Lightning Session A (17:10 - 18:30)	**Optimization and Hydrology**	**Chair: Sara Séguin, Univ. Quebec**	
	Improved Inflow Modelling in Medium-Term Hydropower Scheduling	Amund Skretting Bergset	SINTEF
	Efficient Density Function Estimation for Hydro and Wind Power Applications Using Chebyshev Polynomial Approximations	Fernando Deeke Sasse	UFPR
	Optimizing Long-term Hydro-thermal Scheduling Through Deep Learning: A Comparative Study	Jinghao Wang	NTNU
	Iterative re-optimization with multiple markets in stochastic medium-term hydropower scheduling	Stefan Rex	SINTEF
	Comparison between different parallelization schemes in SDDP policy training	Guilherme Bodin	PSR
	Incorporating short-term constraints in the long-term hydrothermal-wind systems operation planning	Carlos Junior	UFJF
	Impact of Electrical Network Constraints on Water Values and Hydro generation policy for long term Hydro-Thermal-Wind Planning Problem Solved via Stochastic Dual Dynamic Programming: Application to the NEWAVE Model	Robério Barboza	CEPEL
	LinearDecisionRules.jl	Bernardo Costa	FGV

Improved Inflow Modelling in Medium-Term Hydropower Scheduling

Presenter: Amund Skretting Bergset
SINTEF Energy Research

Keywords: Hydropower scheduling, SDDP, Inflow modelling

Objective

Optimal scheduling of hydropower resources is important in the transition towards a zero-emission society as it enables hydropower producers to generate more power when the demand is high and save water when the demand is low. It may also reduce spillage from reservoirs, preventing overflow that can be destructive on downstream infrastructure or settlements. As hydropower scheduling is a large and complex problem, a chain of several optimization models with different time horizons and level of detail is typically applied. In the medium-term scheduling problem, a production strategy is provided based on price and inflow prognoses. To account for the uncertainty in inflow, a stochastic inflow model is necessary. The formulation of this model can have a significant impact on reservoir management.

Methodology

SINTEF has developed a model intended for medium-term hydropower scheduling called Prodrisk, which uses a combination of stochastic dynamic programming (SDP) and stochastic dual dynamic programming (SDDP). The price is treated as an exogenous state in the SDDP algorithm, whereas inflow is treated as a continuous state variable in the SDDP algorithm and is therefore subject to the algorithm's convexity requirements. The stochastic inflow used as input to Prodrisk is modelled as a first-order vector autoregressive (VAR1) process with weekly time steps and a normally distributed noise term. A complication with this model has been the occasional production of negative inflow values, leading to unphysical violations of reservoir volume constraints, which in turn affect the production strategy.

To overcome this problem, a VAR1 model with noise sampled from a 3-parameter lognormal distribution, as described in e.g. [1]-[5], is fitted to the observed inflow. The model ensures non-negative inflow values and uses the selective sampling method described in e.g. [6]-[8] to sample noise, based on a k-means clustering procedure [9].

Results

The main contribution of this presentation is a set of adjustments intended to preserve statistical properties of the estimated inflow from the observed inflow during sampling. This includes a small modification in the selective sampling algorithm, resulting in a more even spread of the k-means centroids. Additional adjustments are included to preserve the standard deviation of the observed inflow, since this is not preserved in the k-means clustering algorithm.

With the absence of negative values in the stochastic inflow model, the strategy from Prodrisk turned out to be more risk-seeking, allowing for lower reservoir volumes. A general reduction in computation time was observed, and simulation results indicated an economic improvement between 0% and 2%. The inflow series used in the case studies had a pronounced spring flood due to snow melting, which was appropriately considered by the inflow model.

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Efficient Density Function Estimation for Hydro and Wind Power Applications Using Chebyshev Polynomial Approximations

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1 Objectives

As part of the Lynx project - Large-Scale Optimization Applied to the Brazilian Hydrothermal Dispatch, this work aims to provide additional power management tools to systems with integrated wind and hydropower. In particular, we present the implementation of a fast polynomial non-parametric method with Chebyshev bases for determining polynomial density functions. This method can be helpful in modeling rivers, reservoir inflows, and wind power. Due to the multimodal character of this kind of distribution, the application of non-parametric methods provides much better results than those from parametric methods in terms of fitting accuracy. Polynomial basis approaches have a practical advantage when calculating the convolution of the distribution since these operations should consist of integrals of polynomial expressions. Compared to other nonparametric methods, such as spline methods [1], polynomial bases [2, 3], and the maximum entropy principle [4, 5], our method has the advantage of being faster in determining, producing fitting polynomials instead of a function defined by intervals. These polynomials are relatively stable (in terms of oscillations) and offer satisfactory accuracy in fitting the data.

2 Methodology

It is an application of the method applied initially by Balestrino et al. [6] to fit continuous probability density functions to wind speed data. In that paper, the authors present an approximation based on the polynomial method with Chebyshev bases and a method to improve the choice of bases using an approximation of the maximum entropy principle. Despite the convergence achieved by using the maximum entropy method described in that article in approximating probability densities, our experience has shown that for a finite data set, the first approximation, using a Chebyshev basis, provides more accurate results if enough moments are considered. The computational speed of the method is due to the fact that the problem is always reduced to the solution of a relatively small linear system, allowing its use for applications that require immediate response. The technique is robust because the optimal number of moments depends mainly on the sampling number. For reproducibility purposes, the implementation script is provided in Python. We have successfully tested the method for wind speed, precipitation, and river flow distributions.

3 Expected Results

The approach should provide an accurate fit to most typical wind speed distributions and typical multimodal distributions in hydro scheduling and wind speed applications in a relatively short computational time compared to other methods. The tool implemented in Python can be integrated into many kinds of analyses developed in the Lynx project, where fast and efficient determination of polynomial density functions is needed.

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Optimizing Long-term Hydro-thermal Scheduling Through Deep Learning: A Comparative Study

Objective

In today's pursuit of climate neutrality by 2050, the European Union (EU) has established a goal to reduce carbon emissions [1]. Renewable Energy Sources (RES), such as hydropower, solar, and wind, are vital in achieving this objective. However, the integration of variable RES introduces uncertainty and variability in electricity generation, posing a challenge to system balancing [2]. Norway, with its reliance on hydropower and large reservoirs, is well-positioned to contribute to the balance of the European power system [3]. To effectively utilize the hydro potential and accurately predict the value of flexible hydro stored in reservoirs, robust decision support systems are required.

The computation of disaggregated hydro reservoirs in the large hydrothermal system is a complex task that has been extensively discussed in recent literature [4, 5]. This problem is dynamic due to the storage capacity of hydro reservoirs and stochastic due to the numerous uncertainties involved. One possible approach is the Scenario fan simulator (SFS) model, which solves a two-stage stochastic linear programming problem using historical observations and the current situation to provide decisions for each week [6, 7]. However, incorporating all technical details and representing a detailed time scale in existing strategical hydropower scheduling methods is computationally challenging and may hinder real-time or near-real-time applications, thus affecting the scheduling operation of hydropower plants.

Methodology

Recently, there has been a growing interest in applying deep learning and artificial intelligence (AI) techniques to predict and optimize various fields. By leveraging massive data to capture essential information, the hydropower scheduling algorithm can benefit from the fast-computing advantage of deep learning techniques, thereby overcoming computational challenges and providing aids to decide if the scheduling needs to be updated. To address the computational time and performance issues associated with disaggregated long-term hydro-thermal planning, we propose a Scenario-based and demand-driven encoder with a graphic neural network (SDE-GNN), structure as shown in Figure 1.

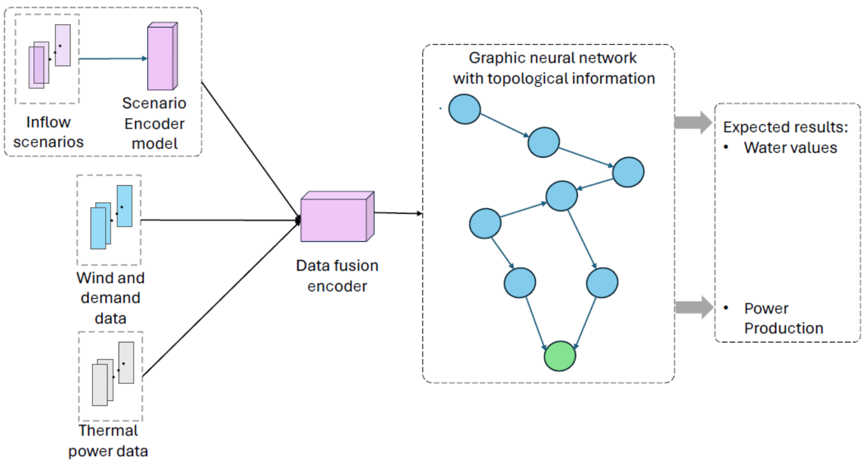

Figure 1. An illustration of the SDE-GNN model, along with its input components and the interconnections between reservoirs in cascaded hydro plants, is provided.

This study aims to demonstrate the performance of the SDE-GNN in comparison to the fundamental SFS model for long-term disaggregated hydro-thermal scheduling. Additionally, the application of SDE-GNN is explored to determine its potential in reducing computational issues, preserving topological information and assisting in deciding whether updates to scheduling are necessary. To further validate its efficacy, we will conduct a case study focused on predicting water values and volumes. The primary objectives of this paper are as follows:

- Topological preservation: The SDE-GNN aims to maintain the topological integrity of hydropower plants.
- Long-term hydro-thermal scheduling: The SDE-GNN supports long-term scheduling for cascaded hydropower systems through disaggregated strategies.
- Water values calculation: The SDE-GNN offers guidelines for determining water consumption strategies, known as water values, and power production.

(Expected) Results

The SDE-GNN model aims to offer improvements in computational efficiency and accuracy over the traditional SFS model for long-term hydro-thermal scheduling. Through the simulation and case studies focused on Norwegian hydropower systems, the following results are anticipated:

1) Computational Efficiency 2) Accuracy and Performance 3) Topological Preservation

The expected findings will contribute to the literature on hydropower scheduling by highlighting the benefits of integrating deep learning techniques with traditional hydrothermal planning methods. Furthermore, these results will underline the potential of AI-driven models in enhancing the efficiency and reliability of renewable energy sources, supporting the broader goal of achieving climate neutrality.

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Iterative re-optimization with multiple markets in stochastic medium-term hydropower scheduling

Presenter: Stefan Rex, SINTEF Energy Research, stefan.rex@sintef.no
Conference Topics: (a) investment and expansion planning in hydro-dominated systems; (b) hydro scheduling in decarbonized power systems

1 Objective

This paper presents a cutting-edge tool to simulate and analyze investment cases in hydropower, based on the stochastic hydro scheduling model Prodrisk [1]. Prodrisk relies on stochastic optimization in a combined SDP/SDDP algorithm, which is designed to deal with uncertainty in the form of multiple (usually 30-80) scenarios for both electricity prices and inflows to the reservoirs. A statistically optimal state-dependent production strategy is calculated in the form of water values, which can be used to simulate operations in any given scenario. When the scenarios are simulated serially, the expected consequences of investments can be studied over a range of several decades.

The rationale behind this work is that if existing flexible resources in the power grid can be better used it will ease the transition of the European power system. In the transition, renewable and, thereby, more volatile sources of electric energy are key to decarbonizing the energy system, and recent years have witnessed major expansion of both wind and solar production. In a volatile environment, it may be insufficient to base the optimization of hydropower operations solely on the day-ahead market prices. It is expected that a range of additional markets and services, in particular balancing markets, will become far more important than in the past. Therefore, investment decisions for upgrades or expansions of hydropower plants must account for the expected income from multiple markets.

As of today, Prodrisk supports a day-ahead market and two reserve markets (up- and down regulation) with deterministic prices in the strategy calculation. Although the addition of further markets is methodically possible, it would cause prohibitive computation times. Here, we address the problem of estimating multi-market profit for investment decisions based on iterative aggregation and de-aggregation of markets.

2 Methodology

We present a solution to the multi-market problem that combines an iterative method for sequential markets [2] with reserves in the water value calculation [3] using an aggregated representation of different reserve types. Our algorithm comprises the day-ahead market, intra-day market, four reserve capacity markets (up and down regulation with spinning or non-spinning units), and the activation of these reserve types, all with individual prices.

The approach can be summarized as follows: the reserve markets are first aggregated in two markets for up- and down regulation with effective prices based on an initial guess for the ratio of spinning/non-spinning allocation and respective activation rates. With these aggregated markets and the day-ahead market, Prodrisk can calculate the strategy, i.e., water values. Afterwards, this strategy is applied in a sequence of simulations with prices for the individual markets where (1) the production schedule is corrected according to intra-day prices, (2) the reserve capacities are successively distributed depending on unit commitments, and (3) reserve activation decisions are made. Afterwards, the results are aggregated again, and the algorithm is iteratively repeated until the effective reserve prices have converged within reasonable limits. The algorithm is illustrated in Figure 1.

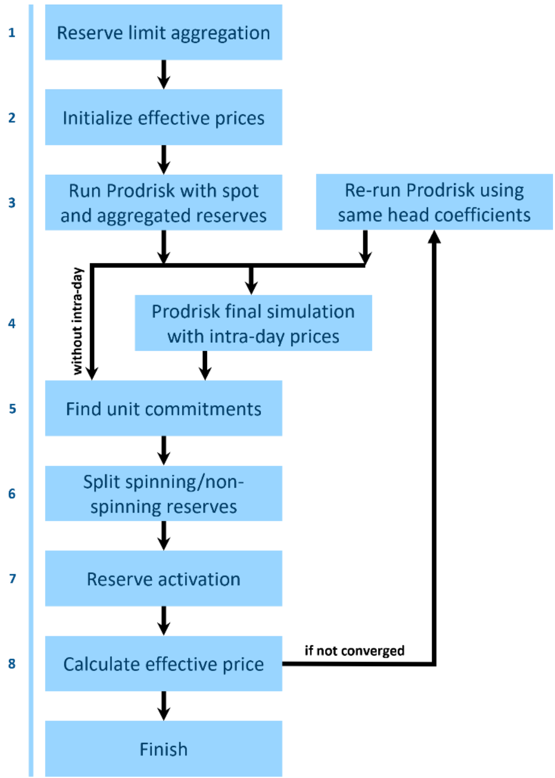

Figure 1: Flow chart of iterative algorithm for sequential markets in Prodrisk

3 Expected results

The algorithm will be demonstrated on an industry case, where we consider the profitability of different investment options in a pumped-storage system. We evaluate the performance of the algorithm, how the different markets are used according to the algorithm, and how water management and production strategies are affected. Furthermore, our results will provide more insight in the importance of the different market types for the expected revenue, as compared to less detailed modeling.

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Abstract to The 8th International Conference on Hydropower Scheduling in Competitive Electricity Markets

Comparison between different parallelization schemes in SDDP policy training

The Stochastic Dual Dynamic Programming (SDDP) algorithm is widely used to solve complex multi-stage decision-making problems under uncertainty, such as hydrothermal dispatch in power systems. Due to its iterative nature and the need to handle large volumes of data and multiple future scenarios, SDDP is a computationally intensive method. With the increasing complexity of modern systems and the need to respond swiftly to energy market fluctuations and climate variability, computational efficiency in SDDP is a topic of great importance. This study aims to explore different parallelization approaches for the SDDP algorithm to improve its performance in terms of execution time and efficient use of computational resources.

The primary motivation for this research lies in the fact that, despite advancements in processing power, the volume of data and the number of scenarios required for accurate analysis have also grown, creating bottlenecks in the practical application of the algorithm. Thus, investigating parallelization techniques enables the application of SDDP in more complex and dynamic contexts, promoting faster and more reliable responses for energy system operation and planning. The parallelization approaches analyzed include process queue-based parallelization, scenario-based parallelization, and stage-based parallelization. Each approach has specific characteristics that may be advantageous depending on the problem structure and available hardware architecture. All approaches will be compared against serial runs, which use only a single computer core.

Parallelization strategies will be analyzed for both the policy phase, where the algorithm approximates future cost functions, and the simulation phase, where the future cost functions are used to simulate potential future scenarios.

For performance analysis, prototypes of the approaches were implemented in a controlled environment using a representative set of hydrothermal dispatch problems. The results on the stability, speed, and reliability of each parallelization scheme will be reported in this study.

The choice of the most suitable parallelization technique depends on several factors, including the number of scenarios, the length of the time horizon, the available hardware architecture, and the memory requirements of the problem. Based on the results, a hybrid approach is recommended for large-scale and complex problems, where scenario-based parallelization and subproblem-based parallelization are combined to maximize efficient use of computational resources. This strategy can provide a robust and efficient solution for hydrothermal dispatch and other applications requiring sequential optimization under uncertainty.

In conclusion, studying different parallelization methods for SDDP is essential to enable its application in large-scale energy systems, where agility and decision accuracy are crucial. This research contributes to advancing performance optimization methods that can be applied not only in the energy sector but also in other areas involving dynamic programming in stochastic scenarios that demand high computational efficiency.

Incorporating short-term constraints in the long-term hydrothermal-wind systems operation planning

Autores: Carlos Araújo Júnior, UFJF, Bruno Dias, UFJF and Andre Diniz, CEPEL

Objective:

The continuous increase in renewable energy sources, such as wind and solar, has introduced unprecedented challenges in the planning and operation scheduling of power systems, mainly due to the high hourly variability of these sources. In the Brazilian National Interconnected System, this variability is only considered in the operation scheduling stage. However, its impacts extend significantly throughout the entire horizon of hydro-thermal-wind operation planning.

This study presents an approach that combines two-stage Benders decomposition with Dual Dynamic Programming. The goal of this combination is to generate Intra-Stage Cost Functions (FCIE), replacing traditional Immediate Cost Functions. FCIE allows a more accurate representation of the hourly characteristics of renewable sources in medium and long-term planning models while avoiding the explicit subdivision of planning into hourly stages. Compared to recent studies in this area, the main contribution of this work is avoiding the need to discretize, a priori, all operational points of hydroelectric generation across multiple subsystems, which becomes infeasible for large-scale problems.

Methodology:

The primary objective of this study is to develop an iterative construction of the multidimensional Immediate Cost Function, referred to in this study as the Intra-Stage Cost Function (FCIE), for each stage and scenario of the planning problem. The proposed approach combines Dual Dynamic Programming with two-stage Benders decomposition.

The overall problem is solved through a two-level approach. At the upper level, a multi-stage problem associated with medium-term hydro-thermal-wind planning is solved using Dual Dynamic Programming. At the lower level, two-stage Benders decomposition is used to handle subproblems with hourly steps, enabling the construction of FCIE.

Results:

The results were obtained through case studies based on the medium-term operation planning of the Brazilian power system, aiming to evaluate the methodology's applicability in a realistic context.

The methodology proves to be efficient in multi-horizon modeling of large systems, eliminating the need to construct FCIE for all operational points of hydroelectric generation, as required in previous approaches. This simplification drastically reduces the number of subproblems solved, enhancing computational efficiency and making the methodology more feasible for large-scale systems.

Impact of Electrical Network Constraints on Water Values and Hydro generation policy for long term Hydro-Thermal-Wind Planning Problem Solved via Stochastic Dual Dynamic Programming: Application to the NEWAVE Model

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The long-term operation planning problem of large interconnected power systems, such as the Brazilian Interconnected System (SIN), aims to establish an optimal operational policy that defines generation targets for power plants and energy exchanges between subsystems. These policies must comply with plant-specific operational constraints, electrical system constraints, energy demand requirements, and system reliability criteria over the planning horizon, with the goal of minimizing operational costs. In recent years, the increasing penetration of intermittent renewable sources, particularly wind power, has introduced additional complexities into SIN's planning and operational processes. The expansion of self-generation and mini/micro distributed generation (MMDG) further intensifies these challenges, requiring improvements in the computational representation of system components. The lack of such representations can lead to inaccuracies in system modeling, thereby increasing time inconsistency in comparison to real-time dispatch.

To accommodate this expansion, especially in the Northeast region, SIN has been extending its transmission network to enable the transfer of surplus generation to other regions. According to projections from the 2034 Decennial Energy Expansion Plan (PDE), the length of the basic grid is expected to increase from 187,000 km in 2024 to over 218,000 km by 2034. This expansion will raise the Northeast submarket's export capacity from 13 GW in 2024 to 28 GW in 2032 and the South submarket's import capacity from 11.4 GW to 16 GW over the same period. These changes impact energy flow dynamics due to dispatch shifts. For example, the Northeast submarket, which was previously considered predominantly an energy importer, has become predominantly an energy exporter. In addition, the amounts of energy exchanged are increasingly larger.

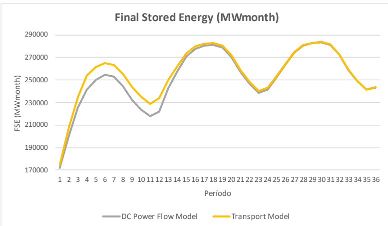
Given this evolving scenario, improving the representation of network constraints in models used for SIN's planning and scheduling is essential. This need arises both in short-term scheduling, which faces increasing uncertainties from wind, solar, and MMDG generation, and in long-term planning, where more detailed system representations are essential to improving water valuation accuracy and minimizing discrepancies between planned and real-time dispatch.

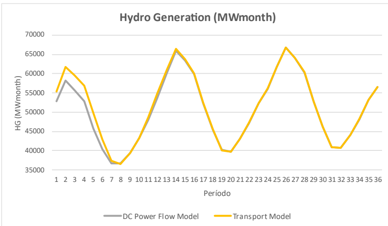
In this context, the NEWAVE model, a stochastic optimization program based on Stochastic Dual Dynamic Programming (SDDP), which incorporates hydro-wind stochasticity when building the operation policy, has been widely employed in the Brazilian power sector since 1998 for official activities such as the Monthly Operation Program (PMO), the Energy Operation Plan (PEN), and the analysis of the Ten-Year Energy Expansion Plan (PDE). Among recent improvements, the increased granularity in representing the hydraulic system through individualized hydroelectric plants over all or part of the planning horizon stands out. Studt cases where initial periods are modeled using individualized hydro plants and subsequent months are represented through Equivalent Energy Reservoirs (EER) are labeled "hybrid cases".

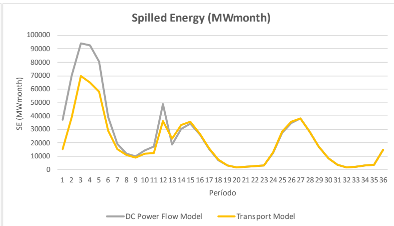
This study proposes further improvement to the NEWAVE model by explicitly incorporating the electrical transmission network using a linearized (DC) power flow model. To mitigate the associated computational costs, two methodologies were developed to represent network constraints in SDDP: (i) dynamic definition of constraint limits; (ii) dynamic inclusion of constraints. The dynamic definition of constraint limit involves including all network constraints in the subproblems, but initially with unbounded limits. After solving the subproblem, the resulting dispatch is checked for violations of transmission line limits. If violations occur, the corresponding limits of violated constraints are established, and the subproblem is solved again. The dynamic inclusion of constraints begins by solving each subproblem without including network constraints. After solving the subproblem, the resulting dispatch is checked for violations in transmission lines whose constraints have not yet been included. If violations are detected, the corresponding constraints are inserted in the problem, and the subproblem is resolved. These two strategies are equivalent from the conceptual point of view, but may differ regarding computational efficiency, even though both aim to reduce computational time without compromising convergence or solution quality.

To assess the impact of the proposed modeling, especially in the dispatch of hydro plants, a comparative study was conducted between the traditional model, which represents submarket exchanges via a transport model, and the new approach, which explicitly models all basic grid circuits using a DC power flow model. We consider a real case for the long-term planning of the large-scale Brazilian system, with 172 hydro plants, 90 thermal plants and incorporating over 15,600 transmission lines and 12,500 buses. The time horizon has 60 monthly time steps –the first 12 stages with an individual modeling and the following 48 stages with an equivalent representation of the hydro plants, with 3 load blocks for each stage. We considered 20 backward scenarios for each stage and 200 scenarios in each forward pass. Additionally, since all sources and loads are individually connected to system buses, the solution of 2000 inflow scenarios over months with explicit grid representation provides both Locational Marginal Pricing (LMP) and submarket operational marginal costs (CMO).

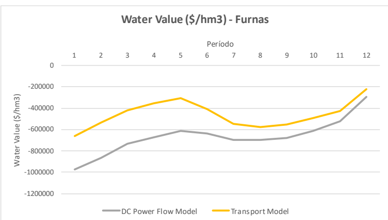
Besides the increase in total costs, assessment of operation reveals a reduction both in final storage and hydro generation, as well as an increase in spillage, when network constraints are included:

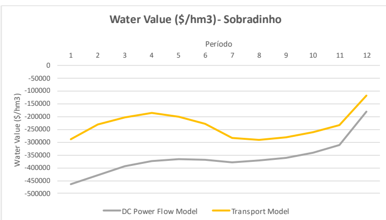


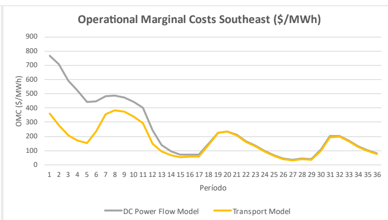




Furthermore, network constraints also directly impact the valuation of stored water in reservoirs, leading to higher water valuation during periods with detailed network constraints. This higher valuation also results in increased thermal generation, as hydro generation becomes relatively more costly. Consequently, operational marginal costs are also higher during these periods.







By enhancing the integration between energy and electrical models, this study contributes to more realistic medium- and long-term operational planning, reducing the gap between planning models and real-time system behavior. Also, it reveals how the consideration of electrical network impacts the operation policy of the hydro plants, since less energy is stored in the reservoirs even with a decrease in hydro generation. This occurs because network constraints limit or enforce the operation of some plants, thus preventing the system from optimizing the operation of hydro cascades to obtain the maximum possible energy, and also leading to an increase in spillage.

LinearDecisionRules.jl: a Julia package for stochastic optimization with applications to hydro dispatch problems

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We present a Julia package that extends the JuMP modeling language to solve stochastic optimization problems with the linear decision rules technique. The package was motivated by the necessity to solve the stochastic hydro dispatch and unit commitment problems. Although the theoretical foundations of the linear decision rules technique are soundly and clearly described in many works in the literature, there is a clear barrier between this theory and wide adoption or practical usage. The precise formulation of the problem being solved and the computation of moments matrix are non-trivial, and their manual computation can be cumbersome and error-prone.

Modeling languages like JuMP aim at simplifying the development and practical usage of optimization models by allowing users to write models with algebraic expressions instead of directly building matrix form representations that are expected by solvers. This leads to a faster and more reliable process. As an extension of JuMP, LinearDecisionRules.jl inherits its basic syntax for defining variables, constraints and objective function, but also adds new features such as the possibility of defining variables that represent the problem uncertainties and separating first stage and second stage decision variables.

The representation of uncertainties is done is two pieces. First, the support of distributions is defined as a set of linear constraints defined with the standard JuMP syntax. Second, the probability distributions are defined using the API provided by the package Distributions.jl, which automatically allows users to consider a wide range of scalar and vector distributions. Additional distributions, not defined in Distributions.jl, are also provided such as general vector distributions truncated in a hypercube and non-parametric multivariate distributions. These features allow users to experiment with this powerful solution method.

The package provides automatic reformulations for both primal and dual linear decision rules. Therefore, in the convex cases, the package easily provides upper and lower bounds for the problem solution. The resulting decision rules can be queried through a user-friendly interface.

We demonstrate the applicability of the package by presenting a range of optimization problems focused on the hydro dispatch. We start with simple examples to demonstrate the basic functionality. Then we move towards problems considering realistic data to demonstrate the effectiveness of the developed package.