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Generation and Transmission Expansion Planning with Full-year Hourly Power Balance

Thiago José da Luz[1]*
https://orcid.org/0000-0002-6018-9429

Clodomiro Unsihuay-Vila[1]
https://orcid.org/0000-0002-1639-7765

[1]Universidade Federal do Paraná, Departamento de Engenharia Elétrica, Curitiba, Paraná, Brasil

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*Correspondence: thiagojluz@ufpr.br; Tel.: +55-41-33613622 (T.J.L.).

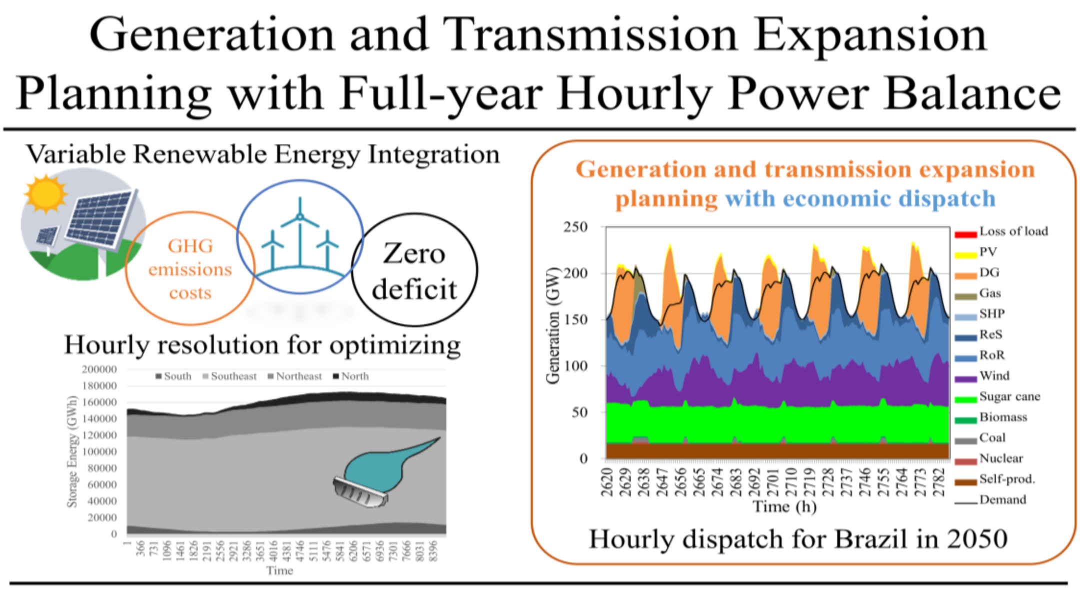
HIGHLIGHTS

- A generation and transmission expansion planning is presented to Brazil in 2050.
- Hourly economic dispatch problem is incorporate in the expansion planning.
- Power plant and hydropower operation, and transmission power flow are optimized.
- The power plant generation was optimized to supply only peak load in the year.

Abstract: Variable renewable energies are leading the energy transition and power system flexibility has become a global priority. Incorporating short-term assessment into long-term planning is essential to capture the operational characteristics of generation and address flexibility issues. This paper presents a novel model for generation and transmission expansion planning with economic dispatch. In the generation expansion planning, the capacity expansion is optimized. In the economic dispatch problem, power plant operation, hydropower generation, and line transmission power flow are optimized. The model is a mixed-integer linear programming problem solved in MATLAB using Gurobi toolbox. A model is proposed to optimize the reservoir of hydropower systems and run-of-river. A case study for supplying Brazilian demand in 2050 is presented. A scenario with greenhouse gas emission costs and no deficit is proposed. This study has shown that the current penalty cost for loss of load is not sufficient to avoid a deficit. It is possible to supply 2050 demand, without large reservoirs or deficits, with a 5.5% curtailment, using 13% of total storage capacity, however; peaking power plants are required.

Keywords: Economic Dispatch; Flexibility; Generation Expansion Planning; Hydro Reservoir; Variable Renewable Energy.

GRAPHICAL ABSTRACT



INTRODUCTION

The power sector is responsible for about three-quarters of greenhouse gas (GHG) emissions [1], and renewable energy accounts for only 26% of the power sector [2]. For this reason, many countries had some form of renewable electricity target [2]. The energy transition is a reality, and it is supported by Variable Renewables Energy (VRE). According to the International Renewable Energy Agency (IRENA), by 2050, 60% of the electricity will come from VRE, primarily solar photovoltaic (PV) and wind power [3]. The energy transition has been led by low-cost VRE, Distributed Energy Resources (DER), sector electrification and digitalization [4]. IRENA defines VRE characterized by variability and uncertainty, such as solar PV and wind power [3]. If, on the one hand, there is unpredictability of generation, on the other hand, there is unpredictability of demand. The duck-shaped curve affected by distributed solar photovoltaic (DPV) is another challenge for the operation of the power system. Indeed, power system flexibility has become a global priority [4].

Flexibility is defined as the ability of the power system to cope with change. To analyze system flexibility, some researchers argue that time-steps of one hour or less are necessary [5,6]. In their review study of generation expansion planning (GEP) with VRE integration, Oree and coauthors [7] assert that short-term integration is needed to capture the operational characteristics of generation and integrate flexibility aspects. Therefore, short-term decisions [8] or unit commitment constraints [9] have been incorporated into long-term planning to represent hourly dynamics and ensure success. Simplified models can lead to significant errors in carbon emissions and operating costs [10]. Underestimating hourly variability can result in a mix in which the energy storage system is unable to balance the difference between supply and demand [11], while neglecting flexibility requirement can result in generation portfolios that are inoperable [9]. On the other hand, a detailed model requires a high computational cost, for instance, Flores-Quiroz and coauthors [12] spent 15 days to solve a problem with 13 typical weeks and a planning horizon of 19 years, using a supercomputer with 2 TB of RAM.

To reduce the spend time and computational cost, some authors simplified the model to annual energy demand [13], load duration curve with energy levels [14], peak load demand [15], data in monthly resolution [16,17], typical weeks [12,18], typical days [19,20], or a day is represented by a few groups of hours [21,22]. There are few studies with hourly time-steps [3,23]. When short-term problems are modeled, they are typically formulated as day-ahead operation planning [24]. Hourly time step for a whole year has been applied to design microgrids [25,26] or in GEP with heuristic decomposition techniques [27].

Brazil has been using the Investment Decision Model (IDM) since 2017 [28], and Paes and coauthors [29] implemented this model adding carbon tax and emission limits. The IDM defines three load levels for each month and the maximum instantaneous demand for each month. The monthly target for hydropower generation is set a priori, and the seasonality of generation and demand is analyzed on the monthly time scale. However, generation flexibility is not tested in this model, nor is the capacity to allocate water resources under the optimization model.

In many countries, hydropower reservoirs are largely responsible for supply flexibility [30]. However, construction of large reservoirs has declined. In Brazil, 70% of storage capacity is concentrated in the Southeast and Middle East regions, and construction of new large reservoirs is not planned in the coming years [31]. In other countries, natural gas and coal-fired power plants take on the role of supply flexibility. Thermal power plants also supply the electricity system in the dry months, however; better use of complementarity among renewables could reduce the use of non-renewable sources [19].

When a one hour time-step is not used, water flow is not optimized. In countries with large reservoirs (e.g. Brazil), optimizing hydropower flow is essential to reduce the need for reservoirs. Power generation expansion planning must include spatial planning, short- and long-term asset optimization [3]. Nevertheless, many authors have used simplified models with annual or monthly averages, ignoring hourly variations and complementarity.

Table 1. Non-exhaustive overview of GEP models.

Reference	Temporal representation	Comment
A: Long-term planning		
Luz and Moura [11]	Two days with hourly resolution	Optimize capacity expansion with monthly balance demand and two days constraints, using nonlinear programming.
Melo et al. [14]	Load duration curve with 12 levels	CARTHER optimizes VRE expansion by MILP. It optimizes conventional generating units to meet the residual load.
Basu [16]	Monthly resolution	Capacity expansion is optimized by monthly balance demand using mixed integer nonlinear programming.
EPE [22,28]	Three load levels per month	Optimizes capacity expansion with peak constraint by MILP.
Paes et al. [29]	Three load levels per month	Optimize capacity expansion with peak constraint and greenhouse gas emissions cost using MILP.
B: Short-term planning		
FAST2 [3]	Full year at hourly resolution	Calculates system dispatch and required upward and downward ramping capabilities.
InFLEXion [3]	Full year at hourly resolution	System operation is optimized. The results are used to assess potential flexibility shortfalls in different situations.
C: Long- and short-term planning		
Koltsaklis and Georgiadis [8]	One day per month with hourly resolution	Capacity expansion and system operation are optimized with thermal units' shut-down cost, using MILP.
Flores-Quiroz et al. [12]	13 representative weeks with hourly resolution	Optimize capacity expansion and system operation with thermal units' shut-down cost, using MILP. They spent 15 days to solve the problem using decomposition.
Luz and Moura [19]	Two days with hourly resolution	Capacity expansion and system operation with battery system are optimized, using multi-objective programming.
Karimianfard [20]	Three days with hourly resolution	Capacity expansion and system operation are optimized using reformulation- and-decomposition approach.
English et al. [21]	Resolution 32 time slices	Capacity expansion is optimized using four demand periods per day, with flexibility constraints.
D: Long- and short-term planning with full year		
IRENA [3]	Full year at hourly resolution	IRENA FlexTool performs capacity expansion and system operation using linear programming.
Gils et al. [23]	Full year at hourly resolution	REMix energy system model performs capacity expansion and system operation using linear programming.
Felix and Vila [26]	Full year at hourly resolution	Renewable energy capacity expansion and transmission for a microgrid using Gurobi in Peru.
Deane et al. [32]	Full year at hourly resolution	Optimizes capacity expansion and system operation using a heuristic two-stage approach.
Proposed model	Full year at hourly resolution	Optimizes capacity expansion and system operation using a single level formulation with MILP. Reservoir level is optimized.

In literature, there are some tools to evaluate the flexibility, such as NREL system evaluation and GIVAR (IEA) to present an overview and characteristics, or FAST2 (IEA), FESTIV (NREL), and InFLEXion (EPRI) to dispatch assessment. To perform capacity expansion and system operation, there are few tools, such as REFlex (NREL), RESOLVE (E3) and IRENA FlexTool [3]. Soft-linking or two-stage is a heurist approach used to couple long- and short-term planning, for instance, Deane and coauthors [32] applied this approach to connect the PLEXOS and TIMES tools. Table 1 provides an overview of the generation expansion planning models presented.

In the literature, tools capable of solving the economic dispatch and capacity expansion usually group hydropower plants or work in the same way with large hydropower and run-of-river. There are few tools that can solve the combination of generation expansion and short-term planning, and typically some simplifications or approximations are applied. Some heuristics approaches to separate the expansion and economic dispatch problems have been developed in the literature; however, heuristics approaches do not have a formal guarantee of convergence. In fact, a reference model with a single level formulation is needed to validate new emerging methodologies. Therefore, this paper presents a generation and transmission expansion planning with full-year hourly power balance constraints. In the generation and transmission expansion planning problem, capacity expansion is optimized by node. The hydropower with reservoir and run-of-river plants are not grouped and are represented by integer variables.

The proposed model is a mixed integer linear programming (MILP) with a single level formulation solved in MATLAB software using the Gurobi toolbox. The economic dispatch problem is included in the expansion planning. In economic dispatch, power plant operation, hydropower generation, and transmission line power flow are optimized. A case study of Brazilian in 2050 is presented. Three scenarios are performed and the GHG emissions costs and deficit penalty price impact are evaluated. The simulation was performed in Microsoft Azure cloud computation. The simulations were run on virtual machine Standard G2 (4 vCPU, 56 GB). The main contributions are:

- A novel generation expansion planning model with economic dispatch for evaluating annual complementarity among regions with transmission constraints using a single level formulation;
- A model for optimizing water storage;
- A case study to supply Brazilian demand in 2050, considering a full-year hourly demand and VRE profile;
- An assessment of future Brazilian flexibility;
- A reference result for evaluating decompositions and simplified approaches in new studies.

The remainder of the paper is structured as follows. The proposed model is presented in Section II. The data used in the case study for the Brazilian scenario is presented in Section III. The results and discussion of the case study are presented in section IV. Finally, Section V summarizes the paper and highlights its main conclusions.

FORMULATION

The formulation is based on [3,17], however; with binary variables. For investment in new hydropower plants, binary variables is used based on available projects in [33]. The model is a MILP problem, with 420,531 continuous and 15 binary decision variables, and 665,672 constraints. The problem was formulated using MatLab, and the optimization problem was solved using Gurobi [34]. The Gurobi (used in [20,25,26]) and CPLEX (used [8,9,12,29]) are widely-used MILP solvers which employs a linear-programming based branch-and-bound algorithm. Both offer academic license; however, in new versions, MatLab connector has been removed from CPLEX (most recent version to include the connector is 12.10). Both solvers were tested and Gurobi performed better in Matlab. Gurobi includes presolve, cutting planes, heuristics, and parallelism.

The objective function is to minimize the expansion and operation cost (1), as well as: the annualized investment costs of the units (2); the annualized CAPEX of the hydropower (3); annualized investment costs of transmission line (4); annual fixed operation and maintenance (O&M) cost (6); OPEX of hydropower (7); penalty cost of insufficient capacity (8); variable O&M cost (9); emission cost (10); penalty cost of loss of load (11); and penalty cost of curtailment of VRE (12).

Objective function:

$$Minimise \begin{bmatrix} c^{inv} + c^{inv_{hydro}} + c^{inv_{trans}} + c^{fixed\_O\&M} + c^{fixed_{hydro}} + c^{loss_{capacity}} \\ + \sum_{t \in T} \left(c_t^{fuel} + c_t^{emission} + c_t^{loss\_load} + c_t^{curtail} \right) \times h_{step} \end{bmatrix} \quad (1)$$

where:

$$c^{inv} = \sum_{u \epsilon U} \sum_{n \epsilon N} \left(Inv_{u,n} \times P_{u,n} \times CRF_u \right) \quad (2)$$

$$c^{inv\_hydro} = \sum_{h \epsilon H} \left(CAPEX_h \times CRF_h \times b_h \right) \quad (3)$$

$$c^{inv\_trans} = \sum_{n \epsilon N} \sum_{n2 \epsilon N_n} \left(Inv_{l,n,n2} \times P_{l,n,n2} \times CRF_l \right) \quad (4)$$

The investment cost is converted to annualized cost by using the Capital Recovery Factor (CRF):

$$CRF_u = \left(i_u (1 + i_u)^{life_u} \right) / \left((1 + i_u)^{life_u} - 1 \right) \quad (5)$$

The annual fixed cost is calculated by:

$$c^{fixed\_O\&M} = \sum_{u \epsilon U} \sum_{n \epsilon N} \left(c_{u,n}^{fixed\_O\&M} \times P_{u,n} \right) \quad (6)$$

$$c^{fixed\_hydro} = \sum_{h \epsilon H} \left(OPEX_h \times b_h \right) \quad (7)$$

$$c^{loss\_capacity} = \sum_{n \epsilon N} \left(c_n^{loss\_capacity} \times P_n^{loss} \right) \quad (8)$$

The annual variable cost is calculated by:

$$c_t^{fuel} = \sum_{u \epsilon Th} \sum_{n \epsilon N} \left(c_{u,n}^{fuel} \times G_{u,n,t} \right) \quad (9)$$

$$c_t^{emission} = \sum_{u \epsilon Th} \sum_{n \epsilon N} \left(c_u^{emission} \times G_{u,n,t} \right) \quad (10)$$

$$c_t^{loss\_load} = \sum_{n \epsilon N} \left(c_n^{loss\_load} \times P_{n,t}^{loss} \right) \quad (11)$$

$$c_t^{curtail} = \sum_{n \epsilon N} \left(c_n^{curtail} \times P_{n,t}^{curtail} \right) \quad (12)$$

The energy balance must be guaranteed in all nodes and at all times with a time step of one hour. The energy balance of each node includes: generation from non-dispatchable renewable energy; thermal power and hydropower; energy imports/exports to the node; the slack variable for loss of load and curtailments; and energy demand.

Energy balance $\forall \{n, t\}$:

$$\begin{gathered} \sum_{r \epsilon R} G_{u,n,t} + \sum_{u \epsilon TH} G_{u,n,t} + \sum_{u \epsilon H} G_{u,n,t} + \sum_{n2 \in N_n} \left[IN_{n2,n,t} \times (1 - tl) \right] + P_{n,t}^{loss} \\ = L_{n,t} + \sum_{n2 \in N_n} OUT_{n,n2,t} + P_{n,t}^{curtail} \end{gathered} \quad (13)$$

where:

$$G_{r,n,t} = CF_{r,n,t} \times \left(P_{u,n} + P_{u,n}^{old} \right) \quad \forall \{r, u\} \in R \quad (14)$$

Hydropower constraints need to ensure reservoir capacity constraints, intra-year depreciation and maximum hourly generation. The run-of-river (RoR) reservoir has little flexibility in water storage. In this paper, the water in the reservoir can be managed for twenty-four hours. Therefore, constraint (15) applies to new and (16) to existing plants (16), $\forall \{n, [t + t2 \leq T]\}$:

$$\sum_{t}^{t+t2} G_{u,n,t} = \sum_{t}^{t+t2} \left(G_{u,n,t}^{nat} \times b_h \right), \quad \forall u \in RoR_{new} \quad (15)$$

$$\sum_{t}^{t+t2} G_{u,n,t} = \sum_{t}^{t+t2} G_{u,n,t}^{nat} , \qquad \forall u \in RoR_{ex} \tag{16}$$

Hydro with large reservoir (ReS) has a large flexibility to storage water for long time. Storage constraint for reservoir capacity, $\forall\{n,t\}$:

$$E_{h,n,t} = G_{u,n,t} - G_{u,n,t}^{nat} + E_{h,n,t-1}, \forall\{u,h\} \in \{ReS\} \tag{17}$$

$$\left(\alpha E_{h,n}^{max} \times b_h\right) \leq E_{h,n,t} \leq \left(E_{h,n}^{max} \times b_h\right) , \qquad \forall h \in ReS_{new} \tag{18}$$

$$\alpha E_{h,n}^{max} \leq E_{h,n,t} \leq E_{h,n}^{max} , \ \forall h \in ReS_{ex} \tag{19}$$

However, to avoid reservoir depreciation, maximum annual generation constraints are required, $\forall\{n\}$:

$$\sum_{t \in T} G_{u,n,t} \leq \sum_{t \in T} \left(G_{u,n,t}^{nat} \times b_u\right), \ \forall\{u \ \epsilon \ ReS_{new}\} \tag{20}$$

$$\sum_{t \in T} G_{u,n,t} \leq \sum_{t \in T} G_{u,n,t}^{nat}, \qquad \forall\{u \ \epsilon \ ReS_{ex}\} \tag{21}$$

Maximum and minimum hourly generation $\forall\{n,t\}$:

$$\left(G_{u,n}^{min} b_h\right) \leq G_{u,n,t} \leq \left(P_{u,n} b_h\right), \ \forall u \in \{RoR_{new}, ReS_{new}\} \tag{22}$$

$$G_{u,n}^{min} \leq G_{u,n,t} \leq P_{u,n} , \qquad \forall u \in \{ RoR_{ex}, ReS_{ex}\} \tag{23}$$

Thermal power was simplified to reduces the number of integer variables, therefore, ramp up & down constraints, startup & shut down time ramp limit constraints were not considered. Simplification allows simulation in reasonable time and memory capacity. Constraint (24) presents the maximum and minimum hourly generation $\forall\{n,t\}$:

$$0 \leq G_{u,n,t} \leq \left(P_{u,n} + P_{u,n}^{old}\right) , \ \forall u \in Th \tag{24}$$

For transfer between nodes is used the transport model [3], in this model transmission lines are considered as “pipelines” that can transfer a maximum power $\forall\{n, n2\} \in N_n$:

$$IN_{n2,n,t} \leq P_{l,n,n2} + P_{l,n,n2}^{old} \tag{25}$$

$$OUT_{n2,n,t} \leq P_{l,n,n2} + P_{l,n,n2}^{old} \tag{26}$$

Maximum and minimum hourly loss of load $\forall\{n,t\}$:

$$0 \leq P_{n,t}^{loss} \leq P_{n}^{loss} \tag{27}$$

Finally, decision variables limits:

$$P_{u,n}^{Min} \leq P_{u,n} \leq P_{u,n}^{Max} \tag{28}$$

$$P_{l,n,n2}^{Min} \leq P_{l,n,n2} \leq P_{l,n,n2}^{Max} \tag{29}$$

$$0 \leq P_{n}^{loss} \leq P_{n}^{Max,loss} \tag{30}$$

$$0 \leq P_{n,t}^{curtail} \leq P_{n}^{Max,curtail} \tag{31}$$

Table 2-4 present the descriptions of the symbols used in the formulation.

Table 2. Constants and indices.

Symbol	Description	Symbol	Description
h	Index for hydropower	R	Set of units r
H	Set of new hydropower h	RoR_{new} RoR_{ex}	Set of new and existing run-of-river
h_{step}	Duration (hours) of the time periods	ReS_{new} ReS_{ex}	Set of new and existing hydroelectric with reservoir
i_u	Discount rate	t	Time step index
l	Index for transmission line	T	Set of time steps t
$life_u$	lifetime	th	Index for thermal power plant
n	Index for node	Th	Set of thermal power plant
N	Set of nodes n	u	Index for unit type
N_n	Set of nodes n2 with a line to node n	U	Set of units u
r	Index for non-dispatchable renewable energy		

Table 3. Parameters.

Symbol	Description	Symbol	Description
α	Minimum reserve energy (%)	$Inv_{u,n}$	Investment cost of new units (USD/MW)
$c_n^{curtail}$	Penalty cost for curtailment of VRE (USD/MWh)	$L_{n,t}$	Hourly demand (MW)
$c_u^{emission}$	Emission costs (USD/MWh)	$OPEX_h$	OPEX of hydropower (USD/yr)
$c_{u,n}^{fixed\_O\&M}$	Annual fixed O&M costs of units (USD/MW/yr)	$P_{l,n,n2}^{Max}$	Maximum investment in transfer capacity between nodes (MW)
$c_{u,n}^{fuel}$	Variable O&M costs of units (USD/MWh)	$P_{u,n}^{Max}$	Maximum investment in generation (MW)
$c_n^{loss\_capaci}$	Penalty cost for insufficient capacity (USD/MW)	$P_n^{Max,curta}$	Maximum Curtailment allowable (MW)
$c_n^{loss\_load}$	Penalty cost for loss of load (USD/MWh)	$P_n^{Max,loss}$	Maximum loss of load allowable (MW)
$CAPEX_h$	Investment cost of hydropower h (USD)	$P_{l,n,n2}^{Min}$	Minimum investment in transfer capacity between nodes (MW)
$CF_{r,n,t}$	Capacity factor for renewable energy (dimensionless)	$P_{u,n}^{Min}$	Minimum investment in generation (MW)
CRF_u	CRF based on lifetime and interest rate *i*	$P_{l,n,n2}^{old}$	Transfer capacity between nodes initially installed (MW)
$E_{h,n}^{max}$	Maximum energy storage capacity (MWh)	$P_{u,n}^{old}$	Power initially installed (MW)
$G_{u,n}^{min}$	Minimum generation (MWh)	$t2$	Window of time that RoR units can reallocate water in the reservoir
$G_{h,n,t}^{nat}$	Natural inflow of the hydro (MWh)	tl	Transmission loss (%)
$Inv_{l,n,n2}$	Investment cost of transfer capacity between nodes (USD/MW)		

Table 4. Variables.

Symbol	Description	Symbol	Description
b_h	Binary variable of investment {0,1}	$E_{h,n,t}$	Energy stored in hydropower h (MWh)
$c_t^{curtail}$	Penalty cost for curtailment of VRE (USD/h)	$E_{h,n,t-1}$	Energy stored in hydropower h, at previous time period
$c_t^{emission}$	Emission costs of thermal units (USD/h)	$G_{r,n,t}$	Auxiliary variable for R set (MW)
c^{fixed_hidro}	Annual O&M costs with hydropower (USD)	$G_{u,n,t}$	Variable of generation for H and Th set (MW)
$c^{fixed\_O\&M}$	Annual O&M costs in new units (USD)	$IN_{n2,n,t}$	Variable of imports of energy from node n2 to node n (MW)
c_t^{fuel}	Fuel costs of thermal units (USD/h)	$OUT_{n,n2,t}$	Decision variable of export of energy from node n to node n2 (MW)
c^{inv}	Annualized investment in new units (USD)	$P_{l,n,n2}$	Variable of investment in transfer capacity between nodes (MW)
c^{inv_hidro}	Annualized investment in new hydropower (USD)	$P_{u,n}$	Variable of investment in generation (MW)
c^{inv_trans}	Annualized investment in new transmission line (USD)	$P_{n,t}^{curtail}$	Variable to indicate Curtailment possibility (MW)
$c^{loss\_capacity}$	Penalty cost for the maximum insufficient capacity (USD)	P_n^{loss}	Variable to insufficient capacity (MW)
$c_t^{loss\_load}$	Penalty cost for loss of load (USD/h)	$P_{n,t}^{loss}$	Variable of loss of load (MW)

BRAZILIAN SCENARIO

The installed capacity of the electrical system in 2021 was considered (generation, storage and transmission), and the investments already programmed for the expansion of the system according to electricity system operator [35]. Data for solar radiation and wind speed were extracted from ten-year energy expansion plan (EEP 2030), as well as economic data [33]. As a major cost reduction in wind and solar PV are expected, current costs are projected to 2050 as the analysis of [19]. Table 5 summarizes the data used.

Table 5. Parameters used for the technologies considered.

Unit Type	Fuel cost/MWh	Fixed cost/kW	Investment cost/kW	CO_2+NO_x+ SO_x cost/MWh	Lifetime	Interest %	Capacity by node (MW)				Maximum investment by node (MW)			
							S	SE	NE	N	S	SE	NE	N
Coal	24	159	2100	26	25	8	1577	158	1303	544	-	-	-	-
CCGT[1]	71	84	1000	17	20	8	1411	5675	1379	1175	-	-	-	-
OCGT[2]	92	96	800	7	20	8	0	2658	2007	1448	-	-	-	-
Nuclear	5	66	5000	-	30	8	0	1990	0	0	-	-	-	-
Sugarcane	-	90	1200	-	20	8	541	1e4	878	107	-	-	-	-
Biomass	-	120	1500	-	20	8	1102	1388	496	383	-	-	-	-
Biogas	-	163	1531	-	20	8	12	155	0	2.4	-	-	-	-
Urban waste	-	276	4000	-	20	8	0	28.2	0	0	-	-	-	-
Wind	-	55	918	-	20	8	2022	0	14800	0	1e5	0	1e5	0
PV	-	39	82	-	20	8	8	923	2128	5	7000	4e5	1e5	4e5
SHP[3]	-	65	1531	-	30	8	2005	3950	143.4	0	4700	1e4	800	0

[1] Combined Cycle Gas Turbine. [2] Open Cycle Gas Turbine. [3] Small Hydro.

For hydropower, it was considered two types: i) reservoir (ReS); and ii) run-of-river (RoR). Table 6-7 summarize hydropower data and the list of available hydropower.

Table 6. Hydro data.

Hydro type	Minimum generation (%)	Minimum storage (%)	Initial reservoir level (%)	Capacity by node (MW)				Storage Capacity by node (GWh)			
				S	SE	NE	N	S	SE	NE	N
ReS	10	20	70	8231	14878	4023	10818	14247	1.5e5	37178	10619
RoR	10	-	-	6700	29808	8731	25850	-	-	-	-

Table 7. List of available hydropower.

Name	Type	Node	Fixed $/kW	Inv. Cost/kW	Cap. (MW)	Storage cap. (GWh)	Life-time	IR %
Maranhão	ReS	SE	129	1939	125	2647	30	8
Mirador	ReS	SE	129	2082	80	1230	30	8
Buriti Queimado	ReS	SE	129	3122	142	1800	30	8
Formoso	ReS	SE	129	2204	342	1981	30	8
Apertados	RoR	S	129	1857	139	-	30	8
Santo Antônio	RoR	S	106	1429	84.3	-	30	8
Itapiranga	RoR	S	106	1653	724.6	-	30	8
Saudade	RoR	S	129	1939	61.4	-	30	8
Telêmaco Borba	RoR	S	106	1612	118	-	30	8
Paranã	RoR	SE	129	1959	90	-	30	8
Itaguaçu	RoR	SE	106	1510	92	-	30	8
Porto Galeano	RoR	SE	106	1673	81	-	30	8
Jatobá	RoR	NE	129	1878	1650	-	30	8
Tabajara	RoR	N	129	1980	400	-	30	8
Castanheira	RoR	N	153	2510	140	-	30	8

Abbreviations: Investment (Inv); Capacity (Cap); Interest rate (IR).

For transmission lines, the installed capacity was considered, plus the capacity already contracted as: N-NE 8,500 MW; N-SE 13,400 MW; NE-SE 7,500 MW; SE-S 11,500 MW. With a cost of: 286 USD/kW for N-NE and NE-SE; 367 USD /kW for N-SE; and 163 USD /kW for SE-S [33]. To DG, the projection of 118 GW for solar PV and 140.1 TWh for self-production was considered, according to National Energy Plan 2050 (NEP 2050) [22]. Finally, a penalty cost of 1,071 USD/MWh was considered for loss of load and 555,612 USD/MW for insufficient capacity [36]. There is no set cost for curtailment in Brazilian system.

RESULTS AND DISCUSSION

This section presents some scenarios to Brazilian in 2050, considering the formulation and data presented.

Base scenario

In this base case, the total expansion cost was USD 28,790 million. Figure 1 presents the results for new units. All available ReS units (689 MW), six RoR units (1,190 MW) in the South and Southeast, and no SHP were added. Non-renewables expansion accounted for 27,119 MW, including coal and gas; nuclear was not installed. Wind and sugarcane together accounted for 139,929 MW, while solar PV installed the minimum (2,000 MW) and biomass, biogas, and urban waste were not installed. Although there is no new solar PV (only the minimum), 118 GW were installed in the DPV.

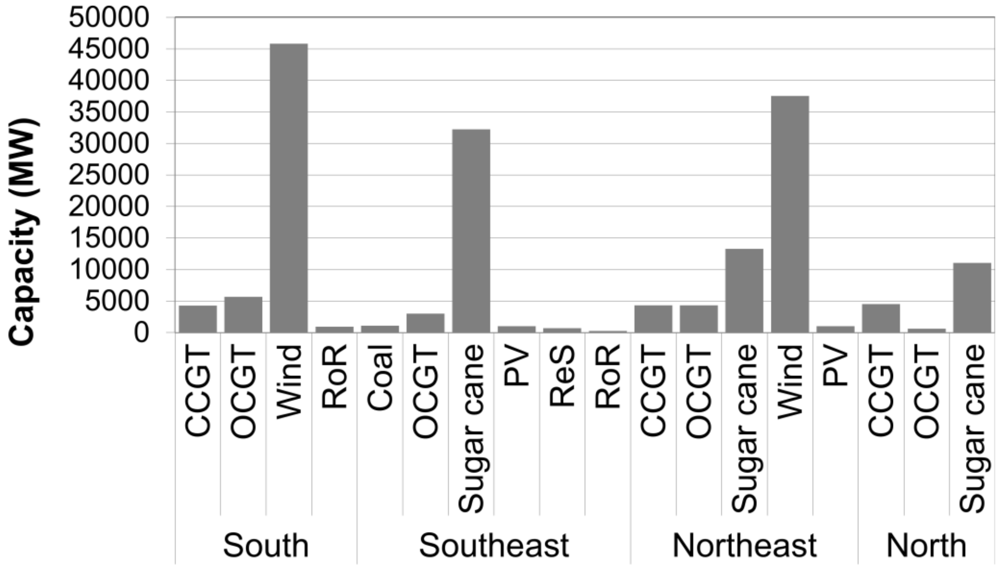


Figure 1. Capacity installed.

Figure 2 shows hourly operation for a week in April, a period when reservoirs have lower levels and lower wind generation. The duck curve phenomenon is caused by DPV.

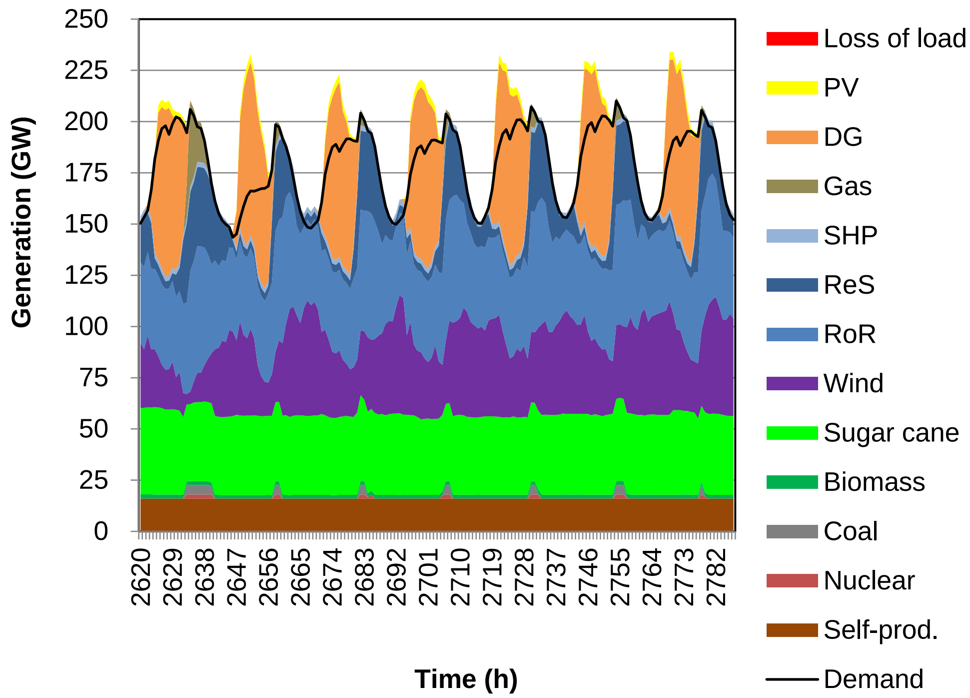


Figure 2. Results of hourly dispatch for a full week of April in 2050.

Greater flexibility capacity is required to reduce generation at the beginning of the day, resulting in the shutdown of all thermal power plants, reduction of hydro ReS to the minimum allowable generation (15%), and curtailment. In contrast, at the end of the day, there is a need to increase generation due to the decrease in DPV and hourly peak demand, which leads to an increase in hydropower generation and the entry of thermal power plants. With an hourly resolution, it is possible to analyze up-ramping and down-ramping demand.

VRE generation (wind and solar PV) represented 43% of annual demand, with 10.7% curtailments, representing 4.5% of annual demand. The maximum simultaneous peak of curtailments was 90.2 GW. The annual deficit was 374 GWh, equivalent to 0.023% of annual demand, and the maximum coincident loss of load was 23.2 GW. Figure 3 presents the results of the transfers by node. The Southeast region has higher energy demand and therefore receives more energy from other regions. The Northeast region has a large wind potential (Figure 1). However, the energy demand is low, thus, the excess energy is exported to the Southeast. For this purpose, 20 GW transmission lines were installed from the Northeast to the Southeast. Figure 3 shows the importance of complementarity in supplying the Southeast. 4.4 GW of transmission lines were installed from South to Southeast, 8.8 GW from North to Southeast.

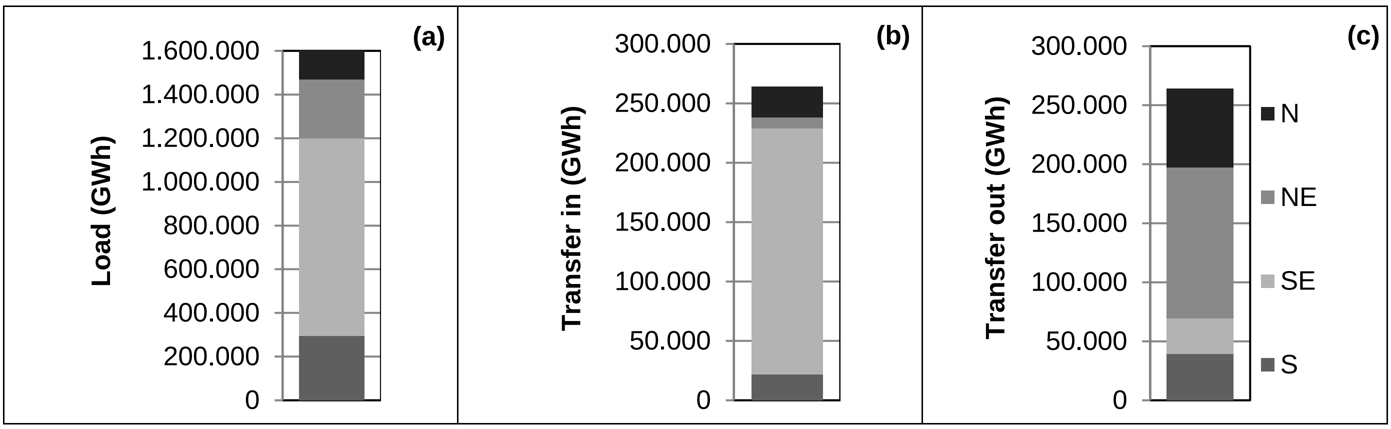


Figure 3. Results of nodes: (a) Load; (b) Transfer to the node; (c) Transfer out of the node.

GHG scenario

In this scenario, the cost of greenhouse gas (GHG) emissions is taken into account. As a result, the total cost of expansion was USD 29,449 million, an increase of 2.3%. The GHG emissions costs amounted to USD 609 million (2% of the total costs). In addition, non-renewable production was reduced by 25.4%. Coal has the higher GHG emission, as result no new plant was built, and generation decreased by 36%. In addition, CCGT expansion capacity and generation was decreased by 18% and 28% (Figure 4).

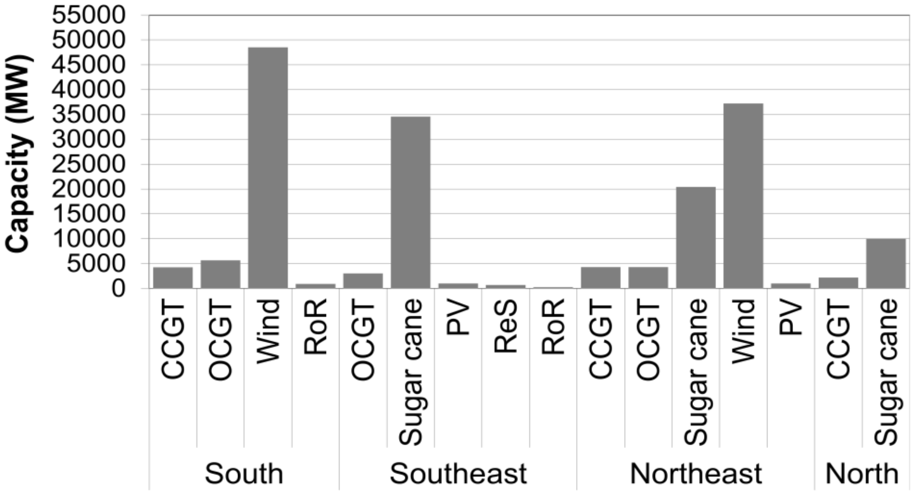


Figure 4. Capacity installed (GHG scenario).

Wind and sugarcane were responsible for offsetting the decline in non-renewable, suppling 50% of annual demand. VRE generation met 44% of annual demand, however; curtailments increased by 33%, equivalent to 6.1% of annual demand. Despite deficit increasing by 9.5%, it is only 0.026% of annual demand.

ZDeficit scenario

This study has shown that the current penalty costs for loss of load are not sufficient to avoid a deficit. In this scenario, the costs for GHG emissions are taken into account, and the penalty costs were increased to avoid a deficit, for which the penalty costs had to be multiplied by three. To achieve this result without a deficit, the total expansion costs had to be increased by 5.9% compared to the GHG scenario and reached USD 31,184 million. To reduce the deficit, VRE was reduced by 39.7% in compared to the GHG scenario, while other non-dispatchable energy source were increased by 50.6% to fill the gap. In the GHG scenario, the deficit was 409 GWh, in the ZDeficit scenario there is no deficit, and the curtailment was reduced to 5.5%. This scenario is characterized by the installation of SHP (Figure 5), and the maximum investment in SHP was achieved in the Southeast and Northeast.

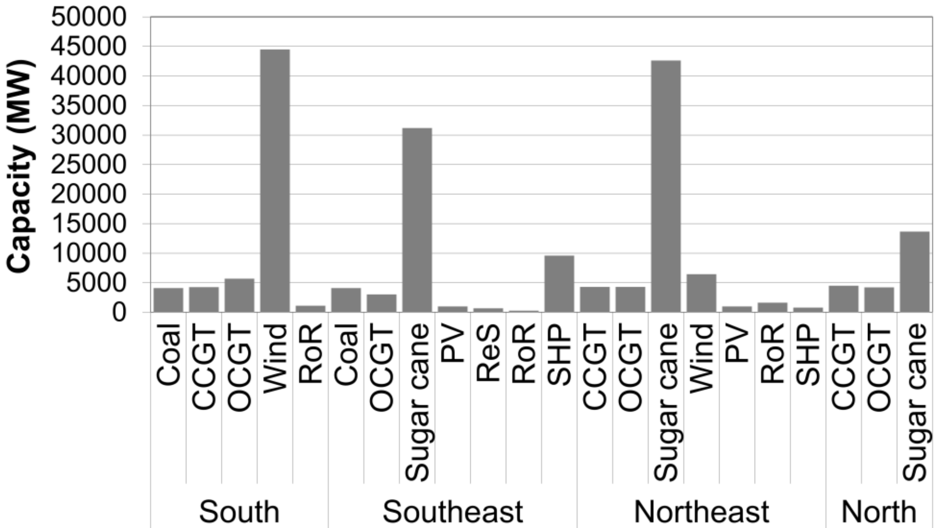


Figure 5. Capacity installed (ZDeficit scenario).

Capacity growth was concentrated in the Southeast and the North. Despite the increase in non-renewable capacity (45%), non-renewable generation decreased by 8.7% compared to the GHG scenario, however; GHG emissions increased by 13.4% because coal-fired power plants were installed (8.2 GW). In fact, more flexible power plants were installed to supply peak demand, resulting in a low capacity factor (Figure 6).

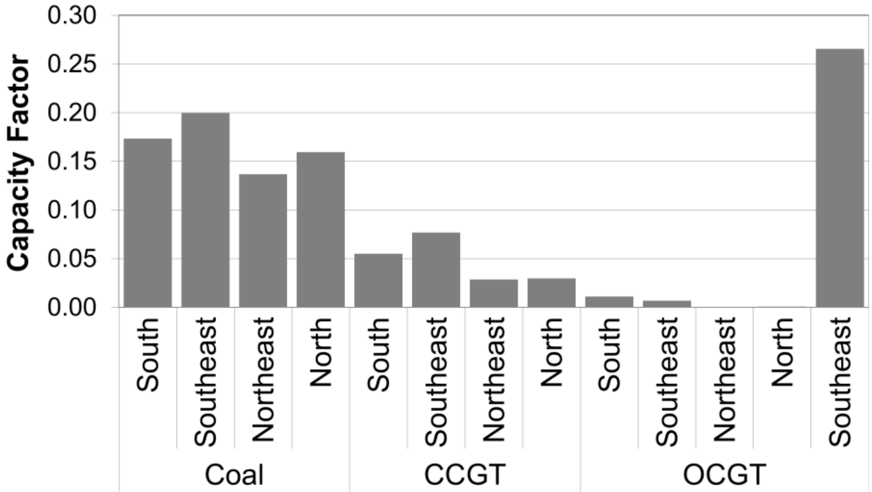


Figure 6. Capacity Factor (ZDeficit scenario).

Figure 7 presents the management of the reservoirs during the year. It can be observed that the reservoirs reach their minimum in March and their maximum in September, using only 13% of the total storage capacity for management. In the North, the minimum level is reached exactly when there are floods in this region, which complements the wind generation. The correlation between hydropower in the North and wind farms in the South is -0.92 [19].

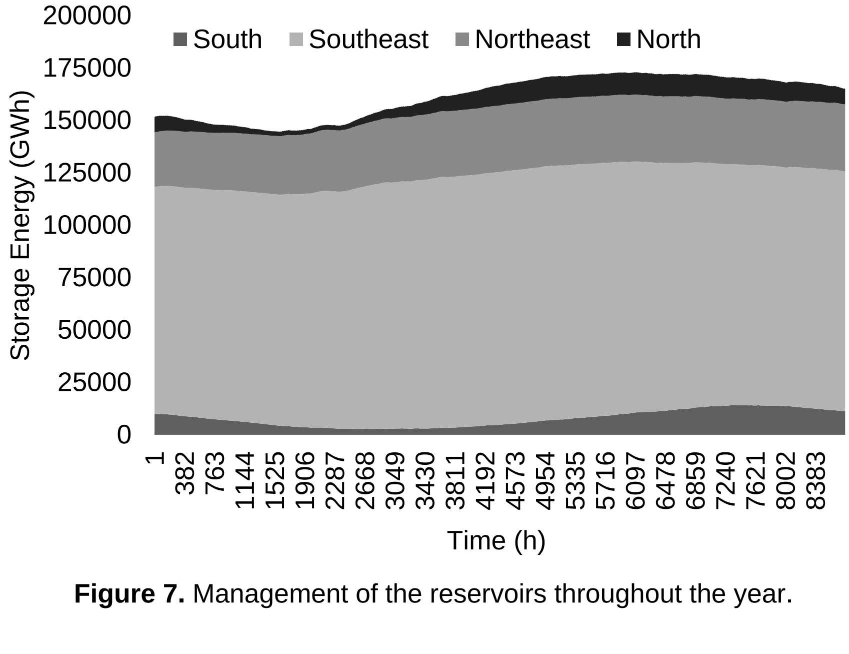


Figure 7. Management of the reservoirs throughout the year.

DISCUSSION

The scenario with zero deficit (ZDeficit) is compared in this section with other works (Table 8). Scenario 2020 is the current system composition and NEP is the baseline scenario projection for 2050 developed by NEP. COPPE and GILS have presented a similar share of hydropower. In this paper, the share of hydropower was lower because only four plants with large reservoirs were considered [33]. The RoR expansion was limited by the flexibility of this technology. To compensate for the low share of hydropower, the share of biomass is higher than other studies. Although biomass technology has a high cost and is non-dispatchable, it played an important role in reducing the storage requirements due to its high complementarity with hydropower [11]. As can be observed, the present study came to a similar conclusion as COPPE, Gils and NEP did for solar PV. Although a more flexible unit is required in the hourly analysis, the non-renewable share was low compared to other studies.

Table 8. Annual participation in the power generation (in %).

Scenario	Hydro	Wind	PV + DG	Bio.	Coal	Gas
2020[1]	65.2	8.8	1.7	9.1	4.7	8.3
ZDeficit	33.6	13.0	18.2	32.8	1.2	0.7
COPEE[2]	53.7	11.3	16.1	9.3	3.3	3.6
GILS[3]	47.0	26.0	18.0	9.0	-	-
NEP[4]	36.0	37.0	17.5	2.2	0.0	5.7

1 [37]. **2** [13]. **3** [23]. **4** [22].

CONCLUSION

A time-steps of one hour in the expansion energy planning is essential to evaluate flexibility. Hourly resolution allowed optimization of water reservoirs, while other studies for the Brazilian case do not. Hourly resolution also made it possible to identify the deficit problem and the need to increase the penalty price. When GHG emissions were taken into account, no coal-fired plant was installed, however; in a zero-deficit scenario, it was necessary. It is possible to supply 2050 demand without large reservoirs or deficits, with a 5.5% curtailment and using 13% of storage capacity, however; peaking power plants are needed to provide flexibility. To improve the low power plant capacity factor, minimum generation constraint can be introduced, as well as battery storage systems and demand response programs. The size of the model was limited by computer capacity. Thermal power ramp up & down constraints, startup & shut down time ramp limit constraints can be implemented in new studies using decomposition technique.

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