Comparative analysis of dynamic and linear programming energy systems models applied to the Bolivian power system

Alizon Huallpara[a*], Marco Navia[b], Isaline Gomand[c], Sergio Balderrama[d], Matija Pavičević[e] and Sylvain Quoilin[f]

[a,d] Universidad Mayor de San Simón, Cohabamba, Bolivia, alizon.huallpara@fcyt.umss.edu.bo, CA
[b,c,f] University of Liege, Liege, Belgium,
[e] UC Louvain, City, Louvain-la-neuve Belgium

Abstract:

Energy system models are indispensable tools for energy planning and decision making. They identify the most cost-effective way of delivering energy to the final consumer. No one tool that addresses all the energy system-related issues. Every model has its own strengths and limitations and serves a different purpose. This paper aims to compare the capabilities of two different model formulations to model both the hydro scheduling and the short-term dispatch problems in hydro-dominated power systems. On the one hand, SDDP, a commercial model for hydrothermal generation scheduling with a representation of the transmission network, has been used by the Bolivian system operator for dispatch simulations. Conversely, Dispa-SET, an open-source unit commitment and economic dispatch model with mid-term hydrothermal coordination capability, has been used previously in several Bolivian case studies. In this paper, both models were applied to the same input dataset of the Bolivian electric system considering probabilistic results for 43 weather years from 1984 to 2021. SDDP optimizes the system under all weather years, while Dispa-SET optimises under one full year, for which 43 runs were made. The results show that SDDP generation, reservoir level and spillage fall into the ranges of Dispa-SET results. Some differences that are present mainly lie in the conceptualization of the methods of both models. SDDP prioritizes the dispatch of hydro units, while Dispa-SET, with a higher temporal and technical resolution, maximizes the use of non-dispatchable units such as variable renewables and run-of-river.

Keywords:

Dispa-SET Bolivia; Energy system modelling; SDDP; Hydro scheduling.

1. Introduction

The Paris Agreement and Sustainable Development Goals (SDGs) are crucial global frameworks addressing environmental and development challenges, requiring changes in every country. The Paris Agreement commits countries to achieve net-zero greenhouse-gas emissions by the middle of the century, while the SDGs consist of 17 SDGs and 169 targets for Prosperity, People, Planet, Peace, and Partnership [1]. SDG7 aims to "Ensure access to affordable, reliable, sustainable and modern energy for all" [2]. For this, renewable generation expansion is critical in helping to mitigate global warming. These agreements have significant implications for national development plans for developed and developing countries [3]. Bolivia's Nationally Determined Contribution (NDC) [4], consistent with the Paris Agreement, presents climate goals and actions aligned with emission reduction and adaptation to the impacts of climate change. Bolivia aims to achieve a transition in electricity generation towards renewable energy and targets 79 % renewable energy consumption and 50 % of renewable installed capacity by 2030. Bolivia's alternative energy goal by 2030 is to reach 19 % energy consumption from Biomass, Solar, Wind and Geothermal energy, contributing to SDGs 7,8,12, and 13.

Energy models are essential analytical tools that can support SDG goals by analyzing potential energy project impacts [5]. Energy models' quantitative analysis supports much of academic research and energy policy-making [6]. There is a wide variety of models, each with its unique blend of paradigms, techniques and solutions. Each model's extensive range of choices makes it unlikely that a single model could incorporate them all at once [7]. While most models' source code is not available for public access or modification, open-source models allow users to access and modify the model code. According to Pfenninger [6], open-access models improve the quality of science, allow more effective collaboration across the science-policy boundary, increase productivity through collaborative burden sharing and allow profound relevance to societal debates. In Energy models, when solving the hydrothermal scheduling problem (HTSP) in a system with a large share of hydro generation, such as Bolivia, water inflows play an essential role in the decision-making process. The scheduling of generators must consider various future possibilities, and if a cascade system exists, water availability is influenced by decisions made in upstream reservoirs. These issues complicate the HTSP, and when an optimization model is designed for it, the decision variables that must be considered include the turbined water used for generation, storage, and spillage [8].

The models of interest for this study are a Stochastic dual dynamic programming model (SDDP) and a Mixed-Integer Linear Programming model (MILP), both bottom-up and dynamic energy models. The Brazilian engineering company PSR has used SDDP algorithm in its software bearing the same name, which has been applied in operations studies in more than 30 countries, including Bolivia. On the other hand, the Dispa-SET model, which uses the MILP algorithm, is an open-source model that has been applied in previous research in different countries, including Bolivia. Both models analyze the components and interconnections between different energy sectors, allowing the comparison of the impact of different technologies on the energy system and finding the best future alternative [9]. They can also find optimal solutions for energy systems under predefined constraints [10]. SDDP and Dispa-SET models have been used in previous research for hydro-thermal scheduling. For example, Gjerden et al. [11] applied SDDP for the Norwegian hydropower system, with 500 hydropower modules applying a stochastical time resolution of one week, showing that the statistical properties of the inflow model significantly impacts the model performance and that the accuracy of SDDP-based models are dependent on the number of inflow series. In [12] the soft-linking between two models was done, where Dispa-SET is used for mid-term hydrothermal coordination, optimal unit commitment and power dispatch over the whole African continent. In this article, the water-energy nexus was analyzed, whose indicators reveal that the water stress induced by power generation activities is problematic in some power pools. Zarate et al. [13] modelled the Bolivian power system on Dispa-SET, focusing on hydropower to assess the effects of different rainfall years on the ability of hydropower to generate and store electricity in the Bolivian electric system.

In this paper, these two energy models are compared, applied to the Bolivian electric system for the year 2026, where renewable energy projects are planned to be implemented. The paper is structured as follows: Section 2 provides an overview of the Bolivian case study; Section 3 describes the methodology that was followed for the model mapping and the simulation configuration; Section 4 presents the modelling results and comparison between the two models; Section 5 concludes.

2. Case study - The Bolivian energy system

The Bolivian electric system consists of the National Interconnected System (SIN) and the Isolated System, which provide electricity to main cities and remote places, respectively. This study focuses on the SIN, which is divided into four zones: North (La Paz and Beni), Oriental(Santa Cruz), Central(Oruro and Cochabamba) and South (Potosí, Chuquisaca and Tarija) (Fig.1). In 2021, SIN energy production was 9628.93 GWh, 33.24% from hydro, 62.31% from thermal (mainly gas), 3.52% from solar PV and 0.93% from wind power plants. [14]

Figure 1: The Bolivian National Interconnected System zones: North (La Paz and Beni), Oriental(Santa Cruz), Central(Oruro and Cochabamba) and South(Potosí, Chuquisaca and Tarija), with the new transmission lines scheduled to be implemented by 2026 [15].

The Bolivian electric plan 2025 [16], proposes expanding the electrical infrastructure and gradually incorporating the Isolated System into the SIN. The plan targets 70 % hydroelectric generation and 4 % alternative energy generation [16]. The plan includes the incorporation of Miguillas power plant with two generation units, Umapalca with 83 MW and Palillada with 116 MW, both located in La Paz; Ivirizu power plant with two generation units, Sehuencas with 194 MW and Juntas with 89 MW of installed power located in Cochabamba, and Condor with 1,4 MW in Potosi. The renewable generation projects to 2025 consider the incorporation of 2 wind farms, La Ventolera, with 23 MW of power, located in Tarija, and Warnes-2, with 20 MW of power, located in Santa Cruz [16] [15]. The total installed capacity in 2022 was 3495 MW, and it is planned to increase to 4036 MW with the hydroelectric and renewable energy projects for 2025. Figure 2 shows the current installed capacity for each zone (2022) and the projected installed capacity for 2025 by zone, with new additions mostly in the form of hydro, VRE and biomass. The existing VRE installed capacity is 29.4% in 2022 and is expected to grow to 38.8% by 2026. The new VRES projects are mainly in the form of hydro and wind.

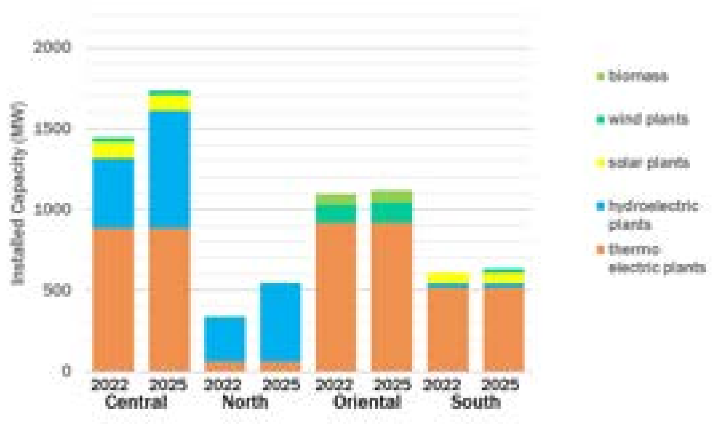


Figure 2: Current (2022) and projected (2025) total installed capacity (MW) by zone. New additions are mostly in the form of hydro, VRE and biomass.

The expansion of the electrical transmission infrastructure between the neighbouring zones by 2026 includes [17] [15].:

- A new transmission line between Central and Oriental zone with the Carrasco-Brechas line of 500 KV, which in the future will be part of the exporting lines to neighboruring countries.
- A new transmission line of 230 KV between Central and North zone with Santivañez-Miguillas line
- A new line between the Central and South zone with 230 KV in the line Mizque-Sucre.

3. Methodology

The work presented in this paper is a continuation of previous Dispa-SET studies for the Bolivian energy system [18] [19], with the novelty of probabilistic analysis of results. The input data for Dispa-SET was obtained from the Bolivian electric system of SDDP software, which is used by CNDC (Comité Nacional de despacho de carga) and ENDE Corporation, to ensure consistency and compare simulation results for 2026 after incorporating new generation and transmission infrastructure.

3.1. Stochastic dual dynamic programming model

SDDP model is used to optimize the expected value of a benefit function or a cost function over a given planning horizon involving weeks or months stages [20]. The optimization problem in this model is solved using dynamic programming, and the solution is used to update a set of dual variables [**?**]. SDDP breaks down the multistage nonlinear problem into a series of stage linear problems (assuming that the overall problem is convex). The dual variables are then used to formulate and solve a linear programming problem that generates a new set of feasible solutions. Rougé et.al. [20] says: " The basic idea behind SDDP is to approximate the convex benefit-to-go function by Benders cuts, mathematical objects that can be thought of as hyperplanes. The algorithm then simulates reservoir operation decisions by using these hyperplanes approximating the true benefit-to-go functions".

SDDP software is a hydrothermal dispatch model with a detailed representation of the transmission network. SDDP considers hydro plants operations, thermal plant modelling, spot markets, supply contracts, hydrological uncertainty, transmission network, and load variations to find the least-cost operating policy of a proposed hydro system. The main outputs from SDDP are hydro and thermal generation, thermal operation costs, energy interchange, fuel consumption, deficit risks and energy not supplied, short-run marginal costs and marginal capacity benefits.

3.2. Mixed-Integer linear programming model

Dispa-SET, a deterministic dynamic programming algorithm, is an open-source unit commitment and economic dispatch (UCED) model, developed within the Joint Research Centre of the EU Commission. It is a multi-sectoral energy model that represents the short-term operation of large-scale power systems with a high level of detail to assess the flexibility needs of systems with a high share of VRES, solving the UCED problem. Dispa-SET is expressed as a Mixed-Integer-Linear-Program (MILP), written in python and solved in GAMS. The model's objective function is to minimize the total operational system cost [21].

Dispa-SET includes a Mid-Term Scheduling (MTS) module, a relaxed formulation of the core hydro thermal MILP formulation, executed in the pre-processing phase, enabling fast and efficient pre-allocation of the State of charge (SOC) of all storage units present in the system. Since Dispa-SET simulations are performed for a whole year with a time step of one hour, the problem dimensions are not computationally tractable if the optimization is done at once [12]. Therefore, in the unit commitment and power dispatch module (UCM), the problem is split into smaller optimization problems that are run recursively throughout the year. The initial values of the optimization for any given day are the final values of the optimization of the previous day. A look-ahead period is included and then discarded to avoid issues linked to the end of the optimization period. This optimal hydro allocation is particularly relevant in systems with a high share of hydro dams and pumped hydro reservoirs [12]. Results from MTS are used as guidance curves of the reservoir levels, which are then used as minimum level constraints in the UCM module.

3.3. Comparison between model capabilities

Both Dispa-SET and SDDP are dynamic, partial equilibrium, hydro scheduling models. The summary of modelling features between SDDP and Dispa-SET is shown in Table 1. Dispa-SET is a model that needs accurate input data that can be run in parallel on several historical weather years. The results from such analysis can be statistically processed and presented in a probabilistic format. SDDP is a stochastic model that needs a significant amount of historical data to calibrate the inputs, considering uncertainties of parameters. Dispa-SET is an open-source model, while SDDP is a commercial model. Dispa-SET has a higher temporal and technical resolution than SDDP, taking into account the variability and uncertainty of renewable energy sources, as well as the demand variability and network congestion.

Table 1: Comparison between SDDP and Dispaset models

	SDDP	Dispa-SET
Type	Stochastic	Deterministic/Probabilistic
Open Source	X	✓
Therm	Mid-term	Mid-term
Geographical area	National/Regional	Regional/National/Continental
Optimization	Dynamic LP	Dynamic MILP/LP
hydro scheduling	✓	✓
Unit Commitment and Power Dispatch	Limited	Full
Resolution	5 blocks/week	hourly/15 min
Equilibrium	Partial	Partial
Multisectorial	Gas/hydrogen/electricity/water	Any
Renewables representation	5 blocks/week	Per hour/ 15 min
Reserves	predefined	co-optimization
Network	DC Power flow	NTC/DC Power flow
Curtailment	X	✓
Shed Load	✓	✓

The inflow modules of the two models are different. The deterministic model (Dispa-SET) tries all possible historical inflows individually. SDDP, on the other hand, uses a stochastic inflow model (periodic auto-regressive model) that, based on the available historical data, generates synthetic inflows (mapping the unknown future with an unlimited amount of possible inflows) in an attempt to match the inflow profile of the historical data [22].

3.4. Model mapping

In this study, SDDP and Dispa-SET models were applied to the same input dataset of the Bolivian electric system to evaluate it for the year 2026 with the new infrastructure projects. Figure 3 presents the link between

SDDP and Dispa-SET models. In the inputs section, the parameters from SDDP are shown next to the equivalent parameters of Dispa-SET, for which conversion scripts written in python were used to have an automatic input data mapping. SDDP does the simulations of the system operation considering weekly stages with five demand blocks (Peak, Semi Peak, Intermediate, Medium and Low). To use the SDDP database for Dispa-SET, the weekly time step resolution was converted to an hourly resolution based on the five hourly demand blocks (Fig. 4) approved by AETN (Autoridad de Fiscalización y Control Social de Electricidad) [23].

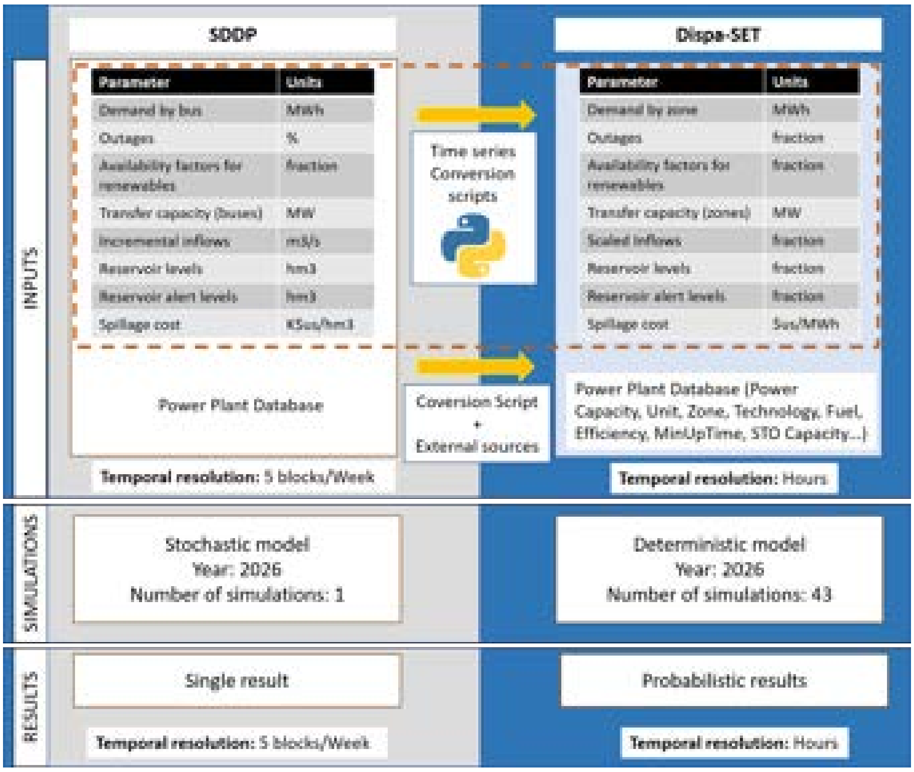


Figure 3: Link of SDDP databases to Dispa-SET for the input data and differences in the simulation configuration and results

Three types of data mapping were done:

- 1-1: Direct mapping of power plant data.
- 1-N: Time series mapping from five blocks per week to an hourly resolution, for parameters such as Outages and Availability factor.
- N-1: Time series mapping from five blocks per week to an hourly resolution, where the parameters described by bus in the SDDP database, such as demand and transfer capacity, were grouped by zone for Dispa-SET.

For Power Plant Database, besides the information from SDDP, external sources of information were needed for the operational parameters of generation units.

Day/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Saturday	B	B	B	B	B	B	B	M	M	M	M	M	M	M	M	M	M	M	I	I	I	I	M	M
Sunday	B	B	B	B	B	B	B	B	B	B	B	B	B	B	B	B	B	B	M	I	I	M	M	B
Monday	B	B	B	B	B	B	B	M	M	M	M	M	M	M	M	M	M	M	I	S	S	I	M	M
Tuesday	B	B	B	B	B	B	B	M	M	M	M	M	M	M	M	M	M	M	I	P	S	I	M	M
Wednesday	B	B	B	B	B	B	B	M	M	M	M	M	M	M	M	M	M	M	I	P	S	I	M	M
Thrusday	B	B	B	B	B	B	B	M	M	M	M	M	M	M	M	M	M	M	I	P	S	I	M	M
Friday	B	B	B	B	B	B	B	M	M	M	M	M	M	M	M	M	M	M	I	P	S	I	M	M

Block	Hours	
Peak	4	P
Semi peak	6	S
Intermediate	16	I
Medium	81	M
Low	61	B

Figure 4: Hourly demand blocks approved by AETN, which show in which hours and days of a week each demand block is present [23].

Most Bolivian hydropower plants are part of a cascade system, where downstream water availability relies on the usage of the unit upstream. Though weekly mean incremental inflow data is available, approximations of inflows and outflows for each unit are required. Three hydro inflow approximation hypotheses were conducted:

- The first one summing the inflows of the unit above plus the external inflows to each unit.
- The second approximation was applied for units that do not have generation capacity but gather or provide flows, using an approximation function to obtain its outflow and spillage.
- The third approximation was applied to Corani, the largest hydro dam, with 2958 storage hours. For this unit, the outflows were considered as the average of the total yearly inflows, considering that Corani has an almost constant generation during the year.

Approximations for each unit's historical weather years (1979 to 2021) were computed, and a statistical analysis was done with the expected generation of the computed inflows. For some units, the variation range between the weather years is particularly high, for example, Sehuencas, with an absolute difference of 1.335 TWh between the lowest and highest values. The approximation was compared to the generation plus spillage of SDDP data for the year 2026. Figure 5 shows that SDDP generation for each hydro unit fits into the range of the expected generation of the Dispa-SET model, proving the hydro inflow approximation hypothesis abovementioned.

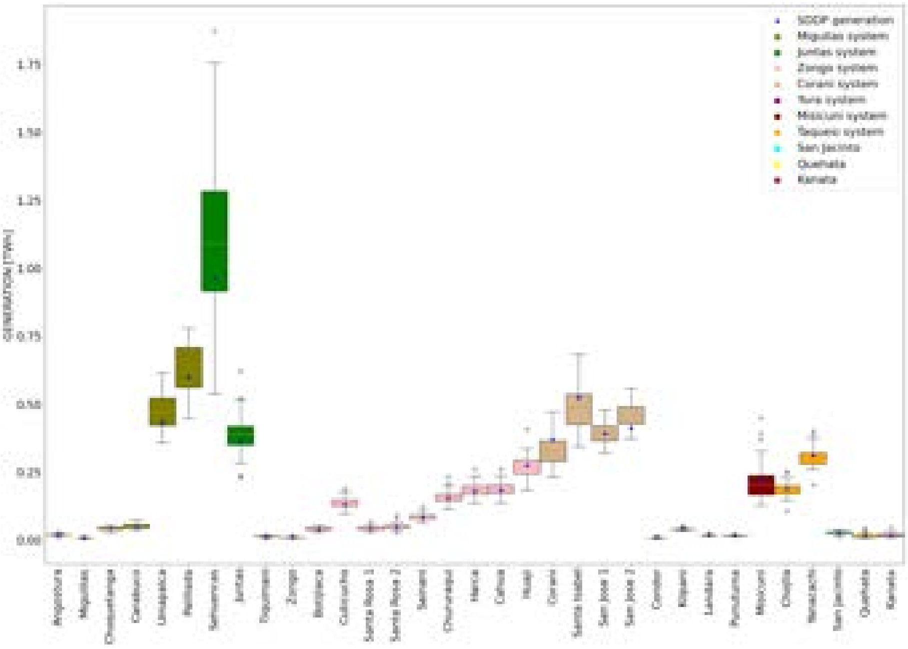


Figure 5: Comparison of SDDP and Dispa-SET generation based on inflows

Bolivia's SDDP simulation begins on the 1st of April, while Dispa-SET's starts on the 1st of January. Various parameters were influenced by the distinction in starting dates, particularly reservoir levels, alert levels, and initial reservoir volumes. Reservoir levels were derived from SDDP runs in Dispa-SET, and the initial reservoir volume inputted in SDDP simulations was adjusted the 1st of April in Dispa-SET.

3.4.1. Reservoir level constraints

The goal of the unit commitment problem is to minimize the total power, transportation system operational cost. The objective function of Dispa-SET is therefore, to minimize the total generation cost over the optimization period (Eq. (1)). In this study, the model has been expanded by the following constraints: Reservoir Alert Level and Spillage cost by unit, as proposed in Eq. (2), where the total system cost is defined as the sum of different cost items such as fixed, variable, ramping, start-up and shut-down, shed load, and the Cost of "storage Alert Level" and "Cost of Spillage" that have been added. In this equation, "i" stands for a subset of simulated hours for one iteration.

$$\underset{i \in I}{\text{minimize}} \left\{ SystemCostRollingHorizon = \sum_{i} SystemCost_i + StorageLevelViolationCosts_i \right\} \tag{1}$$

$$
\begin{aligned}
SystemCost_i = {} & FixedCost_i \cdot TimeStep + StartUpShutDownCosts_i \cdot TimeStep \\
& + VariableCost_i \cdot TimeStep + RampingCost_i \cdot TimeStep + CurtailmentCosts_i \cdot TimeStep \\
& + TransmissionCosts_i \cdot TimeStep + EnergyNotServedCosts_i \cdot TimeStep \\
& + CostStorageAlert_i \cdot LL_StorageAlert \cdot TimeStep + CostSpillage_i \cdot Spillage \\
& + CurtailedPower_i \cdot CostCurtailment \cdot TimeStep
\end{aligned} \tag{2}
$$

The constraint Cost of Storage Alert prevents the reservoir level to go below Storage Alert Level, which will only be violated to avoid power rationing and is set to the equal 1,1* Marginal Cost of the most expensive unit in the system, as in proposed in (3), where "s" is the set of all storage units (with reservoir).

$$
\begin{aligned}
& StorageCapacity_s \cdot Nunits_s \cdot min\,(StorageAlertLevel_{s,i}, AvailabilityFactor_{s,i}) \\
& \leq StorageLevel_{s,i} + LL\_StorageAlert_{s,i}
\end{aligned} \tag{3}
$$

3.5. Simulation configuration

To consider different future possibilities based on water availability, 43 simulations were run in Dispa-SET. Each simulation reflected the inflows from a different historical weather year (1979-2021). During the historical weather years, 1984 was the wettest year, and 2016 was the driest (Fig 6). In Dispa-SET, all units are considered individually for each hydro plant to be observed in the results. The constraint "Reservoir Alert Level" is considered in both models for particular hydro dams such as Corani, Miguillas, Angostura, Zongo, San Jacinto and Misicuni.

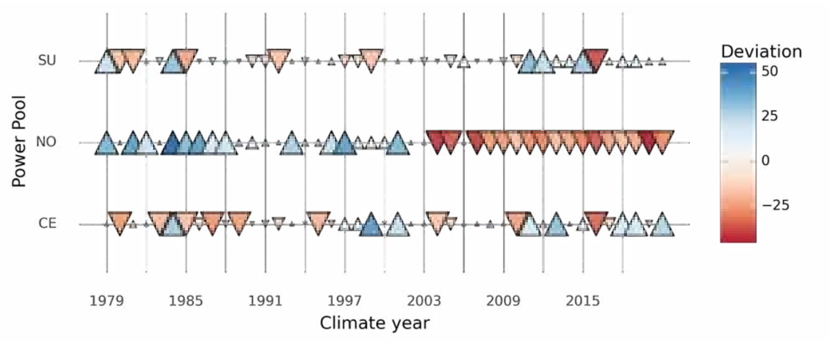


Figure 6: Annual variability (percentage deviation from the mean) of inflows in the 43 climate years. The size of the triangles indicates the inter-annual variability, the direction highlights the increase or decrease compared to the mean, and the colour indicates the intra-annual variability.

From a computational point of view, the variability of the inflows (from 1979 to 2021) directly impacts the simulation times. The simulation time was ranged from 2 hours up to 25 hours for the year 2001, which is the year with excessively high inflows that might not be historically accurate.

4. Results and Discussion

This section presents the expected configuration of the Bolivian electric system for the year 2026. All new VRES and hydro projects are included.

4.1. Energy mix

Figure 7 shows the share of renewable generation for 2026 from all the simulations ordered from the highest to the lowest share of renewable generation. Bolivian electricity production from renewable energy is expected to range between 45.9 % and 65.2 % in 2026. The share of renewable energy in Bolivia in the Stochastic model is 59%, which fits in the range of Dispa-SET share. The North zone is expected to have the highest share of renewable generation with 98 % due to the new hydro projects planned to be installed in this zone. The Central zone is expected to share between 60.3 % to 79 % of renewable energy. Oriental and South zones are expected to still rely more on natural gas to produce electricity than renewable energy. Despite the connections between zones, Bolivia is expected to still depend on natural gas to generate electricity.

In the Bolivian electric plan 2025, VRE was planned to reach 74 % of the total production. From the probabilistic results of the MILP model, it can be seen that with the addition of new power plants, VRE could reach between

45.9% and 65.2 % of the total generation, where biomass is excluded, whereas, in SDDP the VRE share represent 59%.

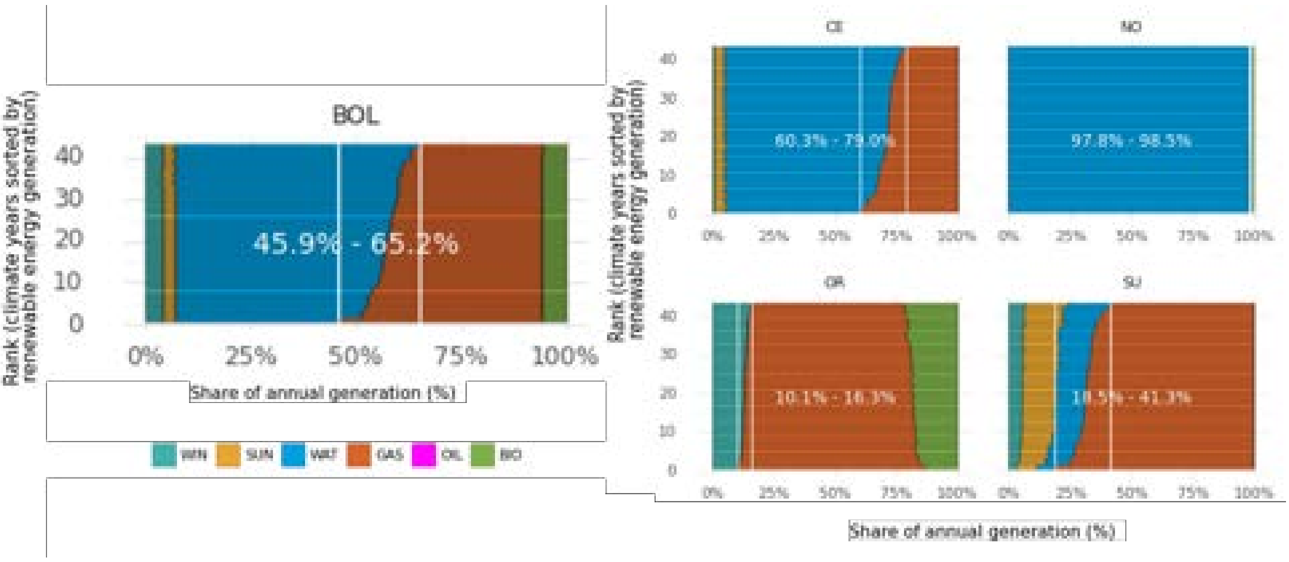


Figure 7: Generation mix and renewables share for the considered climate years of Bolivia and by zone for 2026 from the 43 simulations results, ordered by the share of renewable generation. White lines indicate minimum and maximum shares of renewable generation.

The difference in the total hydro generation between SDDP and Dispa-SET (an average weather year) is 5 %, the Central zone has a difference of 0.1%, the North zone has a difference of 11%, and the South zone has a difference of 7 %. The hydro units with the highest impact on the total generation are Sehuencas, Palillada and Santa Isabel, with a share of 14.5%, 10.6% and 9.3% of the total generation, respectively.

4.2. Power dispatch

The year 2026 power dispatch was analyzed per zone using inflows closest to the average weather year (Fig 8). Bolivia experiences dry months from May to October when the electric system relies on thermo-electric units. During the wet season (December to April), North and Central zones primarily utilize hydroelectric plants. In the dry season, the Central zone uses gas and hydro plants, exporting energy throughout the year to the North, Oriental, and South zones. Conversely, the North zone imports energy during the dry season but exports during the wet season due to hydroelectric production. Oriental and South zones import energy during the wet season but generate electricity from natural gas in the dry season. While the Oriental zone can export its gas-generated production, the South zone still needs to import energy. In all zones, the grid is stable, and there is no congestion in the transmission lines. As for the reservoir levels, they are filled during the wet season.

4.3. Reservoir Levels and generation

The largest Bolivian hydro dams in the Central zone are Corani (with 2958 storage hours), Misicuni (with 2779 storage hours), Miguillas (that will be implemented by 2026 with 1072 storage hours), Angostura (with 525 storage hours), Sehuencas (a new power plant with 257 storage hours); and in the South zone is San Jacinto (with 730 storage hours).

The variation in water supply affects these units' generation, reservoir level and spillage. Simulations results for all these units are presented in Fig. (9), where the black line is the median of the results of all the historical data, the regions with darker colour show that 20% of the results are in that range. The lighter colour shows that 100% of the results are in that range. From the inflows plots, it can be seen that for some years, the inflows are extremely high compared to the median, which indicates the long simulation time, which for some years took up to 25 hours.

The Reservoir levels were compared between the two models. SDDP reservoir level results are plotted as a grey dashed line. The reservoir alert level was included as a solid red line. The inflows are higher during the wet season, and reservoir levels do not go below the reservoir alert level. Sehuencas hydroelectric plant does not have an alert level, but its reservoir level follows a similar tendency to SDDP results. Angostura hydroelectric plant has an alert level and a defined volume for the 1st of April (green cross). For this unit, the reservoir level of SDDP is higher than the median of Dispa-SET in the dry season. However, it's still in the range of the results of Dispa-SET. The reservoir level of Miguillas hydroelectric plant follows a similar tendency to SDDP. Corani reservoir level in SDDP simulation goes up from 0,3 to 0,54 the last week of December. However, given the available inflows, this would not happen, so for this unit, Dispa-SET results are more reliable.

Figure 8: Power dispatch by zone for 2026 based on an average year (2003). The red vertical lines show the limits for the dry season, from April to December

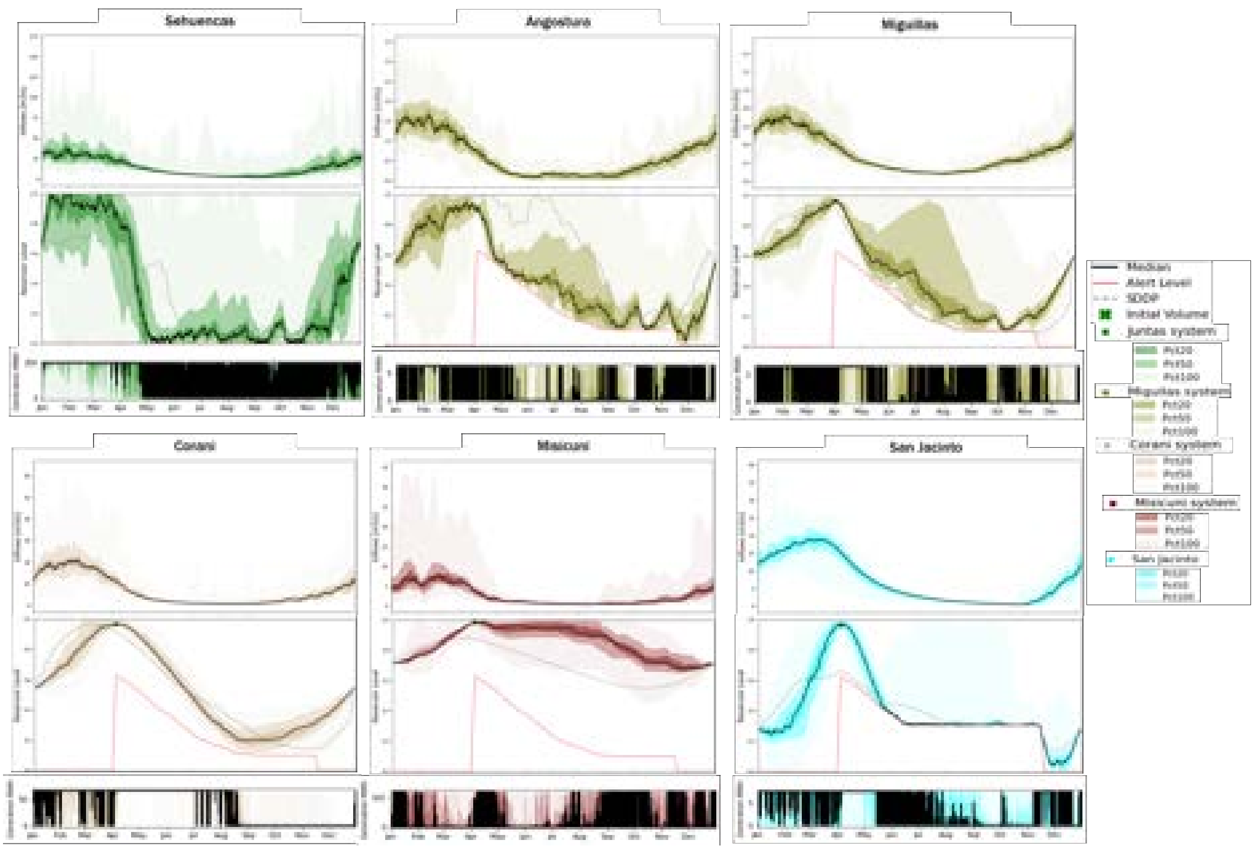


Figure 9: Inflows, Generation and Reservoir Levels from the 43 runs for the biggest hydro dams of Bolivia.

The maximum generation variation range between the weather years was found for Sehuencas, with an absolute difference of 0.941 TWh between the lowest and highest generation (for years 2020 and 1985, respectively). The difference in SDDP generation related to the weather years is 44% compared to the lowest value, 5.7% compared to the median, and 53% compared to the highest value.

4.4. Spillage

Spillage results for both models were compared (Fig.10). Dispa-SET's range of spillage for 43 years is shown in a boxplot for each unit, while blue dots represent SDDP's spillage results. The spillage results from SDDP fit into the range of the results obtained in Dispa-SET. The units Kanata, Zongo, Tiquimani, Kilpani and Punutuma in Dispa-SET do not have any spillage for any year, while in SDDP, there is some spillage. The variation range between the weather years is exceptionally high for Sehuencas, with an absolute difference of 0.54 TWh between the lowest and highest values. The difference in Sehuencas' SDDP spillage related to the weather years is 100% compared to the lowest value, 15.6% compared to the median and 260% compared to the highest value.

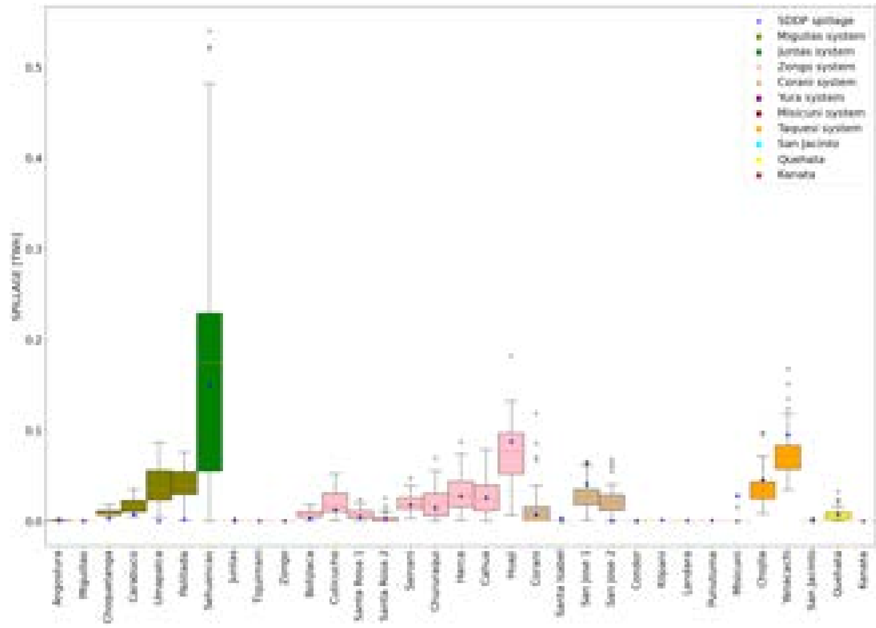
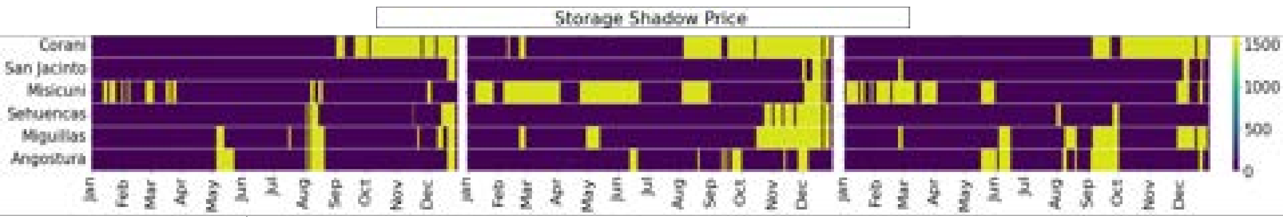


Figure 10: Spillage comparison for 2026 from SDDP (blue dots) and Dispaset (boxplot)

4.5. Water value

The expected marginal value of water, referred as storage shadow price, expresses the opportunity cost of water [24]. Figure 11 shows the Storage Shadow price for the main hydroelectric dams for a wet year (1984), a dry year (2016) and an average year (2003). The storage shadow price, dependent on the water value, is higher in the dry season than in the wet season. For the wet year, the Corani storage shadow price reaches 1500 from September to December, while in the dry year, the price reaches that value one month earlier. Comparing this with the reservoir level (9), the median reaches the lowest level in September. For San Jacinto, the shadow price is higher in December when the reservoir level reaches a lower value. In general, for the dry year, a high shadow price is present during more hours than the wet and average year since water availability is lower.



a) b) c)

Figure 11: Storage shadow price for the main hydro dams a) for a wet year (1984) b) for a dry year (2016) c) for an average year (2003)

5. Conclusions

The article compares the results obtained by two model formulations, SDDP and MILP, applying the same input data and constraints to analyze the Bolivian electric system to 2026. In the MILP formulation, 43 simulations were done to obtain probabilistic results since the Bolivian electric system is highly dependent on hydropower, and its generation varies during the year and year by year. These results were then compared with SDDP. The novelty of this work is the probabilistic way to show the likelihood of certain events happening, such as the distribution of the State of charge (SOC) for each hydro dam, dispatch of each hydro unit, spillage and generation distribution.

The automatic input data mapping from SDDP to the MILP model was successfully implemented. For the inflows of hydroelectric power plants in a cascade system, an approximation was made for each unit for all the historical weather years. We show that SDDP values are within the MILP model range. Furthermore, in the objective function of the MILP model, constraints have been added for the reservoir level (reservoir level alert) and the spillage cost.

Simulation results indicate that the two models' power generation is in the same range. The maximum variation ranges between the weather years are found for the Sehuencas hydropower plant, which is the unit that has the highest impact on the power system, comprising 14.5% of the total generation. The maximum generation variation between the weather years for Sehuencas is 44% compared to the lowest generation value, 5.7% compared to the median and 53% compared to the highest generation.

The reservoir levels obtained in the probabilistic results follow a similar tendency to the reservoir levels of SDDP, except for some minor deviations, especially in small units with low storage hours. Spillage from SDDP falls between Dispa-SET ranges. Sehuencas power plant has the maximum spillage variation ranges between the weather years. The difference in Sehuencas' SDDP spillage related to the weather years is 100% compared to the lowest spillage value, 15.6% compared to the median and 260% compared to the highest spillage value.

The MILP and SDDP formulations can be used as complementary models for decision-making on the Bolivian electric system operation, taking advantage of their strengths and compensating for their limitations. SDDP has a greater detail in the representation of the electric network, and it takes into account uncertainties of the input parameters. Incontrast, the MILP formulation has a higher time resolution that can provide a more detailed and accurate resolution for renewable energy and has probabilistic results that provide statistical analysis. Low-resolution models, like SDDP, may exhibit deviations from more detailed modelling, especially for renewable systems, not considering the dependency of VRE on weather conditions that vary throughout the day. On the other hand, high-resolution models capture the system's dynamic due to the change in weather conditions.

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