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Energy Transition Planning with High Penetration of Variable Renewable Energy in Developing Countries: The Case of the Bolivian Interconnected Power System †

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Abstract: The transition to a more environmentally friendly energy matrix by reducing fossil fuel usage has become one of the most important goals to control climate change. Variable renewable energy sources (VRES) are a central low-carbon alternative. Nevertheless, their variability and low predictability can negatively affect the operation of power systems. On this issue, energy-system-modeling tools have played a fundamental role. When exploring the behavior of the power system against different levels of VRES penetration through them, it is possible to determine certain operational and planning strategies to balance the variations, reduce the operational uncertainty, and increase the supply reliability. In many developing countries, the lack of such proper tools accounting for these effects hinders the deployment potential of VRES. This paper presents a particular energy system model focused on the case of Bolivia. The model manages a database gathered with the relevant parameters of the Bolivian power system currently in operation and those in a portfolio scheduled until 2025. From this database, what-if scenarios are constructed allowing us to expose the Bolivian power system to a set of alternatives regarding VRES penetration and Hydro storage for that same year. The scope is to quantify the VRES integration potential and therefore the capacity of the country to leapfrog to a cleaner and more cost-effective energy system. To that aim, the unit-commitment and dispatch optimization problem are tackled through a Mixed Integer Linear Program (MILP) that solves the cost objective function within its constraints through the branch-and-cut method for each scenario. The results are evaluated and compared in terms of energy balancing, transmission grid capability, curtailment, thermal generation displacement, hydro storage contribution, and energy generation cost. In the results, it was found that the proposed system can reduce the average electricity cost down to 0.22 EUR/MWh and also reduce up to 2.22×10^6 t (96%) of the CO_2 emissions by 2025 with very high penetration of VRES but at the expense of significant amount of curtailment. This is achieved by increasing the VRES installed capacity to 10,142 MW. As a consequence, up to 7.07 TWh (97%) of thermal generation is displaced with up to 8.84 TWh (75%) of load covered by VRES.

Keywords: energy planning; power system modeling; flexibility; unit-commitment; renewable energy; hydro-power; VRES; CO_2 emissions; low-carbon

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1. Introduction

The Paris Agreement key targets, in force as of 2020, include limiting global temperature rise well below 2 °C, increasing adaptation to adverse climate impacts, and enhancing climate resilience and low-carbon development [1]. According to the latest UNEP Emissions Gap report, to be on track for this goal, the world needs to reduce global emissions by over 50% by 2030 and work towards carbon neutrality by 2050 [2]. One-quarter of global greenhouse gases come from the power sector [3]; among them, coal is the largest contributor to climate change. To preserve the agreement, as important outcomes of the COP26 (Climate Change Conference Of the Parties), it has been determined that the construction of new coal power plants must stop, the use of clean energy should increase and existing coal fleets shall be retired by 2040 [4]. Based on IRENA's analysis, energy-related carbon-dioxide (CO_2) emission reductions would have to decline 70% by 2050, compared to current levels, to meet climate goals. A large-scale shift of electricity sources to renewables could deliver up to 60% of those reductions [5]. At COP26, as a way to accelerate these strategies and push the Nationally Determined Contributions (NDCs) [6], 34 countries and 5 public finance institutions have committed to phase down the use of all fossils across the energy sector and ending direct public economic support (c.$24 billion annually) by the end of 2022. Moreover, international partners have mobilized over $20 billion for a just and inclusive transition from coal to clean energy [4].

In this context, more countries are collectively pledging short-term and long-term policies in pursuit of efficient planned transition from predominantly conventional power systems (e.g., hydro dam and thermal) to power systems with a high penetration of Variable Renewable Energy Sources (VRES) [7,8]. The variability and stochasticity of these energy sources induces additional stress on power systems. They complexify the operation and planning activities and could thus potentially slow down the transition process [9]. Current electrical power systems are mostly constituted from turbines coupled to synchronous generators electrically coupled and rotating at the same frequency. However, VRESs are inverter-based resources, and they have very different characteristics from synchronous generators, including a lack of rotational inertia and a limited current injection under fault conditions. Deploying increasing amounts of VRES will therefore require adding (virtual) inertia to the system, which may entail significant changes in the operational policies and planning of power systems [10,11].

Ad hoc modeling tools are required to consider the effects described above. Several models are already well established in countries advanced in these fields but are not widely available in many developing countries. They can be divided into six categories: economic dispatch (ED), hydro-thermal coordination (HYTHCO), maintenance optimization (MO), unit commitment (UC), generation expansion planning (GEP), and production cost optimization (PCO). Such models are all based on similar principles, but their formulations vary significantly depending on their complexity and size [12], with methods ranging from highly detailed operational power systems to low-time-resolution, long-term planning models [13]. The most common formulations rely on linear programming (LP), mixed integer linear programming (MILP) [14], and MINLP for GEP. The construction of these models for the case of developing countries requires coordinated effort between transmission system operators, researchers, and universities to formulate tailored energy planning, often characterized by partial electrification rates, rapidly growing demand levels, and low reliability of the electric grids. Mexico and Uruguay are clear examples of it, with the successful development of local models to carry out economic dispatch [15] such as SIMSEE [16] and DEEM.

Bolivia has a different reality; until 2017, the government has largely invested in fossil-fuel energy power plants [17] in its intent to achieve universal access to electricity by 2025 in line with seventeen Sustainable Development Goals (SDGs) [18] and in pursuit of guaranteed energy supply. However, in the last two years, two photovoltaic power plants [19] and three wind farms [20] have been connected to the main grid, with total installed capacities of 50 MW and 108 MW, respectively. Furthermore, on 24 March 2021, the Bolivian government promulgated the Supreme Decree 4477 [21], which approved four procedures relative to distributed generation system, allowing renewable generation surpluses to be injected into the Electricity Distribution Network. The goal is to involve electricity users and Distributed Generation companies in the change of the energy matrix. Given this context, the following questions arise: is this the right path towards changing the energy matrix? Are the measures adopted possible? To understand the VRES penetration potential of the country, different studies of renewable energy integration to the Bolivian power system has been published.

In [22], the efficiency of the first onshore wind farm in Bolivia is evaluated in terms of the capacity factor; it concluded that the month with the highest wind energy efficiency is October and the month with lowest efficiency is February and that effect of the wind turbulence on the turbines' efficiency is considerable. Additionally, in [23], hourly wind speeds simulated from MERRA-2 were used to analyze wind averages and characteristics over the year in different regions and altitudes in Bolivia, such as the Altiplano, Amazon and Chaco. The main findings were the range of wind speed index in different sites, which varied between 0.90 and 1.09 and the periods of high wind speeds which are May—October in the Altiplano, and June—December in the Amazon and Chaco. Another study of renewable energy integration is proposed in [24] which concludes that Bolivia, due to its highest solar resources, could be able to meet high growth energy supply from the use of solar PV and storage technologies. The low cost of these resources could drive the transition to a fully sustainable energy system, leading to a reduction of carbon emissions towards 2050. Additionally, the study identifies the opportunity for Bolivia to develop a highly decentralized energy system with a similar annual cost to a highly centralized system, which is a relevant finding considering the significant rural populations of Bolivia. Another work on renewable energy sources is proposed in [17]. This study concludes that the diversification of energy supply, in addition to the decentralization of distribution of electricity, as well as the elimination of the subsidy of fossil fuels for energy production and the addition of taxes for carbon emission, could increase the cost-competitiveness of hybrid microgrids.

However, the different studies reviewed above are specific to a single renewable energy source. None of these studies are based on detailed models of the power system that contemplate the supply contribution of the different energy sources and technical and operational aspects of the supply. In contrast, the present study is carried out to bridge this gap and take these aspects into account. A preliminary analysis was already proposed with data collected from the year 2016 and published in 2018. In that previous work, the objective was to evaluate the adequacy of the Bolivian power generation system in terms of energy balancing, electricity generation cost and power plant scheduling in a scenario that considers large solar and wind energy technology deployment [25]. In the present work, the model is improved and updated with data for the year 2020 and incorporates projects planned until 2025. It considers a detailed power plant data base, grid data and time-series related to energy demand, availability factors of variable renewable generation, scaled inflows and storage levels. The (UD) and (ED) formulations of the model aim to optimize investments for the most economically efficient and reliable power systems while addressing environmental and other technical factors. Since the considered period in the analysis is one whole year, several constraints and simplifications, such as linearization [26] and relaxation [27], are applied for computational tractability reasons.

The analysis of the flexibility is carried out in terms of the capability of the power system to respond to large fluctuations in both the generation and the demand [28] within its safe operating technical margins. The results are presented as an evaluation of (i) the adequate installed transmission capacity; (ii) the trade-off between VRE penetration and curtailment; (iii) the vailability of flexible and dispatchable power plants (i.e., with ramp up and ramp down capabilities, reserves); (iv) supply capacity of energy-storage systems, mainly in the form of hydro reservoir storage units in the case of Bolivia; (v) provision of the least expensive supply while maintaining reliability; (vi) and reductions in CO_2 emission to reach the environmental targets.

The main contributions of this work are the following:

- Analyzing of dispatch strategies under different levels of VRES penetration for the Bolivian power system planned by 2025.
- Proposing an energy model as guidance and as an example of implementation of unit-commitment and economical dispatch formulations applying to power systems of developing countries.
- Providing a detailed open-source model for the Bolivian power system, which can be replicated, re-used and/or adapted for other researchers in future works.

The paper is structured into four sections as follows: The first section contains the literature overview and explains the motivation behind the research. The second section describes the methodology and the model formulation. The third section presents the case of study and establishes the scenarios in which the model was applied to the Bolivian power system. The fourth section is dedicated to analysis and discussions of results. The fifth and final section delivers the conclusions of the research.

2. Methodology

2.1. Model Description

The unit commitment and optimal dispatch model adopted for this study is based on the Dispa-SET model, an open-source tool originally developed for the case of the European Union [29]. The pre- and post-processing tools of the model are written in Python, and its model is a mixed integer linear programming (MILP) model, which is implemented in GAMS [30].

The model takes as input a large set of historical data [31] such as energy demand, specific techno-economic information of power generation units, availability of energy sources, and transmission network topology. The resolution can then be separated into two different steps: (i) scheduling the start-up, operation, and shut down of the available generation units (unit commitment) and (ii) allocating (for each period of the simulation horizon of the model) the total power demand among the available generation units in such a way that the overall power system costs is minimized (optimal dispatch). The simulation returns the power generation and storage curves, annual cost statistics, load shedding requirements, level of curtailment, etc. These results allow us to evaluate the system adequacy and flexibility in regards to the penetration and variability VRES capacity.

Objective Function

The objective function's scope is to minimize the costs of the power systems. Its mathematical expression is presented in Equation (1), and it is noticed that the function is a result of the contributions of emerging costs from operational actions or statuses. These include starting-up or shutting-down a power unit (start-up or shut-down costs); whether the unit is on or off (fixed costs); spillage storage (spillage); the ramping-up or ramping-down of a unit (ramp-up or ramp-down); necessary load shedding (load-shed); units of power output (variable costs); ramping and reserve when power exceeds the demand or does not match it (Loss of Load); and finally the power flow transmitted through the lines (transmission). It is assumed that the price signal has no relative impact on the demand [29].

$$MinSystemCost = \left(\sum_{u,n,i} CostStartUp_{u,i} + CostShutDown_{u,i} + CostFixed_u \cdot Committed_{u,i} + CostVariable_{u,i} \cdot Power_{u,i} + CostRampUp_{u,i} + CostRampDown_{u,i} + PriceTransmission_{i,l} \cdot Flow_{i,l} + \sum_n (CostLoadShedding_{i,n} \cdot ShedLoad_{i,n}) + VOLL_{Power} \cdot \sum_n (LostLoadMaxPower_{i,n} + LostLoadMinPower_{i,n}) + VOLL_{Reserve} \cdot LostLoadReserve2U_{i,n} + LostLoadReserve2D_{i,n} + VOLL_{Ramp} \cdot LostLoadRampUp_{u,i} + LostLoadRampDown_{u,i} \right) \quad (1)$$

2.2. Solving the Unit-Commitment and Dispatch Problem

2.2.1. Optimization Horizon

For the present work, the simulation is performed for a whole year with a time step of one hour. In order to improve the computational efficiency, the optimization problem is split into smaller blocks that are run throughout the year as a loop.

An optimization horizon of four days and an overlap period of one day was used to avoid issues linked to the end of the optimization period. Figure 1 shows such an approach. The values of the optimization with which a day is initiated are the final values of the optimization of the previous day. In this case, the optimization is performed over 96 h, but only the first 24 h are conserved [29].

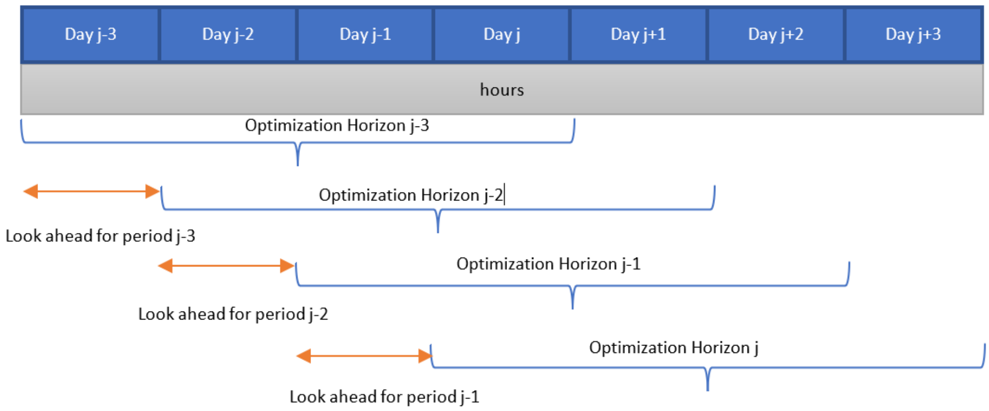

Figure 1. Time horizons of the optimization with the look-ahead period [29].

2.2.2. Hydro Scheduling

No midterm scheduling is computed in the model. Thus, all reservoir levels are imposed as historical curves obtained from interpolating monthly time-series; they are delivered as rates of scaled reservoir levels (from 0 to 1). These reservoir levels are set as constraints of the minimum level in the last time interval of the rolling horizon.

2.2.3. Model Formulations, Constraints and Boundaries

The model is formulated as a Mixed Interger Linear Program (MILP) and is solved within the following constraints [29].

- Energy balance: According to this restriction presented in Equation (2), the sum of all the power produced from all different sources in a node (including storage units generation, imported power from other nodes, and the curtailed power from VRES sources), is equal to the load in that node, plus the power consumed for energy storage, minus the load interrupted and the load shed, for each period and each zone, in the day-ahead market [29].

$$\sum_u \left(Power_{u,i} \cdot Location_{u,n}\right) + \sum_l \left(Flow_{l,i} \cdot LineNode_{l,n}\right) = \left(Demand_{DA,n,h} + \sum_r StorageInput_{s,h} \cdot Location_{s,n} - ShedLoad_{n,i} - LostLoadMaxPower_{n,i} + LostLoadMinPower_{n,i}\right) \quad (2)$$

- Power output constraints: If the unit is committed, the minimum power production is defined by the unit's steady generation level:

$$PowerMustRun_{u,i} \cdot Committed_{u,i} \leq Power_{u,i} \quad (3)$$

If the unit is committed, the power output is restricted by the available capacity:

$$Power_{u,i} \leq \left(PowerCapacity_u \cdot AvailabilityFactor_{u,i} \cdot (1 - OutageFactor_{u,i}) \cdot Committed_{u,i}\right) \quad (4)$$

- Ramping constraints: Each unit has a maximum ramp-up and ramp-down capability. This is translated into limits for ramping up:

$$Power_{u,i} - Power_{u,i-1} \leq \left((Committed_{u,i} - StartUp_{u,i}) \cdot RampUpMaximum_u \cdot TimeStep + StartUp_{u,i} \cdot RampStartUpMaximum_u \cdot TimeStep - ShutDown_{u,i} \cdot PowerMustRu_{u,i} + LLRampUp_{u,i}\right) \quad (5)$$

and limits for ramping down:

$$Power_{u,i-1} - Power_{u,i} \leq \left((Committed_{u,i} - ShutDown_{u,i}) \cdot RampDownMaximum_u \cdot TimeStep + ShutDown_{u,i} \cdot RampShutDownMaximum_u \cdot TimeStep - StartUp_{u,i} \cdot PowerMustRun_{u,i} + LLRampDown_{u,i}\right) \quad (6)$$

- Reserve constraints
  Upward secondary reserve (2U) is the reserve covered by spinning units and is limited by:

$$Reserve2U_{u,i} \leq \left(PowerCapacity_u \cdot AvailabilityFactor_{u,i} \cdot (1 - OutageFactor_{u,i}) \cdot Committed_{u,i} - Power_{u,i}\right) \quad (7)$$

Downward secondary reserve (2D) is similar to the 2U, which is the downward reserve capability of pumping storage units that can only be covered by spinning units and is limited by:

$$Reserve2D_{u,i} \leq \left(Power_{u,i} - PowerMustRun_{u,i} \cdot Committed_{u,i} + (StorageChargingCapacity_u \cdot Nunits_u - StorageInput_{u,i})\right) \quad (8)$$

The capability of reserve with quick start (non-spining) is given by:

$$Reserve3U_{u,i} \leq \left((Nunits_u - Committed_{u,i}) \cdot QuickStartPower_{u,i} \cdot TimeStep\right) \quad (9)$$

The secondary upward and downward reserve demand should be supplied by all the plants authorized in the reserve market:

$$Demand2U_{n,h} \leq \left(\sum_{u,t} (Reserve2U_{u,i} \cdot Technology_{u,t} \cdot Reserve_t \cdot Location_{u,n}) + LL2U_{n,i}\right) \quad (10)$$

$$Demand2D_{n,h} \leq \left(\sum_{u,t} (Reserve2D_{u,i} \cdot Technology_{u,t} \cdot Reserve_t \cdot Location_{u,n}) + LL2D_{n,i}\right) \quad (11)$$

The tertiary reserve can also be provided by non-spinning units with the following constraint:

$$Demand3U_{n,h} \leq \left(\sum_{u,t} [(Reserve2U_{u,i} + Reserve3U_{u,i}) \cdot Technology_{u,t} \cdot Reserve_t \cdot Location_{u,n}] + LL3U_{n,i} \right) \tag{12}$$

- Minimum up/down times: the excessive operation of the generators is limited because of their physical capabilities, there must be a time between starting up and shutting down a generator, and reciprocally vice versa. This constraint for start up is expressed by:

$$\sum_{ii = i - \frac{TimeUpMinimum_u}{TimeStep}}^{i} StartUp_{u,ii} \leq Committed_{u,i} \tag{13}$$

A similar expression for the minimum down time:

$$\sum_{ii = i - \frac{TimeDownMinimum_u}{TimeStep}}^{i} ShutDown_{u,ii} \leq Nunits_u - Committed_{u,i} \tag{14}$$

- Load Shedding: The load shedding is normally regulated and limited by the contracted shedding on that node

$$ShedLoad_{n,i} \leq LoadShedding_{n,i} \tag{15}$$

- Non-dispatchable units (e.g., wind turbines, runoff-river, etc.): For renewable technologies, the maximum time-dependent generation level is set to directly influence the available factor of the power unit. The outage factor is also taken into account as unavailable power.
- Multi-nodes with capacity constraints on the lines (congestion) and limited Net Transfer Capacities (NTC) are as follows:

$$FlowMinimum_{l,i} \leq Flow_{l,i} Flow_{l,i} \leq FlowMaximum_{l,i} \tag{16}$$

2.2.4. Mixed Integer Linear Program Solution Process

In the previous paragraphs, we presented the objective function to be optimized; the time horizon was defined and a set of constraints were delivered in mathematical linear inequalities formulated from logic propositions of operational limits of the power system. The Unit Commitment (UC) aims to find a low-cost operating schedule for the power-generator units optimizing the objective function within its constraints. In this sense, power systems are typically large and mixed, integer non-linear and with non-convex operation constraints, with quadratic objective functions. In the present work, the UC formulation is linearized using the LaGrange relaxation in order to solve the UC optimization problem with discrete programming. Thus, the method applied for finding optimal solutions of various optimization problems is the branch-and-bound algorithm. It consists of discrete and combinatorial optimization with a systematic enumeration of all candidate solutions, where large subsets of ineffective candidates are identified by using upper and lower estimated bounds of the quantity being optimized. The theory and algorithms of the discrete optimization solution can be found in detail in [14,32–34].

2.3. Input Data

The model is data-intensive and requires high technological, temporal and geographical granularity inputs such as a power plant database (non-variable in time), consumption and generation time-series, grid topology, etc. The main model inputs are described in the next sections.

2.3.1. Power Plant Database

The power plant database has specific fields of techno-economic information of every power plant operating in the power system by default. They are briefly listed and presented in Table 1. Their values are preferentially obtained from the system operator. When not available, reference values are taken from relevant references.

Table 1. Power units parameters [29].

Description	Field Name	Units	Value
Power Capacity (for one unit)	PowerCapacity	MW	Accurate [35]
Unit name	Unit		Accurate [35]
Zone	Zone		Accurate [35]
Technology	Technology		Accurate [35]
Primary fuel	Fuel		Accurate [35]
Efficiency	Efficiency	%	Reference [36]
Minimum up time	MinUpTime	h	Reference [36]
Minimum down time	MinDownTime	h	Reference [36]
Ramp-up rate	RampUpRate	%/min	Reference [36–38]
Ramp-down rate	RampDownRate	%/min)	Reference [36–38]
Start-up cost	StartUpCost	EUR	Reference [36]
No load cost	NoLoadCost	EUR/h	Reference [36,39]
Ramping cost	RampingCost	EUR/MW	Reference [40]
Minimum load	PartLoadMin	%	Reference [2,36,41]
Efficiency at minimum load	MinEfficiency	%	Reference [35]
Start-up time	StartUPTime	h	Reference [2,36]
CO_2 intensity	CO_2Intensity	TCO_2/MWh	Reference [42]
Number of units	Nunits		Accurate [35]

For thermal units, ramping costs and startup costs become crucial since the on/off rate of these units and ramping changes are increased in response to a fluctuating system (load or supply) requirement due to VRES penetration.

Prices of fuel and fuel type are important to collect; they can be found in [35,43,44]. The international prices at which Bolivia exports natural gas and gas oil are are 10.42 EUR/MWh and 17.19 EUR/MWh, respectively. However, in Bolivia, the prices of natural gas and gas oil are subsidized by the government. The subsidized prices are 3.57 and 13.91 EUR/MWh, respectively [35,43,44]. For the present work, we suggest using only the subsidized prices to focus only in the technical effects of VRES high penetration. Moreover, Sugarcane pellets prices are taken as 0 EUR/MWh since the bagasse of residual cane from the Bolivian sugar industry was used. Considering that the present Bolivian regulation lacks a CO_2 pricing scheme, a CO_2 emission input does not affect the results. We therefore assume costs related to CO_2 emissions at zero.

2.3.2. Time-Series Data

Time-series data are historical data for the time period analyzed and are composed of 8784 or 8760 data points for each time series. The methodology of data acquisition and determination of time series is described in the next subsections. In some cases, we interpolate monthly data available to generate hourly time series. Reference data available in the bibliography are assumed when the information is restricted by national entities.

- Times series related to the energy demand in each node of energy consumption: central, north, oriental and south zone. The baseline time series are obtained from the national system operator (e.g., CNDC [45]). However, this demand cannot be considered constant in time. A percentage factor of demand growth is therefore assumed for future scenarios.
- Availability Factor: VRES technologies include HROR (run-of-the-river hydro), WTON (onshore wind) and PHOT (photovoltaic solar). Their generation is defined as a proportion of the nominal power capacity, referred to as "availability factor", and is provided as an hourly time series [29].
- Scaled inflows are expressed as a fraction of the nominal power of each unit with hydro storage, and they are provided externally as an hourly time series [29]. They are gathered from [46].
- Storage levels are individual time series corresponding to historical volumes accumulated in each reservoir of the SIN. They are imposed as a lower boundary when each optimization horizon ends. Their mathematical expression is as a fraction of maximum storeable energy [29]. Weekly storage-level averages can be found in [47], from which we generated hourly time series.

2.3.3. Grid Data

Interconnections are modeled through their net transfer capacities (NTCs). They correspond to the commercial transfer capacity between the nodes considered in the simulation. A review of the characteristics of the main interconnection lines in the Bolivian case is available at [42].

2.4. Model Implementation

These input data are gathered in the pre-defined and imposed Dispa-SET format. In the following paragraph, we present the objective function of the model and its current features. However, the detailed unit commitment problem and implementation of the model can be found in [29]. Figure 2 describes the implementation and the work flow of the model. The results allow us to analyze and evaluate the techno-economic incidence, correlation and restrictions of the different variables in the database for mid-term and long-term time horizon scenarios. They also allow us to quantify the system flexibility against the variability of the VRES. This last feature is deductible in terms of curtailment, load shedding and storage levels.

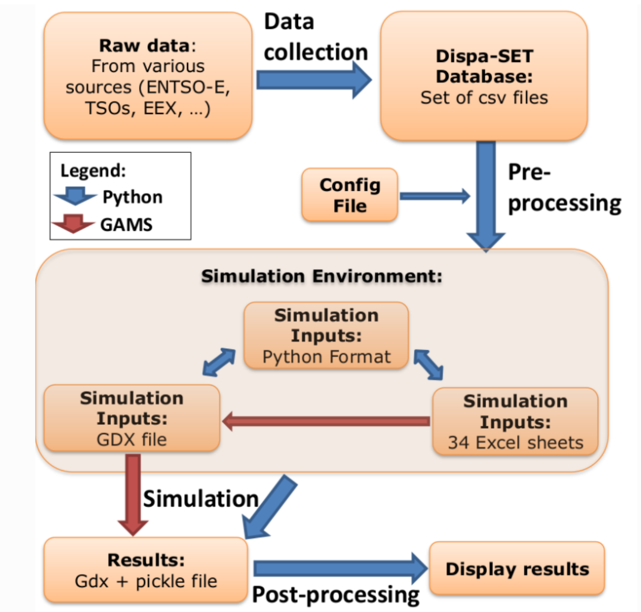

Figure 2. Flow chart of the implementation and processing steps [29].

3. The Bolivian Case Study

The Bolivian Power System (SIN) shows a growing interest from the Bolivian authorities to integrate more renewable energy sources. This is evidenced, e.g., in the SIN expansion plan (PEEBOL2025, Plan Eléctrico del Estado Plurinacional de Bolivia 2025 [42]) and in the annual reports of the different subsidiaries of the National Energy Company (Empresa Nacional de Electricidad, ENDE). In these documents, multiple feasibility and pre-feasibility studies are listed for several run-of-river hydroelectric plants up to 2025 and beyond [42,48]. However, these expansion plans currently only involve a limited number of wind, solar or geothermal plants. Although PEEBOL2025 has been implemented since 2014, the Bolivian electric power matrix is changing slowly compared to other countries in the region (Uruguay, Brazil, Argentina, Chile). The production of VRES increased in percentage from 1.5% (120 GWh) in 2014 to 11% (1046 GWh) in 2020 of the total supply in each year [49,50]. As a result of this slow penetration rate of VRES, the country still depends on natural gas as a primary energy source [25].

3.1. Power System Topology

In Bolivia, the power system is radial and is arranged by areas defined almost naturally by its geography. La Paz and Beni constitutes the North. Santa Cruz and Pando shape the Oriental zone. Oruro and Cochabamba comprise the Central zone. Finally Potosí, Chuquisaca and Tarija in the South zone. Figure 3 shows this zones placed and marked in the map of Bolivia.

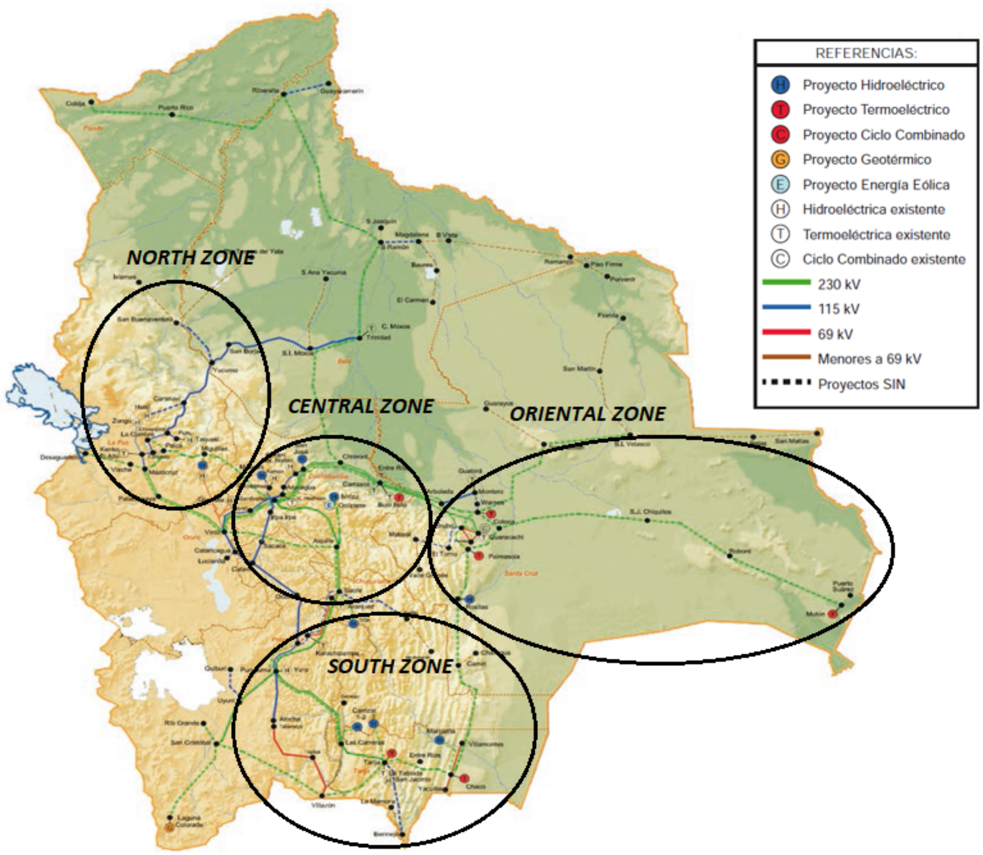

Figure 3. The SIN layout implemented and planned in the period 2020–2025 [35].

The transmission system is composed of transmission lines with high levels of voltage: 69 kV, 115 kV and 230 kV. This transmission lines shape the main power system grid known as STI (Sistema Troncal Interconectado).

The power generation is provided by power units with the following different technologies and fuels:

- Hydroelectric run-of-river power units (HROR WAT),
- Hydroelectric power units with dams (HDAM WAT).
- Open-cycle natural power units (GTUR GAS),
- Combined cycle power units (COMC GAS).
- Diesel engines (GTUR OIL).
- Biodiesel power units (GTUR BIO).
- Wind-onshore turbines (WTON WIN).
- Finally, there are two PV solar power plants (PHOT SUN).

3.2. Energy Demand for 2025

The energy demand of Bolivia is mostly residential. The demand is divided into two categories: regulated consumers supplied by distribution companies and non-regulated that directly participate in electricity markets [35]. By 2020, the energy demand is higher in the Oriental zone at 38.5%, next is the North zone with 23.39%, followed by the Central zone with 22.36% and finally the South zone with 15.69% [35]. The energy demand increased from 8378 GWh in 2016 to 9212 GWh in 2020. For the following years, the projection of the demand was based on large consumer statements, bottom-up methods, methods based on interpolation of growth rates and methods based on the evolution of specific consumption by categories of distributors. A growth rate at an average of 4% per year was determined, reaching a demand of 12,310 GWh for the year 2025 [42].

The time resolution of the energy demand time series is hourly for a period of one year.The energy demand for the year 2020 was extracted from [45] and is provided individually for each zone of the power system mentioned before. Figures 4 and 5 show examples of load curves for the four zones comprising the power system. The load time series for the year 2025 is determined by applying a yearly growth rate to the 2020 load time series, identified from [42].

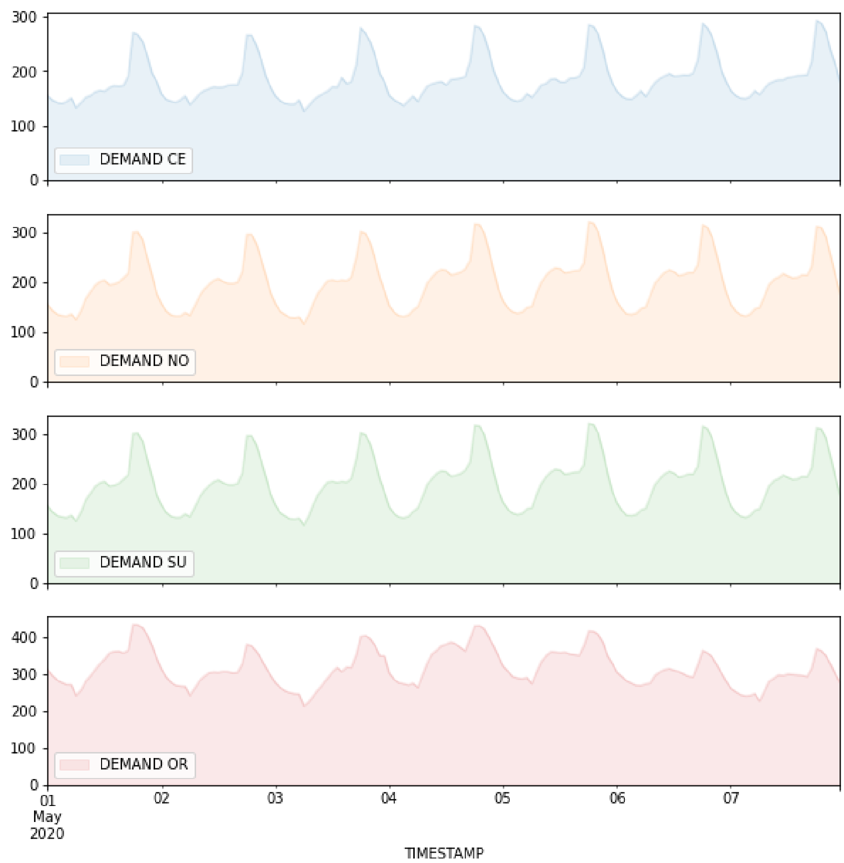

Figure 4. Load curves for all four zones (1–7 May 2020).

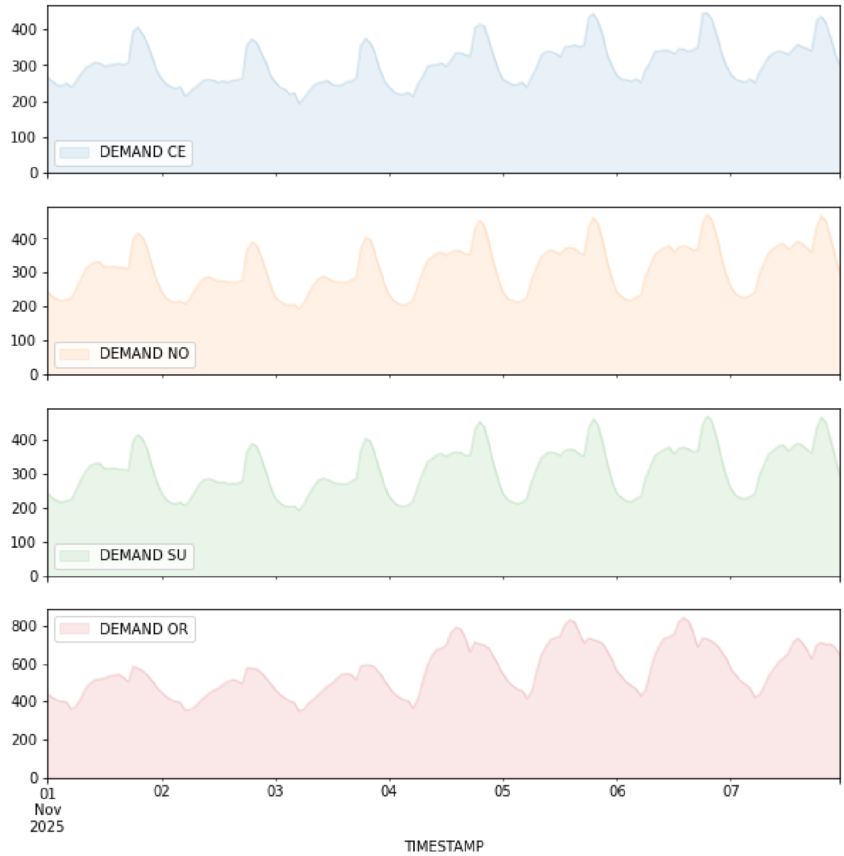

Figure 5. Load curve for all four zones (1–7 November 2025).

3.3. Power Plants Fleet for 2025

The SIN generation's installed effective capacity until 2020 is presented in Table 2, disaggregated by zones and technologies. There is a strong reliance on conventional power generation technologies (thermal and hydroelectric) with a reduced supply from wind, solar and geothermal generation. It reaches a total capacity of 3187 MW, of which 859 MW (26.95%) corresponds to hydroelectric plants. Thermal generation still represents the main primary energy source with 2186 MW (67.18%), 27 MW (0.85%) corresponding to wind farms, 115 MW (3.61%) to solar energy and finally 45.22 MW (1.41%) to biomass power plants.

Based on energy policies and demand requirements, PEEBOL2025 proposes a portfolio of generation and transmission projects until 2025 for the expansion of the electrical infrastructure considering the availability of energy sources. According to [35], the total electricity consumption in 2025 is expected to reach 12.31 TWh, and the generation capacities will be increased: the total installed capacity will exceed 5.19 GW, from which 2.14 GW (41.23%) will be thermal, 2.54 GW (48.85%) will be hydroelectric, 0.22 GW (4.28%) will be wind-onshore, 0.17 GW (3.35%) will be solar PV and 0.45 GW (0.87%) . PEEBOL2025 data reveal that the following five years (2020–2025) the SIN expansion plan will integrate VRES projects in an average of 50MW per year [35]. A summary of planned generation projects in each zone is provided in Table 3 [35,42,48,51,52].

Table 2. Power generation units in 2020 [35].

Area	*Central Name*	*Technology*	*Number of Units*	*Total Power (MW)*
Central	Miguillas System	HDAM WAT	9	21.11
	Corani System		10	280.35
	Misicuni System		3	120
	San Jose San Jose II	HROR WAT	4	124
	Kanata		1	7.54
	Valle Hermoso	GTUR GAS	8	107.65
	Carrasco		3	122.94
	Bulo Bulo		3	135.41
	Entre Rios		4	105.21
	Entre Rios	COMC GAS	3	376.98
	Oruro I	PHOT SUN		50.01
	Qollpana I & II	WTON WIN	10	27
North	Taquesi System	HDAM WAT	2	89.19
	Zongo System		21	188.04
	Quehata	HROR WAT	2	1.97
	Kenko	GTUR GAS	2	-
	El Alto		2	46.19
	Trinidad	GTUR OIL	19	25.28
	Rurrenabaque		1	1.8
	Yucumo		1	0.35
	San Borja		2	1.8
	Say		2	1.62
	San Ignacio de Moxos		2	0.73
	San Buenaventura	GTUR BIO	1	5
Oriental	Guaracachi	COMC GAS	3	192.92
	Warnes		2	248.1
	Guaracachi	GTUR GAS	5	126.72
	Santa Cruz		2	38.07
	Warnes		5	195.56
	Unagro	GTUR BIO	1	14.22
	Guabira		1	21
	IAG		1	5
South	Yura System	HROR WAT	7	19.04
	San Jacinto	HDAM WAT	2	7.6
	Aranjuez	GTUR GAS	10	33.76
	Karachipampa		1	-
	Del Sur		4	147.55
	Del Sur	COMC GAS	2	232.32
	Uyuni ColchaK	PHOT SUN	21	60.06
	Yunchara		2	5
SIN	*All*	*All Technologies*	*184*	*3187.09*

Table 3. Conventional and renewable generation projects planned for the period 2020–2025 [35].

Area	*Central*	*Technology*	*Situation*	*Total*
Central	Oruro II	PHOT SUN	Projected up to 2021	50.01
	Qollpana III	WTON WIN	Projected up to 2023	21
	Sehuencas_juntas	HDAM WAT	Projected up to 2025	279.88
	Banda Azul		Projected up to 2025	133.7
North	Guayaramerin	PHOT SUN	Projected up to 2025	3
	Riberalta		Projected up to 2025	5.8
	Umapalca_Palillada	HDAM WAT	Projected up to 2025	203
	SanCristobal_ Anazani_SantaRosa	HROR WAT	Projected up to 2025	45
	Titicaca	WTON WIN	Projected up to 2025	21
Oriental	San Julian	WTON WIN	Projected up to 2021	39.6
	WARNES I		Projected up to 2021	14.4
	El Dorado		Projected up to 2021	54
	Rositas	HDAM WAT	Projected up to 2025	400
	Warnes II	WTON WIN	Projected up to 2025	21
South	La Ventolera	WTON WIN	Projected up to 2025	24
	Laguna Colorada	STUR	Projected up to 2025	100
	CarrizalI_CarrizalII_CarrizalIII	HDAM WAT	Projected up to 2025	346.5
	Icla_Margarita		Projected up to 2025	270

3.4. VRES Generation Capacity for 2025

The VRES potential in Bolivia is distributed throughout the territory. Hydro-run-of-river (HROR) projects are found in all four zones of the SIN; however, the main HROR projects are located in the central and south areas. Solar energy is feasible in all regions but is particularly suitable for the Andean highlands sector due to its high levels of radiation. Finally, in the departments of Cochabamba and Santa Cruz and in some highland areas nearby, wind energy is predominant [23]. Despite the VRES expansion potential shown in Figures 6–9, the projects planned until 2025 only represent 9.24% of the total effective capacity by that year.

3.4.1. Hydro Resources

The hydroelectric projects were chosen from the studies carried out in different stages of pre-investment and/or pre-feasibility studies [52]. They are located in different regions of Bolivia. Two important projects were completed and started operations in 2020: Misicuni with 120 MW, and San José with 120 MW, as the third stage of the use of the waterfall in the upper basin of the Chapare River.

The hydroelectric generation project portfolio for 2025 includes the incorporation of Miguillas with Umapalca (83 MW) and Palillada (113 MW) hydroelectric plants, located in the department of La Paz, Ivirizu (164 MW) in the department of Cochabamba, Rositas (400 MW) in the department of Santa Cruz on the Rio Grande river, Icla (102 MW) in the departments of Chuquisaca and Potosí on the Pilcomayo river, the Carrizal I, II and III Project (347 MW) on the Camblaya river located between the departments of Tarija and Chuquisaca, and Margarita (150 MW), located in the "Chaco Tarijeño" on the Pilcomayo river. These projects (Figure 10) will contribute to the change of the energy mix with a notable increase of the system inertia and the spinning reserve and will supply the country growing energy demand with 1599 MW [42].

Figure 6. Renewable energypotential [53].

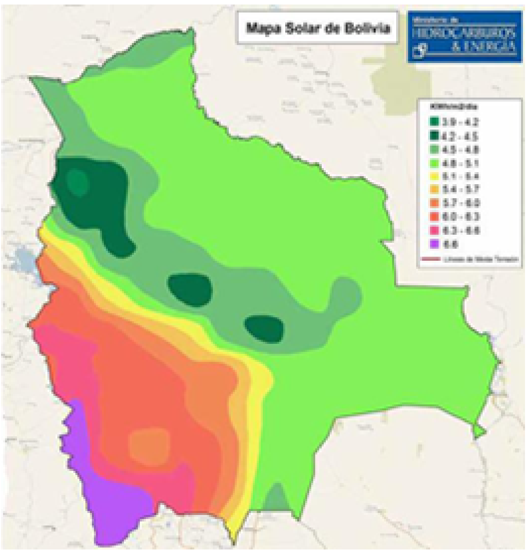

Figure 7. Solar energy potential [53].

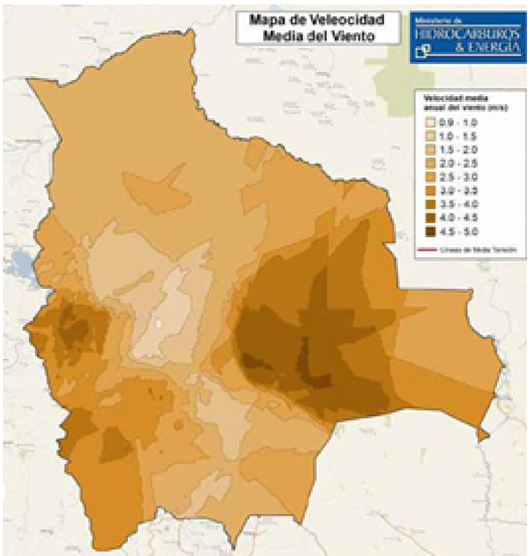

Figure 8. Average wind speeds [53].

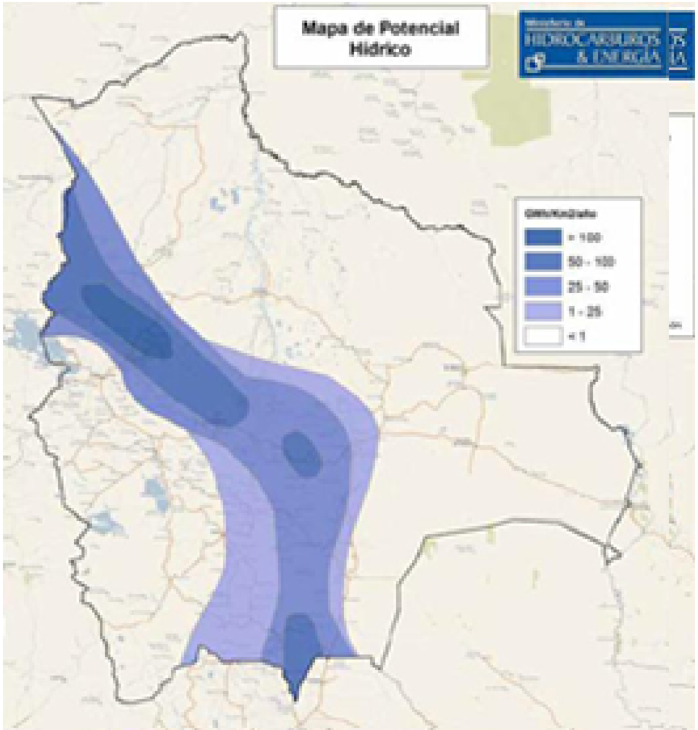

Figure 9. Hydroelectric energy potential [53].

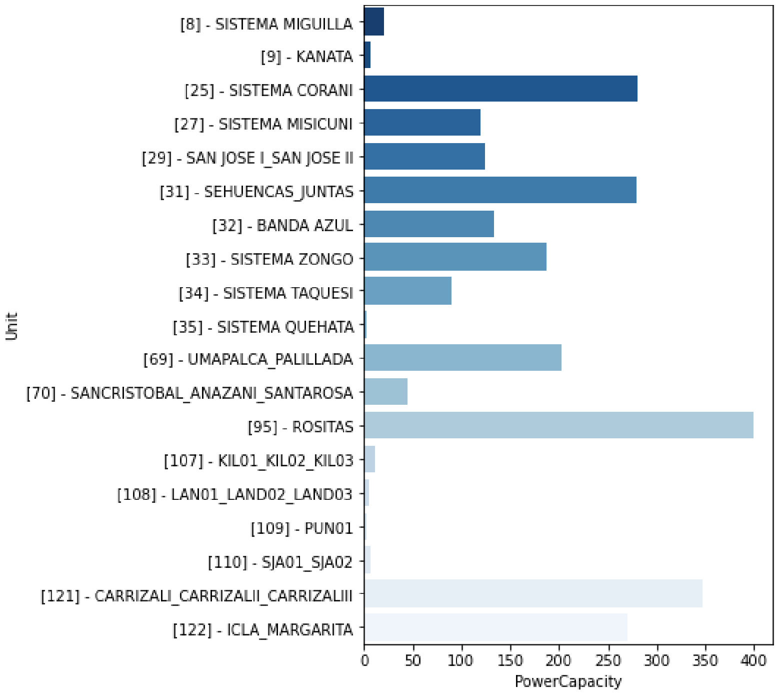

Figure 10. HYDRO ENERGY implemented and planned in the period 2020–2025 [35].

Availability factors for hydro run-of-river resources are derived from interpolating average weekly flows obtained from [46]. Unit technical data such as turbine type, efficiency, nominal power and height of fall were gathered from [54]. Every run-of-river unit is assigned with its own availability factor distribution expressed in time series (e.g., Figure 11).

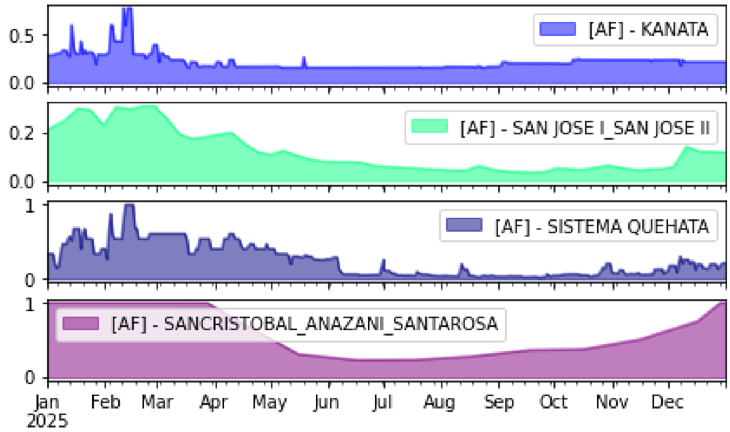

Figure 11. Hydro run-of-river Resources Availability Factor (year 2025) [35].

3.4.2. Solar Resources

The southwest region of the country, as shown in Figure 7, has the highest radiation rates (5.1–7.2 kWh/m^2-day), whereas the northeastern region has the lowest rates (3.9–5.1 kWh/m^2-day) [55,56]. Because sunrise and sunset hours vary by only one hour throughout the year [57], the radiation rate does not exceed 25% between the winter and summer seasons [58]. Additionally, due to Bolivia's high altitude above sea level, the dry climate produces a lower solar dispersion, and thus a large part of the country is subjected to the world's highest level of solar radiation (the tropical zone of the south between parallels 11° and 22°) [58]. Over 97% of the country's territory is suitable for using solar energy as a primary energy source [59]. In contrast, PEEBOL2025 does not mention large-scale solar-energy-integration projects. In 2020, the SIN incorporated its three first solar energy projects: Oruro I (50 MW), Uyuni ColchaK (60 MW) and Yunchara (5 MW). Additionally, at least three more projects are confirmed to be completed by 2025: Oruro II (50 MW), Guayaramerin (3 MW) and Riberalta (5.8 MW) with a total installed solar energy capacity of 173.8 MW until 2025. In Figure 12, the solar plants are presented with its respective power capacity.

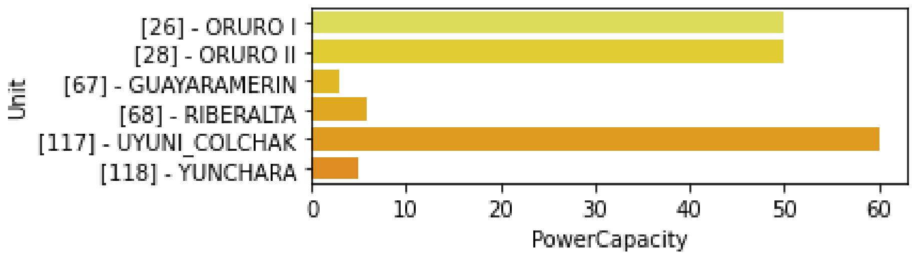

Figure 12. SOLAR ENERGY implemented and planned in the period 2020–2025 [35].

By providing the approximate geographic locations [60] of the solar power plants, it was possible to generate time series of solar availability factors and monthly average solar radiation data of Bolivia using radiation models. For the present work, we used [61]. Additionally, the environmental features [62,63] and PV systems technical features [64–66] are useful to validate the information generated with the radiation models. (e.g., Figures 13 and 14).

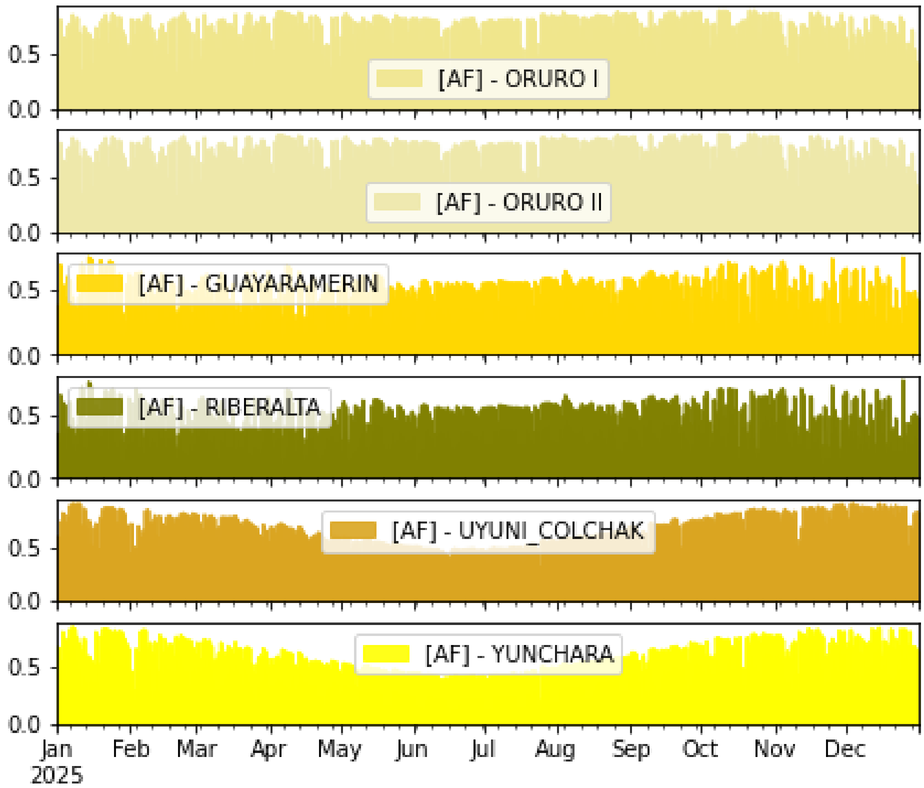

Figure 13. Solar Resource Availability Factor (year 2025).

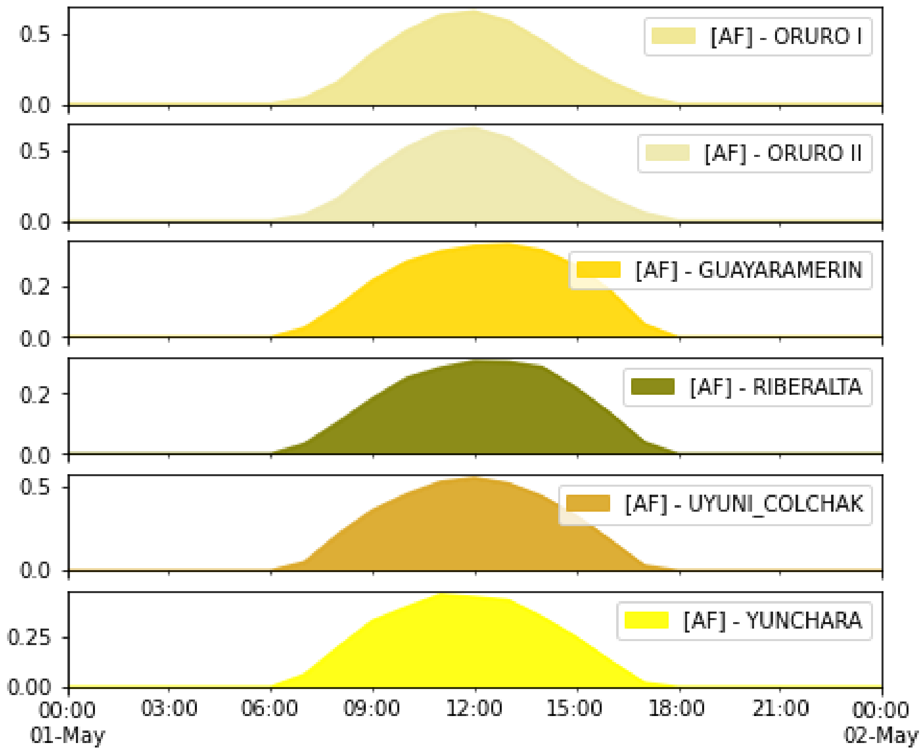

Figure 14. Solar Resources Availability Factor (1 May 2025).

3.4.3. Wind Resources

Wind generation is evaluated based on the Bolivian wind atlas [67] and wind speed measurements at three different heights for a whole year (20 m, 50 m, 80 m). Wind resources in Bolivia are more limited than solar, as indicated in Figure 8. Stronger resource are concentrated in five sectors, and the first wind farm projects are incorporated gradually: on the South and Sest of Santa Cruz city, mostly, with the projects "Warnes-El Dorado" and "San Julian"; from La Paz to Santa Cruz, north of Cochabamba, on the corridor that goes fro, east to west with the project "Qollpana I-Qollpana II-Qollpana III"; on the corridor between Tarija and Sucre departments, which goes from north to south with the project La Ventolera"; around the Titicaca Lake region in the department of La Paz with the project o "Titicaca"; and finally, at the southwest border between Chile, Argentina and Potosi department. The area on the north-to-south corridor between Oruro and Potosi departments provides possible locations for future projects [67]. In Figure 15, the wind power plants are presented with their respective power capacities.

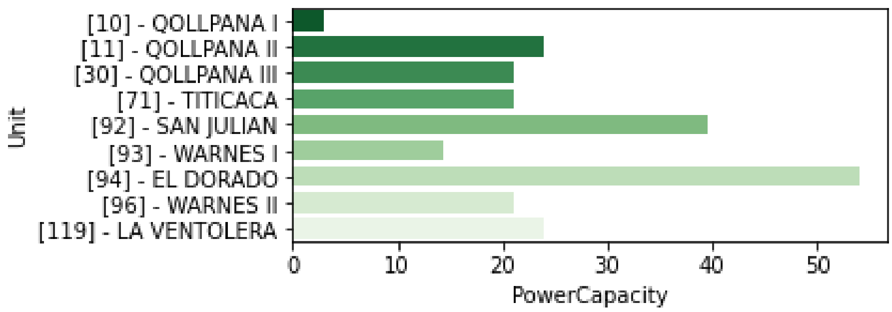

Figure 15. WIND ENERGY implemented and planned in the period 2020–2025 [35].

Wind resource availability factors are generated based on wind speed data from [61] and the approximate geographic location and technical characteristics of both installed and planned wind turbines from [68–70] (e.g., Figures 16 and 17).

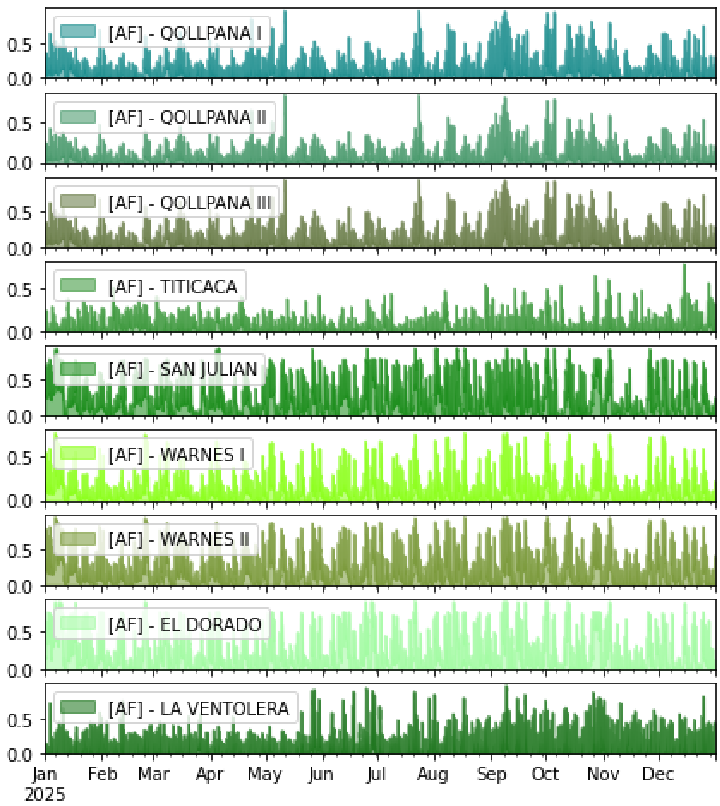

Figure 16. Wind Resource Availability Factor (year 2025).

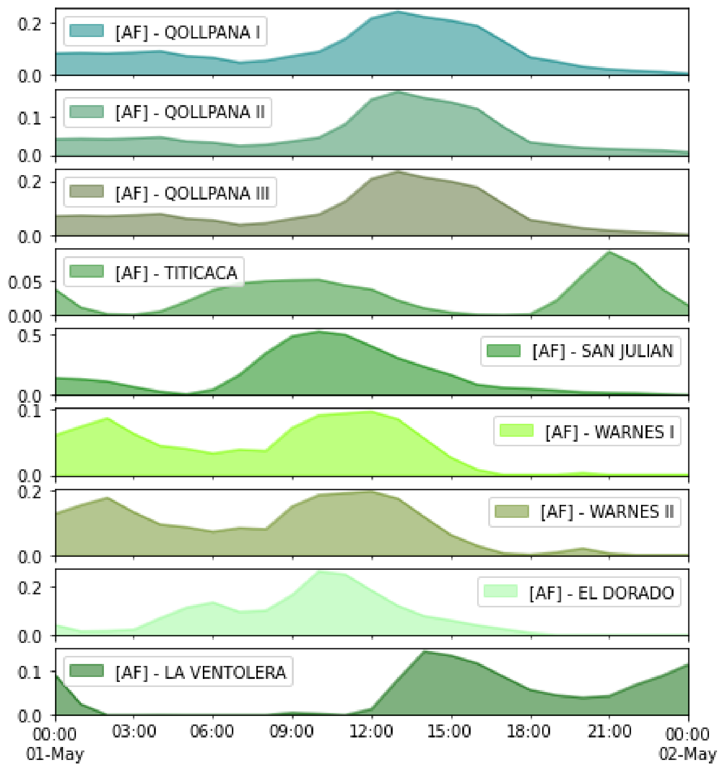

Figure 17. Wind Resource Availability Factor (1 May 2025).

3.5. Grid Data for 2025

The Bolivian grid is relatively simple and radial. There are only four zones clearly defined in the country. Energy can be exchanged between these zones by way of transmission lines, whose power flows are limited by net transfer capacity (DC power flow is not implemented in the current model). Table 4 summarizes the maximum capacity of each transmission line that interconnects the four zones, installed by 2020, extracted from [35].

Table 4. Transmission Capacity between zones in 2020 [35].

Power Flow Direction	*From Central Name*	*To Central Name*	*Voltage Level (kV)*	*NTC (MW)*
CE <—> NO	Santivanez	Palca I	230	430
	Santivanez	Palca II	230	
	Mazocruz	Vinto	230	
CE <—> OR	Carrasco	Yapacani	230	500
	Carrasco	Arboleda	230	
CE <—> SU	Catavi	Ocuri	115	207.5
	Santivanez	Sucre	230	
SIN	*All Centrals*	*All Centrals*	*230–115*	*1137.5*

Based on [35], grid data were also upgraded up to the year 2025, by which a 160 MW line will be added between North and Oriental, a 100 MW line will be added between Central and North, a 300 MW line will be added between Oriental and South, and a 300 MW line will be added between Central and South. Table 5 summarizes the planned transmission projects between the four regions. It is noteworthy that the government is considering interconnection projects (called mega-projects), which are geared toward energy exchange with neighboring countries. Nevertheless, the schedule has not yet been announced and these projects are therefore not considered in this work [52]. In this context, the Bolivian power system is considered an isolated case of study.

Table 5. Transmission projects planned for the period 2020–2025 [35].

Power Flow Direction	*From Central Name*	*To Central Name*	*Voltage Level (kV)*	*NTC (MW)*
OR <—> SU	Camiri	Sucre I	230	300
	Camiri	Sucre II	230	
NO <—> OR	Paraiso	Troncos I	230	160
	Paraiso	Troncos II	230	
CE <—> SU	Santivanez	Sucre I	115	300
	Santivanez	Sucre II	230	
SIN	*All Centrals*	*All Centrals*	*230–115*	*760*

3.6. What-If Scenarios

The baseline scenario of the Bolivian interconnected power system (SIN) by 2025 was built from the known information relative to the SIN of the last year 2020 and assembled, adding to the information of that year all the projects listed in the PEEBOL 2025 (Electrical Plan of the Plurinational State of Bolivia–2025). It was built as a simplified representation of the power system, gathering all the technical information and operative policies from the official web page of National Power dispatch Committee (CNDC, operator of the SIN) [42] and annual records of the ENDE corporation [48,51,71]. Building upon this baseline, multiple determined what-if scenarios were formulated:

- Low-penetration scenarios 1 and 2, with 402 MW and 670 MW of VRES installed capacities, respectively.
- Moderate-penetration scenarios 3 to 5, with 938 MW, 1072 MW and 1206 MW of VRES installed capacities, respectively.
- High-penetration scenarios 6 to 8, with 1340 MW, 2342 MW and 5142 MW of VRES installed capacities, respectively.
- Finally, Very-High-penetration scenarios 9 and 10: with 7642 MW, 10,142 MW and 804 MW of VRES installed capacity.

For each penetration scenario, the reservoir capacity of the hydro dam is assumed to be fully exploited (H scenarios) or completely discarded (NH scenarios). This is used to evaluate the potential contribution of the hydro sector to balance the variations of VRES.

All the parameters summarized in Table 6 were set and implemented into the model as input data to create the simulation environments (in separate folders) for each scenario described before. These variations of input parameters are a batch of simulations of the unit-commitment and optimal dispatch (UC/D) model. Finally, the results allow the possible impact of a large deployment VRES generation to be understood with and without HYDRO storage. The simulations were developed in terms of energy balance, transmission grid capacity, system reserves capacity translated in system inertia, ancillary services requirement and energy generation cost. It should be noted that the installed power capacities of other technologies were kept unchanged, and the current locations of VRES units were conserved.

Table 6. Scenarios.

Total	*With Hydro Storage*		*Without Hydro Storage*		*Projected Installed Capacity*		
Installed Capacity MW	*Scenario*	*Storage Capacity MWh*	*Scenario*	*Storage Capacity MWh*	*Hydro MW*	*Thermal MW*	*VRES MW*
5225.1	1(H)	1,239,106	1(NH)	0	2536.92	2286.18	402
5493.1	2(H)	1,239,106	2(NH)	0	2536.92	2286.18	670
5761.1	3(H)	1,239,106	3(NH)	0	2536.92	2286.18	938
5895.1	4(H)	1,239,106	4(NH)	0	2536.92	2286.18	1072
6029.1	5(H)	1,239,106	5(NH)	0	2536.92	2286.18	1206
6163.1	6(H)	1,239,106	6(NH)	0	2536.92	2286.18	1340
7165.1	7(H)	1,239,106	7(NH)	0	2536.92	2286.18	2342
9965.1	8(H)	1,239,106	8(NH)	0	2536.92	2286.18	5142
12,465.1	9(H)	1,239,106	9(NH)	0	2536.92	2286.18	7642
12,465.1	10(H)	1,239,106	10(NH)	0	2536.92	2286.18	7642

4. Results and Discussion

The results of the different scenarios are summarized in Tables 7–9 and Figures 18–33. In the following subsections, the most relevant simulation outcomes for all scenarios are discussed.

4.1. Accounting for the Flexibility of Hydro Reservoirs

The increment in VRES generation translates into a cascade of effects on the power system. They are described below.

Table 8 shows the assumed increments of VRES generation supply from 1.21 TWh in scenario 1(H) to 8.84 TWh in scenario 10(H). That represents an increase in the covered load by VRES from 10.31% to 75.29%.

High curtailment levels are obtained in the most ambitious scenarios, starting at 0.11 TWh for scenario 8(H) and reaching 10.08 TWh for scenario 10(H) (Table 7). The difference in the curtailment levels can be seen between the low-penetration Scenario and the Very-high-penetration scenario in the Figures 18–25, where the red colored area is the curtailment of each zone.

Another important observation at the high-renewable-penetration level is the near disappearance of thermal generation, from 7.25 TWh for scenario 1(H) down to 0.18 TWh for scenario 10(H). This results in an important reduction in CO_2 emissions, from 2.11 Mt for scenario 1(H) to 0.09 Mt for scenario 10(H). This will accelerate the reduction of CO_2 emissions per capita, which in 2020 was 1.79 t [72]. Another substantial benefit is the reduction in the consumption of fuels (mostly natural gas), making it available for increased exportation.

Is important to notice in this dispatch strategy that the hydroelectric energy contribution remains almost constant, close to 3.2 TWh, which shows an important complementarity between VRES sources. This can be verified by the absence of Load Shedding as from scenario 4(H) in Table 7. We can also observe this in the Figures 18–25, where the blue colored area is the HYDRO generation in each zone and appears normally before and after the solar energy (in yellow).

Table 9 shows that energy flows between zones mainly occur from Central to Oriental (CE –> OR), from North to Oriental (NO –> OR), from Oriental to North (OR –> NO), from Oriental to South (OR –> SU), and from South to Central (SU –> CE). The number of congestion hours is an important indicators of the need to increase its power capacity.

An additional observation from Table 9 is that the Oriental and South zones have a very low hydroelectric supply and storage capacity, which indicates less resilience and lower flexibility levels when incorporating VRES.

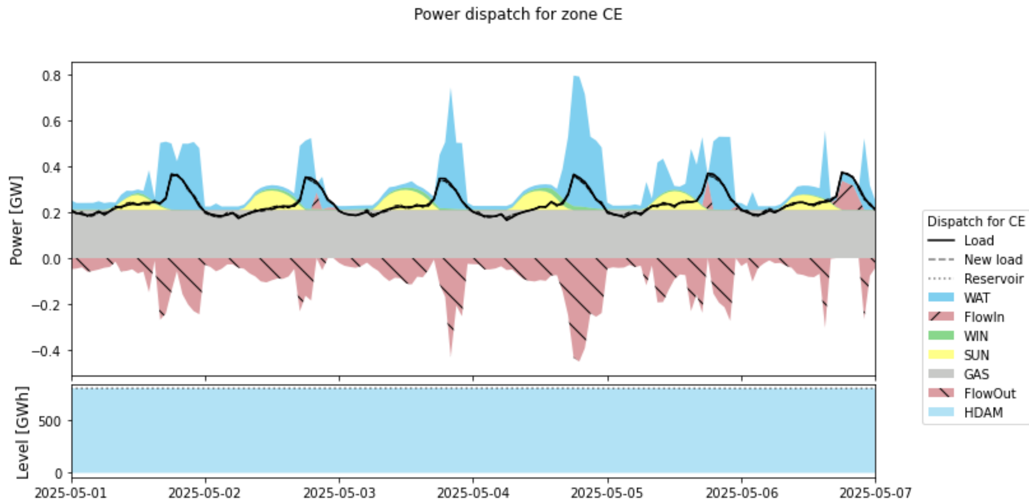

Figure 18. Low0Penetration Scenario 1(H)—Central zone (1–7 May 2025).

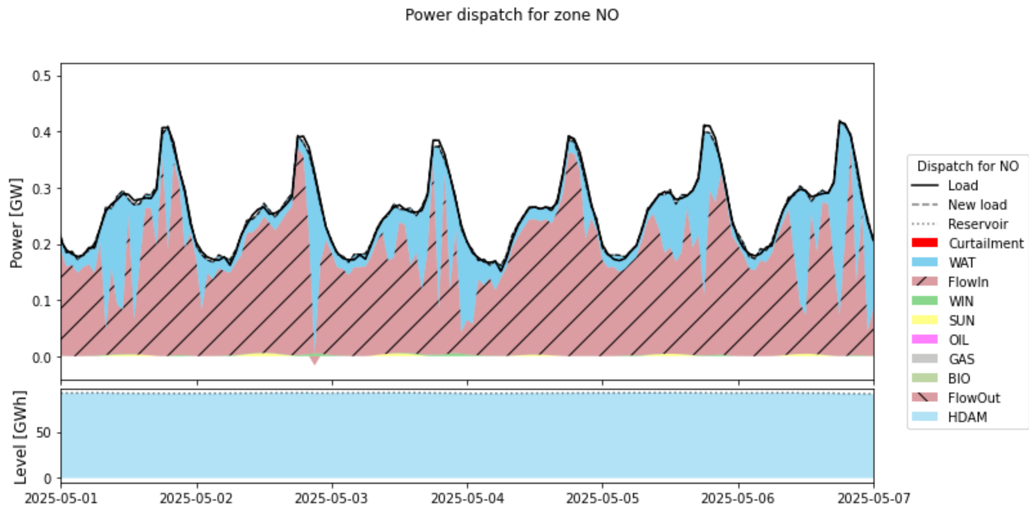

Figure 19. Low0Penetration Scenario 1(H)—North zone (1–7 May 2025).

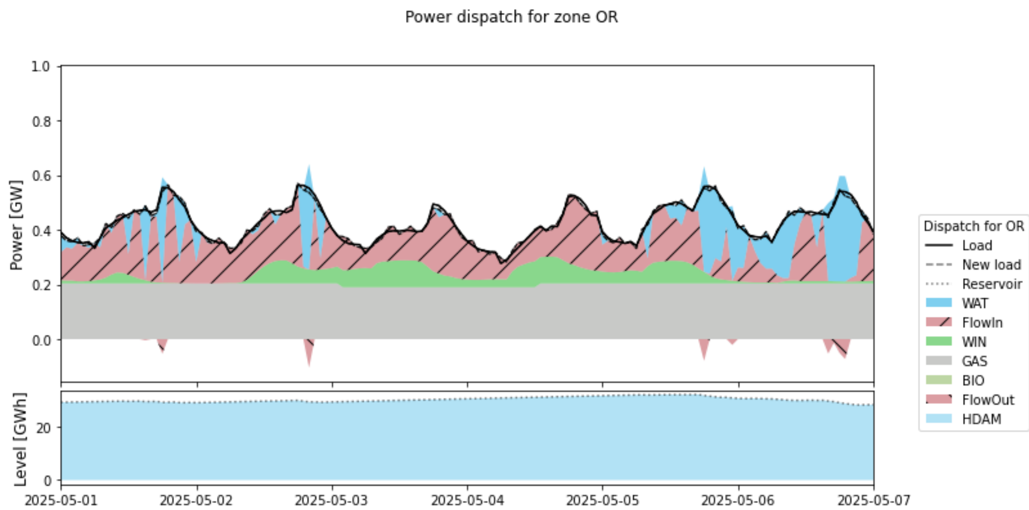

Figure 20. Low-Penetration Scenario 1(H)—Oriental zone (1–7 May 2025).

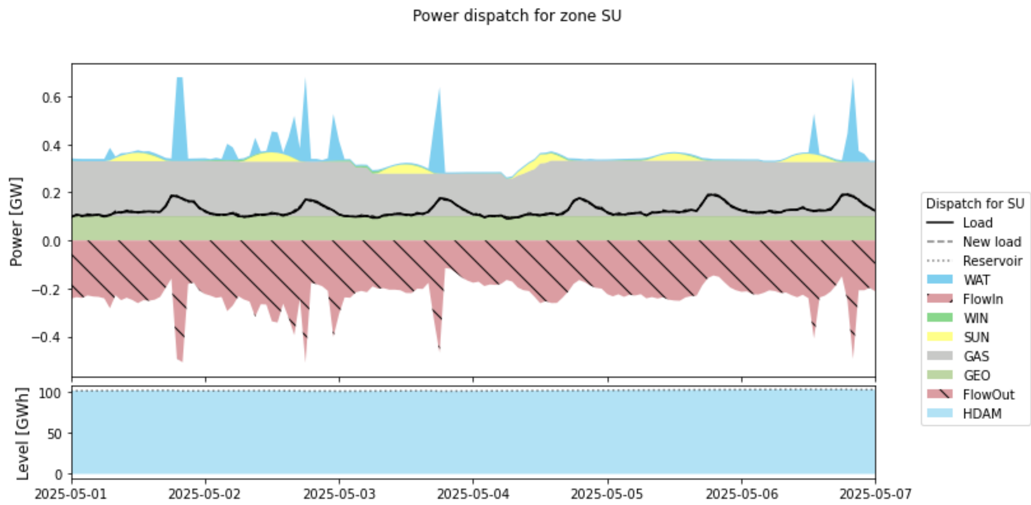

Figure 21. Low-Penetration Scenario 1(H)—South zone (1–7 May 2025).

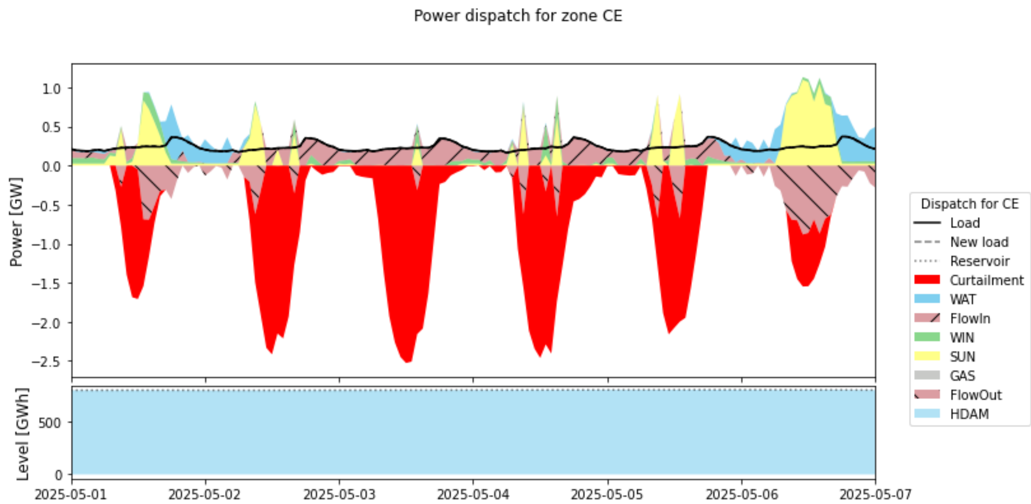

Figure 22. Very-High-Penetration Scenario 10(H)—Central zone (1–7 May 2025).

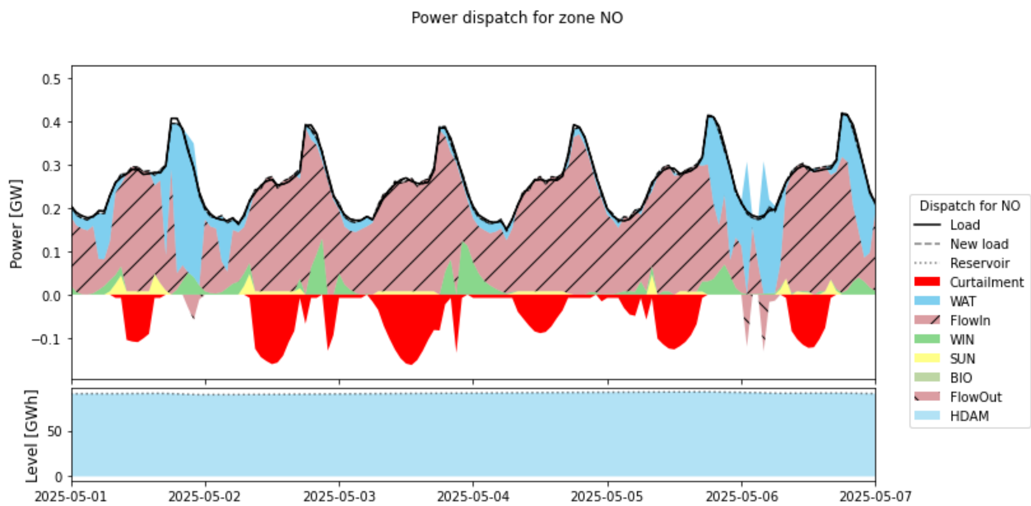

Figure 23. Very-High-Penetration Scenario 10(H)—North zone (1–7 May 2025).

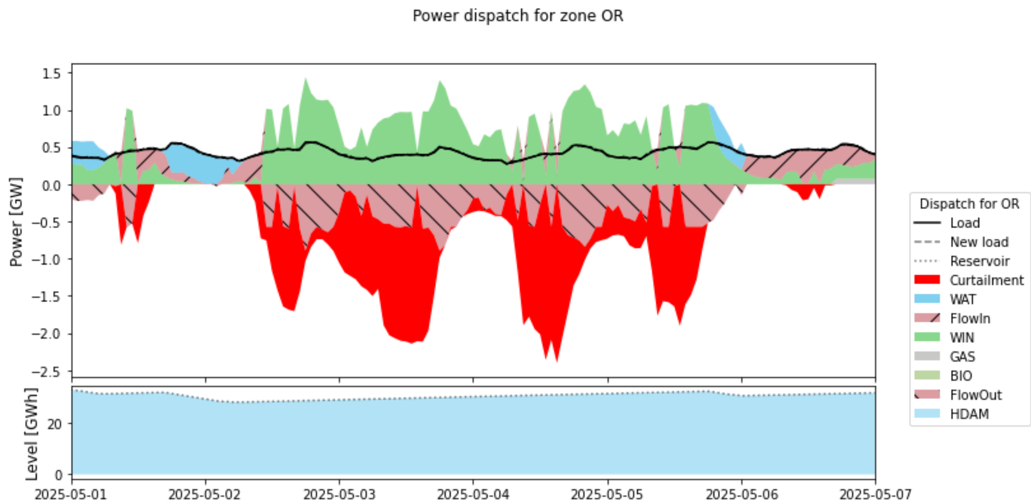

Figure 24. Very-High-Penetration Scenario 10(H)—Oriental zone (1–7 May 2025).

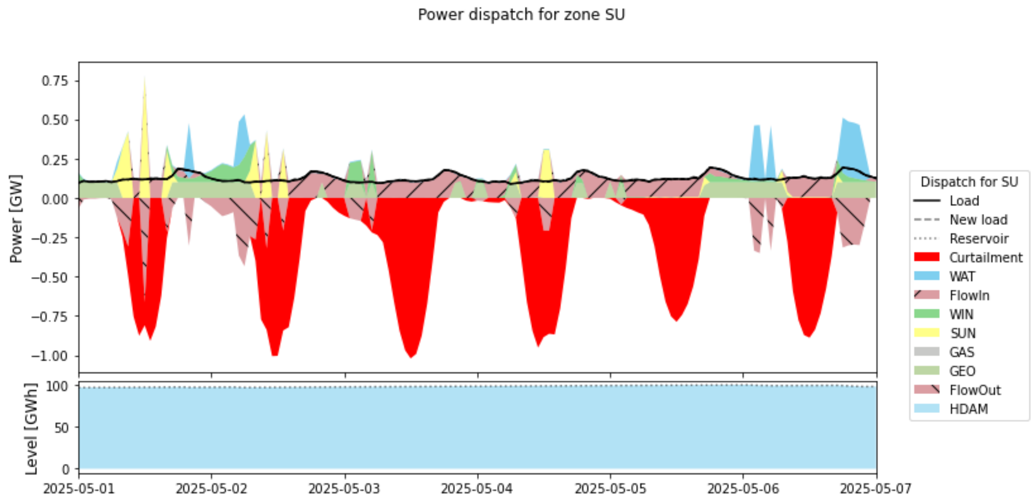

Figure 25. Very-High-Penetration Scenario 10(H)—South zone (1–7 May 2025).

Finally, on the economic side, we can observe from Table 7 that the average power generation cost is reduced from 5.03 EUR/MWh in scenario 1(H) to 0.22 EUR/MWh in scenario 10(H), which is significant. However, the calculated cost does not consider the investment costs of new projects of the maintenance costs of power plants in operation.

Table 7. Electricity Cost, Load Shedding, Curtailment.

Scenario	*Average Electricity Cost EUR/MWh*	*Total Load Shedding TWh*	*Maximum Load Shedding MWh*	*Total Curtailed RES TWh*	*Maximum Curtailed RES MW*	*VRES Installed Capacity MW*
1(H)	5.03	0.0002	53.41	0.0001	7.65	402
2(H)	4.28	0.0000	0.00	0.0001	7.65	670
3(H)	3.58	0.0001	46.22	0.0033	193.94	938
4(H)	3.25	0.0000	21.35	0.0139	387.76	1072
5(H)	2.95	0.0000	52.89	0.0424	510.94	1206
6(H)	2.66	0.0000	0.00	0.0992	905.23	1340

Table 7. *Cont.*

Scenario	*Average Electricity Cost EUR/MWh*	*Total Load Shedding TWh*	*Maximum Load Shedding MWh*	*Total Curtailed RES TWh*	*Maximum Curtailed RES MW*	*VRES Installed Capacity MW*
7(H)	2.63	0.0000	24.14	0.1100	1040.16	2342
8(H)	1.01	0.0000	0.00	2.6500	3109.31	5142
9(H)	0.50	0.0000	0.00	6.1700	5076.59	7642
10(H)	0.22	0.0000	0.00	10.0800	6310.46	10,142
1(NH)	87.72	0.0317	112.07	0.0000	0.00	402
2(NH)	51.83	0.0227	112.07	0.0000	11.53	670
3(NH)	34.17	0.0164	112.07	0.0103	268.24	938
4(NH)	28.29	0.0144	112.07	0.0330	429.76	1072
5(NH)	23.04	0.0129	112.07	0.0710	538.31	1206
6(NH)	18.71	0.0109	112.07	0.1370	665.73	1340
7(NH)	18.12	0.0109	112.07	0.1510	705.55	2342
8(NH)	6.70	0.0034	112.07	2.6800	2561.69	5142
9(NH)	4.87	0.0018	112.07	5.9700	4419.69	7642
10(NH)	3.32	0.0012	112.07	9.6300	6308.87	10,142

Table 8. Generation results for each technology.

Scenario	*HYDRO*		*THERMAL*		*VRES*		*Thermal Generation Displaced*	*Covered Load by VRES*
	Gen TWh	*CO_2 Mt*	*Gen TWh*	*CO_2 Mt*	*Gen TWh*	*CO_2 Mt*	*TWh*	*%*
1(H)	3.28	0.00	7.25	2.11	1.21	0.00	0.00	10.31
2(H)	3.27	0.00	6.44	1.81	2.02	0.00	0.81	17.22
3(H)	3.27	0.00	5.63	1.52	2.83	0.00	1.62	24.13
4(H)	3.27	0.00	5.24	1.39	3.22	0.00	2.01	27.45
5(H)	3.27	0.00	4.87	1.26	3.59	0.00	2.38	30.61
6(H)	3.27	0.00	4.51	1.14	3.95	0.00	2.74	33.67
7(H)	3.27	0.00	3.47	1.12	4.99	0.00	3.78	42.54
8(H)	3.21	0.00	1.35	0.43	7.17	0.00	5.90	61.13
9(H)	3.15	0.00	0.46	0.21	8.13	0.00	6.79	69.25
10(H)	2.72	0.00	0.18	0.09	8.84	0.00	7.07	75.29
1(NH)	0.51	0.00	9.97	3.21	1.21	0.00	0.00	10.35
2(NH)	0.51	0.00	9.17	2.89	2.02	0.00	0.80	17.26
3(NH)	0.51	0.00	8.38	2.61	2.82	0.00	1.59	24.08
4(NH)	0.51	0.00	8.00	2.47	3.20	0.00	1.97	27.33
5(NH)	0.51	0.00	7.64	2.35	3.57	0.00	2.33	30.46
6(NH)	0.51	0.00	7.30	2.24	3.91	0.00	2.67	33.36
7(NH)	0.51	0.00	6.32	2.22	4.89	0.00	3.65	41.72
8(NH)	0.48	0.00	4.18	1.46	7.07	0.00	5.79	60.27
9(NH)	0.41	0.00	3.38	1.10	7.94	0.00	6.59	67.69
10(NH)	0.38	0.00	3.00	0.59	8.35	0.00	6.97	71.18

Table 9. Number of hours of congestion in each line.

Scenario	*CE –> NO*	*CE –> OR*	*CE –> SU*	*NO –> CE*	*NO –> OR*	*OR –> CE*	*OR –> NO*	*OR –> SU*	*SU –> CE*	*SU –> OR*
1(H)	37	2606	0	0	4735	859	2351	4753	1984	928
2(H)	23	3000	0	0	4655	369	2745	5143	1799	527
3(H)	14	3322	1	0	4594	143	2855	5556	1617	229
4(H)	14	3360	0	0	4574	37	2818	5744	1651	132
5(H)	23	3457	0	0	4564	30	2755	5798	1611	120
6(H)	22	3383	0	0	4508	54	2827	5875	1631	98
7(H)	13	3419	0	0	4554	52	2830	5740	1618	147
8(H)	9	3567	7	0	4693	487	2906	5885	1533	71
9(H)	7	3735	72	0	4665	987	2983	6145	1544	103
10(H)	8	3649	85	0	4633	1293	3112	6206	1957	169
1(NH)	10	2360	0	0	4591	0	2353	5828	2696	0
2(NH)	15	2359	0	0	4583	0	2390	6099	2383	0
3(NH)	14	2394	0	0	4619	0	2235	6483	2080	0
4(NH)	16	2394	0	0	4636	0	2220	6523	2006	0
5(NH)	16	2431	0	0	4729	0	2194	6501	1926	0
6(NH)	16	2454	0	0	4817	0	2152	6523	1857	0
7(NH)	18	2479	0	0	4801	0	2128	6534	1836	0
8(NH)	15	2726	0	0	5025	217	2601	6366	925	0
9(NH)	13	2827	2	0	4956	689	2843	6396	1280	3
10(NH)	15	2839	4	0	4892	968	3100	6464	1853	7

4.2. Simulation Results without Hydro Reservoirs

Considering the same VRES installed power levels as in the previous dispatch strategy, the following is observed:

In Table 8, there could be even more increments of VRES generation supply than the strategy with hydro storage; from 1.21 TWh in scenario 1(NH) to 8.35 TWh in scenario 10(NH). This represents an increment in covered load by VRES from 10.35% to 71.18%.

This is observed in Figures 26–33, where the peaks of the curves and areas colored in yellow (solar energy) and green (wind energy) are more pronounced and accentuated. However, this is explained by the fact that the hydro generation is almost zero, and there is no complementarity between hydro and VRES generation during periods with low availability of VRES. In Figures 26–33, there are almost no areas colored with blue that mean that there is no supply of hydro generation.

Furthermore, because of the absence of hydro generation, the curtailment levels are greatly increased. It is null in scenario 1(NH) but reaches 9.63 TWh in scenario 10(NH). This is a similar value to the strategy with hydro storage (Table 6). Without hydro storage, the maximum levels of load shedding are 112.07 MWh. This is explained by the lack of hydro flexibility, which forces the start-up of thermal units to complement the variability of renewables.

Table 8 shows that the supply of thermal energy decreases from 9.97 TWh for scenario 1(NH) to 3.00 TWh for scenario 10(NH). Thermal generation is still significant, especially compared to the strategy with hydro storage. It results in relatively lower reduction of CO_2 emissions (from 3.21 Mt for scenario 1(NH) down to 0.59 Mt for scenario 10(NH)) and a lower reduction in the consumption of natural gas, which reduces the exportation potential for the country.

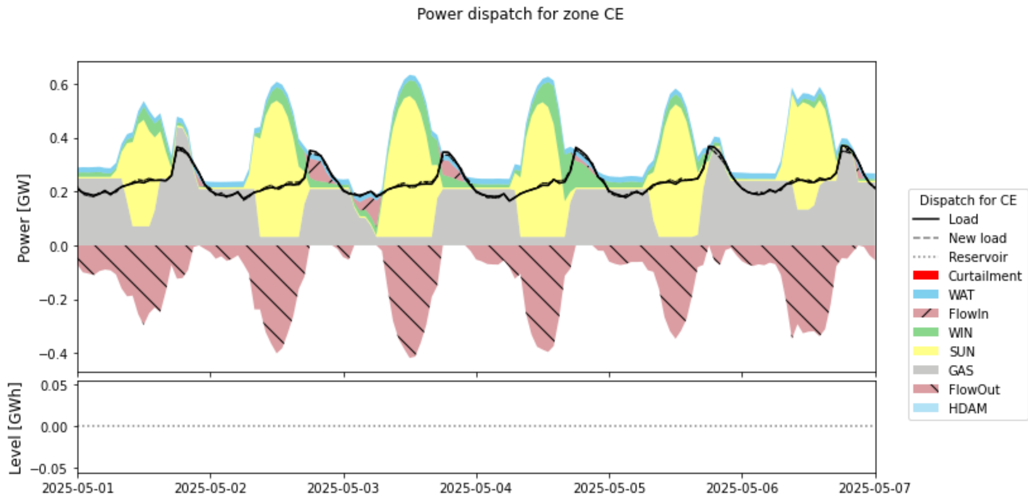

Figure 26. Moderate-Penetration Scenario 1(NH)—Central zone (1–7 May 2025).

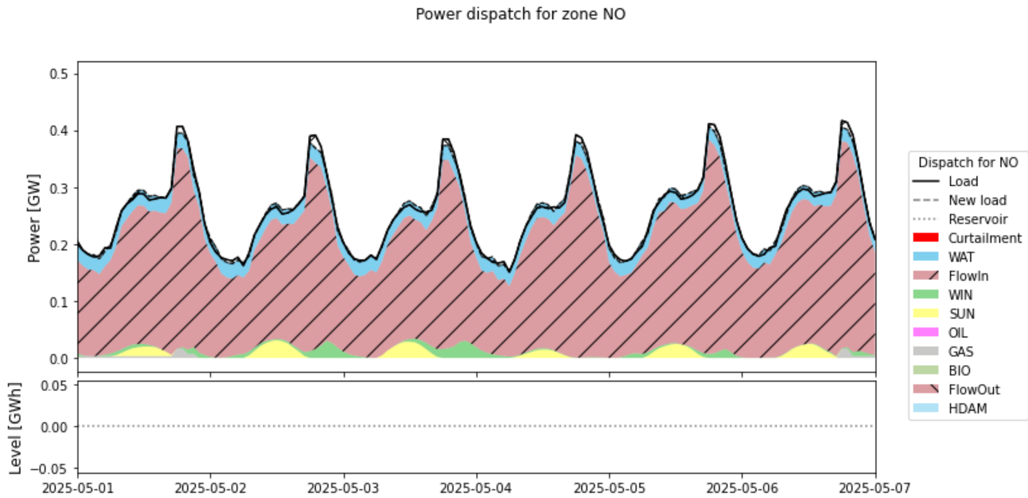

Figure 27. Moderate-Penetration Scenario 1(NH)—North zone (1–7 May 2025).

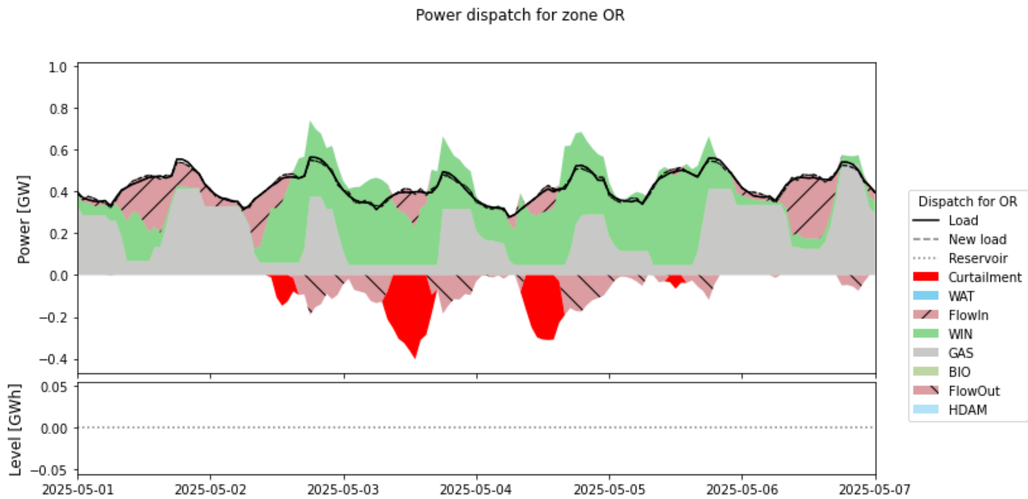

Figure 28. Moderate-Penetration Scenario 1(NH)—Oriental zone (1–7 May 2025).

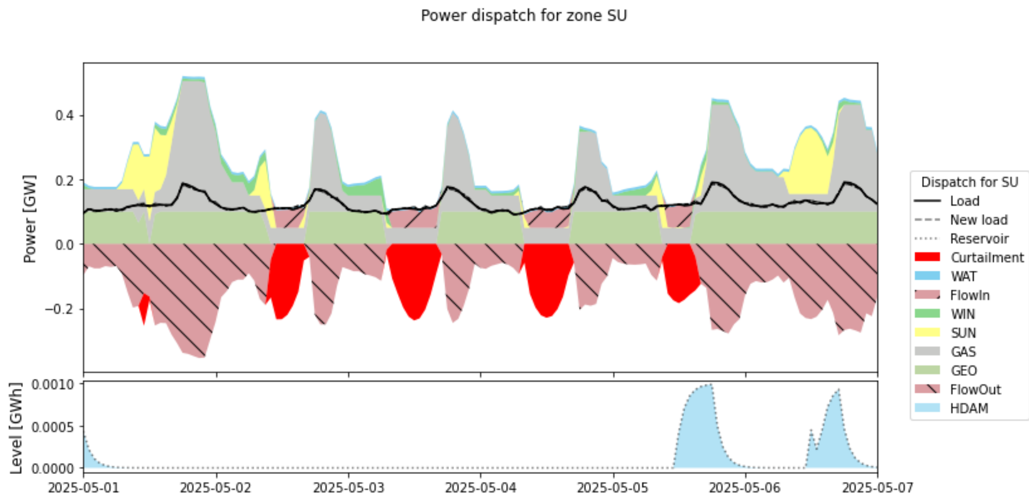

Figure 29. Moderate Penetration Scenario 1(NH)—zone south (1–7 May 2025).

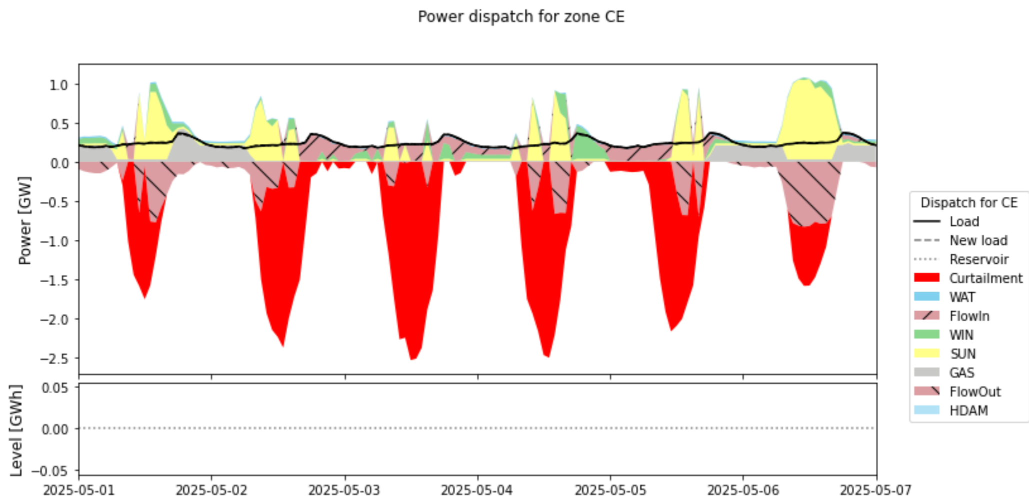

Figure 30. Very-High-Penetration Scenario 10(NH)—Central zone (1–7 May 2025).

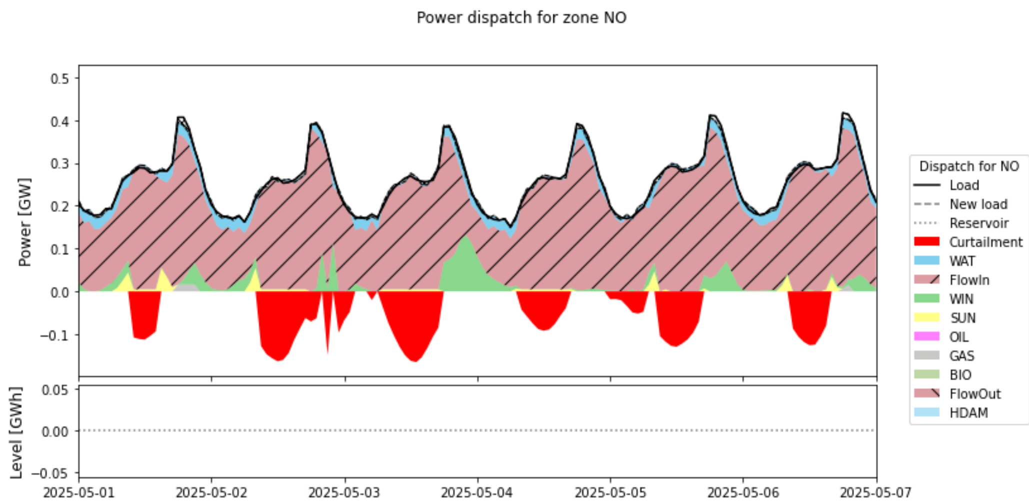

Figure 31. Very High Penetration Scenario 10(NH)—zone north (1–7 May 2025).

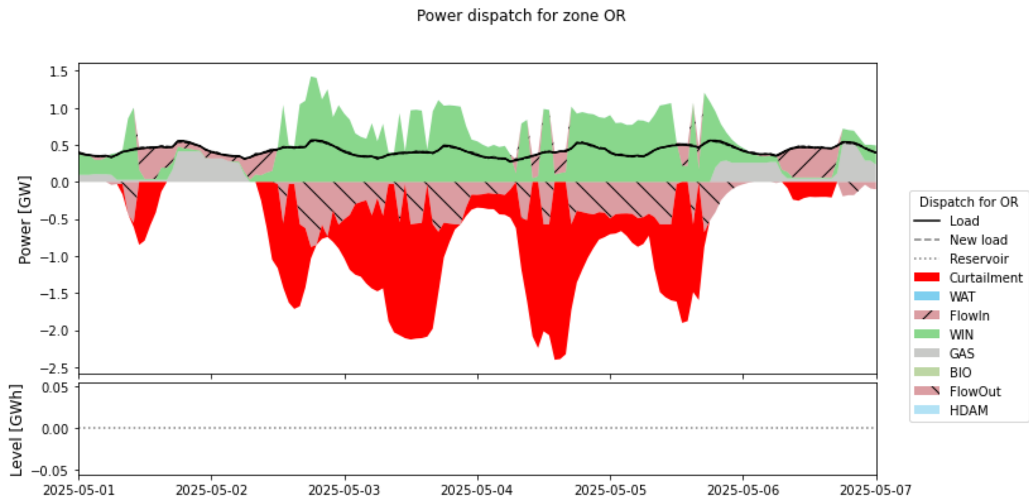

Figure 32. Very-High-Penetration Scenario 10(NH)—Oriental zone (1–7 May 2025).

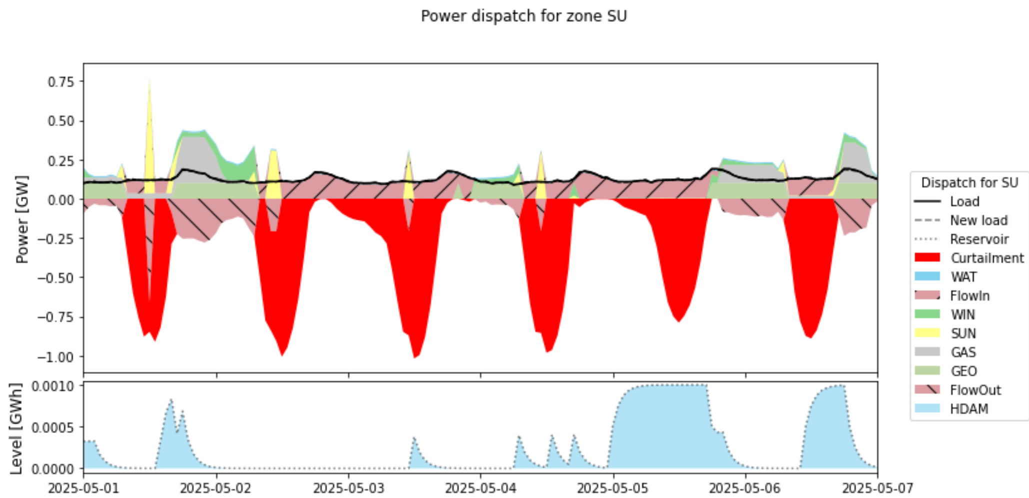

Figure 33. Very-High-Penetration-Scenario 10(NH)—South zone (1–7 May 2025).

For this dispatch strategy, the hydroelectric supply and storage capacity is practically null, which clearly affects the robustness and flexibility by incorporating VRES, because the supply depends only on thermal and VRES generation.

Finally, on the economic side, we observe from Table 7 that the average operational costs are higher than in the strategy with hydro storage because of the large thermal generation used. Furthermore, they are less reduced than in the strategy with hydro storage (from 87.72 EUR/MWh in scenario 1(NH) down to 3.32 EUR/MWh in scenario 10(NH)).

5. Conclusions

This paper proposes the first open and comprehensive model of the Bolivian power system. The source code and input data are released under open licenses, thus ensuring a proper reproducibility and re-usability of this work.

In this work, a number of what-if scenarios with specific VRES expansion objectives are proposed. The goal is to assess the feasibility for the country to leapfrog towards a more renewable energy system instead of the current dependence on fossil fuels.

Simulation results show that high penetration of VRES can be obtained, reaching up to 75%. Furthermore, the installed thermal generation capacity could be displaced in 97%. This deployment of renewable energy, although technically feasible, is obtained at the expense of significant curtailment levels at VRES installed capacities higher than 2500 MW, corresponding to penetration levels higher than 180%.

The deployment of VRES presents important potential for operational costs reduction, with a decrease from 5.03 EUR/MWh down to 0.22 EUR/MWh. However, the importance of hydroelectric generation in economic terms is unquestionable, since the average cost of electricity without hydro storage reaches alarming values of 87.72 EUR/MWh in the worst-case scenario. It must, however, be noted that the investment costs for capacity expansion and the maintenance costs are not included in the simulations. The costs, although significant, remain acceptable when considering the very potential in renewable resources (mainly solar), thus resulting in leveled costs of electricity situated in the lower range of current estimates, which are already lower than traditional technologies in most regions of the world.

Load shedding could be significantly mitigated by the further deployment of VRES sources, thus contributing to the adequacy of the system. This is achieved through the contribution of hydro reservoirs to balance VRES variability. In contrast, in the strategy without hydro storage, the supply of energy is complemented by thermal generation, which results in higher CO_2 emissions.

For the strategy with hydro storage, the significant reservoir capacity present in the country allows a nearly complete displacement of thermal generation. On the other hand, for the strategy without hydro storage, the displacement of thermal generation is much lower, due to the fact that there is no hydro energy available to complement the supply during periods of low availability of VRES, and thermal generation is needed to cover the demand of energy.

The zone with maximum load-shedding levels is the oriental zone. This is the zone that has the largest demand and produces the least hydroelectric energy. Additionally, it has less storage capacity in hydro reservoirs. These features make the oriental zone less flexible in the face of abrupt changes in the supply of VRES due to its variability and therefore results in load shedding.

Results finally indicate the importance of increasing the power capacity of the transmission lines to/from the Oriental zone because they register the higher levels of hourly congestion. This is explained by the large thermal generation capacity and the lower importance of hydro units in that region: when VRESs are not sufficient to cover the demand, hydro generation is imported to the Iriental zone from other zones that have excess of hydro generation to supply their energy demands.

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Abbreviations

The following abbreviations are used in this manuscript:

VRES	Variable Renewable Energy Sources
SIN	National Interconnected System
PEEBOL2025	Electrical Plan of the Plurinational State of Bolivia–2025
CNDC	National Energy Dispatch Committee
ENDE	Bolivian National Electricity Company
DSM	Demand side management
HDAM	Hydroelectric with dam reservoirs
HROR	Hydroelectric run of river
PHOT	Solar Photovoltaic
WTON	Onshore wind turbine
COMC	Combined cycle
GTUR	Gas turbine
STUR	Steam turbine
WAT	Hydro energy
SUN	Solar energy
WIN	Wind energy
BIO	Bagasse, Biodiesel, Biomass
GAS	Gas, as fuel
OIL	Oil, as fuel
CE	Central zone
NO	North zone
OR	Oriental zone
SU	South zone
UD	Unit Commitment
ED	Economic Dispatch
LP	Linear Programing
MILP	Mixed Interger Linear Programing
MINLP	Mixed Interger Non Linear Programming
UNEP	United Nations Environment Programme
COP	Climate Change Conference of the Parties
IRENA	International Renewable Energy Agency
NDC	Nationally Determined Contributions
HYTHCO	Hydro-Thermal Coordination
MO	Maintenance Optimization
GEP	Generation Expansion Planning
PCO	Production Cost Optimization
SIMSEE	Simulation of Electrical Power Systems Software
DEEM	Multinodal Stochastic Economic Dispatch Software
SDG	Sustainable Development Goals
MERRA-2	Modern-Era Retrospective analysis for Research and Applications, Version 2
PV	Photo-Voltaic

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