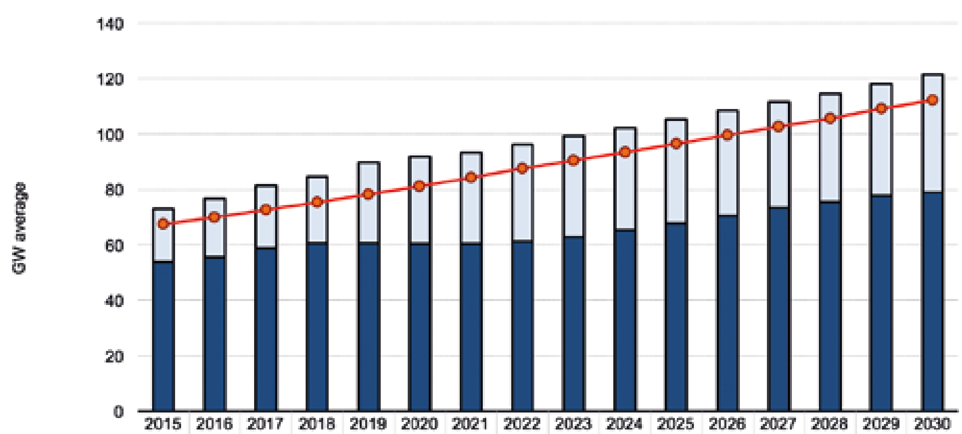


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reserve Energy	1,9	2,7	2,9	3,4	5,2	5,7	6,2	6,7	6,7	6,7	6,7	6,7	6,7	6,7	6,7	6,7
Indicative Projects	0,0	0,0	0,0	0,6	0,9	2,0	3,4	5,8	8,5	10,9	12,2	14,5	17,0	19,7	23,3	26,0
Government Mandatory Projects	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,2	1,0	1,8	3,9	5,9	6,9	7,9	7,9	8,9
Existing/Under Construction	71,1	74,0	78,5	80,6	83,6	84,2	83,8	83,4	83,0	82,9	82,5	81,3	81,0	80,5	80,2	80,0
Demand	67,5	70,0	72,7	75,4	78,2	81,1	84,3	87,5	90,4	93,3	96,6	99,6	102,8	105,6	109,1	112,3

FIGURE 19 - Physical balance of average annual supply and demand

3.2 Hydrothermal share

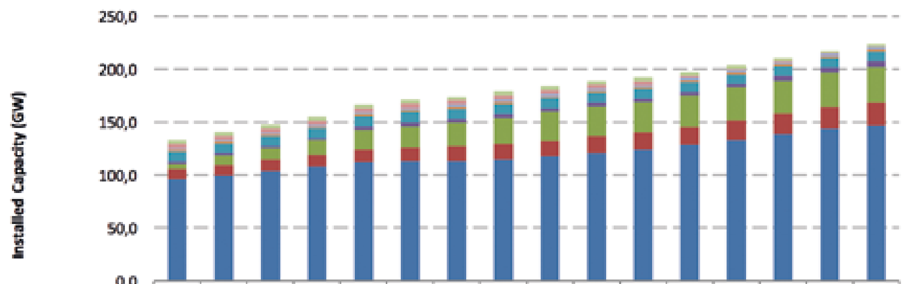
Figure 20 shows the evolution of the hydropower share (in dark blue) and of other energy sources (in light blue) in the guaranteed power output of the system.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	19,1	21,2	22,6	24,1	29,2	31,5	33,0	35,0	36,5	37,1	37,6	37,9	38,3	39,4	40,4	42,5
Hydro	53,9	55,6	58,9	60,4	60,5	60,3	60,3	61,1	62,8	65,2	67,7	70,4	73,3	75,3	77,7	79,0
Demand	67,5	70,0	72,7	75,4	78,2	81,1	84,3	87,5	90,4	93,3	96,6	99,6	102,8	105,6	109,1	112,3
% Hydro	74%	72%	72%	71%	67%	66%	65%	64%	63%	64%	64%	65%	66%	66%	66%	65%
% Thermal	26%	28%	28%	29%	33%	34%	35%	36%	37%	36%	36%	35%	34%	34%	34%	35%

FIGURE 20 - Evolution of thermal participation in the guaranteed power output of the system

Figure 21 shows the supply of energy in terms of installed capacity, by other sources.[20]

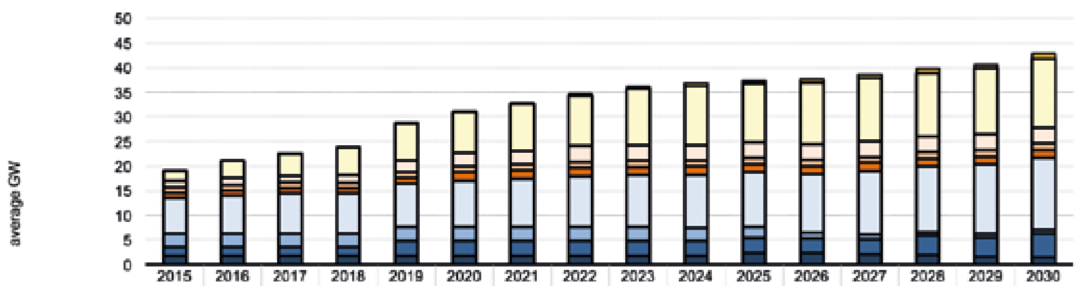


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Others	3,7	3,7	3,7	3,7	3,7	3,7	3,7	3,7	3,7	3,7	4,3	4,1	3,6	3,1	2,4	1,9
Diesel/ fuel oil	4,4	4,1	4,1	4,1	4,1	4,1	4,1	4,1	4,1	3,7	3,0	1,5	1,3	0,9	0,9	0,9
National coal	1,4	1,5	1,5	1,5	1,7	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3	2,3
Imported coal	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4
Biomass	9,3	9,4	9,5	9,6	9,9	10,2	9,6	9,9	9,4	9,4	9,4	9,4	9,4	9,4	9,4	9,4
Nuclear	2,0	2,0	2,0	2,0	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	4,6	4,6	5,8
Wind	5,6	9,1	11,0	13,6	18,4	19,7	22,3	24,5	27,3	28,4	28,4	29,9	30,7	30,7	32,2	33,7
Natural Gas	9,5	10,1	10,6	10,6	11,8	13,1	14,0	14,9	15,3	15,8	16,1	17,2	18,8	19,6	20,8	21,4
Hydro	95,7	99,6	103,8	108,5	112,4	113,3	113,3	114,7	117,3	121,0	124,2	128,2	133,1	138,7	143,7	146,7

FIGURE 21 - Evolution of generating capacity by source (absolute values)

3.2.1 Non-hydroelectric sources

Figure 22 shows the evolution of the guaranteed power output by non-hydroelectric sources. Wind, nuclear and natural gas displayed remarkable growth.

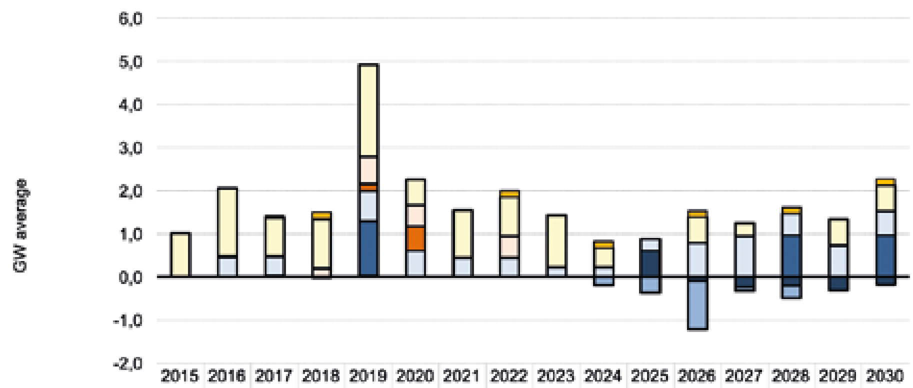


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar	0,0	0,0	0,0	0,2	0,2	0,2	0,2	0,4	0,4	0,5	0,5	0,7	0,7	0,8	0,8	1,0
Wind	2,0	3,5	4,4	5,6	7,7	8,3	9,4	10,3	11,5	11,9	11,9	12,5	12,8	12,8	13,4	14,0
Biomass	1,4	1,4	1,4	1,6	2,2	2,7	2,7	3,2	3,2	3,2	3,2	3,2	3,2	3,2	3,2	3,2
Imported Coal	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2
Local Coal	1,0	1,0	1,0	1,0	1,1	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7
Natural Gas	7,3	7,7	8,2	8,2	8,8	9,5	9,9	10,3	10,6	10,8	11,1	11,9	12,8	13,3	14,0	14,6
Fuel/Diesel Oil	2,8	2,8	2,8	2,8	2,8	2,8	2,8	2,8	2,8	2,6	2,2	1,1	1,0	0,7	0,7	0,7
Nuclear	1,7	1,7	1,7	1,7	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	4,0	4,0	4,9
Others	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	2,4	2,4	2,1	1,9	1,6	1,4

FIGURE 22 - Guaranteed power output of non-hydroelectric generation by source

[20] "Other sources" include PROINFA-inspired projects and industrially processed gas.

Figure 23 shows the increase of guaranteed capacity per year for each source except hydro generation including contracted reserve capacity. The reduced supply of diesel / fuel oil and other sources from 2024 is due to (a) decommissioning of thermal plants contracted in new energy auctions since 2005 and (b) completion of the PROINFA contracts.



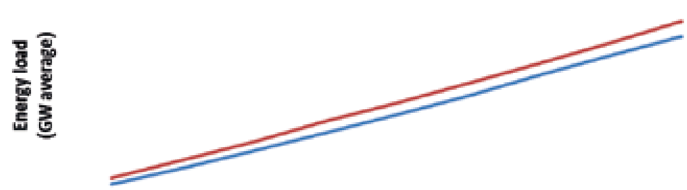
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar	0,0	0,0	0,0	0,2	0,0	0,0	0,0	0,2	0,0	0,2	0,0	0,2	0,0	0,2	0,0	0,2
Wind	1,0	1,6	0,9	1,1	2,1	0,6	1,1	0,9	1,2	0,4	0,0	0,6	0,3	0,0	0,6	0,6
Biomass	0,0	0,0	0,0	0,2	0,6	0,5	0,0	0,5	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Imported Coal	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Local Coal	0,0	0,0	0,0	0,0	0,2	0,6	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Natural Gas	0,0	0,4	0,5	0,0	0,7	0,6	0,4	0,4	0,2	0,2	0,3	0,8	1,0	0,5	0,7	0,6
Fuel/Diesel Oil	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,2	-0,4	-1,1	-0,1	-0,3	0,0	0,0
Nuclear	0,0	0,0	0,0	0,0	1,3	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1,0	0,0	1,0
Others	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,6	-0,1	-0,2	-0,2	-0,3	-0,2

FIGURE 23 - Increase in annual guaranteed power output for each source of non-hydroelectric generation

3.2.2 Comparison with PDE

Government-planned expansion is presented in the *Ten Year Energy Expansion Plan* (PDE 2023), which portrays the government's view of projected demand and power supply development over the next 10 years.

PSR´s demand projection is lower than that of the PDE, as can be seen in Figure 24:



	2015	2016	2017	2018	2019	2020	2021	2022	2023
PSR demand	67.5	70.0	72.7	75.4	78.2	81.1	84.3	87.5	90.4
PDE 2023 demand	68.4	71.2	74.1	77.2	80.1	83.1	86.2	89.4	92.7
Difference	0.9	1.3	1.5	1.8	1.9	2.0	1.9	1.9	2.3

FIGURE 24 - Different demand projections

The main reason for this difference is GDP growth expectations.

TABLE 5 - GDP evolution

HORIZON	GDP PROJECTION (% P.Y.)	
	2014-2018	2019-2023
PSR Projection	1.80%	3.40%
PDE 2023 Projection	4.10%	4.50%

Figure 25 compares the generation *mix* (in terms of installed capacity) between the PSR and PDE expansion scenarios for the last year of the time horizon (2023).

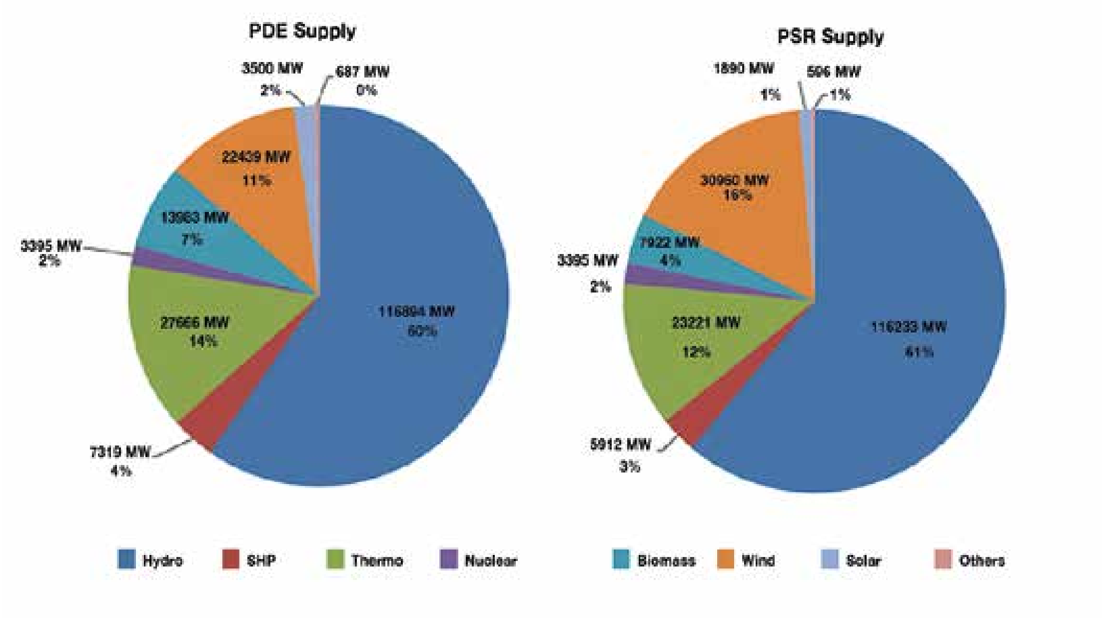


FIGURE 25 - Generation mix in 2023: PDE v PSR scenarios

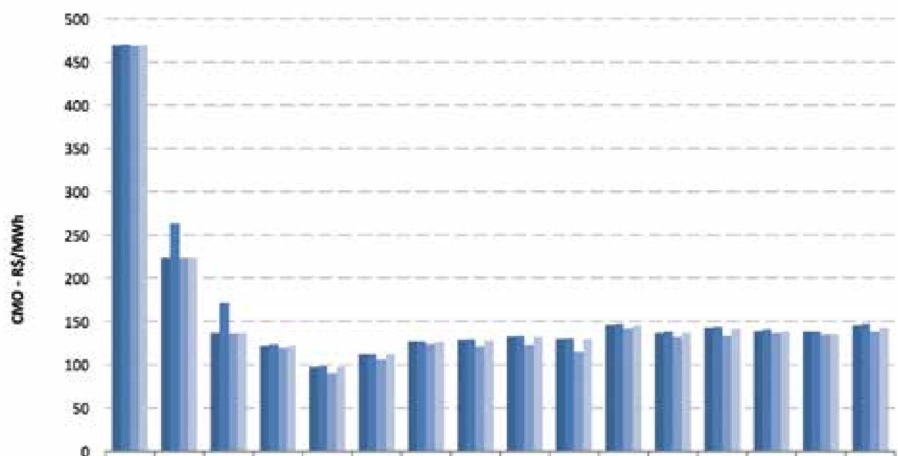
3.3 Results

After the supply and demand scenarios had been determined, the SDDP hydrothermal least-cost dispatch model (developed by PSR) calculated an optimum operating policy for 2015-2030, with an additional five years of static configuration to avoid reservoir depletion ending effect at the end of the period. This was done in monthly stages, with three demand levels at each stage. Hydrological uncertainty was represented by the multivariate stochastic inflow model (PAR-p) adjusted to the incremental inflows of each hydroelectric plant. The initial conditions of storage reservoirs and inflows refer to the end of December 2014. The transmission restrictions between the submarkets were represented by a network flow model.

The SDDP model represents in detail the physical, operational and commercial characteristics of the Brazilian system. The simulation of the system considers all the operating procedures used by the SIN (See Annex A for a description of this model).

3.3.1 Marginal Operating Costs Projection

Once the operating policy was calculated, a simulation was made of the operation of the system for 200 hydrological series[21] produced by the stochastic inflow model. For each t stage, each hydrological s series and each level of demand k, the marginal operational costs (MOC) were calculated for each submarket. Figure 26 shows the projection of the annual marginal operating costs.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Southeast	469	224	137	122	98	112	127	129	133	130	146	137	143	139	138	146
South	470	264	171	123	98	112	127	129	133	131	147	138	143	141	138	147
Northeast	469	224	136	119	90	106	124	121	122	115	142	132	133	136	135	138
North	469	224	137	122	97	112	127	128	132	129	146	136	142	138	136	143

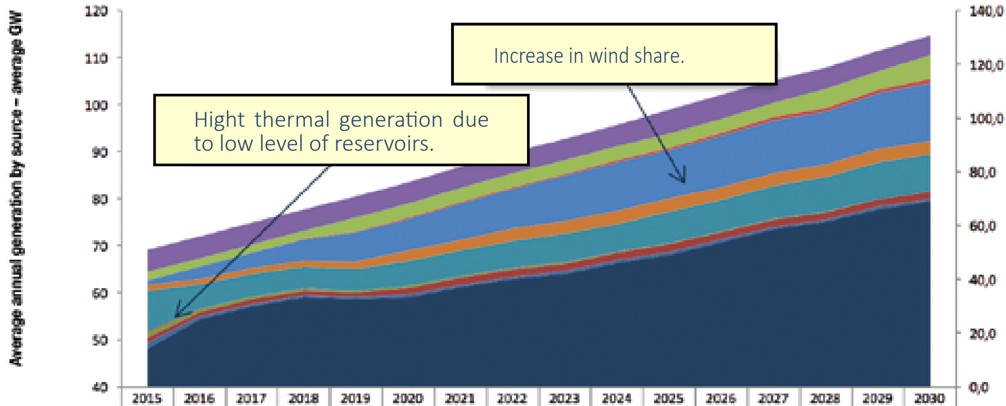
FIGURE 26 - MOC projection for the reference case

High marginal operating costs were noted for the years 2015 and 2016, resulting from low inflows observed in the 2013/2014 wet season and from structural problems such as the friction factor of the hydroelectric plants. The MOC were lower from 2017 where the delayed plants and the new contracted supply from recent auctions appeared in the simulation timeframe. From 2019 to 2023 prices of around 120 R$ per MWh were observed while over the longer term the MOC remains at R$140 per MWh, with a gap of 2% between supply and demand.

[21] Based on experience from previous studies, this number of hydrological scenarios was considered sufficient to capture the diversity of hydrothermal dispatch caused by the different hydrological conditions.

3.3.2 Power Generation

Figure 27 shows the evolution of average annual power generation per source.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Others	4,8	4,7	4,7	4,6	4,5	4,5	4,5	4,5	4,5	4,5	5,1	5,0	4,8	4,6	4,4	4,2
Nuclear	1,7	1,7	1,7	1,7	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,9	3,9	4,9
Solar	0,0	0,0	0,0	0,2	0,2	0,2	0,2	0,4	0,4	0,5	0,5	0,7	0,7	0,8	0,8	1,0
Wind	1,1	2,6	3,3	4,4	6,1	6,7	7,8	8,4	9,6	10,4	10,3	10,9	11,2	11,2	11,8	12,4
Biomass	1,2	1,2	1,2	1,3	1,7	2,2	2,2	2,7	2,7	2,7	2,7	2,7	2,7	2,7	2,7	2,7
Natural Gas	8,4	5,1	4,8	4,7	4,5	5,3	5,4	5,6	6,0	5,9	6,7	6,7	7,1	7,4	7,8	8,0
Diesel	0,4	0,2	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,0	0,0	0,0	0,0	0,0	0,0
Oil	1,2	0,6	0,4	0,5	0,3	0,4	0,3	0,3	0,3	0,3	0,3	0,1	0,1	0,1	0,1	0,1
National coal	1,0	1,0	1,0	0,9	1,0	1,5	1,5	1,5	1,5	1,5	1,6	1,6	1,5	1,5	1,5	1,5
Imported coal	1,3	0,7	0,5	0,5	0,4	0,5	0,5	0,5	0,6	0,5	0,7	0,6	0,6	0,6	0,6	0,5
Hydro	48,1	54,3	57,1	59,0	58,7	59,1	61,1	62,9	64,0	66,4	68,1	70,7	73,4	75,0	77,7	79,4
TOTAL	69,2	72,0	74,9	77,7	80,5	83,4	86,7	89,9	92,8	95,7	98,9	102,0	105,1	107,9	111,4	114,6

FIGURE 27 - Average annual generation per source for the reference case

3.4 CO_2 Emissions

3.4.1 Calculation of emissions

The SDDP simulation model produces the amount of energy generated monthly by the plant, the hydrological scenario and the demand level (e.g. peak and off-peak). Based on generation (MWh) and the unit emission factor (tCO_2 per MWh), the tCO_2 produced by the SIN in each month and each hydrological scenario can be calculated.

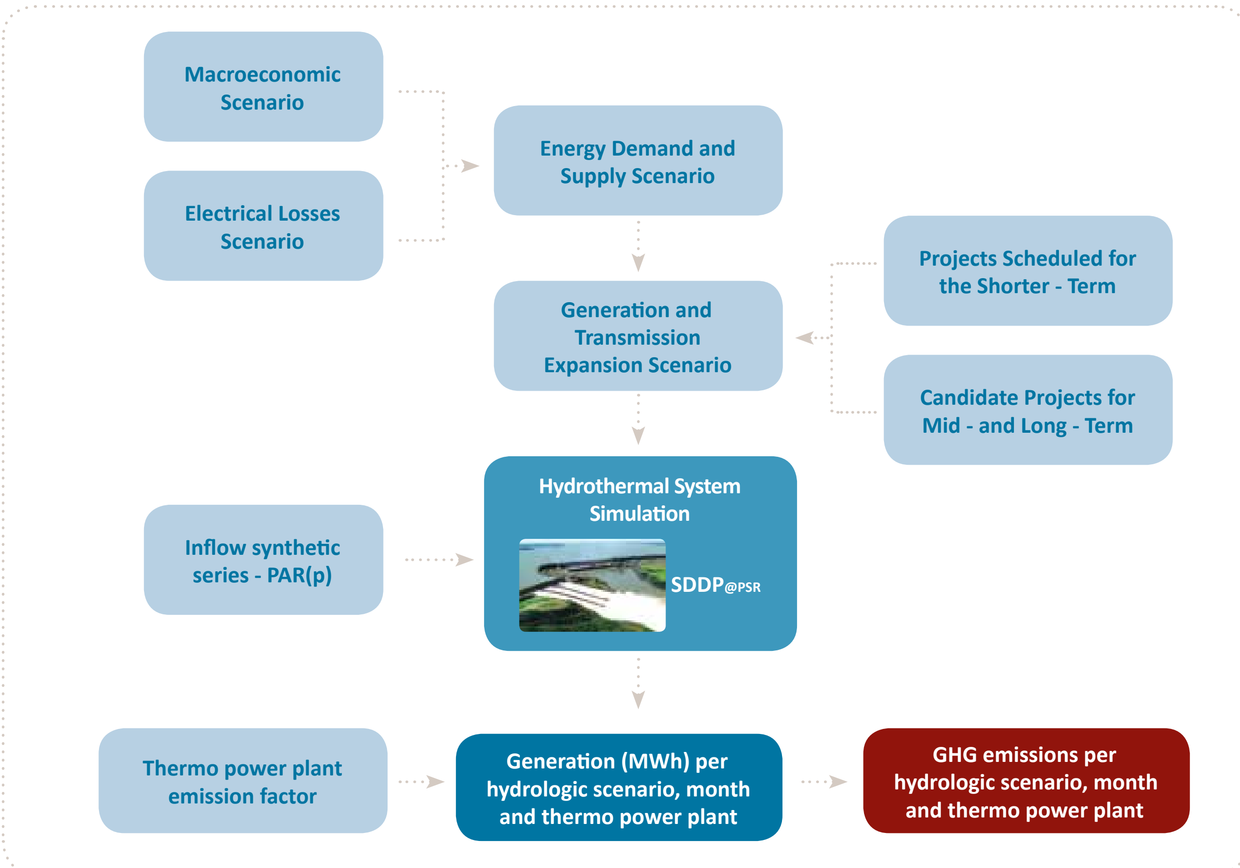


FIGURE 28 - Method for calculating greenhouse gas emissions in the SIN

The emission factor of each plant (tCO_2 per MWh) is determined on the basis of the plant´s efficiency (fuel consumption per MWh generated) and fuel type, as follows.

Emission factor (tCO_2 / MWh) = specific consumption (fuel units / MWh)
× fuel emission factor (tCO_2 per fuel unit)

In this report, calculations of the emission factors of the thermal power plants were based on standard Ministry of Science and Technology (MCT) data.

TABLE 6 - Emission factors of the thermal power plants

FUEL TYPE	UNIT	ENERGETIC FACTOR (TJ/UNIT)	CO_2 EMISSION FACTOR (TC/TJ)	OSIDATION FACTOR	EMISSION FACTOR (TCO_2/MWH)
Oil	MM liters	40.15	21.1	0.990	0.646
Diesel	MM liters	35.52	20.2	0.990	0.651
Natural Gas	MM m^3	36.84	15.3	0.995	0.361 to 0.633
Biomass	MM kg	-	-	1.000	0
National coal	MM kg	11.93	25.8	0.980	1.106
Imported coal	MM kg	-	-	0.980	0.890*
Nuclear	MWh	-	-	1.000	0

The consumption factor of thermal power plants used in the study is based on standard technical efficiency data, with the exception of the natural gas plants for which individual efficiency data are available (Source: *MME Natural Gas Bulletin*). Emission factors will therefore be equal per source, with the exception of the NG plants.

3.4.2 SIN emissions results

Figure 29 shows the minimum, average and maximum emissions for all the SIN plants over the time horizon of the study.

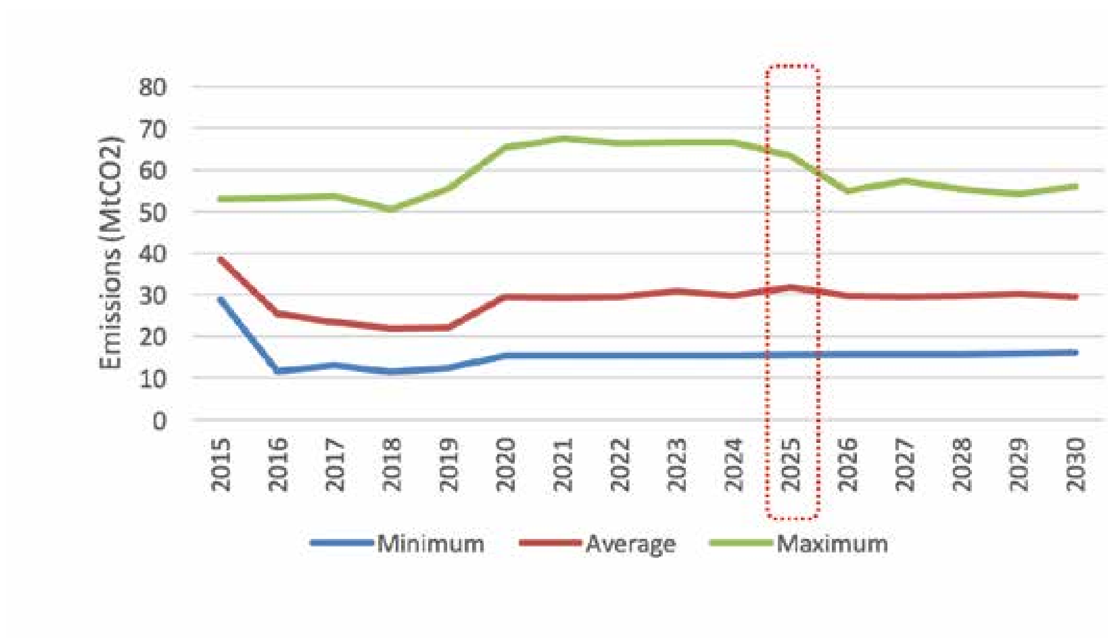
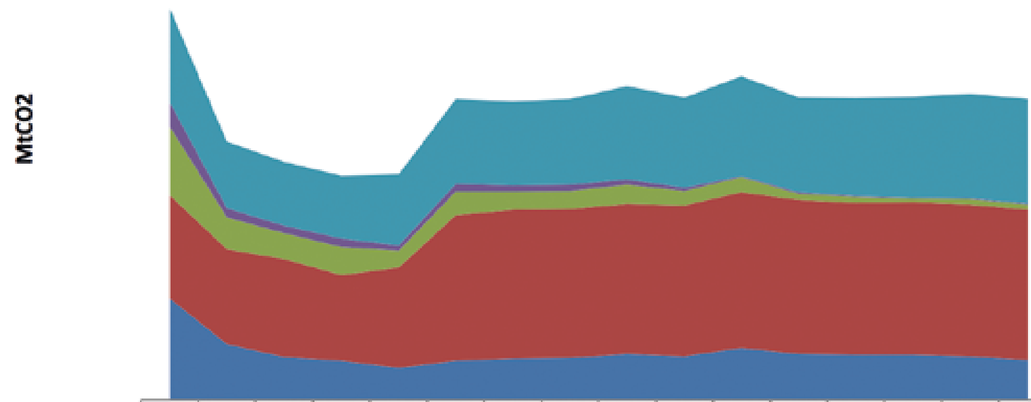


FIGURE 29 - Emissions for the reference case

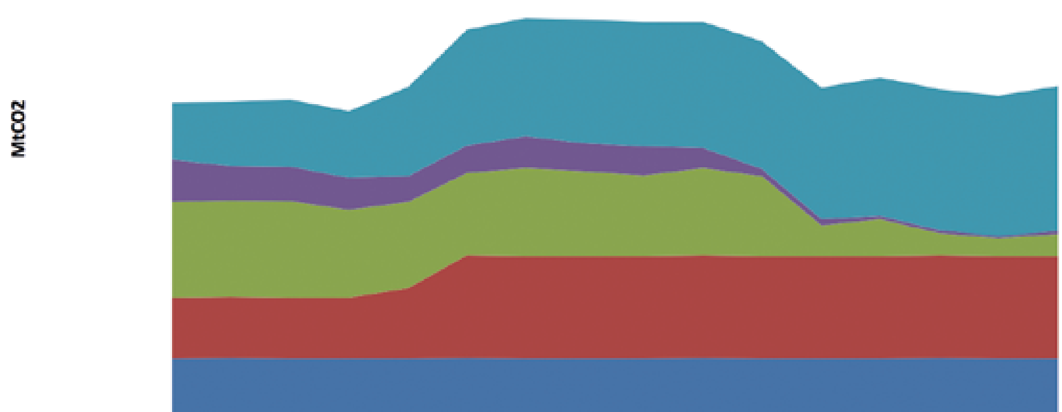
Note: 2025 is the reference year for the emissions reduction target in the INDC of Brazil.

Figures 30 and 31 show the average and maximum annual emissions by source.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural gas	9,2	6,6	6,3	6,2	7,0	8,4	8,3	8,4	9,1	8,8	9,8	9,3	9,6	9,9	10,3	10,3
Diesel	2,4	0,9	0,8	0,8	0,5	0,7	0,5	0,6	0,6	0,3	0,1	0,1	0,1	0,1	0,1	0,1
Oil	6,7	3,1	2,5	2,7	1,6	2,3	1,8	1,8	1,8	1,4	1,4	0,7	0,6	0,4	0,5	0,5
National coal	10,1	9,3	9,6	8,5	9,9	14,4	14,6	14,7	14,8	14,9	15,3	15,1	15,0	15,0	14,9	14,8
Imported coal	10,0	5,5	4,2	3,9	3,2	3,8	4,1	4,1	4,5	4,3	5,1	4,5	4,4	4,5	4,3	3,9
TOTAL	38,4	25,4	23,4	22,0	22,2	29,5	29,4	29,6	30,8	29,7	31,8	29,7	29,7	29,8	30,1	29,6

FIGURE 30 - Average annual emissions by source for the reference case



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural gas	9,7	10,9	11,4	11,2	15,1	19,6	20,1	20,8	21,0	21,3	21,6	22,2	23,3	23,7	23,8	24,4
Diesel	7,1	5,8	5,8	5,3	4,3	4,6	5,3	4,7	4,8	3,4	1,1	1,0	0,6	0,5	0,4	0,5
Oil	16,1	16,2	16,2	14,8	14,5	13,9	14,8	14,3	13,6	14,6	13,5	5,1	6,1	3,7	3,0	3,7
National coal	10,2	10,3	10,3	10,3	11,9	17,3	17,3	17,3	17,3	17,3	17,3	17,3	17,3	17,3	17,3	17,3
Imported coal	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0
TOTAL	53,1	53,3	53,6	51,6	55,8	65,4	67,4	67,1	66,7	66,7	63,4	55,6	57,3	55,3	54,4	55,9

FIGURE 31 - Maximum emissions by source for the reference case

Figure 32 shows the probability density function of the annual emissions in selected years. 2015 is an atypical year since most of the energy matrix is connected for virtually the entire year. The probability distribution is subject to this short-term situation. A reduction is expected in subsequent years arising from the rebalancing of supply and demand resulting in an average reduction of emissions. There is however a small increase between 2020 and 2030 caused by the anticipated increase of fossil fuel thermal generation in the energy matrix.

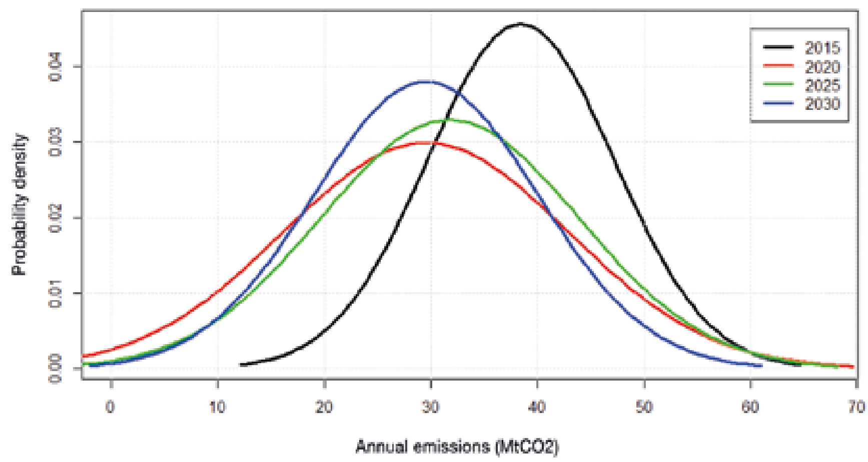


FIGURE 32 - Probability density function of annual emissions for the reference case

Figure 33 shows the probability distribution of SIN emissions in 2030, with an average of around 30 million tons per year, although this varies substantially as a result of hydropower predominating in the energy matrix.

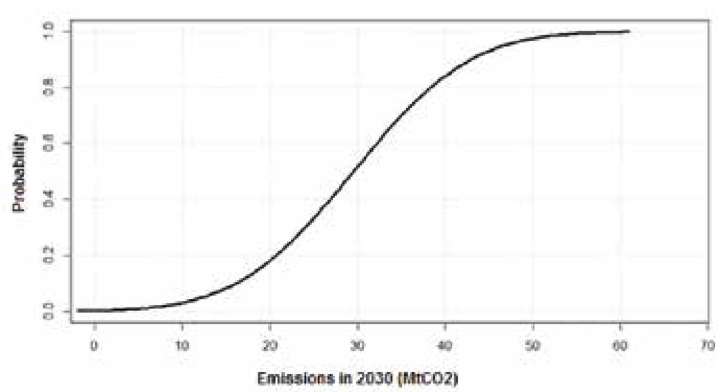


FIGURE 33 - Probability distribution of SIN emissions in 2030 for the reference case

The two figures below show the probability density and probability function for cumulative SIN emissions in 2015-2030.

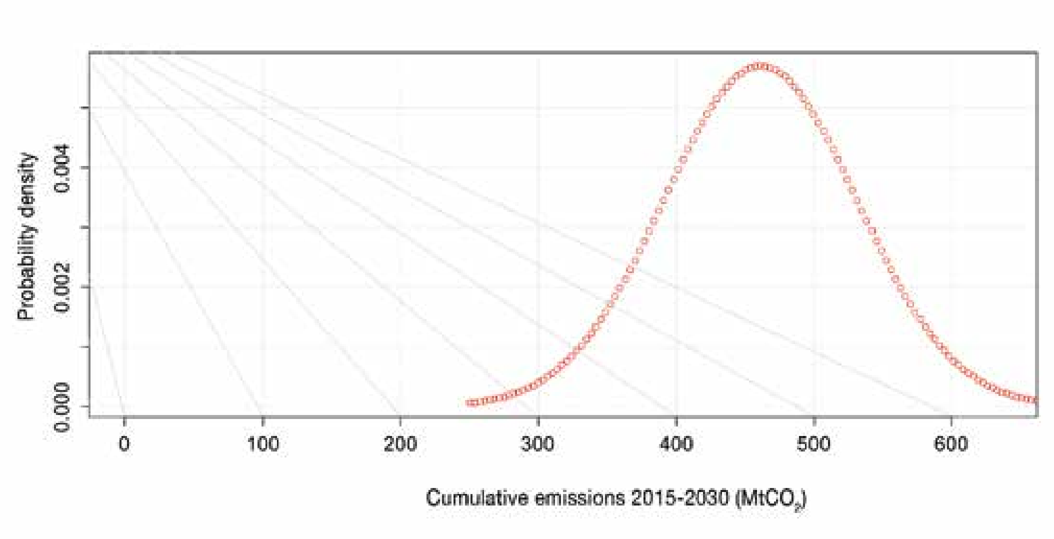


FIGURE 34 - Probability density function of cumulative emissions for the reference case

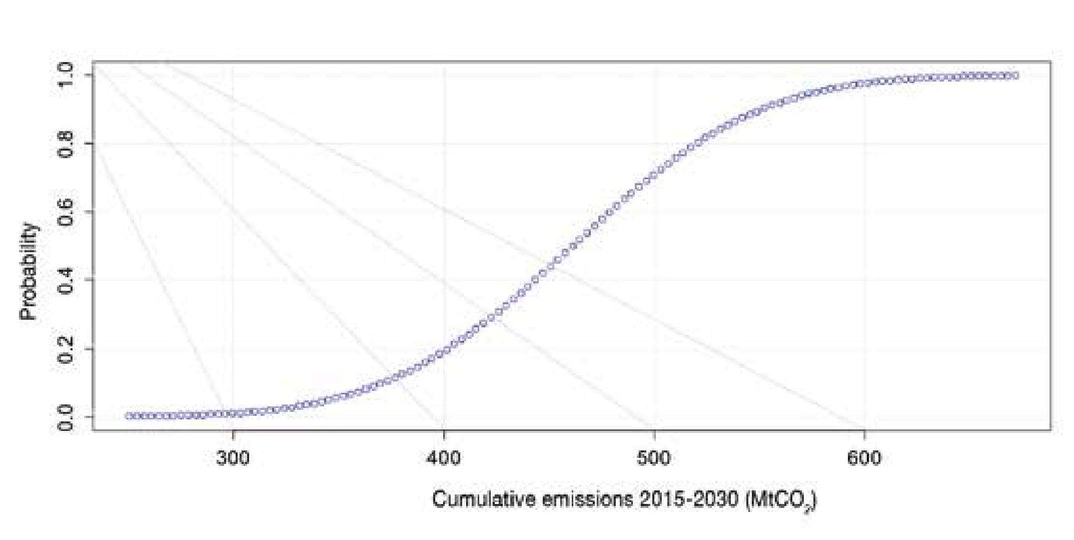


FIGURE 35 - Probability of SIN cumulative emissions for the reference case

The projections differ little on average from those projected by the EPE in the 2023 *Ten Year Plan* (Table 7 below).

Some conclusions can be drawn regarding the GHG emissions from plants connected to the SIN:

- 2016-2019: emission reductions (reverting to the average), due to higher surplus energy in the SIN and the expectation of improved hydrological conditions.
- Decommissioning of the oil-burning plants reduces maximum annual emissions but does not modify average values in view of their low dispatch factors.
- While *average* emissions in 2030 are 30 million tCO2, there is a 10% probability that they will be less than 17 million tCO_2 and a 10% probability of an excess of 50 million tons of tCO_2.
- As for the cumulative emissions, there is a 10% probability of them being less than 380 million tCO_2 and a 10% probability of an excess of over 550 million tCO_2.

In the next chapter we explore this natural variability in more detail and present criteria for selecting a representative *dry hydrology* scenario.

3.4.3 Emissions from self-production energy

This study did not evaluate the greenhouse gas emissions caused by electric power production outside the SIN. These emissions arise from isolated and remote systems generally located in the Amazon region and mainly consisting of small consumer operated generating facilities.

According to the PDE 2023, self-production projections are based on data about new developments and assumptions about expansion potential, especially cogeneration and expansion of industrial installed capacity. In the pulp industry, for example, capacity expansion will depend entirely on cogeneration, while in the steel industry the PDE considered the expansion of installed capacity by evaluating the cogeneration potential of each technological route. As for the petrochemical industry, COMPERJ in Itaboraí, Rio de Janeiro, will be supplied entirely by self-produced power. Based on these assumptions, the amount of self-produced power for the 2023 horizon is considered to expand by 6.1% annually (much higher than verified in the SIN).

TABLE 7 - Self-produced power in Brazil (Source: PDE 2023)

SECTOR	2014	2018	2023
		GWH	
Steel	5.205	5.205	5.205
Petrochemicals	2.459	2.459	2.459
Cellulose/paper	11.187	16.096	20.362
Sugar/alcohol	15.226	18.247	20.584
E&P	10.015	18.093	27.586
Other sectors	9.079	11.724	13.507
Total	**53.171**	**71.825**	**89.703**

For the 2023 horizon, according to the PDE 2023, GHG emissions from self-production will be equivalent to those produced in the SIN in 2023. These emissions are less variable than those in the SIN given that the energy supply is unrelated to (variable) hydroelectric production. The major driver of these emissions is industrial demand in response to the national or international exports market.

4 ANALYSIS OF THE LOW HYDROLOGY CASE

In this chapter we use the term “dry hydrology” based on an analysis of scenarios produced by a model that uses historical inflows. This is a *bottom-up* methodology based on the “normal” hydrological variability of the reference case (without considering climate change effects), and focused on the selection of a representative subset of scenarios.

In this case, we adopt the stationary inflow hypothesis according to which future HPP inflows will repeat those of the past[22]. Using this approach, we assess the effects of low hydrology occurrence on Brazil´s power sector indicators, such as operating costs, increased output by thermal power plants and GHG emissions. This evaluation provides a clearer understanding of the *variability* of emissions in the Brazilian electricity sector due to hydrologic fluctuations.

Comparisons are made for annual emissions and cumulative emissions between 2015-2030 (of particular interest in terms of atmospheric CO_2 concentrations and climate change).

Session 4.2 presents a sensitivity analysis of the GHG produced by the Brazilian power sector (without the stationary hydrological hypothesis). In this analysis, the mathematical model that produces hydrology scenarios (inflows) uses parameters (average, standard deviation, asymmetric) that differ from the values based on the historical sample. A *top-down* approach is used involving: (i) downscaling different models of atmospheric circulation for Brazilian watersheds, taking account of IPCC scenarios; and (ii) a hydrological model (time series) up to year 2100 with results of (i) above, i.e. temperature, humidity and rain producing inflows up to 2100. Based on the new estimated parameters for these inflows (i.e. different from the historical inflows), the SDDP hydrology model generates new inflow scenarios and the SIN operation is conducted considering the reference case (same assumptions about supply and demand).

4.1 Characterization of low hydrology

4.1.1 Introduction

An operating policy tailored to *hydrological forecasting* can be a risky strategy. The heavy dependence of the SIN on hydrology suggests that decision-making is based on different future scenarios. This approach involves making decisions under uncertainty to minimize average operating costs, or cost overruns in worst case scenarios.

[22] The stationary hypothesis can be considered a restriction of this approach; however, the proposed “bottom-up” approach is deemed to be essential for this study as it is consistent with the current practice of the sector in Brazil.

- If a “wet” scenario is used, optimization will involve heavier use of hydropower. However, in the event of a real-life “dry” hydrologic scenario, the system will reach a low water storage level, possibly even leading to rationing (high-risk operation planning).
- Decisions based on a “dry” scenario means less hydropower and higher costs due to the high thermal dispatch. If in real life the hydrologic scenario is wet, reservoirs could reach a situation of excessive storage, possibly leading to spillage (highly conservative operation planning).

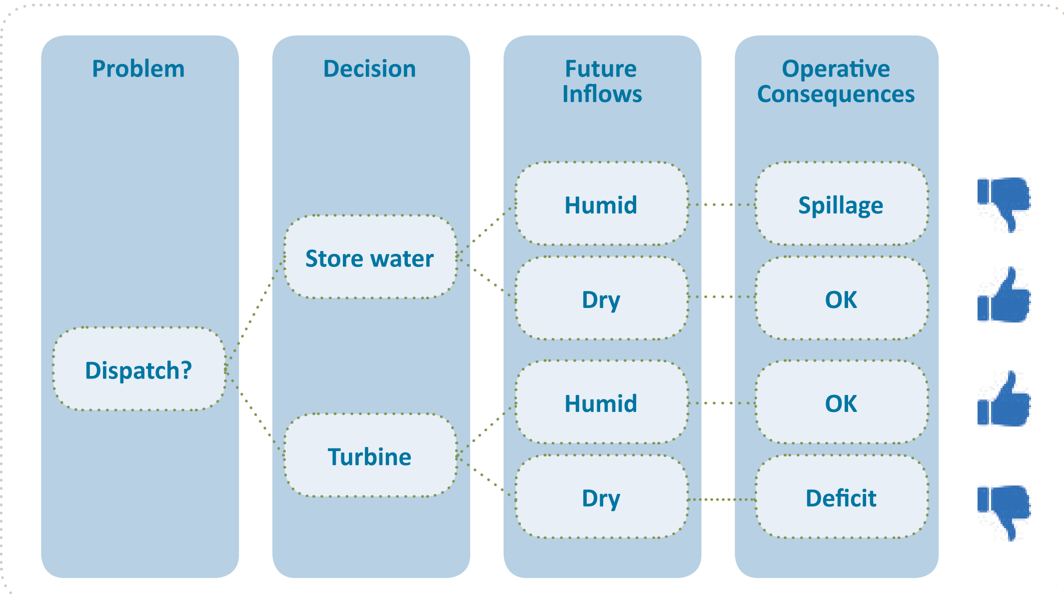


FIGURE 36 - Operational outcomes of hydrothermal dispatch decisions

The use of an optimization model under uncertainty - specifically a stochastic model for hydrothermal dispatch - is more appropriate. This approach is based on the generation of synthetic inflow series for the planning horizon. There are two approaches to generating inflow scenarios:

- **APPROACH 1**: Historical series.
- **APPROACH 2**: Modeling synthetic inflows using stochastic models to ensure statistical “similarity” with historical inflows.

1. Generation of future inflow series based on past statistics (since 1931), retaining parameters such as average inflow rates, standard deviation, and spatial and temporal correlation: synthetic series;
2. Periodic autoregressive models, seasonal dependence structure ;
3. Production of droughts as severe as those in historical record;
4. Generation of synthetic inflow series to calculate hydrothermal operating policy and for simulating the operation.

Figure 37 shows details of Approach 2.

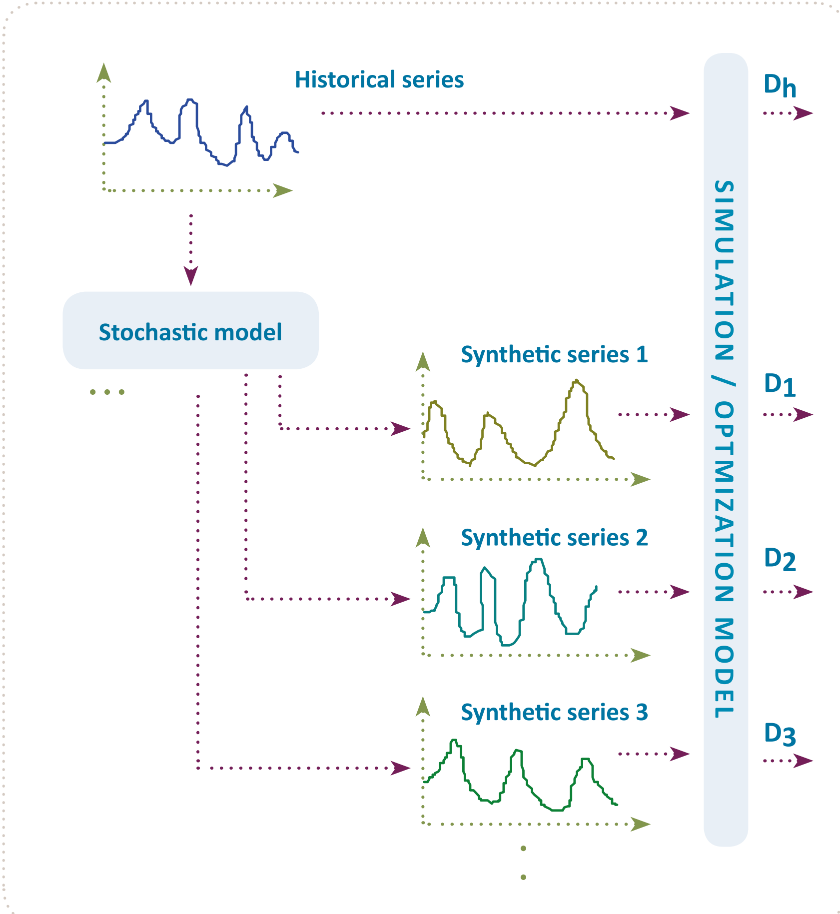


FIGURE 37 - Modeling synthetic inflows using stochastic model

Operational and expansion planning in Brazil uses synthetic inflow series, or natural inflow energy, given that the *historical time series* is only one of the possible outcomes of a stochastic process (e.g. as if nature had randomly picked the time series according to some set of probabilistic laws, with a random component producing a different but equally probable series). This reasoning leads to the use of a Monte Carlo method which allows the synthetic series generated with a periodic autoregressive model to reproduce historical statistics.

4.1.2 Natural Inflow Energy – ENA

Inflows can be mapped as "input energy" as follows:

$$ena(i,t,s)=q(i,t,s)\times\varphi(i)$$

EQUATION 2

Where:

$q(i,t,s)$	natural inflow to plant $\boldsymbol{i}$ in month $\boldsymbol{t}$, scenario $\boldsymbol{s}$ (m^3 / s)
$\phi(i)$	production factor of plant $\boldsymbol{i}$ basically depends on the turbine-generator´s drop and power output (MW / m^3 / s)
$ena(i,t,s)$	natural inflow energy (MW)

The ENA of a region k can be calculated by the sum of the ENAs of plants in the region.

$$ENA(t,s) = \sum_{i \in k} ena(i,t,s)$$

EQUATION 3

The amount is usually expressed as average MW or GWh (the MW multiplied by the number of hours of e.g. one month, and dividing it by 1000).

4.1.3 Synthetic series models

Stochastic models must ensure statistical similarity between the historic and synthetic series, thus preserving key statistics such as average, standard deviation, spatial and temporal correlations. In all the cases, river inflows are assumed to be *stationary* i.e. future inflows are consistent over time and repeat the same probability distribution as past inflows. This is a controversial assumption (see the chapter on climate and land use changes).

After the stochastic models that capture the statistical behavior of the hydrology have been estimated, natural inflow scenarios can be generated with a Monte Carlo method. This study also uses synthetic flow series generated with a periodic autoregressive model - PAR (p).

- Synthetic inflows generated by the PAR (p) model depend on p previous months.
- The model is periodic (“p” varies according to month).
- The adjustment of the stochastic model is performed for each hydrological station.

For simplicity, we present the PAR (1) univariate model:

a_m is the inflow of month m. From a_m we obtain $x_m = (a_m - \mu_m)/\sigma_m$.

ε is a lognormal white noise of 3 parameters and ρ_m is the serial autocorrelation of x_m.

$$\text{PAR}(1)\text{: } x_m = \rho_m x_{m-1} + (1 - \rho^2_m)^{1/2} \varepsilon$$

EQUATION 4

The probability distribution varies over time to ensure strictly non-negative inflows.

The sample average $\hat{\mu}_m$ of each month is estimated by:

$$\hat{\mu}_m = \frac{1}{N} \sum_{n=1}^{N} a_{(n-1)*12+m}$$

EQUATION 5

Standard deviation $\hat{\sigma}_m$:

$$\hat{\sigma}_m = \sqrt{\frac{1}{N-1} \sum_{i=1}^{N} (a_{(i-1)*12+m} - \hat{\mu}_m)^2}$$

EQUATION 6

The correlation coefficient $\hat{\rho}_m$:

$$\hat{\rho}_m = \frac{\frac{1}{N-1} \sum_{i=1}^{N} (a_{(i-1)*12+m} - \hat{\mu}_m) * (a_{(i-1)*12+m-1} - \hat{\mu}_{m-1})}{\hat{\sigma}_m * \hat{\sigma}_{m-1}}$$

EQUATION 7

Figure 38 shows the SIN ENA produced by the PAR (p) model to generate 200 hydrological scenarios (January 2015) conditioned to the first year (TWh) (because of temporal correlation).

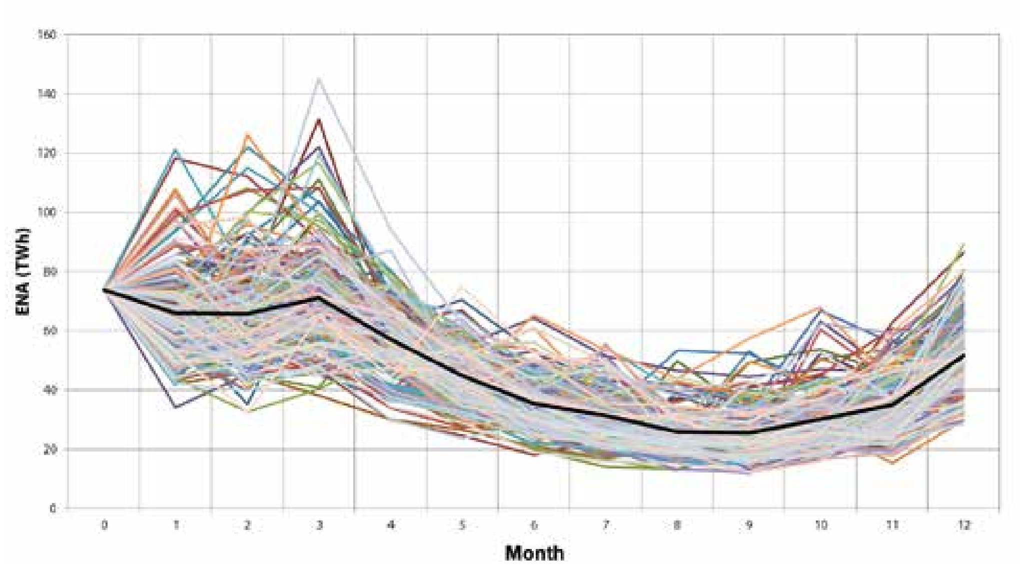


FIGURE 38 - Variability of ENAs generated by hydrological scenarios of the PAR (p) model

4.1.4 Temporal Correlation

We illustrate the temporal correlation with historical Natural Inflow Energy (ENA) data. Figure 39 shows the probability distribution of the ENA of the Southeast region February-April, without temporal correlation (i.e. "marginal probability distribution").

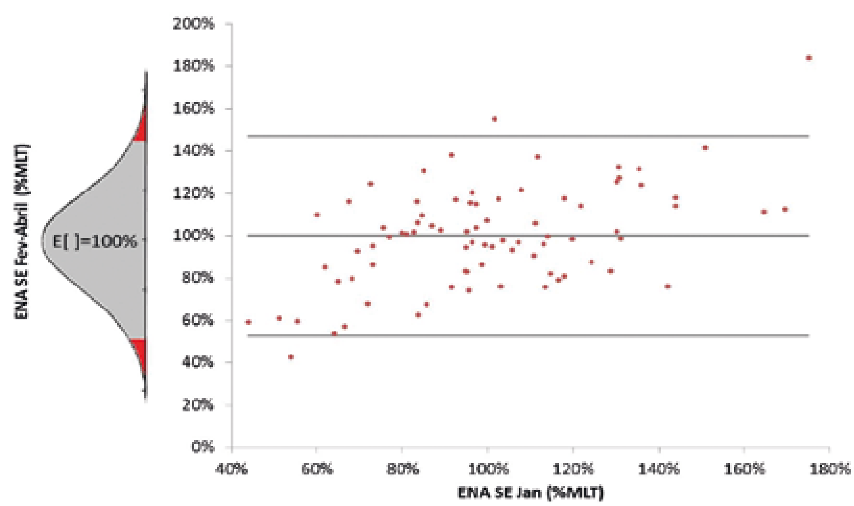


FIGURE 39 - Distribution probability of ENAs of the Southeast in February-April, without temporal correlation

Figure 40 shows the probability distribution of ENAs for February to April *conditioned* to the ENA verified in January. This distribution is a proxy of that used in the PAR(p). In this case, the expected value *conditioned* to the ENA for January 2015 (only 44% of the average inflow) implies a reduction in the average ENA projected for 75% of the MLT (long term average corresponding to the arithmetic average of the average natural inflows).

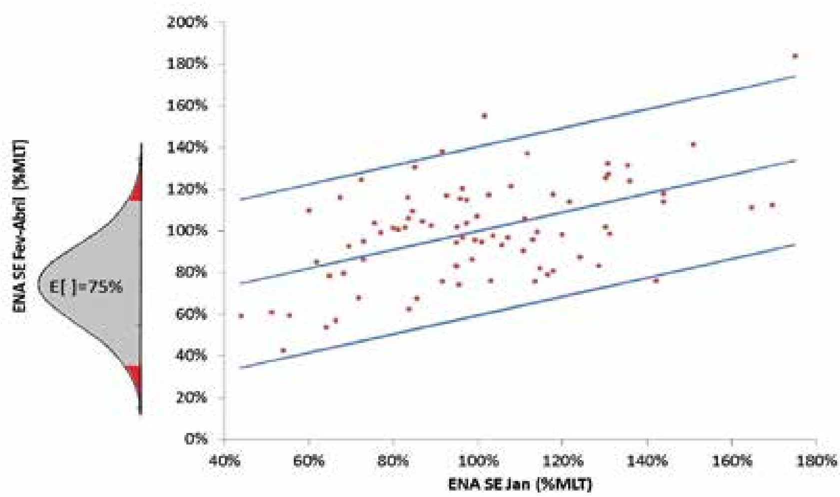


FIGURE 40 - Distribution probability of ENAs of the Southeast in February-April, with temporal correlation

4.1.5 Selection of dry hydrology

The selection of dry hydrology was based on probabilistic criterion with a confidence interval. Therefore the selection of the scenarios involves a value of cumulative ENA (inflow energy) over the study horizon so that, with high probability, the cumulative ENA can surpass it. Given that the selection was based on values of cumulative ENA for the entire horizon it is possible that there are good hydrologic years within the series selected as «dry» years. This occurs because the analysis of the whole series showed that the cumulative ENA is low. In other words, it is possible that from the standpoint of emissions reduction a wet year followed by a very dry year may generate less emissions than during two dry years, not far from the average. The emissions are more sensitive to the length of the period in which the thermal plants are activated than to actual generation. This occurs due to SIN inertia over reservoir water levels. It is not possible to classify dry hydrology for a specific year.

Definition: We characterize **Dry Hydrology** as a set of scenarios where the cumulative ENA up to 2030 is among the 10% lowest values of the sample. Although the 10% criteria is arbitrary, it is consistent with the 10% limit adopted by the sector to define the acceptable risk; in addition, most of water right issued in the country are based on a 90% guarantee level.

Figure 41 shows the ENAs for the years 2015, 2020, 2025 and 2030 and the cumulative ENAs. For cumulative ENAs, the values placed to the left of the percentile 10% are representative of dry hydrology.

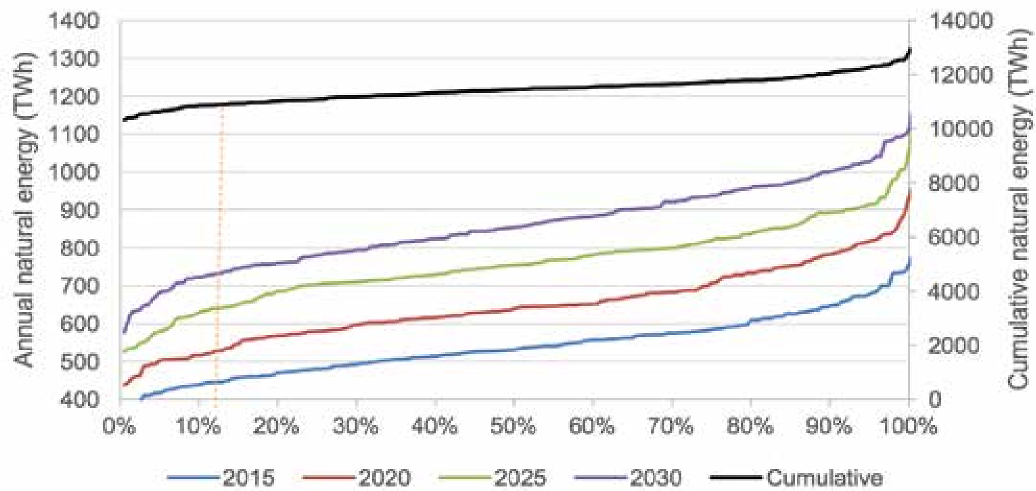


FIGURE 41 - Cumulative Natural Energy 2015-2030

Alternatively, Figure 42 illustrates the probabilities distribution of cumulative ENAs with an indication of the subset of dry hydrology scenarios.

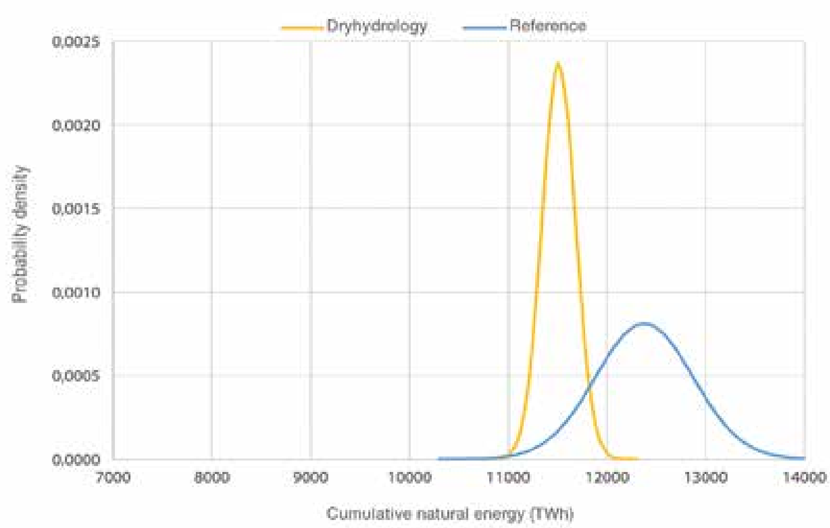


FIGURE 42 - Definition of dry hydrology

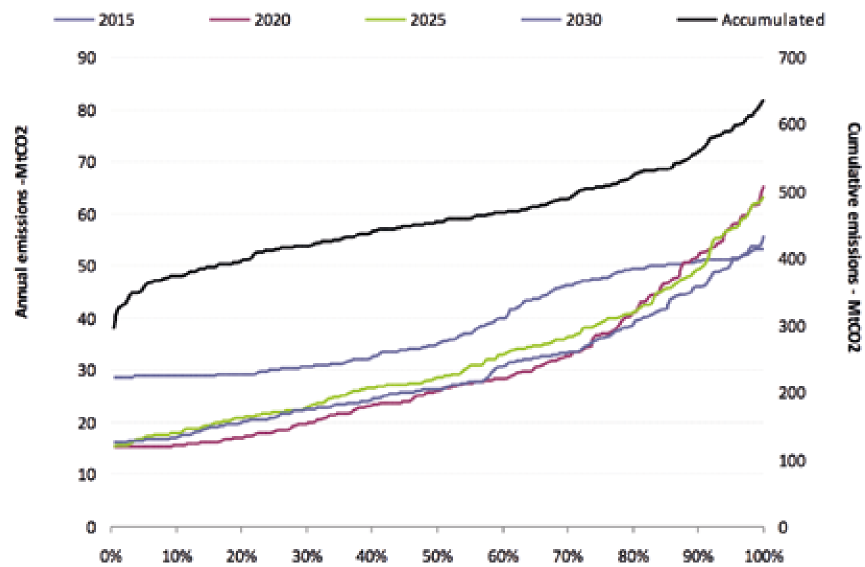


FIGURE 43 - Probability distribution of annual emissions for the reference case

The relationship between the average expected value of the cumulative ENA of the dry hydrology subset, in yellow (11510 TWh), and the average expected value of the cumulative ENA for the entire sample of simulated series in the reference case (blue curve - 12378TWh), is 93%.

Figure 43 represents the probability distribution of emissions for years 2015, 2020, 2025 and 2030 in addition to the cumulative ENAs for the entire study horizon. It can be noted that in the later years the series with higher emissions represent values of around 4 times greater than the series with lesser emissions.

From the simulation with SDDP it is possible to relate the ENA and respective GHG cumulative emissions for the period considered for the 200 hydologic scenarios. Figure 44 shows that the highest cumulative emissions, as expected, are related to the lowest ENAs. For the subgroup of dry series the average emissions amount to 575 million tons over the period, as can be seen in Figure 44.

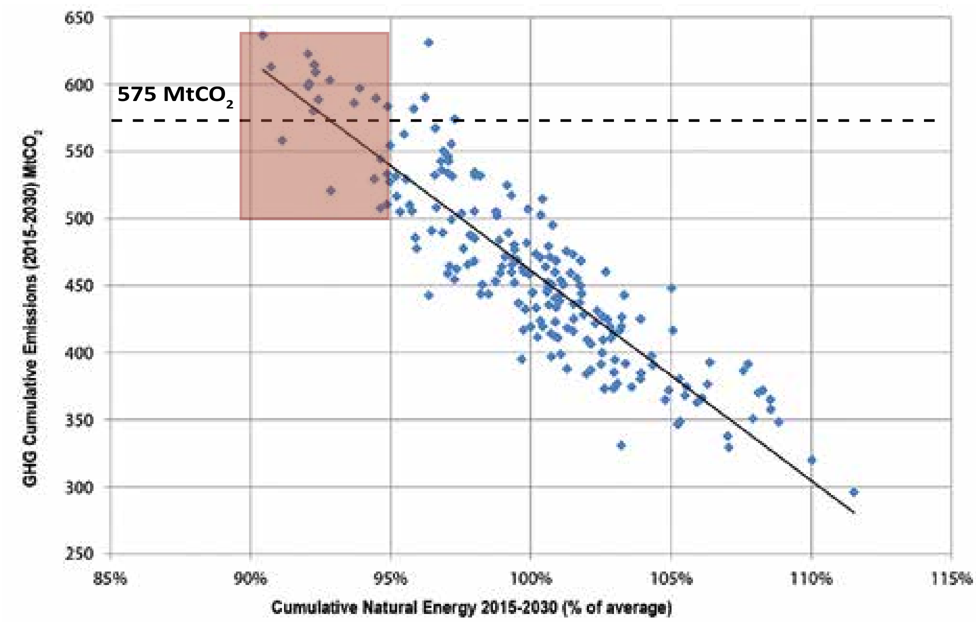


FIGURE 44 - Selection of dry scenarios

At first glance this criterion for selecting "low hydrology" may seem overly rigorous because of its limited likelihood. However, the following additional aspects should be considered, that, when combined, could make the selection more probable.

1. It is assumed that the time series generation model is stationary, but this assumption is increasingly questioned given the growing evidence that soil use changes (e.g. deforestation for logging, extensive livestock raising or crops) disturb the hydrological regime. It follows that using the same rainfall assumption, inflows in the rivers can be affected by human activity. In this context, the probability perceived as "remote" by the stationarity hypothesis could in fact be not so remote.
2. Recent examples of change include the inflows in the São Francisco river (especially the Sobradinho reservoir), which have reduced by 20% over the last 20 years compared to the long-term average[23]. For this particular case, if we assume that inflow regime did not change, there is only a 5% probability for annual inflow being less than 67% of average. If we reduce average inflows by a 20% reduction to "incorporate" the new inflow pattern exhibited in the past 20 years, than, the probability of annual inflows being less than 67% of the average spikes to 26%, i.e. over five times higher.
3. The current process for generating inflow scenarios assumes that the parameters estimated on the basis of historical data are populational. If parameter uncertainty, is considered (it relates to the sample size) than the probability distribution of inflow energy changes, with a shift toward "fat tails".
4. The possibility of climate change altering the hydrological regime through crop evapotranspiration (ET) and rainfall changes can contribute to increasing the probability of events hitherto regarded as improbable.

[23] PSR Energy Report. Edition No. 83, Nov. 2013.

4.1.6 On the probabilistic definition of dry hydrology

For almost four decades synthetic hydrology has been used for the probabilistic assessment of the energy supply in the Brazilian power sector.[24] Scenarios generated by hydrologic models have been used in planning models for the operation of the National Interconnected System (SIN).

In simple terms, a significant sample of scenarios is used to define an operating policy (the amount of water to be released from reservoirs at given times, resulting in conversion into energy and - by subtraction - the amount of fuel to be used in thermal and other sources to meet the needs of the energy consumption market). This operation essentially seeks to maintain reliable energy supply from SIN. The models use ENA scenarios to address this problem or - in their more detailed version, by the representation of individual power plants (SDDP, as used in this study) - use inflow scenarios for each hydroelectric plant.

Another application of hydrologic scenarios is the methodology used for calculating the Physical Guarantee of Supply. In this case, the probabilities distribution of energy that could be produced without interruption by a series of SIN hydroelectric plants was historically evaluated. This criterion defined the Assured Energy (subsequently called Guaranteed Energy) of the hydropower plants. From the methodological standpoint the procedure abandoned the use of historical inflows, employing the argument that the driest (or critical) period in the first half of the 1950s would be merely the realization of a stochastic process that it was intended to model. The criteria was effectively based on a conservative value, associated to a dry hydrology with low probability of occurrence in the distribution of energy produced by the hydroelectric plants. The criterion adopted was to select the percentile 95% of yearly supply reliability or, alternatively, to admit an annual 5% probability of failure in electricity delivery.

The criterion for ONS operation of the plants was also the subject of extensive methodological changes following the rationing event that occurred in 2001. The methodology used for the dispatch problem, based on the expected operating cost, was accompanied by other restrictions such as the target level of reservoir storage) and the Aversion to Risk Curve. More recently (from 2013), in the target function of the hydrothermic dispatch problem, a combination of the expected value of the operating costs for all the simulated series and the expected value of the operating costs for a subset of selected dry series has been used. This second term in the target function is known as Conditional Value at Risk (CVaR). The incorporation of CVaR in the calculation of operating policy eliminated the Risk Aversion Curve and the hydrothermal dispatch Target Level.

[24] ARARIPE NETO, T. A.; COTIA, C. B.; PEREIRA, M. V. F. & KELMAN, J. Comparison of Stochastic and Deterministic Approaches in Hydrothermal Generation Scheduling. In: IFAC Symposium on Planning and Operation of Electric Energy Systems, Rio de Janeiro, 1985. p. 201-206.

KELMAN, J.; KELMAN, R. & PEREIRA, M. V. F. Energia Firme de Sistemas Hidrelétricos e Usos Múltiplos dos Recursos Hídricos. RBRH – Revista Brasileira de Recursos Hídricos, vol. 9, n. 1, jan. / mar. 2004. p. 189-198.

KELMAN, J.; STEDINGER, J. R.; COOPER, L. A.; HSU, E. & YUAN, S. Sampling Stochastic Dynamic Programming Applied to Reservoir Operation. In: Water Resources Research, v. 26, n. 3, p. 447-454, March, 1990.

KELMAN, J. Uso de Séries Sintéticas no Planejamento e Operação de Sistemas Hidrotérmicos.In: I Seminário Latinoamericano Sobre Aproveitamento de Recursos Hidráulicos. Colombia, Medellín,1987.

KELMAN, J.; GOMES, F. B. M.; PINHEIRO, S. F. & PEREIRA, M. V. F. Revisão do Conceito de Energia Firme Através do Uso de Séries Hidrológicas Sintéticas.In: V Seminário Nacional de Produção e Transmissão de Energia Elétrica, Recife, 1979. 17 p.

MACEIRA, M. E. P.; KELMAN, J. & DAMÁZIO, J. M. Utilização de Modelos Par para Simulação e Previsão de Séries Hidrológicas Mensais.In: VII Simpósio Brasileiro de Hidrologia e Recursos Hídricos, ABRH, Salvador, 1987.

PEREIRA, M. V. F.; DE OLIVEIRA, G. C. & COSTA, C. C. G. & KELMAN, J. Stochastic Streamflow Models for Hydroelectric Systems. Water Resources Research, v. 20, n. 3, 1984. p. 379-390.

SALAZAR, P. G.; PEREIRA, M. V. F. KELMAN, J. & GOMES, F. B. M. Geração de Séries Hidrológicas Mensais para Estudos Energéticos. In: IV Seminário Nacional de Produção e Transmissão de Energia Elétrica, Rio de Janeiro, 1977.

From the generic standpoint this approach to decision making (thermal dispatch) gives more weight to unfavorable (dry) scenarios) than to normal scenarios. The greater weight in the target function of the less favorable hydrological scenarios anticipates the activation of the thermal plants as a preventive measure. In practice, there is an equivalence between this approach and an approach where the cost of service failure (or deficit cost) is increased to force preventive action via activation of the thermal plants to reduce the probability of future deficits accompanied by higher costs.

The use of CVaR is very common in financial market applications where investment decisions seek to maximize expected return by imposing restrictions on investment portfolio risks. The approach became very popular after the publication of the article "*Conditional value-at-risk for general loss distributions*" (2002) by R. Tyrrell Rockafellar and Stanislav Uryasev, which showed that - unlike optimization with VaR restriction that is not convex (more complex), the problem formulated with restrictions on the value of the expected cost (or revenue) of the scenarios that are more critical than the chosen VaR risk level (CVaR) would be convex and easy to implement through scenarios.

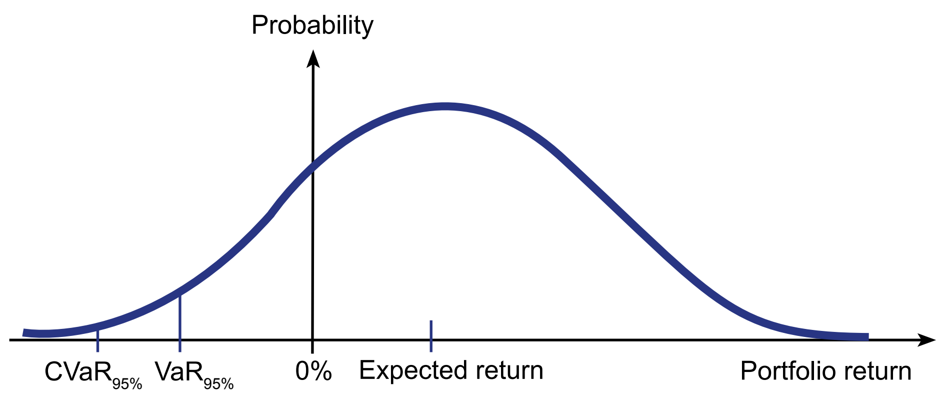


FIGURE 45 - VaR and CVaR concept

The definition of dry hydrology in the report is therefore in tune with the fairly usual practice of using a probabilistic assessment of the variable of interest, which in this case was characterized as Cumulative Natural Inflow Energy on the analysis horizon 2015-2030.

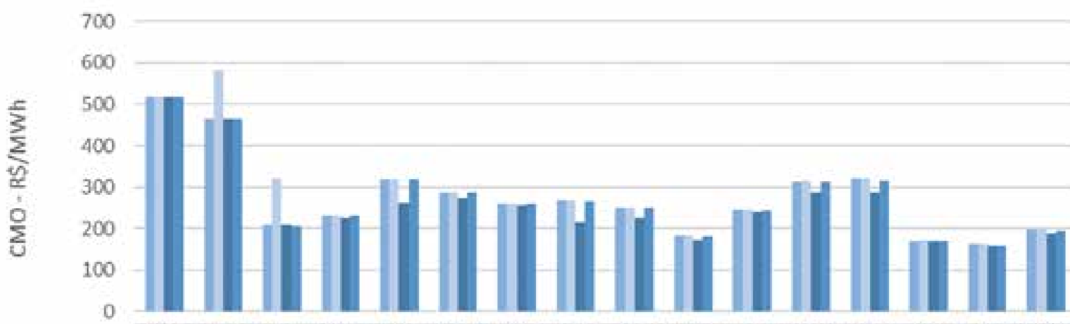
We have chosen, in this case, the percentile 10% (in contrast to the established use of 5% for SIN energy supply) because we found that - in terms of greenhouse gas emissions - this cut-off point is more suitable. We also observed from the analysis, as expected, that a good relationship exists between the variable chosen to characterize dry hydrology and the total level of GHG emissions in the Brazilian power sector, with the approximately linear growth of these emissions for reducing the cumulative ENA.

4.1.7 Results

The results of the low hydrology analysis are extracted from the reference case simulations, taking into account only the 17 low hydrology series.

4.1.7.1 MOC Projection

Figure 46 shows the marginal operating costs (MOC) projected for each year of the historical time series. MOC are high in 2015 and 2016, a result of the low inflows during the 2013/2014 wet season, and of a series of structural problems such as the friction factor of the HPPs. The MOC were much lower from 2017 caused by delayed plants and the new energy supply from the recent auctions. In 2019-2023, prices increased to between R$250 and R$320 per MWh. In the longer term the marginal operating costs continue to rise gradually and then decline abruptly to around R$200 per MWh by the end of the time series (all values in 2015 R$). This reduction of the MOC at the end of the period is mainly due to the entrance of new hydropower generation capacities.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sudeste	518	465	208	233	319	289	260	268	252	183	245	314	321	171	163	198
Sul	518	581	320	233	320	289	260	268	252	183	245	315	321	173	165	199
Nordeste	518	465	208	225	262	274	257	214	227	172	240	288	289	169	158	191
Norte	517	464	208	232	318	289	258	267	251	180	244	313	316	170	158	195

FIGURE 46 - Projection of marginal operating costs for the dry hydrology subset

Figure 46.b presents a comparison of average MOCs for the Reference and the Low-Hydrology scenarios.

The doted line reflects the incremental variation induced by the low-hydrology constrain.

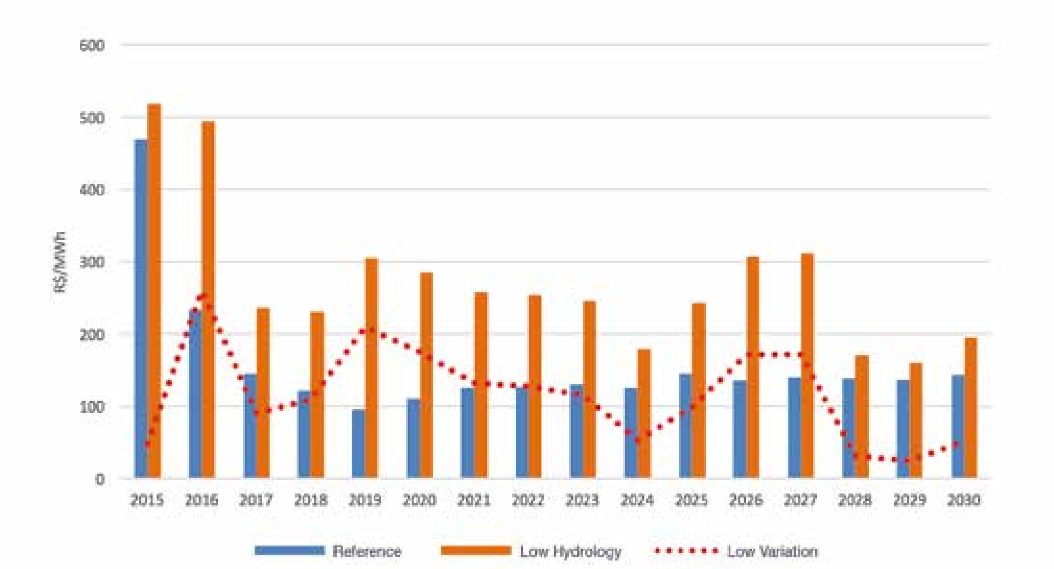
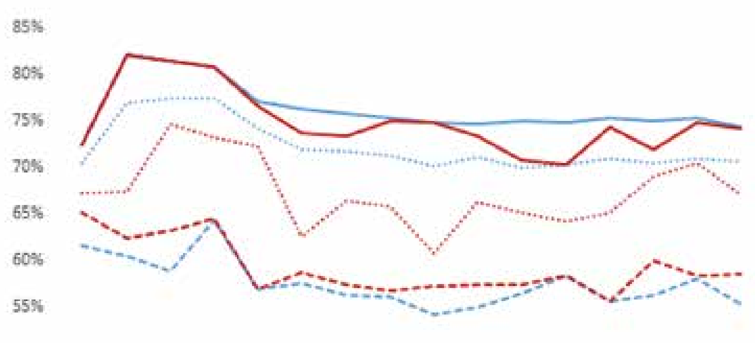


FIGURE 47 - Comparing MOCs for the Reference and the Low-Hydrology scenarios

4.1.7.2 Power Generation

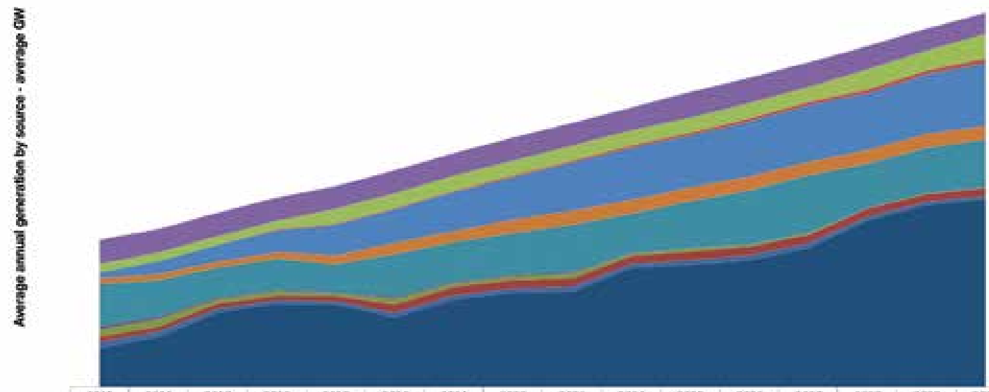
Figure 47.a details the annual evolution of the probability of hydropower share, which is reduced around 5% over the period.

Figure 47.b shows the evolution of average annual power generation by source.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maximum-reference	72%	82%	81%	81%	77%	76%	76%	75%	75%	75%	75%	75%	75%	75%	75%	74%
Median-reference	70%	77%	77%	77%	74%	72%	72%	71%	70%	71%	70%	70%	71%	71%	71%	71%
Minimum-reference	62%	61%	59%	64%	57%	58%	56%	56%	54%	55%	56%	58%	56%	56%	58%	55%
Maximum-low hydrology	72%	82%	81%	81%	77%	74%	73%	75%	75%	73%	71%	70%	74%	72%	75%	74%
Median-low hydrology	67%	67%	75%	73%	72%	63%	66%	66%	61%	66%	65%	64%	65%	69%	71%	67%
Minimum-low hydrology	65%	62%	63%	65%	57%	59%	57%	57%	57%	57%	57%	58%	56%	60%	58%	59%

FIGURE 48 - Hydropower share in the Reference and the Low-Hydrology scenarios



	2015	2016	2017	2018	2019	2020	2021	2022
Others	4.8	4.7	4.7	4.6	4.5	4.5	4.5	4.5
Nuclear	1.7	1.7	1.7	1.7	3.0	3.0	3.0	3.0
Solar	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.4
Wind	1.1	2.6	3.3	4.4	6.1	6.7	7.8	8.4
Biomass	1.2	1.2	1.2	1.3	1.7	2.2	2.2	2.7
Natural Gas	8.4	7.3	6.1	6.1	5.7	8.5	7.9	8.3
Diesel	0.6	0.5	0.3	0.3	0.2	0.4	0.2	0.3
Oil	1.5	1.5	0.9	1.0	0.5	1.2	0.7	0.8
National coal	1.0	1.0	1.0	0.9	1.1	1.7	1.7	1.6
Imported coal	1.3	1.1	0.8	0.7	0.6	1.0	0.9	0.9
Hydro	47.6	49.9	54.8	56.5	56.4	53.8	57.3	58.7
TOTAL	69.2	71.4	74.7	77.7	80.0	83.1	86.6	89.6

	2023	2024	2025	2026	2027	2028	2029	2030
Others	4.5	4.5	5.1	5.1	4.9	4.7	4.4	4.2
Nuclear	3.0	3.0	3.0	3.0	3.0	4.0	3.9	4.9
Solar	0.4	0.5	0.5	0.7	0.7	0.8	0.8	1.0
Wind	9.6	10.4	10.4	11.0	11.3	11.3	11.9	12.5
Biomass	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Natural Gas	9.5	7.8	9.4	10.8	11.4	8.8	9.0	9.5
Diesel	0.3	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Oil	1.0	0.5	0.6	0.4	0.4	0.1	0.1	0.2
National coal	1.7	1.6	1.7	1.7	1.7	1.6	1.6	1.6
Imported coal	1.0	0.8	1.0	1.0	1.0	0.7	0.6	0.6
Hydro	58.9	63.6	64.3	65.2	67.6	73.1	76.2	77.3
TOTAL	92.6	95.6	98.7	101.5	104.6	107.9	111.3	114.5

FIGURE 49 - Average annual power generation by source for the dry hydrology subset

Table 8 compares the energy generated (by source) in the reference case and the dry hydrology subset. The main differences are the increase of emissions-causing thermal sources such as important coal, oil and diesel and the reduction of hydropower generation (relatively small but considerable in absolute values).

Figure 17.a details the annual evolution of the probability of hydropower share, which is reduced around 5% over the period.

Total generation also shows a small reduction due to the high energy deficit in the dry hydrology scenarios subset, as can be seen in Figure 48.

TABLE 8 - Comparison of average annual generation (GWM)

SOURCE	REFERENCE SCENARIO	LOW HYDROLOGY SUBSET	RELATIVE DIFFERENCE
Imported coal	10	14	46.2%
National coal	22	23	6.9%
Oil	5	11	114.0%
Diesel	2	3	117.0%
Natural Gas	99	134	35.4%
Biomass	35	36	0.6%
Wind	128	129	0.1%
Solar	6	6	-0.1%
Nuclear	46	47	0.6%
Others	74	74	0.4%
Hydro	1035	981	-5.2%
Total	**1463**	**1459**	**-0.3%**

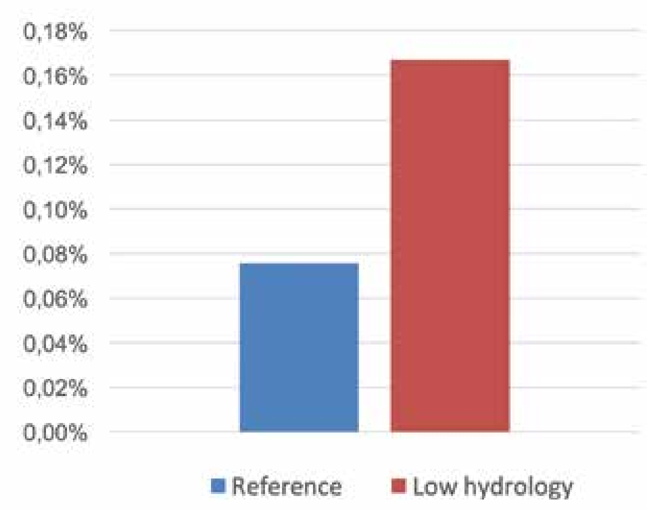


FIGURE 50 - Average cumulative deficit (2015-2030) compared to average demand

4.1.7.3 CO_2 emissions

Figure 49 shows the average emissions of the low hydrology series compared to the average values for the reference case, calculated on the total of 200 scenarios. The "low hydrology" subset has an average value 31% higher than the complete set.

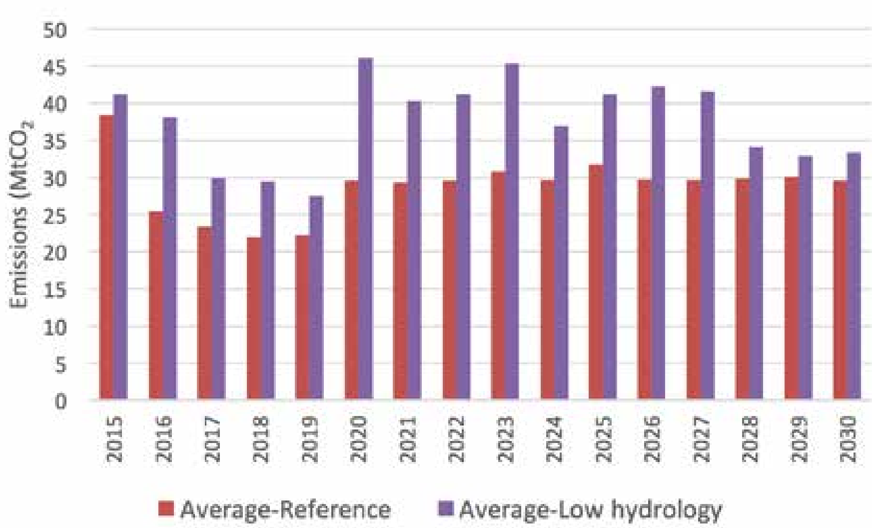


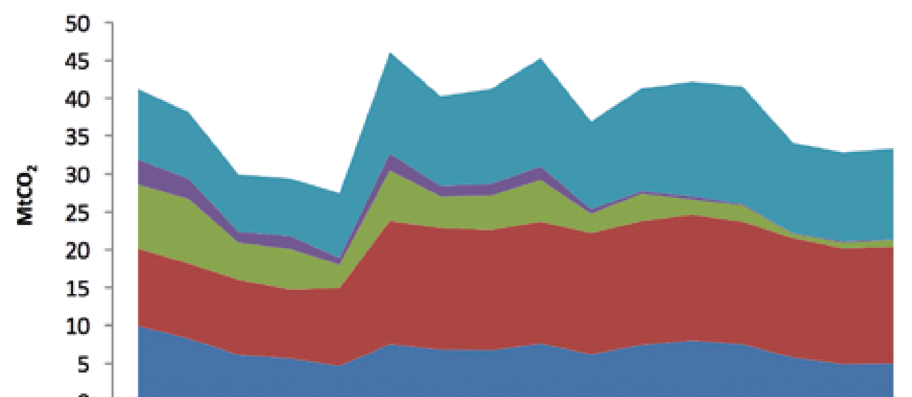
FIGURE 51 - Average of the low hydrology series compared to the complete set

Figure 50 shows the minimum, average and maximum emissions of the SIN for the dry hydrology subset over the study time horizon.

FIGURE 52 - Statistics for the low hydrology series

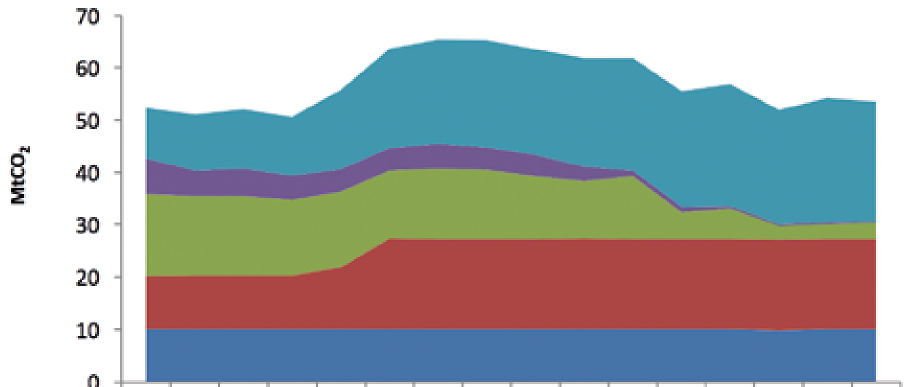
Note: 2025 is the reference year for the emissions reduction target in the INDC of Brazil.

Figures 51 and 52 show annual average and maximum emissions by source for the "dry hydrology" subset.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural gas	9,3	8,8	7,5	7,6	8,5	13,4	11,9	12,5	14,3	11,6	13,5	15,1	15,5	11,9	11,8	12,0
Diesel	3,3	2,6	1,5	1,6	0,9	2,2	1,3	1,5	1,8	0,6	0,3	0,4	0,2	0,1	0,1	0,1
Oil	8,5	8,5	4,8	5,4	3,1	6,7	4,2	4,6	5,5	2,6	3,6	2,1	2,1	0,6	0,7	0,9
National coal	10,1	9,9	9,9	9,1	10,3	16,3	16,1	15,9	16,1	15,9	16,3	16,6	16,3	15,7	15,3	15,4
Imported coal	10,0	8,3	6,2	5,7	4,7	7,5	6,8	6,7	7,6	6,3	7,5	8,0	7,5	5,8	4,9	5,0
TOTAL	41,2	38,1	29,9	29,5	27,5	46,1	40,3	41,2	45,3	36,9	41,3	42,2	41,6	34,1	32,9	33,4

FIGURE 53 - Annual average emissions by source for the dry hydrology subset



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural gas	9,6	10,8	11,3	11,2	15,1	18,9	20,0	20,5	20,2	20,8	21,5	22,2	23,3	21,8	23,8	22,8
Diesel	6,8	4,9	5,3	4,7	4,3	4,4	4,6	4,2	4,1	2,7	1,0	1,0	0,5	0,4	0,4	0,4
Oil	15,7	15,1	15,2	14,4	14,5	13,0	13,5	13,3	12,0	11,1	12,1	5,1	5,8	2,7	2,9	3,1
National coal	10,2	10,3	10,3	10,3	11,9	17,3	17,3	17,3	17,3	17,3	17,3	17,3	17,3	17,3	17,3	17,3
Imported coal	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	9,8	10,0	10,0
TOTAL	52,3	51,2	52,1	50,6	55,7	63,7	65,3	65,3	63,5	61,9	61,9	55,6	56,9	52,0	54,3	53,5

FIGURE 54 - Maximum annual emissions by source for the dry hydrology subset

Figure 53 shows the probability density function of the annual emissions in selected dry years. Results for year 2015 are similar to others analyzed, unlike the results obtained with all the 200 series. This is due to an increase in the average values of the later years compared to the reference scenario. The average reduction of emissions in subsequent years is due to supply/demand re-balancing.

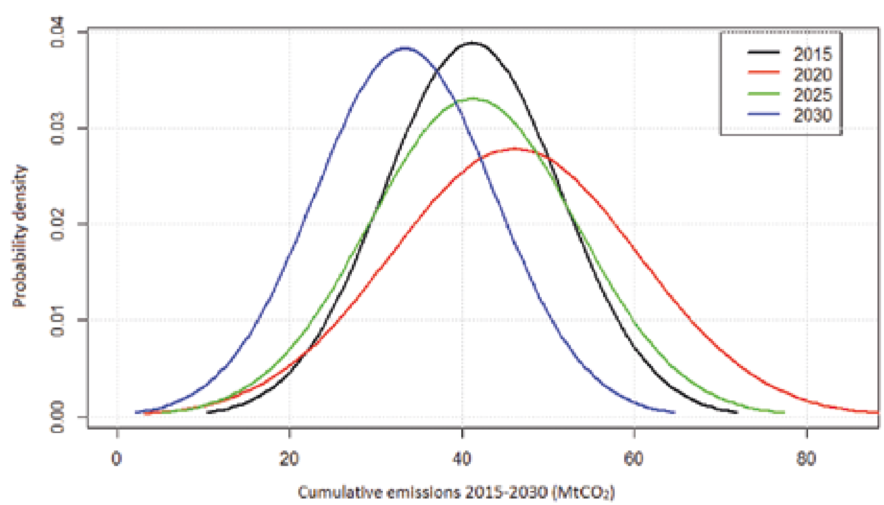


FIGURE 55 - Probability density function of the annual emissions for dry hydrology

Figure 54 shows the probability distribution of SIN emissions in 2030, averaging around 30 million tons per year. The emissions vary substantially due to the importance of hydropower in the energy matrix. Meanwhile, total cumulative emissions increased by 5 million tCO_2 in the reference case.

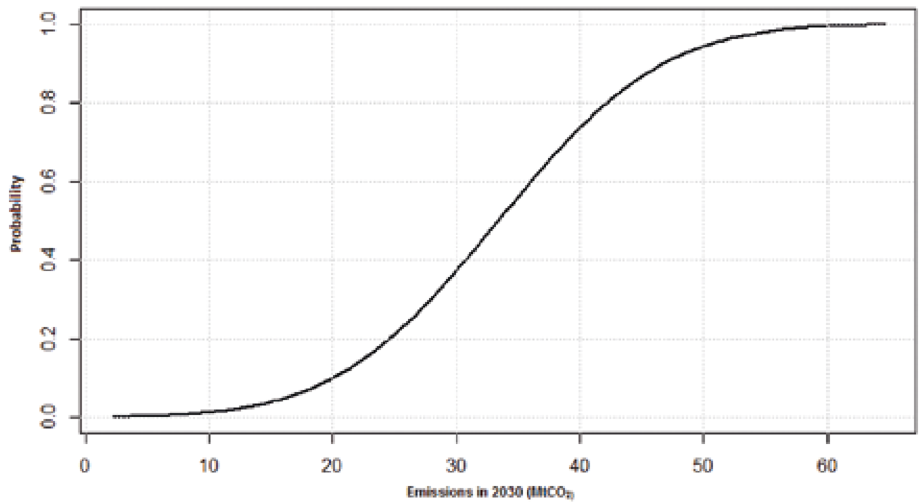


FIGURE 56 - Probability distributions of the SIN emissions in 2030 for dry hydrology

Figure 55 shows the probability density function of the SIN emissions for 2015-2030 for the dry hydrology subset and the reference case: an average increase of 150 million tCO2 and a considerable reduction in the standard deviation (basically most of the thermal plant power has already been dispatched in the dry hydrology case).

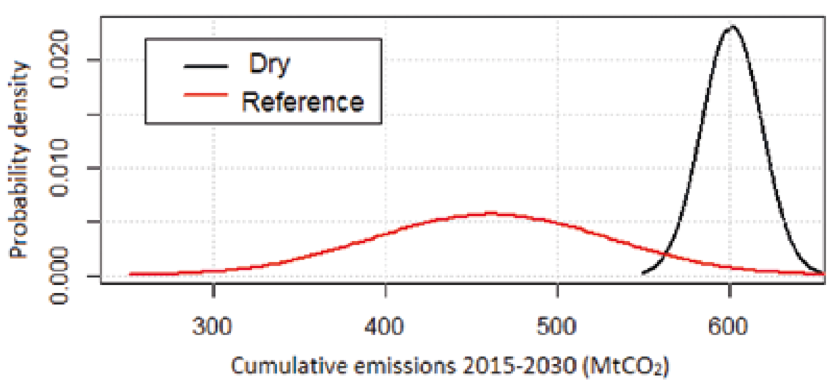


FIGURE 57 - Probability density function of cumulative emissions for dry hydrology

Figure 56 shows an average increase of 150 million tCO_2 cumulative emissions for dry hydrology in 2015-2030 over the reference case.

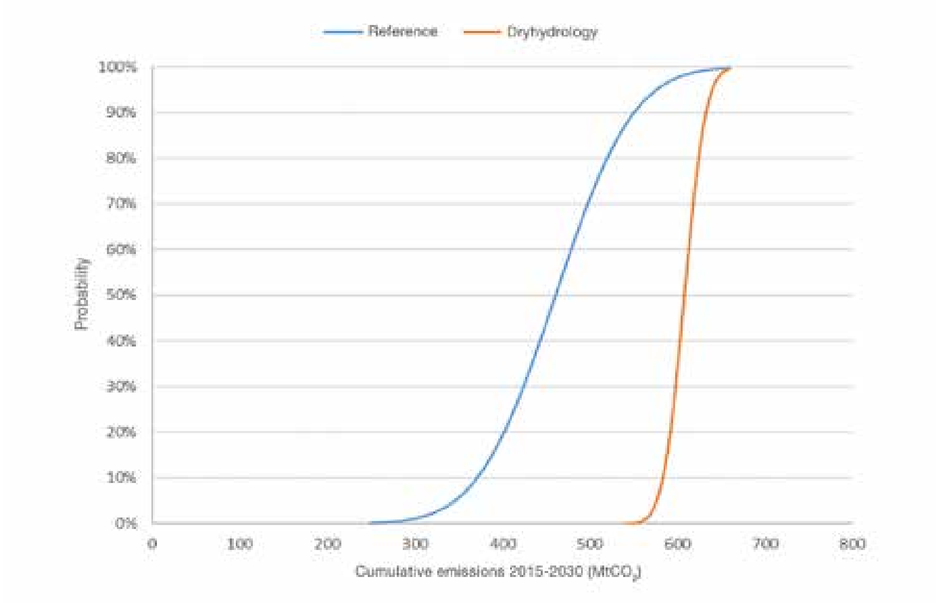


FIGURE 58 - Probability for SIN cumulative emissions for dry hydrology

The selection of a "dry hydrology" scenario was based on the empirical distribution of Natural Inflow Energy of the power plants over the entire time horizon, using as a sample the 200 scenarios generated by the PAR (p) model for monthly inflows mapped by the production coefficients (MWh per m^3) of the hydropower plants, as indicated earlier. The "cut-off" point was established, defining a "dry" hydrologic scenario as 575 million tCO_2. The "low hydrology" series produce annual emissions of around four times higher than those in wet years, and twice the cumulative emissions for 2015-2030.

4.2 Comparison with the downscaling method of global climate models

4.2.1 Background

The Brazilian Government, through the Secretariat for Strategic Affairs (SAE), is currently conducting a comprehensive study to assess the impacts of different climate change scenarios on different sectors of the economy including the power sector. Part of the SAE study is reproduced in this section to enable a sensitivity analysis of greenhouse gases produced by the Brazilian power sector. In order to get a sense of how the low-hidrology based on the stationary hypothesis compares with the hypothesis of hydrology without stationarity generated by global climate change models, elements of the SAE study were used in this section.

The scenarios used to assess the impacts of climate change were established in the *Fifth Assessment Report of the UN Intergovernmental Panel on Climate Change (IPCC)* and are linked to the atmospheric concentration of greenhouse gases. The IPCC Report adopted global climate change scenarios based on *Representative Concentration Pathways* (RCP), as indicated in Figure 57:

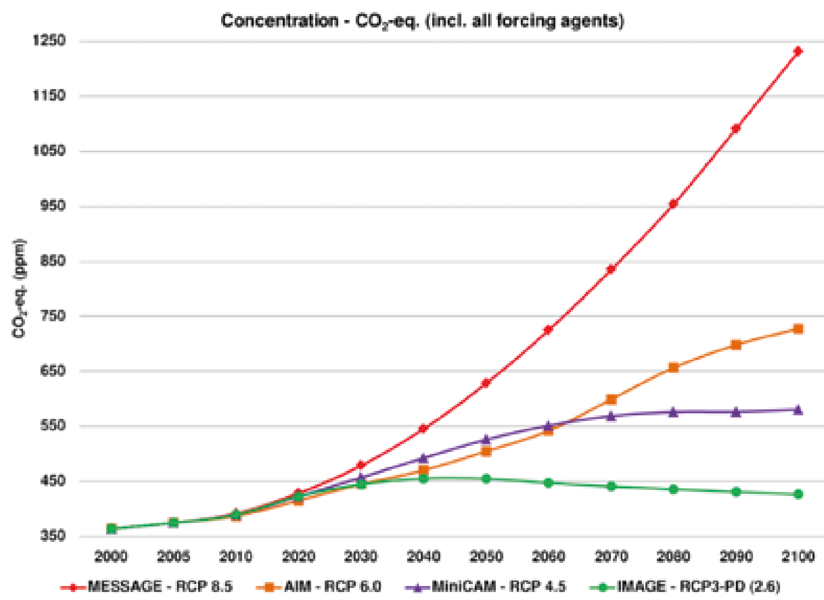


FIGURE 59 - Concentration of CO_2 eq. for RCP scenarios

The SAE studies on impacts in the power sector used the RCP 8.5 and RCP = 4.5 scenarios:

RCP 8,5: GHG emissions rise steadily during the 21st century. This results in 2100 in a higher than 3-fold increase in the concentration of CO_2 in the atmosphere. Average increase in ground temperature is 3.7 degrees Celsius, while the average rise in sea levels is 0.63 meters (temperature and sea level figures are the average calculated from a range of different climate models used for the same GHG assumptions).

RCP 4,5: GHG emissions reach a peak in 2040, after which they begin to taper off due to GHG control measures such as more power from renewable sources or nuclear reactors. The atmospheric *concentration* of GHG stabilizes from 2060 to above 550 parts per million until the end of the century (an increase of 50% over pre-industrial emissions). Average temperatures in this case would increase 1.8 degrees Celsius and average rises in sea level would be 0.47 meters in 2100.

4.2.2 Information Flow

The impact studies commissioned by the SAE involved several institutions:

1. The National Institute for Space Research (INPE) was responsible for downscaling (dynamic scaling reduction technique) of the Global Circulation Model results (lower resolution). The results were used in two IPCC scenarios to increase spatial resolution via simulations with a denser points network generated by the ETA model. Two global circulation models used by INPE were combined with the IPCC scenarios: (i) the *Model for Interdisciplinary Research on Climate* (MIROC) from Japanese institutions and (ii) the *Hadley Centre Global Environmental Model* (HADGEM) of the UK Met Office. The INPE downscaling procedure produced four scenarios with higher resolution and monthly temperature and rainfall figures up to year 2100.

2. FUNCEME (Ceará Meteorology and Water Resources Foundation) used the INPE scenarios to transform rainfall data into flow series using physical hydrological models such as SMAP calibrated for the spatial scale of hydrological stations of HPPs run by the ONS (National Power System Operator). The process involves adjusting parameters of the equations on evaporation, infiltration and storage, etc. in aquifers to enable the model to simulate historical hydropower inflows in detail. The process also involves validating the model for a different set of rainfall and temperature data to verify whether the resulting inflows match those that have been observed. FUNCEME's efforts produced for the INPE rainfall and temperature time series produced a flow series for the four previously mentioned scenarios. The process is repeated monthly to configure 195 ONS hydro plants for the 2100 horizon.

3. PSR, in collaboration with COPPE, used these inflow series for the 2100 study horizon. To evaluate the impact on the power sector, new parameters (average, variance and correlations) were adjusted for the series of projected inflows in each scenario for the 2100 horizon (see Annex C).

4. These parameters differ from those used in the methodology employed in the simulations of the previous chapters, for both the reference and alternative case (based on historical stationary flow series). The SDDP hydrothermal operation model was again used in the analysis. Different multivariate hydrological series were generated by SDDP for the 195 hydrological stations considering a modification in the hydrological model parameters. SDDP was based on a supply and demand configuration used in the EPE *Ten Year Energy Plan* (extended by PSR for subsequent years). For the RCP 8.5 scenario the expansion did not consider externalities on GHG emissions. The expansion related to the RCP 4.5 produces a carbon tax of US$100 / tCO_2 after 2030 (ETP, 2015) and effective energy efficiency measures that significantly reduce the projected demand compared to the RCP 8.5 case.

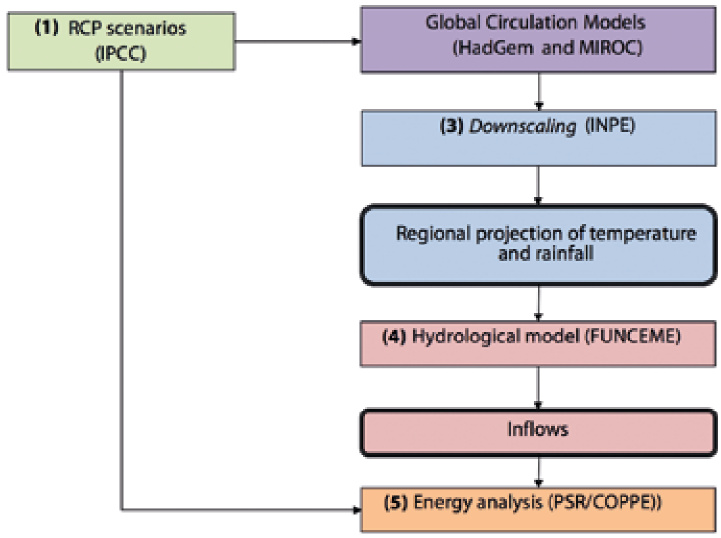


FIGURE 60 - Information and processes flow

4.2.3 Results of general circulation models

4.2.3.1 HadGEM / Eta

Figures 59 and 60 compare plants that are representative of Brazil´s hydrological diversity (Sobradinho and Tucuruí) with the historical natural inflows projected by INPE / FUNCEME based on a rainfall-runoff model combined with the HadGEM / Eta climate model. In both cases a dramatic change ("discontinuity") is observed between the historical and projected flow series (average reduction of 44-57%).

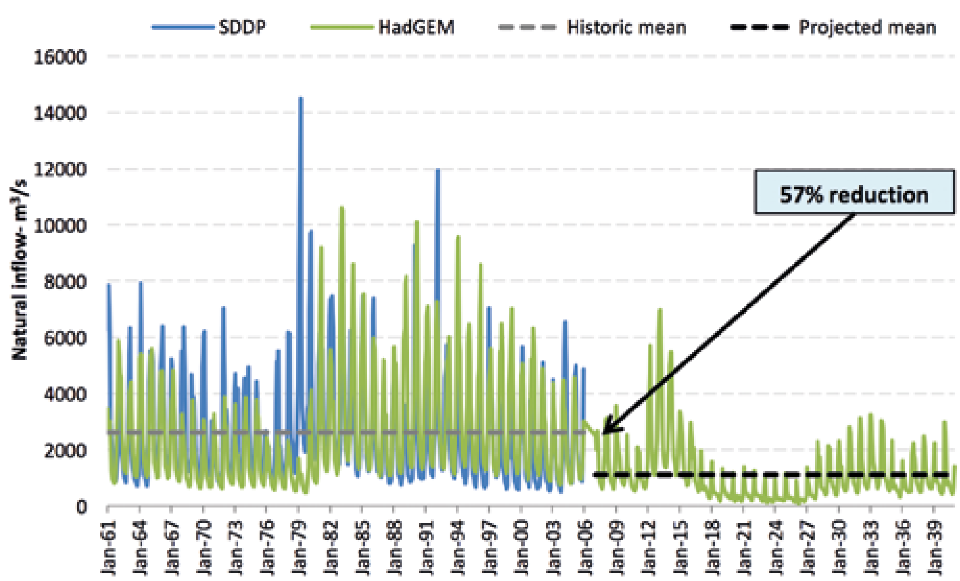


FIGURE 61 - Natural inflow at Sobradinho HPP (HadGEM/Eta)

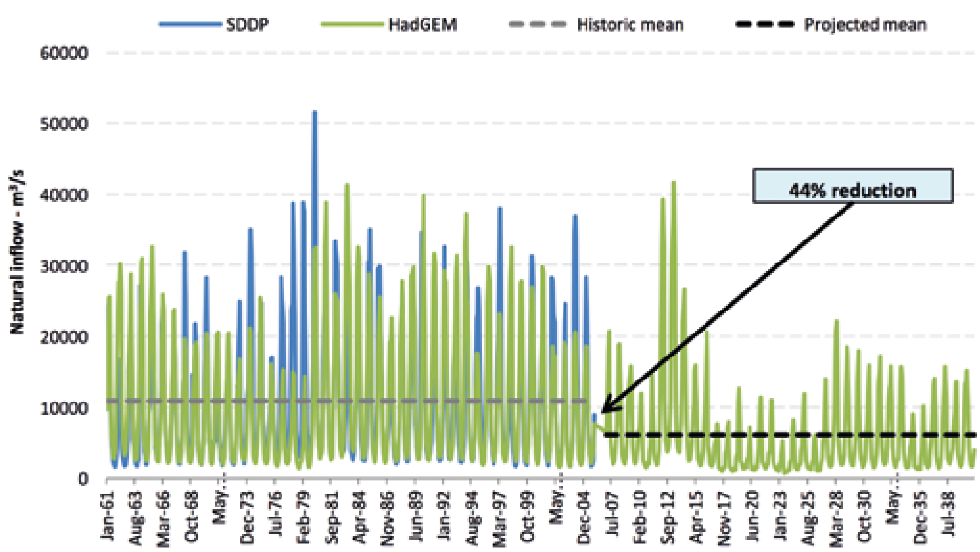


FIGURE 62 - Natural inflow at Tucuruí HPP (HadGEM/Eta)

4.2.3.2 MIROC / Eta model

The following two figures compare for the Sobradinho and Tucuruí HPPs flow gauging stations the historical natural inflows with the inflows projected by INPE / FUNCEME based on a rainfall-runoff model combined with the MIROC / Eta climate model. In both cases there is a significant change in projected inflow rates compared with the historical rates, although this change is less dramatic than in the Had-GEM / Eta case (average reduction of 12-34%).

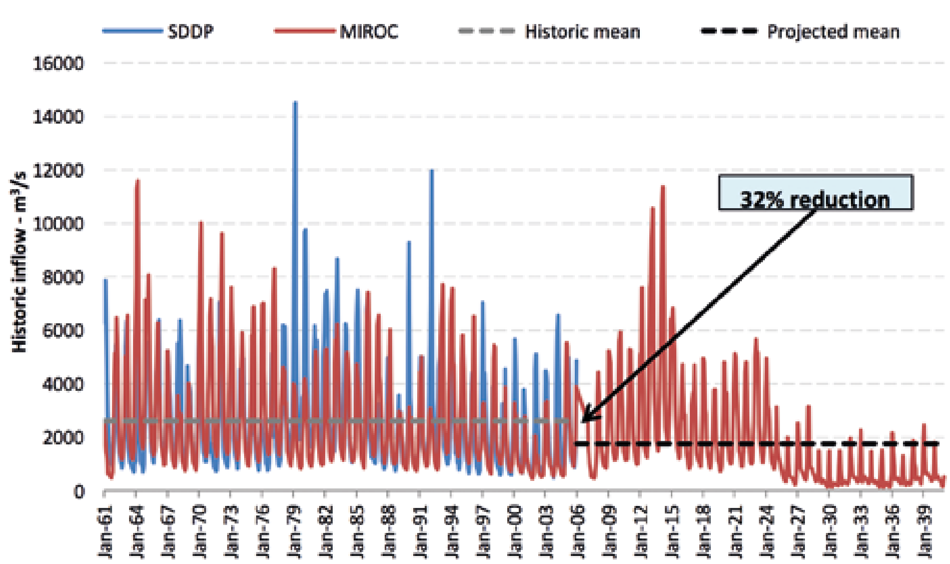


FIGURE 63 - Natural inflow at Sobradinho HPP (MIROC/Eta)

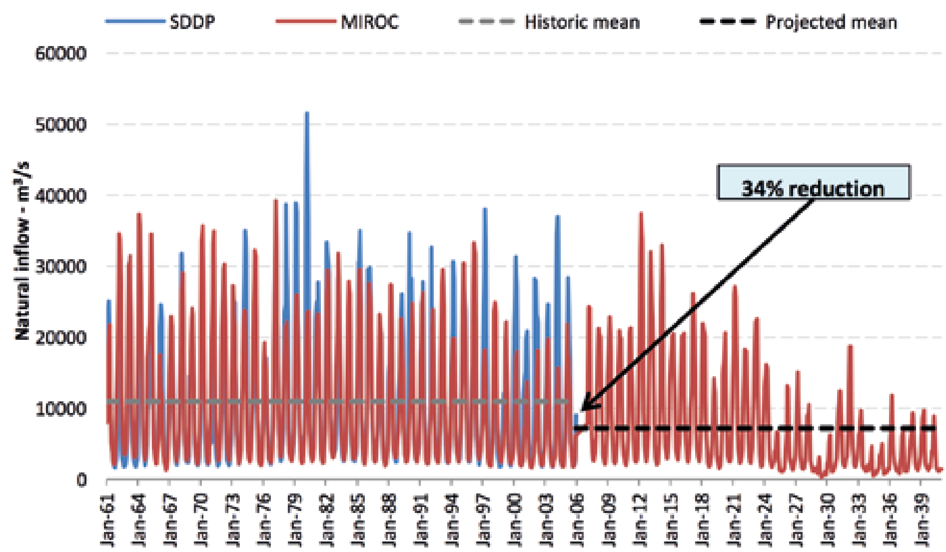


FIGURE 64 - Natural inflow at Tucuruí HPP (MIROC/Eta)

These hydrographs show a **significant reduction in the inflows up to 2040** in both general climate circulation models used.

4.2.4 Results

4.2.4.1 Reference case for projection of the HadGEM / Eta climate model

Figure 63 compares two SIN Natural Inflow Energy projections generated for the reference case:

1. Projections based on the average and standard deviation values of the historical series for each natural inflow gauging station of the hydropower matrix; and
2. Projections generated from the average and standard deviation values generated by the HadGEM / Eta model for each natural inflow gauging station of the hydropower matrix.

The inflows generated by the HadGEM / Eta model result in an average ENA of around 30% less than the historical ENA. This leads to extremely high marginal operating costs, and to power cuts where the SIN cannot meet demand.

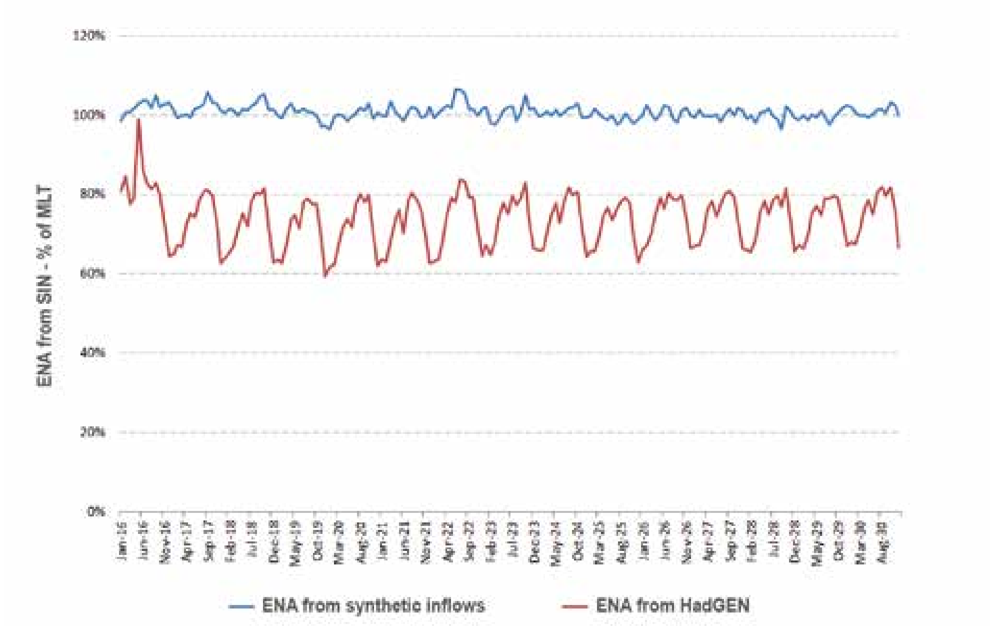


FIGURE 65 - Comparison between the ENAs - HadGEM/Eta model

4.2.4.1.1 Impact on hydroelectric production

Figure 64 shows SDDP-simulated hydroelectric output for the first years. Using the HadGEM / Eta model produces a substantial reduction in the cases with climate change for the CPR 8.5 and RCP 4.5 scenarios. The results are significant since the SDDP produces a high deficit probability in the simulated scenarios and substantially higher operating costs compared to cases without climate change.

PSR recommends that studies and models should be revisited "upstream" (INPE and FUNCEME).

In practice, if climate change evolves as quickly as studies suggest, Brazil would need to substantially expand its power generation capacity above what is currently being planned. In this case, operating costs would increase because more fossil-burning thermal power plants would come to service. COPPE is using the MESSAGE (an energy planning model) to apply the power sector expansion plan to these cases. Non-automatic integration between MESSAGE and the SDDP was done in the context of the project for the SAE.

Among the set of actions that could be adopted to mitigate the effects of climate change on the power sector one would be to re-start the construction of regulatory reservoirs wherever physically and environmentally feasible.

Most of the HPPs constructed over the last 15 years were built with no regulatory reservoirs. This has reduced the capacity of the national power system to manage prolonged droughts by using stored water during wet periods.

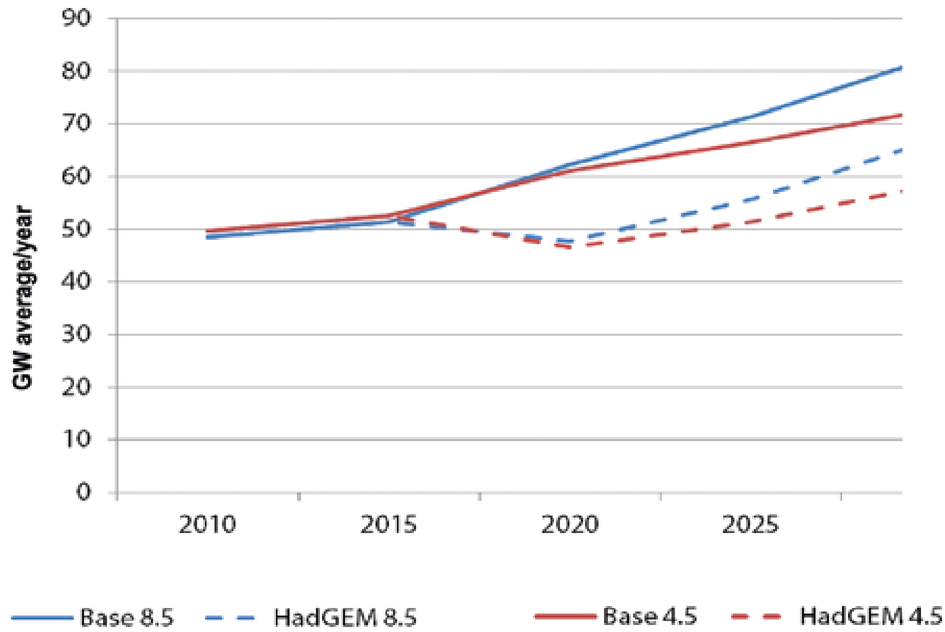


FIGURE 66 - Impact on hydroelectric output - HadGEM model/Eta

4.2.4.1.2 *Impact on operating costs and MOCs*

High marginal operating costs are due to the hydrological events leading to power cuts. When the MOC are compared to total operating costs, the HadGEM / Eta simulation results in total costs of over 17 times higher than those of the reference case – clearly indicating a structurally unbalanced system. Given the dramatic reduction of hydropower availability due to climate change it would be necessary to contract additional energy to restore the balance.

4.2.4.2 *Reference case for projection of the MIROC / Eta climate model*

Figure 65 compares two SIN Natural Inflow Energy projections generated for the reference case:

1. Projections based on the average and standard deviation values of the historical series for each natural inflow gauging station of the hydropower matrix; and
2. Projections generated from the average and standard deviation values generated by the *MIROC / Eta climate model* for each natural flow gauging station of the hydropower matrix.

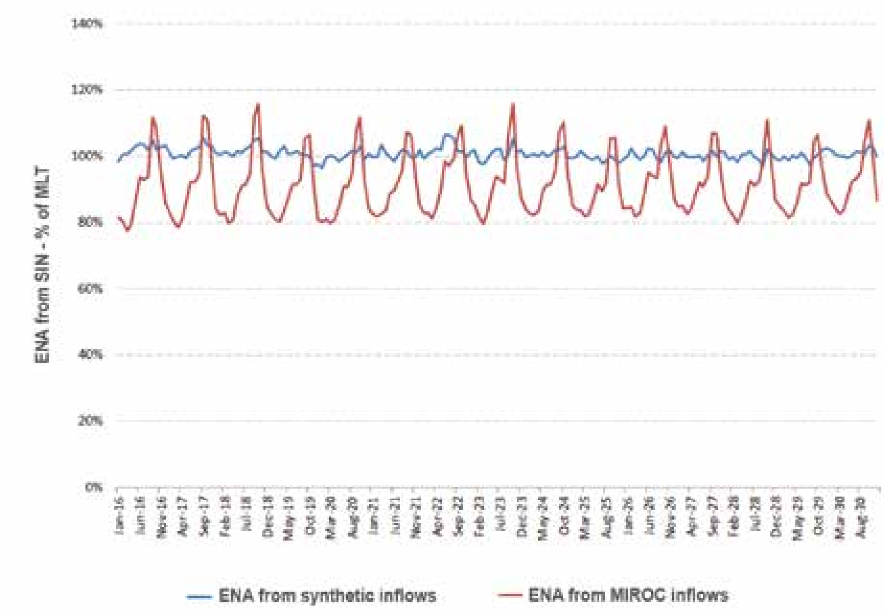
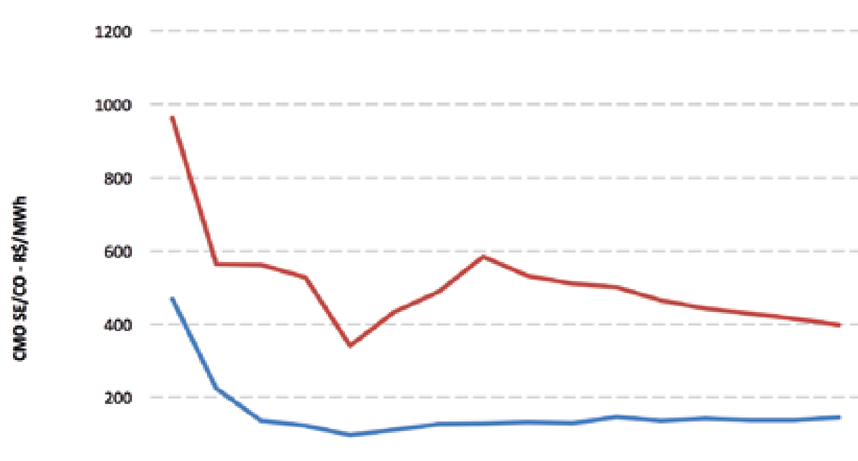


FIGURE 67 - Comparison between ENAs - MIROC/Eta model

4.2.4.2.1 Impact on operating costs and MOCs

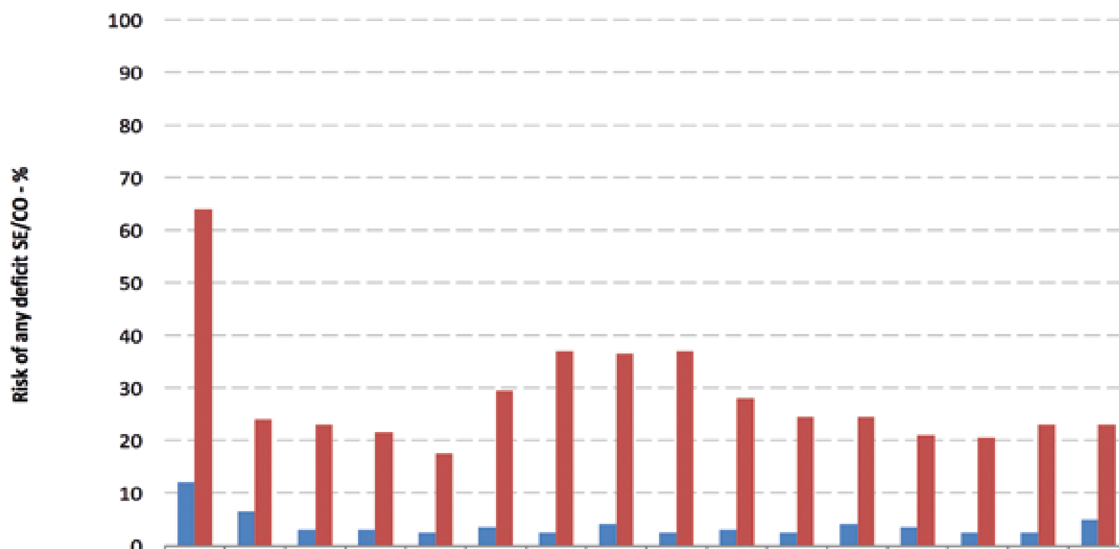
The inflows generated by the MIROC / Eta model result in a average ENA of around 30% less than the historical ENA. This leads to extremely high marginal operating costs, and power cuts in the majority of the simulated hydrological scenarios where the SIN is unable to meet demand.

High marginal operating costs arise from hydrological scenarios with power cuts. Figure 67 compares the risk of an energy deficit in the SE / CO subsystem of the simulation, considering the inflows generated by the MI-ROC/Eta model, with the simulation of historical inflows.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference	469	224	137	122	98	112	127	129	133	130	146	137	143	139	138	146
MIROC	962	563	562	527	341	433	489	584	531	511	501	465	442	428	415	398

FIGURE 68 - Comparison between MOC for SE/ CO subsystem - MIROC/Eta model



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference	12,0	6,5	3,0	3,0	2,5	3,5	2,5	4,0	2,5	3,0	2,5	4,0	3,5	2,5	2,5	5,0
MIROC	64,0	24,0	23,0	21,5	17,5	29,5	37,0	36,5	37,0	28,0	24,5	24,5	21,0	20,5	23,0	23,0

FIGURE 69 - Risk of deficit - MIROC/Eta model

When the MOC are compared to the total operating costs, the result of the HadGEM / Eta simulation total costs are eight times higher than those of the reference case - indicating a structurally unbalanced system. Given the dramatic reduction of availability of hydropower in this climate change situation it would be necessary to contract additional energy to restore the balance.

4.2.5 Summary

- The premise of the probabilistic assessment that characterized dry hydrology is that the future repeats the past with regard to the probabilistic characteristics of the inflows. This premise has been increasingly challenged for at least two reasons: the impact of climate change and anthropogenic changes in land use. A “top-down” approach based on the assumption of climate change using global circulation models - which were regionalized by the INPE for Brazil and, through physical rainfall-runoff modelling, used to generate hydrological scenarios - produces important results concerning average water availability reduction. Arguments for more investment to expand the power sector were presented in the report. In this context, dry hydrology, as defined in the report, would cease to be an “unlikely” event (see Figure 68). Consequently, the recommendation stands: to continue studying deeply the impacts of climate change on the water sector which, in Brazil’s case, is closely linked to the electrical sector due to the predominance of power generation plants deployed in the country´s main river basins.

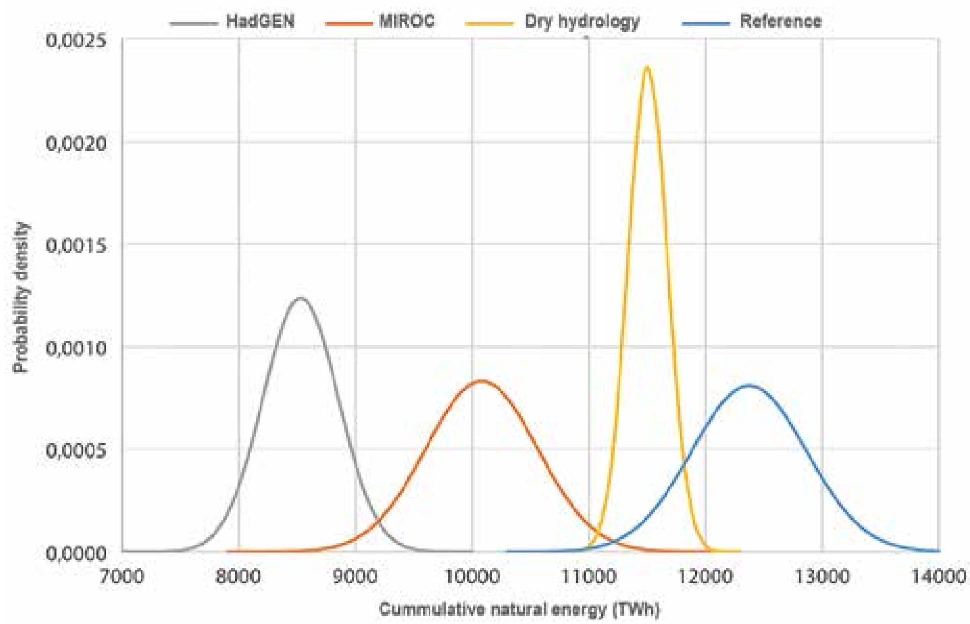


FIGURE 70 - Probabilities distribution of the cumulative ENAs, 2015-2030

- The impacts on the SIN operation arising from climate change hydrological scenarios are significant. Caution therefore needs to be exercised when interpreting the results of the models. It is well-known that downscaling global circulation models can overshoot results in certain applications and for this reason it would be interesting to evaluate other downscaling models or, alternatively, conduct a direct resampling of the GCM results. Given the extreme results, we decided in this report to avoid presenting the results of the four scenarios based on assumptions about RCPs and global circulation models. Expansion of the reference case used in the climate sensitivity analysis would obviously be insufficient to ensure an adequate supply of power in the SIN (i.e. electricity rationing).
- Impacts on climate can also have consequences for other sources, e.g. altered wind patterns (impact on wind energy), rainfall (impact on energy production from sugar cane biomass) and secondary effects on hydroelectric production, from e.g. increased irrigation water that reduces water available for HPPs. With the exception of the impacts on the remaining consumptive uses, other possible impacts were not evaluated in the present study.
- The above reinforces the need for the results of the SAE study to be used as a warning to the authorities to provide more resources for research in this area, given the high current investment in hydroelectric plants in Brazil. The SAE research is of major strategic importance since it could lead to a set of preventive measures being established at the planning stage.

5 ALTERNATIVE CASE

This chapter focuses on the construction of an Alternative supply/demand expansion case for offsetting increased GHG emissions during low hydrologic scenarios. This alternative case has been built on the basis of a separate work conducted by PSR in Partnership with COPPE/UFRJ. This alternative approach involves substituting energy sources based on burning fossil fuels with renewable sources such as wind, solar and biomass, while meeting the same reliability criteria. Although we used the same macroeconomic and population growth assumptions as for the reference case, the main difference was the *lower* energy demand due to more robust energy efficiency and distributed generation measures. Hydrologic variability is the same in this case as in the reference case, i.e. without climate change.

5.1 Demand

An Alternative expansion case was used to evaluate the impacts on GHG emissions in the event of the Brazilian power sector adopting energy-efficient measures and encouraging more distributed generation such as solar energy. As a result of the set of energy conservation measures designed in partnership with COPPE, the Alternative case results in a 15% reduction of the energy demand in 2030 in comparison of the Reference scenario; this is equivalent to a reduction of the NIS load of 14 GW in average.

The reduction of GHG emissions largely arises from increased efficiency (11.7 GWM), and to a lesser extent (1.9 GWM) from using more solar energy equipment (normally with a capacity of below 1 MW) in the networks (distributed generation).

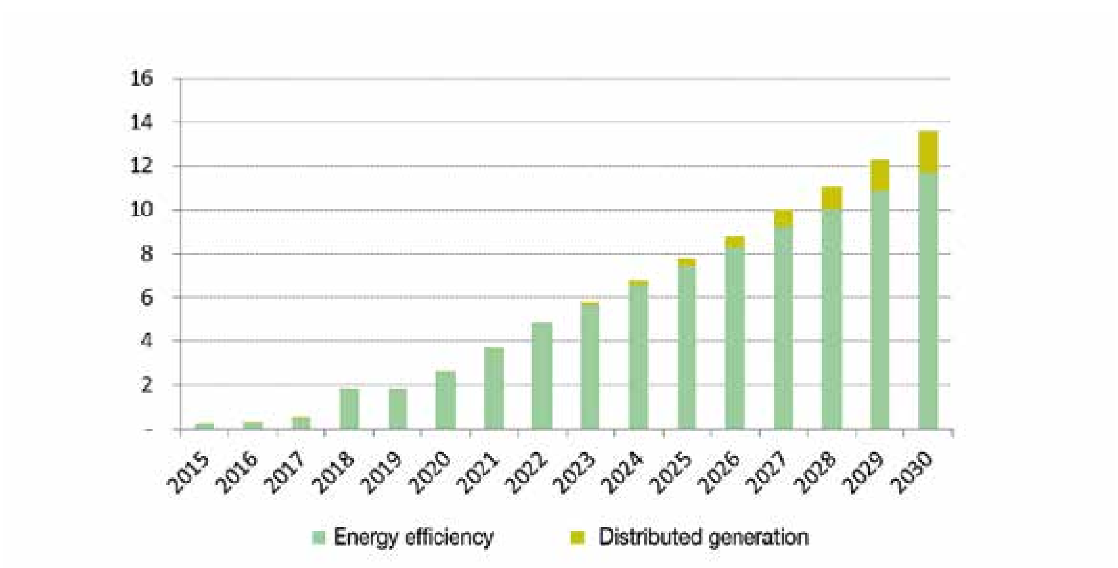


FIGURE 71 - Contribution of Energy Efficiency and DG to reduction of consumption (GWm)

The parameters for increasing the use of distributed PV are based on an econometric model developed by PSR[25] based on:

- kWh per kWp production efficiency based on PV and local irradiation;
- Final cost of the PV installation (including taxes and service charges);
- Local utility tariffs;
- Federal and State electricity tariffs;
- Cash flow to calculate *Payback*;
- Calculation of potential market share of the technology;
- Technical diffusion model.

In terms of inputted distributed generation capacity, the PSR scenario envisages around 12 GW by year 2030. However, since the solar capacity factor is low (around 16%), this does not produce a significant power consumption reduction.

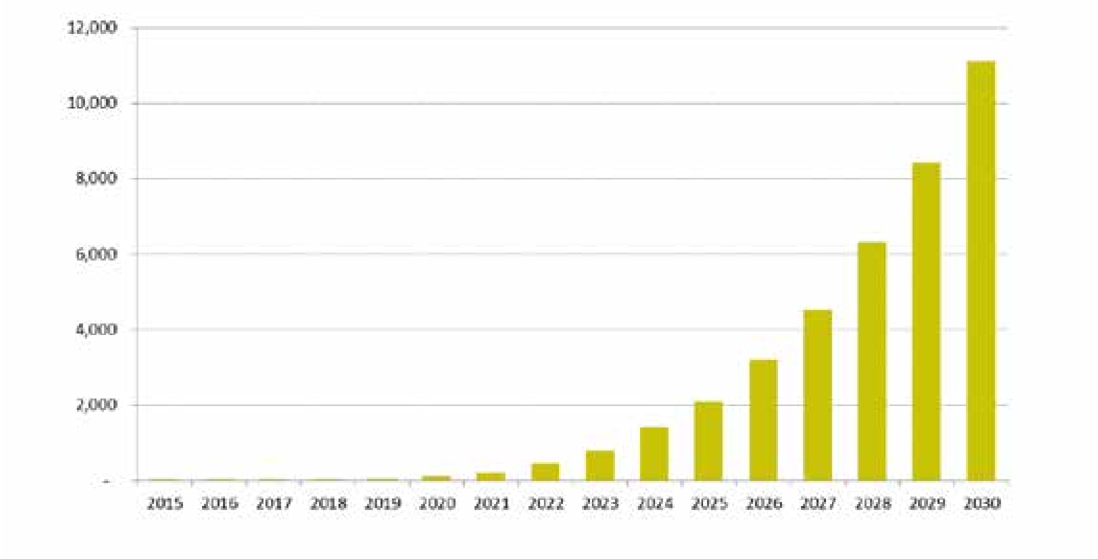
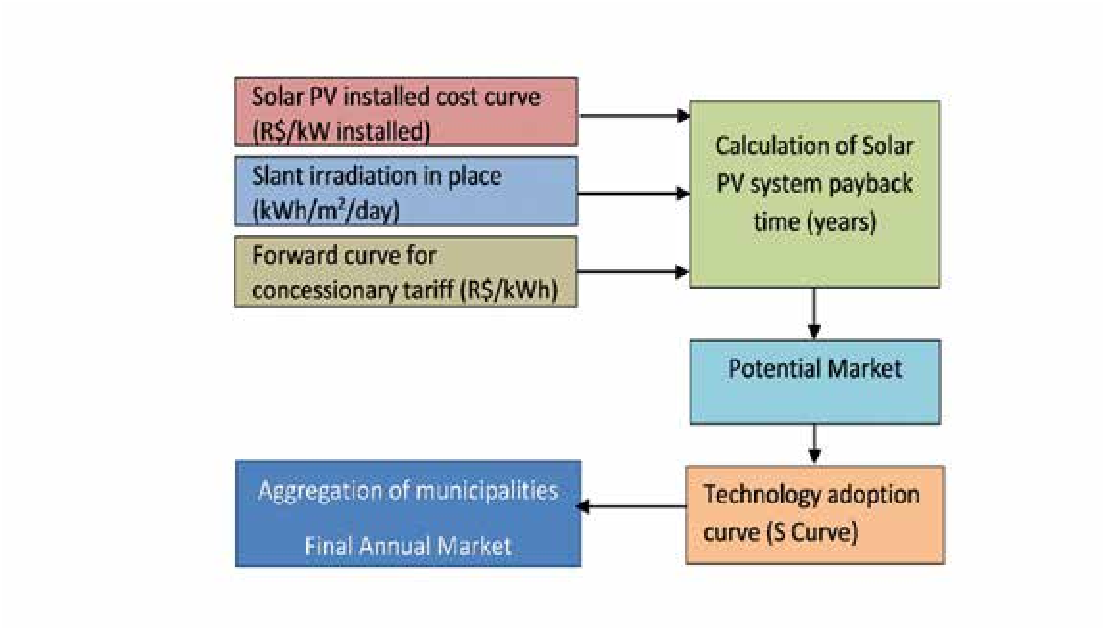


FIGURE 72 - Insertion of Photovoltaic Solar Energy on the consumption side (MW)

Figure 73 shows the type of model adopted.

[25] CPFL R&D Project related to ANEEL Call for Bids No. 013.



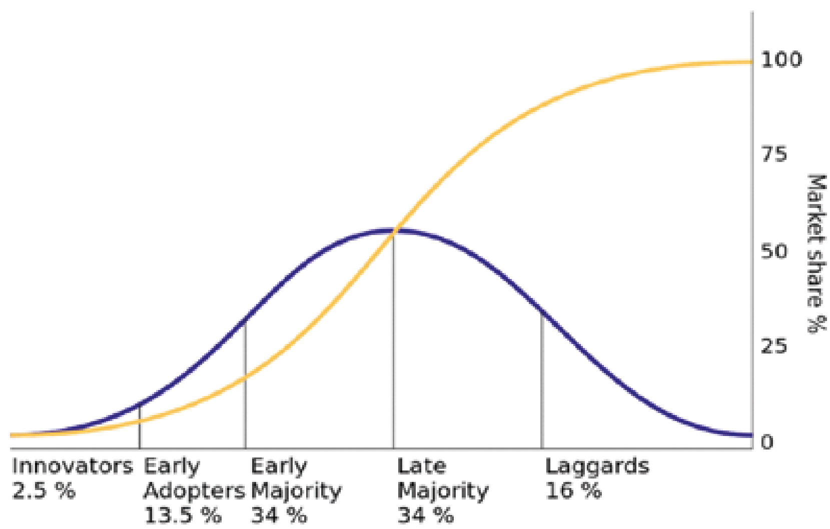
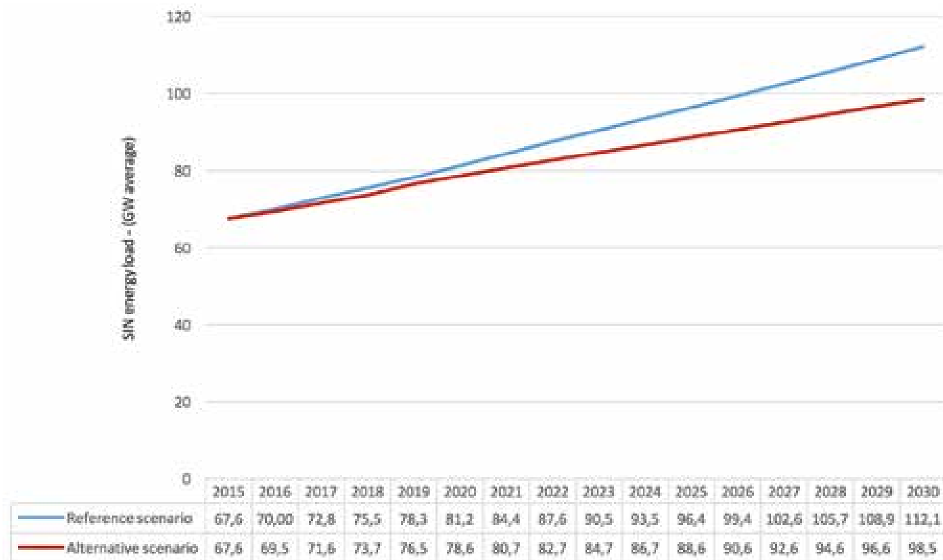


FIGURE 73 - Model of increased distribution of solar energy

Figure 74 compares projected demand in the reference case with the alternative case. (approximately 13.6 GW average reduction in the SIN power load in 2030).



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference scenario	67,6	70,00	72,8	75,5	78,3	81,2	84,4	87,6	90,5	93,5	96,4	99,4	102,6	105,7	108,9	112,1
Alternative scenario	67,6	69,5	71,6	73,7	76,5	78,6	80,7	82,7	84,7	86,7	88,6	90,6	92,6	94,6	96,6	98,5

FIGURE 74 - Projection of demand (reference case v alternative case)

5.2 Supply

Lower consumption in this scenario must be accompanied by a reduction of supply, since the commercial basis of the power sector envisages 100% consumption, which in turn drives the construction of new power plants.

PSR reduced the supply of both renewable and fossil sources from 2020, since by then the new power plants will have been contracted. After 2020, reduced supply results from withdrawal of supply or from postponing the entry into operation of hydroelectric, wind, thermal, gas or coal plants. Figure 75 shows that the main reductions will be in the hydropower and natural gas areas.

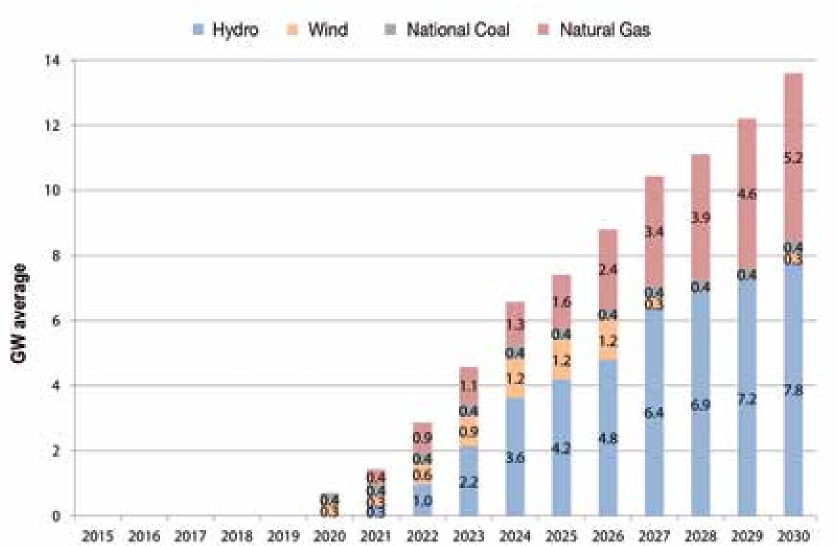


FIGURE 75 - Power reduction, by source, for the alternative case compared to the reference case

Figure 76 compares the power generation mix (in terms of installed capacity) between the reference case and the alternative case for year 2030. There is an increase in the amount generated from renewable sources (mainly hydropower and wind) and reduced generation from fossil fuels such as natural gas.

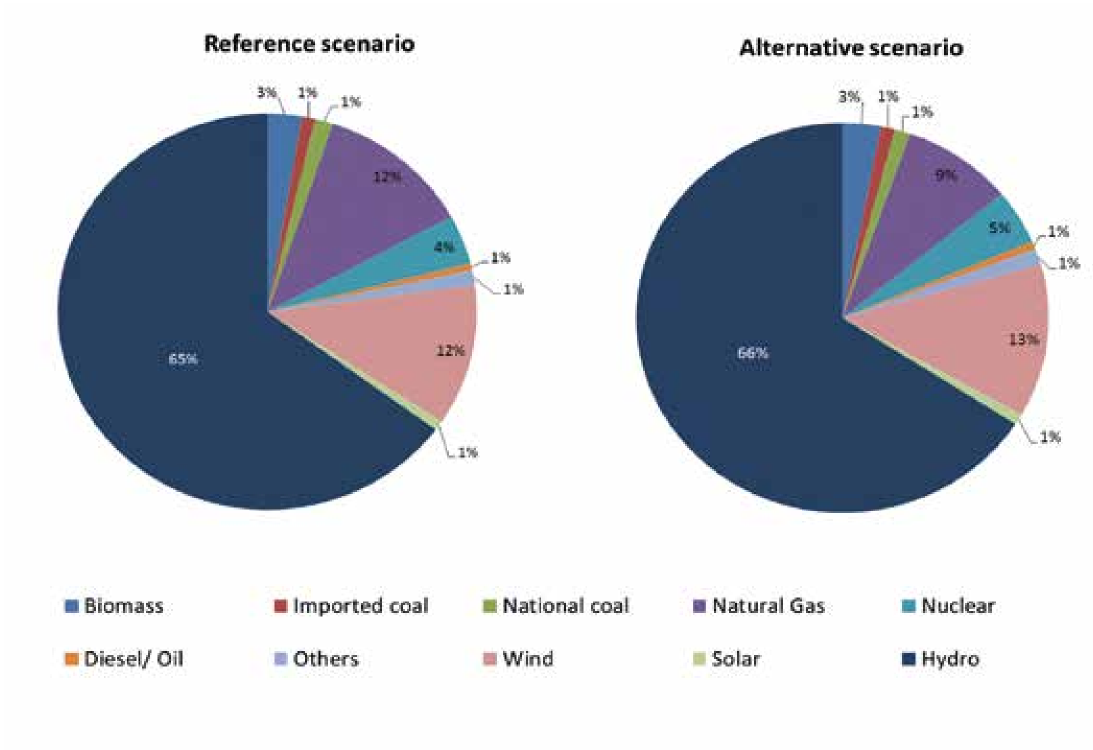


FIGURE 76 - Comparison of the power generation matrix in 2030

5.3 Results

Lower market growth and energy supply adjustments were included in the SDDP model to simulate the SIN operation, with the following results:

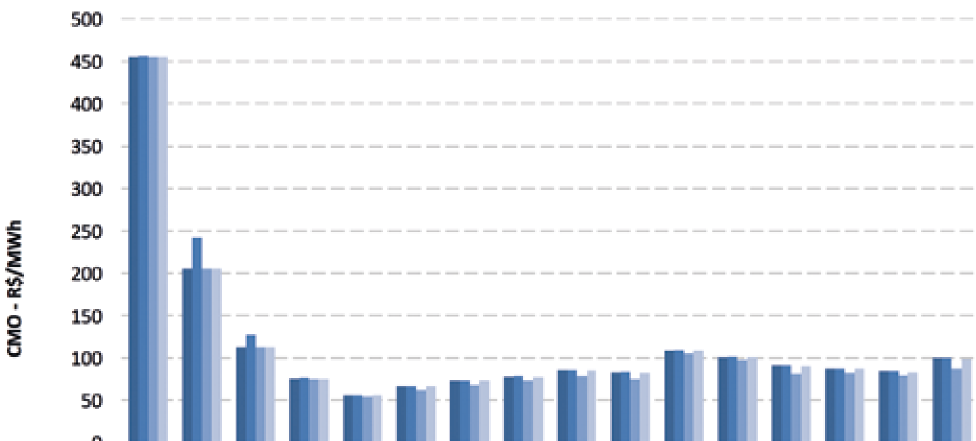
5.3.1 MOC Projection

Figure 77 shows the annual projected marginal operating costs (MOC).

The Marginal Operating Costs (MOCs) for 2015 and 2016 are high, due to the low inflows during the 2013/2014 wet season and to structural problems such as the HPP friction factor.

However, these MOCs are lower than those of the Reference scenario (around R$455/MWh instead of R$470/MWh in 2015 and R$115/MWh instead of R$225/MWh in 2016).

From 2017, the MOC are lower because delayed plants and new contracted supply from the auctions have been included in the simulation horizon. From 2019 to 2023, the MOC are R$80 per MWh, increasing to R$100 per MWh over the longer term (with a demand/supply margin of around 2%), that is also smaller than in the Reference scenario (around R$140/MWh on the long term).



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Southeast	455	205	113	75	56	67	73	78	86	83	109	101	91	87	84	100
South	456	242	128	77	56	67	73	78	86	84	109	101	91	88	84	100
Northeast	455	205	113	75	54	62	68	73	78	75	105	97	81	82	79	87
North	455	205	112	75	56	67	73	77	85	83	108	101	90	87	83	99

FIGURE 77 - Projection of MOC for the alternative case

Figure 78 allows for a comparison of MOCs of both the Low-Hydrology and the Alternative scenario with those of the Reference scenario. While the Low-Hydrology scenario results in higher values than the Reference one along all the period, the Alternative case results in values always lower than the Reference one. The dote line allows to visualize the cumulative effect of the low-hydrology and the set of measures proposed in the Alternative case. The conclusion is that the proposed measures of the Alternative scenario would more that compensate the increase of MOCs induced by the considered low-hydrology.

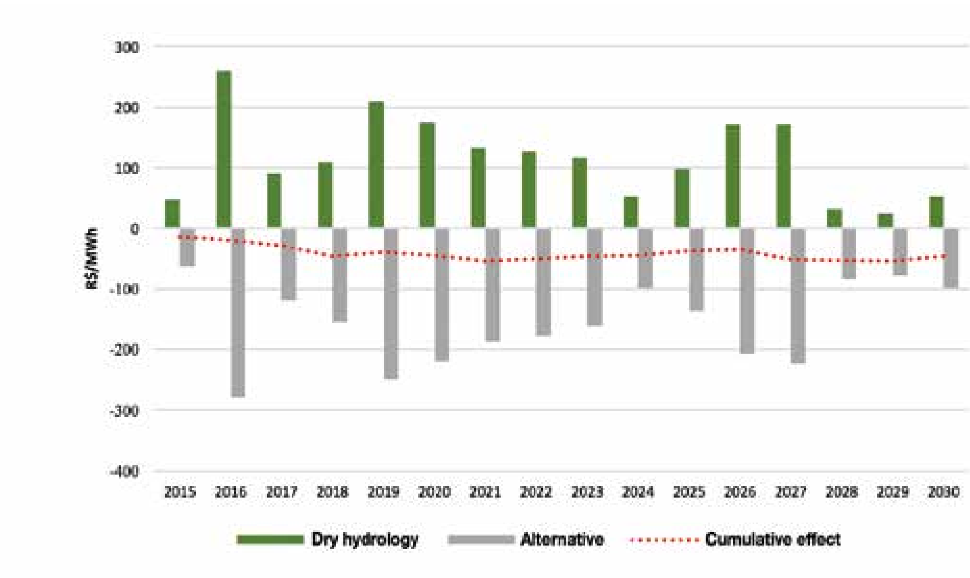
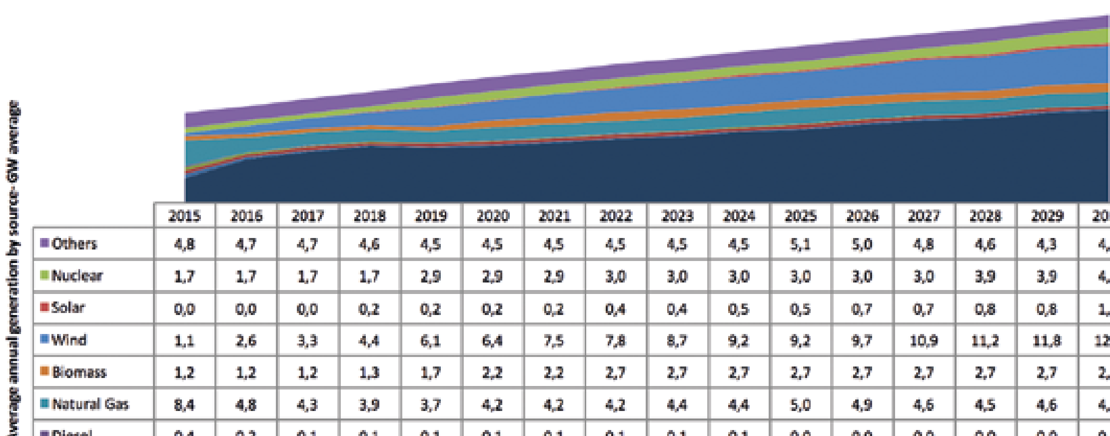


FIGURE 78 - Comparison of MOCs of the Low-Hydrology and the Alternative scenario

Figure 79 shows the evolution of average annual generation by source.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Others	4,8	4,7	4,7	4,6	4,5	4,5	4,5	4,5	4,5	4,5	5,1	5,0	4,8	4,6	4,3	4,2
Nuclear	1,7	1,7	1,7	1,7	2,9	2,9	2,9	3,0	3,0	3,0	3,0	3,0	3,0	3,9	3,9	4,8
Solar	0,0	0,0	0,0	0,2	0,2	0,2	0,2	0,4	0,4	0,5	0,5	0,7	0,7	0,8	0,8	1,0
Wind	1,1	2,6	3,3	4,4	6,1	6,4	7,5	7,8	8,7	9,2	9,2	9,7	10,9	11,2	11,8	12,1
Biomass	1,2	1,2	1,2	1,3	1,7	2,2	2,2	2,7	2,7	2,7	2,7	2,7	2,7	2,7	2,7	2,7
Natural Gas	8,4	4,8	4,3	3,9	3,7	4,2	4,2	4,2	4,4	4,4	5,0	4,9	4,6	4,5	4,6	4,5
Diesel	0,4	0,2	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,0	0,0	0,0	0,0	0,0	0,0
Oil	1,2	0,5	0,3	0,3	0,2	0,3	0,2	0,2	0,3	0,3	0,3	0,1	0,1	0,1	0,1	0,1
National coal	1,0	0,9	1,0	0,8	1,0	1,1	1,1	1,1	1,1	1,1	1,2	1,2	1,1	1,1	1,1	1,1
Imported coal	1,3	0,6	0,4	0,3	0,2	0,3	0,3	0,3	0,4	0,4	0,5	0,4	0,4	0,3	0,4	0,3
Hydro	48,1	54,2	56,7	58,3	57,9	58,4	59,6	60,7	61,5	62,9	63,7	65,4	66,8	67,5	69,3	70,1
TOTAL	69,2	71,4	73,7	76,0	78,6	80,8	82,9	85,0	86,9	89,0	91,1	93,1	95,1	96,8	99,0	100,9

FIGURE 79 - Evolution of average yearly generation by source for the alternative case

5.3.2 CO_2 Emissions

Figure 80 shows the minimum, average and maximum emissions for the SIN plants over the study horizon. The average reduction of emissions for the reference case is 20% (see Figure 28): the rationalization of the energy consumption and the dissemination of distributed generation based on renewable energy reduces the need to dispatch polluting plants, thus reducing total emissions.

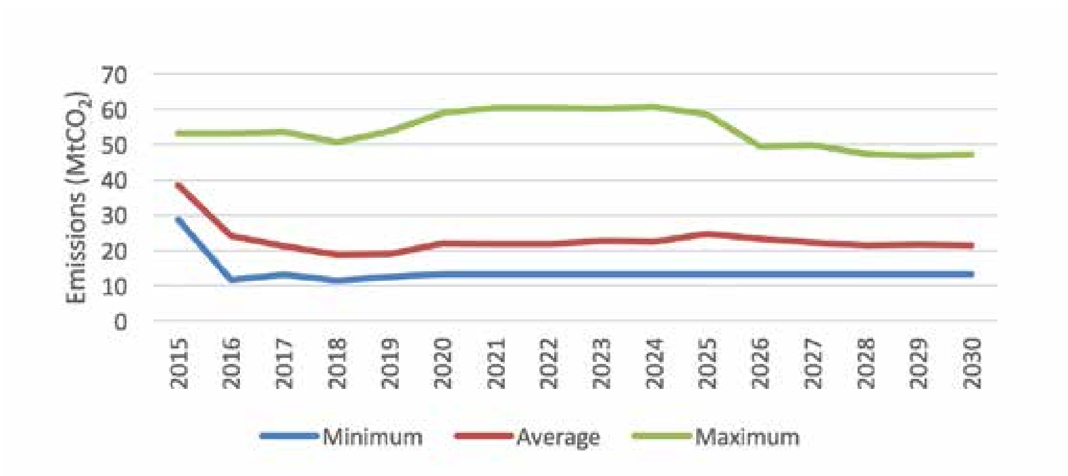
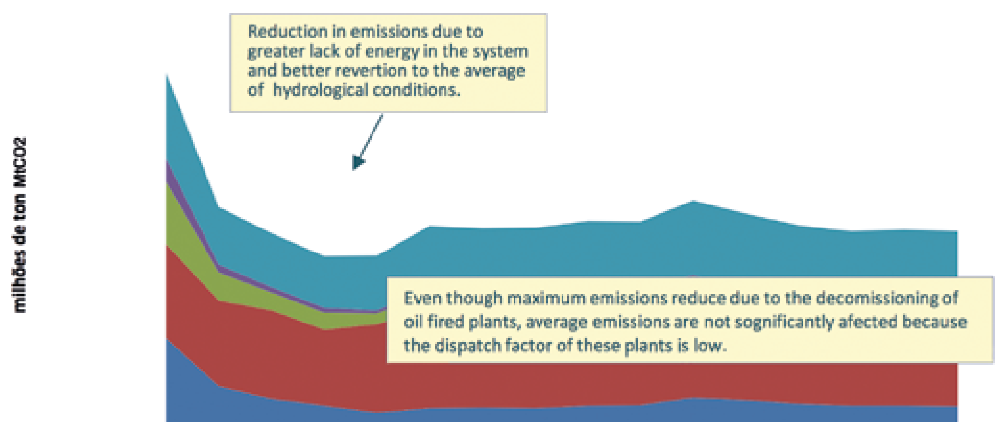


FIGURE 80 - Emissions for the alternative case

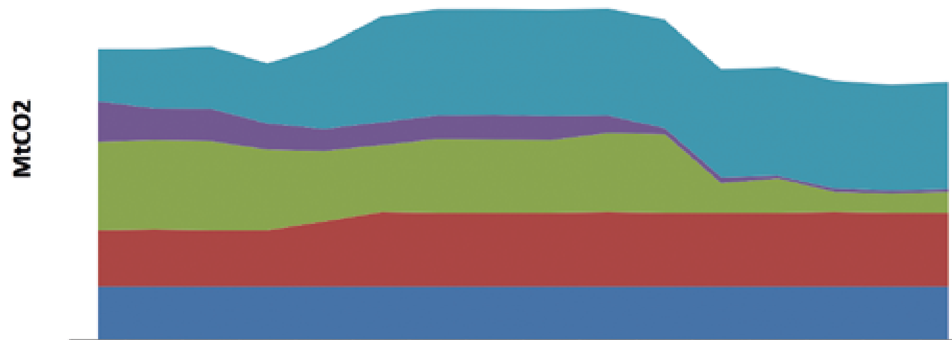
Figure 81 shows the average annual emissions by source.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas	9,2	6,2	5,8	5,5	5,9	6,8	6,8	6,7	6,9	7,0	8,0	7,9	7,4	7,2	7,4	7,3
Diesel	2,5	0,9	0,6	0,5	0,4	0,5	0,4	0,4	0,4	0,3	0,1	0,2	0,1	0,1	0,1	0,1
Oil	6,7	2,9	1,9	1,8	1,2	1,6	1,3	1,4	1,4	1,4	1,7	0,8	0,7	0,4	0,6	0,5
National coal	10,1	9,2	9,5	8,2	9,5	10,7	10,8	10,9	11,0	11,0	11,3	11,2	11,0	11,0	10,9	10,8
Imported coal	10,0	4,9	3,5	2,7	1,9	2,5	2,6	2,5	2,8	2,8	3,6	3,3	2,9	2,7	2,8	2,7
TOTAL	38,5	24,1	21,3	18,8	18,9	22,1	21,8	21,9	22,6	22,5	24,8	23,4	22,2	21,5	21,7	21,5

FIGURE 81 - Average annual emissions by source for the alternative case

Figure 82 shows the **maximum** average annual emissions by source.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas	9,7	10,9	11,4	11,1	15,0	19,2	19,4	19,3	19,4	19,6	19,7	19,6	19,7	19,6	19,3	19,5
Diesel	7,3	5,8	5,8	4,7	4,0	4,2	4,3	4,5	4,4	3,1	1,2	1,1	0,6	0,5	0,5	0,5
Oil	16,1	16,2	16,2	14,6	12,9	12,2	13,3	13,3	13,1	14,4	14,2	5,4	6,1	3,7	3,6	3,7
National coal	10,2	10,3	10,3	10,3	11,8	13,5	13,4	13,4	13,4	13,5	13,4	13,4	13,4	13,5	13,4	13,4
Imported coal	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0
TOTAL	53,3	53,3	53,6	50,6	53,7	59,1	60,4	60,5	60,3	60,6	58,5	49,5	49,8	47,4	46,7	47,2

FIGURE 82 - Maximum average emissions by source for the alternative case

Figure 83 shows the probability density function of GHG emissions in selected years.

With the exception of 2015, with probabilities distribution subject to short-term imbalance, further emissions reductions to below 30 million tons per year are envisaged (i.e. lower than in the reference case).

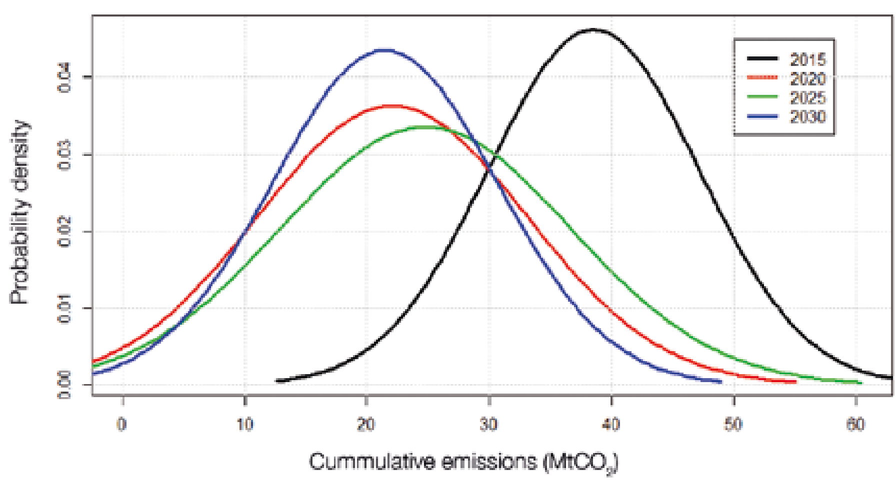


FIGURE 83 - Probability density function of GHG emissions for the alternative case

Figure 81 compares the probability distributions between the reference and alternative cases. The difference with the SIN GHG emissions is fairly substantial. Emissions in the alternative case are on average 20% less than those in the reference case.

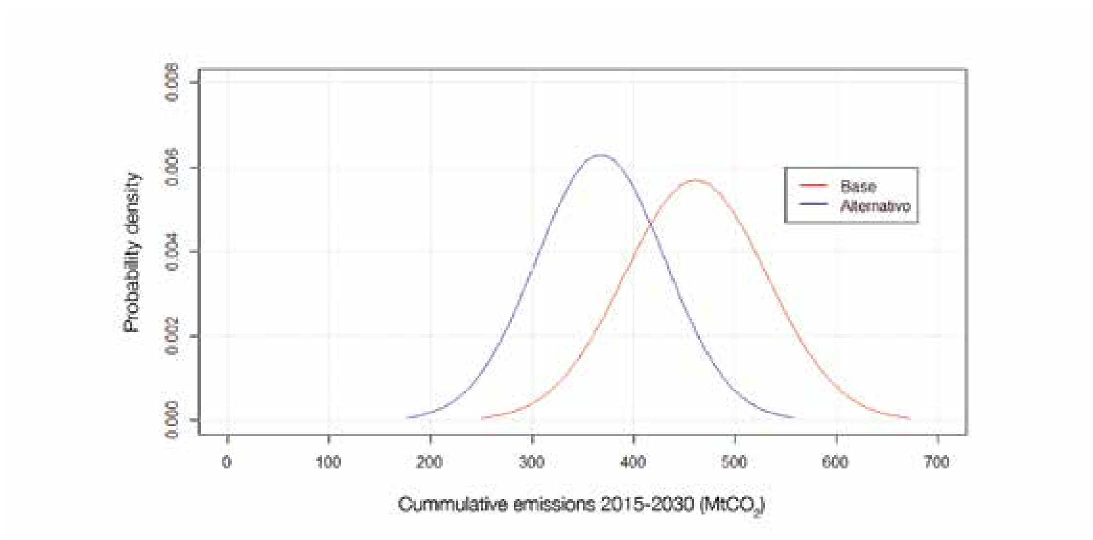


FIGURE 84 - Probability distribution of cumulative emissions (2015-2030)

Figure 85 shows the probability distribution of emissions for 2015, 2020, 2025 and 2030, in addition to cumulative emissions over the study horizon. In the later years the series with higher emissions have values of around 4 times higher than those with lower emissions.

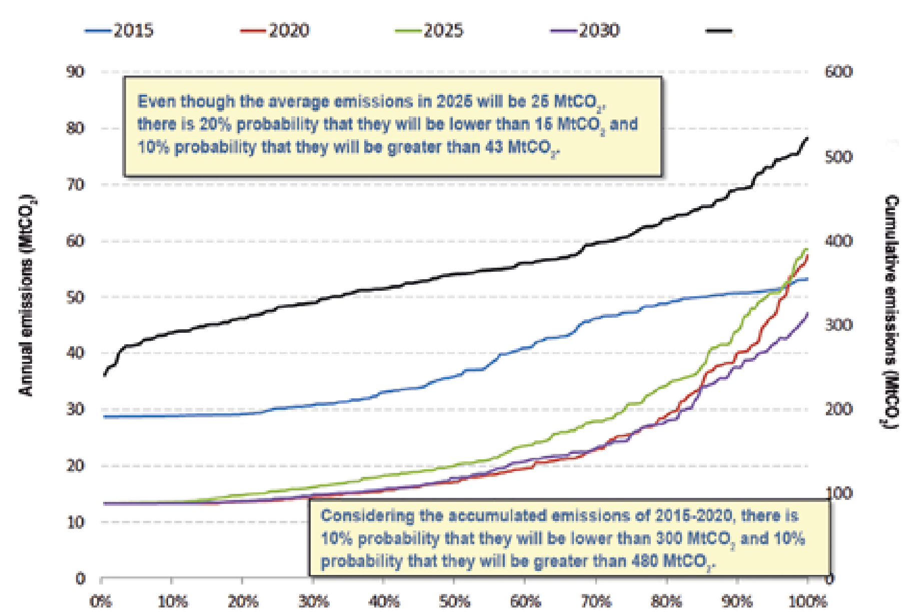


FIGURE 85 - Probability distribution of annual emissions

For more results of the alternative case, see Annex E.

We conclude that consumption rationalization measures and/or increased distributed generation can contribute to a reduction of around 20% of GHG emissions over the time horizon of the study.

Thus, the Alternative scenario appears as a “no regret” one, since it provides an energy supply at the same time cleaner and cheaper than the reference one, despite the restrictions on the availability of hydropower generation that result from the considred low-hydrology.

6 CONCLUSION

The main conclusions of the study are:

In case of low-hydrology, the availability of hydropower generation is reduced, requiring dispatching more thermal power plants and thus increasing GHG emissions.

Annual emissions during a dry year (around 60MtCO_2) can be four time higher than in a wet year (around 15MtCO_2).

Under the Low-Hydrology scenario considered in this study, the cumulated GHG emissions of the national power system for 2016-2030 period are around twice higher than under the Reference scenario.

The average marginal operating cost would be around twice higher under the Low-Hydrology scenario between 2017 and 2027 (above R$200/MWh) compared to the Reference scenario (around R$100/MWh).

With respect to year 2025, the year for which Brazil has set its emissions reductions target in its INDC:

- the median value of the contribution of hydropower (in energy) would decrease about 5% under the Low-Hydrology scenario compared to the Reference scenario (from 70% to 65%);
- the average value of annual emissions of the national integrated power system would increase 30% in comparison to the Reference scenario (from 31.8 MtCO_2 to 41.3MtCO_2).

Under an Alternative scenario, energy conservation measures and increased dissemination of renewable could compensate both the increases of the MOC and the emissions observed in the Low-Hydrology scenario.

ANNEX A
SDDP COMPUTATIONAL MODEL

The SDDP model, developed by PSR, was used to simulate the hydrothermal dispatch of the SIN. SDDP[26] is a proprietary stochastic energy dispatch model for optimizing and simulating hydrothermal systems while considering transmission and natural gas network constraints. Developed in the early 1990s, it has been used in studies and / or as part of the dispatch centers in more than 40 countries, including all the countries of North, South and Central America, four Western European countries (Austria, France, Spain and Norway), the nine countries of the Balkan region, Turkey, Malaysia, New Zealand and China. The SDDP was first used in Brazil from 1998, at the time of the first sectorial reform, by electricity and gas companies (e.g. CPFL and PETROBRAS).

The main characteristics of the SDDP model are:

- Detailed representation ("individual plants") of the hydropower system: water balance of plants in cascade, storage and inflow rate limits, dead storage, maximum flow through turbines, energy production coefficients, and others;
- Stochastic inflow model representing hydrological system characteristics such as seasonality, time and spatial inflow correlations, droughts, and others;
- Detailed representation of thermal plants (concave or convex efficiency curves, multi-fuel thermal plants, "start-up" cost, and others);
- General representation of fuel availability constraints, and detailed representation of natural gas production and transportation system (gas-well production, pipeline network, non-thermoelectric demand for gas, LNG imports, etc.);
- Detailed transmission network: active power flow model (Kirchhoff´s laws), power circuit flow limits, losses, reliability constraints (such as the N-1 criterion), export and import limits among electric power areas and sum of flow constraints in the "tie lines". Alternatively, a more aggregated representation can be used, with energy interchange limits between regions or submarkets;
- Integrated operation optimization for various power systems or the coordinated operation mode where interchanges are based on short-term marginal costs differences;
- Discrete representation of load duration curves (at system level) or (at busbar level) for monthly, weekly or hourly time steps.

[26] SDDP is a model used to calculate the least-cost operation policy of a hydrothermal power generation system ("*Stochastic Dual Dynamic Programming*") and was originally developed by Mario Veiga of PSR. The same methodology is used in the NEWAVE model.

The SDDP produces two main groups of results:

i. **SYSTEM OPERATION STATISTICS**: hydro and thermal power production; production costs; fuel consumption; circuit flows; risk of deficit and expected value of unserved energy; energy interchanges between regions.

ii. **ECONOMIC DATA**: marginal operating costs (MOCs); marginal benefits of reinforcing resources[27], such as the installed capacity of power plants, turbine flow capacity of a hydro power plant; storage capacity of a reservoir; increased power interchange capacity between regions or individual transmission circuits.

[27] Marginal benefit data are typically used in expansion planning studies where the benefit is compared with the cost (also marginal) of investment in new capacity. This interaction between planning and operational models - 'Benders decomposition' - underpins computational systems such as the MODPIN module, the SUPER / OLADE / BID system, and the OptGen model developed by PSR.

ANNEX B

RELATED ASPECTS OF THE REFERENCE CASE

Suitability with regard to new energy auctions

Since 2010 there was a reduction in the price of energy and an increased number of wind power contracts in each "new energy" auction.

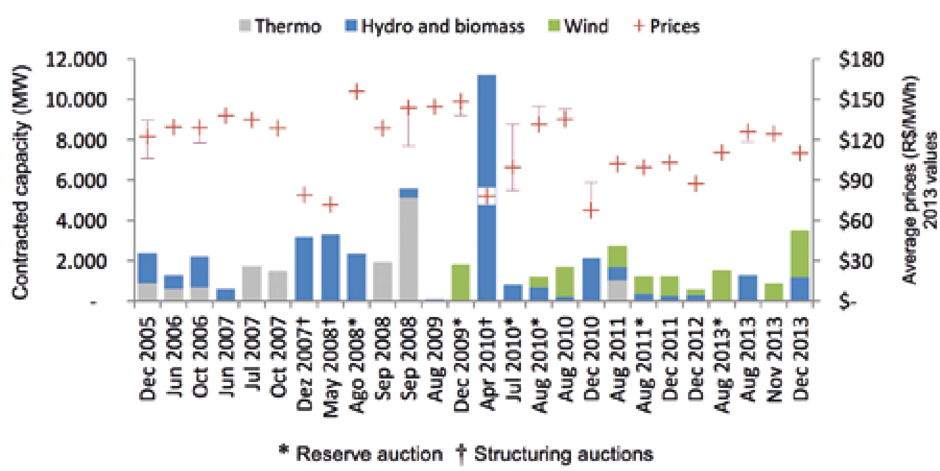


FIGURE 86 - Evolution of prices and amount of energy contracted in new energy auctions

In these auctions, around 5 GW of the installed capacity of oil-fired plants was not considered in the natural gas expansion scenario (due to authorization being withdrawn from unbuilt projects).

Interconnections between subsystems

Methodology

The marginal transmission benefit (MTB) of a given interconnection, expressed in R$ per kW per year, arises from a reduction in the system´s operating costs when the capacity of the interconnection is increased by 1 kW. This parameter is obtained from the optimum solution of SDDP's dispatch problem[28]. If it exceeds the investment cost, it would make sense to expand the circuit in question.

After evaluating the MTB during construction of the Expansion Scenario, certain interconnection expansions are incorporated in the energy system.

In the short-term, the transmission capacities reflect the values in the most recent *Monthly Operations Plan* (PMO) of the ONS. In the medium-long term they are defined according to the "marginal transmission benefit."

Figure 87 summarizes the process of constructing the transmission expansion scenario.

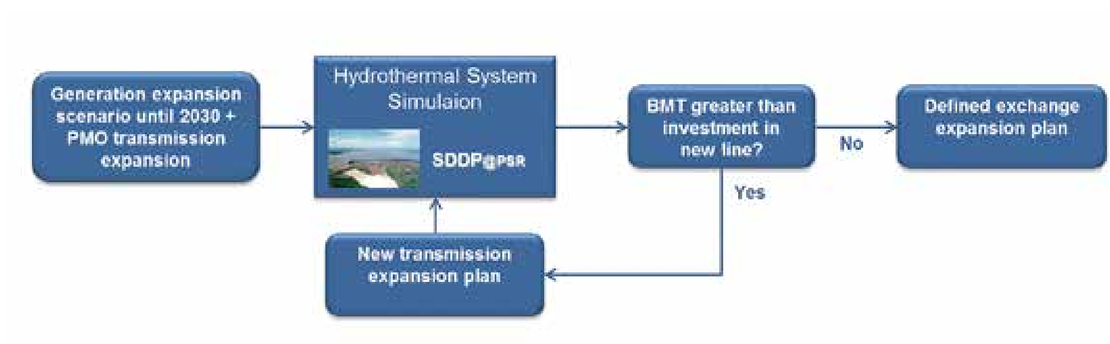


FIGURE 87 - Construction of the transmission expansion scenario

Network Configuration

Figures 88 and 89 show the geographic and schematic configuration of the subsystems considered in the simulation of system operation.

[28] This subproduct is the Lagrange multiplier ('shadow price') of the restricted transmission capacity linked to the hydrothermal dispatch problem.

FIGURE 88 - Representation of the system (geographic)

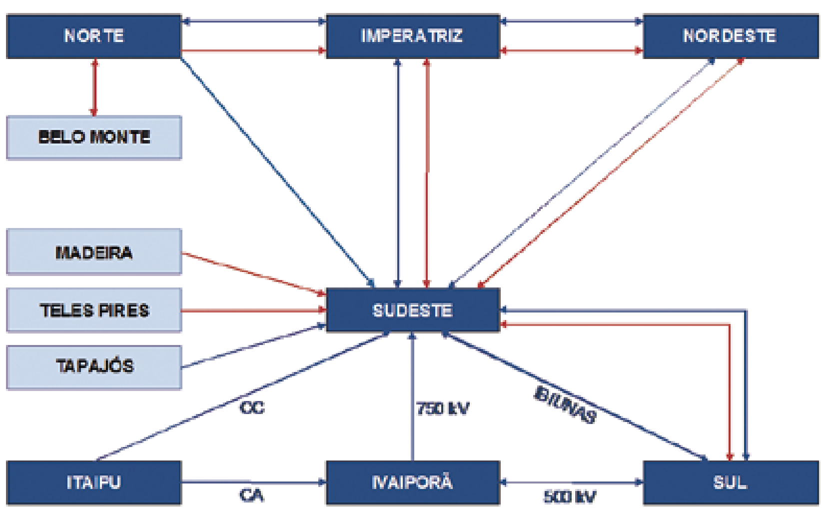


FIGURE 89 - Representation of the system (schematic)

Result of energy interchanges expansion

Figure 90 shows interchange capacity between the subsystems in 2015.

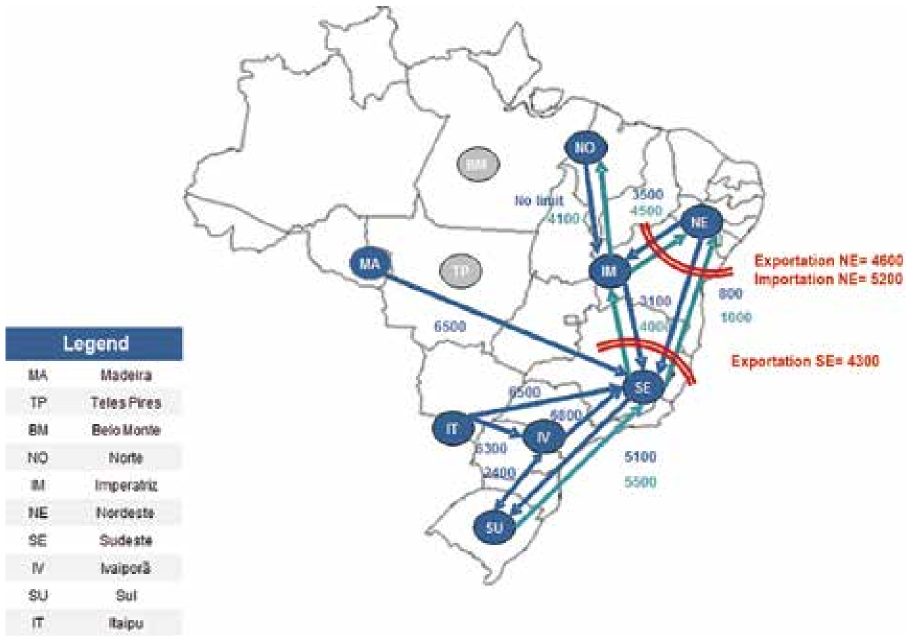


FIGURE 90 - Interchange capacity between subsystems in 2015

Figure 91 shows the interchange capacity between subsystems planned for 2020, according to the previously described methodology.

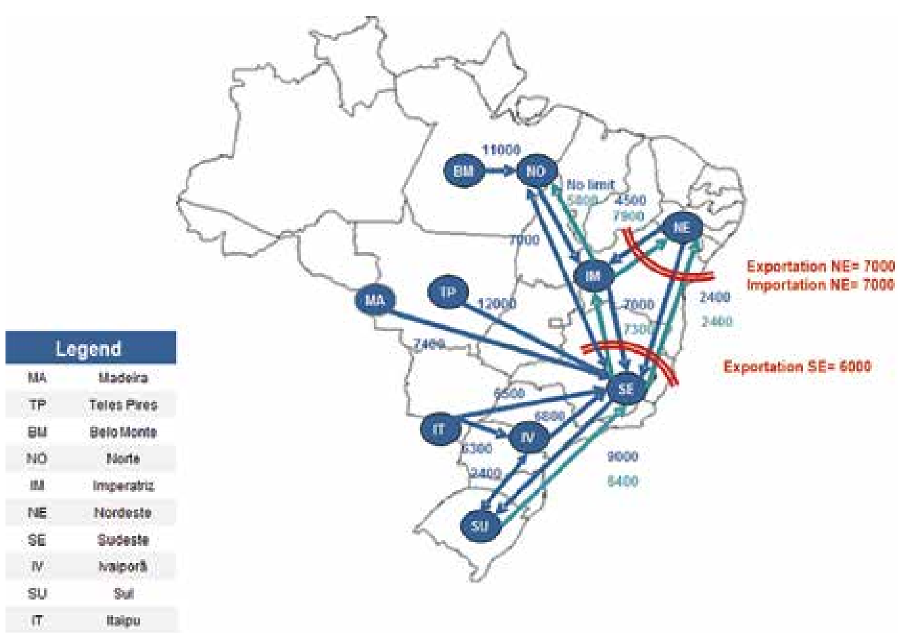


FIGURE 91 - Interchange capacity between subsystems in 2020

Figure 92 shows the interchange capacity between the subsystems required in 2025, according to the methodology described in section 3.3.3.1.

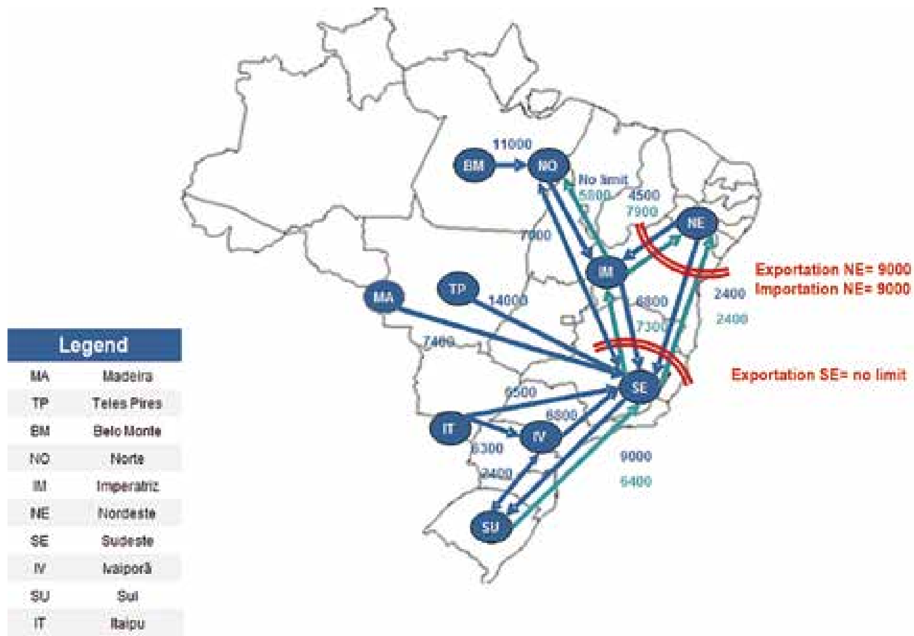


FIGURE 92 - Interchange capacity between subsystems in 2025

Figure 93 shows the interchange capacity between the subsystems required in 2030, according to the previously described methodology.

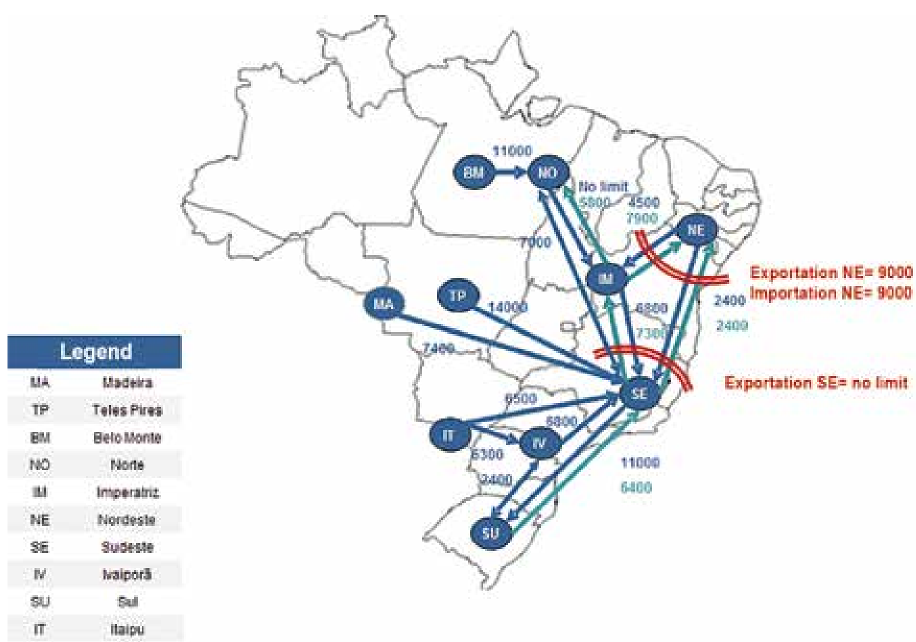


FIGURE 93 - Interchange capacity between subsystems in 2030

Reduction of projected wind production

It is considered that the wind farms auctioned by 2013 will produce 15% less energy than their respective physical guarantees (energy sold in auction). The 15% reduction is the estimated difference between P90 and P50 of their certified production, where P50 is the percentile used by EPE up to 2013 for establishing the value of the physical guarantee of wind power generation, and which serves as a benchmark for the winning projects in the 2009-2012 auctions.

Guaranteed Supply Criteria

Background

An optimal power supply expansion plan must conform to supply security policy and minimize the investment and operational costs of the system. The security policy of the *National Energy Policy Council* (CNPE) determines that an energy supply deficit must not exceed 5% in any of the SIN subsystems. This approach was also used to calculate the physical guarantees of the energy generation projects.

According to economic theory, the least-cost plan is achieved when the marginal operating cost (MOC) equals the marginal expansion cost (MEC), e.g. the EPE *Ten Year Energy Expansion Plan* (PDE 2007-2016) used a MEC of 138 R$ per MWh as its expansion criterion. This represents the weighted average of prices of the projects that sold energy in the October 2006 A-5 auction for delivery as from 2011.

The procedure traditionally used in Brazil´s power sector for developing an expansion plan can be summarized as follows:

i. The cost of a level 1 energy deficit[29] is defined (currently R$2,950.00 per MWh);

ii. An expansion plan is prepared to conform to supply security policy (lower than 5% risk) and where the MOC is equal to the MEC, i.e. R$138 per MWh.

However, as mentioned above, the supply security criterion is also used in the simulations that calculate the physical guarantees of the plants. These simulations result in MOC's of around R$230 per MWh (significantly higher than the MEC). However, if the physical guarantees of all the projects are based on a simulation with an MOC of around R$230 per MWh and if there is equilibrium in the simulation between energy demand and supply[30], the only way to meet the least-cost criterion is through system over-supply.

For example, in order to meet system expansion criteria, the PDE 2008-2017 needed to develop an expansion plan with an oversupply of about 8% relative to demand. However, this high oversupply does not conform to current procurement rules which determine that demand must be 100% equal to

[29] Expansion planning uses a single deficit level, i.e. the deficit cost is always equal to R$2.950 per MWh, regardless of the size of deficit. Cutting demand by 10% therefore costs twice as much as cutting demand by 5%. In the system operation, a deficit cost is used in 4 levels where cutting demand by 10% costs over twice as much as cutting demand by 5%.

[30] Total physical guarantee of the system can be interpreted as the maximum demand that the system can supply with 95% probability. This is calculated (given a hydrothermal configuration) by increasing demand until the risks of deficit are equal to 5%. This demand is known as the critical load of the system. The process is followed by a criterion for apportioning the critical load among the plants. In this way physical guarantee output is equal to demand.

contracted supply, i.e. the expansion criteria is not consistent with the model's market criteria[31]. In the light of this, PSR believes that the PDE is not a realistic reference for analyzing tariffs, prices and energy sales in general.

This occurs because the value of the deficit cost used in the simulations (US$2,950.00 per MWh) is inconsistent with the expansion criteria adopted. In other words, with this deficit cost it is not feasible to define an expansion plan that can simultaneously ensure: (i) a deficit risk lower than 5%; (ii) a MOC equal to the MEC; and (iii) supply equal to demand.

In PSR's view, the solution is to first review the system´s security criteria, given that a deficit risk of 5% indicates a cumulative probability of 19% of a deficit occurring during a presidential mandate (every four years) The value suggested by PSR is 3%, equivalent to a cumulative probability of 11% in the event of a deficit occurring every four years.

However, a change in the security criteria would have a direct impact on the calculation of the physical guarantees of the projects. PSR estimates that this would imply a 4% reduction in the physical guarantees. Considering this reduction and the fact that demand has to be 100% contracted, it is clear that new supply would need to be contracted.

For example, consider a system currently in equilibrium (supply = demand) with 100 MW average power. If the physical guarantees were revised the supply would be reduced to 96 MW and there would be a need to contract an additional 4 MW to return the system to equilibrium.

Since the physical guarantee of a project is an acquired right and its reduction involves a financial loss, changing the supply criteria could be achieved by maintaining the original physical guarantees and obliging free and captive consumers to contract more than 100% of demand. In this case the original supply would continue to be 100 MW but, added to the 4 MW contracted by consumers, this would result in 104 MW (i.e. 4% over-supply).

If a project´s' physical guarantee is unchanged, the transition to new supply security criteria (with a deficit risk of less than 3%) could be undertaken by contracting reserve energy - a mechanism established in Law No 10848/2004. The first reserve energy auction was held in August 2008. The physical guarantees of new projects to be auctioned would be calculated in accordance with the new criteria.

Equality between MOC and MEC

In July 2008, CNPE Resolution No. 9 changed the criteria for calculating the physical guarantees of power plants. However, contrary to all expectations, the criterion proposed by the Council was not based on supply risk, but on the definition of a *baseline value for the expected operative marginal cost value* (E [MCV]).

[31] Distributors are not allowed to pass energy costs contracted above 103% to final consumer.

It is not possible, with this new option, to know *a priori* what the level of the country's power supply reliability is likely to be. In other words, supply reliability is no longer a *primary* indicator of the need for supply expansion but rather a side effect, i.e. a *consequence* of the baseline value definition in terms of (E [MCV].

For example, in July 2008, EPE defined the MEC as R$ 148 per MWh[32] As a result, the deficit risks calculated with the new CNPE methodology are 3.6% in the Southeast, 2.2% in the South, 2.9% in the Northeast, and 2.3% in the North[33]. Apart from being difficult to justify, given the different reliability levels of different regions, it is noteworthy that the Southeast region, where most of the electricity supply activities are concentrated, has the worst quality of supply.

According to the CNPE resolution, the physical guarantees of the new projects will be calculated using the new methodology. In the case of thermal power plants, this would involve a reduction in line with their variable unit costs (CUV), which could be as much as 30% in the case of oil-powered thermal plants. In the case of HPPs the reduction would be around 6%.

The Resolution also establishes that existing projects which had their physical guarantee calculated and published by the Ministry of Mines and Energy (MME) prior to the Resolution will continue to be regulated by the old criteria (deficit risk = 5%). The Resolution is not clear with respect to the physical guarantee of the HPPs following the renewal of concessions.

PSR's Expansion Scenario contains the following assumptions for calculating the physical guarantee of power projects:

- For plants that have had their physical guarantee calculated and published by the MME, the Expansion Scenario considers their original physical guarantee;
- For future plants the Expansion Scenario considers the physical guarantee calculated according to the new criterion.

As discussed in section 4.1.6, hydrothermal dispatch has been based since September 2013 on the CVaR risk aversion methodology. This new methodology increases the physical guarantee of hydroelectric and thermal plants with low CUVs. In the case of a thermal power plant with a high CUV (> US$ 120 per MWh), the higher the CUV, the greater the reduction of the physical guarantee due to the CVaR.

The Expansion Scenario considers the impact of this methodology in the calculation of the physical guarantees of new projects, but does not consider that the certificates of existing plants will be revised.

The friction factor

The disarray in Brazil´s hydroelectric system in 2012 led to the agents having to pay for, from late 2013, huge costs due to the activation of thermal plants. The Brazilian Interconnected System (SIN) began year 2012 with the highest stocks for the previous 16 years, but ended the year with the worst shortage for the last 12 years, as shown in Figure 94.

[32] This value differs from the MEC defined by EPE in the PDE 2007-2016.

[33] Source: EPE

FIGURE 94 - Depletion of the National Interconnected System (SIN) in 2012

The first suspected cause of the sudden depletion was the extremely strong inflows in 2012, although 20 of the 80 historical series (25%) were in fact drier than the 2012 inflows. The second suspected cause was a possible imbalance between the system´s physical guarantee of supply and demand. The generating agents in early 2012 believed that there was “plenty” of physical guarantee in the system (2.4 GW average). However, given the delays in the entry into operation of the new generating package (a reduction of around 1500 MW average) and transmission constraints in the Northeast that reduced the balance by about 800 MW, this surplus did not in fact materialize in 2012.

In an effort to explain this unprecedented drawdown, PSR simulated the operation of the system for 2012 using input data with the same real values: demand, renewable generation (wind, biomass, etc.), thermal generation (same ONS operating decisions), and inflows. Hydroelectric generation was also the same (difference between demand for renewable and thermal generation). This led to the situation where the only “degree of freedom” of the simulation model was how to empty the reservoirs. Figure 95 shows the results of the simulations. [34]

[34] ONS and certain agents attempted to reproduce the above results and obtained different outcomes. The differences were due to the fact that every week (or month) the agents returned to using the real initial volumes instead of the results of the simulation. Thus the cumulative effect of the deviations was not represented.

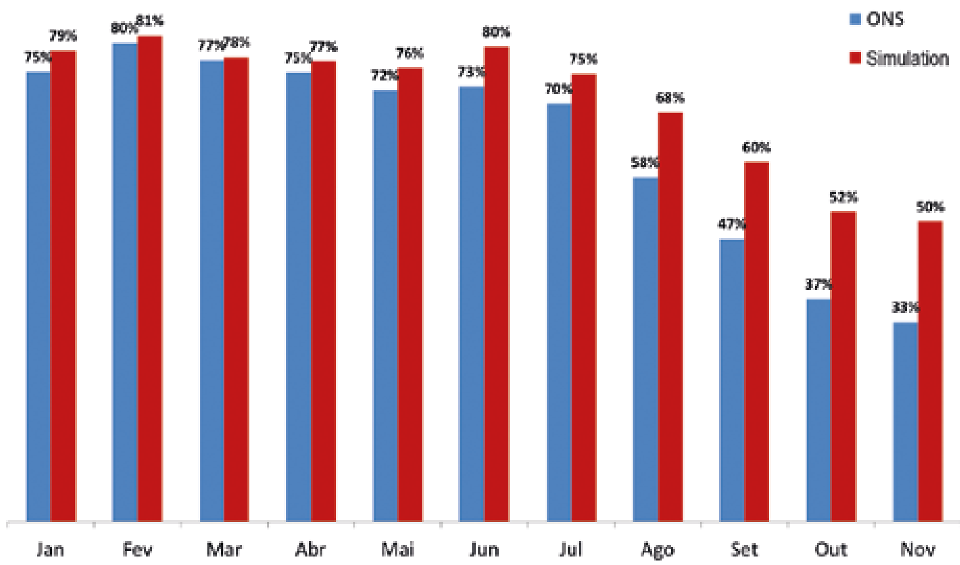


FIGURE 95 - 2012: Simulation of the operation and values obtained (ONS)

The difference was 17% in the SIN storage level, i.e. while actual SIN storage was 33%, the PSR simulation produced a storage level of 50% for the SIN. Given that ONS obviously know how to operate the system, the only explanation is that real-life operational restrictions are not represented in the operation model. This is of concern given that all the risk analyses done by the Brazilian government use simulation models similar to those used by PSR. It follows that the government has an over-optimistic approach to security.

A simplified way to quantify the effect of real-life operational limitations that are not represented in the operation model was to divide the additional stored energy indicated by the simulation model (difference of storage levels of between 33% and 50%) by the total hydropower produced between January and November (considering that total hydroelectric energy is identical for the real operation and the simulation). The result was 9%. In simple terms, it was as if there was a “friction factor” causing the HPPs to use 9% more water than expected to produce each MWh.

This effect could be partly explained by the unprecedented inflows in the Northeast: since 1993, the dry season inflows in the Northeast were below the historical average, as shown in Figure 96. Given that the stochastic models used for hydrothermal dispatch present projections that converge towards the historical average in a 6 - 12 month period, the programming of hydrothermal dispatch is often over-optimistic, indicating a need to export less energy than necessary to the Northeast region. The result was a faster real drawdown than that indicated by computer models. To deflect this bias, PSR increases withdrawals upstream of the Sobradinho reservoir in the dry season in order to represent the average inflows post-1993. This was calibrated manually only in the case of the São Francisco river.

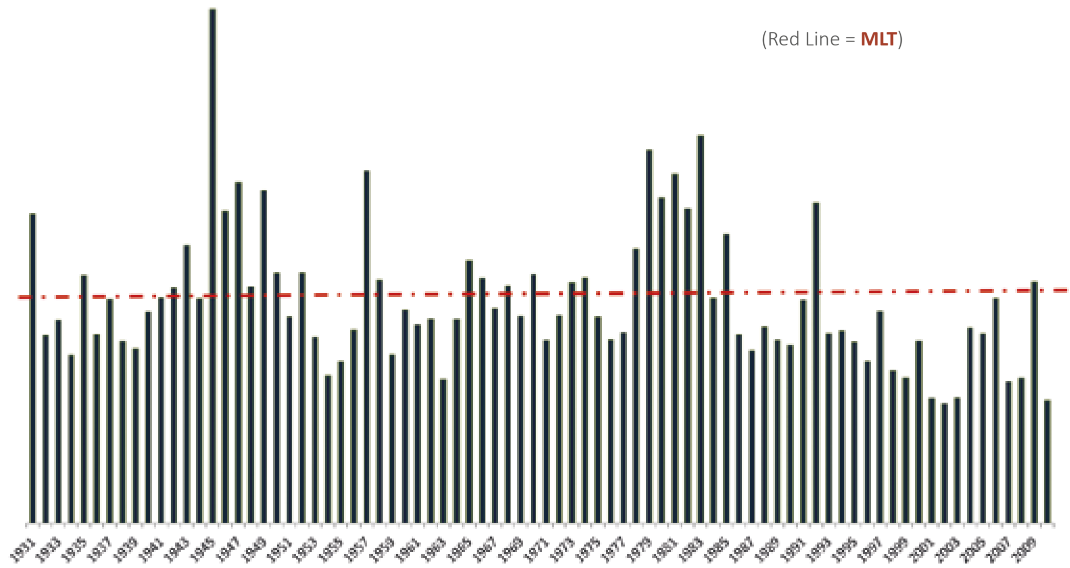


FIGURE 96 - Inflow patterns in the Northeast

The other part of the "friction factor" effect arises from HPP operational restrictions that are not incorporated in the computational models such as: (i) reservoir silting; (ii) power restrictions; (iii) operational limits on maximum and minimum turbine operations due to environmental constraints; (iv) hydroelectric production coefficients not reflecting the real physical production capacity of the plants; (v) need to generate reserve, etc. Of the 17% difference in total storage in late 2012, 3% are explained by the Northeast inflows and 14% by restrictions on the hydropower plants.

Figure 97 shows the same exercise for 2013. As in the previous year, reservoir depletion 2013 was higher in real life than that indicated by the simulation models. If the system had had no "friction factor", the reservoir levels at the end of December 2013 would have reached 65% (22% higher). This difference would have made it possible to supply an annual average load of 5.3 GW.

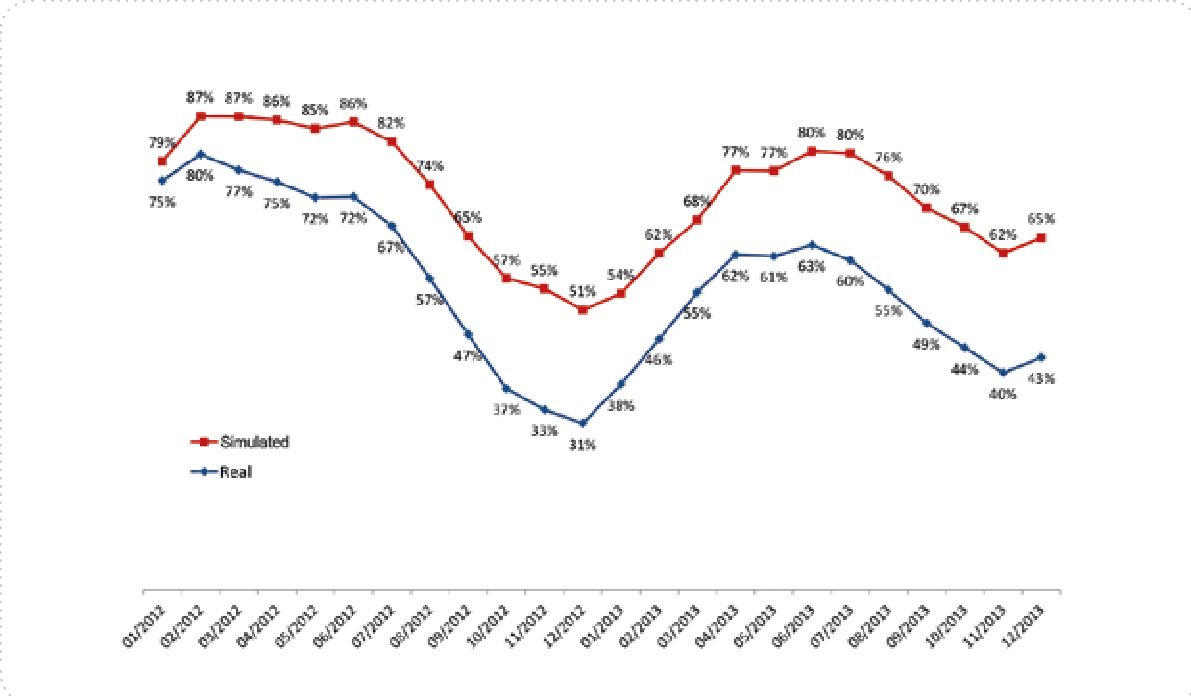


FIGURE 97 - 2012/2013: Simulation of the operation and values (ONS)

In summary, the results of the simulation models may be closer to the real-life operation by adjusting certain "parameters". PSR identified two critical parameters for adjustment:

- Abnormal inflows in the Northeast (that cause a larger energy transfer to this region than that indicated by the models). This adjustment considered that projected Northeast inflows converge towards the average for the past 21 years.
- Misalignments between the real parameters and those of HPP projects. Adjustment considered a reduction of 4% in the production capacity of the HPPs.

The misalignment between simulation and reality, known as the "friction factor" causes a structural imbalance in the system even when the energy supply equals demand. The level in the SIN reservoir would have been 22% higher level at the end of December 2013 without this structural imbalance.

Reserve energy requirement

As discussed above, the "friction factor" causes a structural imbalance in the system even if supply equals demand. The following procedure was used to calculate the amount of energy needed to rebalance the system:

1. Calculation of the critical load of the system uses a static simulation (the same used for calculating the physical guarantee of hydroelectric and thermal plants) based on the actual supply criterion (simulation considering the CVaR, MOC = MEC = R$139 per MWh criteria used in the 2014 A-5 auction), without the friction factor.

a. The static simulation represents the performance of the system in structural balance;

b. This balance is defined as 100% of the demand to be contracted with energy generators with a physical guarantee calculated according to the same supply criteria.

2. The critical load of the system is again calculated as in Step 1 above, but taking the friction factor into account. Greater depletion of the reservoirs means that the critical load of the system will be lower.

3. The need for new supply to structurally balance a system is calculated by the difference between the critical load calculated in Steps 1 and 2 above.

PSR carried out the above procedure for the configuration projected for 2018. The result showed a need to contract 2 GW of new capacity to rebalance the system. This new energy is additional to the supply requirements to meet increased demand. Two approaches can be used to contract this additional amount:

- **DIRECT**: contracting 2 GW of reserve energy. In this event, the government defines the amount of energy that needs to be contracted through reserve energy auctions. Since the reserve energy does not represent physical guarantee for the system, the amount contracted is additional to demand growth.
- **INDIRECT**: the total physical guarantee of the HPPs is reduced by 2 GW (a review of the physical guarantee of the plants is due in 2014 according to MME Ordinance No. 303/2004). This will reduce the physical guarantee of the HPPs by about 4%, resulting in a lack of ballast in the system, and therefore the need to contract new energy.
    - The HPPs can contract new energy if they have already sold energy through long-term power purchase agreements; or
    - By the consumer (ACR or ACL), given that there will not be enough reserve energy to meet consumption.

PSR's assumption for the Expansion Scenario is that the Government will not revise the physical guarantee certificates of the hydroelectric plants even if the existence of friction factors is proven. One way to compensate the system would be to contract reserve energy for the SIN, i.e. the *direct* approach, involving contracting 1 GW reserve energy to enter operation in January 2018, and 1 GW to enter operation in January 2019.

System expansion planning criteria

The System Expansion plan must meet Brazil's power sector regulations: (i) contractual requirement of 100% coverage of demand; (ii) the need for a degree of oversupply to meet uncertain demand growth; and (iii) generation of reserve energy proposed by the Government. The scenario should also consider that structuring projects such as Belo Monte and energy importation from Peru, have a fixed date for start of operation, i.e. they do not depend on supply requirements or the need to compete with other energy sources.

To determine the degree of over-contracting by distributors to handle future demand, the ESTD model developed by PSR was used. Using data from the portfolio of distributors´ subcontractors, the model determines the optimal strategy for contracting new energy (A-3 and A-5 auctions) and existing energy

(A-1 and adjustment auction), considering current market rules and demand uncertainty. The model was applied to the 23 most representative distributors in Brazil, and the simulation of the contracting strategy considered the study´s total time horizon.

In addition to examining distributors´ contracting strategy it was necessary to determine how energy will be contracted to expand the Free Contracting Environment (*Ambiente de Contratação Livre-ACL*). At first sight the free market could take advantage of the energy over-supply projected for the coming years to grow with existing energy instead of investing in new capacity. In this way oversupply would be reduced, with existing energy gradually shifted to the ACL.

However, some new HPPs (mainly Belo Monte and the Madeira River plants, and those resulting from the 2010 A-5 auction) plan to sell part of their energy on the free market. This means that despite the projected oversupply the system will expand to supply the ACL. The main impact of maintaining this oversupply will probably be a trend towards price reductions in the free market, resulting in changes in the energy sales strategies of the HPPs, which will begin to gradually reduce the amount of energy for supplying the ACL. This trend was noted in 2010 with the decision to reduce from 30% to 15% the maximum amount of energy for sale by the HPPs in the December 2010 A-5 auction. The Government alleged that the reduction was due to some developers finding it difficult to sell energy in the ACL.

To map this change of behavior in SIN generating capacity expansion, the following strategies to meet the growth of the free market were considered in the long term scenario:

- 2015-2019: expansion of the free market supplied with energy that the HPPs had not sold to the ACR.
- Post-2019: free market accounts for 85% of its own growth (i.e. self-production and / or contracting new energy); 15% of the remainder purchased from the HPP hydrological risk surpluses.

Figure 98 summarizes this approach.

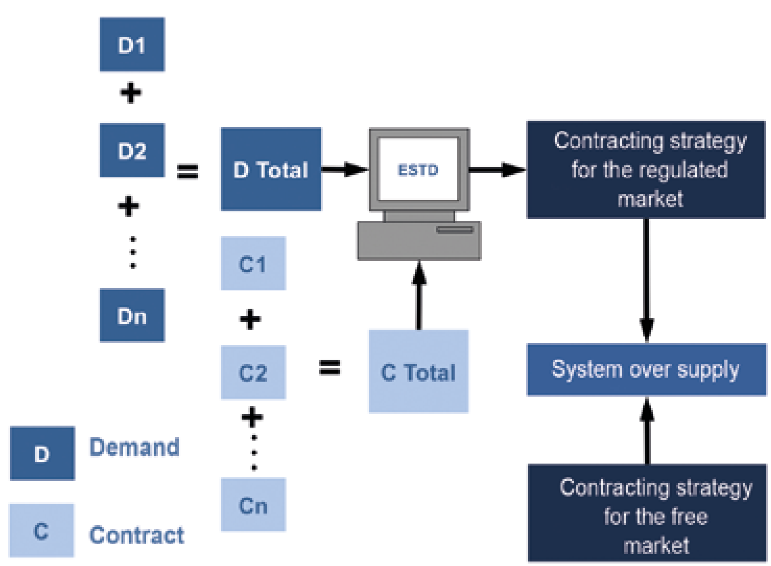


FIGURE 98 - **Methodology for calculating over-supply of the system**

Figure 99 shows the development of oversupply of the system from 2018-2030.

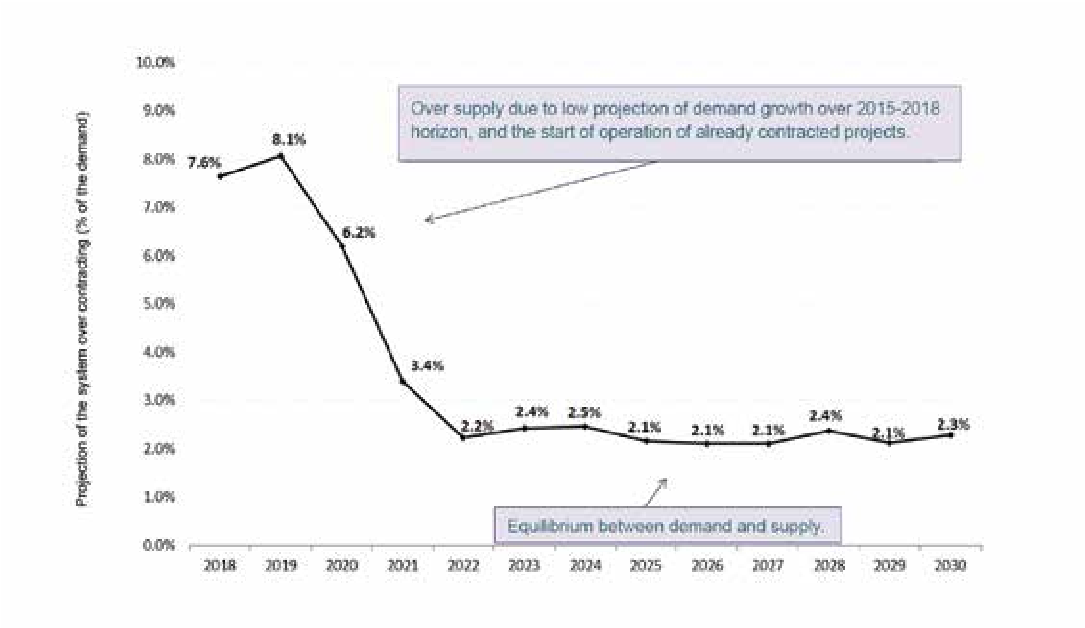


FIGURE 99 - Projected oversupply of the system [without reserve energy]

The PSR Expansion Plan criteria can be summarized as follows:

- Date fixed for start of operation of structuring projects;
- New supply is injected into the system until an oversupply of physical guarantee is reached according to the simulation of agents' contracting strategy;
- Reserve energy is injected into the system.

In summary, the system expansion criterion of the reference case is considered to be the need for contractual coverage of demand. This coverage is measured in terms of projects´ physical guarantee calculated with the methodology described in the previous item. The scenario considers a deficit cost on four levels, with the deficit risks and marginal operational costs being a subproduct of this process, unrelated to the marginal expansion cost [MEC].[35]

[35] The main reason is that the system contains plants with guaranteed power outputs calculated according to different criteria.

Simulation of hydrothermal dispatch of the system

After adjusting the scenario the system must be simulated considering *all the operating procedures* currently in force, described below.

Adjusting Variable Unit Costs

The thermal plants contracted in the new energy auctions are eligible for an adjustment of the portion of the CVU related to fuel costs, e.g. the plants that were successful in the first new energy auction held in December 2005 have their CVU adjusted yearly according to the variation in the fuel prices between October of the current year and October of the previous year. The fuel costs of the thermal plants contracted in auctions from 2007 onwards are adjusted monthly to reflect international oil price fluctuations.

The CCEE is responsible for readjusting the CVU of thermoelectric plants and for informing the new values for use by the ONS in the PMO. This is a monthly adjustment based on the rules of each new energy auction, and the new value remains constant during the entire horizon of the PMO. This means that if the CVU of a natural gas thermal plant increases as a result of a short-term problem, this value will have an impact on the projection of PLD for the entire horizon.

To incorporate the successive adjustments of the CVUs throughout the horizon of this study, at each stage of the previously described, the CVU of the thermoelectric plants is readjusted on the basis of international oil price forecasts. For the year 2000, readjustments of the CVU were based on the August PMO. For the other years the CVU was adjusted according to projected imported coal prices (US$ per ton), *Henry Hub* (US$ per MMBtu) and oil prices (US$ per bbl.)[36] up to 2030. Table 9 shows the values used for the projection.

TABLE 9 - Fuel price projections (constant currency)

YEAR	OIL(US$ per bbl)	HENRY HUB (US$ per MMBTu)	IMP.COAL (US$ per ton)
2014	58	3.1	92
2015	75	3.5	97
2016	77	3.7	101
2017	78	3.8	103
2018	80	3.9	105
2019	81	4.0	106
2020	83	4.1	107
2021	85	4.2	108
2022	86	4.3	110
2023	88	4.4	112
2024	90	4.5	113
2025	92	4.6	114
2030	93	4.7	116

Source: EIA Report of October 2014 (Oil and Henry Hub); PSR (Coal)

[36] Projected prices of fuel oil and diesel based on oil prices.

If fuel prices are higher than those shown in the table they will affect the variable costs of gas, imported coal and oil-powered plants, but their impact on future prices will be limited because the PLD (spot price) is based on water values in the hydroelectric plants that in turn represent an average of the opportunity cost of hydropower calculated for different hydrological scenarios. Since the majority (80%) of the hydrological scenarios experience spillage (zero as an opportunity cost for water), some scenarios (approx.15%) lead to thermal units being marginal (with variable costs such as the opportunity cost for water), and a few scenarios (approx. 5%) have deficits (deficit cost as an opportunity cost for water), the average of the different opportunity costs produces a number that balances the effect of immediate oil price variations on energy spot prices. The underlying reason for this is that thermoelectric plants are responsible for 25% of Brazil's installed capacity, but for under 10% of the country's energy production, with gas-powered plants accounting for around 60-70% of thermoelectric installed capacity. This situation could change in the future as thermal generation increases, and is fully accounted for in our Expansion Scenario simulations.

CNPE Resolution No.3

CNPE Resolution No. 3 of 6 March 2013 addresses the adoption of risk aversion mechanisms involved in the methodology for calculating PLD from September 2013. The Resolution also changes the rules for payment of the System Service Charge which will apply to all market agents: generators, traders and consumers.

The MME published the new methodology (CVaR), implemented from September 2013, to be used for calculating the short-term prices («PLD»). This is a probabilistic methodology in which risk aversion is represented by operational costs. The model seeks to minimize a convex combination of the expected operational costs and the «conditional value at risk» (CVaR) of the same cost. In short, the new aim of the hydrothermal dispatch models will change from minimization of the expected value of operational costs (Min E (CO) to minimization of a convex combination of the expected values of operational costs and a CVaR of the same cost for a given level of risk α: $(1- \lambda) \times E(CO) + \lambda\, CVaR\alpha\, (CO)$, where α is a parameter (between zero and 1) defined by the system operator. The parameters defined for 2014 are: $\alpha = 50\%$ and $\lambda = 25\%$.

The risk-averse profile is indirectly represented by: (i) scenarios with higher operating costs represented by CVaR in the above weighted sum; and (ii) more expensive scenarios that tend to be associated with drier hydrological conditions and which probably include the subset of water deficit scenarios.

The new methodology introduces risk aversion mechanisms for calculating the hydrothermal operating policies to increase supply security and to capture the cost of this risk aversion in the PLD. This study was conducted considering the CVaR risk aversion methodology and using the official parameters established by the Ministry of Mines and Energy.

Short-term operating procedures (Target Level)

CNPE Resolution No. 3 establishes that the National System Operator (ONS) can dispatch thermal power plants in no order of priority to ensure security of supply. This ordinance was based on a simulation of the Short-Term Operating Procedure [POCP]. From PSR's standpoint, although the MME has suggested that this procedure will be seldom used after the implementation of the CVaR, the system operator will nevertheless continue to dispatch thermal plants regardless of the "order of priority" to ensure that the reservoirs´ pre-determined target levels are reached by the end of November every year. The POCP methodology is described below.

In 2008 the ONS proposed changing the operating methodology to enhance supply security. The idea was to ensure storage levels considered to be "safe" by the beginning of the rainy season: 38% in the SE, 35% in the NE[37]. The ONS proposal was approved by Normative Resolution No. P51/2009 after scrutiny by Public Hearing 062/2008. This new short-term operating procedure (POCP), known as the "target level", was implemented in the SDDP.

The CVU of the thermal plants activated by the target level is not used for calculating the PLD, and the difference between the CVU and the PLD is paid by consumers through the System Service Charge (ESS). However, these dispatches influence the storage trajectory, which in turn affects the evolution of the PLD. We used the following procedure to illustrate this impact:

i. **PHYSICAL SIMULATION OF THE SYSTEM**: to calculate the operating policy of the system considering the target levels to provide the Future Cost Function (FCF) and system storage trajectories;

ii. **COMMERCIAL SIMULATION OF THE SYSTEM**: to simulate the system, based on the FCF and the storage trajectory of the previous item, without considering the target levels, and thus to obtain the PLDs.

Simulation of the friction factor

As discussed in Section 9.5, the simulation of the system was conducted considering the "friction factor", by making the following adjustments to the hydrothermal dispatch model:

- Abnormal inflows in the NE region (causing more energy to be transferred to this region than indicated by the models). This adjustment was undertaken considering that the projection of inflows in the Northeast have converged towards the average for the past 21 years (1992-2012); and
- Misalignments between the real parameters and those of HPP projects. The adjustment considered a reduction of 4% in the production capacity of the hydroelectric plants.

The "friction factor" is considered only in the final simulation of the system, since it is not used in the calculation of the FCF (i.e. in the calculation of water value).

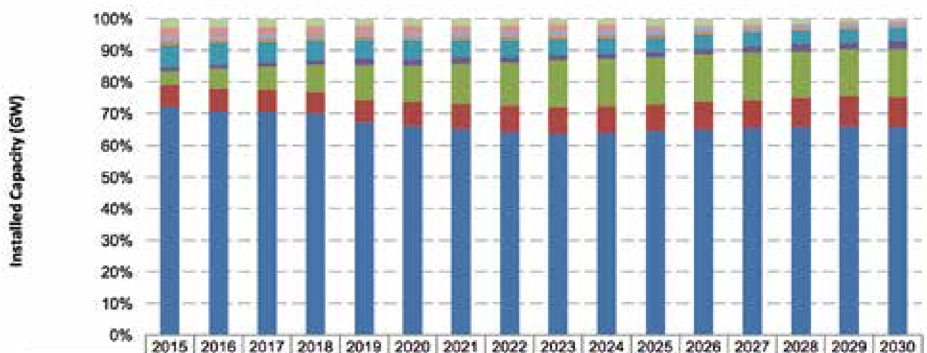
[37] Values approved by ANEEL in early 2013 and used in this study.

ANNEX C

ADDITIONAL RESULTS OF THE REFERENCE CASE

Hydrothermal share

Figure 100 shows the energy supply in terms of installed capacity, by source.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Others	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%
Diesel/Oil	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	1%	1%	0%	0%	0%
National Coal	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Imported Coal	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Biomass	7%	7%	6%	6%	6%	6%	6%	6%	5%	5%	5%	5%	5%	4%	4%	4%
Nuclear	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	3%
Wind	4%	6%	7%	9%	11%	12%	13%	14%	15%	15%	15%	15%	15%	15%	15%	15%
Natural Gas	7%	7%	7%	7%	7%	8%	8%	8%	8%	8%	8%	9%	9%	9%	10%	10%
Hydro	72%	71%	70%	70%	67%	66%	65%	64%	64%	64%	64%	65%	65%	66%	66%	66%

FIGURE 100 - Evolution of energy generating matrix by source (relative values)

Structuring projects

Opportunities for new projects grow year by year. Projects can be divided into two types: "structuring" supply projects awaiting tendering (e.g. São Louis do Tapajós) and "indicative" supply projects whose technologies, location, etc. will depend on the outcome of the auctions).

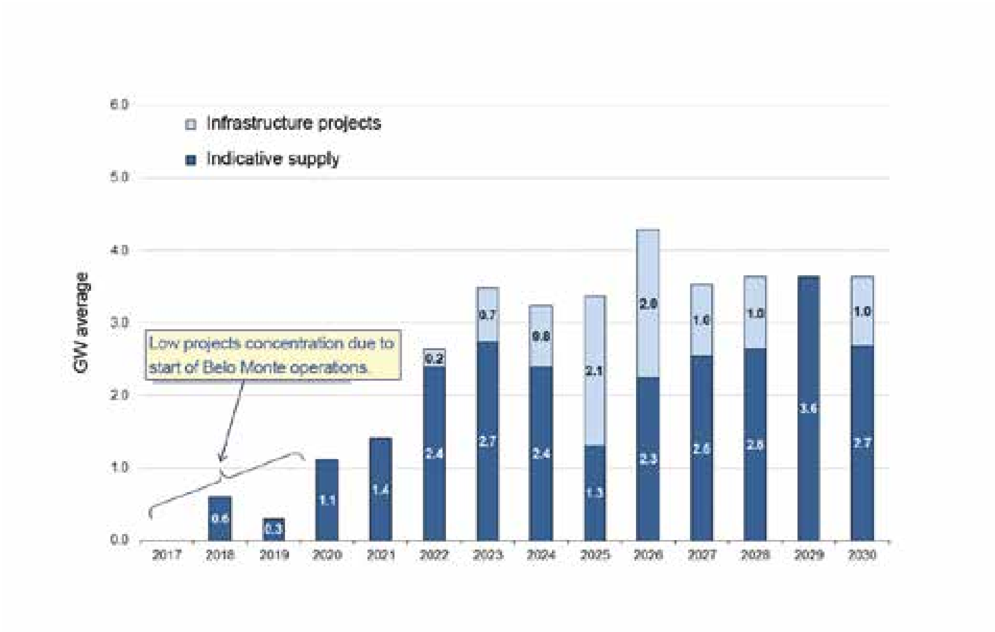
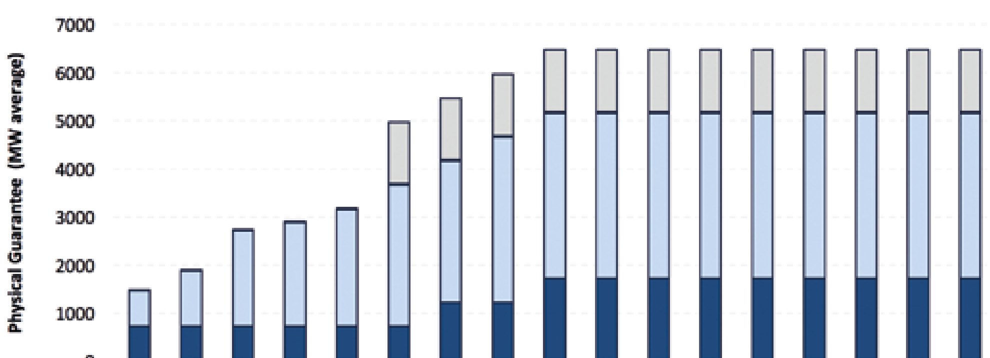


FIGURE 101 - "Structuring" and "indicative" supply projects

Evolution of reserve energy

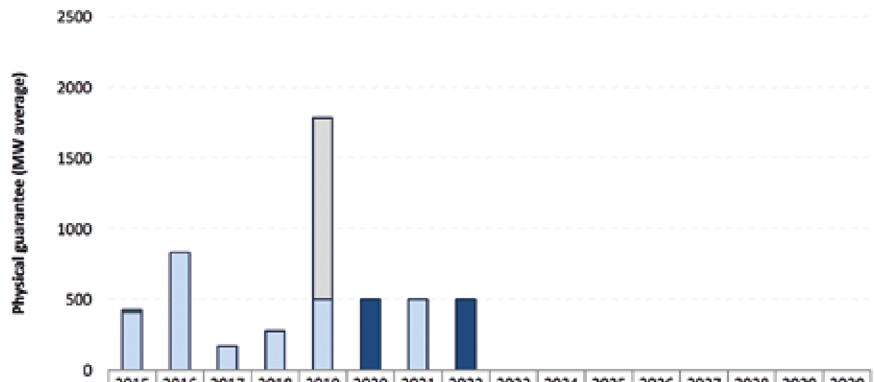
Figure 102 shows the evolution of the system´s reserve energy, by source.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Angra III	0	0	0	0	0	1283	1283	1283	1283	1283	1283	1283	1283	1283	1283	1283	1283
SHP	5	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Wind	754	1162	1993	2162	2439	2939	2939	3439	3439	3439	3439	3439	3439	3439	3439	3439	3439
Biomass	724	724	724	724	724	724	1224	1224	1724	1724	1724	1724	1724	1724	1724	1724	1724
Total	1483	1908	2739	2907	3185	4968	5468	5968	6468	6468	6468	6468	6468	6468	6468	6468	6468

FIGURE 102 - Evolution of reserve energy of the system, by source

Figure 103 shows the annual increase of reserve energy in the system, by source. The 1 GW of wind energy entering the system in 2018 and the 1 GW biomass power entering in 2019 assume that additional energy will be contracted to offset the HPP friction factor.

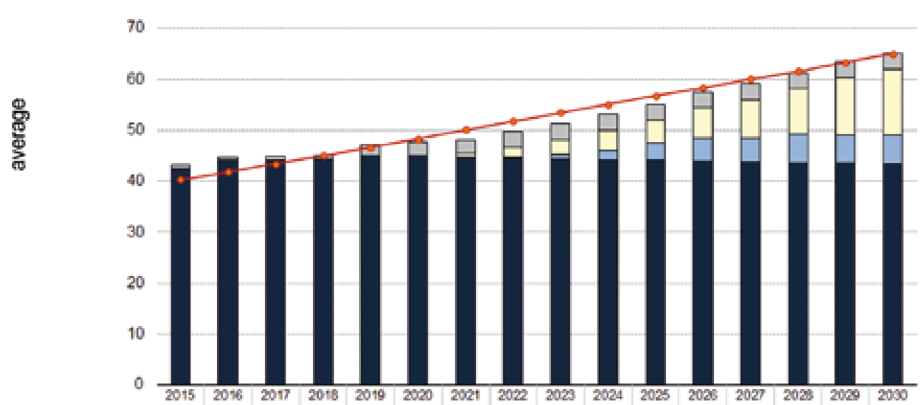


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Angra III	0	0	0	0	1283	0	0	0	0	0	0	0	0	0	0	0
SHP	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	409	831	168	278	500	0	500	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	500	0	500	0	0	0	0	0	0	0	0
Total	425	831	168	278	1783	500	500	500	0	0	0	0	0	0	0	0

FIGURE 103 - Annual increase in reserve energy in the system by source

Demand and supply balance by submarket

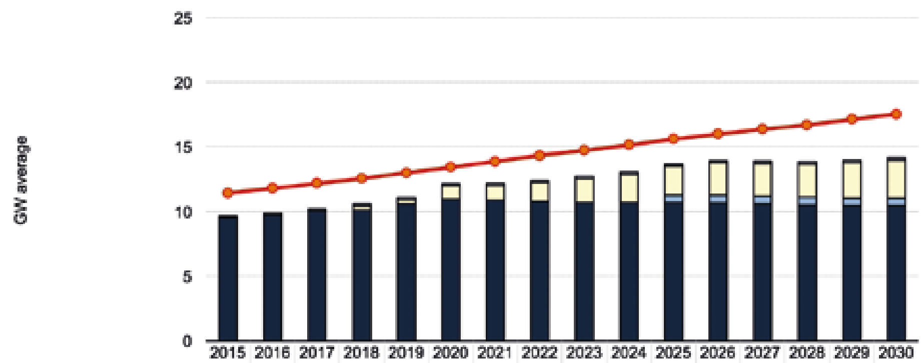
The Southeast was structurally balanced at the beginning of the time horizon (2016), but from 2017 the region started to import energy.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reserve	0.7	0.7	0.7	0.8	2.1	2.6	2.6	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Indicative Projects	0.0	0.0	0.0	0.0	0.0	0.1	0.8	1.9	2.9	4.0	4.5	5.9	7.7	8.9	11.3	13.0
Infrastructure Projects	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.0	1.8	3.3	4.6	4.6	5.6	5.6	5.6
Guaranteed Supply	42.5	44.1	44.2	44.3	45.1	45.0	44.8	44.5	44.3	44.2	44.2	44.0	43.8	43.7	43.5	43.5
Southeast	40.4	41.9	43.5	45.1	46.7	48.4	50.1	51.8	53.4	55.0	56.8	58.4	60.1	61.5	63.4	65.1

FIGURE 104 - Balance in the Southeast submarket

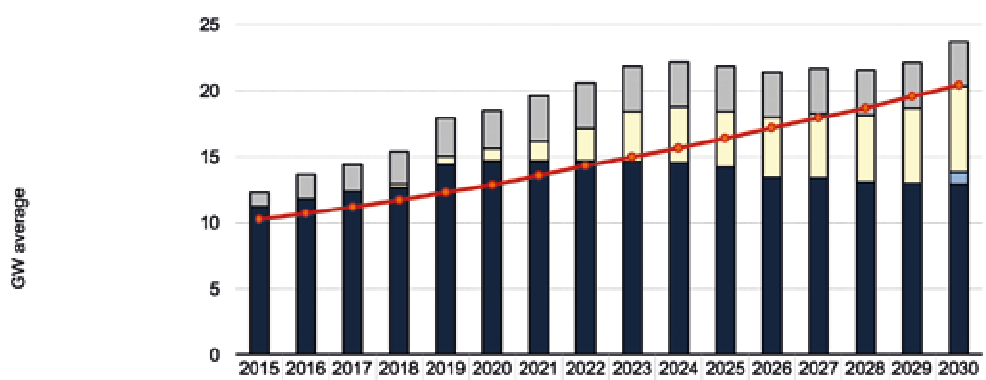
The South region is a “structural importer” of energy throughout the entire horizon of the study. This results from the limited hydrothermal potential and from the assumption that energy generation based on nationally produced coal is unlikely to evolve. Projected supply in the region mainly consists of wind power generation.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reserve	0,1	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2
Indicative Projects	0,0	0,0	0,0	0,3	0,3	1,0	1,1	1,4	1,9	2,2	2,2	2,5	2,5	2,6	2,7	2,9
Infrastructure Projects	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,6	0,6	0,6	0,6	0,6	0,6
Guaranteed Offer	9,6	9,7	10,0	10,1	10,6	11,0	10,9	10,8	10,7	10,7	10,7	10,7	10,6	10,5	10,5	10,5
Southeast	11,4	11,8	12,2	12,6	13,0	13,4	13,9	14,3	14,7	15,2	15,6	16,0	16,4	16,7	17,1	17,5

FIGURE 105 - South submarket balance

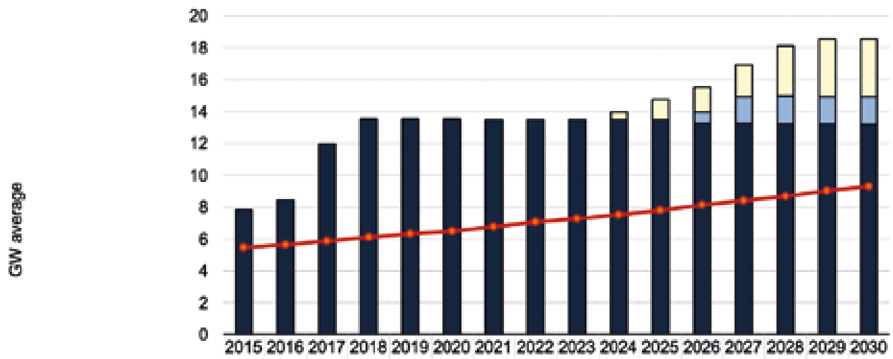
The Northeast submarket is characterized as a structural exporter throughout the entire period of study owing to the local development of wind potential (Figure 115).



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reserve	1,1	1,9	2,0	2,4	2,9	2,9	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4
Indicative Projects	0,0	0,0	0,0	0,3	0,6	0,9	1,5	2,5	3,8	4,2	4,2	4,5	4,8	5,1	5,7	6,5
Infrastructure Projects	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1,0
Guaranteed Supply	11,2	11,8	12,4	12,6	14,4	14,7	14,7	14,6	14,6	14,5	14,2	13,4	13,4	13,1	13,0	12,9
Northeast	10,2	10,7	11,2	11,7	12,3	12,9	13,6	14,3	14,9	15,6	16,4	17,2	17,9	18,7	19,5	20,4

FIGURE 106 - Northeast submarket balance

From 2017, with the development of the North's hydroelectric potential, especially Belo Monte, this submarket will become a major energy exporter (Figure 107).



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reserve	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Indicative Projects	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,5	1,3	1,5	2,0	3,1	3,6	3,6
Infrastructure Projects	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,7	1,7	1,7	1,7	1,7
Guaranteed Supply	7,8	8,4	12,0	13,5	13,5	13,5	13,5	13,5	13,5	13,5	13,5	13,2	13,2	13,2	13,2	13,2
North	5,5	5,6	5,9	6,1	6,3	6,5	6,8	7,1	7,3	7,5	7,8	8,1	8,4	8,7	9,0	9,3

FIGURE 107 - North submarket balance

ANNEX D

ALTERING THE PARAMETERS OF THE HYDROLOGICAL MODEL TO REFLECT THE CLIMATE CHANGE ASSUMPTION

This annex shows how statistics were estimated for the hydrological gauging stations in the SIN case studies on climate change. The changes in the hydrological model were limited to the average and variance (first two moments) of inflows, although some authors argue that the impact of climate change could lead to changes on higher-order statistical moments (asymmetry and kurtosis).

These modified statistics presented some limitations:

- The inflows series used for cases of climate change by FUNCEME for PSR[38] considered a subset of stations of the *Monthly Operation Plan* (PMO) of ONS used in the study cases. The changes to the statistics of other hydrological stations therefore had to be done indirectly, as indicated in Table 10:

TABLE 10 - Need to complete missing inflows data

WITHOUT CLIMATE CHANGE	WITH CLIMATE CHANGE
Inflows of hydrological stations considered in the study (PMO/NOS)	Inflows of hydrological stations sent by FUNCEM
	Inflows of missing stations

- The series made available are natural flow series, while the required statistics refer to incremental flow series. These series cannot be directly determined due to the absence of a large number of stations;
- The available series are not 100% compatible with the topology of the case since the application of the series in the topology results in a large number of negative incremental averages.

[38] Series generated by FUNCEME based on the use of rainfall-runoff models for climate series prepared by INPE based on *downscaling* general circulation models (*Hadgen and Miroc*) done with the Eta model.

Formulation

$V_N^{i,p}$ The series of historical natural inflows to station *i*, month *p*;

$V_I^{i,p}$ The series of historical incremental inflows to station *i*, month *p*;

$\mu_H^{i,p}$ Average of historical incremental inflows to station *i*, month *p*;

$\sigma_H^{i,p}$ Standard deviation of historical incremental inflows to station *i*, month *p*;

$\mu_N^{i,p}$ Average incremental inflows to station *i*, month *p*;

$\sigma_N^{i,p}$ Standard deviation of natural inflows to station *i*, month *p*;

$\mu_I^{i,p}$ Average incremental inflows to station *i*, month *p*;

$\sigma_I^{i,p}$ Standard deviation of incremental inflows to station *i*, month *p*;

M^i Set of hydrological stations upstream of station *i*;

D Subset of hydrological stations defined for the evaluated scenario (for which natural inflows average and standard deviation are known);

U Subset of hydrological stations not defined for the evaluated scenario (for which natural inflows average and standard deviation are known);

$\mu_{Nesp}^{i,p}$ Average natural flow rates specified for station *i*, belonging to subset *D*, month *p*;

$\sigma_{Nesp}^{i,p}$ The standard deviation of the natural inflows specified for station *i* belonging to subset *D*, month *p*.

$Cor\ (V_I^{i,p}, V_N^{j,p})$ Correlation between the historical incremental inflows of station *i* and historical natural inflows for station *j*, for month *p*.

$Cor\ (V_N^{i,p}, V_N^{j,p})$ Correlation between the historical natural inflows of station *i* and historical natural inflows for station *j* for month *p*.

The average natural flow rates can be written as:

$$\mu_N^{i,p} = \mu_I^{i,p} + \sum_{j \in M^i} \mu_N^{j,p}$$

EQUATION 9

The variance of the sum of random variables K is defined by:

$$\sigma^2 = \sum_{i=1}^{k} \sigma_i{}^2 + 2 \sum_{i=1}^{k-1} \sum_{j=i+1}^{k} Cov(i,j)$$

EQUATION 10

Where *Cov(i,j)is* the the covariance between series *i* and *j*, which can also be defined as:

$$Cov(i,j) = Cor(i,j)\sigma_i\sigma_j$$

EQUATION 11

Assuming that the historical correlations are maintained for the scenario, the variances of the natural flow can be expressed as:

$$\left(\sigma_N^{i,p}\right)^2 = \left(\sigma_I^{i,p}\right)^2 + \sum_{j\in M^i}\left(\sigma_N^{j,p}\right)^2 + 2\sum_{j\in M^i} Cor\left(V_I^{i,p}, V_N^{j,p}\right)\sigma_I^{i,p}\sigma_N^{j,p} + 2\sum_{j\in M^i}\sum_{l\in M^i, l>j} Cor\left(V_N^{j,p}, V_N^{l,p}\right)\sigma_N^{j,p}\sigma_N^{l,p}$$

EQUATION 12

From these definitions two independent problems can be formulated for the desired objective:

Problem 1: To determine the incremental averages of all the hydrological stations using the averages of the natural inflows provided.

$$\min_{\mu_N^{i,p}, \mu_I^{i,p}} \; k_1 \cdot \sum_{i\in D\cup U}\sum_{p=1}^{12} s^{i,p} \cdot \mu_H^{i,p} + k_2 \cdot \sum_{i\in U}\sum_{p=1}^{12}\left(d_+^{i,p} + d_-^{i,p}\right)\cdot \mu_H^{i,p}$$

EQUATION 13

$$\begin{array}{ll}
s^{i,p} + \mu_I^{i,p} \geq 0 & \forall i \in D \cup U, p \in (1,12) \\
d_+^{i,p} + \mu_N^{i,p} - \mu_H^{i,p} \geq 0 & \forall i \in U, p \in (1,12) \\
d_-^{i,p} + \mu_H^{i,p} - \mu_N^{i,p} \geq 0 & \forall i \in U, p \in (1,12) \\
\mu_N^{i,p} = \mu_I^{i,p} + \sum_{j\in M^i}\mu_N^{j,p} & \forall i \in D \cup U, p \in (1,12) \\
\mu_N^{i,p} = \mu_{Nesp}^{i,p} & \forall i \in D, p \in (1,12) \\
s^{i,p} \geq 0, d_+^{i,p} \geq 0, d_-^{i,p} \geq 0 & \\
k_1 \gg k_2 &
\end{array}$$

The main aim is to minimize the occurrence of negative incremental averages by ensuring that the averages of the natural inflows for the hydrological stations are respected.

A secondary objective is to ensure that the incremental averages of the unknown stations approximate the historical incremental averages. This objective is positive because not all the stations affected (or are less affected) by the primary objective, and in this way the optimizer can decide a random solution for these stations in the absence of a secondary objective.

PROBLEM 2: to determine the standard deviations of the incremental inflows of all the hydrological stations, using the standard natural inflows deviations provided.

$$\min_{\sigma_N^{i,p},\,\sigma_I^{i,p}} \; k_3 \cdot \sum_{i\in D} \sum_{p=1}^{12} \left(\Delta\sigma_{N+}^{i,p} + \Delta\sigma_{N-}^{i,p}\right) \cdot \mu_H^{i,p} + k_4 \cdot \sum_{i\in U} \sum_{p=1}^{12} \left(\Delta\sigma_{I+}^{i,p} + \Delta\sigma_{I-}^{i,p}\right) \cdot \mu_H^{i,p}$$

EQUATION 14

$$\Delta\sigma_{N+}^{i,p} + \sigma_N^{i,p} - \sigma_{Nesp}^{i,p} \geq 0 \qquad \forall i \in D, p \in (1{,}12)$$

$$\Delta\sigma_{N-}^{i,p} + \sigma_{Nesp}^{i,p} - \sigma_N^{i,p} \leq 0 \qquad \forall i \in D, p \in (1{,}12)$$

$$\Delta\sigma_{I+}^{i,p} + \sigma_I^{i,p} - \sigma_H^{i,p} \geq 0 \qquad \forall i \in U, p \in (1{,}12)$$

$$\Delta\sigma_{I-}^{i,p} + \sigma_H^{i,p} - \sigma_I^{i,p} \geq 0 \qquad \forall i \in U, p \in (1{,}12)$$

$$\Delta\sigma_I^{i,p} = 0 \qquad \forall \sigma_H^{i,p} = 0$$

$$\left(\sigma_N^{i,p}\right)^2 = \left(\sigma_I^{i,p}\right)^2 + \sum_{j\in M^i} \left(\sigma_N^{j,p}\right)^2 + 2\sum_{j\in M^i} Cor\left(V_I^{i,p}, V_N^{j,p}\right) \sigma_I^{i,p} \sigma_N^{j,p} \qquad \forall i,j \in D \cup U, p \in (1{,}12)$$

$$+2\sum_{j\in M^i} \sum_{l\in M^i, l>j} Cor\left(V_N^{j,p}, V_N^{l,p}\right) \sigma_N^{j,p} \sigma_N^{l,p}$$

$$\Delta\sigma_{N+}^{i,p} \geq 0, \Delta\sigma_{N-}^{i,p} \geq 0, \Delta\sigma_{I+}^{i,p} \geq 0, \Delta\sigma_{I-}^{i,p}$$

$$k_3 \gg k_4$$

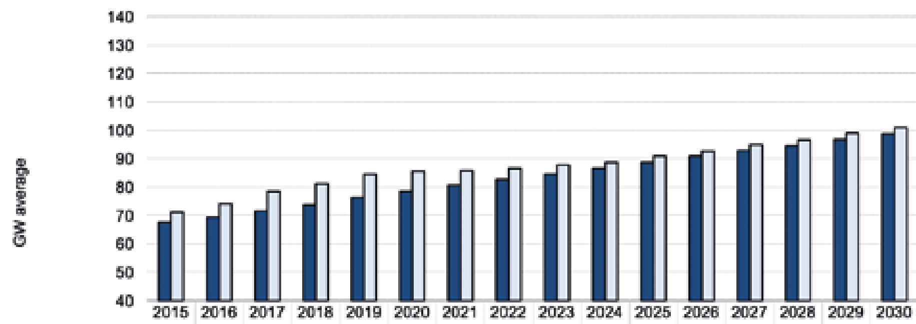
In this case it can be seen that a viable solution does not exist in which the standard deviations for the series of known natural inflows correspond exactly to the values informed. In this way, this requirement is formulated in a "soft" way given that the main objective is to minimize the difference between the specified standard deviations and those obtained for the informed hydrological stations.

As with Problem 1, a secondary goal is inserted, primarily to ensure that the incremental standard deviations of the series less affected by the principal objective approximate the historical incremental standard deviation.

ANNEX E

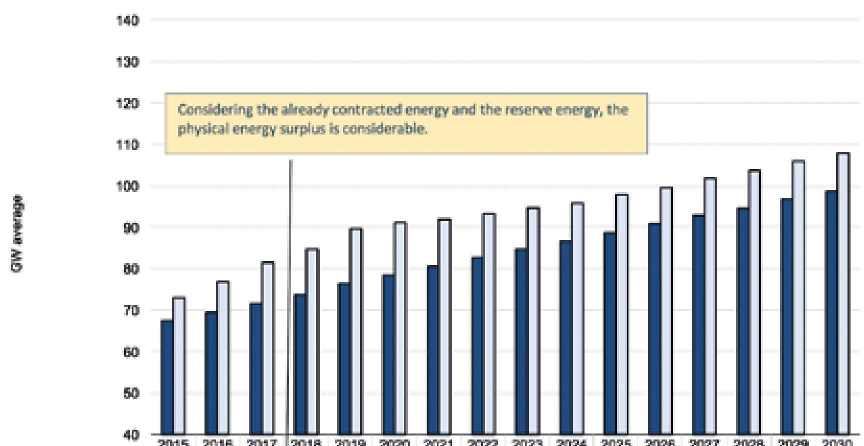
ADDITIONAL RESULTS OF THE ALTERNATIVE CASE

Balance between SIN energy supply and demand



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand	67,5	69,4	71,5	73,6	76,4	78,5	80,6	82,6	84,6	86,6	88,8	90,8	92,8	94,5	96,7	98,7
Firm Energy	71,1	74,0	78,5	81,2	84,5	85,5	85,8	86,6	87,7	88,7	90,9	92,6	94,8	96,6	98,9	100,9
Firm Energy - Demand	3,6	4,6	7,0	7,5	8,2	7,0	5,2	4,0	3,1	2,2	2,1	1,8	2,0	2,2	2,1	2,3
% Demand	5,4%	6,7%	9,8%	10,2%	10,7%	8,9%	6,4%	4,8%	3,7%	2,5%	2,4%	2,0%	2,1%	2,3%	2,2%	2,3%

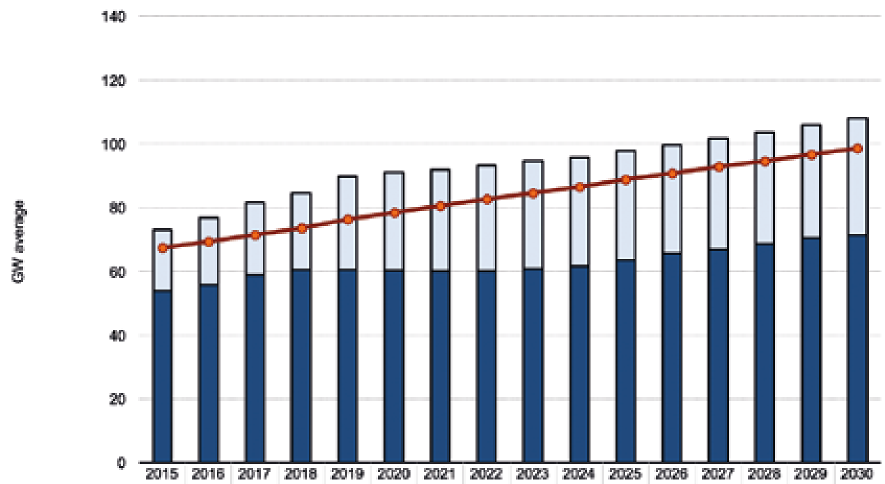
FIGURE 108 - Physical balance of average annual supply and demand without reserve energy



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand	67,5	69,4	71,5	73,6	76,4	78,5	80,6	82,6	84,6	86,6	88,8	90,8	92,8	94,5	96,7	98,7
Firm Energy	73,0	76,8	81,5	84,6	89,7	91,1	91,9	93,3	94,7	95,7	97,9	99,6	101,8	103,6	105,8	107,9
Firm Energy - Demand	5,6	7,4	10,0	10,9	13,3	12,7	11,4	10,7	10,1	9,1	9,1	8,8	9,0	9,1	9,1	9,2
% Demand	8,2%	10,6%	13,9%	14,8%	17,5%	16,1%	14,1%	12,9%	11,9%	10,6%	10,3%	9,7%	9,6%	9,7%	9,4%	9,4%

FIGURE 109 - Physical balance of average annual supply and demand with reserve energy

Hydrothermal share

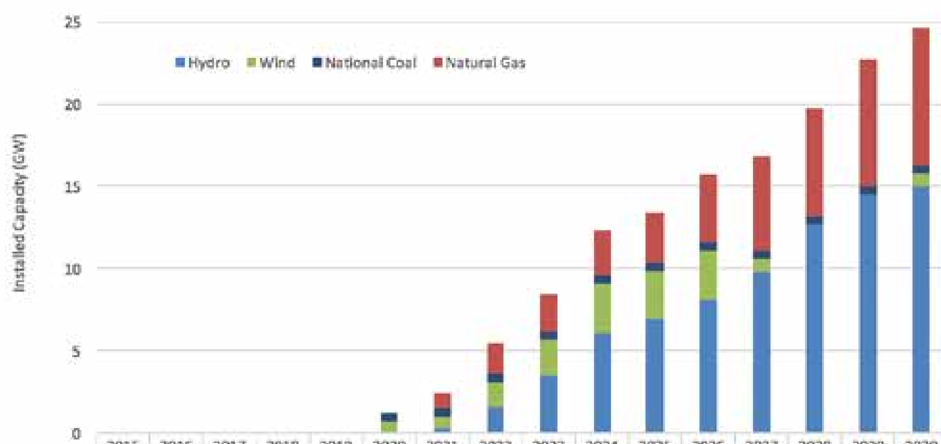


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	19,2	21,2	22,6	24,1	29,2	30,8	31,9	33,1	34,0	34,1	34,4	33,9	34,8	35,1	35,4	36,6
Hydro	53,8	55,6	58,9	60,4	60,5	60,3	60,0	60,1	60,6	61,6	63,5	65,6	66,9	68,5	70,4	71,3
Demand	67,5	69,4	71,5	73,6	76,4	78,5	80,6	82,6	84,6	86,6	88,8	90,8	92,8	94,5	96,7	98,7
% Hydro	74%	72%	72%	71%	67%	66%	65%	64%	64%	64%	65%	66%	66%	66%	67%	66%
% Thermal	26%	28%	28%	29%	33%	34%	35%	36%	36%	36%	35%	34%	34%	34%	33%	34%

Wind and Solar projects are considered as thermal power plants

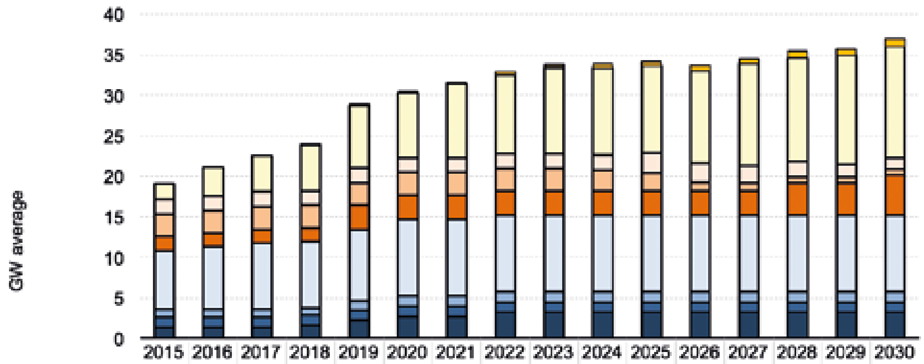
FIGURE 110 - Hydrothermal share including reserve energy

Figure 111 shows the reduction in supply absolute values of installed capacity for the alternative case compared with the reference case.



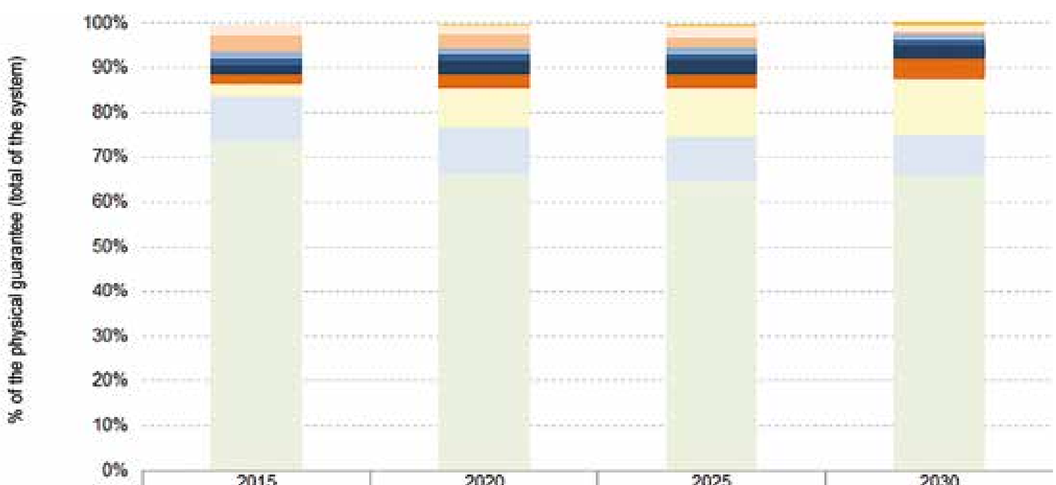
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas	0,0	0,0	0,0	0,0	0,0	0,0	0,9	1,8	2,2	2,7	3,0	4,1	5,7	6,5	7,7	8,3
National Coal	0,0	0,0	0,0	0,0	0,0	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5
Wind	0,0	0,0	0,0	0,0	0,0	0,7	0,7	1,5	2,2	3,0	3,0	3,0	0,8	0,0	0,0	0,8
Hydro	0,0	0,0	0,0	0,0	0,0	0,0	0,3	1,6	3,5	6,1	6,9	8,1	9,8	12,7	14,5	15,0

FIGURE 111 - Reduction of installed capacity in the alternative case



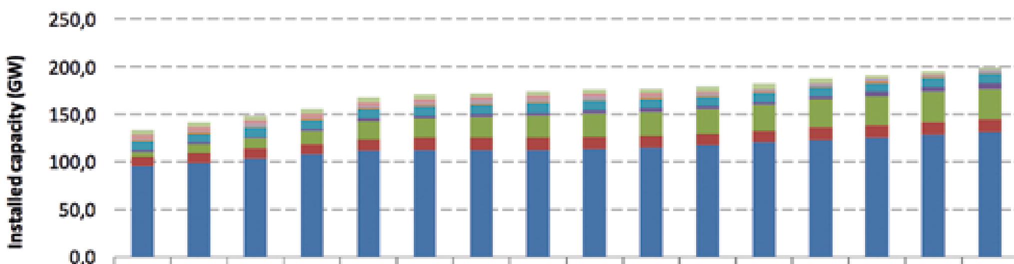
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar	0,0	0,0	0,0	0,2	0,2	0,2	0,2	0,4	0,4	0,5	0,5	0,7	0,7	0,8	0,8	1,0
Wind	2,0	3,5	4,4	5,6	7,7	8,0	9,1	9,7	10,6	10,7	10,7	11,3	12,5	12,8	13,4	13,7
Others	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	2,4	2,4	2,1	1,9	1,6	1,4
Diesel/Oil	2,8	2,8	2,8	2,8	2,8	2,8	2,8	2,8	2,8	2,6	2,2	1,1	1,0	0,7	0,7	0,7
Nuclear	1,7	1,7	1,7	1,7	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	4,0	4,0	4,9
Natural Gas	7,3	7,7	8,2	8,2	8,8	9,5	9,5	9,5	9,5	9,5	9,5	9,5	9,5	9,5	9,5	9,5
National Coal	1,0	1,0	1,0	1,0	1,1	1,3	1,3	1,3	1,3	1,3	1,3	1,3	1,3	1,3	1,3	1,3
Imported Coal	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2
Biomass	1,4	1,4	1,4	1,6	2,2	2,7	2,7	3,2	3,2	3,2	3,2	3,2	3,2	3,2	3,2	3,2

FIGURE 112 - Breakdown of non-hydroelectric sources including reserve energy



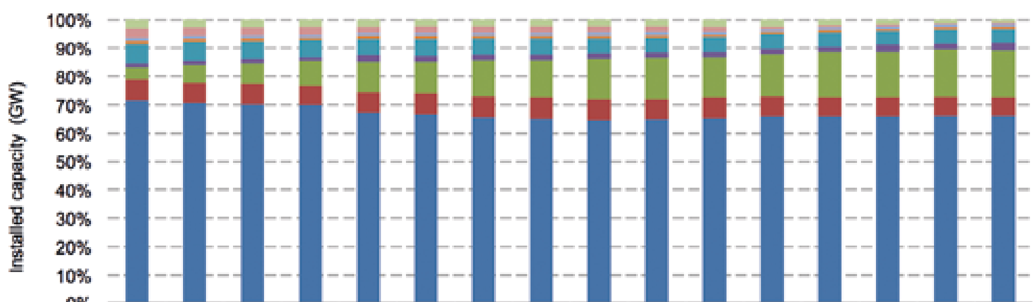
	2015	2020	2025	2030
Solar	0.0%	0.2%	0.5%	0.9%
Others	2.5%	2.0%	2.5%	1.3%
Fuel Oil/Diesel	3.8%	3.0%	2.3%	0.7%
National Coal	1.3%	1.4%	1.3%	1.2%
Imported Coal	1.7%	1.4%	1.3%	1.1%
Biomass	1.9%	3.0%	3.3%	3.0%
Nuclear	2.3%	3.3%	3.1%	4.6%
Wind	2.7%	8.8%	11.0%	12.7%
Natural Gas	9.9%	10.4%	9.7%	8.8%
Hydro	73.7%	66.2%	64.9%	66.0%

FIGURE 113 - Evolution of the electricity matrix



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Others	3,7	3,7	3,7	3,7	3,7	3,7	3,7	3,7	3,7	3,7	4,3	4,1	3,6	3,1	2,4	1,9
Diesel/Oil	4,4	4,1	4,1	4,1	4,1	4,1	4,1	4,1	4,1	3,7	3,0	1,5	1,3	0,9	0,9	0,9
National coal	1,4	1,5	1,5	1,5	1,7	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8
Imported coal	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4
Biomass	9,3	9,4	9,5	9,6	9,9	10,2	9,6	9,9	9,4	9,4	9,4	9,4	9,4	9,4	9,4	9,4
Nuclear	2,0	2,0	2,0	2,0	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	3,4	4,6	4,6	5,8
Wind	5,6	9,1	11,0	13,6	18,4	19,0	21,6	23,0	25,1	25,4	25,4	26,9	29,9	30,7	32,2	32,9
Natural Gas	9,5	10,1	10,6	10,6	11,8	13,1	13,1	13,1	13,1	13,1	13,1	13,1	13,1	13,1	13,1	13,1
Hydro	95,7	99,6	103,8	108,5	112,4	113,3	113,0	113,1	113,8	114,9	117,3	120,1	123,3	126,0	129,2	131,7

FIGURE 114 - Evolution of the generating matrix by source (absolute values)



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Others	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%
Diesel/Oil	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	1%	1%	0%	0%	0%
National coal	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Imported coal	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Biomass	7%	7%	6%	6%	6%	6%	6%	6%	5%	5%	5%	5%	5%	5%	5%	5%
Nuclear	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	3%
Wind	4%	6%	7%	9%	11%	11%	13%	13%	14%	14%	14%	15%	16%	16%	17%	17%
Natural Gas	7%	7%	7%	7%	7%	8%	8%	8%	7%	7%	7%	7%	7%	7%	7%	7%
Hydro	72%	71%	70%	70%	67%	67%	66%	65%	65%	65%	65%	66%	66%	66%	66%	66%

FIGURE 115 - Evolution on the generating matrix by source

GLOSSARY

A-3 / A-5 – auctions

ABRH – Association on Hydric Resources

ACL – Free Contracting Environment

ACR – Regulated Procurement Environment

ANA – National Water Agency

ANEEL – National Electric Power Agency

ANP – National Petroleum Agency

AP – Public Hearing

BMT – Marginal Transmission Benefit

CAR – Risk Aversion Curve

CCC – Fuel Consumption Account

CCEAR – Energy Trading Agreement in the Regulated Market

CCEE – Electric Energy Trading Board

CDE – Energy Development Account

CEPEL – Energy Research Center

CER – Reserve Energy Contract

CERPCH – Centre for Small Hydroelectric Power Plants

CFURH – Financial compensation for the use of water resources

CMSE – Power Sector Monitoring Committee

CNPE – National Energy Policy Council

CNPJ – National Registration for Legal Entities

CO_2 – Carbon dioxide

COPPE/UFRJ – Engineering Institute, Federal University of Rio de Janeiro

CPAMP – Permanent Commission for Analysis of Methodologies and Computational Programs in the Energy Sector

CPFL – Power Distribution Company (Companhia Paulista de Força e Luz)

CVAR – Conditional Value at Risk

CVU – Variable Unit Cost

EIA – U.S. Energy Information Administration

ENA – Natural Inflow Energy

EPE – Energy Research Company

ESS – Services Charges System

ETP – Energy Technology Perspectives

FAO – Food and Agriculture Organization of the United Nations

FCF – Future Cost Function

FUNCEME – Ceará Meteorology and Water Resources Foundation

DG – Distributed Generation

GDP – Gross National Product

GF – Physical Guarantee

GHG – Greenhouse gases

GO – State of Goiás

GW – Gigawatt

HADGEM – Hadley Centre Global Environment Model

HPP – Hydroelectric power plant

IBAMA – Brazilian Environment Institute

IBGE – Brazilian Institute on Geography and Statistical Research

ICB – Value Index

IGP-M – General Market Price Index

INB – Nuclear Industries Association of Brazil

INDC – Intended Nationally Determined Contributions

INPE – National Agency on Spatial Research

IPCA – Broad National Consumer Price Index

IPCC – Intergovernmental Panel on Climate Change

KGU – kilogram of Uranium

KWP – kilo wattpico

LEE – Existing Energy Auction

LER – Reserve Energy Auction

LNG – Liquefied Natural Gas

LP – Preliminary Environmental License

LT – Power transmission line

MAPA – Ministry of Agriculture, Livestock and Supply

MCSD – Excess and Deficit Compensation Mechanism

MCT – Ministry of Science and Technology

MESSAGE – An energy planning model

MG – State of Minas Gerais

MIROC – Model for Interdisciplinary Research on Climate

MLT – Long term avarage

MMA – Ministry of Environment

MMBTU – 1,000,000 British Thermal Unit

MME – Ministry of Mines and Energy

MOC – Marginal Operating Cost

MRA – Assured Energy Reduction Mechanism

MRE – Energy Reallocation Mechanism

MT – State of Mato Grosso

MW – Megawatt

MWH – Megawatt per hour

NE – Northeast region

NEWAVE – Dynamic Stochastic Optimization Model (mid-long term)

OC – Oil fuel

ONS – National System Operator

PAR (P) – Periodic Autoregressive model

PCH – Small Hydroelectric Power Plants

PDE – 10-year Expansion Plan

PIS/COFINS – Brazilian taxes charged from the gross profit of the legal entities

PLD – Difference Settlement Price

PMO – Monthly Operating Program

PMR – Partnership for Market Readiness

POCP – Short-Term Operating Procedure

PR – State of Paraná

PRECIS – Providing Regional Climates for Impacts Studies

PROINFA – Incentive Program to Encourage the Development of Alternative Sources of Electric Power

PV – Photovoltaic solar energy

RAP – Annual Allowed Income

RCP – Representative Concentration Pathways

RGR – Global Reversion Reserve

RJ – State of Rio de Janeiro

RS – State of Rio Grande do Sul

SAE – Bureau of Strategic Affairs

SC – State of Santa Catarina

SDDP – Stochastic Dual Dynamic Programming

SE/CO – Subsystem Southeast and Central-West regions

SIN – National Interconnected System

SMAP – Soil Moisture Accounting Procedure

SP – State of São Paulo

t – tons

tCO^2/MWH – tons of carbon dioxide per megawatt per hour

TEIF – Equivalent Forced Outage Rate

TEIP – Equivalent Programmed Outage Rate

TEO – Optimization Energy Tariff

TFSEE – Electric Energy Power Services Inspection

TPP – Thermal power plant

TUSD – Tariff for the Use of the Electric Energy Distribution System

TUST – Tariff for the Use of the Electric Energy Transmission System

U_3O_8 – Triuranium octoxide

UBP – Public good usage (consumption)

UNFCCC – United Nations Framework Convention on Climage Change

UNSI – Non-individually simulated plants

VR – Reference Value

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