Lightning Session B (17:10 - 18:30)	**Modeling and Applications**	**Chair: Birger MO, SINTEF**	
	Floating Hydroelectric Power Plant (FHPP)	Arthur Ottoni	Univ. Itajubá
	Detailed Representation of Hydropower and Pumped Hydropower Storage in Capacity Expansion Models	Christian Øyn Naversen	NTNU
	Feasibility analysis for the Installation of a Pumped Hydro Energy Storage in the Brazilian National Interconnected System	Lucas Lima	UFJF
	Methodology for analyzing the coupling between short, medium and long-term generation planning: a characterization of the Future Cost Function	André Marcato	UFJF
	Valuation of Reactive Power Support and the Role of Hydropower in Power Systems under Decarbonization	Paulo Barbosa	Essenz Soluções
	The Impact of Hydropower Scheduling on Transient Stability Studies	Nícolas Netto	CEPEL
	Model for determining critical reservoir levels for energy security	Rafael Almeida	CEPEL
	Physical Guarantee for Interconnected Systems	Rafael Klausner	PUC-RJ

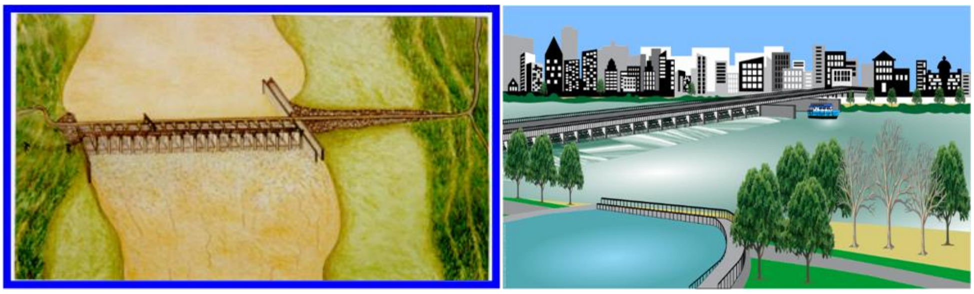
8th International Conference on Hydropower Scheduling in Competitive Electricity Markets

<u>Topic selected for the development of the Summary</u>: " Integration of New Elements into the Energy Network". <u>Summary Title</u>: "Floating Hydroelectric Power Plant (FHPP) - CHF ® ". <u>Author</u>: Arthur Benedicto Ottoni (Full Professor at the Federal University of Itajubá/MG ; e-mail: arthurottoni@unifei.edu.br ; http://lattes.cnpq.br/6008427332874279).

The generation of sustainable hydroelectric energy in the 21st century has not seen technological evolution, especially due to environmental issues. The Floating Hydroelectric Power Plant -FHPP (CHF ®) is an innovative technology for generating hybrid hydroenergy (pressure energy - Bulb Turbines and speed energy - Hydrokinetic Turbines), renewable energy, unprecedented in the Brazilian and World Energy Market and in Bibliographic research, suitable for this moment of energy transition .

The main objective of the FHP Plant, when it was conceived, was to generate hydropower with "negligible" (negative) environmental impacts. Further studies and technology research identified the following specific objectives in relation to the FHP Plant: **(a)** it has simplified planning and construction in relation to a conventional Hydroelectric Plant of the same size; **(b)** the design of the technology makes it possible to generate energy in several river stretches, such as downstream of flow regularization dams; in a small unused gap, embedded in a "cascade" series of Conventional Hydroelectric Plants; among others.

The FHPP is a Hydroelectric Plant with hybrid hydropower generation (pressure and speed) made from small hydraulic falls ($2 \leq H \leq 8$ meters), limited to the river channel as much as possible. In **Figures 1.A** and **1.B**, the Hydraulic Arrangements of the FHP Plant are presented respectively in a Enclosure Section - SE of a Rural River Section **(A)** and an Urban River Section **(B)**. The Enclosure Section (SE) of the FHP Plant is the section of the river where the Plant's works will be designed and implemented: access spans made up of transverse Marginal Encounters (EM) (right and left banks); Power Generation Modules (MGEs); Longitudinal Pillars (PL); Bottom Coating Apron (AR) (Support Apron); Navigation Module (MN); Module for the transit of floating bodies (MF).



(A) **(B)**

<u>FIGURE 1</u>: (A) Enclosure Section (SE) of the FHP Plant in a Rural River Section; (B) Enclosure Section (SE) of the FHP Plant in an Urban River Section (Reference: OTTONI, A.B. ; et al., 2003)

The FHP Plant Arrangement makes it possible to use the unused water potential in the World estimated at 996 GW (XU, R, et al, 2023), a <u>Sustainable Energy System</u>, suitable for this <u>moment of energy transition, as much of this hydroenergy potential is not yet usable in the world's river basins there are restrictions on their exploration due to environmental issues</u> .

The operation of the FHP Plant in its Enclosure Section - SE, for a project load "H", the independent variable is the tare ("ballast water flow rates"), and the others dependent variables are : float height - $\mathbf{H_F}$; bottom speed - $\mathbf{V_F}$; bottom flow - $\mathbf{Q_F}$; flow Turbine Bulb-$\mathbf{Q_{TB}}$; turbine pressure power - $\mathbf{P_{TB}}$; hydro kinetic energy power - $\mathbf{P_{THC}}$.

The simulation of the FHP Plant in the Experimental Hydraulic Laboratory made it possible to obtain the Hydroenergetic Characteristic Curves, whose results of the hydroenergetic quantities in the Enclosure Sections (SE) of the **FHP Plant on the Paraíba do Sul river in São Fidelis, RJ (MGE 32.5 ; SE with a width of 460 meters and a height of 9.50 meters)**, river stretch with regularized flows, and the **FHP Plant on the Itapemirim river in Lamarão, ES (MGE 15 ; SE with a width of 110 meters and a height of 10 meters)**, river stretch without regularized flows, long and dry series, are presented in **Table 1.**

Paraíba do Sul River in São Fidélis/RJ (Ad = 55,500 km²) – Long Serie (1973 - 2024)									
H [m]	Pi [MW]	Qpi [m³/s]	Ptb [MW]	Qtb [m³/s]	Pthc [MW]	Vmédio [m/s]	Ptotal [MW]	Fc Etb [%]	Fc Etotal [%]
3	18.6	618.8	11.2	449.8	5.2	5.4	16.4	60.2	88.2
5	34.2	684.6	20.5	494.5	11.1	7.0	31.6	59.9	92.4
7	51.2	731.6	28.2	486.1	3.3	4.7	31.5	55.1	61.5
8	60.1	751.3	32.4	488.3	2.5	4.3	35.0	53.9	58.2

Paraíba do Sul River in São Fidélis/RJ (Ad = 55,500 km²) – Dry Serie (2016)									
H [m]	Pi [MW]	Qpi [m³/s]	Ptb [MW]	Qtb [m³/s]	Pthc [MW]	Vmédio [m/s]	Ptotal [MW]	Fc Etb [%]	Fc Etotal [%]
3	18.6	618.8	9.0	361.4	3.8	4.9	12.8	48.4	68.8
5	34.2	684.6	15.0	361.0	7.2	6.1	22.2	43.9	64.9
7	51.2	731.6	22.1	380.7	3.2	4.6	25.3	43.9	49.4
8	60.1	751.3	25.0	377.0	3.2	4.6	28.2	41.5	46.9

Itapemirim River in Lamarão/ES (Ad = 6,181 km²) – Long Serie (1971 - 2022)									
H [m]	Pi [MW]	Qpi [m³/s]	Ptb [MW]	Qtb [m³/s]	Pthc [MW]	Vmédio [m/s]	Ptotal [MW]	Fc Etb [%]	Fc Etotal [%]
3	2.7	106.5	1.5	59.4	0.4	8.1	1.9	55.6	70.4
5	4.4	106.8	2.2	53.5	0.6	10.7	2.8	50.0	63.6
7	6.2	107.1	3.3	56.8	0.2	8.2	3,5	53,2	56,5
8	7.1	107.2	3.6	54.7	0.1	8.0	3.8	50.7	53.5

Itapemirim River in Lamarão/ES (Ad = 6,181 km²) – Dry Serie (2016)									
H [m]	Pi [MW]	Qpi [m³/s]	Ptb [MW]	Qtb [m³/s]	Pthc [MW]	Vmédio [m/s]	Ptotal [MW]	Fc Etb [%]	Fc Etotal [%]
3	2.7	106.5	1.0	38.2	0.1	1.4	1.2	37.0	44.4
5	4.4	106.8	1.4	33.3	0.4	2.3	1.8	31.8	40.9
7	6.2	107.1	2.1	35.5	0.1	1.6	2.2	33.9	35.5
8	7.1	107.2	2.3	34.0	0.1	1.5	2.4	32.4	33.8

TABLE 1: Result of the Hydroenergetic Quantities of the FHP Plants on the Paraíba do Sul River in São Fidelis, RJ (MGE 32.5) and the Itapemirm River in Lamarão/ES (MGE 15) (Reference: TO, 2022).

Detailed Representation of Hydropower and Pumped Hydropower Storage in Capacity Expansion Models

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***Index Terms*—Hydropower Representation, Pumped Hydropower Storage, Flexibility, Capacity Expansion Modeling**

ABSTRACT

Decarbonization measures in the power system call for a transition away from fossil-based generation technologies to low-carbon solutions such as wind and solar power. These variable renewable energy (VRE) sources feature uncertain generation patterns, leading to challenges in both short-term and long-term balancing of demand and generation. Flexible generation and storage technologies, such as reservoir hydropower and pumped hydropower storage (PHS), become more important as the power system adopts a larger share of generation from variable renewable sources.

Decision makers in the power system often rely on the output from capacity expansion models. These models adopt a central planning approach to optimize both investment and operational decisions for all participants, for a future power system description. Due to a large scope, these models rely on simplifications to reduce computational complexity. Hydropower is often aggregated to a single reservoir and turbine per area, removing topological restrictions on flow between reservoirs, in addition to individual reservoir and turbine limits. This type of aggregation overestimates the overall flexibility potential of many smaller hydropower plants, potentially resulting in unrealistic system configurations with high VRE shares. Electricity is often the only energy carrier modeled, and non-linearities regarding the conversion from water to electricity are often heavily simplified in capacity expansion models.

On the other hand, hydropower scheduling models feature more detailed representations of hydropower compared to capacity expansion models. These may include binary unit commitment decisions, ramping constraints, discharge constraints and individual reservoir constraints. The physical water is modeled as inflow and tracked down the river system cascade. Turbine representations are no longer on/off decisions, but a function of head height, turbine efficiency and generator efficiency.

This work aims to improve the formulation of hydropower operation in a state-of-the-art capacity expansion model. First, a literature review is conducted to map the current representation of hydropower in power system investment models. Then, a candidate model is chosen. Thereafter, the hydropower representation of the chosen model is improved by implementing techniques from hydropower scheduling models, such as reservoir disaggregation, accurate turbine representations and binary unit commitment decisions. One apparent challenge is an increase in computational complexity, and the work will reveal tradeoffs between modeling increased resource accuracy versus computational time. Additionally, PHS investment options are to be implemented by investing in reversible turbines between existing hydropower reservoirs.

This framework is applied to a future case to investigate how Norwegian hydropower storage can contribute to balancing VRE generation expansion under different climate policies. It is expected that a more accurate hydropower formulation will reduce the modeled flexibility from hydropower to a level that is more realistic, and thus providing a better insight into how competitive Norwegian hydropower is compared to other storage technologies.

Although hydropower investment options are not chosen through central planning, the work will give insight on mechanics linking VRE generation and hydropower flexibility that is more accurate than representations in current power system investment models.

Feasibility analysis for the installation of a Pumped Hydro Energy Storage in the Brazilian National Interconnected System

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Objective

Energy sources are crucial for societal development. Global demands and pressures for a cleaner, more sustainable energy mix have positioned electrical energy at the forefront. According to the International Energy Agency, 21% of global energy consumption is electrical, with 12.47% derived from renewable sources. This marks a 60% increase in contribution of renewable over the past two decades.

In a national perspective, Brazil is following the same path. The Ten-Year Energy Plan (PDE) aims to align the Brazilian energy matrix with international policies, targeting a 50% reduction in emissions by 2030, and an increase of renewable sources to reach 45% of the matrix by 2050. Furthermore, on PDE 2032, it is clear that much of this change will come from a greater use of electricity, with an expected growth rate of 1.9%.

Brazil has a large-scale hydro-thermal-wind energy system, with an installed capacity exceeding 230 GW. Approximately 46% of this capacity comes from hydroelectric plants, 10% from thermal power plants, and the remainder from variable renewable sources such as wind, solar, and biomass energy. Policies indicate both growth in renewable energy sources and a halt in the construction of large hydroelectric plants with extensive reservoir.

This strategy, however, presents a series of challenges to the system's operation. Renewable energy sources, for instance, pose the issue of intermittency, complicating their optimal integration into the grid. As a result, system operators have been forced to adapt their strategies to maximize the use of these resources while ensuring the security and reliability of the system. In this context, energy storage solutions are becoming increasingly critical, as they enhance the system's operational flexibility.

Therefore, the present work introduces pumped hydro energy storage as a mechanism to better integrate renewable energy sources, enabling the storage of excess energy that would otherwise be lost, for use at the opportune moment. Additionally, it aims to analyze the economic feasibility of these plants, considering the system's operation costs and the Levelized Cost of Energy (LCOE), this approach allows for comparing this strategy with other energy storage mechanisms, such as electrochemical, electromechanical, thermal, and hydrogen-based systems.

Methodology

The methodology adopted in this work is based on the analysis of the economic impact of using the proposed Energy Storage System. Therefore, the Short-Term Planning Model for the Operation of Interconnected Hydro-Thermal Systems, DECOMP [1], developed by CEPEL, was used.

Thus, pumped storage plants were incorporated into the actual generation complex in DECOMP, taking into account their geographical location and the cost associated with the construction of their reservoirs, as derived from a study conducted by GESEL [2]. The model then yielded the optimal operational policy for the system over a 2-month planning horizon. Subsequently, an analysis was conducted on the economic outcomes associated with this operational policy. The key parameters evaluated included: Future Cost, System Operating Cost, Marginal Cost (MC), and, finally, the Levelized Cost of Energy (LCOE).

The Future Cost represents the expected cost to operate the system in the future, in other words, this value will determine the operational standards of the system . Another important parameter is the Operating Cost, which is minimized by the DECOMP model alongside with the Future Cost and it is associated with hydrological risks and the fuel cost. Furthermore, the MC represents the cost of adding 1 MWh to the system and is also directly derived from the DECOMP model.

Finally, there is the Levelized Cost of Energy, which is calculated using parameters such as CAPEX, which represents the installation cost of the pumped hydro storage plant (PHS) and OPEX, that includes operational and maintenance costs, as well as charges and taxes. These costs are then weighted by the actual generation, taking into account an interest rate and the natural degradation rate. This value allows the evaluation of different energy supply models, regardless of their specific characteristics, as it encompasses all investment and maintenance costs, and is rationalized by the generation capacity throughout the entire lifespan of the project, resulting in a cost per unit of energy generated.

Results

The outcomes indicate that the inclusion of this storage system in the national interconnected grid leads to a reduction in future cost ranging from approximately 0.047% for smaller PHSs to up to 0.35% for larger ones, analyzing operating costs it was observed a decrease of up to 3.7%. Finally, the MC show reductions up to 3.4%, validating the effectiveness of this storage mechanism.

Furthermore, it was observed that the LCOE underscores the competitiveness of this energy storage system. The results indicate that mapping and studying the installation areas and a good ratio between reservoir capacity and pumping/generation capacity are crucial to achieve a favorable LCOE. In an ideal scenario, the system proves to be one of the best options, even when compared to established methods, presenting LCOE similar to the electrochemical storage mechanism which is around 30% lower than LCOE for new methods such as hydrogen based.

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Methodology for analyzing the coupling between short, medium and long-term generation planning: a characterization of the Future Cost Function

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***Abstract*—This paper proposes a methodology based on analytical geometry to analyze the coupling between studies of different timeframes used in planning and scheduling operations. The methodology defines the region where each cut of the Future Cost Function (FCF) becomes active in the domain of the state variables and establishes metrics related to the amplitude of the domain of each cut. The approach was applied to a case involving the medium- and short-term models used in Brazil, proving to be effective and valuable for more detailed analyses of the FCF, identifying the impacts of this function on both the operation of power plants and the formation of energy prices. The information obtained from these analyses is intended to contribute to the improvement of methodologies that improve the coupling between the studies, providing a more adherent and robust process.**

***Index Terms*— coupling, Future Cost Function, region of activity, analytical geometry**

I. Introduction

Hydrothermal scheduling defines the operating policy for reservoirs and generating units to minimize operating costs and meet reliability, quality and safety criteria [1]. To make the problem manageable, it is divided into coordinated stages that define long-, medium- and short-term studies [2]. The models that define these studies need to be coupled to transmit information about the state of the system, using either primal or dual approaches [3]. In the primal approach, the medium- and long-term models signal operating measures to the short-term model, establishing operating targets for hydroelectric plants, thermal plants or exchanges, guaranteeing the viability and economy of the operation.

The dual approach, used in the Brazilian and Norwegian models [4], consists of constructing a multivariate Future Cost Function (FCF) that relates the expected cost of operation to the volumes stored in all reservoirs at the end of the study horizon [5]. The FCF provides water values that indicate the future benefits, measured at present value, of maintaining the water stored in the reservoirs. In addition, it can signal to the short-term model non-operational regions of the longer-term models.

FCF analysis is highly complex due to its multidimensional nature and its piecewise linear modeling consisting of Benders cuts and often lacks detailed interpretations of both its characteristics and the quality of the coupling it provides. Thus, there is a lack of studies on the characterization of FCF that provide more detailed analytical and conceptual analyses. These analyses are fundamental, because the FCF constructed by the longer-term models is used to insert information into the shorter-term model, especially economic information that can lead to unexpected operations. As observed in official studies in Brazil, where the behavior of power plants was affected by coupling at points not visited by the medium-term model [6].

It is therefore important to develop methodologies for analyzing the FCF, allowing qualitative and quantitative analysis of the points of coupling between the models. These analyses can support improvements that increase adherence between the models' results. As a result, we can better understand the impact that a more detailed representation of the generation park, the transmission network and the restrictions have on reservoir storage at the end of the month or operating week. This paper proposes a methodology based on analytical geometry for analyzing the coupling between energy models. The methodology consists of defining an operating region in which a given FCF cut is active. With this information, some analyses can be carried out:

- Calculation of the distance between the operating point of the short- and medium-term models and the region of future cost activity and the operating point of the longer-term model;
- Analysis of the quality of FCF information in a given region, focusing on the region of coupling between models;
- Detailed analysis of the impact of the storage of a reservoir or set of reservoirs on the region defined by the FCF active cut off.

The methodology was tested through a case study of the coupling between the DECOMP and DESSEM models, used in Brazil for medium and short-term operational planning, respectively. DECOMP uses the Dual Dynamic Programming (DDP) algorithm to solve the multistage problem and therefore constructs the FCF as a piecewise linear function using the Benders decomposition technique. Due to the short-term detail, DESSEM uses the Mixed Integer Linear Programming (MILP) algorithm and has a horizon of up to 7 days, coupling with the FCF of the 1st week of DECOMP.

II. Methodology

The methodology developed uses analytical geometry concepts to define the operating region in which a given FCF cut is active, called the cut activity region. This approach makes it possible to identify the region where each cut becomes active in the domain of the FCF state variables and to establish metrics associated with the amplitude of each cut's domain. After eliminating the redundant cuts, the FCF is defined by a convex envelope made up of a finite number of half-spaces, defined by the Benders cuts. For each non-dominated cut of the FCF, a set of expressions is obtained that define the region in which this cut is predominant. The region of activity is delimited exclusively by the state variables, as detailed in [7].

Mathematically, the FCF can be represented by a polytope P in an n-dimensional space made up of m half-spaces (S_m). To determine the region of activity of a cut k, we first define the faces of S_k in relation to the other half-spaces. In this context, the face represents the region of S_k that is active when considering another half-space l. Next, we define the face of P in relation to half-space k, by the intersection of all its faces in relation to the other half-spaces. Finally, the region of activity of k is the projection of this face in $n-1$ space. For the hydrothermal scheduling problem, the space to be projected corresponds to the reservoir storage variables, eliminating the axis referring to future cost.

Using this methodology, it is possible to establish metrics related to the operating points defined by each model, such as analyzing the distances between the coupling points of the models, where the cuts were built and used, when consulting the FCF associated with the same instant of time. In addition, the methodology makes it possible to analyze how the value of the water varies as a function of the state of the system, by means of the region of activity of the cuts and their respective inclinations, as well as analyzing how the different types of more specific data from the medium- and short-term models affect the coupling with the long-term and medium-term models, respectively.

III. Results

The methodology was used to analyze the case described in [6]. In this case, a discrepancy was observed between the marginal operating costs of the short and medium-term models, as well as an unexpected operation involving some hydroelectric plants. The medium-term model built a FCF containing 31 cuts, but the coupling by the short-term model was carried out at a different point from the operating point indicated in the medium-term, which caused a significant difference between the water values of some plants.

The methodology presented above was used to analyze the distance from each operating point to the region of activity of each cut. Thus, the distance between the point of operation and the region of activity of each cut was analyzed. The results show that DECOMP is operating point is located at the intersection between the activity regions of the cuts built in the last iterations of the model. On the other hand, the DESSEM operating point is located exclusively in the cut activity region built in the second iteration of DECOMP. Furthermore, the point is considerably distant from the border of the activity region defined by the active cuts in DECOMP.

In addition, an analysis was carried out by plants for those that showed a high-water value at the coupling point. Three plants on the Corumbá River showed unexpected behavior, while the Mauá plant had the highest observed water value. In the analysis by plant, the operating values were kept fixed, except for the plant analyzed. For the plants with unexpected behavior, it was observed that only one cut was dominant in the entire domain of their reservoirs. For the reservoir with the highest water value, it was observed that, in the interval from 0 hm^3 to 356,71 hm^3, the active cut was the case of convergence, as the plant converged at point 343,88 hm^3. In the domain from 356,71 hm^3 to maximum storage, the active cut-off was built in the 20th iteration of DECOMP, showing more behaved water values.

Thus, based on the plant's storage at the start of the study and the flow forecasts for every day of the operating week, considering the restrictions that must be met, the plant is unable to operate outside the outage domain region in which the convergence of the case occurred. The analyses provided by the methodology indicate that, in this case, the Mauá plant determines the active outage in the DESSEM model. In addition, DECOMP built few outages in the region operated by the plant and DESSEM reached different storages from DECOMP, for which the FCF built by DECOMP was not well represented.

IV. Conclusions

For the case analyzed, the methodology provided a detailed analysis of the coupling between the models. It should be noted that, without the use of the tool, it would only be possible to carry out an empirical and simplified analysis of the region of activity. The methodology provides an in-depth characterization of the FCF, by calculating the distances between points in the state space and between a given point and the region of activity of each cut. The region of activity of each cut is defined based on geometric concepts, which involves eliminating the dimension associated with the future cost of the FCF and simplifying the other restrictions based on the cut under analysis. In addition, constraint elimination strategies are adopted to define the shape of the activity region, so that each region is delimited by a convex shell made up of a finite number of constraints.

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8th INTERNATIONAL CONFERENCE ON HYDROPOWER SCHEDULING IN COMPETITIVE ELECTRICITY MARKETS

Rio de Janeiro, Brazil, May 26th - 28th, 2025

Valuation of Reactive Power Support and the Role of Hydropower in Power Systems under Decarbonization

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Keywords: Reactive Power Support, Grid Flexibility, Hydropower, System Reliability, Economic Valuation

Objectives

This study addresses the growing relevance of voltage control through reactive support in electric power systems, especially as a result of the increase in distributed generation and the large-scale incorporation of renewable energy sources. Pilot initiatives in several countries have explored competitive mechanisms for these services, highlighting the cases of system operators in Great Britain and Australia.

Context

In Brazil, the technical and economic regulations on the provision of ancillary services are well defined, with mandatory provision requirements for generators. For some services, there is reimbursement of costs incurred in providing the services, as is the case with reactive support with generating units operation in synchronous compensation. However, the value and remuneration components are below international practices and trends in terms of incentives and attractiveness to generators. Some components that represent effective costs (e.g. availability to supply reactive power and opportunity costs) still do not have remuneration in Brazil, what is distinct to practices already in force in European countries, the USA and Australia.

Fixed-rate forms of remuneration for ancillary services are still the most common, although models are emerging in which system operators acquire services via market mechanisms. Illustrative cases, such as the experiences of the United Kingdom and Australia, show that these innovative strategies have been successful in terms of efficiency (competitive prices) and security of service supply (there has been no frustration with the demands placed in auctions). It is also interesting to note the mixed models, in which part of the need for reactive power is obtained in a mandatory way with fixed tariffs, and another part is obtained through a market mechanism.

Methodology

Considering all questions raised before, this work proposes to investigate the ways of valuing and compensating the reactive support service, including a review of international experiences, as well as focusing the Brazilian context. The work also proposes to evaluate the technical attributes of hydroelectric technology that highlight its role in providing dynamic voltage support in power system control areas, which is illustrated through dynamic simulations in studies of large geoelectric regions in the USA.

Two valuation methodologies are proposed in this work. In a first methodology, the remuneration metric is based on the valuation of the availability of reactive power provided by the hydro-generating unit, regardless of the quantity of reactive power delivered (currently already remunerated in Brazil, by the MVAr-h delivered by each hydro-generating unit). A second methodology defines the cost of an alternative solution for supplying reactive power, which, to be close to the product offered by hydroelectric plants, is the cost of a synchronous compensator installed on the electrical grid.

The case studies and illustration of the valuation methodologies and metrics include numerical examples based on the time series of reactive provision of selected hydropower plants in the South region of Brazil, including Itá, Machadinho, Passo Fundo, Cana Brava, Salto Osório and Salto Santiago.

Results

Based on real data from historical time series, in 2022, the Itá hydroelectric plant, for example, operated 15,098 hours in synchronous compensation mode by order of the ONS (the Brazilian Independent System Operator), totaling revenue from the application of the TSA (standard ancillary services tariff) equal to R$ 10.908 (Brazilian currency) million for the reactive energy supplied/absorbed. In the methodology that is based on the reactive capacity of the units made available, the annual value of R$ 2.439 million in remuneration is obtained (in addition to that already paid by the TSA - ancillary service fee for reactive support). In the alternative solution value method (synchronous compensator), the annual value would be R$2.739 million, also additional to the value already collected by applying the TSA. In average, for the hydropower plants under study, the additional financial compensation is in the range of 20% to 30%.

The reactive support service valuation methodologies proposed in the work for specific geoelectric regions are sufficiently general and can be applied to any other geoelectric region of interest. Based on this, and the review of international experiences, it is expected to directly contribute to the ongoing discussion of reviewing the regulations associated with the service of reactive power provision. Improving the remuneration of generators who provide the service will bring incentives that potentially increase the number of providers, with the effect of reducing the level of losses and improving the quality of voltage profile control and grid stabilization.

The Impact of Hydropower Scheduling on Transient Stability Studies

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Hydropower scheduling plays a crucial role in the operational reliability and economic efficiency of power systems. However, its impact on transient stability studies has been less explored, despite the direct influence that variations in water head height and turbine operation have on electromechanical dynamics. This work investigates the effects of hydropower scheduling decisions on transient stability, focusing on the interplay between hydroelectric dispatch, water level fluctuations, and system stability margins. By analyzing the coupling between hydraulic and electrical phenomena, this study aims to provide insights into how scheduling strategies can enhance or compromise grid resilience.

The methodology involves a detailed integration between hydropower scheduling and transient stability analysis. Initially, hydrological scenarios are extracted from energy scheduling models, which simulate reservoir inflows under stochastic conditions. These models incorporate water availability constraints, seasonal variations, and dispatch strategies, producing a set of realistic water head height values for different time horizons. These extracted values serve as dynamic inputs for electromechanical stability studies, ensuring that the transient analysis considers real-world fluctuations in hydraulic conditions rather than static assumptions.

Once the hydrological data is obtained, it is integrated into the turbine governor models of hydroelectric plants within the transient stability simulation framework. The governor models are adjusted to dynamically update their response based on varying water head heights, modifying the mechanical power output accordingly. This adaptation allows the simulations to reflect operational constraints imposed by hydropower scheduling, capturing variations in system inertia, damping characteristics, and frequency control behavior. A set of contingency events, including generator outages, transmission faults, and sudden load changes, is then simulated to observe how different scheduling strategies affect system stability under stress conditions.

To quantify the impact of hydropower scheduling on transient stability, statistical analyses are performed on the simulation results. The system's response across multiple hydrological scenarios is aggregated, allowing for the assessment of variations in key stability metrics such as frequency deviations, rotor angle oscillations, and damping factors. The outcomes from models using fixed water head height assumptions are compared against those incorporating dynamically updated values from the hydropower scheduling process. This comparative approach helps to identify whether the traditional assumptions used in transient stability studies lead to misestimated stability margins and provides insights into how improved scheduling techniques can enhance overall grid resilience.

Preliminary analyses suggest that hydropower scheduling decisions significantly influence transient stability margins. Reservoir drawdown and rapid dispatch variations may reduce effective inertia contributions, leading to increased oscillations and weaker damping. Higher water head levels tend to improve dynamic performance by enhancing mechanical power response, stabilizing frequency deviations during disturbances. Fixed head height assumptions commonly used in transient stability studies may lead to incorrect stability assessments, either underestimating or overestimating the system's ability to withstand faults.

By incorporating hydropower scheduling constraints into transient stability studies, it becomes possible to refine contingency planning and enhance operational security. Coordinated scheduling strategies that integrate stability constraints could improve fault ride-through capability, mitigating cascading failures and improving system robustness. This study provides a basis for further exploration of real-time stability-aware hydropower scheduling models, bridging the gap between energy planning and transient security analysis. By dynamically linking hydropower scheduling outputs with stability simulations, system operators can better anticipate potential instability risks and develop more resilient scheduling strategies, ensuring secure and efficient operation of hydro-dominated power systems.

Model for determining critical reservoir levels for energy security

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I. INTRODUCTION AND OBJECTIVES

Energy security consists of managing energy resources to ensure the fulfillment of present and future demand, even in adverse situations. A secure system tends to operate more conservatively, meaning it is more robust but also more costly. The significant uncertainty of potential future critical scenarios makes it difficult to accurately estimate when and with what probability an adverse situation might occur, such as a prolonged drought or a fuel crisis, making it complex to assess the level of energy security required for a power system.

Predominantly hydroelectric systems, such as those in Brazil, Norway [1], Chile [2], Canada [3], among others, are subject to seasonal variations in inflows in river basins. Thus, large reservoirs aim to ensure the best allocation of energy resources over time. These reservoirs also play an important role in ensuring energy security due to their large storage and generation capacity—considering the set of downstream hydroelectric plants in the cascade—thus contributing to meeting demand even in prolonged critical situations [4].

In Brazil, the Electric Sector Monitoring Committee (CMSE)[5] is responsible for monitoring and evaluating the performance and robustness of the Brazilian Interconnected Power System (BIPS), which includes monitoring reservoir levels to ensure energy supply. Given this, the CMSE currently determines the use of Reference Storage Curves (CRefs) to evaluate the reservoir levels and measure the energy security of the system.

The CRefs are curves that represent the minimum storage levels necessary to meet demand and operational constraints under given system condition. The processes and assumptions used in the design of these curves are meticulous, elaborate, and systematic, ensuring that they adequately reflect the reservoir levels required to guarantee the desired level of energy security. Thus, the process of developing the CRef curve becomes quite complex and laborious. They currently use a mid-term energy planning model (DECOMP)[6] to obtain these curves but since this model is not designed for energy security purposes, the process of obtaining the curves involves multiple executions and adjustments to the data set, which is very time-consuming.

A. Objectives

The objective of this work is to present a computer implementation of a mathematical methodology capable of calculating minimum storage curves indicating the system's level of criticality in terms of energy security, which can be used for the development of operational security policies, such as CRefs. Thus, the computational model proposes:

- A mathematical model specialized in minimizing reservoir levels while maintaining system security;
- A flexible modeling approach that allows for the evaluation and formulation of assumptions used in determining system security;
- enabling the development of various studies and analyses regarding minimum reservoir levels and energy security.

II. METHODOLOGY

The model proposed in this work consists of a multi-period, deterministic linear/piece-wise-linear optimization problem. The system representation considers the same modeling aspects present in the mid-term energy planning model, see [7] for details. However, the model presented here is not based on minimizing current and future operating costs, but rather on minimizing the stored energy in the reservoirs of hydroelectric plants, aiming to determine the minimum stored energy necessary to meet demand and constraints until the end of the study horizon.

A. Thermal Plant Representation

To determine the security curves, a desired thermal dispatch level is defined. Thus, the modeling of thermal plants is no longer based on their incremental cost (Unit Variable Cost - CVU) but on the dispatch level established for the security curve. Therefore, a reference CVU ($\mathrm{CVU_{ref}}$) is defined, which will determine the thermal dispatch level. In other words, thermal plants with CVU lower than the reference CVU are dispatched in their entirety, and thermal plants with CVU higher than the reference CVU are not dispatched. This characteristic is modeled by defining the generation limits and cost in the objective function of the thermal plants as follows:

- if $\mathrm{CVU_i} > \mathrm{CVU_{ref}}$ then $gtmax_i = gtmin_i$, that is, the maximum thermal generation of plant i is equal to its minimum generation (the plant is not dispatched beyond its mandatory minimum value);
- if $\mathrm{CVU_i} \leq \mathrm{CVU_{ref}}$ then $c_i = -100$, that is, the generation cost of the plant in the objective function (c_i) assumes a negative value, calibrated to -100, so that the plant is incentivized to always generate its maximum, with generation cuts only if necessary to meet operational constraints.

B. Stored Energy

The stored energy of a hydroelectric plant is given by the volume of water accumulated in the plant's reservoir that can potentially be used for energy generation. Therefore, (EA) is the sum of the stored energy of a hydroelectric plant, for each period t of that specific plant and is given by:

$$\mathrm{EA}_t = \sum_{j=1}^{NUH} k_{j,t} \times \mathrm{Earm}_{j,t}, \quad \forall t \in [0, N_{PER}] \tag{1}$$

where:

- NUH: is the number of hydroelectric plants in the study;
- $\mathrm{Earm}_{j,t}$: corresponds to the stored energy of hydroelectric plant j in period t;

- $k_{j,t}$: is a participation factor, externally provided, of the stored energy of the hydroplant j in the expression of stored energy EA_t for period t.

C. Objective Function

As previously highlighted, the objective function of this model (fobj) is associated with the minimization of stored energies, thus taking the following form:

$$\text{fobj} = \sum_{i \in \text{UsiT}} \sum_{t \in T} \sum_{p \in P} (c_i \times gt_i^p) + \sum_{t \in T} EA_t \tag{2}$$

where:

- gt_i^p: thermal generation of plant i in period t at load level p, which has its cost defined according to the procedure described in subsection II-A, in order to encourage the generation of thermal plants whose cost is below the reference CVU to be at maximum.

Additionally the objective function also includes slack variables for operational constraints, which are highly penalized, as well as micro-penalties associated with spillage, turbining, and exchanges. The slack variables are not activated (since the executed cases must be feasible or made feasible), thus they do not interfere with the total value of the objective function.

III. RESULTS AND CONCLUSIONS

To demonstrate the methodology's results, we used the Brazilian system and the available data for the year 2022. To compare with the CRef, we used the same assumptions, which are:

Horizon and discretization: The optimization horizon was extended between the months of Dec/2021 and Nov/2022, corresponding to the end of the dry period, divided monthly.

Security restrictions: The security restrictions described in Technical Note [8] were represented through volume restrictions (minimum storage) for the entire horizon in question and for each monthly regulation hydroelectric plant.

Inflows scenario: The inflows observed in the months of October/2020 to September/2021, which was the most critical period of inflows in recent years, were considered.

Thermal dispatch: For the level of thermal dispatch, 6 simulations were carried out:

- CVU = 0.00: no thermal plant is dispatched (dispatched power: 407MW)
- CVU = 100.00: thermals with CVU less than 100.00 R$/MWh are dispatched (dispatched power: 4,028 MW)
- CVU = 200.00: thermals with CVU less than 200.00 R$/MWh are dispatched (dispatched power: 5,652 MW)
- CVU = 331.05: thermals with CVU less than 331.05 R$/MWh are dispatched (dispatched power: 7,307 MW)
- CVU = 740.32: thermals with CVU less than 740.32 R$/MWh are dispatched (dispatched power: 11,860 MW)
- CVU = 99999999: all thermals are dispatched (dispatched power: 18,907 MW)

It is observed that the last three values are used to determine three reference curves currently.

Calculation of minimum stored energy: The expression of stored energy to be minimized, equation (1), was considered with the following parameters:

- $k_{inic}^t = k_j^t = 1 \forall t$, if the plants j belong to the Southeast submarket
- $k_{inic}^t = k_j^t = 2 \forall t$, if the plants j do not belong to the Southeast submarket

Thus, the minimization of energy has more weight on the plants of the South, North, and Northeast submarkets in relation to the Southeast submarket, so that the storages of the Southeast plants are used primarily to guarantee energy security. The calibration of these parameters aimed to emulate the procedure currently done in the determination of CRefs, where the storage of the Southeast is uniformly increased until the security restrictions are met.

Thus, based on the case described above, the CRefs for the year 2022 were obtained with the proposed computational model. Figure 1 shows the curves related to the total storage of the BIPS for each reference CVU value, by the proposed model, and in black is the official curve obtained by the Brazilian independent system operator (ONS) with the current procedure, for the CVU of 740.32 R$/MWh. It is observed that the obtained curves have a behavior similar to the official curve, since:

- the minimum storage of the system decreases as the reference CVU increases.
- the behavior of the curve reflects the increase in minimum storage in the rainy period (from December to March) and gradual reduction of this storage as the dry period approaches its end.

However, the curves obtained by the proposed model assumed different (more reduced) values compared to the official curves, which may have happened not only due to the difference in the construction process (the optimization allows the minimum values to be found exactly), but mainly due to possible differences in the input data and assumptions adopted, since it was not possible to exactly reproduce the case study officially used, as it is not fully available. Another possibilty for the reduced values could be from a greater accuracy in obtaining the optimal minimum storage values, due to the adoption of a single optimization problem for obtaining the CRefs, instead of applying a manual iterative process.

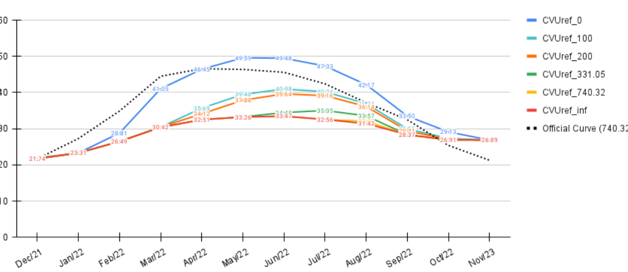

Fig. 1. Reference curves of the BIPS storaged energy for different reference CVU values for each month

In conclusion, the proposed procedure proves to be a reliable and highly efficient alternative for obtaining the CRefs, as the computational time required to obtain all the curves was around a few minutes, which would even allow for a wider range of variants of this procedure to evaluate the effect of changing some of the parameters of this procedure, in addition to other studies on the energy security of the system.

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Physical Guarantee for Interconnected Systems

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Measuring with precision the individual contribution to maximum demand, while considering a reliability constraint, remains one of the significant challenges in modern energy markets. The difficulty arises from the complexity of the system's generation, which aggregates production from diverse resources, including thermal, hydroelectric, renewables such as solar and wind, and battery storage.

In the Brazilian context, a central concept for the operation of the electricity sector is **Physical Guarantee (GF)**. GF represents the maximum amount of demand the system can meet under specific reliability criteria and is calculated from a base load, adjusted by a linear scaling factor.

To model GF accurately, we employ a bi-level optimization framework based on an Economic Dispatch Multi-Stage Stochastic Optimization problem. This approach allows us to better capture the inherent uncertainties in energy production and consumption, providing a more robust assessment of system reliability.

For system operators, determining each resource's contribution to GF is essential to identifying which elements of the system help mitigate blackouts. For generators, this determination defines the value received for capacity payments. Moreover, in decentralized capacity markets, such as CAISO, SPP, and France, system agents are responsible for ensuring adequate reliability. However, calculating an individual unit's contribution factor is challenging, as it is a system-wide characteristic rather than an isolated unit.

In Brazil, two traditional methods are used to allocate GF. The first is called Revenue Allocation, which distributes based on each generator's share in the system's total revenue. The second method, referred to as Critical Period Allocation, assigns demand based on each generator's energy production during periods of low hydrological storage or other resource shortages, often called dry periods.

These traditional approaches, however, lack rigorous evaluation in terms of effectiveness and fairness in allocating GF among resources. To address this, we model GF allocation as a Cooperative Game, where all energy resources work together to maintain system reliability and determine each resource's contribution to GF.

With this approach, we propose two new procedures for calculating units' GF within a Stochastic Optimization framework, which we call: **Marginal Benefits** and **Aumann-Shapley.** These procedures focus on determining the marginal contribution of each resource to system operation. However, calculating the derivatives of a Stochastic Optimization problem that represent marginal contributions is non-trivial. To overcome this challenge, we propose a combination of the chain rule and simplex sensitivity analysis that can work alongside decomposition methods, such as the Stochastic Dual Dynamic Programming (SDDP) typically used to solve multi-stage Stochastic Optimization problems.

We validated these new approaches through detailed case studies that demonstrate their effectiveness in different scenarios. These methods were also applied to the Brazilian Electrical System to assess their practical feasibility in a real-world context, and the results show significant potential to improve the accuracy and fairness of GF allocation.

Among the various applications of Physical Guarantee (GF), we chose to explore the dynamics of energy auctions. Initially, we analyzed the current format, which uses a cost-benefit index to simplify system operation. Then, we proposed an expansion model with a reliability-constrained operation, in a sealed-envelope style, as well as presenting a hybrid expansion model that uses Physical Guarantee as a proxy for reliability constraints. With this, we demonstrate that the current auction model is inadequate for both calculating generator revenues and preventing system deficits, highlighting the need for a more sophisticated approach based on reliability criteria.