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2031
TEN-YEAR ENERGY EXPANSION PLAN

epe
Empresa de Pesquisa Energética

Ministério de
Minas e Energia

3. Central Power Generation

At SEB, 2021 was marked by the challenging situation of water scarcity, which was overcome thanks to the attention and coordinated actions between the MME, sector institutions and society in general, both within the scope of the CMSE and the Chamber of Exceptional Rules for Hydroenergetic Management (CREG). The inflows to the SIN hydroplants have accumulated, in the last eight years, consecutive values below the average. This behavior can be observed especially in the SE/CO and NE subsystems, which add up to 88% of the maximum hydro reservoir. When specifically evaluating the period from October 2020 to September 2021, the most critical inflows of the last 91 years were recorded in 6 months. In addition, 9 of the 12 months are among the 5 worst in all history.

As a consequence of the low rainfall, the dry period of 2021 started with the reservoirs in the SE/CW region, which represent 70% of the total capacity of the SIN, with only 32% of total energy storage (the worst level for this time of year since 2001). As the Brazilian generating mix is characterized by a strong hydro presence (60% of total installed capacity in 2021), with large hydro reservoirs, the entire sector has, since then, been closely monitoring this situation and facing the challenge imposed with conjunctural measures and other structural character. It is in this context, and incorporating lessons learned, that the studies and indications for the central generation expansion of PDE 2031were developed and are placed for wide debate with society.

From a structural standpoint, it is important to highlight the diversification of the generation mix based on investments in renewable resources in addition to hydroplants, such as wind, biomass and photovoltaic, complemented by the expansion of dispatchable generation, such as natural gas thermal power plants. The hydro plants, which at the beginning of the century accounted for 83% of installed capacity, should reduce its relative share to 46% by the end of the timeframe (also considering the growth of distributed generation). As demonstrated in previous cycles, this diversification tends to increase supply reliability due to the portfolio effect between resources and regions of the country, contributing to better management of the risk of energy supply.

On the other hand, as the characterisctics of the generation mix changes, new challenges arise to guarantee future energy supply. Among the lessons learned in the 2020-2021period, the water scarcity showed how the different water usages impact the management of reservoirs and highlight the way in which the operational restrictions of Hydro Plants (UHE in the Portuguese acronym) represented in the dispatch models can be improved. In this sense, PDE 2031 proposes a new approach to the use of existing restrictions in the Newave model that can bring greater realism on the energy expenditure that occurs in the UHEs. It should be noted that the proposed changes are restricted to input data, which brings agility to the feedback process of these tools, incorporating challenges of the operation performed by the ONS. This development is a prompt response that PDE 2031 brings in its report, in search of greater predictability for the sector and anticipation of its indications.

Thus, PDE presents itself, once again, as a fundamental instrument to address the challenges imposed by the uncertainties inherent to the planning of a renewable-based system. In addition to the aforementioned improvement in the representation of hydro plant operational constraints, PDE 2031 maintains permanent monitoring of the security of supply of the SIN, through the application of explicit criteria (according to CNPE resolution nº 29) and the calculation of energy and power requirements for the timeframe, always incorporating actions related to the modernization of the sector. In what ifs sensitivities[1], more restrictive scenarios will be considered, such as situations of lower inflows, in addition to studies running new simulation tools.

In this way, PDE 2031 continues to improve, as a result of constant interaction with players, and brings new discussions and debates.

Box 3 - 1: Other important improvements to address water scarcity

Considering the expressive participation of the hydro generation in the SIN, the concern with the worst hydrology scenarios has always guided the operation and expansion planning studies. When these critical scenarios take place, there are usually restrictions on supply that raise society's concern about the possibility of electricity rationing measures or even the occurrence of blackouts. The second half of 2021 was marked by discussions like these. The role of the MME together with other ministries and institutions, such as EPE, ONS, CCEE, ANEEL and ANA, led the sector to overcome shortages without adopting compulsory rationing measures. However, it is necessary to reflect on structural improvements that contribute to the fact that situations like this do not require specific regulations and depend, less and less, on short-term measures.

When dealing with supply constraint, the “natural” answers indicate a greater contracting of generation resources for the long term, aiming to meet tighter planning criteria. However, due to uncertainties, such as demand growth and competitiveness of future technologies, the adoption of excessive long-term contracting can generate regret with high tariff costs and difficult to manage, causing impacts on the entire economy.

In this sense, in addition to providing resource adequacy, it is important for the sector to accelerate improvements in input data, methodologies and computational models used in expansion, operation and pricing. In addition to the concern for the best representation of hydro plants inflexibility, as discussed in this chapter, it is important that the sector continues to improve other representations, such as:

- Future forecasts of affluent natural energy (ENA), seeking to consider climactic variables and the correction of the rapid reversion to the historical average inflows;
- Generation characteristics of the Hydro plants, seeking an individualized representation in the long-term model;
- The future net load, mainly considering the uncertainties and the evolution of importance of variable renewables and distributed generation;
- The evolution of the variable costs of thermal power plants in the long term, in addition to the discount rate considered by the simulation models;
- The capacity and characteristics of the transmission network of the SIN and the need for operating reserve, seeking to review the criteria and requirements for system flexibility.

These improvements, by themselves, are capable of promotinga better allocation of existing resources, in addition to providing a more adequate economic signal of the real scarcity of the power system, but they may not be sufficient for the correct mobilization of market players.

Thus, improvements in wholesale rules, such as the adoption of preferential risk allocation of ACR contracts in generation players, the gradual increase in the structural price cap (aiming to reconcile the risk aversion of contracting players with the costs and risks of the system), the possibility of load reduction offers, increased liquidity and security (for example, with the implementation of weekly settlement), among others, encourage energy efficiency measures and improve decision-making by large players.

In retail, it is important that prices are better reflected to the end consumer. As observed in several international experiences, the massive implementation of smart meters and dynamic tariffs, with greater temporal granularity, allows greater rationalization of consumption, new business models and the mobilization of energy resources distributed in medium and low voltage.

[1] PDE 2031 what if sensitivity scenarios will be published later, in addition to this report.

Box 3 - 1: Other important improvements to address water scarcity

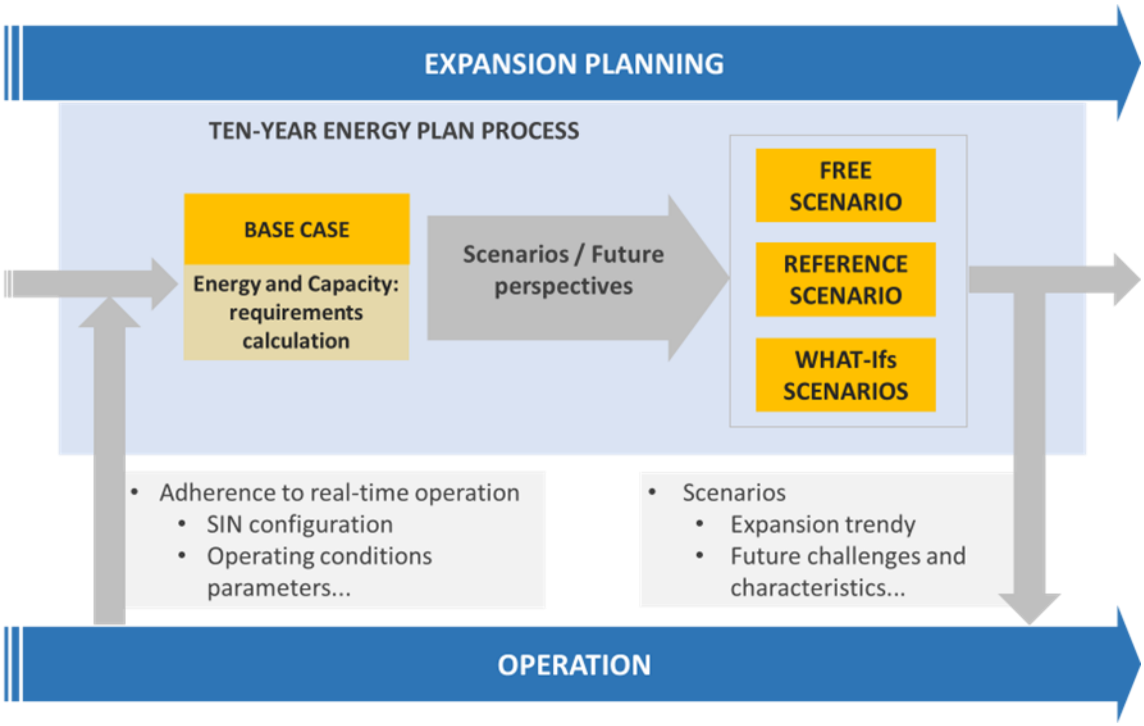
Overcoming the challenges to implement the indicated improvements, in addition to improving the allocation of resources in the short and medium term, it can increase the assertiveness of long-term contracting and promote supply reliability at a lower cost for Brazilian society.

3.1 Methodology

Expansion planning is in constantly methodological evolution, where improvements are included in each cycle in order to seek greater adherence to operating conditions.

The objective of this section is to describe the development process of the Ten-year Energy Expansion Plan regarding the central power generation, summarized in **Figure 3 - 1**. The cyclical character of expansion planning studies can be seen in the figure, in which information from the operation feed the planning simulation, on the other hand, results obtained for the planned power system are used by operation layer. This document, the official MME instrument for medium-term planning, incorporates updated information, on its reference date, of forecast energy and power demand, schedules for the implementation of generation and transmission projects that will be connected to the SIN grid, as well as the national energy planning guidelines. As a result, the indicative plan PDE forms the expansion planning cycle of the Brazilian electric power system.

Figure 3 - 1: Flowchart of the process applied to the ten-year planning



Source: Prepared by EPE.

Initially, the important methodological improvement of the SIN planning process is highlighted with the establishment and continuous evaluation of the supply criteria, defined by the National Energy Policy Council (CNPE), in December 2019 (Order nº 29), which started to consider not only the risk, but the depth of risk, both for energy and also for capacity. The first practical application in the expansion of the generation mix will be perceived by society in 2026, when the projects contracted by the Capacity Reserve Auction (LRC) held on December 21, 2021 enter into commercial operation[2].

The SIN operation variables are recurrently measured through probabilistic analysis and risk prediction in relation to the security of supply. Risk assessments are particularly interesting to deal with hydrological uncertainties, as well as to assess the system's robustness in more severe conditions, mainly due to the predominance of renewable resources of the SIN and their availability associated with natural events, modeled by stochastic processes.

The PDE elaboration process includes several stages, and the characterization of the representative configuration of the SIN (called Base Case) is the starting point of the study. At this point, the survey and updating of information related to the generation mix and the existing and contracted transmission network is carried out. This set of projects will integrate the simulations of the models that calculate the power for the different regions of the SIN. Considering the simulation of the Base Case and the comparison of the results with the supply criteria, it is possible to identify the moments in which these criteria are not met and quantify the additional supply needed by the power system, associated with the dimensions of energy and capacity. The assumption is that the configuration of the Base Case does not have indicative expansions (generation and transmission) of the power system.

Due to the high degree of complexity of the SIN, in order to carry out the analyses it is essential to conceptualize the temporal and spatial dependence relationships that impact the expansion and efficient management of existing assets. Once the energy and capacity requirements have been quantified, the process of optimizing the expansion of the supply begins, which minimizes the total cost of investment and operation for the planning timeframe and presents estimates for future operating conditions, also the costs to meet the demand forecast.

The basket of projects (future projects available to be part of the expansion plan) that are candidates for expansion is established considering the feasibility of projects to start commercial operations in the ten-year timeframe (the details of this basket can be found in section 3-4 of this report).

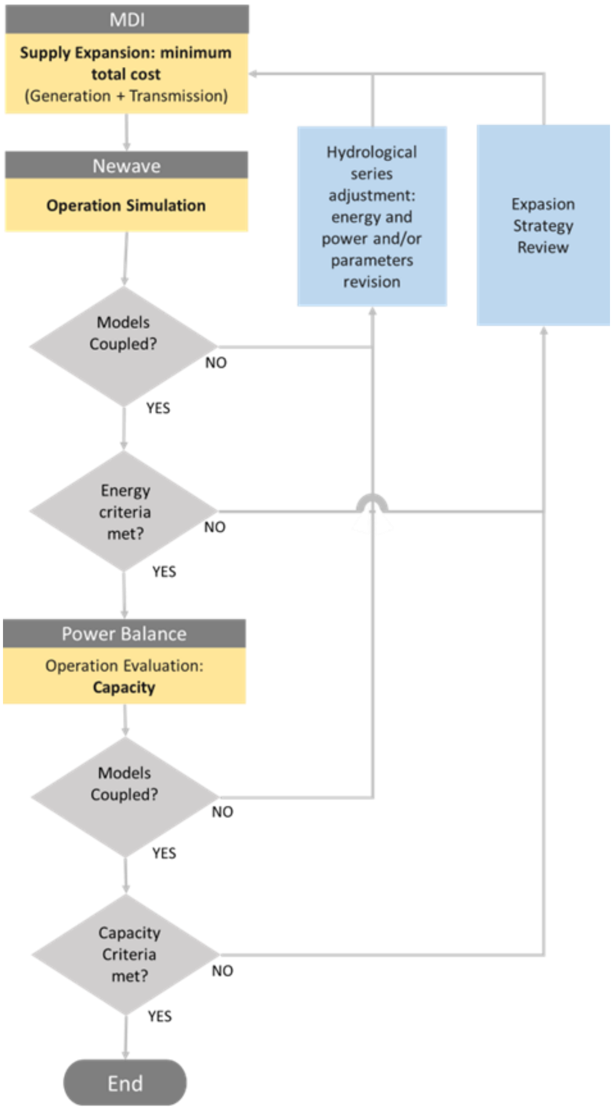
The timeframe of analysis and prospection of possible scenarios for the electrical energy supply considered in the study is 16 years[3]. The methodology for evaluating possible expansions of the electric generation and transmission power system briefly involves three simulation steps, illustrated in **Figure 3 - 2**: (i) simulation with the Investment Decision Model (MDI) to obtain the indicative expansion schedule; (ii) operation simulation with the Newave Model; (iii) Simulation with the Balance of Capacity to verify compliance

[2] PDE 2031 simulations have a reference date of September 2021, which is why the result of the first LRC auction was not included. For this reason, part of the indicative supply presented in the future expansion scenarios of this Plan can be considered as already procured for this auction.

[3] Currently, PDE simulations start in May of the current year, therefore, before the beginning of the ten-year timeframe. After the ten years that contemplate the main focus of the study, the simulation continues for another 5 years that bring relevant information for the evaluation of investments, especially for coupled analyzes between generation and transmission. Thus, the total simulated timeframe is 16 years.

with the requirements of peak demand of the SIN. With the last two steps, the security of supply is assessed and, whenever necessary, the previous steps of the process are fed back, so that corrective measures can be highlighted.

Figure 3 - 2: Flowchart of simulation stages for electricity supply expansion scenarios



Source: Prepared by EPE.

Each of the stages focuses on representing the economic and operational attributes of the generation options and the transmission network to guide investment decisions and optimized dispatch of the central electric power system. The temporal discretizations proposed in each of these simulated stages consider the level of detail and the computational effort required for analyzes in the ten-year planning timeframe.

Finally, after performing all the steps described and elaborating the expansion scenarios of the Free Scenario, purely economic expansion, and the Reference Scenario, which includes the energy policy guidelines, the planning process establishes the evaluation phase of energy adequacy and expansion of the power system for distinct what-if sensitivities. In this way, it is possible to deal with the uncertainties inherent to the planning process with what-if sensitivities that explore different conditions of generation supply and transmission network and respective measurement of the impacts on the security of supply of the forecast demands for the future electric power system.

In view of the challenging scenario of facing the situation of water adversity, mainly in the hydrographic basins of the Southeast and South regions during the years 2020 and 2021, important improvements have been incorporated into the planning process of the SIN to make it more adherent to real-time operation. And given the hydro power predominance of the generation mix (60% of the installed capacity in 2021), quantities that influence the operation of the UHE are being reassessed and recalibrated for this ten-year planning cycle. In the simulation models, this adjustment was performed through minimum operating levels of hydro reservoirs with accumulation capacity[4], as well as outflows and minimum generation targets associated with each of the hydro plants. The objective of this approach, which will be detailed below, is to reflect constraints on resource management (also called “hydro inflexibilities”) in the mathematical models. The result on the operation of the UHE is then effectively perceived by the central dispatched generating mix.

[4] Following the latest indication from CPAMP.

Within this context, it is noteworthy that, during the year 2021, Provisional Measure No. 1,055 instituted the CREG to establish an articulation between the entities and bodies responsible for activities related to the water usages and, thus, guarantee the effectiveness of actions to increase the guarantee of security and continuity of electricity supply in the country.

In order to adhere to the operating conditions perceived and incorporating the lessons learned in this period, it is important to emphasize that all the configurations presented in this PDE take into account the changes in the operating restrictions associated with the availability of the hydraulic resource for the simulation of hydro plants in the MDI, Newave models and Power Balance. As previously mentioned, the variables changed at this time are: minimum operating volumes, minimum outflows and monthly targets for minimum hydro generations. The adjustment applied to these last quantities is presented in section 3.1.1, where the calibration and estimation of these parameters used in the simulation models are defined. In section 3.2.1, the impacts of this new representation on the Base Case simulations are presented, through the comparison of some operating variables as well as estimates of marginal operating costs – CMO.

Through this dynamic planning modality, which, in addition to evaluating various scenarios, incorporates what has been seen in the real operation of the system, actions are recommended to mitigate the insufficiency of energy supply in times of adverse conjuncture from the point of view of scarcity of energy resources.

With this, the indicative planning of the SIN fulfills the role of anticipating effective measures in order to signal the expansion of the generating complex in a challenging context, including the already occurring energy transition. The changes in supply characteristics, mainly due to the massive insertion of variable renewable sources, and reduced operating costs lead to the need to develop mechanisms for the adequacy of the electricity supply to deal with the uncertainties and variations inherent to the availability of natural resources used by the various renewable sources that make up the SIN, such as hydroelectric, wind and solar photovoltaic plants.

3.1.1 METHODOLOGY OF OPERATING CONSTRAINTS

In the last decade, Brazil has been going through a sequence of periods with inflows below the historical average, which raise questions about possible changes in this regime in several hydrographic basins. This period culminated in the worst drought in 91 years, with the reduction to critical levels of hydro reservoirs in the Southeast/Mid-West and South of the country.

In this context of scarcity of water resources, the years 2020 and 2021 presented severe situations for meeting the load, which lead to reflections on all the processes of the sector, from the short-term operation to the planning of the medium and long-term generation expansion.

These operating conditions showed that the impact of some constraints was not being perceived in normal situations. In other words, only when it was necessary to reduce the production of the UHE as much as possible, to preserve the levels of the reservoirs, it was noticed that the lower production obtained in practice was higher than what the medium and long-term computer models were simulating. In addition to directly affecting the results obtained by Newave, this effect can be propagated to other models in the chain that use the future cost function, resulting from Newave, as input data for more detailed simulations. In order to make the observed operational conjuncture more adherent, PDE 2031 presents a methodology for a review of the representation of some conditions of the recent past, also being applied as constraints for the future, in order to bring to the discussion how these values can result in greater predictability and impact on actions and on the assessment of compliance with supply criteria.

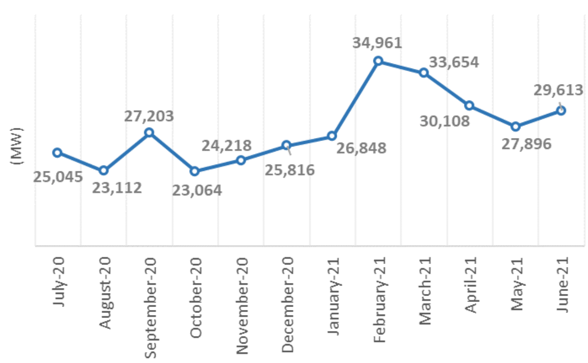
The current official data that are considered in the Newave model lead to better future conditions than what has been possible in the real-time operation of the power system. These constraints lead to making the production of the UHEs more flexible and compatible with values that today are inadequately optimistic, especially to what the operation of the years 2020 and 2021 demonstrated.

One of the reasons for this change is that, before reviewing the constraints presented in this plan, when considering greater resource management on a monthly scale, the signal for planning is for greater power availability power, coming from hydro plants, with lower associated energy expenditure. Consequently, the power system requirements would be met in a way that is incompatible with what was identified in the recent real-time operation, both in terms of cost and water usage. Therefore, incorporating into the models the fact that, in practice, there is no short-term operating range in hydro plants as large as represented, indicates that this available power to meet the peak demand requires a greater resource allocation. In other words, in order to meet peak loads allocating to hydro plants, the associated energy expenditure must be effectively considered. Or, alternatively, the generation expansion must provide for additional supply to complement this service in situations where the UHE will not be enough.

From the second half of 2020 until the end of the dry season of 2021, the operation policy of the SIN hydro plants, carried out by the ONS with the approval of the CMSE, had as its main objective the preservation of the levels of the reservoirs. This led not only to the reduction of generation in hydro plants but, later on, to the need to relax some operating constraints. Considering the period between July 2020 and June 2021, when the flexibilities of the hydro operating constraints approved by CREG for a conjunctural situation were not yet in force, **Chart 3 - 1** presents the lowest hourly generation of each month of the set of dispatchable hydro plants present in Newave.

Looking at the final months of the dry season of 2020, October and November, the first was the month with the lowest value, where the minimum hourly generation was around 23,000 MWh/h in total. To represent this new system behavior in the Newave model, the minimum outflow restriction for the total SIN was increased, making it compatible with the total power generation seen in October 2020, as this is the lowest value observed in the history of the last five years.

Chart 3 - 1: Lowest Verified Hydraulic Generation 2020 to 2021SIN



Source: Prepared by EPE.

Hydro plants also have outflow variation rate constraints, currently not represented in Newave. These constraints mean that a given UHE needs to allocate more water, in real-time operation, to vary production (for example, at peak times) than the model can see. When considering only minimal generation constraints, Newave admits that, in critical situations, it can produce a small amount of power on average monthly and modulate instantly to peak when it is needed. Thus, only the minimum constraints are not enough to represent all the energy use of the UHE, being necessary to update another operating parameters that, in this case, considers the load levels as well.

Again, the generation verified in the recent past was considered as an estimate for the energy expenditure that results in an amount sufficient for the plants to vary their production in order to meet the variations in load and other variable renewable resources. Using once again the final two months of the dry season of 2020, it was identified that at the light load level, the average production of the SIN hydro plants was approximately 32,000 average MW. At first, a minimum generation per level at this value is sufficient to guarantee all the modulation of generation necessary for the UHEs.

Although Newave represents the power system in grouped form, the methodology used in this plan provides an individualized representation of the operating constraints that impact on hydro generation, which are later aggregated by the Newave model, based on: higher minimum outflow restriction (adherent to the lowest generation hourly verified) and monthly generation targets (adherent to the lowest verified level of hydro generation), both obtained from the same historical reference data and in a structural condition. The temporal (monthly) correlation between the minimum outflow values and the monthly generation target is kept in this situation, which guarantees the adequacy between the constraints imposed on the model and the coupling between the energy and capacity assessments.

With this modeling, it is expected to improve the Future Cost Function resulting from the Newave model for purposes of expansion planning studies, in addition to the methodological evolutions discussed in the Standing Committee for Analysis of Methodologies and Computer Programs in the Electricity Sector (CPAMP). The Future Cost Function impacts the value of water (opportunity cost of dispatching hydro plants) and, consequently, important operating variables for planning, such as the risk of loss of load and capacity availability. In this way, this new information will be part of the entire process of this PDE and will influence the indication of the new generation entry, thus bringing greater predictability on the use of resources and allowing the anticipation of corrective actions or adjustments associated with planning decisions.

Table 3 - 1 summarizes how the operating constraints proposed in PDE 2031 are represented.

In relation to the minimum outflow data of each plant, even if the reference is the minimum coincident generation, according to **Table 3 - 1**, the values registered in the model must be converted into flow (m3/s), through the use of the quota x volume polynomial of each plant, considering the assumption that the plants have 65% of their useful volume. In addition, some UHE plants such as Itaipu and the São Francisco plants had their minimum flow values adjusted according to the operating reality and modulation limitations imposed to provide maximum power availability at any time. In the case of generation targets, not all the values obtained from referencing **Table 3 - 1** can be registered, since the model does not allow that are at the top of the cascade plants to have generation targets, due to the uncertainty of natural inflows and the impossibility of having plants regulating the inflows upstream. Thus, the differences between the reference values of 23,000 MWh/h and 32,000 MWavg are justified, for generation associated with the minimum outflow and minimum generation target per level, respectively, for those presented in **Table 3 - 1** and effectively modeled in Newave.

Table 3 - 1: Synthesis of the operation of the UHE considered from PDE 2031

Constraints	Concept	Modeled average values [5](MW average)
Minimum Outflow Rate	The lowest hourly hydro generation of the SIN was adopted as a reference, in a structural condition, where the individual generation of each coincident plant at that moment was obtained.	26,000
Minimum Hydro Generation Target	For the definition of the minimum average generation per level, the average of the individual generation	29,000

[5] Despite the modeled data indicating the values shown above, the Newave representation makes the total considered by the model close to 16,000 average MW for the case with tighter constraints, due to traversing the parabola constructed by this variable.

	of each plant at the moments coinciding with the aggregated generation of the SIN during the duration of the light load level in October and November was adopted as a reference.	

It should be noted that the approach proposed here does not entail any changes in relation to the already known PDE process or in any mathematical formulation of the Newave model, and does not conflict with any actions carried out within the scope of the CPAMP studies. All suggested changes occur only to input data to better reflect constraints that are imposed on the real operation of the power system. Furthermore, it is important to emphasize that this is a first approach, for which future improvements, especially from a broad discussion process, may prove necessary.

Box 3 - 2: The consideration of Climate Change for planning adaptation

Box 3.6 of PDE 2026 addressed, through a literature review, the relationship between climate change and electricity generation.
From the point of view of GHG emission mitigation actions, despite the concern about the emissions impacts of the expansion to meet the energy and power requirements of the system, the Brazilian electric sector accounts for a comparatively low share in relation to total emissions from the country. On the adaptation side of the electricity sector, climate change may have impacts both on electricity consumption habits, for example with the increase in energy demand for cooling homes, and on the availability of natural resources, such as water, wind and solar radiationfor the generation of electricity.

In this context, methodological and input data changes are necessary to consider climate change in planning studies, so that PDE indications promote mitigation and adaptation measures that increase the resilience of the generation mix in the face of possible droughts, temperature increases and extreme events in general.

Regarding the representation of water availability, despite the current metrics adopted for the security of supply criteria focus on reduced percentiles, that is, they reflect the worst scenarios observed, it is important that planning constantly assess the best ways to represent future scenarios. Thus, we highlight the assessment of possible structural changes in the hydrological inflow regime and in the availability of inflows for hydro generation. Such changes include both changes in average annual terms of hydrological conditions, as well as eventual regime changes, such as greater frequency and duration of dry periods and reductions in the wet period, associated with extreme rainfall events. Thus, as proposed in this chapter, for the consideration of hydro inflexibility in a more adherent way to the real-time operation of the system, it is necessary to improve the methodologies of representation of future series of inflows in the planning studies of the electric sector in face of the effects of climate change.

Given the complexity of the topic, it is important that timeframes are established and that methodological development takes place consistently between them.

As short-term actions, which can bring immediate results, in addition to the bibliographic reassessment and analysis of international experiences, which has already been addressed by several authors, the realization of studies with generation of hydrological scenarios from reduced historical series, aiming to better reflect the recent climate change (considering similar analyzes carried out by CPAMP in the 2017/2018 cycle) can bring numerical sensitivities about its effects on expansion. In this sense, a what-if sensitivity is also foreseen for PDE 2031 for this purpose.

In the medium term it is proposed to carry out studies in partnership with other institutions to use climate scenarios presented in the AR6 of the IPCC. In order to do so, the rainfall forecasts that best reflect the specificities of Brazilian hydrological basins would be selected, in order to create a series of inflows through rainfall-runoff simulations. Based on these results, future scenarios of inflows to the hydro plants can be created to assess the operation of the system, which can provide more details on the evaluations obtained in the short term.

Box 3 - 2: The consideration of Climate Change for planning adaptation

Finally, for the long term, it is essential to assess with suppliers the models used in the planning studies of the SIN on possible changes in the consideration of uncertainties and climatic variables in the forecast of hydrological scenarios, from natural resources to other renewables and load growth.

In addition to the actions mentioned, it is important to analyze and study the different regions of Brazil, in addition to individualization by energy resource.

In this way, it is expected to capture the future characteristics of energy demand and the existing and indicative supply of the SIN, in the face of global climate change, seeking to identify the vulnerabilities of the Brazilian electrical system and create strategies to efficiently overcome them.

3.2 Initial Generation and Transmission Power System Configuration: PDE 2031 Base Case

The studies for expansion planning are based on the existing power system configuration in May 2021, the expansion contracted in regulated auctions and the prospect of entry by the ACL with reference to August 2021[6], as well as published legal acts that influence the expansion until the same date. At the beginning of the studies, the SIN had an installed capacity of around 178 GW of centralized supply, with the participation of different generation sources. The auctions held until August 2021 and the prospect of the entry of projects made possible through the ACL, which has a strong expansion of renewable sources, result in an increase of approximately 17 GW of installed capacity in the ten-year timeframe, as shown in Annex 1.

As in recent cycles, PDE 2031 focuses on the existing thermal power supply at the end of the contract, in addition to the need to modernize the existing thermal fleet due to the long period in operation. In addition, it is worth noting that the Energy Development Account (CDE) and the Thermoelectric Priority Program (PPT) expired over the ten-year timeframe. In addition to the removal of plants with termination of CCEAR or loss of benefit from the CDE/PPT, plants that do not have any type of contract and have available power greater than zero in the PMO (Monthly Energy Operation Program) of May are removed of 2021. This change in relation to PDE 2030 makes the calculation of requirements more adherent with the possibility of contracting existing UTEs, for example, through the Power Capacity Reserve Auction (as the one carried out in December 2021), as well as more adherent to real-time operation, mainly due to the difficulties of predictability, stability and sufficiency of generation from plants in 2021.

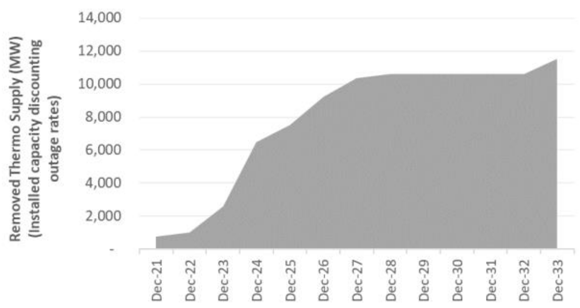
Thus, it is estimated that, due to the uncertainty associated with the future availability of these projects[7], approximately 16,000 MW of the current installed capacity should not be considered in the base configuration (Base Case) during the ten-year period. In terms of capacity available to the power system, this thermal supply represents around 10,000 MW, as shown in **Chart 3 - 2**. In this context, if all these plants do not actually remain in operation, there is a reduction from 25 GW in 2021 to 13.6 GW in 2031[8] of thermal power installed capacity.

[6] Due to the reference date, the results of the following auctions are not considered: Simplified Procedure for Contracting and Reserve of Power Capacity.

[7] Without the commitment to the system, plants without contracts could have different destinations, depending on the decision of their shareholders, such as decommissioning and merchant operation.

[8] In relation to the supply of thermal plants, the share of this source will increase between 2022 and 2025, due to the contracting that took place in the Simplified Competitive Procedure in 2021 However, due to the start

Chart 3 - 2: Thermo supply withdrawn from PDE 2031 Base Case

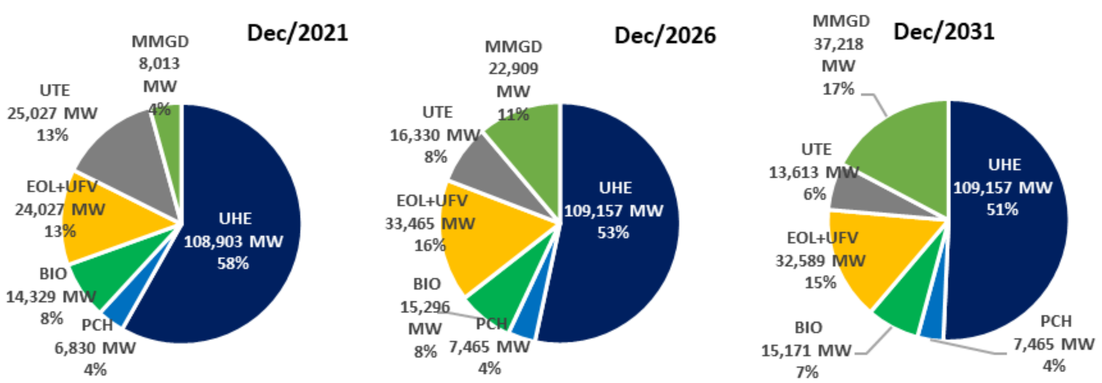


Source: Prepared by EPE.

With this information and considering the assumptions adopted, the indicative expansion scenarios of PDE 2031 assess the economic attractiveness of maintaining this thermal power supply connected to the power system, through retrofit, given the opportunity to expand new plants, with greater investment and efficiency. In this sense, approximately 8,200 MW of thermal power retrofitting were made available to the model. This representation is consistent with the fact that the uncontracted installed capacity may be subject to a specific assessment in the planning of auctions, as it constitutes an opportunity, for example, for modernization and fuel replacement of this group of plants.

Chart 3 - 3 illustrates the variation in shares of the existing and contracted supply over the years 2021, 2026 and 2031, without considering new indicative expansion. In these graphs, the portion of Micro and Mini Distributed Generation (MMGD) is also included, due to its growing relevance. This configuration is called PDE 2031 Base Case and will be used to quantify the system requirements. It is observed that the absolute hydroelectric participation in the total generation mix remains practically unchanged, with the additional contracting only of UHE Juruena, which was not considered in PDE 2030. On the other hand, there is significant growth in wind (EOL) and centralized photovoltaic solar (UFV) sources, which together add around 9 GW to the installed capacity already under implementation, from December 2021 to the end of 2031.

Chart 3 - 3: Evolution of the Existing and Contracted Installed Capacity of the SIN



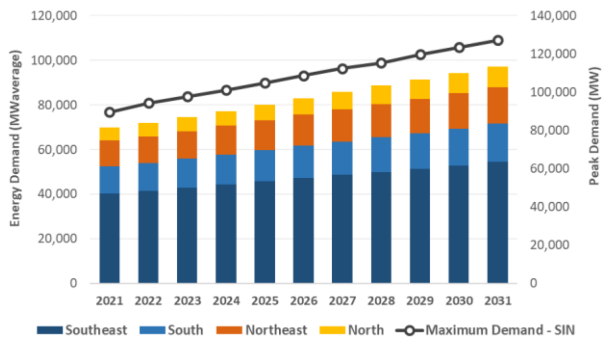
date of the studies for PDE 2031, this amount was not considered in the simulations of this cycle.

Source: Prepared by EPE.
Notes: (1) The amount presented as small hydro (PCH) also includes existing micro hydro (CGH).
(2) About 90% of the total indicated in the graph by biomass is composed of plants from this source, but small thermoplants that can use other fuels are also included.
(3) This graph considers the removal of wind and biomass projects from PROINFA at the end of the contract. These same projects are considered again in the Reference Scenario, in accordance with the provisions of Law 14,182.
(4) The initial supply considers 2,975 MW of thermal power plants whose available power is zero.
(5) Includes the portion of UHE Itaipu belonging to Paraguay, whose surplus energy is exported to the Brazilian market.

From this configuration, the evaluation of the SIN supply conditions is carried out. The need to expand the generation system is due to the increase in demand, energy and power forecasts for all regions of the SIN, based on the assumptions of the evolution of macroeconomic indicators. The demand forecast already includes the electrical losses in the transmission network. The load curves were represented in four-different levels in theoperation simulation model. The heavy, medium and light load levels were constructed from CPAMP studies that redefine the load levels, consolidated in public consultation No. 51/2018. The fourth level, with a duration of 10 hours/month, was established in order to represent the maximum instantaneous demand of the system.

The average annual growth of the load of the SIN (without deduction of the Micro and Mini Distributed Generation - MMGD), in the ten-year timeframe, is about 2,750 average MW – CAGR of 3.4%. **Chart 3 - 4** presents the SIN load forecast (average monthly energy and instantaneous maximum demand) for the Reference Scenario, without deducting the MMGD portion. Maximum demand shows a growth rate of 3.4% over the ten-year timeframe. More details on the demand forecast and the economic recovery after the most critical period of the COVID-19 pandemic are presented in Chapter 2.

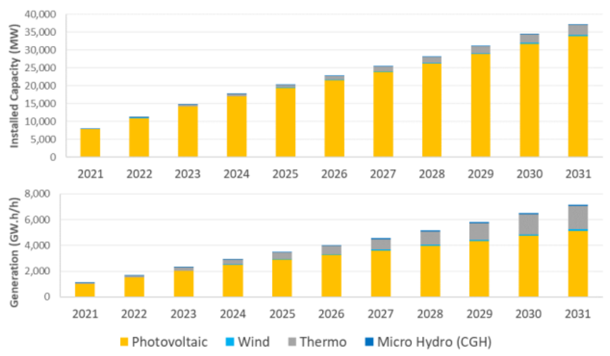
Chart 3 - 4: Load Forecast in the PDE 2031 Base Case



Source: Prepared by EPE.

In relation to MMGD, PDE 2031 used as a premise the provisions of the Legal Framework for Distributed Generation, in accordance with Bill 5,829/19. In summary, the legal framework provides greater incentives compared to what was forecast in PDE 2030, which provided for the withdrawal of only the FIO B (distribution) portion of the compensation mechanism, in addition to the use of transmission, charges, losses and energy, continue to be compensated by micro and mini generators (local and remote). Details on the assumptions adopted for MMGD are presented in Chapter 9.

Chart 3 - 5: MMGD's capacity and energy expansion

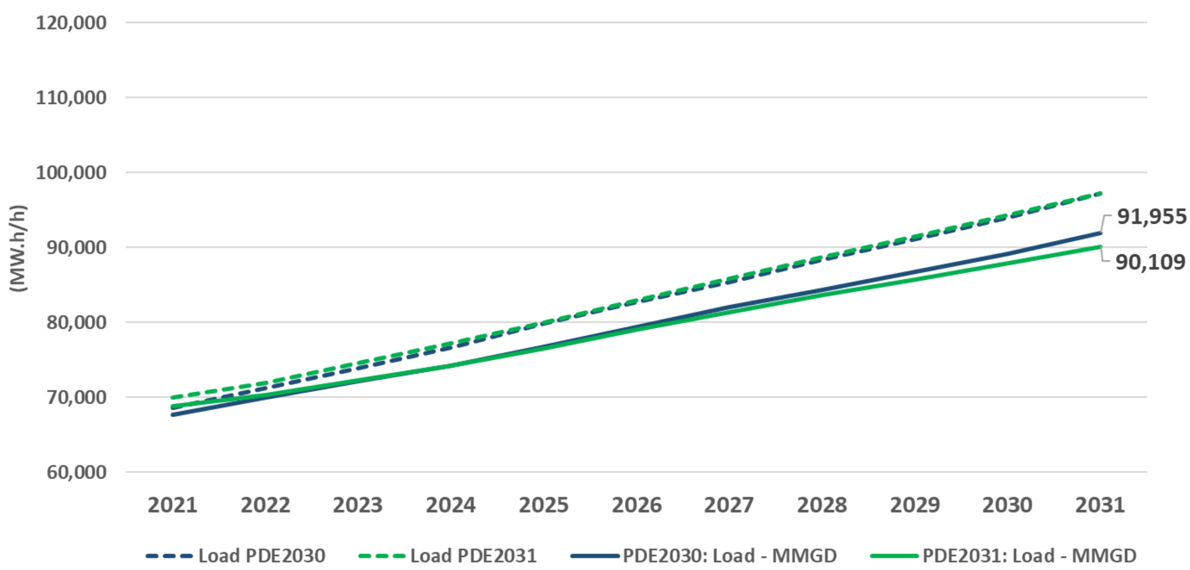


Source: Prepared by EPE.

The MMGD forecast scenario considers penetration of approximately 37 GW of installed power (and 7,100 average MW) at the end of the ten-year timeframe. As can be seen in **Chart 3 - 5**, solar photovoltaic technology remains the main source in this segment, accounting for about 93% of all the total MMGD expansion. Compared to PDE 2030, there is an increase of about 20 GW of MMGD expansion in 2031, thus resulting in a decrease in the load to be met by centralized energy generation.

The impact of the MMGD forecast on the demand to be met by the centralized generation can be seen in **Chart 3 - 6**. Comparing with PDE 2030, despite the demand forecast remaining stable between the two plans, a reduction of 1,800 average MW is identified, in 2031, considering the amount to be met by the centralized supply.

Chart 3 - 6: Energy load and MMGD: PDE 2031 and PDE2030



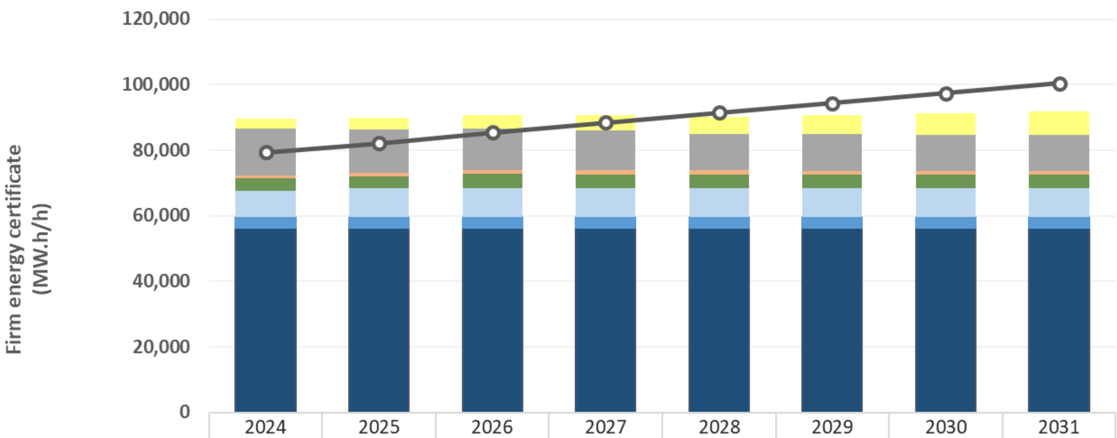
Note: Load – MMGD refers to the load met by the centralized power generation

Source: Prepared by EPE.

From the contractual point of view, what signals the need to expand the ACR and ACL is the firm energy contracts called GF of these markets (GF granted versus demand forecast). On the other hand, the sizing of reserve energy auctions was done through the balance between the simulated GF and the SIN demand forecast. However, with the publication of CNPE Resolution No. 29 (2019), and MME Ordinance No. 59 (2020), the balance of the system began to be measured by the current supply criteria.

Thus, as can be seen in **Chart 3 - 7**, the system has excess of GF until the year 2027, which would indicate the need for expansion only in 2028. It is worth noting that, in this analysis, the MMGD forecast was considered, as it will reduce the need for centralized generation expansion. It is also worth mentioning that the physical guarantees do not take into account the new representation of the operating constraints incorporated in this PDE. However, in view of the importance of hydro plants for security of supply, including from a contractual point of view (GF), as **Chart 3 - 7** explains, the discussion on the incorporation of the advances proposed in this PDE in other studies, including the calculation of GF, if necessary. It is important to emphasize, however, that the challenge for this is not simple and requires a broad discussion about the ways of representing and the resulting impacts, which may require a significant time of maturation between the beginning of these discussions and the actual application.

Chart 3 - 7: SIN: firm energy contract and demand balance



	2024	2025	2026	2027	2028	2029	2030	2031
MMGD	2,949	3,497	4,024	4,564	5,148	5,798	6,511	7,169
UTE	14,235	13,297	12,757	12,341	11,209	11,073	11,073	11,073
SOL	1,004	1,122	1,190	1,190	1,190	1,190	1,190	1,190
BIO	3,641	3,681	4,193	4,129	4,110	4,110	4,109	4,106
EOL	8,165	8,701	8,825	8,804	8,793	8,727	8,656	8,617
PCH	3,183	3,247	3,269	3,271	3,271	3,271	3,271	3,271
UHE	56,363	56,398	56,423	56,438	56,438	56,438	56,438	56,438
Demand	79,414	82,184	85,408	88,399	91,426	94,352	97,407	100,496
Total Supply (+MMGD)	89,540	89,942	90,681	90,736	90,158	90,607	91,248	91,863
Difference	10,126	7,759	5,274	2,337	-1,267	-3,745	-6,159	-8,633

Note: For MMGD, the expected annual production associated with the forecast expansion was considered.
Source: Prepared by EPE.

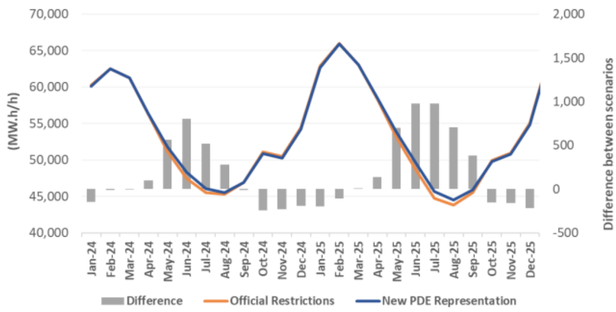
3.2.1 IMPACT OF OPERATING CONSTRAINTS ON PDE 2031 BASE CASE

The expectation of the Brazilian electric power system to maintain, in the ten-year timeframe, the supply of predominantly renewable generation in the generation mix brings challenges for planning, as PDE has been presenting over the years. The hydrosource, which will still be predominant in the SIN, will need greater management and predictability for its operation, so that it can be used to accommodate load fluctuations and the increase in the participation of variable renewable energy (VRE), if this is the operation strategy of the power system.

The new proposal to represent the operating constraints for thehydro plants, described in section 3.1, is an important step and was considered in the simulations presented in this report. It is relevant to highlight that the constraints incorporated in this Plan were the result of a long process of interaction with the ONS, presented by EPE to the CMSE of July 2021, for discussion with other institutions participating in the Committee, and which could already be incorporated into PDE due to its indicative character, with fewer legal limitations for the incorporation of improvements like this. To demonstrate the benefits of the proposed approach, some simulation results of the Base Case will be compared with original constraints (that is, using official Newave data according to the PMO of September 2021) and the same Base Case, but with the proposed operating constraints in this PDE (that is, using more restrictive data on minimum outflow and monthly generation target, as observed in the 2020/2021 biennium). Initially, it should be noted that PDE 2031 simulations start in May 2021, and consider the storage of the reservoirs verified on this date as a initial simulation point.

Focusing on hydro operation, the behavior of total hydro generation and storage levels of the SIN will be analyzed. It is possible to observe the impact of the alteration of the input data in the operation results of the plants. **Chart 3 - 8** shows that, in the case with a change in the operating constraints, there is an increase in the hydro generation of the SIN during the months of lower demand. In July 2025, for example, this difference reaches 1,000 MW.h/h on average (2,000 simulated hydrological scenarios).

Chart 3 - 8: Hydro Generation in SIN with and without new operating constraints



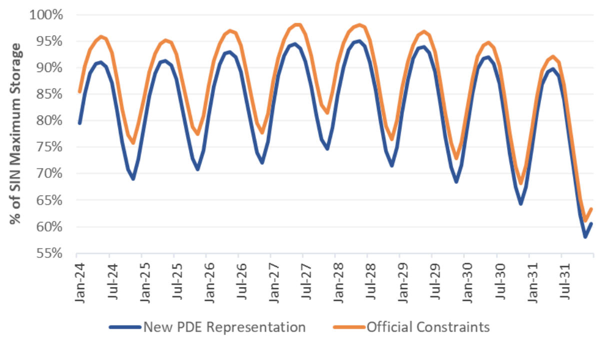
Source: Prepared by EPE.

As a consequence of the higher compulsory hydro production in months of lower demand, the lower management of the water resource makes storage reduced throughout the year, as presented by **Chart 3 - 9**, showing the difficulty of hydro plants in filling the reservoirs when these operating constraints are tighter.

Graph 3 - 10, shows the distribution probability for the SIN storage considering 2,000 simulated hydrological scenarios for (a) May 2025 and (b) November 2025, highlighting, respectively, the end of the dry period and the end of the wet period. It is important to analyze the difference in SIN storage behavior for different months of the year, especially at times when the reservoirs tend to have the highest (end of the wet season) and lowest (end of the dry season) storage levels. It is evident that the new representation of the operating constraints in the simulations partially reduces the optimism resulting from the simulations.

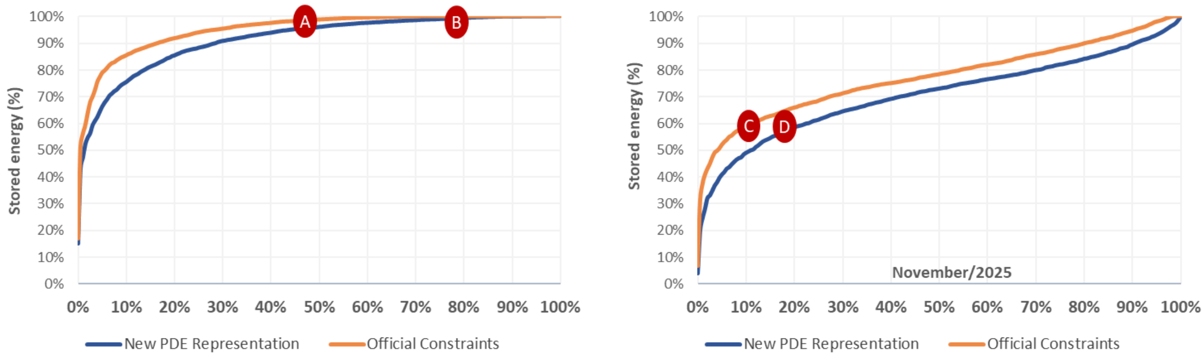
While, with official data, the model has about a 50% probability of ending the wet period completely full (point A), this value is reduced to approximately 20% with the operating constraints proposed in PDE 2031 (point B). At the end of the dry season, in addition to presenting lower levels in all scenarios, the probability of storage below 60% increases from a 10% chance (official constraints) to 24% (with the new proposed representation), at points C and D, respectively. It is important to emphasize, however, that although the results obtained are in line with the objective of bringing more realism to the simulations, continuous advances are necessary both to improve the proposed representation and in other work tasks, especially those discussed within the scope of CPAMP.

Chart 3 - 9: SIN average storage with and without new operational restrictions



Source: Prepared by EPE.

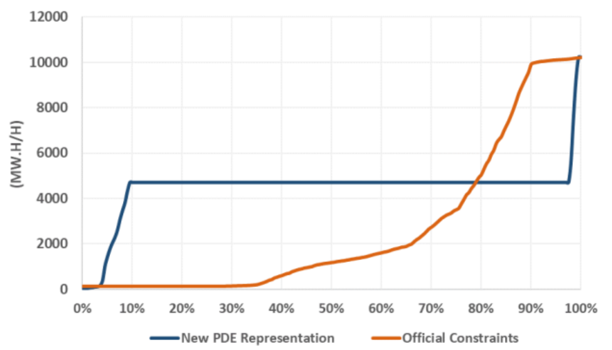
Chart 3 - 10: SIN's storage distribution with and without new operational constraints



Source: Prepared by EPE.

Deepening the understanding of the impact of these changes, the constraints more adherent to the verified data in the most recent periods also change the generation between load levels. For example, in the Northeast region, situations in which the mathematical model simulated zero hydro generation at the light load level in just over 30% of the scenarios (**Chart 3 - 11**) can no longer be observed.

Chart 3 - 11: Hydro Generation with and without new operating constraints – Light Load – Northeast – November/25

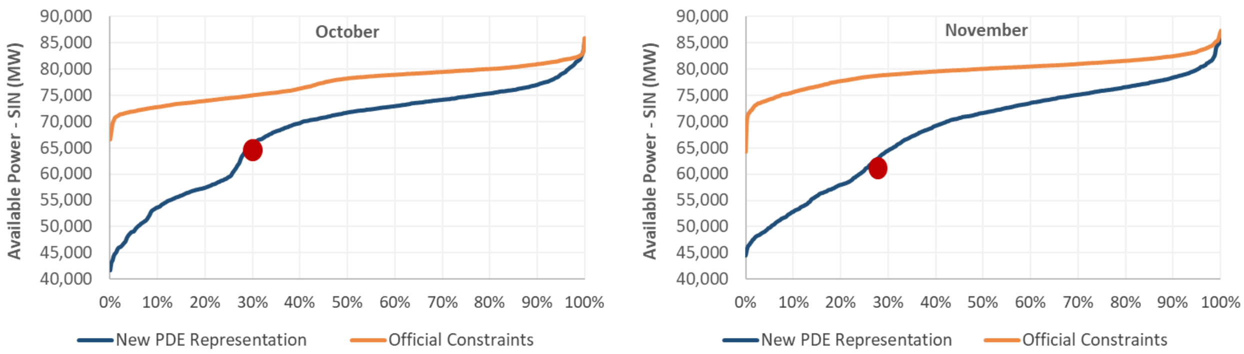


Source: Prepared by EPE.

Changes in water constraints directly reflect the maximum power availability of hydro plants. The analysis of the group of SIN plants reflects this impact. As the simulations start in May 2021, Graph 3-12 presents the probability distributions for October and November 2021, in order to be comparable to what was verified in the 2020 operation results (red circle). It can be seen that the case with increased water constraints has greater variation among the 2,000 simulated series, where possible critical scenarios are more evident. In other words, the new approach proposed in this PDE allows the future risk to be perceived in advance, bringing greater predictability about the uncertainty that exists for this magnitude. Analyzing, for example, the month of October 2021, it is clear that extreme scenarios, indicated by the lowest values of available power, become part of the sample seen by planning, with values up to 50% lower than the lowest value found in the case without change of water constraints. Furthermore, in 32% of the series – indicated in the graph by the red dot – the case with the new representation of the constraints has maximum power availabilities lower than the lowest value found with the official constraints, reinforcing the change in the behavior of hydro plants with this new approach.

Chart 3 - 12 still allows comparing the two simulations with verified hydro power availability data from 2020. In May 2021, that is, when the wet season of that year was over, the levels of reservoirs in the Southeast/Mid-West region were around 32%, the worst level for this time of year since 2001. In October 2020, the highest power availability seen at the SIN UHE was 66,000 MW. In the simulation with the new representation of the operating constraints, in about 30% of the simulated series values lower than that were identified, while in the case using the official constraints, only in the worst scenario (that is, 1 in 2,000 series) the value verified in 2020 could be reached. In other words, the inclusion of new operating constraints makes it clear that there was a 30% probability of occurrence of scenarios equal to or worse than those seen in the previous year of real-time operation, given the starting condition of the studies, and 70% of scenarios that were better than that situation. This comparison, between the simulations and the one verified in the real-time operation, demonstrates the predictability that the new representation can bring to planning studies.

Chart 3 - 12: Maximum Power Availability – Hydro Plants – SIN – October/2021 (a) and November/2021 (b)

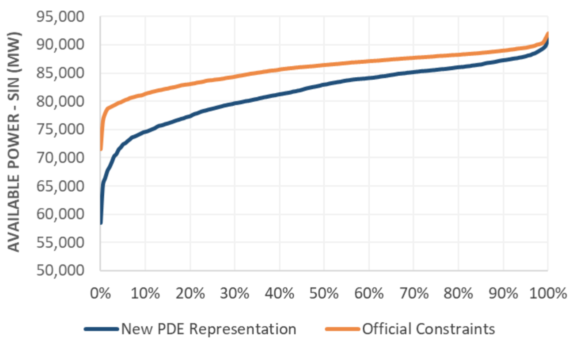


Source: Prepared by EPE.

The same result occurs in the November 2021 simulation. The simulated case with the new representation of the constraints presents 25% of the series with available power lower than the one verified in the same month of the previous year (about 62,000 MW). On the other hand, without changing the proposed constraints, this scenario is not even a possible simulated result. This result shows the robustness of the new constraint modeling proposal in order to bring improvements, since the new representation in the models are closer to the situation that has been observed in real-time operation.

Observing this same variable, but advancing in the period of analysis, **Chart 3 - 13** presents the result for November 2026. The behavior between the two curves is the same observed for the 2021 result, demonstrating that the curve with the new representation of constraints is always below the simulation with the official ones. In this case, a greater approximation between the lower values of the distributions can be seen, an effect of the trend of improvement in operating conditions in relation to the 2021 scenario. In addition, values closer to the available power verified in 2020 continue to appear considering the new modeling, even with less probability than presented in **Chart 3 - 12**. This reinforces that the approach proposed in PDE 2031 for operating constraints brings more realism to the simulated results.

Chart 3 - 13: Maximum Power Availability – Hydropower Plants – SIN – November/2026



Source: Prepared by EPE.

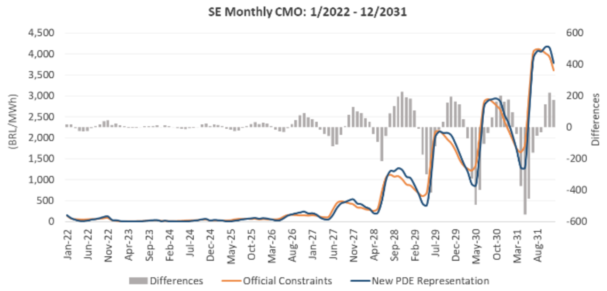
Another important aspect to be assessed is the impact of these constraints on the estimates for the marginal costs of the operation - CMO. This is an important variable that helps in the analyses and indicative scenarios explored by the expansion planning, as well as for its adherence to the future perspective and real-time operation of the generating mix. In this sense, **Graph 3 – 14** shows the CMO results for the SE/CO subsystem for two simulations. It should be noted that the other subsystems of the SIN have a similar behavior to the SE/CO and therefore will not be presented. It is also noted that the Base Case CMOs with the new proposed representation of constraints indicates lower values for the months from March to July, typically characterized as the end of the wet season, when compared to the simulated values for the Base Case with official constraints. On the other hand, the months from September to November, typically at the end of the dry period, tend to indicate slightly higher values of CMO in the Base Case with the new constraints than in the Base Case with the official ones. This reinforces the seasonal characteristic of the hydrosupply of the SIN, especially when the operating constraints associated with the hydro generation, inflow and minimum volume are active in the simulated hydrological series and point to more critical conditions for meeting the energy supply and power availability for those months of the timeframe under analysis.

Another important point to highlight is that, unlike the impact identified in the other variables, the new representation of operating constraints did not change the average CMO in the same way. That is, analyzing only from the perspective of the marginal cost of operation, the signal for expansion would not reflect the greater energy expenditure (seen, for example, in storage levels and in the availability of power) and would not signal the need to restore the demand and supply balance. In this way, PDE 2031 will not only use the average CMO as a coupling variable between the operation and expansion models, which made up the economic supply criterion (when establishing equality between CMO and CME[9]) applied to expansion planning

[9] With the introduction of the MDI model in the process of planning the expansion of the electric power supply, the indication of investment decision is obtained by the economic signal resulting from the minimization of the total costs of investment and operation. However, as the GF calculation does not use the MDI, but only the operation optimization model – Newave, the CMO=CME criterion was maintained, in order to ensure consistency with the expansion planning study – PDE. In the final report of the new supply criteria, published in

studies , prior to the publication of CNPE Resolution No. 29 (2019) and MME Ordinance No. 59 (2020). As will be presented together with the “Free Scenario” (section 3.5), PDE will also, and mainly, consider the adherence between the operating variables of the MDI and Newave models.

Chart 3 - 14: SE/CO CMO - Average of 2000 inflow scenarios



Source: Prepared by EPE.

December 2020, the details of the analyzes that resulted in the revision of the criteria are presented accordingly.

Box 3 - 3: First Capacity Reserve Auction: from conception in PDE to the event held in 2021

In December 2021, the first Capacity Reserve Auction (LRC/2021) of the SIN took place[10]. The realization of this event represents more than the contracting of additional capacity: it is the first auction for the SIN in which the product sold does not refer to the average energy produced, but to the availability of power for the system, which will use the resource only when necessary. This first auction contracted approximately 4.5 GW of power availability, with a delivery commitment starting in 2026.

The change in the service to be provided could already be seen during the event, where the metric used for competition was not the traditional “BRL/MWh”, used when it is desired to contract energy at the lowest price. In the LRC/2021, the competition took place in “BRL/MW.year”, seeking to reflect the competitors' power availability, also weighted by a small variable portion[11]. This new metric of comparison between projects shows that, for this product, the most efficient for the system is to pay the lowest fixed cost, since the dispatch expected by these plants will occur at specific times to meet the peak loads and/or scarcity situations of renewable resources. Retaining of technologies with this operational perspective increases the safety of the system and allows for a greater insertion of variable renewable resources, adding greater operational flexibility.

The realization of this auction in 2021 is the result of a long planning process, in which the indications of the Ten-year Plan have an important contribution. In 2010, when EPE presented the studies for PDE 2019, an extensive process of discussion, methodological evolution and formatting of the product to be marketed was started. At that time, studies pointed out that, in addition to the traditional energy restriction (which leads to commercialization in terms of the amount produced on an annual scale), the SIN would also be constrainted in terms of power availability (i.e., instant availability when the power system requires it). From there, the studies evolved until PDE 2026 presented for the first time the specific amount of expansion for this service. That Plan contained several advances necessary for this indication to be implemented. Among these advances, the need to review the supply criteria was reinforced, without which it would not be possible for society to contest whether the indicated supply was indeed adequate.

In December 2019, the approval of the new security of supply criteria, with the “power” dimension explicit, allowed PDE 2030 to present the calculation of energy and power requirements, making clear the distinction of the characteristics between them, but also the coupling that exists in the contribution between the supply of the power system.

In other words, the first LRC, which represents an important change in the way the Brazilian electricity sector expands its generation supply, was not an isolated act, but the result of a long construction process, indicated by the expansion plan for more than ten years before its realization. This process, conducted directly by the MME, included a lot of discussion with several institutions in the energy sector, as well as with the whole society (through 2 public consultations) and incorporated many advances brought by all.

However, it is important to highlight that there is still a lot to evolve for the SIN to have an efficient capacity market. While the structural solution for contracting the adequacy of the system, the separation of firm capacity and energy contracts, is not made feasible among the set of legal changes being debated in the National Congress for the modernization of the sector, it is essential to resolve the technical and regulatory issues that today made the first LRC was addressed to thermal power plants. It is important to move towards technologically neutral competition. For example, expanding/modernizing existing UHEs and demand-response are technically viable alternatives and, as demonstrated since PDE 2029, can be economically attractive. In addition, renewable sources, even if combined with storage systems, can also provide the power service, as PDE also shows.

Many of the necessary advances have already been discussed within the scope of the modernization of the SIN. However, some of them may already be incorporated in the next events, with adjustments that do not depend on the alteration of the entire current regulatory framework. For this, the involvement of players is essential to unlock and search for the best solutions to break the barriers that exist today.

[10] The results of the first LRC were not incorporated into PDE 2031 studies. The reference date and start of the simulations of this ten-year cycle was September 2021.

[11] More information in document EPE-DEE-IT-111/2021-r0, available on EPE website.

3.3 Power System Requirements in the ten-year horizon

The latest PDE cycles have explicitly indicated the need for expansion to meet energy and power requirements. It is noteworthy that in PDE 2019 (2010) the first public discussion of the future need for power was made, and that PDE 2026 (2017) was the first reported plan with explicit expansion to guarantee capacity. This indication was accompanied by the need to review the security of supply criteria, which until 2019 only considered energy needs. In order to guarantee the adequacy of energy and power supply, the MME instituted, through a subgroup of the Electric Sector Modernization GT, the study of new supply criteria to be applied in the planning of the expansion and operation of the SIN. The activities of this working group culminated in the publication of CNPE Resolution No. 29, of 2019, which established the metrics for the new criteria, in addition to MME Ordinance No. 59, of 2020, which established the parameters associated with these metrics. With this new regulation, the SIN now has explicit criteria for capacity supply, in addition to having its energy supply criteria complemented to the new reality of the power system.

From the establishment of these new criteria, PDE 2030 presented a methodological proposal to quantify the amount of additional supply that the power system requires so that future operating conditions comply with the established limits, ensuring compliance in all its dimensions. This required amount of incremental supply was called System Requirements.

Based on the Base Case power system configuration, the assessment of the adequacy of energy and power supply considers the simulation with 2,000 hydrological scenarios. The metrics and parameters established for this assessment are:

- CVaR[12] 1% of Unserved Energy (ENS) ≤ 5% of Demand

Risk and its unserved energy depth: on an annual basis, the 1% worst scenarios for meeting energy demand are assessed, where the average load shedding in these scenarios cannot exceed 5% of the demand of the SIN and for each subsystem.

- CVaR 10% CMO ≤ 800 [BRL/MWh]

Energy-economic criterion: on a monthly basis, the 10% scenarios with the highest CMO are assessed, where the average of these scenarios cannot exceed BRL 800/MWh in any subsystem assessed.

- CVaR 5% of Unserved Power (PNS) ≤ 5% of Demand

Risk and its unserved power depth: on a monthly basis, the 5% worst scenarios for meeting the maximum power demand are assessed, where the average of these scenarios cannot exceed 5% of the instantaneous demand of the SIN and for each subsystem.

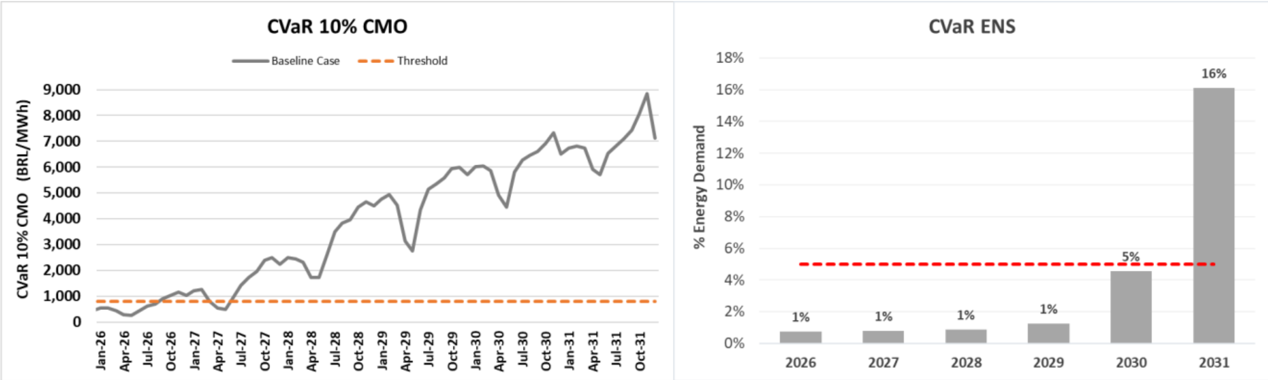
- LOLP[13] ≤ 5%

Power risk: on an annual basis, there is a limit of 5% probability of occurrence of any deficit due to insufficient power capacity, for the SIN and for each subsystem.

The first step in evaluating the fulfillment of the supply criteria is the verification of the violation of the energy criteria. **Chart 3 - 15** shows that both criteria are met. In graph (a) it is noted that the limit for the CVaR 10% of the CMO (for the average of the four load levels), on a monthly basis, is violated from 2026 onwards, with a tendency to increase over the years and peaks in the months of September to March. Graph (b) shows the average of the 1% worst scenarios for Unserved Energy (CVaR 1% ENS), on an annual basis, where it is identified that the limit for this criterion is violated only in 2031.

[12] CVaR = Conditioned Value at Risk (Expected value conditioned to a certain confidence level)
[13] LOLP = Loss of Load Probability (risk of unserved load)

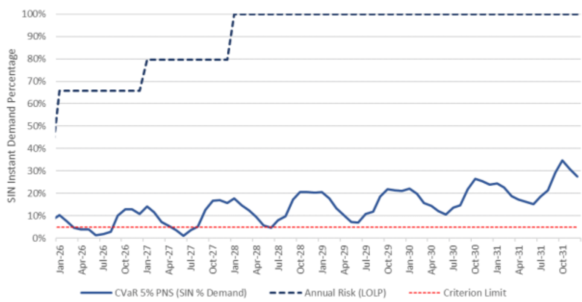
Chart 3 - 15: Assessment of Compliance with the Energy Supply Criteria: (a) CVaR 10% CMO; (b) CVaR ENS



Source: Prepared by EPE.

Chart 3 - 16, in its turn, presents the evaluation of compliance with the two criteria related to power supply[14]. It is observed that there is a violation of the power criteria from 2024 onwards, where there is also a growing characteristic of the violation over the future years. It is noteworthy that the results presented consider the output of the thermal power plants presented in Annex A, which are later considered as candidates for retrofitting. This result also does not consider the results of the Simplified Competitive Procedure, carried out in 2021, which contracted 1,100 MW of supply that will be available for the SIN between 2022 and 2025, nor of the first Capacity Reserve Auction, which contracted about 4,600 MW for start of operation in 2026. These two events were held after the reference date for the start of the simulations of this Ten-year Plan.

Chart 3 - 16: Assessments of Compliance With Power Supply Criteria CVaR 5% PNS [Instant Demand %] and LOLP



Source: Prepared by EPE.

To quantify the energy requirement from the scenarios that violate the CVaR 10% CMO criterion, the identified variables that impact the CMO established by the Newave model are: the dispatch of thermal power plants with CVU above the established limit, the unserved energy and the violations of operating constraints. The sum of these amounts in the 10% worst CMO scenarios, assessed on a monthly basis, indicates the amount of energy to be inserted into the power system so that compliance with this of updated security of supply

[14] Power balance assessment is coupled with the energy simulation result for 2,000 hydrological scenarios simulated with the Newave model.

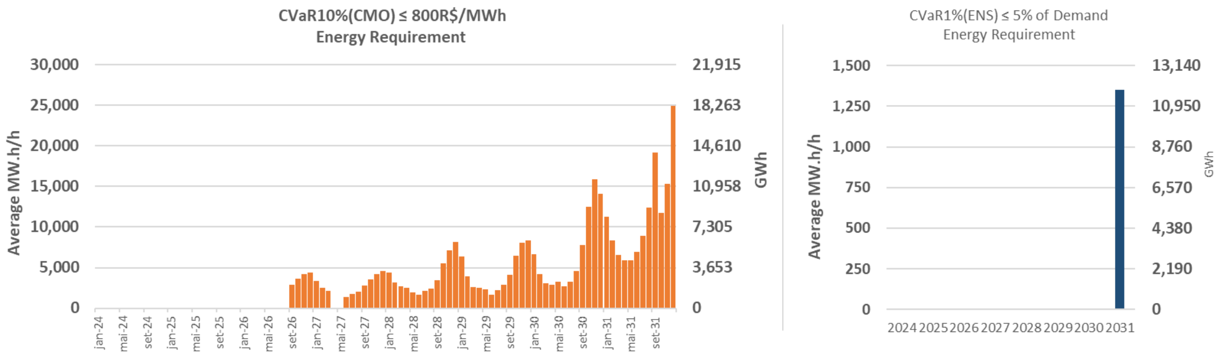
criterion. It is worth noting that violations of operating constraints must also be considered, as they represent situations in which the power system does not have sufficient supply to guarantee all services that depend on the use of water[15]. For the mathematical model used, these restrictions impact the value of water and, consequently, the marginal cost of operation, thus contributing to the violation of the CVaR CMO criterion.

As for the CVaR of ENS and PNS, as both are directly related to the amount of energy and power non served, the supply to be added is exactly the difference between the value obtained for each variable and the limit established by the supply criterion.

As for the LOLP metric, where only power deficits with probability less than or equal to 5% are accepted, the variable that impacts is also the load shedding itself. Thus, if a supply equivalent to the depth of the deficit that results in this 5% worst-case scenario is added to the system, that is, the VaR 5%, the risk of occurrence of load shedding will be reduced to the limit of the criterion. Thus, this will be the minimum amount necessary for the power system to be adequately supplied.

From this quantification method described, **Chart 3 - 17** presents the requirement calculated according to the temporal discretization of the two metrics for evaluating the fulfillment of the energy criterion, in average MW.h/h per month. There is a clear seasonality present in the assessment of the requirement by the CVaR 10% of the CMO, where the highest amounts occur in the second semester (which includes the dry season), from 2026. This requirement has increasing values over the years. Until 2031, the only energy criterion violated, and which therefore has an associated requirement, is the CVaR 10% CMO, and the calculation of the requirement by the CVaR 1% ENS occurs only in 2031. Furthermore, it can be compared that the results are not similar to the firm energy credit balance metric, described in item 3.2.

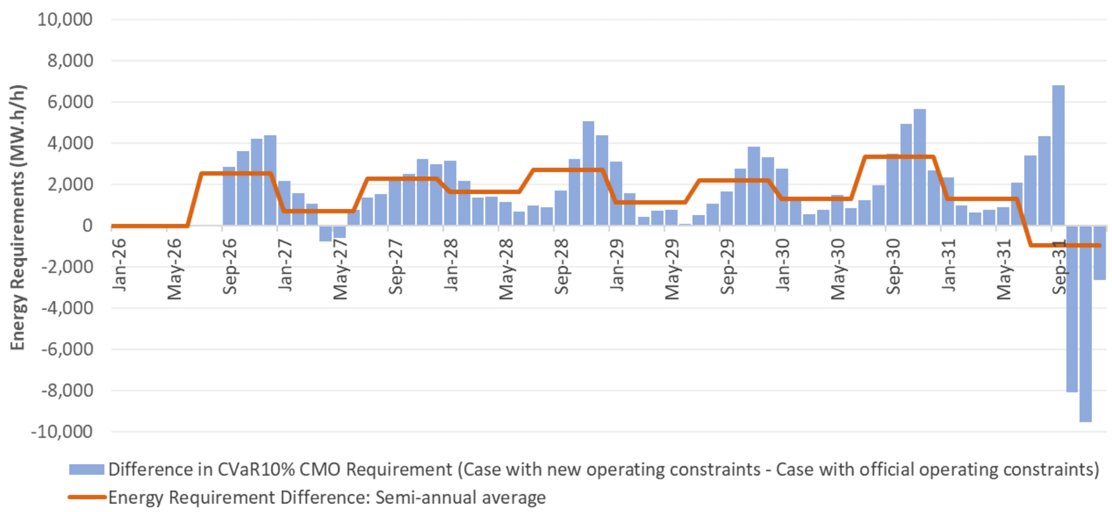
Chart 3 - 17: Energy requirement calculated for metrics CVaR10%(CMO) ≤ 800[BRL/MWh] and CVaR1%(ENS) ≤ 5 [% of Demand]



Source: Prepared by EPE.

[15] The identification of moments in which the electrical power system is not able to meet all operating constraints is an important step to support coordinated actions between sectors. In possession of the moments and amounts of non-compliance with the constraints, the planning studies of the SIN can assess the cost of mitigating actions, from the point of view of the electricity sector, and discuss with other sectors broader measures for the solution, which bring greater social welfare at the lowest cost to society.

Chart 3 - 18: Difference between energy requirement calculated with and without official changes in operating constraints



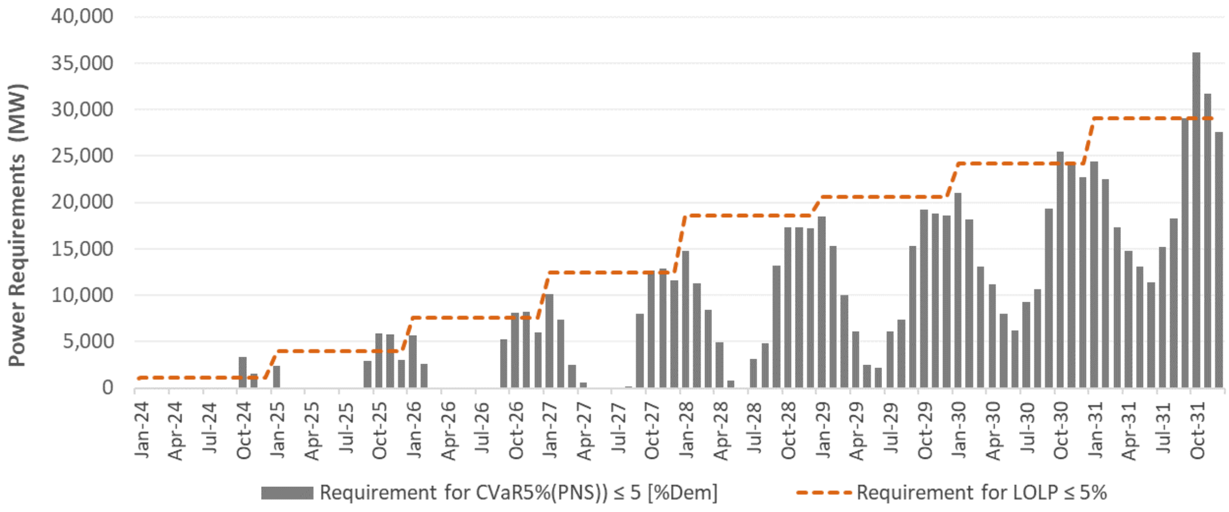
Source: Prepared by EPE.

To measure the impact of operating constraints on the calculation of SIN energy requirements, **Chart 3 - 18** compares the requirement calculated by PDE 2031 Base Case, which considers the hydraulic restrictions modeled in this cycle, and the same supply configuration, but with official constraints. The first point to be highlighted is that with the incorporation of the new operating constraints, the requirement is simulated in 2026, while the case with original constraints only has energy requirements startingin January 2027. In addition, there is an increase in the need for supply throughout the ten-year timeframe. The increase in energy demand in the power system occurs mainly at the end of the dry period, when the higher energy expenditure during the year increases the probability of low reservoir levels, perceived by the simulation model (Newave).

Considering the capacity requirement, **Chart 3 - 19** shows that at the beginning of the horizon the amounts are concentrated between the months of September to March, when the loss of power related to reservoirs tends to be more intense (from September to December) and also in the moments when the peak demand reaches higher values (from January to March). From 2029, all months have CVaR PNS values greater than zero.

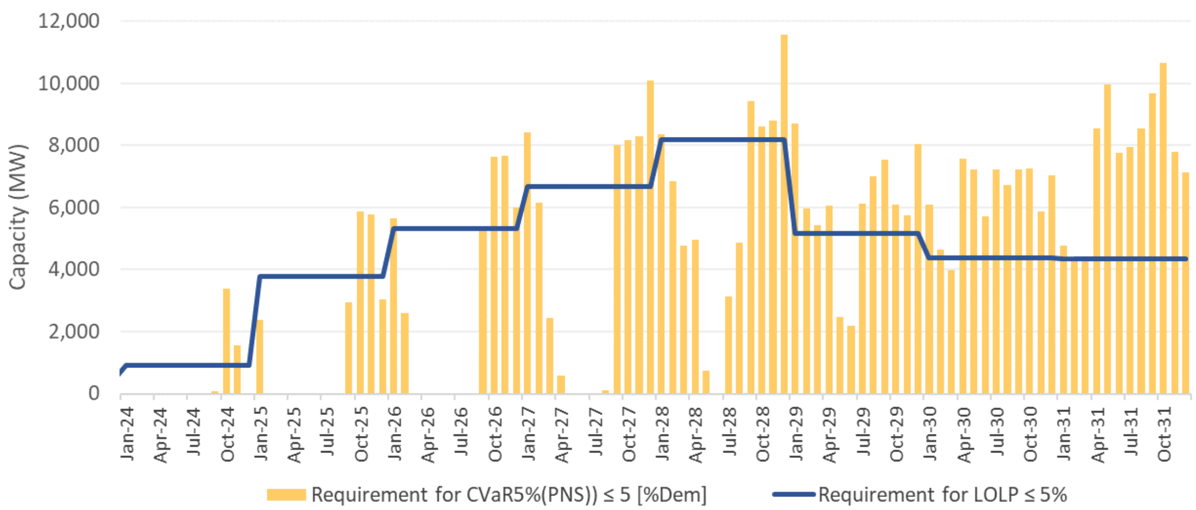
As power is an instantaneous quantity, unlike energy that can be accumulated over time, the comparison between the requirements calculated by the two metrics (CVaR PNS and LOLP) can be done directly. The evolution of these amounts shows that the need calculated by the CVaR PNS is higher than the value calculated by the LOLP until 2027. In 2028, the LOLP requirement exceeds the CVaR PNS, by the year 2030. However, it should be noted that this is the total capacity requirement, and part of it will be met by the contribution of the indicated sources to meet the energy requirement.

Chart 3 - 19: Power requirements calculated for CVaR5%(PNS) ≤ 5 [%Dem] and LOLP ≤ 5% metrics



Source: Prepared by EPE.

Chart 3 - 20: Difference in MW between cases for metrics CVaR5%(PNS) ≤ 5 [%Dem] and LOLP ≤ 5%



Source: Prepared by EPE.

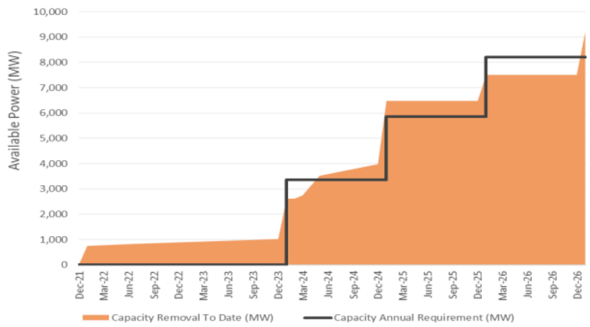
Again, comparing PDE 2031 Base Case with the operatingconstraints as proposed in this cycle and the simulation with official ones, it can be seen that when making explicit the greater water usage for the UHEs to make power available to the power system, there is an increase in the requirement, as shown in **Chart 3 - 20**. The increase occurs mainly between the months of September and February, reaching a maximum of about 12,000 MW in December 2028. These differences observed in the power system requirements will be reflected in the indicative expansion, since it is verified that the update of the operating constraints proposed in this plan leads to an advance and increase of these requirements.

Thus, additional expansion will be necessary to balance the reduction in hydro plants management.

As can be seen in the analyzes carried out, the consideration of operating constraints in hydro plants proposed in this PDE, which seek to correlate the lessons learned from the critical hydrological conditions of the last two years, makes the analysis of energy and power requirements more robust, with the trend of increase of the same given the possibility of deterioration of the power system considering severe events. This analysis also highlights the importance of the water source in the SIN to meet the demand and the need to look attentively to the expansion of the power system, the composition of future supply (including the UHEs) and the provision of services that the power system requires in the ten-year horizon.

Chart 3 - 21 compares the amount of thermal phaseout, taken in each year of the ten-year simulation, with the power capacity requirement of the SIN, presented in Graph 3-19. It can be understood, in a simplified way, that the need presented by PDE 2031 until the year 2026 occurs, mainly, due to withdrawals from these thermal power plants. Furthermore, as in the past these projects were contracted to supply the system's energy, the indication of PDE points to the possible celebration of commitments more suited to the specific power system requirements, which in this case is the supply of capacity. The challenge of new projects against existing ones, to assess what is best for the consumer in the long term, is an important step that the construction of the first LRC brought to the SIN.

Chart 3 - 21: Comparison between the thermal phaseout and the power system capacity requirement of PDE 2031



Source: Prepared by EPE.

3.4 Available Potential Resources for Expansion

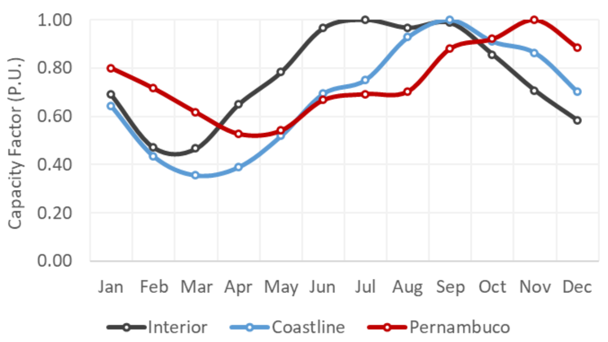
In order to cope with the growth of the load in a safe, economical way and with respect to environmental legislation, Brazil has different energy potential resources, with emphasis on renewable energy (hydro, wind, biomass and solar). The indicative supply takes into account the energy need, the cost of implementing and operating each source (including taxes and associated charges), in addition to the estimated deadlines for the start-up of the plants to be contracted, both within the scope of the ACR and the ACL .

Wind and solar photovoltaic sources have proved to be economically competitive compared to other technologies that are candidates for generation expansion. For this reason, this Plan continues to improve its representation, both in operation terms and in the costs considered, signaling for the development of these technologies in a continuous and compatible way with the needs of generation expansion of the power system and the basket of supply available to the market. On the other hand, massively expanding renewable resources in the energy supply brings challenges such as the expansion of complementary capacity, due to its limited vocation for meeting power requirements and production variability, even considering the portfolio effect between the generation complexes[16]. In PDE indicative project

[16] More information about the portfolio effect of these sources at bit.ly/FactSheetEOL and bit.ly/FactSheetFV

candidates, the energy and power contribution of these sources is estimated based on monthly factors, based on regionalized hourly data. The methodology for estimating capacity factors and generating long-term series used in this analysis is detailed in Technical Note EPE/DEE/011/2021-R1, available on EPE website. It is important to emphasize the complementarity of wind resources with a large part of Brazil's hydro resources. That is, the winds are stronger during the dry period of the year. In the Northeast region, for example, this behavior is observed in all its wind sub-regions, as shown in **Chart 3 - 22**.

Chart 3 - 22: Seasonality of Wind Power Plants in the Northeast throughout the year



Source: Prepared by EPE.

Additionally, the innovation, incorporated in PDE 2030, of the analysis of the contribution of wind and photovoltaic power together, capturing the effects of spatial dispersion and daily complementarity, is maintained. Thus, while photovoltaic alone results in a null contribution, when assessed together with wind power, the resulting power availability is greater than the individual sums of these sources[17].

Another important aspect about wind and solar photovoltaic sources is the possibility of "hybridization", that is, the joint connection of photovoltaic and wind plants, discussed for the first time in PDE 2027, as well as in other works already published by EPE in recent years. Furthermore, the recent regulation of hybrid and associated plants, through ANEEL Normative Resolution No. 954/2021, reinforces the importance of the topic. For modeling purposes, these sources are considered individually in the Plan studies, which do not affect the development of "associated" projects, which may physically and contractually share the connection infrastructure and use of the transmission system.

Still on wind and solar photovoltaic sources, PDE 2031 brings as a novelty the adoption of four levels of implementation costs, with the objective of improving the representation of the ranges of values observed in typical projects of these sources. Therefore, the costs of each of the levels were estimated from percentiles calculated from data samples from wind generation projects and solar photovoltaic plants, mainly those of participants and winners of the most recent auctions.

A reference that was used in the elaboration of the cost estimates, not only for wind and photovoltaic sources but also for the other sources that make up the energy supply basket of PDE 2031, was the report "Caderno de Preços da Geração"[18], published in August 2021 by EPE, which contains estimates and analyzes of investment values (CAPEX), operation and maintenance (O&M) costs, and unit variable cost (CVU), based on domestic and international data, for each type of source of power generation.

As in PDE 2030, offshore wind technology was considered as a candidate for expansion, with costs and assumptions related to wind turbines updated based on available data on the implementation of these projects in other countries, considering the uncertainties related to the internalization of these costs in projects that will be implemented in Brazil. With this update, there was a reduction in costs, mainly related to CAPEX, of projects being installed

[17] See Power Supply Notebooks, at https://www.epe.gov.br/sites-pt/publicacoes-dados-abertos/publicacoes/PublicacoesArquivos/publicacao-490/topico-522/PDE%202030%20-%20Avalia%C3%A7%C3%A3o%20do%20Suprimento%20de%20Pot%C3%AAncia%20no%20Sistema%20El%C3%A9trico%20e%20impactos%20da%20Covid-19%20REV.pdf

[18] Available at: https://bit.ly/cadernodeprecosepe

around the world, which reflected in a lower value adopted for PDE 2031 than in the previous study.

Photovoltaic solar technology continues its technological evolution, and this is reflected in this Ten-year Plan. The simulations of this cycle considered the use of bifacial modules, a trend seen in all large projects in the recent past (*Greener*, 2021). Compared to PDE 2030, the lifetime of the photovoltaic solar source was increased from 20 to 25 years, taking into account information from typical projects of this type of technology.

Regarding floating photovoltaic plants, the simulations have been improved, representing locations where there are R&D projects being developed. The results of these studies continue to be monitored in order to verify whether this technology will achieve competitiveness in the future. Evaluating only in terms of costs for floating photovoltaic solar technology (without considering, for example, how the charge will be for the use of the water mirror and existing transmission systems), it appears that the values can range from 18% to 25% higher than those of traditional UFVs, mainly due to the higher cost of floats, as pointed out in a study by EPE (2020) and published reports regarding this source (NREL, 2021; World Bank, 2019). As it is a new technology in Brazil, there are not enough data or studies to assess whether such a cost exists in domestic projects and what its magnitude would be, especially due to the uncertainty about the cost of operation and maintenance. Therefore, for PDE 2031, as adopted in the previous cycle, values 25% higher than the average value of a traditional photovoltaic plant, with the same useful life, were considered as a premise.

The existing potential and benefits provided by the development of small hydro plants (Small Hydroelectric Power Plants – PCH and Micro Hydroelectric Power Plants – CGH), with a vast array of projects not yet used, is also considered in PDE. The various benefits for the Brazilian electricity generation mix, such as synergies with other renewable sources (wind, biomass and photovoltaic) and, mainly, operational and storage flexibility in the short-term operational timeframe should become more evident with the implementation of the hourly price and the future creation of pay-for-capacity mechanisms.

For this reason, the Investment Decision Model includes in the list of candidates for expansion, the possibility of having typical PCH and CGH projects, available from 2024. The representation of this supply in PDE 2031 maintains the use of three levels of implementation costs, having been considered an increase in values in relation to PDE 2030, reflecting analyzes made on the information available regarding this source.

Bioelectricity, especially that from sugarcane bagasse, continues to present a competitive potential for use in the production of electricity in the SIN. Although the forecasts on the increase in sugar and ethanol production imply greater energy use of bagasse, historical data (BEN, 2019) indicate that processes are increasingly efficient, annually decreasing the demand for this input for each unit of product and, thus, the incremental surplus of bagasse that can be used in the electricity sector. For this reason, PDE presents an estimated amount as an upper limit for use in electricity generation. The profile of annual bioelectricity generation from sugarcane in Brazil is complementary to most of the hydro generation of the SIN, as the moments of lower water availability in the main plants with reservoirs in the country coincide with the harvest periods in the south of the country, the largest producing region, and peaks in bioelectricity production. This characteristic constitutes an important synergy between these generation sources in the Brazilian generation mix, which must always be considered in planning studies.

On the side of the sugar-alcohol sector, the greater diversification of sugar-energy products, with the gradual expansion of the production of bioelectricity from sugarcane bagasse, is considered as another asset of this sector, which involves the commercialization of four products: sugar, ethanol, electricity and, more recently, decarbonization credits (CBIO). With the entry into force of the National Biofuels Policy – RENOVABIO, it is expected that there will be an increase in the efficiency of sugarcane production units, raising the environmental energy efficiency score, and thus increasing the amount of CBIO that can be commercialized. In this aspect, bioelectricity is consolidated with significant potential for the domestic energy portfolio.

The variety of products commercialized by this sector brings different business models and strategies to be deployed. In other words, different cost structures depend on the dynamic of energy, sugar and ethanol markets. PDE studies search continuously to enhance the representation of the bioelectricity in its considerations. For the estimation of the costs associated with the thermoelectric source of sugarcane bagasse biomass, the same procedure adopted for wind, solar photovoltaic and PCH sources was carried out, and levels of values were stipulated, in order to cover the ranges of costs that are observed in projects to generate this resource. Thus, in addition to bringing greater refinement to the representation of this technology, the retrofit potential of end-of-life projects are implicitly incorporated within the defined ranges. It is important to mention that the interactions with the sugar-alcohol stakeholders can bring improvements to the next PDE publications.

In addition to bagasse, emphasis should be given to the potential of biogas. This energy commodity is rich in methane, whose calorific value is close to that of natural gas. Thus, one of the possible routes of its use is in aeroderivative turbines or in engines for electric generation. There are several substrates that can be used for biogas production, and biodigesters for the treatment of organic waste from the agro-industrial sector have the greatest potential in the domestic scenario, in addition to animal and urban waste. For this reason, PDE 2031 continues to explicitly represent this supply in the basket of candidate projects for central expansion planning. Among the various possibilities for obtaining biogas, the technology used in energy simulations represents the typical characteristics of the processes in the sugar-energy sector, which, among the centralized generation options, is one of the most competitive.

The energy use of urban solid waste (RSU, Portuguese acronym) through incineration is being considered to represent this resource in PDE 2031, as an energy and environmental policy guideline indicated by the MME, with the fraction of this resource currently used corresponding to only part of its potential.

Interministerial Ordinance No. 274, of April 30, 2019[19], regulates the recovery of urban solid waste referenced in the National Solid Waste Policy (PNRS), established by Law No. 12,305, of August 2, 2010[20]. Although it is a form of final destination for RSU widely used in Europe and in some Asian countries, in Brazil this technological route is still little explored in its entirety, which requires high investment costs for its implementation and maintenance and, consequently, makes the uncompetitive electrical generation cost. However, it is important to emphasize the positive externalities associated with the RSU incineration process, which are mentioned in the PNRS, such as, for example, the solution for reducing the volume and mass of waste in sanitary landfills, in addition to the complete destruction of hazardous organic waste, motivation for transversal action between the Ministry of Mines and Energy, Ministry of Regional Development and the Ministry of Environment. It is worth mentioning that this joint movement is also supported by Presidential Decree No. 10,117, of December 19, 2019, which deals with the qualification of projects to expand the energy recovery capacity of urban solid waste within the scope of the Investment Partnership Program of the Presidency of the Republic. As with other sources, such as offshore wind and floating photovoltaic, the costs related to the energy use of RSU were estimated taking into account references from international projects, since large-scale projects with this type of technology have not yet been implemented in Brazil.

[19] Available at: https://www.in.gov.br/en/web/dou/-/portaria-interministerial-n%C2%BA-274-de-30-de-abril-de-2019-86235505

[20] Available at: http://www.planalto.gov.br/ccivil_03/_ato2007-2010/2010/lei/l12305.htm

PDE also presents thermoelectric projects provides as an alternative for power generation supply by using forest biomass. Since the record participation of wood chip biomass projects in the A-5 auction of 2016, investments in this type of generation in the regulated market have shown a gradual reduction, with the last sale of new energy in the SIN taking place in 2017[21], despite the great potential in the country. Wood chip biomass projects adopt the concept of energy forests using eucalyptus biomass, with a high degree of domestic content in the implementation of the project, as well as operating costs referenced to local price indices. In addition, the option of entrepreneurs for plants with reduced installed capacity (less than 100 MW), close to biomass production areas, allows for a reduction in logistical costs with fuel, in addition to allowing access to strategic locations, close to load centers.

The other forms of biomass power generation are not yet 31xplicitly represented in the central generation mix planning. However, they have shown considerable growth potential and are already represented in distributed generation, mentioned in Chapter 9 – Energy Efficiency and Distributed Generation.

With regard to natural gas, this has been presented as the main fossil fuel for expansion of power generation in the last PDEs. In addition to imported LNG, the fuel most commonly used in new plants without compulsory (or flexible) power generation, the development of pre-salt oil reserves and the new discoveries of post-salt basins, such as in Sergipe, have significantly increased the supply of domestic natural gas. This resource, with abundant supplies, could significantly contribute to the operational safety of the Brazilian electricity generation mix in the ten-year timeframe, whose contribution depth will depend on the final price of natural gas delivered to the thermal plant. It is also expected that regulatory improvements resulting from the New Market for Natural Gas will favor new business models, including flexible fuel supply to thermal power plants. The role of the natural gas trader or the development of new modes of transport contracting, in a competitive environment, can promote the best use of the existing infrastructure and the signing of contracts to meet personalized consumption patterns, more adhering to the future requirements of the power sector, especially to capacity.

Seeking to represent the sources in PDE energy supply basket in the best way and increasingly contribute to important discussions involving the integration of the gas and electricity sectors, the following options were considered as candidates for generation expansion to the natural gas thermal power:

- Plants with variable cost referenced to LNG, in combined cycle, and with two possibilities of operation: (i) fully flexible (no compulsory generation); (ii) with a (seasonal) inflexibility factor of 30%.
- Plants with variable cost referenced to LNG, in a simple cycle, with totally flexible operation (no compulsory generation).
- Combined cycle plants using domestic gas, with lower fuel prices and with two operating alternatives: (i) with an inflexibility factor (flat) of 30%; (ii) totally inflexible, that is, with compulsory generation.
- Retrofit plants, for the use of part of the infrastructure of projects at the end of their contractual useful life, with CAPEX of around 40%[22] of a new plant, with variable cost referenced to LNG and with totally flexible operation.

It is worth noting that the main difference between the thermal power plants that are candidates for LNG and those with contracts with traders lies on the structure of fixed and variable costs associated with the fuel supply. In the first case, part of the costs that are fixed and assumed by the generator, such as the availability of the

[21] For more details, see bit.ly/UTEbiomassa.

[22] The actual cost for retrofitting and/or upgrading existing plants varies from plant to plant, depending on technical/operating conditions and cost structures. For an accurate analysis, a case-by-case evaluation would be necessary. However, the approach adopted in PDE does not have this objective, but only to estimate, in general, the amount that can be attractive for the SIN.

regasification service. In the second case, practically all the costs with the natural gas infrastructure and with the molecule are assumed by the gas trader or distributor, which passes them on to the thermal generator in the form of a variable cost of supplying natural gas.

The six natural gas thermal power generation business models available for the expansion allow the feasibility of different electrical power system future configurations. The thermal plants that use domestic natural gas and the LNG thermal plants with an inflexibility factor tend to be more competitive in meeting the combined energy and power requirements of the electrical power system. In this way, they compete directly with other solutions for the generation expansion oriented to energy supply, such as wind, photovoltaic and hydro plants, in addition to competing with flexible plants in the supply of capacity. On the other hand, plants without compulsory generation (flexible), both new and retrofitted, tend to compete in meeting the capacity requirement, with the energy requirement being met by other solutions, mainly renewable ones. Thus, the level of insertion of each of these natural gas thermal power business models is largely explained by the competitiveness of the relationship between inflexibility, seasonality of production, fixed costs and variable fuel costs, intrinsic to each commercial approach.

All thermal supply candidate was represented considering forecasts of fuel price variation. Fixed and variable costs were estimated for each technology and operating modality.

Regarding coal in the supply of electricity, especially that extracted from mines in the southern region of Brazil, its discussion involves several sectors of the economy and must be treated with great attention. All impacts, whether positive or negative, as well as benefits and challenges must be considered, along with gains in electro-energy security and economic-financial viability, to support the decisions to be taken. Contributing to this discussion, from an economic point of view for the electricity sector, PDE 2031 places domestic mineral coal as a candidate for expansion in two ways. For the plants currently in operation, which have the CDE subsidy[23], their economic attractiveness was assessed, from 2027, considering the possibility of modernization or retrofit, and the CVU incorporating the costs of the CDE[24]. New plants are also considered candidates for expansion, more modern and efficient, but with a higher implementation cost than the retrofit. It should be noted, however, that there are several challenges for investing in new plants, especially with regard to the financing conditions of these projects, which, ultimately, lead to higher total costs.

Additionally, it is import to mention the consideration of the entry into commercial operation of Angra 3, which represents the nuclear expansion in the ten-year horizon, together with a new plant considered as an energy policy. The attributes of generation reliability, high capacity factor and free of greenhouse gas emissions, make this technology an option in the Brazilian electricity generation mix. The country is also privileged in the supply of this fuel, with large uranium reserves, strategic territorial environments for the allocation of plants, as well as complete mastery of all the technology of the nuclear fuel cycle, from mining to the assembly of the fuel element. It is also worth mentioning the technical staff of people with successful experience in the operation and maintenance of Angra 1 and 2 plants, as well as teaching and research centers in the nuclear area. It is important to highlight the investments needed to extend the useful life of Angra 1 for another 20 years in the ten-year timeframe (expected to extend its operation until 2044). Besides, in order to make the energy policy guideline of this PDE 2031 viable, with regard to the new nuclear plant, studies and preparatory measures for the development of suitable projects from an economic-

[23] Of the existing domestic coal complex, only UTE Pampa Sul does not benefit from the CDE.

[24] The assumption adopted considered the current CVU of the plants in this condition added to the amounts spent by the CDE in 2019, as published by the CCEE.

financial,engineering and socio-environmental point of view are expected to be carried out in the coming years, in line with what was presented in box 3.5 of PDE 2029 and in box 3.7 of PDE 2030. Finally, it is worth remembering that more information about the expansion expectations of this technology is available in the PNE 2050.

In addition to the already mentioned natural gas thermal plants, PDE is, at each cycle, improving the modeling of specific technologies to meet the power complementation of the system. Storage technologies[25], such as pumped hydro plants[26] and batteries[27], have already been explicitly addressed since PDE 2026. Despite being a simplified modeling, which still does not guarantee the comparison between the types of service of each one, the representation used already allows to identify possible tendencies of future operation, in which the existence of these resources in the power system can reduce the operation costs in the peak demand times, as well as Demand Response programs.

The costs inherent to storage technologies are strongly related to the type of operation and application of the projects, as described in the Generation Price Book (2021). For example, among the parameters that have a great influence on the costs related to the set of batteries to be deployed is the number of hours of expected storage. According to the analyzed studies, there is an international trend of scale gains for CAPEX and reduction of O&M costs as the duration of energy storage increases. As verified for the offshore wind, a reduction in battery costs was observed over the last few years. This resulted in a lower cost assumption than the one adopted in PDE 2030, even though there are still uncertainties associated with these values in the implementation of projects in Brazil, mainly related to internalization costs.

Another challenge in considering storage systems is their representation in models. Firstly, due to the previous definition of a fixed amount of storage hours, while the systems can have different sizes, depending on the application. Second, due to the time scale considered in the simulations, which does not allow capturing, for example, the benefit that batteries have, such as the instantaneous response and the charging and discharging capacity considering smaller timeframes, minutes for example. Therefore, constant methodological improvement in planning is necessary, in order to capture the potential benefits of each generation technology.

The PDE 2031 brings, again, in the reference scenario, options for demand response and modernization with the expansion of hydro plants. The modernization and repowering of the existing hydroelectric complex represents significant potential, an increase of up to 11,000 MW of the potential listed in NT EPE-DEE-088/2019-r0, to be explored in the coming years, as highlighted since PDE2029, this solution being an opportunity to leverage the benefits of hydro plants already operating in the power system. The aging of the plants and the need to reform their assets was noticed by some players who started implementing measures in their units, highlighting, in 2021, investments in the plants of Sobradinho, Paulo Afonso IV and São Simão. It is noteworthy that the number of plants and the amount of capacity and energy involved, as well as the incremental achievable, should be greater when the remuneration mechanisms that value the different services provided by the technologies, as has been discussed in the scope of the Electric Sector Modernization, are in force. Therefore, the expectation is that the remuneration mechanisms are stablished accordingly, the plant owners could address their investments to possible hydro retrofit projects.

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[25] It is worth noting that these technologies still lack legal and regulatory instruments that establish the way in which they are contracted, the business models and the remuneration of the benefits generated as a result of their insertion in the SEB, which is under discussion within the scope of the regulatory agenda of the Aneel (Socket 011/2020).

[26] See bit.ly/UHR-EPE

[27] See bit.ly/bateriasEPE

Demand response (DR) for economic incentives is one of the expansion options in PDE reference case, competing on equal terms with other available generation technologies.

And to estimate the fixed and variable costs of this mechanism, the work “Industrial demand response and its influence on the formation of short-term prices in the electricity market: a proposal” (Soares, 2017) was used. With this methodology, it is possible to calculate the minimum values that potential participants can make the proposals in future DR mechanisms. And to better represent these proposals, PDE 2031 brings as a novelty the adoption of three levels of implementation costs, with the objective of improving the representation of the different industrial classes that can participate in this DR mechanism.

Likewise, distinct potentials were estimated for these three groups of demand response participants for the four subsystems. The estimate uses a top-down approach, based on the physical production scenario, specific consumption and flexibility assumptions (Gils, 2014) by selected industrial sector.

The DR potential in the ten-year timeframe was estimated at 3,000 MW. It is expected that, with the dynamization of this sector in Brazil, this potential will grow, following the profile of this mechanism in meeting the demand in a simple and safe way, competing with other conventional generation technologies.

The EPE has been exploring this important topic and new studies are still under development, such as the estimation of potential by industrial sectors to participate in demand response programs in Brazil, as well as improving the estimation of fixed and variable costs of this mechanism.

Regarding the program used in 2021, it was a good Federal Program to capture the behavior of industrial consumers under this mechanism. Despite the robust supply indicated by consumers, the program was suspended in the same year. This program was important to show the sector that the demand response is well accepted in the industrial sector, with a contribution of about 600MW.h/h, even in a scenario of economic recovery. The adoption of clear rules and the maintenance of the mechanism, making it perennial in the SIN, will make it possible for the RD to become an important process for meeting the demand of the SIN.

The existence of all these explicit options in the MDI (generation sources, storage technologies, UHE expansion and demand response) allows discussing different ways of meeting power system requirements and identifying the service provided by each technologies. More than properly valuing the attribute of each source, it is up to the expansion plan to present, quantitatively, the needs of the power system and transform them into services to be commercialized. Once these needs are clearly characterized, the market will be able to present the most efficient solutions for the service, either through the expansion of supply or in solutions on the demand side. The MDI, like any mathematical model, seeks to represent all these possibilities through approximations. The process of methodological evolution is continuous, and the contribution of all players in the incorporation of improvements is essential so that each PDE cycle brings improvements.

In order to expand the limits of exchanges between the subsystems, estimates of investment costs for each interconnection and the minimum dates for entry into operation were considered according to the stages of the studies necessary for the implementation of each transmission project. In addition, the budgets of the various generation projects include the costs of connecting to the central grid. Thus, the results obtained using the MDI already take into account estimates of transmission expansion needs, which means that the investment decision model produces G + T expansion, albeit in a simplified way.

Table 3 - 2 and **Table 3 - 4** present, respectively, cost information and a summary[28] of the modeling considerations of the available resources for the expansion of the supply in PDE 2031.

Finally, PDE has been addressing the importance, for Brazil and the region, of energy integration with neighboring countries. The unprecedented Brazilian hydrological condition not only demanded new local measures to guarantee supply, but also led to the opening of energy exchanges at unprecedented levels[29]. Data from CAMMESA, ADME and ONS indicate that Brazilian imports of electricity from Argentina and Uruguay amounted to approximately 6,000 GWh from January to November 2021. Considering this import as a generation plant, energy integration would represent, in this case, a plant of 750MW.h/h, considering the total hours per month. The circumstances that Brazil lived through confirmed that integration contributes to lessening moments of scarcity and providing security of supply via energy generation from plants on the other side of borders. The financial volumes transacted also allow us to suppose that an emergency and transitory measure, if converted into free exchange for the fulfillment of contracts, will bring, in addition to the optimization of the use of resources, new business in the area and benefit for the entire region.

3.4.1 HYDROGEN AND ITS USE FOR THE ELECTRICITY SECTOR

Discussions on the production and use of hydrogen have recently gained considerable relevance in Brazil, especially with regard to production for export. Several projects were announced throughout 2021 in the ports of Pecém/CE, SUAPE/PE and Açu/RJ with a focus on the global market (all still in the technical and economic feasibility study phase). It is not by chance that this PDE has chapter 12 dedicated to the topic, addressing the multiple production routes and uses of this commodity. In this section, it is important to point out the impacts that the potential hydrogen industry could have on the centralized supply of electricity.

The countries' energy and climate policies have sought solutions for sectors where carbon emissions are difficult to be reduced. Within the scope of green economy recovery policies, originally led by the European Union, hydrogen produced from the electrolysis of water using renewable sources, also called green hydrogen, was identified as a strategic substitute for fossil fuels to obtain long-term clean energy for hard-to-attenuate sectors and as an energy storage technology to deal with the increased insertion of variable renewable energy in electrical power systems. The expected advance in global demand for green hydrogen places Brazil in the spotlight as a potential international supplier, given the local wealth of renewable resources and consequent generation competitiveness, especially wind and photovoltaic sources.

Considering that the production process of green hydrogen, characterized by the electrolysis of water, is electro-intensive, there may be competition for renewable resources for the production of electricity between this industry and the SIN. As a consequence, demand will further drive the expansion of wind and photovoltaic sources. Two determining aspects for the economy of this industry in Brazil are the scale of production and the cost of transporting hydrogen (either in pure form, or in the form of ammonia or other products), from Brazil to consumer markets, with emphasis on the Europe.

If, on the one hand, green hydrogen could impact the demand for electricity, on the other hand, it could be a primary energy alternative for the electricity supply, either as a fuel for thermal power generation or in fuel cell generation. A possible role

[28] More details can be obtained from PDE 2031 Cost Parameters Notebook.

[29] SÍNTESIS DEL MERCADO ELÉCTRICO MAYORISTA DE LA REPÚBLICA ARGENTINA, AÑO XXI Nº 249.

for hydrogen in centralized generation would be energy storage for greater use of non-controllable renewable sources. In times of excess renewable production, it would be possible to allocate part of the electricity to the production of hydrogen, which could then be stored and used in electricity generation in times of scarcity, contributing to greater flexibility in the electrical power system.

In this sense, it is worth highlighting the ongoing research and development projects developed by Furnas and EDP Brazil. Both aim at production from the electrolysis of water, using photovoltaic solar energy, but for different applications. The first seeks to assess the use of hydrogen for energy storage and use in a fuel cell, together with UHE Itumbiara, which can bring synergies and optimization of hydro power generation, including on a seasonal scale. The second aims to use hydrogen/ammonia partially replacing coal in thermal power generation, reducing emissions.

It is also important mention the example of the Angra I and II nuclear plants, which have a hydrogen production plant with a capacity of 150 kg/day, intended for internal applications to ensure the integrity of equipment. According to information from Electronuclear, with small adjustments, the plant could produce up to 300 kg/day and, with the entry into commercial operation of Angra III, up to 500 kg/day. The hydrogen currently produced and used in power plants is discarded into the atmosphere. To be commercialized, the gas will have to go through a purification process.

These and other projects demonstrate the diversity of possible applications and business models, in addition to bringing greater knowledge about the challenges and impacts of the production, use and transport of hydrogen and its products.

Currently, the cost of hydrogen produced from water electrolysis, using renewable sources, is estimated to be between 3.0 and 8.0 US$/kg in the international market (IEA, 2021), while in Brazil, the cost would be between 2.2 and 5.2 US$/kg, if energy from wind or photovoltaic plants is considered (DKTI, 2021). Even considering the most optimistic cost reduction forecasts on the timeframe of this PDE, it reaches 1.2 US$/kg (BNEF, 2020; IRENA, 2019; DOE, 2021), comparable to blue hydrogen production costs (IEA, 2021). On an energy basis, this cost corresponds to 10.6 US$/MMBtu, whose relative competitiveness depends on the long-term price expectations of natural gas or other energy sources. Thus, it appears that in Brazil, the supply of hydrogen for electricity generation is not yet fully mature over the ten-year timeframe. Therefore, its penetration in the domestic market will depend on hydrogen promotion policies (MME, 2021), as well as restriction or pricing of greenhouse gas emissions, with greater opportunities in sectors that are difficult to be decarbonized.

Therefore, the promising hydrogen market may have significant repercussions on the electric energy market, either by boosting new renewable generation projects, or as an energy vector for storage and generation. In any case, ongoing projects will also impact transmission planning, whether as load or as generation, given their magnitude, and it is essential that developers previously assess the conditions of access to SIN facilities. In addition, the formalization of consultations or requests for access with the System Operator is important to bring greater visibility to the projects and to allow their adequate consideration in the transmission expansion planning studies.

Table 3 - 2: Summary of Cost Considerations for MDI Technologies

Plant Type	Min and max CAPEX ranges [BRL/kW]	Reference CAPEX, without IDC [BRL/kW]	O&M [BRL/kW/year]	Levies/Taxes [BRL/kW/year]	CVU [BRL/MWh]
Storage – Batteries	5,000 to 9,800	6200	60	270	-
Biogas - Sugar-ethanol waste	3,000 to 10,000	8000	480	205	-
Biomass - Sugarcane Bagasse (1)	2000 to 5500	3000	90	140	-
Biomass - Sugarcane Bagasse (2)		4000	90	145	-
Biomass - Sugarcane Bagasse (3)		5000	90	155	-
Biomass - Woodchips	4,000 to 8,000	6000	120	170	200
Domestic Coal	8,000 to 13,500	10300	160	595	130
Onshore Wind (1)	3,200 to 5,500	3800	90	145	-
Onshore Wind (2)		4200	90	150	-
Onshore Wind (3)		4500	90	150	-
Onshore Wind (4)		5000	90	155	-
Offshore Wind	9,800 to 18,600	10300	360	415	-
Natural Gas (Combined Cycle) 100% Flexible	3,400 to 5,900 (only UTE)	4300	80 (UTE) + 80 (Regas)	250	385
Natural Gas (Combined Cycle) 30% Inflexible (Seasonal)	3,400 to 5,900 (only UTE)	4300	80 (UTE) + 80 (Regas)	250	303
Natural Gas (Open Cycle) 100% Flexible	2,900 to 4,700	3600	80 (UTE)	220	600
Natural Gas – Domestic (Comb. C) 30% to 70% Inflexible (Flat)	3,400 to 5,900 (only UTE)	5300	150	280	259
Natural Gas – Domestic (Comb. C) 100% Inflexible (Flat)	3,400 to 5,900 (only UTE)	5300	150	280	215
Hydropower plants	Variable *(Table 3-3)*	Variable *(Table 3-3)*	30 to 50	480 to 700	-
Pumped Hydropower Plants	2,400 to 12,000	6500	70	330	-
Nuclear	22,000 to 29,400	25800	520	660	47
PCH (1)	3,500 to 11,500	6000	90	140	-
PCH (2)		8000	90	150	-
PCH (3)		11000	90	180	-
RSU (Urban Solid Waste Incineration)	14,500 to 27,000	23000	920	845	-
Solar Photovoltaic (1)	2,500 to 5,000	2800	50	130	-
Solar Photovoltaic (2)		3300	50	135	-
Solar Photovoltaic (3)		3800	50	140	-
Solar Photovoltaic (4)		4500	50	145	-
Floating Photovoltaic	3,800 to 6,500	5000	65	150	-
HPP Upgrading	1,150 to 2,250	-	50	300	-
Demand Response	-	-	39 - 151	5	464 – 1,824

Source: EPE (2021) – No. EPE-DEE-RE-089/2021-r0

Table 3 - 3: MDI's Hydro Power Plant Candidates

EarliestEntry Date Into Operation	UHE	Capacity (MW)	River	STATE	CAPEX Including IDC (BRL/kW)	Status of Feasibility and Environmental Studies (EVTE and EIA/Rima)
2028	Apertados	139	Piquiri	PR	10697.63	EVTE and EIA/Rima delivered. Public Hearings performed.
2028	Castanheira (ARN-120)	140	Arinos	MT	14438.35	EVTE,EIA/Rima and ECI delivered.
2028	Ercilândia	87.1	Piquiri	PR	12413.85	EVTE and EIA/Rima delivered. Public Hearings performed.
2028	Telêmaco Borba	118	Tibagi	PR	9168.89	EVTE and EIA/Rima delivered. Public Hearings performed. ECI under preparation.
2028	Tabajara	400	Ji-Paraná	RO	11364.22	EVTE and EIA/Rima and ECI delivered. Complementing in EIA and in ECI required.
2029	Formoso	342	São Francisco	MG	12667.21	EVTE and EIA ongoing
2031	Bem Querer (J1A)	650	Branco	RR	10564.81	EVTE under review. EIA and ECI ongoing.
2031	Santo Antônio	84.3	Chapecó	SC	8044.15	EVTE delivered. Waiting reclassification of UHE at ANEEL.
	TOTAL	**1960.4**				

Source: Prepared by EPE

Table 3 - 4: Available Resources for Generation Expansion

Source	Available as of	How contribution is defined		
		MDI	NEWAVE	Capacity
Hydro plants	2026*	Energy and capacity series, obtained from simulation in the SUISHI model, using historical inflow series	NEWAVE hydrothermal simulation using equivalent energy reservoirs and 2,000 synthetic inflow series	Maximum capacity calculation available for all historical series using NT EPE-DEE-NT-035-r2/2017 methodology
Pumped Hydro Plants	2026	Energy stored in moments of excess discounted from losses resulting from the storage and discharge process	Load increment to represent the load	Increase in the capacity available for meeting peak demand
PCH and CGH	2026	Defined with monthly discretization from historical generation data		
Offshore Wind**	2027	Use of reanalysis data for points along the Brazilian coast, applying the same methodology used for the onshore wind resource contribution		
Onshore wind**	2026	Energy: from auction-enabled project data. Contribution to load levels: built from the Anemometric Measurement Monitoring System (AMA) database.		P95 of the expected generation for all hours of the month, alone and together
Solar photovoltaic**	2026	Energy: from auction-enabled project data. Contribution to load levels: built from simulations with satellite data.		
Floating Solar Photovoltaic**	2026	Estimation from simulations, with satellite database, considering fixed systems and reduction of operating temperature of the modules		
Thermal Power Plants for Sugar-Energy Biomass	2026	Defined with monthly discretization from historical generation data thermal power plants that fit the premise described in section 3.2.		
RSU Thermal power plants (Urban Solid Waste Incineration)	2026	Constant production throughout the year		
Biogas thermal power plants (Sugar-ethanol waste)	2026	Seasonality defined from the processes of the sugar-energy sector and the possibility of storing the commodity.		
Forest Biomass Thermal power Plants	2026	Dispatch defined by the optimization model, from the defined CVUs		Available Power
Natural Gas Thermal power plants	2026			
Coal Thermal power plants	2026			
Lithium-Ion Batteries	2026	Energy stored in moments of excess discounted from losses resulting from the storage and discharge process	Load increment to represent the load	Increase in the power available for meeting peak demand

Source: prepared by EPE

Notes: (*) Each project has its date estimated individually, as shown in Table 3-3.

(**) See Technical Note n. EPE/DEE/011/2021 on methodology and assumptions for obtaining generation data from wind and photovoltaic plants connected to the centralized power system in planning studies

Box 3 - 4: Outlook for Storage in the SIN and Opportunities for Inserting Pumped-Hydro

In Brazil, the large reservoirs of the UHE built mainly in the 1960s and 1990s are responsible for energy storage in the SIN, being used mainly for the production of energy in dry periods, in addition to providing capacity and flexibility for the operation of the power system under the varied conditions of demand and availability of generation and transmission asset.

However, despite the increase in the load, the Ten-year Plans point to reduced hydro power expansion in the coming years, especially in plants with monthly regularization capacity. Furthermore, the use of existing reservoirs has been limited by unfavorable hydrological conditions, operating hydraulic constraints and multiple uses of water.

In this context, Pumped Hydroelectric Power Plants (UHR) can represent an important resource for the future, since they have attributes compatible with the growing needs of the SIN. This characteristic has motivated the studies developed by EPE related to technology such as those indicated in the Technical Notes[30] EPE-DEE-NT-006/2019-r0 and EPE/DEE/SEG/013/2021, in addition to the participation and monitoring of projects conducted by other institutions.

The possible services that UHRs can provide include:

- Instant capacity;
- Flexibility to vary the generation and load monitoring;
- Power reserve for frequency control;
- Reactive control (voltage control);
- Postponement of investment in transmission assets;
- Provision of inertia;
- Reduction of cycles in thermoelectric units;
- Self-reestablishment.

Despite the potential technical and economic benefits, international experience shows that the regulatory conditions and business models present in different energy markets are still not adequate to encourage the construction of new plants. Considering the intrinsic peculiarities of this type of project, such as the non-existence of products that remunerate the different benefits offered, the unpredictability of revenue incompatible with the large volume of investment, the lack of a long-term economic signal compatible with the supply time , the lack of definition regarding the regulatory framework, among other aspects, there are non-technical barriers that discourage the insertion of these projects in the markets to better take advantage of their benefits.

Since November 2020, EPE has represented Brazil and contributed to the "International Forum on Pumped Storage Hydropower" (IFPSH), a Federal Program that has more than 13 countries and more than 70 organizations. This forum aims to exchange experiences, best practices and recommendations to guide the development of this technology in energy markets. In September 2021, the main products were published[31], covering aspects related to sustainability, costs, capabilities, policies and market structures.

Although many of the solutions presented are associated with the particularities of each country, the experiences and recommendations constitute a starting point for a better understanding of the potential benefits, risks and obstacles, and can be the object of more detailed evaluations and subsidize the formulation and improvement of the design of market and aspects related to energy planning in Brazil.

[30] Available at:
https://www.epe.gov.br/pt/publicacoes-dados-abertos/publicacoes/nt-006-2019-estudos-de-inventario-de-usinas-hidreleticas-reversiveis
https://www.epe.gov.br/pt/publicacoes-dados-abertos/publicacoes/ferramentas-geouhr-i-e-geouhr-ii
https://www.epe.gov.br/pt/imprensa/noticias/epe-publica-nota-tecnica-usinas-hidreletricas-reversiveis-uhr-desafios-para-insercao-em-mercados-de-energia-eletrica-
[31] Available at:
https://pumped-storage-forum.hydropower.org/resources/publications

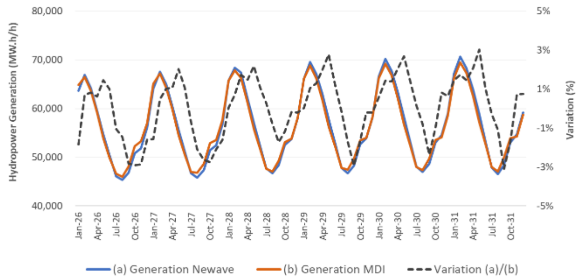
3.5 Free Scenario

Assessing the power system requirements needed by 2031 is an important step in the planning process. Thus, a set of possibilities can be opened for the composition of the indicative expansion of the power system. One of these possible future scenarios is the so-called “Free Scenario”, which aims to present analyzes if the expansion were based on a minimum cost perspective, before the adoption of the representations in the mathematical model described in section 3-6. Such evaluation is presented since PDE 2026 publication and it is a cost reference in order to compare power system expansion alternatives in the optimization model.

In order to use the result of the Free Scenario to reflect the market perspective of expansion, it must not be influenced by energy policies. Therefore, the delimitations that translate the policy guidelines that will be applied in the Reference Scenario, and described in section 3-6, are not applied to the Free Scenario. The only restrictions considered refer to the available resources, and their respective limits, for each source and the costs associated with the technologies.

For the elaboration of the Free Scenario, all the simulation stages shown in **Figure 3 - 2**, located in the item that describes the methodology for elaborating the ten-year planning, are covered. As the methodology uses different and coupled mathematical models. This means that, even though MDI has a more simplified mathematical modeling of SIN operation than Newave, both models must result in compatible generation variables. In **Chart 3 - 23**, it can be seen that the average monthly hydro generation for the period between 2026 and 2031, the main interval for indications of expansion of this PDE, presents synchronized values both in time and in magnitude. The differences between both results range from -3% to 3% for the period. With this, the coupling required by planning is guaranteed, and it is ensured that investment decisions are based on operating perspectives that adhere to what the operation model simulates.

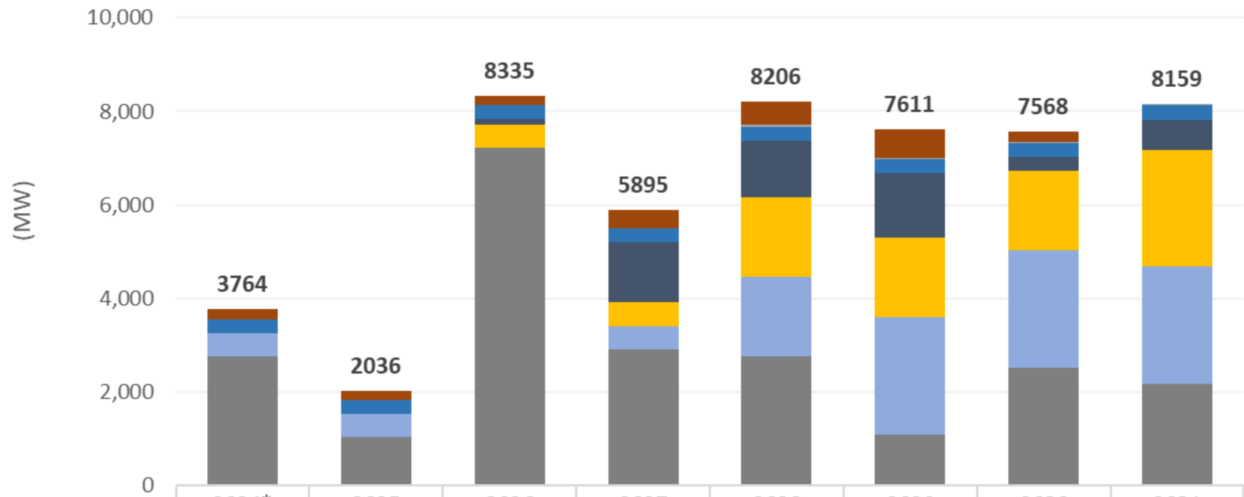
Chart 3 - 23: Coupling between MDI and Newave models through the average monthly Hydro Generation



Source: Prepared by EPE.

As a result, as shown in **Graph 3 – 24**, the “Free Scenario” indicates that the optimal expansion from a purely market perspective is essentially composed of renewable sources with a contribution to energy, being complemented, especially to meet the capacity supply, by thermal power plants without compulsory generation, as well as demand response and UHE modernization, which are competitive options for this function.

Chart 3 - 24: Generation Expansion Indicative based on Free Scenario



	2024*	2025	2026	2027	2028	2029	2030	2031
Total	3764	2036	8335	5895	8206	7611	7568	8159
Demand Response	200	200	200	400	500	600	211	0
Biomass	0	0	0	0	35	35	35	35
PCH + CGH	300	300	300	300	300	300	300	300
Hydro	0	0	121	1280	1214	1381	302	650
Solar	0	0	500	500	1700	1700	1700	2500
Wind	500	500	0	500	1700	2500	2500	2500
Flexible UTE	2764	1036	7214	2915	2757	1095	2520	2174

Source: Prepared by EPE.

Note: The indicative expansion in 2024 accumulates eventual decisions of the MDI for the maintenance of existing thermal power plants that end their contracts before that date.

The high indicative expansion for capacity supply in 2026 is a reflection of the disregard of thermal power plants at the end of the contract as well as the new representation of the operating constraints of the UHE. Part of this nomination was already contracted in the first Capacity Reserve Auction[32].

The thermals of this indicative expansion correspond to new fully flexible projects and the retrofitting of part of the existing thermal plants that were removed from the Base Case. Even though such projects have the main role of guaranteeing the fulfillment of peak demand, these technologies will also be available to add energy to the power system in critical scenarios, albeit with a lower probability of occurrence.

Considering the addiction of power to the SIN, the modernization with expansion of existing hydro plants again proves to be a viable alternative for the expansion, totaling 4,300 MW. After a break of indication of new hydro projects in the previous PDE context, the Free Scenario brings the indication of the Bem Querer hydro plant[33] as a participant in the indicative expansion, with a perspective of entry in

[32] It is worth remembering that the result of the first LRC was not considered in PDE 2031 simulations due to the reference date of this plan.

[33] It is also worth noting that UHE Tabajara obtained authorization to hold public hearings. Depending on how its licensing process is developed, this plant may participate in energy auctions still on the timeframe of this PDE.

the year 2031. The plant, which is located in Rio Branco, has 650 MW of installed capacity and is an attractive option for supplying the SIN due to the behavior of its hydrological regime. As shown by the seasonality of the SIN energy requirement, presented in **Chart 3 - 17**, it is in the dry period of the hydrographic basins where the largest accumulation reservoirs of the SIN are located that the greatest needs of the power system occur. The complementary seasonality of UHE Bem Querer in relation to other regions makes this hydro plant an important resource to meet the requirements of the power system.

The new proposed representation of water constraints in this PDE, making the simulation more adherent to the real-time operation, led to an increase in the energy requirement of the power system, as shown above, which was reflected in the energy expansion for the Free Scenario, compared to past plans. The larger requirement, resulting in larger generation expansion, led, in addition to the indication of the Bem Querer hydro plant, to a significant increase in photovoltaic and wind power plants, to compensate for the higher energy expenditure of the UHE to meet the power system requirements.

Another important aspect that this PDE 2031 result presents is the impact of considering different cost ranges for wind and photovoltaic plants. This new modeling made the MDI reflect the intersection and similarity of prices that these technologies have shown in energy auctions and commercialization in the deregulated market. In previous PDE publications, the cost for expansion was defined by only a single representative value for each technology, wind and solar. This led the model to choose only one option, making it necessary to limit maximum and minimum values per source so that the generation mix reflects any diversification. In PDE 2031, reflecting the diverse range of wind and solar costs, the mathematical model itself starts to optimize the expansion utilizing proportions of these different technologies. In addition to making it more adherent to what is being done, the representation by cost ranges explains how much and how the different characteristics meet the needs of the power system, bringing more information about the two most competitive options on the energy requirement.

When analyzing the period after the ten-year timeframe, between 2032 and 2036, the MDI maintains the expansion profile of previous years. With the depletion of the potential available for the lower cost ranges, the model maintains the renewable expansion with an indication of the third more expensive range of photovoltaic costs and the fourth range for wind. In addition to reinforcing the gains obtained with the new cost modeling for candidate plants, this result also points to the competitiveness of these technologies, even considering the existing dispersion in the vast domestic potential. Power complementation in this timeframe basically takes place through thermal power plants without compulsory generation, since all available potential for UHE expansion and demand response are chosen in the ten-year period. It is clear, therefore, the importance of further studies to define, more and more precisely, how much these technologies can add to the SIN.

The results of the indicative expansion of the Free Scenario show total investment values of BRL 173.5 billion in the period from 2023 to 2031. To carry out the operation of this forecasted power system, a total of BRL 93 billion would be needed[34].

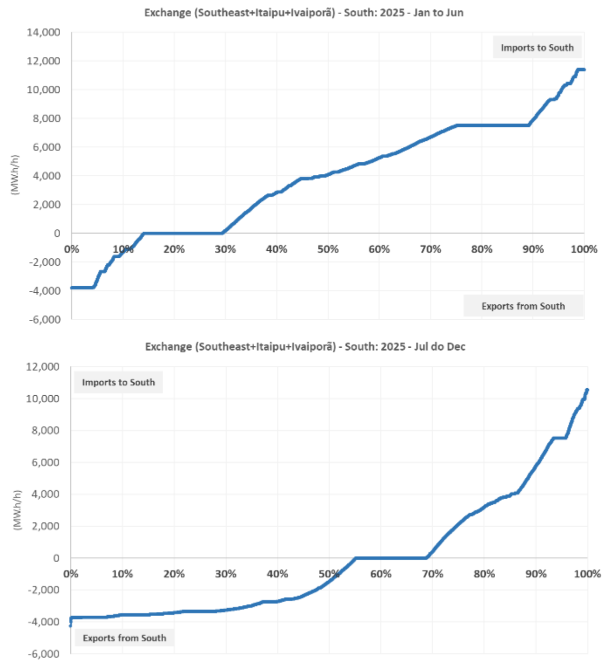
Challenging circumstances for the operation, such as the recent scenario of water scarcity, especially in the Southeast and South regions of the country, make the transmission systems and local thermal resources more used to close the balance of peak demand. Therefore, the transmission reinforcements planned to expand the interconnection capacity between these two subsystems, Southeast and South, deserve attention in terms of their estimated time for entry into operation. PDE 2031 considers expansions already

[34] Total operation values between 2021 and 2031, without considering present value.

contracted with an entry forecasted for 2022 and 2027. It is essential to monitor and implement these expansions in order to contribute to the security of supply,energy and power to the SIN, in this short and medium term timeframe. In addition to these reinforcements, the effectiveness of the generation contracted in the Simplified Contracting Procedure (PSC)[35], carried out in 2021 to increase the generation supply of the SIN between 2022 and 2025, is necessary to ensure, above all, the power balance on this timeframe.

The attention to be focused on the South region can be seen in **Chart 3 - 25**, which presents the import and export flows related to the South, in MW.h/h, referring to the average load level (which is equivalent to approximately 20% of the total hours of the analyzed months), for the year 2025. It can be seen that in both directions of energy flows, the capacity of exchanges is reached. Although 70% of the scenarios present the South region as an energy importer in 2025, export scenarios are the ones with the most limits are reached, in about 10% of the total sample.

Chart 3 - 25: Import and Export Flows of the Southern Subsystem: 2025



Source: Prepared by EPE.

Another difference from previous PDE publication cycles is that in the Free Scenario of PDE 2031, the expansion of regional interconnections is also indicated as part of the solution to minimize investment and operation costs for the ten-year planning timeframe. The evidence of this transmission expansion, which brings energy studies closer to more detailed electrical analyses, is also due to the perception that is more adherent to the reality of critical scenarios, a consequence of the new representation of hydro operating constraints.

In terms of amounts, the electro-energy models indicate the need for approximately 900 MW of expansion for the exchange between the Southeast and South subsystems by 2031. This indication is in line with the need presented in Chapter 4 of this PDE, where detailed electrical studies also support this expansion. Looking beyond the ten-year timeframe, when analyzing the period

35 As with the results of the first LRC, the PCS was also not considered in PDE 2031 simulations due to the reference date of this plan.

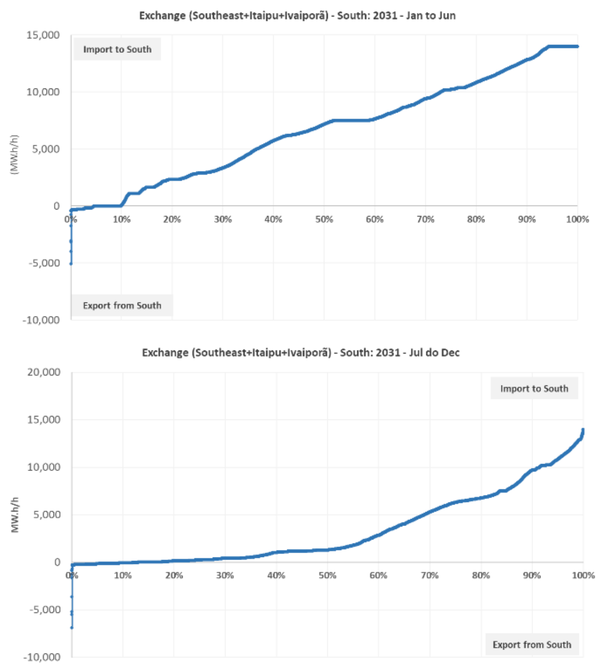
between 2032 and 2036, the MDI indicates additional expansions in the interconnections. Still on the exchange between the Southeast-South regions, increments are pointed out in every year, accounting for around 4,000 MW by 2036. Expansions are also indicated for the flow of surplus energy from the Northeast region, due to the growth of variable renewable sources in this region, which are competitive for minimizing the total costs of investments in the SIN. The expansions of this interconnection perceived by the energy studies begin in 2033 and also occur annually until 2036, when they reach about 5,000 MW.

Detailed electrical assessments on the need for expansion of interconnections for the post-decennial timeframe are being conducted and will point out the best implementation strategies, considering not only the growing needs, but also the appropriate time scale for the expansions to come online.

The indicative expansion of the transmission system reinforces the active role of planning in anticipating actions to meet the energy and power criteria of the SIN, economically evaluating alternatives that can add both regional generation power supply and interregional connections.

Therefore, by following the forecasts of expansion of the power supply of the Free Scenario, the use of this exchange is expected to be intensified, especially in the reception by the South region, as illustrated in **Chart 3 - 26** for the year 2031. It is noted that, even with the expansion of the transmission capacities, the flows are constrained in about 10% of the hydrological scenarios simulated.

Chart 3 - 26: Import and Export Flows of the Southern Subsystem: 2031



Source: Prepared by EPE.

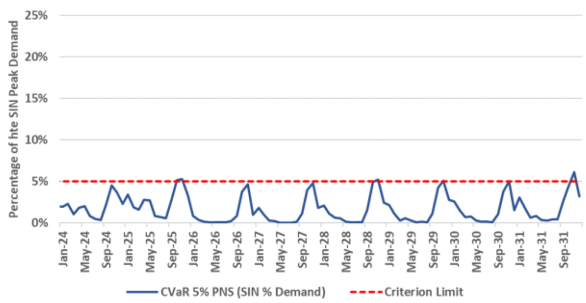
In order to monitor the adequacy of the supply related to the expansion indicated by Free Scenario, the indices used by the energy and capacity supply criteria were also calculated. As PDE 2031 simulations do not consider the PCS results, the graphs will be presented from 2026 onwards. It is worth mentioning, once again, that the effectiveness of the contracted supply in the simplified procedure is important to guarantee the conditions for meeting the capacity balance of the SIN until the year 2025. In addition, constant monitoring of the system's operating conditions, as done by the CMSE, is also necessary. The southern region of the country needs special attention in this regard, as it receives power from the other regions of the SIN, especially in critical hydrological scenarios.

Although the LRC results are also not part of the simulation, due to the possibility of expanding new technologies for power supply during the period of operation of the supply contracted in this event, it must be considered that a portion of the indicative supply has already been contracted. In this way, the assessment from 2026 is not affected by the non-consideration of the LRC.

For the power criterion, presented in **Chart 3 - 27**, in all years of the horizon the limit is reached, punctually in the month of September[36]. As for the energy criterion, the parameters associated with each metric are below the limits throughout the same period. The ENS CVaR criterion (% of Demand) is always below 0.3% throughout the study timeframe and for this reason is not presented in this report. The CVaR 10% of the CMO is presented in **Chart 3 - 28**.

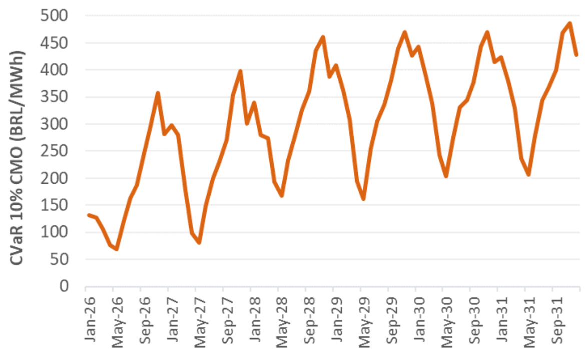
In other words, the results indicated in the Free Scenario fulfill the objective of indicating an expansion based mainly on market aspects, with the criteria of energy supply and power being met accordingly.

Chart 3 - 27: Capacity Supply Criterion



Source: Prepared by EPE.

Chart 3 - 28: Energy supply criterion – CVaR CMO

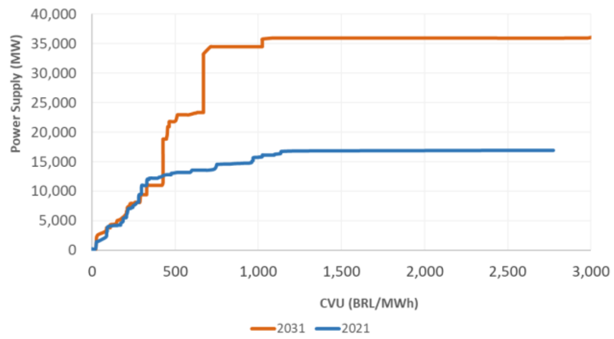


Source: Prepared by EPE.

Another relevant result of the Free Scenario is presented in **Chart 3 - 29**, which brings the supply curve,accumulated by CVU, comparing the configuration of the beginning of the horizon, in 2021, with the end of the ten-year timeframe, where the indicative expansion is already included. It can be seen that the indicative expansion, in addition to adding more supply to the power system, reduces the variable cost to be paid when the future generation mix is used. For example, with the 2021 generation mix configuration for a maximum CVU of BRL 500/MWh, around 13,000 MW of thermal power is made available to the SIN. With this same CVU, for the 2031 generation mix configuration, around 22,000 MW are available, already considering the evolution of fuel prices adopted in PDE. Another aspect that can be observed in this same graph is that more than 33,000 MW are made available to the SIN in this indicative expansion, with a variable cost of less than BRL 700/MWh, demonstrating that the strategy indicated in this scenario, using thermal power plants without compulsory dispatch, is capable of reducing the cost of energy generation at times when its use is necessary, when compared to the current generation fleet.

[36] In 2031, in a single month, this value reaches 6%, which will be monitored by planning.

Chart 3 - 29: Power Supply curve per CVU for the 2021 to 2031 generation mix – Free Scenario



Source: Prepared by EPE.

3.6 Energy Policy and Main Assumptions for the Reference Scenario

In this section, the set of energy policies included in the MDI simulation model for the preparation of PDE 2031 Reference Scenario will be described. The Reference Scenario is another possible future realization, consisting of the same expansion options as the Free Scenario, but incorporating established energy policy guidelines: (i) by the MME; (ii) by the Legislative Power.

With regard to the Legislative side, the set of guidelines used in PDE 2031 considers Law No. 14,182, of July 12, 2021, and also Law No. 14,120, of March 1, 2021.

The guidelines used to comply with the provisions of Law 14,182 are:

I. To represent the provisions of article 21, which defines that 50% of the demand declared by the distributors of the A-5 and A-6 new energy auctions must be destined to the contracting of hydro power plants of up to 50 MW (fifty megawatts), until the total of installed capacity reach 2,000 MW (two thousand megawatts), PDE 2031 brings the uniform expansion of PCH, with a minimum and maximum limit of 400 MW/year and 800 MW/year, as of 2026.

II. To represent the provisions of article 20, which deals with the contracting of Natural Gas thermal power plants, with operating inflexibility of at least 70%, in specific regions, adding up to 8,000 MW, PDE 2031 will include:

   a. For the North region: 1,000 MW in 2026, 1,000 MW in 2027 and 500 MW in 2028;
   b. For the Northeast region: 1,000 MW in 2027;
   c. For the Southeast and Mid-West regions: 2,500 MW in 2028, 1,000 MW in 2029 and 1,000 MW in 2030.

III. In order to represent the provisions of article 23, which deals with the possibility of renewing PROINFA contracts, in the Reference Scenario, the extension of all parks of this program was simulated.

In addition to the aforementioned Laws, PDE 2031 has the following energy policy guidelines:

• Limit of 3,500 MW/year, as of 2024, for the total expansion of wind *plus* solar photovoltaic;

• Total expansion limit of 6,000 MW of solar photovoltaic until 2031;

• Establishment of uniform expansion, with a minimum limit of 80 MW/year and a maximum of 400 MW/year, for biomass projects;

• Expansion established at 50 MW/year, starting in 2026, for Urban Solid Waste (RSU) projects;

• Inclusion of a new 1,000 MW Nuclear plant, in the SE/CW region, in 2031;

• Expansion of 350 MW/year of coal-fired projects (retrofit or replacement of power plants)in the South region, starting in 2028, with an inflexibility of 30%[37].

3.7 Reference Scenario

Based on the set of assumptions, summarized in the previous item, and covering the entire methodology for elaborating the expansion of supply for the ten-year timeframe, the indicative expansion for the Reference Scenario presents a total of approximately 43,000 MW, indicated for the period until 2031. Graph 3-30 shows this supply, where the predominance of thermal power plants, flexible (without dispatch obligation) and inflexible (with compulsory generation), corresponding to almost 60% of the indicative total, in terms of installed capacity. Among this amount are plants powered by natural gas, coal and nuclear, the latter in the year 2031.

Renewable sources are also relevant in the expansion of this Reference Scenario, represented mainly by wind farms and centralized PCHs, in addition to solar photovoltaic, which has a significant growth in distributed generation. In this scenario, MMGD will reach 13% of the total installed capacity in 2031.

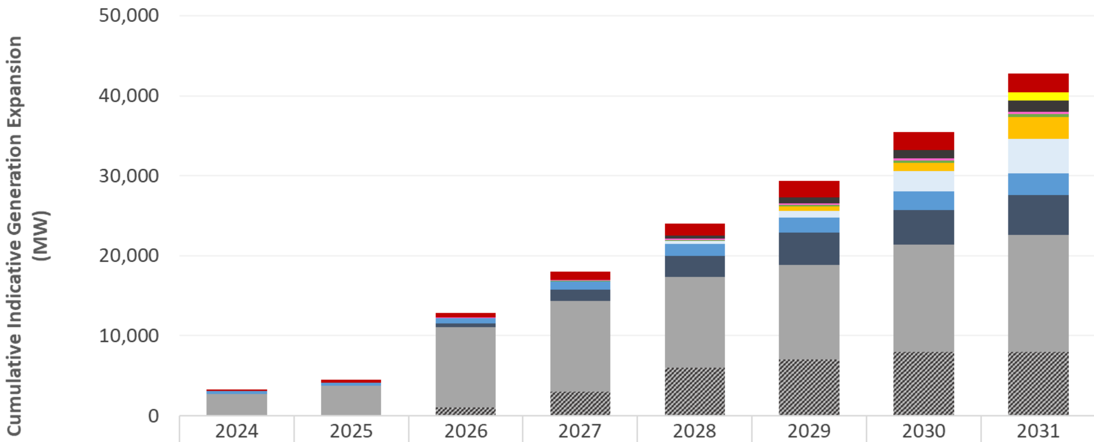
Urban solid waste is again indicated as an energy and environmental policy, showing a significant increase in participation when compared to the past PDE. In the current PDE, the centralized expansion of this technology is 50 MW per year, totaling 300 MW by 2031.

The demand response mechanism has a good participation in meeting the capacity, reaching more than 2 GW of expansion in the ten-year timeframe, proving to be a robust option for meeting the capacity requirement. This result confirms the importance of further studies for the introduction of the demand response in the SIN operation, as already carried out in the course of 2021. It is necessary to verify the positive points and improvements in the program carried out, with the main objective of bringing the largest number of participants into this mechanism, with clear rules and regulatory safety.

As also indicated in Free Scenario, along with the modernization of existing hydro power plants, this technology is an important alternative to complement the capacity supply. These two options have repeatedly demonstrated economic attractiveness in PDE studies.

[37] This restriction complies with the provisions of Art. 4 of Law 14.299/2022, published after the start date of the studies of this PDE.

Chart 3 - 30: **Cumulative Indicative Generation Expansion for the Reference Scenario**



	2024	2025	2026	2027	2028	2029	2030	2031
Total	3,264	4,500	12,858	17,994	23,987	29,380	35,497	42,726
RD	200	400	600	1,000	1,500	2,100	2,311	2,311
Nuclear	0	0	0	0	0	0	0	1,000
Coal	0	0	0	0	350	700	1,050	1,400
RSU	0	0	50	100	150	200	250	300
Biomass	0	0	0	80	160	240	320	400
Solar	0	0	0	0	0	500	1,000	2,700
Wind	0	0	0	0	344	844	2,544	4,344
PCH + CGH	300	300	700	1,100	1,500	1,900	2,300	2,700
Hydropower plant	0	0	426	1,401	2,614	3,995	4,297	4,947
Flexible Natural Gas	2,764	3,800	10,082	11,313	11,369	11,901	13,424	14,624
Inflexible Natural Gas	0	0	1,000	3,000	6,000	7,000	8,000	8,000

Source: Prepared by EPE.

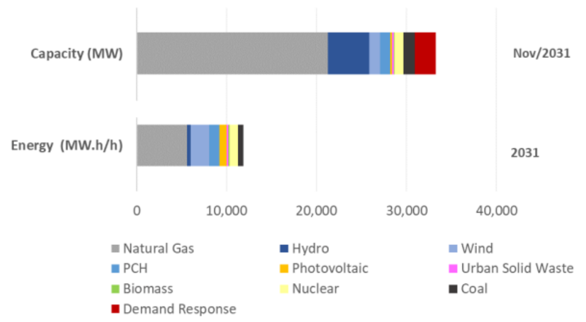
Note: The indicative expansion in 2024 accumulates eventual decisions of the MDI for the maintenance of existing thermal power plants that end their contracts before that date.

In the Reference Scenario, UHE Bem Querer also appears as the only new hydro power plant for the ten-year timeframe[38]. Again, it is worth highlighting the benefits that this project can bring to the SIN due to its complementarity in relation to the hydrological regime of the other basins, adding energy and capacity when the other hydro reservoirs tend to receive lower inflows and tend to be empty.

The technologies that make up this generation expansion scenario contribute to the fulfillment of energy and capacity in order to meet the requirements of the SIN. **Chart 3 - 31** brings the contribution of each generation technology to each requirement, in2031. The energy contribution was calculated in annual average terms, reaching approximately 12,000 MW.h/h at the end of the simulated horizon. The capacity contribution was estimated for the month of November, and the indicative supply adds more than 33,000 MW to the power system. **Chart 3 - 32** Shows the generation mix of this scenario for the beginning and end of the ten-year planning horizon.

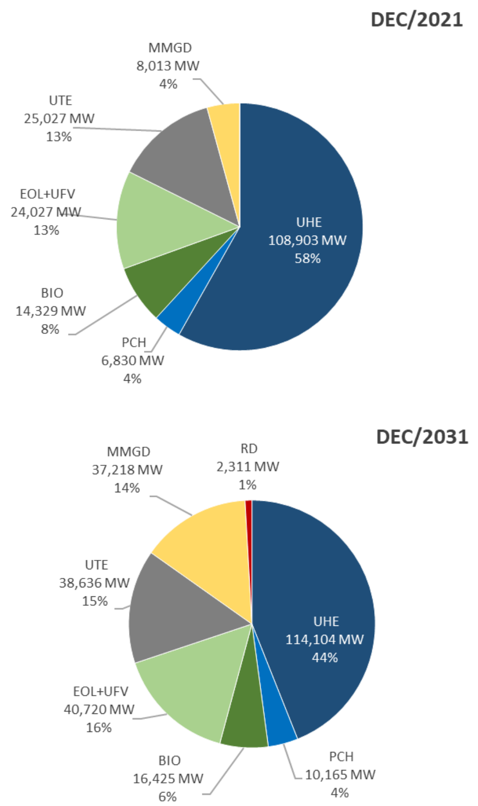
[38] UHE Tabajara obtained authorization to hold public hearings. Depending on how its licensing process is developed, this hydro plant may participate in energy auctions still on the horizon of this PDE.

Chart 3 - 31: Contribution of Energy and Capacity of the Reference Scenario of PDE 2031



Source: Prepared by EPE.

Chart 3 - 32: Reference Scenario Generation Mix of PDE 2031 in 2021 and 2031



Note: Biomass includes MSW and Biogas
Source: Prepared by EPE.

The Reference expansion also indicates transmission system expansion. In the ten-year horizon, the interconnections between the Southeast and South subsystems account for reinforcements of around 800 MW by 2031.

When analyzing the period after the ten-year timeframe, between 2032 and 2036, due to the end of the expansion entry to comply with Law 14,182, the MDI again indicates a significant amount of wind and photovoltaic supply, totaling 17,500 MW in this period (that is, more than twice the amount indicated in the ten-year period). Capacity complementation for the longuer horizon, 15 years, is predominantly carried out by thermal power plants without compulsory generation.

The postponement of indicative expansions of wind and solar renewable sources in relation to the Free Scenario simulation, means that the expansions indicated for the interconnections between the Northeast and Southeast, with a view of exporting excess energy through the first region, are also postponed. As a result, about 800 MW referring to the capacity of the NE-SE transmission system, necessary to accommodate energy exchanges between these regions, will be configured in 2036 in theReference Scenario.

It is important to mention that the expansion of interconnections presented here only reflects the vision of energy studies. Detailed studies, carried out from the electrical assessments, are presented in Chapter 4. The comparison between the expansion of interconnections for the Free and the Reference Scenarios, where this second one shows less expansion, are a reflection of the existence of energy policies in practically all regions of the SIN. This “spreading” of supply reduces the exchange of energy between regions, according to different seasonal characteristics, which is reflected in a lower expansion of exchange for optimization. On the other hand, only in electrical studies will it be possible to capture the need for capacity exchange for the flow signaled by these public policies. As the energy studies represent the geo-electrical subsystems in aggregate form, where the internal transmission network is not explained, it is not possible to capture this type of need. Thus, the analysis presented in this section reflects only one aspect of the use of interconnections, while the final need for transmission expansion can only be determined by electrical studies.

The results of the indicative expansion of the Reference Scenario present total values of BRL 191.8 billion[39] of new investment in the ten-year period. To carry out the operation of this power system in the same period, a total of BRL 145 billion would be needed[40].

As a result of this expansion, the optimization process solved by the mathematical models reflects the operation marginal costs of expanding the system, as shown in **Table 3 - 5**.

Table 3 - 5: Reference Expansion CME

CME - Reference Expansion	Average value from 2027 to 2031 (BRL/MWh)
Marginal Expansion Cost (CMEenergy), energy constraint	53
Marginal Expansion Cost (Double CME), power and capacity constraints	90

As presented in section 3.2.1 of this report, in view of the proposed changes for modeling hydro plants inflexibility, the CMO would no longer be sufficient to signal all the power system expansion needs. Thus, both for the Free Scenario[41] and for the Reference Scenario, there is a detachment between the values of CMO and CME. For the expansion of the Reference Scenario, the CMO values obtained were BRL 35.37/MWh, for the annual average in the second five-year period, while the CME that considers energy and capacity constraints was BRL 90.38/MWh , and only with the energy constraint of BRL 52.66/MW.

At first, these detachments could indicate that the resulting expansions do not pay off, that is, operating and stressing the existing and already contracted power system would be cheaper than promoting expansion investments. However, in view of the generation and cost assumptions used in the modeling, it appears that, without the indicated expansion solutions, the security of supply criteria, especially capacity, are not met in the ten-year horizon.

Another possible interpretation is that the returns from the operation are not sufficient to remunerate the proposed investments. Even for the Free Scenario, where both the CME and the CMO have less influence from expansion constraints, operational inflexibilities or energy policies, this result may indicate that, eventually, the operation of the power system has been modeled in such a way that the effects of aversion to risk desired by society, and expressed by the supply criteria, do not reflect properly in the price. In addition to the constant calibration work of the CVaR in the computational models, conducted by CPAMP, other aspects can influence this detachment, such as the value and form of representation of the non-served energy cost in the modeling, parameters for generating scenarios of affluent natural energy, representation of uncertainties of variable renewable sources and load, transmission limits, among others.

This hypothesis may give rise to important future reflections for adjustments of parameters and assumptions in the models chain deployed in the national power sector. As in relation to the definition of the non-served energy cost, since it could be low in relation to the real cost perceived by society in the event of a shortage of supply. In addition, improving the representation for the need to meet the load, especially at higher temporal discretization, is fundamental. Only then can the estimate of long-

[39] These values do not include the investment in gas pipelines and supply points in the respective locations of the plants.

[40] Total operation values between 2021 and 2031, without considering present value.

[41] In the expansion of the Free Round, the average annual CMO observed for the 2nd five-year period was BRL66.90/MWh, while the double CME was BRL157.44/MWh and the energy CME was BRL121.04/ Mwh. It should be noted, however, that the CME value of PDE 2031 is given by the Reference Scenario, with the value referring to the Free Round used only for the analysis presented here.

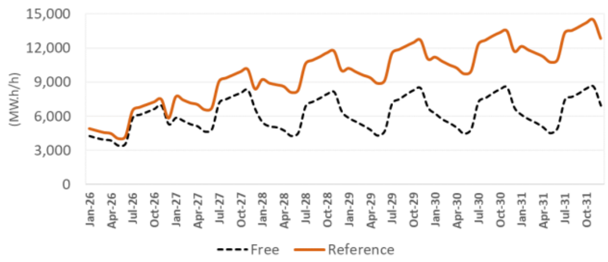
term marginal operating costs also capture this need. Eventually, the use of expressive non-served energy cost for the peak demand, representing system interruption costs, can improve the operational policy proposed by the long-term model.

If, even after the aforementioned possible adjustments, the CMO remains below the CME necessary to meet the supply criteria, the hypothesis that the returns from the operation are not sufficient to remunerate the proposed investments are reinforced. In this case, this result may indicate to the contracting environment the need for additional revenues, which will cover not only the expected market failures[42], but also the cost necessary to make the investment viable in the suitability of the generation portfolio.

As the Reference Scenario considers the application of energy policies in determining the expansion of generation supply, especially for thermal power plants, the results of operating variables are impacted.

Graph 3 – 33 presents the total thermal power generation of the SIN, average of the 2,000 scenarios simulated by Newave, for the timeframe from 2026 to 2031, resulting from the simulations for both the Free Scenario and the Reference Scenario. It is understandable that there is higher generation of UTEs in the Reference Scenario, since the level of compulsory generation applied as a premise for expansion to natural gas defined by Law 14,182 of 2021 is at least 70% of the respective supply expected to come into operation, considering the period of the ten-year planning.

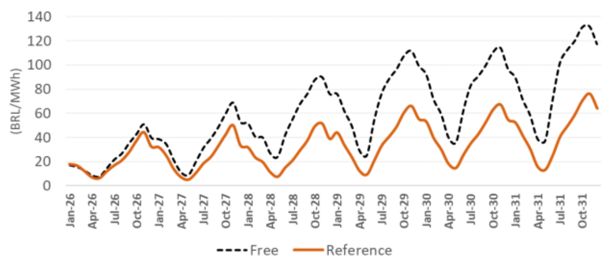
Chart 3 - 33: Total Thermal Power Generation of the SIN: 2026 to 2031



Source: Prepared by EPE.

Another immediate consequence of the application of thermal power inflexibility levels is noted in **Graph 3 – 34**, which presents the marginal costs of monthly energy operation, in BRL/MWh, for the SE/CO. The other regions present similar behavior. The Reference Scenario presents lower values when compared to the Free Scenario values. The average reduction in the period from 2026 to 2031 is approximately 50% for the four main subsystems of the SIN.

Chart 3 - 34: Average monthly CMO for SE/CO



Source: Prepared by EPE.

Although the previous graphs have shown that the CMO value of the Reference Scenario tends to be lower than that of the Free Scenario, in terms of total operating costs the situation is different. When considering the present value[43] of the operating

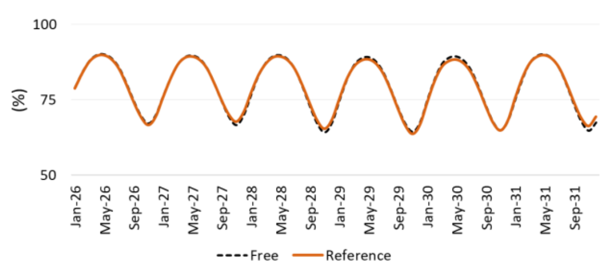
[42] Theme discussed in detail in item 3.2 of the report supporting the Firm capacity credit and Energy Workshop, prepared by the Electric Sector Modernization Working Group (available at: https://www.epe.gov.br/sites-pt/sala-de-imprensa/noticias/documents/20190816_workshop_lastro_energia.pdf).

[43] Using a discount rate of 8% per year.

costs of each month of the two scenarios, for the period from 2021 to 2036, the Reference scenario presents higher values in the order of BRL 50 billion (63%) in relation to the Free Scenario. The increase in operating costs is due, mainly, to the replacement of zero-CVU renewable sources, from the Free Scenario, by inflexible thermal power plants, with compulsory generation, which lead to an increase in total thermal power generation presented in **Chart 3 - 33**. These costs are referred to the power sector. It is possible that the integrated analysis of energetic sectors verifies other gains, mainly related to the expansion of natural gas infrastructure.

Another variable resulting from the hydrothermal operation of the SIN, energy stored, and which characterizes the management strategy of the UHE reservoirs at the end of each monthly period for the ten-year timeframe. **Graph 3 – 35** indicates the final stored energy of each month, as a percentage of the maximum storable energy of the SIN. It is possible to notice that both configurations have close storage trajectories. That is, even starting from expansion scenarios with different generation supply assumptions, both show similar results regarding the monthly expected value for the energy stored in the accumulation reservoirs of the UHE in the SIN. It is worth remembering that the two simulations already consider the new proposed representation of operational restrictions, as presented throughout this report.

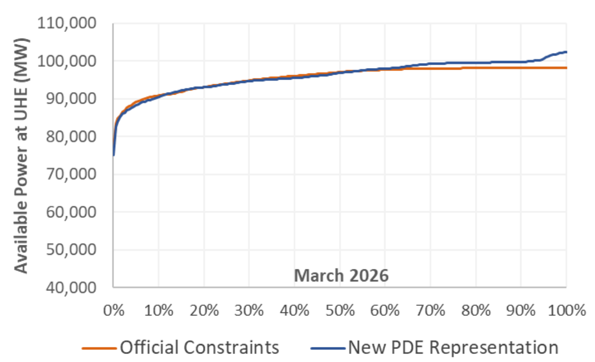
Chart 3 - 35: SIN Monthly Final Stored Energy: 2026 to 2031



Source: Prepared by EPE.

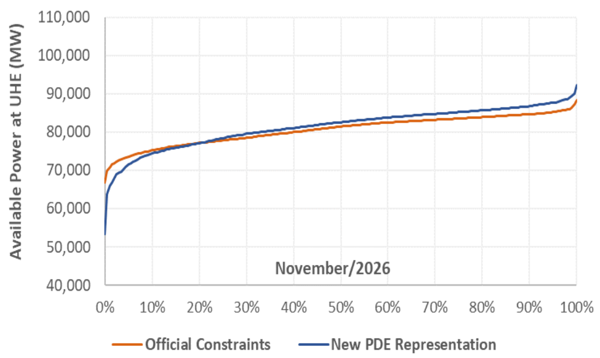
The new representation of the operating constraints changes the behavior of the available capacity (PDisp) in the UHE for the case with indicative generation expansion of the Reference Scenario. Graphs 3-36 to 3-38 show the comparison of this variable for the months of March and November 2026 and November 2031, respectively. In each graph, the simulation results are compared considering the official constraints and the new approach proposed in the current PDE. As it can be seen, in March 2026, when the UHEs tend to have a high PDisp in the power system, the main differences occur only in the best scenarios. In November of the same year, when the UHE reservoirs tend to be at lower levels and the power system can present the largest difficulties in supplying power, in addition to the same effect on the scenarios of higher PDisp, it is also possible to note the existence of more severe scenarios, close to the values obtained in 2020. **Chart 3 - 38**, for November 2031, confirms this fact, making it clear that with the new operating constraints, PDE starts identifying, across the timeframe, the possibility of the occurrence of critical situations, such as those experienced in the 2020/2021 biennium. Another important point to highlight is that the consideration of the new operating constraints, which considers minimum hydro generation targets so that the UHE can have operational flexibility, the allocation of energy resources is considered at all stages of the study, ensuring not only the availability of the resource but also accounting for energy expenditure.

Chart 3 - 36: **Available Power – Hydro Plants – SIN – March/2026**



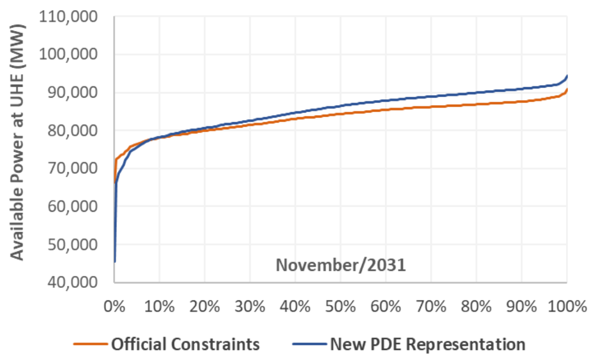
Source: Prepared by EPE.

Chart 3 - 37: Available Power – Hydro Plants – SIN – November/2026



Source: Prepared by EPE.

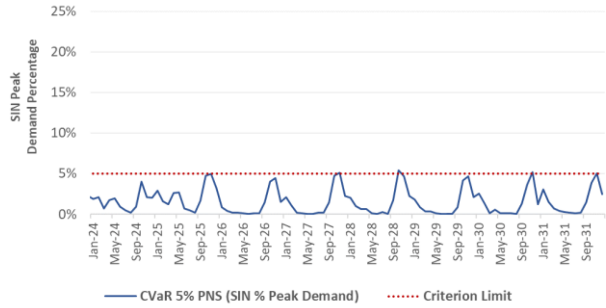
Chart 3 - 38: Available Power – Hydro Plants – SIN – November/2031



Source: Prepared by EPE.

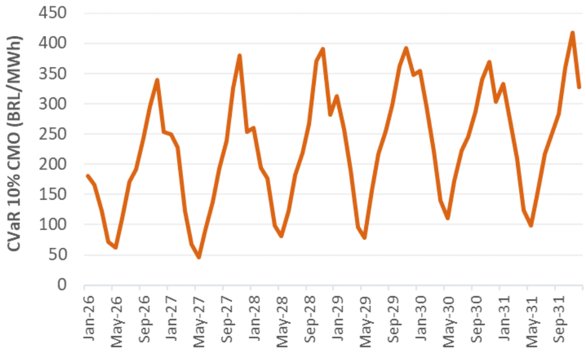
The energy and capacity supply criteria are also met for the indicative expansion of the Reference Scenario, even with the consideration of critical situations. For the capacity criterion, presented in **Chart 3 - 39**, in a few months of the year, mostly in the month of September, the limits are reached. As for the energy criterion, shown in Graph 3-40, at no time does the CVaR CMO reach the established limit. In other words, as in the Free Scenario, the generation expansion indicated in this Reference Scenario, which incorporates the Energy Policy guidelines, the energy and capacity criteria are met as well.

Chart 3 - 39: Compliance with capacity supply criterion



Source: Prepared by EPE.

Chart 3 - 40: Compliance with EnergySupply Criteria



Source: Prepared by EPE.

HOW TO IMPLEMENT THE INDICATIVE EXPASION CONSIDERING THE PRESENT REGULATORY FRAMEWORK

The Reference Scenario indicates that the generation expansion with less economic competitiveness from ACL (market observation and present rules based on commercialization of firm energy certificates) represents 3/4 of the total additional power supply. On the other hand, considering the PDE perspective, 1/4 of the SIN's load growth would be met by wholesale market. This is the challenge of the Reference Scenario of PDE: the thermal power plants are prescribed to be contracted under the Capacity Reserve Auctions, but the remaining capacity to integrate the total of 1/4 allocated to the wholesale market needs to be addressed.

The uncertainty is related also with the expansion linked to the ACL (unregulated market), i.e., if the market will be based on variable renewables forward contracts to promote the generation expansion, or if the market will rely on ex-post contract strategy, with the energy contracts being cleared on short-term basis, depending on energy certificates available coming from other generation resources, taking into account the perspective of low marginal energy costs in the PDE ten-year timeframe.

3.8 Estimation of GHG Emissions

Table 3 - 6 presents a summary of the emission levels of greenhouse gases for the SIN, obtained through the NEWAVE simulation, for the Free and Reference Scenarios. The emission values in 2026 and 2031 are presented, as well as the percentage difference between these years based on the two aforementioned scenarios.

The Free Scenario presents an emission reduction of 5.7 million tCO2eq in the period from 2026 to 2031, which is equivalent to a reduction of about 30%compared to 2026 emissions. On the other hand, the Reference Scenario records an increase of 14.7 million tCO2eq, in the period from 2026 to 2031, equivalent to an increase of 74% in relation to the reference data of 2026.

PDE 2031 Reference Scenario presents an emission estimate for 2031 of 34.6 million tCO2eq.

It is important to note that the emissions estimated in this section are related to the centralized power system.

Thus, it is not presented here the reduction of emissions related to other economic sectors. Eventual opportunities associated with natural gas market, especially gas infrastructure, may reflect in larger attractiveness of this energetic resource compared to more pollutant fuels.

Therefore, even considering the perspective of higher emissions coming from the power sector, according to the Reference Scenario, it is relevant to mention the challenges of decarbonization and net zero emissions in line with the Brazil’s targets must be addressed in a broad manner. The Chapters 7 and 10 of the PDE document bring more information concerning the mitigation of emissions across other economic sectors.

Table 3 - 6: Estimation of Greenhouse Gas Emissionsalu[44]

PDE 2031		Emissions		
		Million tCO2eq		% variation from 2026 to 2031
Case	Description	2026	2031	
2	Reference Scenario	19.9	34.6	74%
1	Free Scenario	19.1	13.4	-30%

[44] Emission calculation takes into account the estimated efficiency of each dispatched thermal power plant.

MAIN POINTS OF THE CHAPTER
CENTRALIZED POWER GENERATION

- *PDE 2031 expansion studies of centralized power generation were carried out in the period when the Brazilian electrical power system was facing the biggest water crisis in its history. In this sense, one of the main objectives pursued was the incorporation of lessons learned, pointing to structural planning solutions.*
- *The main innovation brought about in this cycle was the new proposal to represent the operating constraints of the UHE, based on the operating conditions perceived during the 2020/2021 two-year-period. With this, PDE highlights, once again, the importance that the entire planning process must be "feedback" from the conditions perceived in the real-time operation of the power system.*
- *The results demonstrate that the new proposed operating constraints brings the planning studies closer to the real-time operation. The analysis of future operating conditions, from the total hydro power generation, energy stored in the reservoirs and available capacity of the UHEs with the use of the new representation of constraints proposed in this PDE document demonstrate that, with them, the future scenarios are able to visualize extreme situations with greater probability of occurrence and, therefore, anticipate mitigating measures.*
- *The new representation of constraints also resulted in higher energy and capacity requirements of the power system. The impact of this requirement on generation expansion is evident when comparing the indicative power supply of PDE 2031 with previous planning cycles, considering that the demand to be met by the centralized power supply showed a reduction in its total amount.*
- *The scenario called Free Scenario, which does not consider the effects of energy policies on generation expansion, maintains the trend of past planning cycles, with a predominance of renewable sources for energy supply (especially wind and solar photovoltaic) and capacity complementation through thermal power plants without compulsory generation, modernization with expansion of existing hydro plants and demand response.*
- *By incorporating the energy policy guidelines, in particular the provisions of Law No. 14,182 of 2021, the replacement of part of the indicative expansion of centralized wind and solar plants by thermal power plants with compulsory generation fueled by natural gas, mineral coal and nuclear power is identified. This change in generation composition results in a higher operating cost for the power system.*
- *The two expansions presented meet the criteria for energy and capacity supply, demonstrating that they are viable alternatives for the safe expansion of the power system.*
- *Due to the great effort to incorporate the lessons learned from the recent past, the elaboration of the what if sensitivity studies will be the subject of a complementary publication, to be made available soon.*

Appendix A: Centralized Power Generation

Schedule 1

Table AI-1 - Centralized Power Generation: Incremental development of Existing and Already Contracted Installed Capacity by Fuel Source

Sources	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Biomass	355	713	175	70	146	245	0	0	0	0	0	1705
Wind	2822	2691	1776	303	1429	194	0	0	0	0	0	9215
Hydro	0	95	47	0	50	62	0	0	0	0	0	254
PCH+CGH	117	187	168	105	159	17	0	0	0	0	0	753
Photovoltaic	1364	1803	456	199	562	236	0	0	0	0	0	4620
Thermal	1338	-3531	717	-1533	-2595	-1339	-557	-2161	0	0	0	-9662
Grand Total	5997	1957	3339	-856	-250	-585	-557	-2161	0	0	0	6884

Note: Considers the removal of plants from PROINFA at the end of the contract and thermal power plants that fit the premise described in section 3.2.

Table AI-2 - Motivating Fact for the Reduction in Thermal power Participation in the SIN for PDE Timeframe

Motivating Fact	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
CCEAR Termination (COAL UTE)	0	0	0	0	0	1 080	365	0	0	0	1 445
CCEAR Termination (NG UTE)	0	0	922	1 259	1 133	500	0	0	0	0	3 814
CCEAR Termination (OD/OC UTE)	0	192	984	1 483	207	381	201	0	0	0	3 448
CCEAR Termination (Biomass UTE)	0	0	4	0	0	0	0	0	0	0	4
End of CDE subsidies (COAL UTE)	0	0	0	0	0	0	1 227	0	0	0	1 227
End of PPT subsidies (NG UTE)	562	0	1 686	572	0	0	0	0	0	0	2 820
End of Plant Service life	3 384	0	0	50	0	0	368	0	0	0	3 802
TOTAL	3 946	192	3 596	3 364	1 339	1 962	2 161	0	0	0	16 560

Annex II

Table AII-1 - Centralized Power Generation: Development of installed capacity per fuel source for Reference Scenario

SOURCE(a)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
RENEWABLES	147089	152578	155249	156222	158568	160198	161703	163791	166702	169733	174413
HYDRO(b)	101903	101998	102045	102045	102095	102583	103558	104772	106153	106454	107104
OTHER RENEWABLES:	45186	50580	53204	54177	56473	57615	58145	59019	60549	63279	67309
PCH and CGH	6830	7017	7185	7590	7748	8165	8565	8965	9365	9765	10165
WIND	19600	22291	24066	24369	25798	25993	25993	26336	26836	28536	30336
BIOMASS(c) + BIOGAS + RSU	14329	15043	15267	15333	15480	15775	15905	16035	16165	16295	16425
CENTRALIZED SOLAR	4427	6230	6686	6885	7447	7683	7683	7683	8183	8683	10383
NON-RENEWABLES(d)	25027	21496	22213	23029	21469	27412	30087	31331	33214	36087	38636
NUCLEAR	1990	1990	1990	1990	1990	1990	3395	3395	3395	3395	4395
NATURAL GAS(e)	15722	12991	13612	15412	15385	21534	24266	26953	28486	31009	32208
COAL	3017	3017	3017	3017	3017	3017	1937	695	1045	1395	1745
FUEL OIL	3355	2579	2579	2145	613	582	201	0	0	0	0
DIESEL	943	918	1014	464	464	288	288	288	288	288	288
SIN TOTAL	172116	174074	177462	179251	180037	187610	191790	195122	199916	205820	213050
Itaipu 50Hz (f)	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000
TOTAL AVAILABLE	179116	181074	184462	186251	187037	194610	198790	202122	206916	212820	220050

Notes:
(a) It does not consider self-production for exclusive use, which, for energy studies, is represented as load abatement.
(b) The values in the table indicate the installed power in December of each year, considering the motorization of UHEs.
(c) Includes biomass plants with CVU > O and CVU = 0 (sugarcane bagasse). For sugarcane bagasse plants, the projects are accounted with the total installed power.
(d) Thermal power plants are removed from the Reference Scenario expasion on the expiration dates of their contracts.
(e) In natural gas, the amount of process gas is also included.
(f) Portion of UHE Itaipu belonging to Paraguay, whose surplus energy is exported to the Brazilian power market.

Table AII-2 - Centralized Power Generation: Expansion of Installed Capacity by Fuel Source (annual increment)

SOURCE(a)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
RENEWABLES	-	5489	2672	973	2346	1630	1505	2088	2911	3032	4680	**27324**
HYDRO(b)	-	95	47	0	50	488	975	1214	1381	302	650	**5201**
OTHER RENEWABLES:	-	5394	2624	973	2296	1142	530	874	1530	2730	4030	**22123**
PCH and CGH	-	187	168	405	159	417	400	400	400	400	400	**3335**
WIND	-	2691	1776	303	1429	194	0	344	500	1700	1800	**10737**
BIOMASS(c) + BIOGAS + RSU	-	713	225	66	146	295	130	130	130	130	130	**2095**
CENTRALIZED SOLAR	-	1803	456	199	562	236	0	0	500	500	1700	**5956**
NON-RENEWABLES(d)	-	-3531	717	816	-1559	5943	2675	1245	1883	2873	2549	**13609**
NUCLEAR	-	0	0	0	0	0	1405	0	0	0	1000	**2405**
NATURAL GAS(e)	-	-2730	621	1800	-27	6149	2731	2687	1533	2523	1199	**16487**
COAL	-	0	0	0	0	0	-1080	-1242	350	350	350	**-1272**
FUEL OIL	-	-776	0	-433	-1532	-31	-381	-201	0	0	0	**-3355**
DIESEL	-	-25	96	-551	0	-176	0	0	0	0	0	**-655**
SIN TOTAL	-	1957	3389	1789	786	7573	4179	3332	4794	5905	7229	40933
Itaipu 50Hz (f)	-	0	0	0	0	0	0	0	0	0	0	**0**
TOTAL AVAILABLE	-	1957	3389	1789	786	7573	4179	3332	4794	5905	7229	40933

Notes:
(a) It does not consider self-production for exclusive use, which, for energy studies, is represented as load abatement.
(b) The values in the table indicate the installed power in December of each year, considering the motorization of UHEs.
(c) Includes biomass plants with CVU > O and CVU = 0 (sugarcane bagasse). For sugarcane bagasse plants, the projects are accounted with the total installed power.
(d) Thermal power plants are removed from the Reference Scenario expansion Plan on the expiration dates of their contracts.
(e) In natural gas, the amount of process gas is also included.
(f) Portion of UHE Itaipu belonging to Paraguay, whose surplus energy is exported to the Brazilian power market.

Annex III: Indicative Evolution of Future Centralized Expansion Scenarios (2021-2029):

Table AIII-1 - Indicative Expansion in the Free Scenario

Source(a)	Power System Expansion - Installed Capacity (MW)										Investment until 2031 (Million BRL)
	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total	
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	35	35	35	35	140	840
RSU	0	0	0	0	0	0	0	0	0	0	0
Photovoltaic	0	0	0	500	500	1700	1700	1700	2500	8600	27280
Wind	0	500	500	0	500	1700	2500	2500	2500	10700	44260
PCH + CGH	0	300	300	300	300	300	300	300	300	2400	14500
UHE	0	0	0	121	1280	1214	1381	302	650	4948	14260
Flexible Natural Gas(b)	415	2349	1036	7214	2915	2757	1095	2520	2174	22475	72443
Inflexible Natural Gas(c)	0	0	0	0	0	0	0	0	0	0	0
TOTAL	415	3149	1836	8135	5495	7706	7011	7357	8159	49263	173583

Notes:
(a) Shows the total installed capacity, according to the year indicated in the Investment Decision Model (MDI).
(b) Considers the indicated generation expansion of new flexible thermal power plants and the retrofit of thermal power plants at the end of the contract.
(c) The investment does not consider the fuel costs related to the inflexible generation portion.

Table AIII-2 - Indicative Expansion in the Reference Scenario

Source(a)	System Expansion - Installed Power (MW)										Investment until 2031 (Million BRL)
	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total	
Nuclear	0	0	0	0	0	0	0	0	1000	1000	25800
Coal	0	0	0	0	0	350	350	350	350	1400	14420
Biomass	0	0	0	0	80	80	80	80	80	400	1200
RSU	0	0	0	50	50	50	50	50	50	300	6900
Photovoltaic	0	0	0	0	0	0	500	500	1700	2700	8160
Wind	0	0	0	0	0	344	500	1700	1800	4344	17537
PCH + CGH	0	300	0	400	400	400	400	400	400	2700	16900
UHE	0	0	0	426	975	1214	1381	302	650	4948	14260
Flexible Natural Gas(b)	415	2349	1036	6282	1231	55	533	1523	1199	14623	44178
Inflexible Natural Gas(c)	0	0	0	1000	2000	3000	1000	1000	0	8000	42400
TOTAL	415	2649	1036	8158	4736	5493	4794	5905	7229	40415	191755

Notes:
(a) Shows the total installed capacity, according to the year indicated in the Investment Decision Model (MDI).
(b) Considers the indicated generation expansion of new flexible thermal power plants and the retrofit of thermal power plants at the end of the contract.

(c) The investment does not consider the fuel costs related to the inflexible generation portion.

Annex IV

Table A-IV-1 - List of thermal power plants removed from the power system by motivating fact

Reason for Removal	Name	Installed Power (MW)	Maximum Available Power (MW)	Exit Date
CCEAR | COAL	P. PECEM I	720.3	632.9	Dec/26
	PORTO ITAQUI	360.1	327.5	Dec/26
	P. PECEM II	365	330.2	Dec/27
CCEAR | OD/OC	ALTOS	13.1	0	Dec/22
	ARACATI	11.5	0	Dec/22
	BATURITE	11.5	0	Dec/22
	CAMPO MAIOR	13.1	0	Dec/22
	CAUCAIA	14.8	0	Dec/22
	CRATO	13.1	0	Dec/22
	ENGUIA PECEM	14.8	0	Dec/22
	IGUATU	14.8	0	Dec/22
	JUAZEIRO N	14.8	0	Dec/22
	MARAMBAIA	13.1	0	Dec/22
	NAZARIA	13.1	0	Dec/22
	DAIA	44.4	0	Dec/22
	XAVANTES	53.6	53.5	Dec/23
	PETROLINA	136.2	99.1	Dec/23
	Potiguar	53.1	40.9	Dec/23
	GOIANIA II	140.3	82.3	Dec/23
	Termomanaus	143	115.8	Dec/23
	Pau Ferro I	94.1	84.8	Dec/23
	Potiguar III	66.4	41.5	Dec/23
	MURICY	147.2	113.5	Dec/23
	Camacari PI	150	85.7	Dec/23
	VIANA	174.6	169.4	Dec/24
	CAMPINA GDE	169.1	71.9	Dec/24
	GLOBAL I	148.8	120.1	Dec/24
	GLOBAL II	148.8	118.3	Dec/24
CCEAR | OD/OC	MARACANAU I	168	76.6	Dec/24
	TERMONE	170.9	157.1	Dec/24
	TERMOPB	170.9	157.8	Dec/24
	GERAMAR II	165.9	156.5	Dec/24

Reason for Removal	Name	Installed Power (MW)	Maximum Available Power (MW)	Exit Date
CCEAR | NG	SEROPEDICA	385.9	273.1	Dec/23
	TRES LAGOAS	350	287.1	Dec/23
	TERMOBAHIA	185.9	133.8	Feb/24
	TERMORIO	1036	846.7	Dec/24
	TERMOCEARA	223	132.8	Dec/24
	LINHARES	204	195.9	Dec/25
	TERMOMACAE	928.7	780.5	Dec/25
	ST.CRUZ NOVA	500	431.4	Dec/26
	BAIXADA FLU	530	418.1	Dec/33
	MARANHAO III	518.8	492.1	Dec/33
CCEAR | BIOMASS	Cisframa	4	3.3	Dec/23
CDE | COAL	J.LACERDA C	363	247.5	Dec/27
	J.LACERDA B	262	170.6	Dec/27
	J.LACERDA A1	100	48	Dec/27
	J.LACERDA A2	132	88.6	Dec/27
	FIGUEIRA	20	10.1	Dec/27
	CANDIOTA 3	350	193.5	Dec/27
PPT | NG	CANOAS	248.6	213.2	Dec/21
	JUIZ DE FORA	87.1	79.1	Jan/22
	IBIRITE	226	186.2	Jul/22
	FORTALEZA	326.6	307.7	Dec/23
	NORTEFLU	826.8	772	Mar/24
	TERMOPE	532.8	477.7	May/24
	N.PIRATINING	572.1	279.3	Dec/24
SERVICE LIFE | NG	CUIABA G CC	529.2	0	Dec/21
	URUGUAIANA	639.9	0	Dec/21
	ARAUCARIA	484.5	0	Dec/21
	APARECIDA	166	115.8	Dec/21
SERVICE LIFE | NG	C. ROCHA	85.4	0	Dec/21
	JARAQUI	75.5	63	Dec/21
	MANAUARA	66.8	64.9	Dec/21
	PONTA NEGRA	66	64	Dec/21

Reason for Removal	Name	Installed Power (MW)	Maximum Available Power (MW)	Exit Date
	GERAMAR I	165.9	153.4	Dec/24
	BAHIA I	31	25.3	Dec/25
	PALMEIRAS GO	175.6	40.2	Dec/25
	SUAPE II	381.3	308.9	Dec/26
	PERNAMBU_III	200.8	47.8	Dec/27

Reason for Removal	Name	Installed Power (MW)	Maximum Available Power (MW)	Exit Date
	TAMBAQUI	93	63.4	Dec/21
	W. ARJONA	177.1	169.6	Dec/21
	VALE DO ACU	367.9	252	Sep/28
SERVICE LIFE | OD/OC	ST.CRUZ 34	436	0	Dec/21
	R.SILVEIRA	25	0	Dec/21
	PIRAT.12 G	200	0	Dec/21
	T.NORTE 2	340	0	Dec/21
	TERMOCABO	49.7	41.6	Dec/24