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Economic Dispatch Considering Hourly Capacity Allocation with a Variable Renewable and Hydro-Based Generation Portfolio

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Abstract

The objective of this paper is to assess an economic dispatch considering a power system portfolio, which includes predominant amount of hydro power and increasing quantities of intermittent renewables in relation to the total electric capacity. With growing importance of intermittent wind and solar generation taking part into power systems worldwide, there is need for greater chronological resolution to estimate the flexibility of the power system to offer firm capacity. In this way, a linear optimization model operating hourly is developed to calculate the minimum power system cost, while stablishing the capacity allocation to meet the projected load throughout one-year simulation, as an estimation of how the hourly economic dispatch impacts the scheduling of generators belonging to a power system with this portfolio composition. A central focus is how to operate the available hydro capacity to back up intermittent renewables, evaluating the physical hydro operating constraints, monthly energy balance and maximum power availability. A case study was simulated based on the Brazil's power system configuration, showing that existing hydro capacity provide hourly flexibility to back-up intermittent renewables, potentially saving 1.2 Billion R$, about 3.6% of total system cost referred to 2019. It is worthwhile to realize that the developed methodology can be employed to other power systems with similar capacity portfolio structure for the purpose of calculating its optimum allocation for a specified region and target year.

Keywords

Economic Dispatch, Energy Planning, Operation Flexibility, Power System, Transmission System, Variable Renewable Energy

1. Introduction

The word "green" is being widely used in multiple economic sectors today and it translates into initiatives that are taken to foster the decarbonization of the energy supply around the world, one example of energy planning is the growing shares of variable renewable energy (VRE) into the electric generation portfolio. In this regard, even power systems that already have predominant participation of renewables into its total power capacity, because of VRE cost reduction and technology improvements, still experience increase in intermittent renewables taking part in its total amount of electricity production. Consequently, countries that had relied on hydro power face the random variable associated with the river's inflows and, while implementing VRE generation, their power systems become even more attached to stochastic resource availability like wind and solar. Historically, most of South American countries expanded their generation capacity throughout large hydro projects with reservoirs, to help manage the seasonal water availability [1] [2] [3].

Considering the Brazilian power system, apart from the large presence of hydro plants connected to the grid, there are some concerns about their production availability, therefore the purpose of this paper is to simulate a linear optimization model (EleMod) to minimize its total system operation cost [4] [5]. Brazil is chosen because of its big size system and "greener" portfolio than other countries in terms of renewable shares of its total electric power generation. According to its Ten-year National Energy Plan [6], the renewable sources—hydro, solar, wind and biomass—nowadays accounts for roughly 86% of the total installed electric capacity. By 2029, the renewable share is expected to fall slightly to about 81% of the total installed capacity due to development of natural gas. However, the system planned for 2029 has more variable renewable energy (VRE), primarily wind and solar, than in 2020. It is planned that in 2029 VRE will account for 22% and hydro plants will have 53% of the total system capacity, compared with 11% and 67%, respectively in 2020. In addition to VRE, biomass is another important renewable source in Brazil's power system portfolio. The majority of this resource is driven by sugar cane bagasse and has its availability associated with the harvest period—from April to October—conferring more controllable power generation and offering complementarity to hydro production, especially in those months that characterize the dry season. In 2020, biomass accounted for 14 GW, or 8% of total capacity, mainly located in the Southeast region [7].

In this context of high shares of VRE and hydro-based generation, this paper aims at investigating Brazil's power system hourly capacity allocation. While hydro capacity supported by large dams can be quite flexible, due to river flow conditions, there are limits on maximum output in many parts of the country, even when considering monthly output. The water resources are monitored not only for providing hydropower generation, but they are also managed to cope with their seasonality and to guarantee the water usage for other sectors, which includes public service, irrigation, sanitation, operation of reservoirs, dam safety, navigation and agricultural uses. The interconnected Brazilian power system (IBPS) was designed and built to make use of distinct hydro power availability across national regions, *i.e.*, benefit from diverse river inflow conditions that characterize the hydrological complementarity between basins over the country aiming at minimizing the whole power system operation cost to meet the load. However, with potentially large increases of VRE into power systems, further enhancements are needed for the ability of dispatchable capacity, mainly hydro and also thermal plants, to efficiently meet the hourly load and respond to VRE hourly variability [8] [9] [10] [11].

Therefore, the IBPS is an interesting case study because of its predominance of hydro-based generation, high presence of VRE, and recently, its move to calculate wholesale spot prices at an hourly time scale, day-ahead power system scheduling. The remaining structure of the paper is as follows. Section 2 provides an overview of the Brazilian power system, focusing on the recent and planned development of VRE capacity. Section 3 provides a description of the adopted methodology, showing the additional formulation related to hydro power availability in order to calculate the optimum economic dispatch in the purposed model (EleMod). Section 4 presents datasets used to set up the model, and key assumptions. Section 5 comprises results of the simulated year (2019): hourly energy balances in the Northeast region of Brazil, ability of hydro capacity to modulate its energy production considering monthly expected water availability according to the simulation of stochastic operation planning and horizon (5-years upfront), annual total power system cost and cumulative distribution of hourly marginal electricity cost. Section 6 summarizes the conclusions and Section 7 proposes future studies.

2. Overview: The Brazilian Power System

The Ten-year National Energy Plan [6], issued annually, highlights a gradual decline in the share of large-scale hydropower capacity, an increase in the share of other renewables and a slightly increasing share of thermal power capacity through the end of the decade (**Figure 1**).

As of 2020, the total capacity in the power system is 172 GW, with large-hydro plants at 109 GW, wind at 15 GW, solar photovoltaic at 3 GW, biomass at 14 GW and thermal technologies at 24 GW (nuclear, gas, coal, diesel and oil). In 2029, the portfolio is projected to have 228 GW of capacity. It maintains a predominance of large hydro capacity at 111 GW. Wind increasing to 40 GW and solar photovoltaic to 11 GW are responsible for the increasing share of the non-hydro renewables as biomass at 15 GW increases by only 1 GW. Thermal technologies add 18 GW for a total of 42 GW of capacity, four and one-half times the increase in hydro capacity (**Table 1**).

Another important aspect of the increase of VRE is that most of the wind increase of 21 GW and solar increase of 7 GW is in the Northeast (NE) region of Brazil, accounting for almost of 80% of the total addition of VRE. The NE region

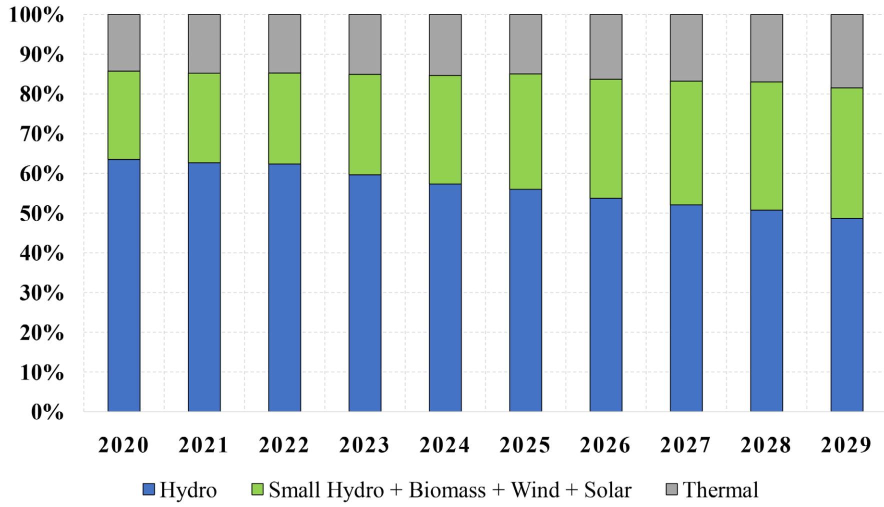

Figure 1. Shares of each power source in the Brazilian power system. (Source: Energy Research Office Brazil, 2019).

Table 1. The Brazilian power system: total installed capacity.

Source	2020 (GW)	2020 (%)	2029 (GW)	2029 (%)
Hydro	109	63	111	49
Small hydro	7	4	9	4
Wind	15	9	40	17
Solar	3	2	11	5
Biomass	14	8	15	7
Thermal[a]	24	14	42	18
Total	**172**	**100**	**228**	**100**

[a]Thermal = nuclear, gas, coal, diesel and oil. (Source: Energy Research Office Brazil, 2019).

has higher annual average wind speed than other regions in Brazil—with coastal areas mapped with annual average wind speed around 7 m/s, at 100 m [12].

Yet, it is expected that due to the portfolio effect and geographical dispersion of the wind generation projects, they could also provide firm capacity to the power system depending on the time of the day and season [13] [14]. Additionally, considering the seasonality of wind and hydro resource availabilities in the NE, studies have showed that there is energy complementarity between these two renewable generation options, Mummey *et al.*, 2017, with dry months being characterized by favorable wind availability [15]-[20].

For the solar resource, the NE region has annual average values of total daily radiation reaching up to 5.05 kWh/m^2·day, with the Southeast region at 4.75 kWh/m^2·day, the South region at 4.20 kWh/m^2·day and the North region at 3.26 kWh/m^2·day—detailed methodology of estimating the solar radiation can be found in the Brazilian Atlas of Solar Energy [21].

Figure 2 highlights the NE total capacity in 2019. Wind is the leading VRE source in the NE total power capacity, around 13 GW. Additionally, wind, solar and biomass account for almost of 46% of total power capacity in this region.

3. Methodology

The reference configuration for simulating hourly operations for the Brazilian power system for 2019, is taken from the Ten-year National Energy Plan, according to the flowchart (Figure 3). Therefore, in this article, it has been simulated the optimal operation of the power system, Layer 1 and 2, since the capacity expansion is already defined according to the Reference Layer.

The monthly hydro production is simulated using a dual-dynamic stochastic programming model, NEWAVE, utilized for operating the Brazilian system and developed by Electrical Energy Research Center (CEPEL) [22]. From this energy simulation (Layer 1), the objective function in NEWAVE is to minimize the total system cost, considering, in the case of the Brazilian system operator (ONS), the mid-term horizon of five years and monthly steps. From this Layer 1 optimization problem, it is possible to obtain the monthly hydro supply and the economic

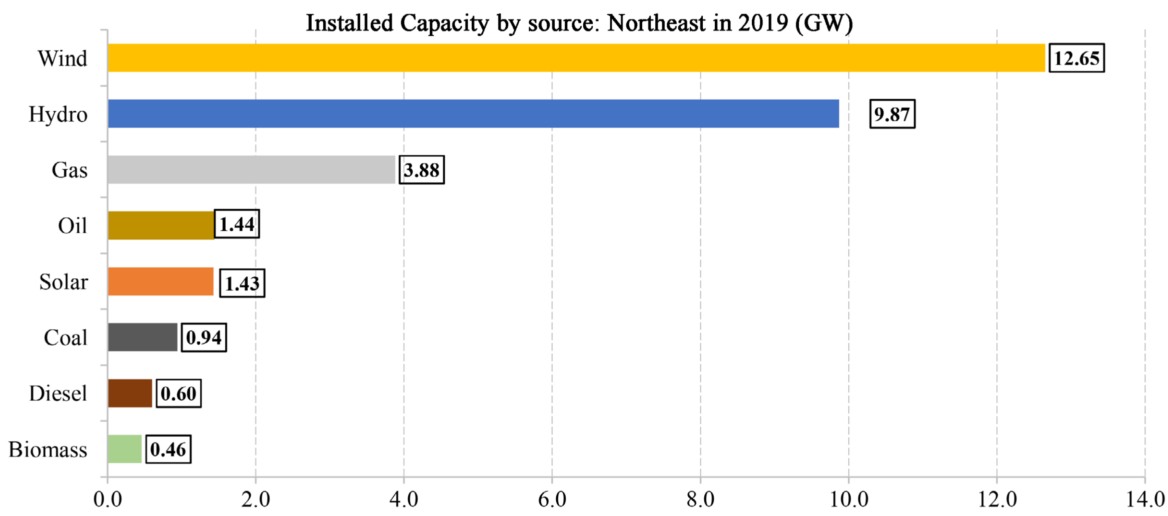

Figure 2. Northeast region: installed capacity in 2019. (Source: Energy Research Office Brazil, 2019).

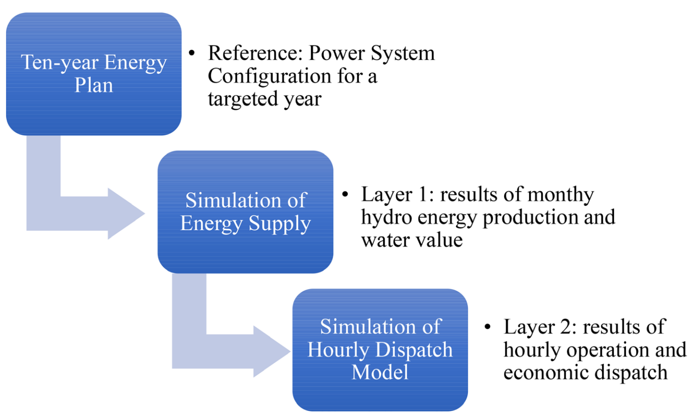

Figure 3. Flowchart with reference data and layers of simulation.

value of hydro generation, which is defined as the avoided cost of running thermal power [23].

Therefore, Layer Reference and Layer 1 are initial phases in order to extract outputs to form the restrictions in the capacity model, EleMod. Then, it is calculated the optimal hourly economic dispatch of hydro and thermal power production to meet demand less the prescribed hourly supply of wind and solar for a targeted year. Therefore, Layer 2 characterizes the focus of the proposed methodology. The hourly dispatch component of EleMod was used in this study to minimize the total operation cost for the Brazilian power system (Layer 2), although the capacity planning problem can be also simulated in this linear optimization model. Details of EleMod can be found in [4]. For this article, only the main equations are highlighted, as well as the new restrictions implemented to model the Brazilian system as a study case.

Figure 4 shows the regions considered in our study: Acre/Rondônia (AC), Belo Monte (BM), Imperatriz (IMP), Itaipu (IT), Ivaiporã (IV), Manaus/Amapá/Boa Vista (MAN), Norte (N), Nordeste (NE), Sul (S), Sudeste/Centro-oeste/Paraná (SE), Teles Pires/Tapajós (TP) and Xingú (XIN). In this diagram, blue zones represent regions modeled with loads to be meet inside them. On the other hand, orange zones are only connection points, which represent transmission interconnections and there is no load to be met in this case.

In this work, a pre-processing k-means clustering algorithm [24] is used to aggregate individual thermal units into a manageable set of 12 thermal "technologies". The clustering algorithm makes feasible to group together technologies based on fuel source and variable operation cost. The process resulted in

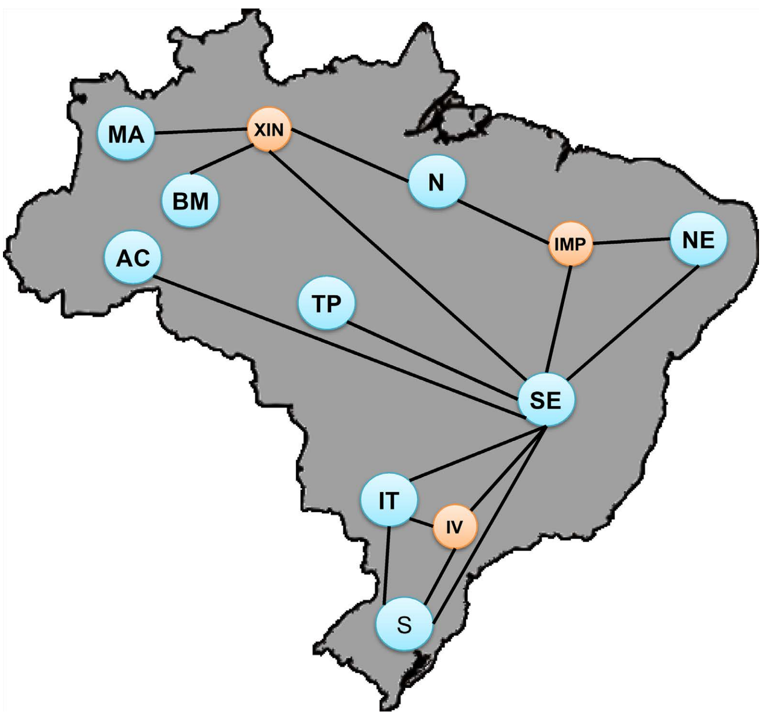

Figure 4. Schematic diagram of the 12-region of the Brazilian power system.

four representative natural gas technologies, three coal technologies, a diesel technology, an oil technology, a nuclear technology, and two biomass technologies. A capacity for each representative technology is specified for each region, according to Layer 1, with reference configuration of 2019 generation portfolio. Wind and solar capacity and the hourly patterns of production are prescribed, and it enters as a reduction in demand, defining the remaining load that thermal and hydro power need to meet. Finally, hydro capacity is modeled as a set of 9 hydrological basins (blue zones in **Figure 4**), using such representation allows EleMod model to dispatch the hydro capacity located in each of these zones, based on the water values or marginal costs of generating hydro energy that were imported from Layer 1—which aggregates the hydro basins by the same zones.

3.1. Objective Function in EleMod

The objective function in Equation (1) follows a deterministic approach in each region being simulated, with pre-specified hourly scenarios for both, wind and solar generation, as well as electric load. This approach was first formulated by Perez-Arriaga and Meseguer [5] to handle the cost recovery and power system planning in Spain.

$$\min \sum\nolimits_r Z_r \tag{1}$$

where the following symbols are deployed:

Z_r: total power system cost per region r, $\forall r \in RE$ -[R$]

RE: number of regions

T: number of years in the simulation horizon

M: number of months

D: number of days

H: number of hours

N: number of thermal technologies

C: number of wind classes

Additionally, Equation (2) shows the multiple parts while optimizing the total system cost per region.

$$Z_r = I_r + O_r + CP_r + NSE_r + SUP_r + PHS_r + HYD_r \tag{2}$$

With,

$$I_r = \sum\nolimits_{t,n} vk_{t,n} * pcf_n + \sum\nolimits_{t,c} vkw_{t,c} * pcfw + \sum\nolimits_t vks_t * pcfs \tag{3}$$

where:

I_r: total investment cost in region r, $\forall r \in RE$ [R$]

$vk_{t,n}$: variable new installed capacity per year t and thermal technology n, $\forall t \in T$, $\forall n \in N$ [GW]

pcf_n: parameter annualized investment cost per thermal technology n, $\forall n \in N$ [R$/GW·year]

$vkw_{t,c}$: variable new installed capacity per year t and wind class c, $\forall t \in T$, $\forall c \in C$ [GW]

$pcfw$: parameter annualized investment cost of wind [R$/GW·year]

vks_t: variable new solar installed capacity per year t, $\forall t \in T$ [GW]

$pcfs$: parameter annualized investment cost of solar [R$/GW·year]

$$O_r = \sum_{t,h,n} vg_{t,h,n} * \left(pfp_{t,n} * phr_n + pcvom_n \right) \tag{4}$$

where:

O_r: total thermal operation cost in region r, $\forall r \in RE$ [R$]

$vg_{t,h,n}$: variable thermal generated energy per year t, hour h and thermal technology n, $\forall t \in T$, $\forall h \in H$, $\forall n \in N$ [GWh]

$pfp_{t,n}$: parameter fuel price used per thermal technology n and year t, $\forall n \in N$, $\forall t \in T$ [R$/MMBtu]

phr_n: parameter heat rate per thermal technology n, $\forall n \in N$ [MMBtu/GWh]

$pcvom_n$: parameter cost associated with non-fuel variable O&M per thermal technology n, $\forall n \in N$ [R$/GWh]

$$CP_r = \sum_{t,d,n} \left(vcp_{t,d,n} - vg_{t,d,h,n} \right) * pcvom_n \tag{5}$$

where:

CP_r: total connected thermal power cost in region r, $\forall r \in RE$ [R$]

$vcp_{t,d,n}$: variable connected thermal power for year t, per day d and thermal technology n, $\forall t \in T$, $\forall d \in D$, $\forall n \in N$ [GW]

$vg_{t,d,h,n}$: variable generated thermal energy per year t, day d, hour h and thermal technology n, $\forall t \in T$, $\forall d \in D$, $\forall h \in d \cap h \in H$, $\forall n \in N$ [GWh]

$pcvom_n$: parameter cost associated with non-fuel variable O&M per thermal technology n, $\forall n \in N$ [R$/GWh]

$$NSE_r = \sum_{t,h} vnse_{t,h} * pcnse \tag{6}$$

where:

NSE_r: total non-served energy cost in region r, $\forall r \in RE$ [R$]

$vnse_{t,h}$: variable non-served energy per year t and hour h, $\forall t \in T$, $\forall h \in H$ [GWh]

$pcnse$: parameter penalty for non-served energy or value of lost load [R$/GWh]

$$SUP_r = \sum_{t,d,n} vsup_{t,d,n} * pcsup_n \tag{7}$$

where:

SUP_r: total start-up thermal cost in region r, $\forall r \in RE$ [R$]

$vsup_{t,d,n}$: variable start-up power from day $(d - 1)$ to d, per year t, day d and thermal technology n, $\forall t \in T$, $\forall d \in D$, $\forall n \in N$ [GW/day]

$pcsup_n$: parameter cost associated with start-up per thermal technology n, $\forall n \in N$ [R$/GW]

$$PHS_r = \sum_t vkphs_t * \left(pcfphs + pcfphsom \right) + \sum_{t,h} vtepphs_{t,h} * pcphsvom \tag{8}$$

where:

PHS_r: total investment and operation cost of pumped-hydro storage system in region r, $\forall r \in RE$ [R$]

$vkphs_t$: variable new pumped-hydro storage system installed capacity per year t, $\forall t \in T$ [GW] *pcfphs*: parameter annualized investment cost of pumped-hydro storage system [R$/GW.year]

pcfphsom: parameter annualized cost associated with fixed O & M for pumped-hydro storage system [R$/GW·year]

$vtepphs_{t,h}$: variable total energy involved in the process of charging/discharging the pumped-hydro storage system per year t and hour h, $\forall t \in T$, $\forall h \in H$ [GWh]

pcphsvom: parameter associated with variable operation cost for pumped-hydro storage system [R$/GWh]

3.2. Hydro Power Cost

In the IBPS, the share of hydro plants in the total energy generation mix is high—approximately 65% over the historic period from 1932 to 2017 [25]. The economic dispatch of the hydrothermal system is optimized by ONS, in order to deploy hydro and thermal resources to meet the monthly electric load [26].

While planning the energy supply in the case of Brazil, ONS looks five years ahead of the real-time operation, in this context of uncertainties, the operator faces the dilemma of deploying hydro generation resources today or saving them to be used in the next monthly stages of the optimization problem—the solution is calculated using the optimization technique called dual-dynamic stochastic programming, historically used for this mid-term power system operation planning in Brazil—Layer 1 in (**Figure 3**), considering its high hydro predominance [27] [28]. Beyond that, the economic value of the water, water value (WV), is used to represent the trade-off between applying the hydro resources today and preserving them to be utilized in the future months (valued as the opportunity cost of thermal generation) [29] [30] [31] [32]. Therefore, the WV, which represent the marginal costs of hydro generation, are extracted from the monthly simulation called stochastic operation planning.

Considering Equation (2) that represents different operation costs associated with each generation technology, the modeling proposed in this paper implements a complementary parameter based on the WV, *pwatervalue*. We introduce it in EleMod model by adding to the term *HYDr*, the cost of generating energy from hydro resource and obtained from stochastic process applied to inflow series mentioned in Layer 1 in (**Figure 3**).

$$HYD_r = \sum_{t,m,h} vhydro_{t,m,h} * pwatervalue_{t,m,h} \quad (9)$$

where:

HYD_r: total hydro energy cost in region r, $\forall r \in RE$ [R$]

$vhydro_{t,m,h}$: variable hydro generation per year t, month m and hour h, $\forall t \in T$, $\forall m \in M$, $\forall h \in m \cap h \in H$, [GWh]

$pwatervalue_{t,m,h}$: parameter cost associated with water economic value per year t, month m and hour h, $\forall t \in T$, $\forall m \in M$, $\forall h \in m \cap h \in H$, [R$/GWh]

Considering the values of water, shadow prices associated with hydro generation constraints, they are loaded in EleMod—Layer 2 in (**Figure 3**), in order to calculate a more accurate economic dispatch, with hourly time scale.

3.3. Additional Constraints to Hydro Power

Since Equation (9) was adjusted to incorporate $pwatervalue_{t,m,h}$, two additional constraints are implemented in the current formulation of EleMod to represent hydro operations: 1) total maximum hydro power availability, *phydropower*, in Equation (10) and 2) total amount of hydro energy programmed to be generated, *phydroplangen*, as showed in Equation (11)—both parameters, *phydropower* and *phydroplangen*, were obtained from the power system configuration reported in the Ten-year National Energy Plan [6], after running the optimization model [27] to acquire the results described in Layer 1 (**Figure 3**)—stochastic operation planning.

$$vhydro_{t,m,h,r} \le phydropower_{t,m,r} \tag{10}$$

where:

$vhydro_{t,m,h,r}$: variable hydro energy generated per year t, month m, hour h and region r, $\forall t \in T$, $\forall m \in M$, $\forall h \in m \cap h \in H$, $\forall r \in RE$ [GWh]

$phydropower_{t,m,r}$: parameter total maximum hydro power availability correlated to the monthly hydro generation and its end-of-month reservoir level condition per year t, month m and region r, $\forall t \in T$, $\forall m \in M$, $\forall r \in RE$ [GW]

$$\sum\nolimits_h vhydro_h(t,m,r) = phydroplangen(t,m,r) \tag{11}$$

where:

$vhydro_h$: variable hydro energy generated per year t, month m, hour h and region r, $\forall t \in T$, $\forall m \in M$, $\forall h \in m \cap h \in H$, $\forall r \in RE$ [GWh]

phydroplangen: parameter total hydro energy programmed to be generated per year t, month m and region r, $\forall t \in T$, $\forall m \in M$, $\forall r \in RE$ GWh].

4. Datasets

The cost structure includes a variable cost (combining the fixed O&M and fuel price) and a start-up cost for each clustered thermal technology represented in EleMod (**Table 2**).

In addition, for the *pwatervalue* input data, the expected values were extracted from the stochastic operation planning simulation (Layer 1, **Figure 3**), with monthly historical inflows for each basin (1931-2017) [6] [25].

For the purpose of this paper, the monthly average water values across 85 years of historical data are summarized in **Table 3**, and in EleMod, they are applied to hydro capacity to simulate the 2019-power system hourly economic dispatch. In other words, even the methodology could be applied to simulate the system for each historical hydrological scenario, it was assumed the average water value of each month and region a proxy for the hydro marginal cost (each region uses the monthly average of 85-historical scenarios of water values from 1934 till 2019) towards the study cases presented in this paper.

Table 2. Thermal technology classes.

Thermal technology	Description	Variable cost (R$/kWh)	Start-up cost (R$/kWh)
n_{01}	Gas OC[a]	0.07412	0.0193
n_{02}	Gas OC[a]	0.21923	0.0193
n_{03}	Gas CC[b]	0.39278	0.00515
n_{04}	Gas CC[b]	0.57269	0.00515
n_{05}	Coal	0.08659	0.0386
n_{06}	Coal	0.21694	0.0386
n_{07}	Coal	0.47568	0.0386
n_{08}	Diesel	1.26428	0.0193
n_{09}	Oil	0.78319	0.0193
n_{10}	Nuclear	0.02562	0.2577
n_{11}	Biomass	0.11497	0.0386
n_{12}	Biomass	0.40589	0.0386

[a]OC = open cycle, [b]CC = combined cycle.

Table 3. Monthly Average Water Value (1931-2017) Applied to 2019 Hydro Capacity (R$/kWh).

m^a	SE[b]	SUL[c]	NE[d]	N[e]	MAN[f]
Jan	0.1172	0.2171	0.1541	0.0301	0.8174
Feb	0.1112	0.0978	0.0966	0.0224	0.5640
Mar	0.1033	0.0976	0.0844	0.0187	0.4516
Apr	0.0961	0.1426	0.0775	0.0107	0.1577
May	0.1006	0.3016	0.0812	0.0127	0.0850
Jun	0.1141	0.1325	0.1183	0.0671	0.0978
Jul	0.1053	0.0810	0.1113	0.0758	0.0992
Aug	0.1148	0.0910	0.1176	0.0729	0.1078
Sep	0.1203	0.1128	0.1106	0.0984	0.1842
Oct	0.1309	0.1061	0.1376	0.0907	0.3040
Nov	0.1190	0.2161	0.1498	0.1268	0.7331
Dec	0.0764	0.0774	0.0926	0.0433	0.6320

m^a = month of the year, SE[b] = southeast, SUL[c] = south, NE[d] = northeast, N[e] = north, MAN[f] = manaus. There are 12 regions in total but we only display the values for the five main regions.

The hourly resource availability of wind and solar resource, applied on the 2019-power capacity, are also based on the average for each hour over the years 2005 to 2014. Therefore, they are just used to represent a proxy of a typical hourly resource availability, as referred in the Ten-year National Energy Plan [6]. In addition, the hourly load requirement is based on average hourly historical data, 2013-2018, extracted from the ONS website [25].

Finally, in each region, a value of R$ 4,944/kWh was considered as a penalty for non-served energy, or value of loss of load (VLL). The configuration of the transmission interties between regions referred to the same capacities simulated in the stochastic operation planning phase—Layer 1 (**Figure 3**) [6].

5. Results

For the purpose of this paper, even the simulation involves the optimization of the total power system cost, with 12 regions, the focus is to present the results on the NE region, considering the presence of VRE in 2019 accounting for 43% of the total regional capacity.

Wet and dry seasons are selected to characterize and demonstrate the hourly operation in two distinct months, February (wet) and September (dry). Historical inflow data are used to show the seasonality of one of the main hydro reservoirs located in the NE region [25].

Figure 5 presents the monthly average inflows for one relevant reservoir, Sobradinho, in the NE. For the 5-year period (2015 to 2019), the highest average inflows are seen in February 2016, about 3200 m^3/s. On the contrary, September is presented as a dry month, with average inflows of about 300 m^3/s.

The following section details the hourly operation and economic dispatch for the Brazilian power system with focus on the aforementioned region and selected months. In addition, we highlight the hydro generation and its ability to modulate the hourly load, after incorporating the maximum power availability

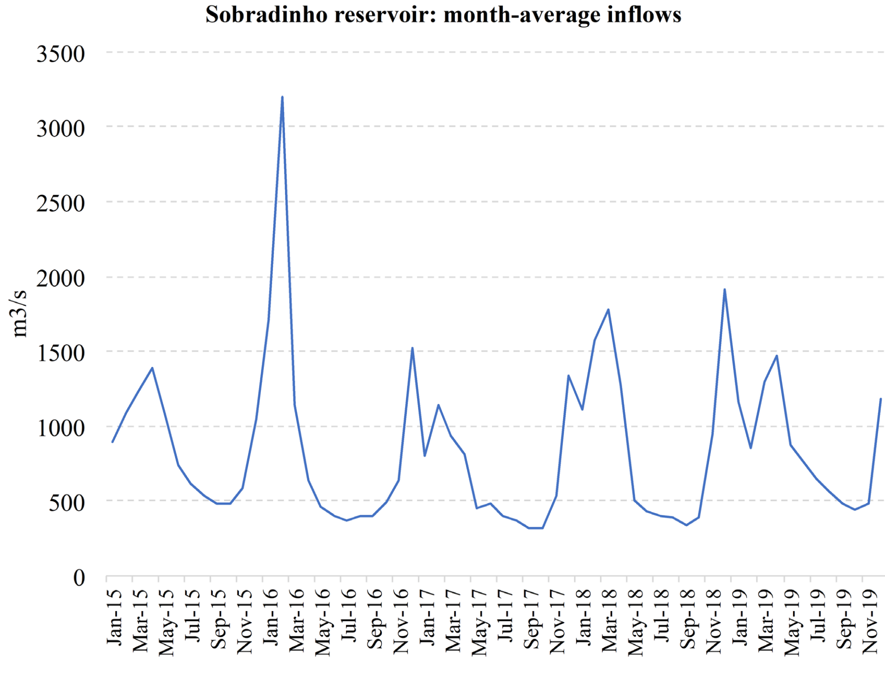

Figure 5. Sobradinho reservoir in the Northeast: inflows from 2015 to 2019.

and monthly hydro energy constraints in the formulation of EleMod model, as described in Equation (10) and Equation (11).

5.1. Hourly Operation: Wet Season

Figure 6 shows the NE economic dispatch, for the hour interval from 746 to 1412, corresponding to February 2019. During this month, the NE is mostly importing energy from other regions (light green area). Moreover, wind generation can represent the majority of the load balance in some hours throughout the month.

For example, in the 814th hour, wind production is approximately 7.7 GW and corresponds to 66% of total hourly load balance.

In the case of solar generation, the contribution is less important, 1.4 GW. It reaches its highest contribution, around 11% of the hourly load in the 1215th hour.

Gas thermal generation serves as a base generator in this scenario, given the higher average cost of hydro dispatch, 0.096 R$/kWh, compared to the gas variable operation cost, 0.074 R$/kWh.

Hydro generation is being modulated to accommodate the hourly variability of wind production.

Two specific hours are picked up to highlight these results. In hour 752, hydro generation is equivalent to only 0.030 GW, minimum hydro generation to meet the outflow requirement, while wind production reaches up to 6.3 GW. In hour 1283, while the hydro generation is being operated at its maximum power availability 8.4

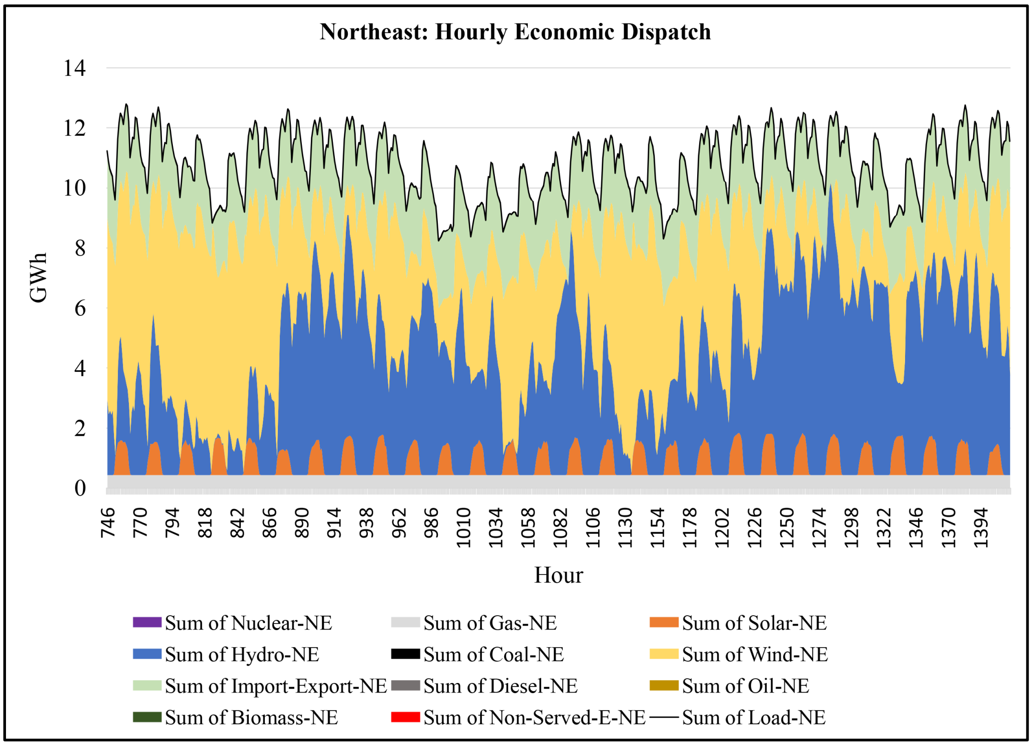

Figure 6. Northeast region: hourly-economic dispatch of February 2019.

GW, wind generation is zero.

5.2. Hourly Operation: Dry Season

Figure 7 graphs the hourly operation over a dry month in the NE region. September is characterized as a dry season and, according to energy complementarity, it has shown itself as a windy period. While the month has a lot of wind generation, it is highly variable and intermittent. Thus, the load following ability of controllable hydro capacity plays an important role in compensating the hours of reduced wind production, as well as the interconnections, represented by the capacity of the NE region to exchange power with other regions like North and Southeast, both elements offer flexibility to the functioning of the NE load balance.

According to Figure 7, the analysis of hydro generation shows that it is being deployed in its maximum power availability to follow the load across various hours of the month, the maximum hydro capacity is ramped up to 9.25 GW, precisely, between 6393rd and 6399th hour.

Additionally, since wind availability has favorable conditions during the month of September, the NE region acts as an energy exporter to other regions connected to the power grid—light green area above the black line shows the power surpluses—the average exported value is 3.6 GWh/hour, while weighing all the hours of the targeted month. Using the average opportunity cost for the water value (WV), 0.11 R$/kWh, pushes the hydropower to be operated as the marginal generation technology, just because during the dry season the hydro opportunity cost is somewhat higher than in the wet season. As a result, the

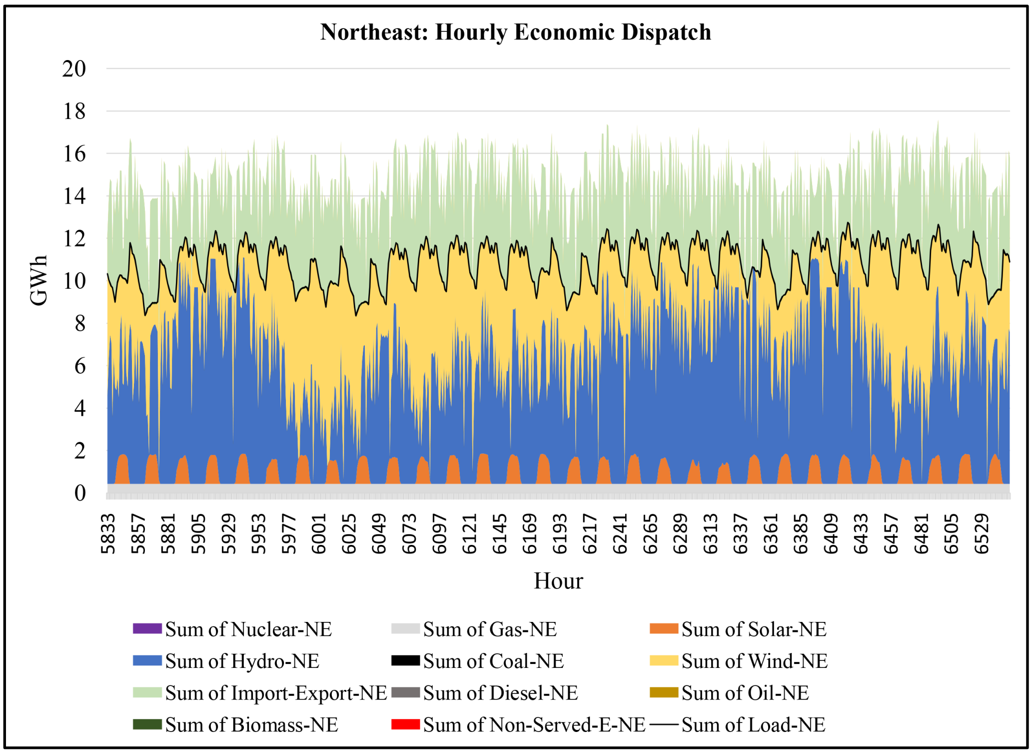

Figure 7. Northeast region: hourly-economic dispatch of September 2019.

thermal fleet, gas 0.43 GW (0.07 R$/kWh), remain in the base load.

5.3. Hydro Power Flexibility

After showing the simulated energy balance in the NE region, the focus is to point the comparison between hydro generation under two conditions, in order to highlight the value of its hourly flexibility: 1) results as modeled in this article (RAM), with new restrictions associated with hydro energy profile and maximum hydro power availability, and 2) if the hydro generation is modeled only using the energy generation profile, identified as business as usual (BAU). In Figure 8, as a matter of scale, we opt to show only the first-four weeks of September (dry season), in order to facilitate the interpretation of hydro generation and its ability to modulate it. The same result patterns were obtained for the remaining hours of September and also to February (wet season). In this paper, we presented only the simulation of the hydro generation located in the NE region, but the optimization was performed for the IBPS, which is represented by 12-regions, also confirming the modulation of whole system hydro capacity available in 2019.

Figure 8 refers to NE, in the RAM case, it is possible to note that hydro varies its generation over the hours in order to follow the load, and the maximum power, specially between 5890th and 5947th hours, extends up to 9.25 GW.

For the BAU case, hydro generation is shaped by the energy profile and reaches the maximum power of only 5.8 GW over the same hours.

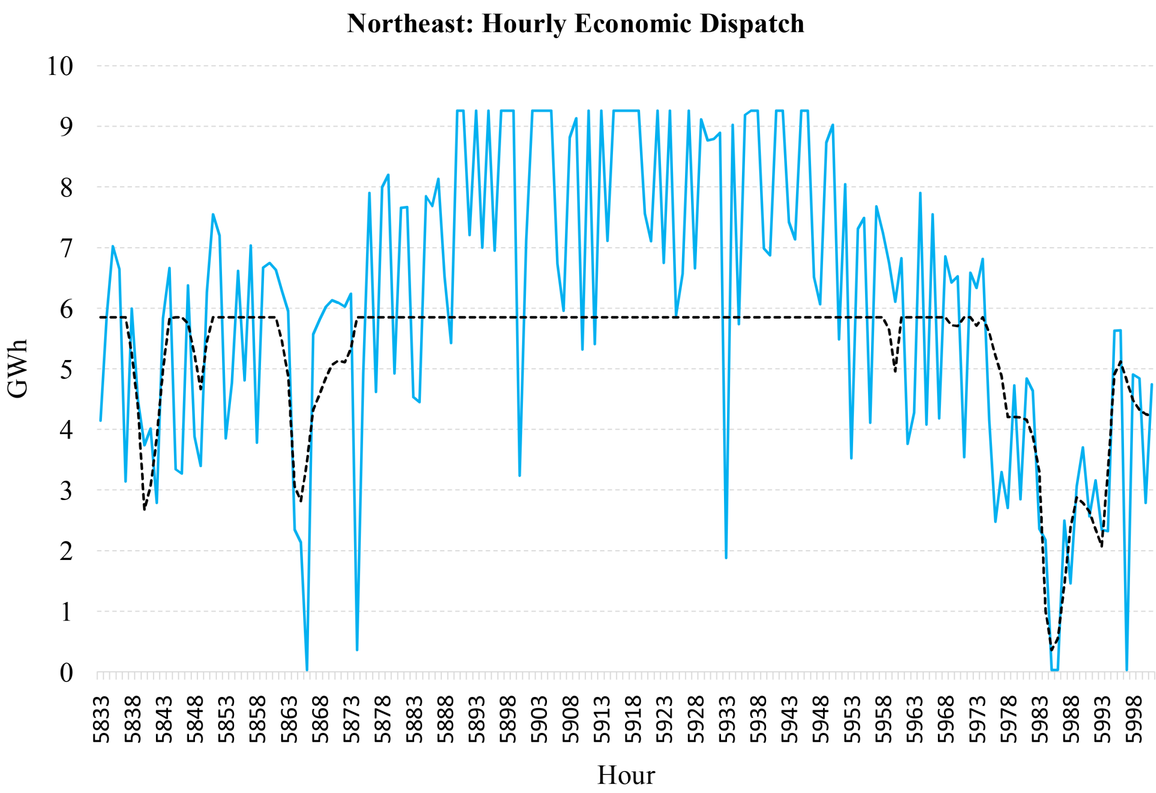

Figure 8. Northeast region: hourly-economic dispatch of September 2019.

5.4. Operation Cost

In terms of total power system cost in 2019, using the proposed methodology (RAM), the overall cost is around 34.2 Billion R$, while the thermal cost makes up to 3.7 Billion R$ that includes the operation and start-up costs. On the other hand, when hydro maximum power availability is not considered in the formulation (BAU), the total system cost increases to 35.5 Billion R$, with thermal cost responding to roughly 5 Billion R$. Therefore, taking into account more flexible hydro generation to back up the VRE intermittency could save up to 1.3 Billion R$ over 2019-year total system cost—based on the typical hourly scenarios of load, wind and solar and average water values specified in this case study.

Focusing on the RAM simulation, in **Figure 9**, the orange dots indicate the hydro generation cost for every hour across 2019—vertical axis on the left-hand side. It is noted that the higher values are concentrated mostly during the second half of the year, from 3571st to 7906th hours (dry season). Besides, in terms of thermal resources, they are being deployed at their full capacity and serving as base load generators, without intra-hour modulation of production, therefore, saving start-up costs. Thus, thermal cost, fuel energy costs, are showed as steady values, according to the blue line—as a matter of scale, the thermal generation cost are referred to the secondary-vertical axis on the right-hand side.

To characterize the importance of hydro generation as the marginal technology in this simulation, **Figure 10** exhibits the marginal electricity cost (MEC) for

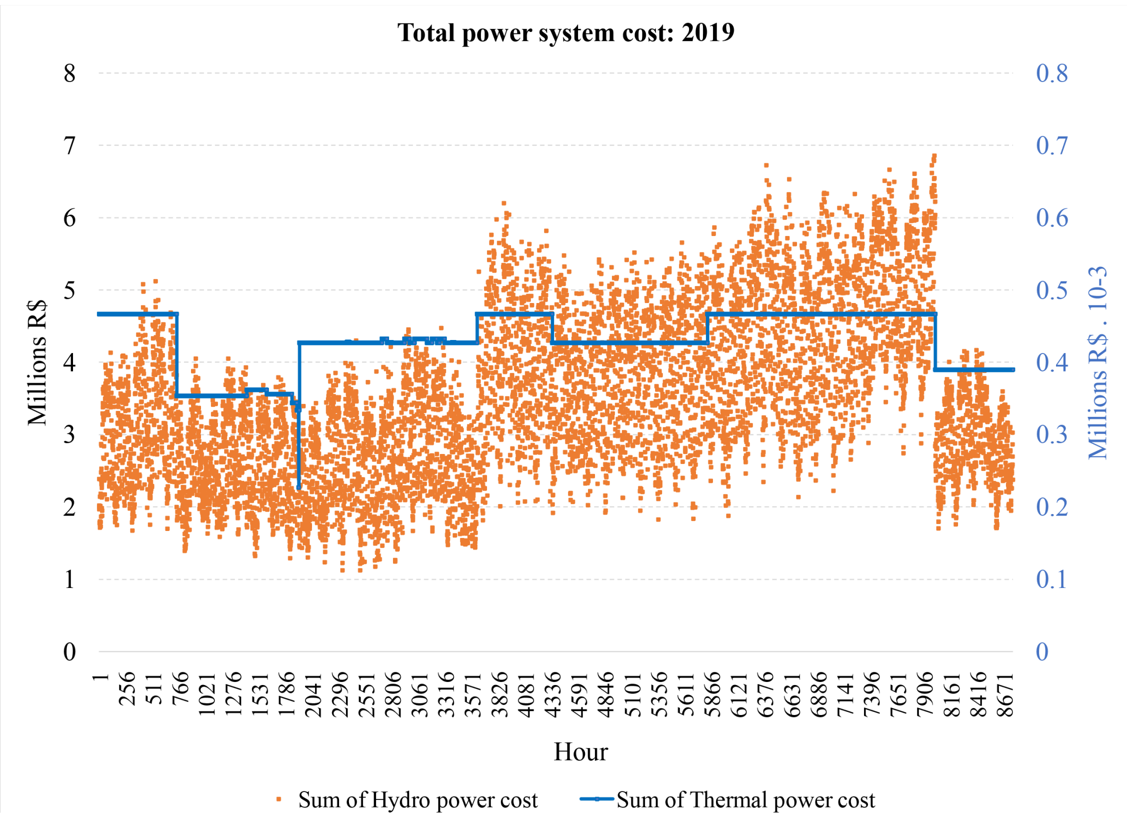

Figure 9. Hourly power system costs: hydro and thermal power.

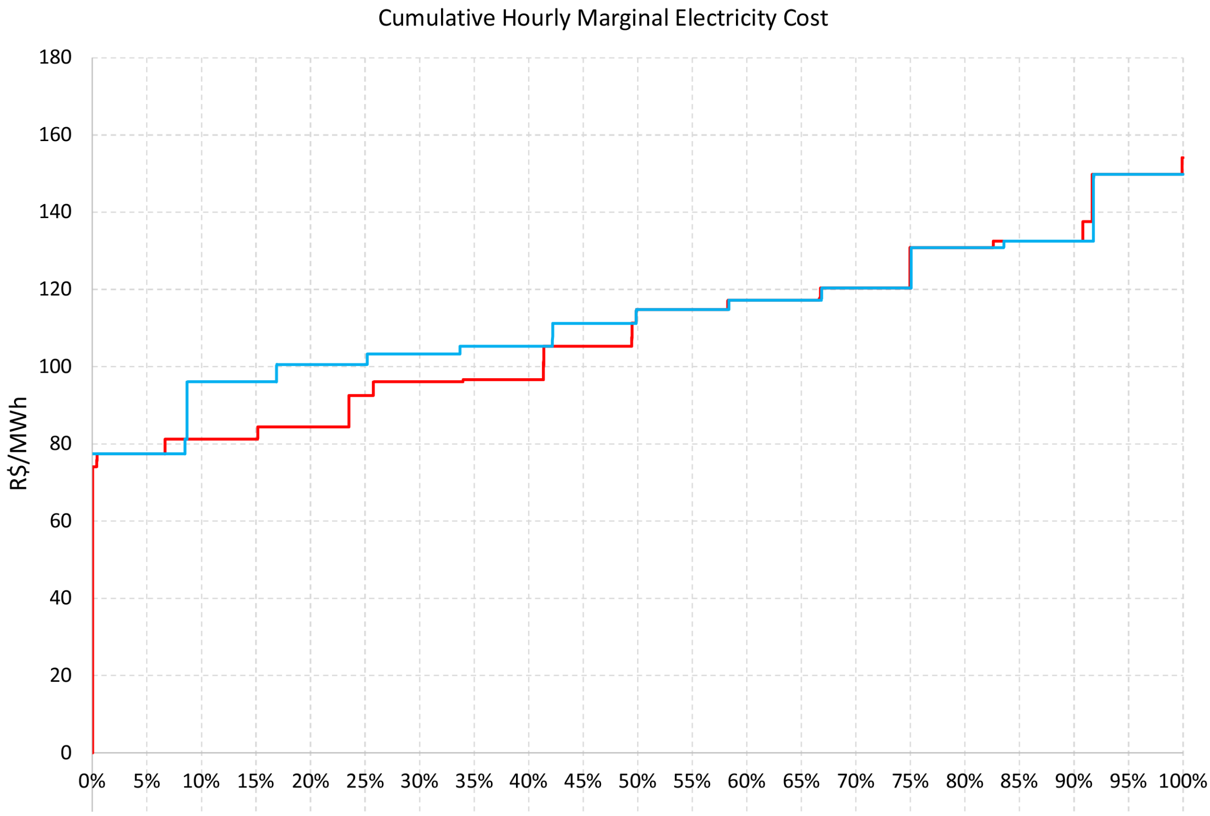

Figure 10. Cumulative distribution of the marginal electricity cost in 2019.

two regions: 1) the Southeast has a minimum MEC of 80 R$/MWh and, in the Northeast, there is a small percentage of hours, which MEC are reaching even zero, besides 2) there is 85% of the full range of Southeast MEC higher than 100 R$/MWh, whereas, in the case of the Northeast, the MEC above 100 R$/MWh make up 59% of the total hours simulated along 2019—the last results are mainly influenced by the overall presence of zero-marginal electricity cost wind and solar technologies in the NE region.

6. Conclusions

Variable renewable electricity is advancing rapidly worldwide. In the case of Brazil, wind and solar, already account for almost 11% of its total capacity. In the Northeast region, the percentage of VRE, in 2019, represented 45% of the total electric capacity.

It was demonstrated with a general-linear optimization model, EleMod, applied as a case study to Brazil, the important role that hydropower might play in following the hourly load in power systems with relevant presence of renewable resources. First, providing flexibility to deal with the inherent variation of VRE production and its forecast deviations—a comparison between two scenarios of hydro generation quantified the ability of hydro to modulate its production in order to compensate hourly load and VRE production. Second, the total system cost was calculated to show the impact of hydro flexibility to reduce thermal operation cost, saving up to 1.3 billion R$ (3.6%) of total system cost in 2019. Last but not least, another key element of operational flexibility is the interconnected characteristic of the Brazilian power system, capable of making use of different resource availability and seasonality—the Northeast region was highlighted as an example of power exporter or importer during this one-year case study—watchfully aware of the wind and hydro energy complementarity throughout the year.

Hence, this study analyzed two important pathways to support the efficiency of the Brazilian power system operation: the use of the hourly timeframe to determine the optimal economic dispatch throughout the total system electric capacity, as well as the ability of hydro to follow the hourly load is also critical for providing firm generation and power flexibility to the electric system. Based on historical reasons like vertical integration of electric sector and economic scale of the generation projects, most South America countries have relied on hydro power as a major component to meet the load. Considering the rapid growth of VRE in their power systems, showed in this Brazil case study, we pointed out how hydro fleet can also play a key role in supporting the power supply, especially when the VRE are not available.

7. Discussions

Future studies might involve the simulation of individualized hydro plants, because with greater discretization of each individual hydro project, it is possible to estimate a site-specific operation restriction or real-time physical constraint, related to water quality and supply, irrigation, navigation, recreation and electricity generation, which makes inferior the maximum hydropower availability and, consequently, impacting the ability of the power system in meeting the net-load requirements with hourly time step.

As a continuous research, further analysis might also include similar approach to simulate the near future configuration of the Brazilian power system with even higher shares of VRE, comprising of the potential for storage technologies coming into the hourly operation and, likewise, the assessment of the impact of climate change in the system requirements and supply adequacy under uncertain-generation scenarios applied to VRE.

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Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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