Water values and marginal costs for power generation planning under more restrictive constraints and a more detailed representation of hydro plants

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***Abstract*— Power generation planning for real large-scale systems is a complex multistage stochastic problem, which requires modeling approximations for the representations of system components and operating constraints in order to be efficiently solved by the stochastic dual dynamic programming (SDDP) approach. This paper presents an analysis of the impacts of a more detailed representation of the hydro plants and the inclusion of more restrictive hydraulic constraints in the recourse functions that are built by the SDDP strategy, as well as in the simulation outputs of this problem. While some results are rather obvious - as the increase in systems costs - others are counterintuitive, such as the decrease in thermal generation levels and water values in some situations. Results are presented for the individualized modeling of the hydro plants in the official models applied for long-term hydrothermal planning in Brazil.**

***Index Terms* – Power generation planning, stochastic dual dynamic programming, water values, hydraulic constraints.**

Nomenclature and acronyms

CMH:	implict marginal hydro generation cost;
CVAR:	conditional value-at-risk measure;
EER:	equivalent energy reservoir;
FCF:	future cost function;
HG:	hydro generation;
HPP:	hydro power plants;
IND:	individual representation of hydro power plants;
ISO:	independent system operator;
LNG:	liquefied natural gas thermal plants;
LTGP:	long term power generation planning;
MC:	marginal cost;
MTGP:	mid-term power generation planning;
PAR(p):	periodic autoregressive model;
PAR(p)-A:	PAR model with additional annual correlation term;
SDDP:	stochastic dual dynamic programming;
SMC:	system marginal cost;
TC:	total costs;
TG:	thermal generation;
WV:	water value.

I. Introduction and Motivation

Long term power generation planning (LTGP) of hydro-thermal-wind systems aims at the optimal use of generation resources within the planning horizon, meeting the demand for energy while accurately representing the system components, and also satisfying many operational constraints and system security requirements. However, due to the high computational effort to solve such problem by the stochastic dual dynamic programming (SDDP) approach [1], aggregation of hydro power plants (HPP) in equivalent energy reservoirs (EERs), initially proposed in [2], is still a useful practice [3] to obtain good operation policies, i.e., recourse functions of each stage, in reasonable CPU times. This type of modeling was adapted to the Brazilian case [4] with several improvements so far [5]. In addition to considering the data and constraints per hydroelectric plant in the construction of the EER, the equivalent modeling seeks to represent in the most possible detailed way the individual characteristics of the plants, such as the hydraulic coupling between EERs [6] and losses due to spillage in run-of-the-river plants [7]. The EER modeling seeks an adequate balance between accurate consideration of uncertainties, detailed system representation, CPU effort to solve the problem, strict convergence criteria for the SDDP approach and quality of the operative policy.

In Brazil, NEWAVE [5] is an optimization model for long term power generation planning, considering uncertainty on hydro inflows by a periodic autoregressive model with annual correlation term (PAR(p)-A) [8], as well as uncertainty on wind generation, which impacts the net demand [9]. The problem is solved by SDDP, building optimal operation policies for each stage. It has been widely used since 1998 in many activities of the electricity sector such as calculation of the assured energy of the plants, evaluation of ten-year expansion plans, and also for system dispatch and price setting, together with the mid-term DECOMP [10] and short-term DESSEM [11] models.

However, the operation of hydro plants and watercourses has been progressively impacted by environmental concerns related to nature, human activities such as fishing, recreation and navigation, and other uses of water, as for example for irrigation and human/animal supply. For a more detailed review of these constraints we refer to [12] and references therein. Such concerns have imposed severe minimum/maximum outflow constraints for the reservoirs, which highly impact the operation of predominantly hydro systems. Due to the need for a more detailed representation of water courses to meet these requirements, the official operation planning and price setting in Brazil is evolving from an EER modeling of reservoirs in the long term to a "hybrid" setting [13], where an individual representation (IND) of HPPs is performed up to stage T^{ind} (typically, the end of the first year of the planning horizon) and an EER modeling is employed in the following stages, as shown in Figure 1, where the boxes indicate the subproblem related to each stage t. Therefore, water storage is initially modeled as stored volume V until stage T^{ind} and converted into stored energy E in the transition state T^{ind}. As a consequence, the Future Cost Functions (FCF) built during the SDDP method have V / E as arguments before / after stage T^{ind}, respectively.

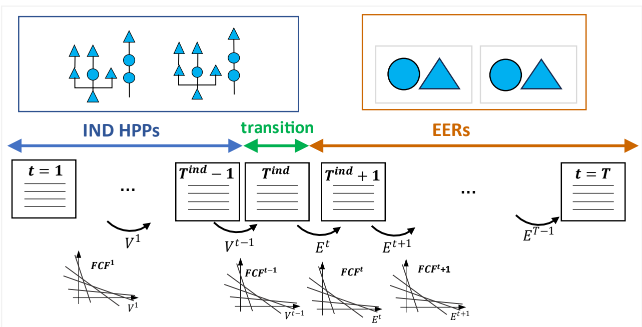

Figure 1. General scheme for the modeling of hydro plants (triangles: run-of-the-river plants; circle: reservoirs) in long term planning.

Denoting Ω_i the set of all reservoirs belong to EER i, the relation between stored energy E_i and storages in all reservoirs belonging to Ω_i is given by $E_i^t = \sum_{j \in \Omega_i} \rho_{cum\,j} V_j^t$, where $\rho_{cum\,j}$ is the average cumulated productivity of each reservoir j downstream the cascade. For details we refer to [2], [4].

The hybrid approach takes the benefits of an individual representation of HPPs on the horizon closest to operational decision-making, and an aggregated representation with as many EERs as are needed to represent hydrological diversity between watersheds on more distant time horizons, without overly increasing the CPU time to solve the problem. In addition, individualized modeling allows for additional representation of other specific hydraulic components such as pumping stations and bypass channels between plants, as well as more detailed hydraulic and electrical constraints that could not be represented in much detail with an EER model.

A. *Objective of this work*

This work aims to: (i) conceptually evaluate the impacts, on the water values and marginal system operation costs, of the individual representation of HPPs and more detailed hydro constraints in the LTGP problem solved by SDDP; (ii) analyze the major changes in system operation when shifting from an EER to an individual model of HPP; (iii) to evaluate the characteristics of the individualized future cost function (FCF) obtained by SDDP when max/minimum release constraints for the HPPs are enforced. We note that the literature related to individualized representation of HPPs in LTGP problems in large-scale systems with a detailed representation of constraints is very scarce [13]-[15]. To the best of the authors´ knowledge, there is no work that presents a careful analysis of the effects of individualized modeling and representation of hydraulic constraints on the simulation results of the plants, since existing works [16], [17] consider a very simplified representation of the generation characteristics of hydroelectric plants, both in EER and individual modeling of the HPPs. In addition, some of the findings of the paper are counterintuitive and help for a better understanding of the effect of hydro constraints on water values and marginal costs of the hydrothermal coordination problem.

Therefore, the main objective of this paper is to make a comparative analysis of the simulation outputs of the official hydrothermal planning model used in Brazil [5], [13] with aggregate and individual representation of the hydro plants, as well as between an individual representation with or without more severe hydraulic constraints.

II. Individual vs. Aggregate Representation

We show in Table I and Table II a comparative analysis of the modeling of system components and constraints in our LTGP problem with the EER and IND modeling approaches for the HPPs. Water is converted into energy in the EER modeling to consider the position of each plant along the cascade [2]-[4]. Some aspects of the system modeling do not depend on the type of representation of HPPs, such as demand attainment, interchanges among system areas, CVAR risk averse measure [18], modeling of LNG thermal power plants [19], etc.

TABLE I. Component Modeling – EER vs. IND representation.

Component	EER modeling	IND modeling
Individual hydro power plants	No	Yes, with aggregated generation units
LNG/ conventional thermal plants	Yes, with anticipated dispatch [19]	
Wind power plants	Yes, with uncertainty and curtailment [9]	
Solar plants	Yes, fixed generation	
Small plants not centrally dispatched	Yes, fixed generation	
System areas	Yes	
Electrical network	Major transmission lines	

A. *Formulation of hydro constraints in the IND modeling*

The IND modeling consists in an individual representation of hydro plants, with upstream/downstream relations along the cascades. Even though a plant may have many generating units, we consider single turbined outflow (Q) and generation (GH) variables for the whole plant. In the case of Brazil, the number of such variables reduces from 738 units to 162 hydro plants.

TABLE II - .MODELING OF CONSTRAINTS – EER VS. IND.

Constraints	EER modeling	IND modeling
Individual water balance constraints	No	Yes
Evaporation	Yes, variable with energy stored in EERs	Yes, variable with water stored in HPPs
Hydro production function	EER maximum power as a function of stored energy level	Piecewise liner model for HPP generation - AHPF [20]
Maximum turbined outflow	Yes (energy)	Yes (water flow)
Min/max hydro generation constraints	Yes	Yes
Min/max storage constraints	Yes (energy)	Yes (volume)
Water intakes for other uses	Yes, as a fixed value	Yes, as a fixed value
Minimum release constraints	Yes (except run-of-the river plants)	Yes (all plants)
Electrical constraints	Yes (within the EER)	Yes (general)
Maintenance and availability factors for hydro units	Yes	Yes
Max. release constraints	Yes (energy)	Yes (turbined or total release outflows)

We present below the mathematical formulation of hydro constraints in the IND modeling: minimum and maximum generation $(1a)$, minimum storage (V) constraints $(1b)$, water intakes Q_{out} for other uses $(1c)$, minimum and maximum total discharge $(Q_d = Q + S)$ constraints $(1d)$, where S is the spillage of the plant, and total turbined outflow constraint $(1e)$.

$$GH_{\min_i}^{t} \leq GH_i^{t,p} + \delta_{GH_{\min_i}}^{t,p} - \delta_{GH_{\max_i}}^{t,p} \leq GH_{\max_i}^{t} \tag{1a}$$

$$V_{\min_i}^{t} \leq V_i^t + \delta_{V_{\min_i}}^{t} \tag{1b}$$

$$Q_{\text{out}_i}^{t} + \delta_{Q_{\text{out}_i}}^{t^-} - \delta_{Q_{\text{out}_i}}^{t^+} = Q_{\text{out}_i}^{t} \tag{1c}$$

$$Q_{D_{\min_i}}^{t} \leq Q_i^t + S_i^t + \delta_{D_{\min_i}}^{t} - \delta_{D_{\max_i}}^{t} \leq Q_{D_{\max_i}}^{t} \tag{1d}$$

$$Q_{\min_i}^{t} \leq Q_i^t + \delta_{Q_{\min_i}}^{t} - \delta_{Q_{\max_i}}^{t} \leq Q_{\max_i}^{t} \tag{1e}$$

In the notation above, i, t and p indexes the hydro plants, time interval and corresponding load levels, respectively, and (x_{min}, x_{max}) denotes minimum and maximum constraints for variable x. We add slack variables $\delta_{x_{min_i}}^{t}$, and $\delta_{x_{max_i}}^{t}$, which are heavily penalized in the objective function, to allow violation of the constraints (if necessary) and thus ensure the relatively complete recourse property for the stochastic program.

Besides the constraints (1), hydro plants and reservoirs are also subject to the physical constraints in the first three rows of Table II, and are categorized in two groups: reservoirs with monthly regulation or weekly/hourly regulation. Due to the monthly time discretization in the LTGP model, variation of storage is considered only for plants in the first group, while plants in the second group are run-of-the-river plants. We note that, in the EER modeling, hydro constraints – which are always enforced in hm^3 or m^3/s, depending on its type – are converted into energy constraints, as described in [5]-[7], [13], [21].

B. *Penalties for constraint violations*

An important aspect when handling the LTGP problem is that, due to extremely large number of combinations of hydro inflows along the time steps of the planning horizon, it is nearly impossible to satisfy all operating constraints, even in the EER modeling, but especially in the IND modeling. We note that the aggregation procedure in the EER model allows the inflow to a given plant to help satisfying constraints related to other plants. Violation of hydro constraints are handled by an exact penalization scheme. A special care must be taken when choosing penalty values, since a violated constraint impacts system operation, water values (WVs) and system marginal costs (SMCs). We proceed as follows:

- for energy constraints, e.g., $GH_{\min}$ and $GH_{\max}$, the penalty value in \$/MWh ($PenMWh$) should be larger than the cost of any available resource, such as thermal plants;
- the penalty value should be lower than the deficit cost, in order to avoid the so called "preventive deficit", which is load curtailment in a given stage even when there is still water in the reservoir, to avoid larger (and more expensive) curtailments in the future. Although this is a possible solution for the problem, it is a measure rarely implemented by the ISO in practice;
- for hydro constraints, the reference value $PenMWh$ for energy constraints (in \$/MWh) must be converted to a penalty value in \$/hm^3, in such a way to maximize the use of water for energy, as follows:

  ✓ water intakes: $PenMWh$ is multiplied by the maximum cumulated productivity (MWh/hm^3) along all cascades. The cumulated productivity for each plant is computed in its main downstream cascade, and the maximum value is used in the penalty conversion to assure the penalty to be at least equal to the penalty of violation of the energy constraints.

  ✓ min/max outflow/discharge: $PenMWh$ is multiplied by the average individual productivity (MWh/hm^3) of all plants.

III. DISCUSSION ON SOME ASPECTS OF THE IND MODEL

In this section we discuss some important aspects that should be assessed when shifting from an equivalent EER model to an individualized IND model for the hydro plants in the LTGP problem, both in the point of view of representation of uncertainty and from the point of view of representing the physical and operational characteristics of the plants.

A. Scenario generation with PAR(p) or PAR(p)-A models

When a more refined representation of plants is applied, the specific hydrological behavior of the region in which each plant is located is more accurately represented. On the other hand, there is an increase in the dimensionality of this problem by increasing the number of state variables associated with past inflows, due to the periodic autoregressive model PAR(p) [22] Thus, it is essential to seek strategies that allow finding a reasonable balance between representation of uncertainty and computational efficiency, possibly with inflow aggregation techniques [23]. We note that scenario sampling for individualized inflows for the hydro plants is a very difficult task, because such a high dimension in the vector of random variables affects the distance measures used in clustering algorithms, due to the increasing similarity of the distances between the data points, causing the relative differences between the distances to lose meaning.

The NEWAVE model uses the Selective Sampling scenario reduction method of [24], which aims to capture the spatial correlation of inflows and represent them with a reduced number of synthetic scenarios. Also, the PAR(p) model of [22] was recently improved to better represent the annual correlation among water inflows, yielding the so-called PAR(p)-A model of [8]. When shifting from EER to IND model for hydro plants, we calibrate parameters for each plant, instead of using a high-dimensional PAR(p)-A model. Although several statistical tests in [25] confirm the effectiveness of the PAR(p)-A model in generating critical scenarios, thus reproducing the good statistical properties of the PAR(p) model, more exhaustive analyses can be performed with the PAR(p)-A model applied to the individualized model for the hydro plants.

B. Higher degree of freedom in operation decisions and greater difficulty in building the FCF

The use of the IND model leads to a future cost function (FCF) with a much larger dimension, since there is an additional axis for the storage of each hydroelectric plant with regulating reservoir. This increases the degree of freedom for decision-making, as the valuation of water individually in each plant allows a wider range of "implicit" operating rules embedded in the FCF. For example, a key assumption when applying the EER model is the simultaneous filling (or emptying) of the reservoirs along the cascade. However, it may be more profitable to allocate a given incoming water flow in more interesting locations both in terms of efficiency in the reservoirs (for hydro production) or in terms of storing water for future use, and the IND model allows such flexibility. Moreover, in the FCF built through an EER model of the hydro plants, the water values are not able to indicate the risk of spillage in some specific plants of the hydro basin, where inflows may be high.

Despite the greater potential and flexibility of the IND model to assign water values in the FCF, the state space of the system largely increases, requiring a greater number of forward scenarios – and, consequently, Benders cuts and / or SDDP iterations – to explore the state space of the problem, thus requiring a much greater computational effort. In summary, there is a trade-off between the greater potential of the IND model and the difficulty in exploring it.

C. Higher severity of hydro constraints in the IND model

Another relevant aspect is that the inclusion of specific constraints for hydro plants, time steps and scenarios along the time horizon of the LTGP problem largely increases the difficulty in satisfying all constraints in all scenarios. For example, from the spatial perspective, a minimum energy storage constraints or maximum outflow constraint for the EERs can be met by different combinations of operation decisions for the individual plants, and all of them may be satisfactory for the ISO. On the other hand, enforcing specific storage or release constraints for each individual hydro plant may lead to a very restricted system operation, since the operation of a given plant cannot be compensated by the operation of other plants.

From the temporal point of view, the enforcement of constraints in successive time steps largely increases the difficulty in satisfying them for all scenarios. To illustrate this fact, Figure 2 shows the induced feasible region, for the water stored at the end of time step $t-1$, when minimum ($Q_{D_{\min}}$, in red) and maximum ($Q_{D_{\max}}$, in blue) constraints, which are parametrized in opposite direction in the x axis, are imposed in successive time steps in the future. Each dashed line indicates the effect of the constraint imposed at a given future time step and scenario, and the solid lines represent the most restrictive (dominating) ones. As the constraint becomes stricter, i.e., greater minimum releases and lower maximum releases, both towards the right side of the chart, higher and lower storage volumes at the end of $t-1$ are required to meet these constraints, and the feasible region for optimal storage (in dark gray) shrinks. Therefore, constraint violations become more often, which makes it very important to carefully tune the penalty values for slack variables δ.

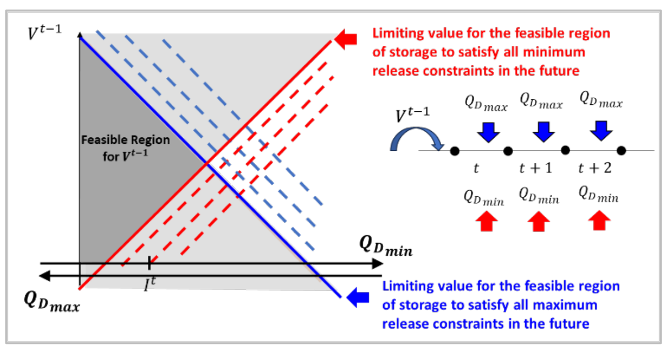

Figure 2. Feasible region for the storage at the end of time step $t-1$, as a function of minimum and maximum release constraints (x axis).

In view of such difficulty, in the individual model of the hydro plant we still allow the inclusion of storage constraints for each EER. They are represented in the optimization problem by expressing the corresponding energy storage variable of the EER as the combination of individual storages of the hydro plants, each one with its coefficient in the composition of the total energy storage of the EER.

IV. CONCEPTUAL ANALYSIS OF THE IMPACT OF HYDRO CONSTRAINTS

We discuss the impact of each type of hydro constraint in total costs (TC), marginal costs (MC) and water values (WV) for the subproblem of a given time step t and scenario of the LTGP problem. The analysis is summarized in Table III, where the first column indicates the type of constraint and the second column its possible status - binding ("bind") or violated (viol."). The upward (red) darts and downward (green) darts indicate an increase and decrease, respectively, in the variable indicated in the first row, caused for each combination of constraint and corresponding status. The symbol "ND" indicates the situations where the effect of the constraint/status is not clear, in theory.

TABLE III - . IMPACT OF HYDRO CONSTRAINTS IN SEVERAL VARIABLES OF A GIVEN TIME STEP AND PERIOD OF THE LTGP PROBLEM

Const. Type	**Status**	**Total cost (TC)**	**Stage *t* cost**	**Stage t SMC**	**Future Cost**	**Water Value ($t-1$)**
$Q_{\min}, GH_{\min}$	bind	↑=	↓=	↓	↑	↑
$Q_{\min}, GH_{\min}$	viol.	↑=	↑ (Viol.)	=	=	↑
$V_{\min}$	bind	↑=	↑=	↑	ND	↑
$V_{\min}$	viol.	↑=	↑ (Viol.)	=	↑	↑
$Q_{\max}, GH_{\max}$	bind	↑=	↑=	↑	ND	↓
$Q_{\max}, GH_{\max}$	viol.	↑=	↑ (Viol.)	=	=	↓
$V_{\max}$	bind	↑=	↓=	↓	↑	↓
$V_{\max}$	viol.	↑=	↑ (Viol.)	=	=	↓
Q_{out}	bind	↑=	↑=	↑=	↑	↑=
Q_{out}	viol.	↑=	↑ (Viol.)	=	=	↑=

We note that the results presented in the table were obtained from simulations of the model, and some of them did not follow our *a priori* intuition, as for example the decrease in water values when maximum release constraints are imposed. The intuitive explanation of each cell is as follows:

- total cost (TC): will always be higher, because a more restricted problem will always have a greater or equal cost than a less restricted problem. The same idea is valid for the value of the future cost function for a fixed state, when constraints are included;
- constraint that prevent the generation of the hydro plant, such as maximum release/generation or minimum storage: increases the SMC at the time step when it is applied, since it may avoid the use of cheaper resources, which will be replaced by more expensive ones. The present cost at this interval may increase or not, because the hydro generation may have been replaced by another hydro plant, thus not increasing thermal generation. The impact in the FCF is also undefined, since it may increase or not. As for the impact on the water value used to build the derivative of the FCF of the previous stage, it differs depending on the type of constraint:

  ✓ maximum release/generation: reduce water values, especially when storage is high, in order to stimulate previous stages to release water and avoid spillage in the future;

  ✓ minimum storage: increases water values, in order to stimulate previous stages to save water to meet the constraint in the future.
- constraint that enforces generation, such as minimum release/generation or maximum storage: has the effect of reducing the SMC at stage t, as it forces a more expensive generation, leaving less room for generation of cheaper thermal plants or hydro plants with lower water values. The total cost in the stage may decrease or not, because hydro generation may replace the generation of another hydro, but the future cost is higher, due to the "undesired" use of a more expensive resource at stage t, thus changing system conditions in the future. The impact on the water values also depends on the type of constraint:

  ✓ minimum release/generation: increases the water value, especially when storage is low, to stimulate previous stages to save water to meet the constraint in the future;

  ✓ maximum storage: decreases the water value, to stimulate previous stages to use water and avoid spillage;
- constraint that removes resources, such as water intakes and evaporation: increases the SMC when applied to a plant that has been dispatched; due to lower storages, increases both future costs and water values. If it causes an increase in thermal generation, the stage cost also increases;
- varying the bound of a constraint that is already violated: increases or decreases the violation cost but does not impact other variables, since the constraint cannot be met anyway.

Figure 3 illustrates the impact of hydro constraints in the water values (derivatives) of the FCF for a very toy problem of a single reservoir and two stages: minimum release constraints increase WV at lower values of storage, while maximum release constraints decrease WV at higher values of storage. In the case of plants in cascade this analysis is more involving (see section V-B). A more detailed analysis of this effect is discussed in [12]. We note that the relationships shown in Table III may not hold in the case of state-dependent constraints [26].

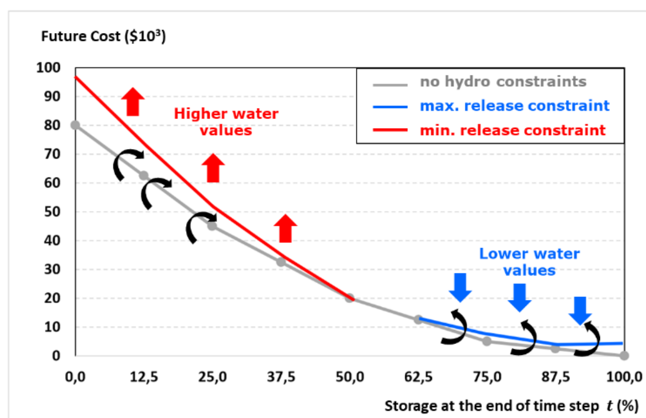

Figure 3. Impact of min/max release constraints at time step $t+1$ in the WVs of the FCF at the end of time step t (toy problem with 1 reservoir).

V. NUMERICAL EXPERIMENTS

We present comparative results between the EER and IND modelings of hydro plants in the NEWAVE model [5], with or without additional hydro constraints, for real Brazilian cases. The IND modelling has 162 hydro plants (60 with monthly regulation and 102 run of the river plants), which are aggregated in 12 EERs in the EER modeling. We also assess the impact of each policy in the results of the first stage decisions in the mid-term model DECOMP [10], which has a 2-month horizon and couples with the NEWAVE police. Both models have a similar representation of hydro plants and other aspects, but differ in the following: (i) NEWAVE has 120 monthly stages with 20 scenarios each and applies the sampling-based SDDP method, while DECOMP has weekly stages for the 1st month and over 500 scenarios for the 2nd month, and applies DDP visiting all scenarios; DECOMP is more focused in the operation, so it has a larger set of constraints, which must be met for all scenarios, while NEWAVE is more focused in planning aspects, having a smaller set of constraints that may be violated in some scenarios, with a penalty cost. We note that the set of hydro constraints in the DECOMP model is more comprehensive than the set of hydro constraints in the EER modeling in NEWAVE, since individual constraints by plant cannot be represented in the latter model. For details we refer to [5], [10].

A. Comparison of results between mid-term problem (MTGP) and EER/IND models for the LTGP problem

We assess the performance of the police built by NEWAVE (LTGP problem) by using it as a boundary condition for the mid-term planning problem (MTGP), in 12 study cases from January to December 2021, which was a very dry period in Brazil. Two comparisons were conducted, as shown in Figure 4: LTGP operation results (with EER) vs. MTGP results, where the police used at the end of the horizon of the MTGP is the one build by LTGP with EER (blue lines); LTGP operation results (with IND) vs. MTGP operation results using the IND police (orange lines). Figure 4 shows the values of hydro and thermal generation and Figure 5 shows the SMC for the first month in each case for NEWAVE and DECOMP. In both figures, “SUM_DIFF” indicates the sum of the absolute differences over all months for the corresponding variables, which is a measure of the total magnitude of differences, in MWmonth.

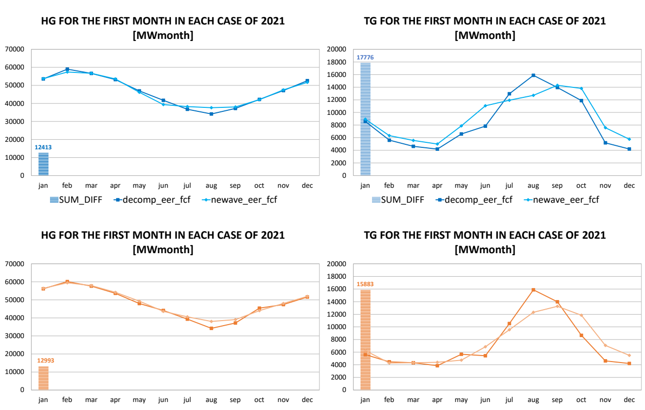

Figure 4. Comparison of hydro (HG) and thermal (TG) generation of LTGP and MTGP problems, for EER (top) and IND (bottom) models in LTGP.

There are small deviations in total hydro/thermal generation (HG/TG) of the two models when using IND modeling in NEWAVE, which can be due to the similar hydro representation in the two models. However, when comparing DECOMP results coupling to an EER × IND policy for the LTGP model, there is an increase in total hydro generation and a decrease of SMC in the IND model. This might be explained by the better use of the hydro resources in the IND model, which has more flexibility to define water values in the FCF.

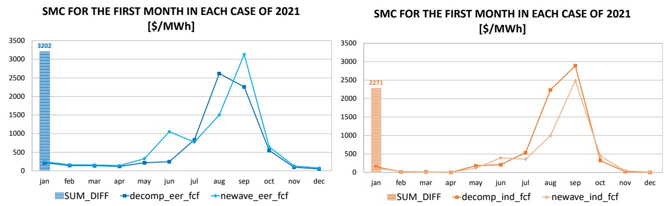

Figure 5. Comparison of SMCs of LTGP and MTGP problems for the EER (left) and IND (right) model in the LTGP problem.

B. DECOMP results with different NEWAVE FCFs

We now make a deeper comparison between IND and EER policies for the Feb. 2021 case, where the system situation was very critical. In the results of the previous section, there was an increase in hydro generation in the IND cases as compared to the respective cases with an EER model. As discussed previously, the EER model naturally handles minimum release constraints in a more optimistic way, because in the EER modeling such minimum energy release can be supplied by any plant belonging to the EER, while in IND modeling the constraints are explicitly enforced for each plant. In order to evaluate the impact in the IND modeling and minimum release constraints, policies provided by three NEWAVE cases have been considered, which were run for 50 SDDP iterations, each one with 200 forward scenarios (total of 10,000 Benders cuts):

Case 1: EER model along the whole horizon (official case), where the hydro constraints are simplified by construction.

Case 2: IND model in the 1st year with detailed hydro constraints for the individual plants.

Case 3: The same IND model for the hydro plants as in Case 2, but removing minimum release constraints.

Such policies are multivariate piecewise linear functions, given by a set of “cuts”, that yield the future cost and water values for any combination of final storages in the reservoirs. Since it is very complex to compare polices just by analyzing the functions, we couple these policies to the same DECOMP case, where all hydro constraints of the official runs are considered, using DECOMP results to evaluate the impact of each police. We note that those results are obtained based on the individual water values for the hydro plants, which are the partial derivatives of the FCF (given by the coefficient of each plant in the active cut), and also the so-called “incremental water values”, which represents the marginal value of keeping water in a reservoir instead of releasing the same water to the downstream reservoir, and is given by the difference between the water values of the upstream and downstream plants. Finally, CMH, discussed in [27], is the implicit marginal cost of hydro generation, which combines the water values ($/hm^3) with the efficiency of each plant (MWh/hm^3).

Figure 6 shows the total system stored energy and the SMC of its largest subsystem (SE) along the weeks in the time discretization of DECOMP. It can be observed that the stored energy in cases 1 and 3 (EER and IND models without minimum release constraints) are very close, and greater differences appear when we compare these cases with case 2 (with minimum release constraints). This may suggest that the EER model is not capable of capturing the spatial behavior of hydro constraints.

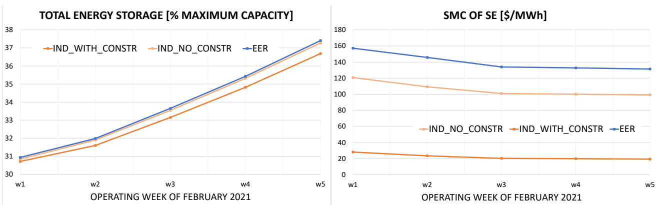

Figure 6. Weekly operation of DECOMP with different FCF options of the NEWAVE model

To better understand this behavior, we perform a detailed analysis on the operation of each plant, trying to find the ones that contribute the most to the increase in hydro generation and, as a consequence, a reduction in energy storage. The distribution of water values (WV) in the set of all cuts of NEWAVE model for those plants (Tucuruí, Itaipu, Salto Santiago and Marimbondo) is shown in Figure 7, for the FCF which was coupled to DECOMP. The WVs are defined to be negative, by convention, and indicate the variation in the system operation costs with an additional drop of water in the reservoir. Therefore, their signal is opposite to the SMCs, which indicate the variation of systems costs with an increase in the demand.

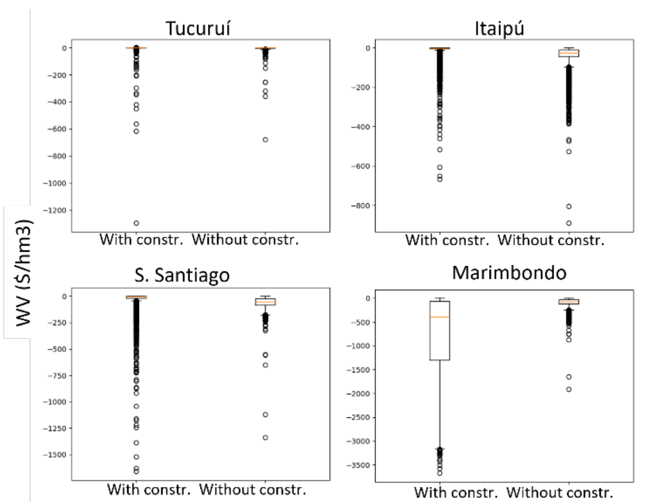

Figure 7. Box-Plot of water values in all cuts of the FCF of the NEWAVE model, for Tucuruí, Itaipu, Salto Santiago and Marimbondo power plants, for the cases with (left) and without (right) minimum release constraints.

Water values are lower (more negative) with minimum release constraints (see Figure 3) for the first three plants, which explains the increase in hydro generation in the DECOMP model. However, for Marimbondo plant water values are higher (less negative) in the case with constraints, which may sound at first sight counterintuitive. However, when evaluating the benefit of generating (or storing) water in a hydro plant, the value of the water from the downstream plant should also be considered, in order to properly compute the incremental value of water, as explained previously. Therefore, Figure 8 shows that, for Marimbondo plant, even with a higher absolute water values in Case 2 (on the left), the incremental water values are lower (on the right). We also analyzed three plants that are the last ones in the corresponding cascades, where absolute water values are equal to incremental values of water. In conclusion, to evaluate the merit order in the generation of hydro plants regarding the water value, one must evaluate the concept of "hydro marginal cost" (CMH) [27].

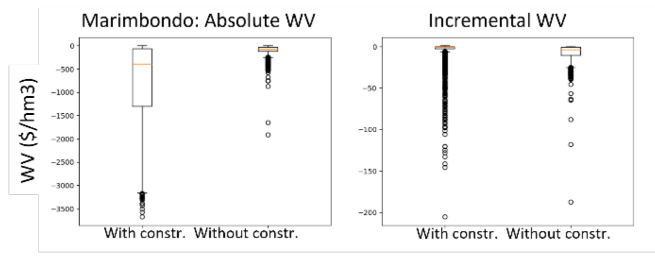

Figure 8. Boxplot of absolute and incremental water values in NEWAVE cuts for Marimbondo power plant.

Thus, since those plant present lower incremental water values for the case with minimum release constraints, it is not advantageous to store water in these plants. This behavior may also seem not intuitive as we see the analysis in Table III, since the inclusion of minimum release constraints should have caused an increase in the water values of the FCF in earlier stages. However, this opposite effect can happen because: (i) minimum release constraints upstream the cascade may lead to a considerable amount of water arriving at the plant, making it advantageous to leave some "space" in the reservoir to accommodate this water and avoid future spillages; (ii) minimum release constraints downstream the cascade may indicate the need to have more storage in plants that are closer to the locations where such constraints are enforced, e.g., Ilha Solteira, to ensure their satisfaction without spillage upstream the cascade, which could occur if those upstream plants had to release large amounts of water to meet these minimum release constraints at a given period. We conclude by noting that this analysis is very complex due to the interplay among all hydro plants, and further studies are necessary for a full understanding of the operation of hydro cascades.

VI. CONCLUSIONS.

This paper compares, both conceptually and empirically, the effects of considering individualized (IND) or equivalent energy reservoir (EER) models of hydro plants in long term power generation planning (LTGP) problems, and its impact on the results of the mid-term problem (MTGP), which is coupled to the LTGP recourse function. We evaluated the impact of considering minimum/maximum release/storage for the hydro plants in both IND and EER models. Conceptual analyses show that the impacts of the IND model and the inclusion of hydro constraints in system marginal costs and water values depends on whether the constraint prevents or enforces a generation, or if it removes resources from the cascade. Numerical results for official cases of the Brazilian system allow us to conclude that there is an increase in adherence between results of the LTGP and MTGP problems when the IND model is applied in the LTGP problem. The analyses suggest that the effect on water values of including minimum release constraints is distinct from one plant to the other, depending on its location in the cascade and the specific point where the constraints are applied. An important conclusion is that, although minimum release constraints increase the absolute values of water, the marginal cost of hydro generation (CMH) can decrease or increase, encouraging or not the increase of hydro generation.

As future works, we suggest further analysis on the topic, to name a few: (i) assessment of the spatial distribution of water values in plants in cascade with the introduction of hydro constraints, and how this affects the computation of the incremental value of water; (ii) a more detailed analysis of the effect of including minimum release constraints upstream or downstream a cascade; (iii) a sensitivity analysis and analytical assessment of the values to be applied for the penalties for violation of constraints, and whether they should vary spatially (depending on the position of the plant in the cascade) or temporally (depending on the position of the stage in the study horizon); (iv) extend the analysis in this paper for the case of state-dependent hydro constraints, where minimum/maximum release constraints are a function of storage; (v) perform the analysis with the inclusion of new features in the model, as for example uncertain solar generation and the application of demand response programs.

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