Pontifícia Universidade Católica
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Denise Tieko Naruto

Co-optimization of generation, reserves and renewable curtailment for day-ahead programming considering the uncertainties of variable renewable sources

Dissertação de Mestrado

Dissertation presented to the Programa de Pós–graduação em Engenharia Elétrica, of the Departamento de Engenharia Elétrica, PUC-Rio as partial fulfillment of the requirements for the degree of Mestre em Engenharia Elétrica.

Advisor: Prof. Alexandre Street de Aguiar

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To my sister.

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Abstract

Naruto, Denise Tieko; Street de Aguiar, Alexandre (Advisor). **Co-optimization of generation, reserves and renewable curtailment for day-ahead programming considering the uncertainties of variable renewable sources**. Rio de Janeiro, 2025. 194p. Dissertação de Mestrado – Departamento de Engenharia Elétrica, Pontifícia Universidade Católica do Rio de Janeiro.

The energy transition is significantly changing the world's energy mixes. In Brazil, hydroelectric power has occupied more than half of the total installed energy capacity for almost fifty years, however its energy mix is also being transformed by the variable renewable energy. The increase of wind and solar photovoltaic power plants in the system is a concern for systems operators worldwide. Wind and solar energy do not produce greenhouse gases but they have characteristics that make the system planning and operation more complex and dynamic. In an electrical grid with high intermittency and variability generation, the system needs more flexibility to safely deliver power to consumers. In the absence of sufficient flexibility, the operator has as last step the power curtailment. In many countries, this resource is being widely used due to the rapid deployment of wind and photovoltaic power plants in recent years. These restrictions can generate additional costs for the generator or the consumer and may pose a challenge to achieving renewable energy global targets. Hence, substantial renewable curtailment are undesirable and require additional measures to improve their predictability and equity. This work proposes a methodology to optimize the variable curtailment of renewable energy together with the allocation of system reserves, considering the intrinsic uncertainty of these sources. This work aims to support the operator in his decision-making in daily scheduling by bringing it closer to real-time operation, as well as to improve reserve requirements and define a transparent criterion for distributing renewable generation curtailment.

Keywords

Energy and Reserve Optimization; Renewable energy curtailment; Day-Ahead Generation Planning; Reserves requirements.

Resumo

Naruto, Denise Tieko; Street de Aguiar, Alexandre. **Co-otimização da geração, reservas e cortes de renováveis para programação do dia seguinte considerando as incertezas das fontes renováveis**. Rio de Janeiro, 2025. 194p. Dissertação de Mestrado – Departamento de Engenharia Elétrica, Pontifícia Universidade Católica do Rio de Janeiro.

A transição energética está mudando significativamente as matrizes energéticas do mundo. No Brasil, a energia hidrelétrica ocupa mais da metade da capacidade total instalada há quase cinquenta anos, porém a sua matriz também está se transformando devido a energia renovável intermitente. O crescimento das conexões de usinas eólicas e solares fotovoltaicas no sistema é uma preocupação para operadores de sistemas em todo o mundo. As energias eólica e solar fotovoltaica não produzem gases de efeito estufa, mas possuem características que tornam o planejamento e a operação do sistema mais complexo e dinâmico. Em uma rede elétrica com alta intermitência e variabilidade na geração, o sistema precisa de mais flexibilidade para entregar energia com segurança aos consumidores. Na ausência de flexibilidade suficiente, o operador tem como último passo o corte de geração. Em muitos países, esse recurso está sendo amplamente utilizado devido à rápida implantação das usinas eólicas e solares nos últimos anos. Essas restrições podem gerar custos adicionais para o gerador ou consumidor e podem representar um desafio para atingir as metas globais de energia renovável. Portanto, cortes substanciais são indesejáveis e requerem medidas adicionais para melhorar a sua previsibilidade e equidade. Este trabalho propõe uma metodologia para otimizar o corte de energia renovável intermitente conjuntamente com a alocação das reservas, considerando a incerteza intrínseca dessas fontes. Esse trabalho visa apoiar o operador em sua tomada de decisão na programação diária aproximando-a da operação em tempo real, bem como aprimorar os requisitos das reservas e definir um critério transparente de distribuição de cortes de energia eólica e solar.

Palavras-chave

Otimização de energia e reserva; Cortes de energia renovável; Programação Diária da Operação; Requisitos de reserva.

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Notation

A. Sets and Indices

T	Set of time periods t.
D	Set of historical days d.
G^T	Set of thermoelectric generating units i.
G^H	Set of hydroelectric generating units i.
I	Set of generating units i.
I^C	Set of controllable generating units i, namely thermal and hydroelectric generation power plants.
I^{NC}	Set of non-controllable generating units i, namely wind and solar generation power plants.
L	Set of transmission lines l.
L^{wc}	Set of transmission lines with worst-case power flow violations l^{wc}.
B	Set of system buses b.
S	Set of network subsystems s.
US	Set of upstream hydro generating units us.
US_τ	Set of upstream hydro generating units us with water time travel τ.
N	Set of hydroelectric plants n.
N_τ	Set of hydroelectric plants n with water time travel τ.
K	Set of Future Cost Function's cut k.

B. Constants

c_i	Generation cost of generation unit i.
c_i^{res}	Reserves cost of generation unit i.
$\hat{g}_{it}$	Generation forecast of variable renewable energy units i at period t.
$\hat{g}_{ibt}$	Generation forecast of variable renewable energy units i connected in bus b at period t.
$\hat{d}_t$	Load demand forecast at period t.
$\hat{d}_{bt}$	Load demand forecast connected in bus b at period t.
G_{it}^{max}	Maximum generation capacity of variable renewable energy units i at period t.
G_{it}^{min}	Minimum generation capacity of variable renewable energy units i at period t.
F_l^{min}	Minimum power flow capacity in system line l.
F_l^{max}	Maximum power flow capacity in system line l.
$F_{l^{wc}}^{min}$	Minimum power flow capacity in system line with worst-case overcapacity violation l^{wc}.
$F_{l^{wc}}^{max}$	Maximum power flow capacity in system line with worst-case overcapacity violation l^{wc}.
β_{lb}	Sensitivity factor relating power flow variation on line l and generation injected in bus b.
$\beta_{l^{wc}b}$	Sensitivity factor relating generation injected on bus b and power flow variation on line with worst-case overcapacity violation l^{wc}.
R_t^{up}	Maximum upward reserve capacity of hydroelectric units at period t.
R_t^{dn}	Maximum downward reserve capacity of hydroelectric units at period t.
T_i^{on}	Minimum activation time of generating unit i.
T_i^{off}	Minimum deactivation time of generating unit i.
Q_n^{us}	Water turbine flow from upstream hydroelectric plant n in a longer horizon .
Q_n	Water turbine flow of hydroelectric plant n.
Q_i	Water turbine flow of hydro generating unit i.
S_n^{us}	Spilled water flow from upstream hydroelectric plant n in a longer horizon.
S_n	Spilled water flow of hydroelectric plant n.
$\overline{S}_{nt}$	Maximum spilled water of hydroelectric n at period t.
$\overline{Vol}_{nt}$	Maximum water reservoir of hydroelectric plant n at period t.
$\underline{Vol}_{nt}$	Minimum water reservoir of hydroelectric plant n at period t.

Vol_n	Water reservoir volume of hydroelectric plant n.
Ve_n	Dead storage water reservoir volume of hydroelectric plant n.
V_n^{us}	Volume of the spillway sill of hydroelectric plant n.
$\overline{DV}_n$	Maximum water diversion of hydroelectric plant n.
$\underline{DV}_n$	Minimum water diversion of hydroelectric plant n.
GH_n	Productivity function of hydroelectric plant n.
GH_i	Productivity function of hydro generating unit i.
H_i^{us}	Upstream elevation of hydro generating unit i.
H_i^{dn}	Downstream elevation of hydro generating unit i.
h_i^{loss}	Losses of hydro generating unit i.
ρ_i^{esp}	Specific productivity of hydro generating unit i.
τ	Water travel time.
M	Big number.
A_{nk}	Angular coefficient of Future Cost Function's cut k of reservoir of hydroelectric plant n.
B_{nk}	Independent term of Future Cost Function's cut k of reservoir of hydroelectric plant n.

C. Decision Variables

g_{it}	Dispatch of generating units i at period t.
g_{ibt}	Dispatch of generating units i at period t connected in bus b.
r_{it}^{up}	Upward reserve of generating units i at period t.
r_{it}^{dn}	Downward reserve of generating units i at period t.
δ_{it}	Power curtailment of generating units i at period t.
α_{FCF}	Future Cost Function.
x_{it}	Activation status of generating unit i at period t.
y_{it}	Shutdown status of generating unit i at period t.
z_{it}	*On/off* status of generating unit i at period t.
vol_{nt}	Water reservoir of hydroelectric plant n at period t.
inf_{nt}	Water inflow given by lateral inflow forecast of hydroelectric plant n.
q_{nt}	Turbine water flow of hydroelectric plant n at period t.
q_{nt}^{us}	Turbine water flow from upstream hydroelectric plant$n$ at period t.
s_{nt}	Spillage water of hydroelectric plant n at period t.
s_{nt}^{us}	Spilled water flow from upstream hydroelectric plant n at period t.
dv_{nt}	Water diversion of hydroelectric plant n at period t.
dv_{nt}^{us}	Water diversion from upstream hydroelectric plant n at period t.
w_{nt}	*On/off* status of the spillway operation of hydroelectric plant n at period t.

C. Others

α Quantile of the data distribution.

Δ_{dt} Generation variation between the periods $(t+1)$ and t in relation to the generation in period t.

$\Delta^{up}_{[(DT)\alpha]}$ Generation variation value located in the $DT\alpha$-th position, considering negative variations, of the total D historical days and T periods of the day.

$\Delta^{dn}_{[(DT)\alpha]}$ Generation variation value located in the $DT\alpha$-th position, considering positive variations, of the total D historical days and T periods of the day.

κ_s Variability metric of renewable generation power plants, namely wind and solar power plants, connected in the subsystem s.

$\overline{\kappa}_s$ Mean of variability metrics, considering positive and negative generation variations, of total renewable generation power plants, namely wind and solar plants, connected in the subsystem s.

$\kappa^{(\alpha)up}_{st}$ Variability metric of total renewable generation power plants, namely wind and solar plants, connected in the subsystem s at period t, considering negative variations.

$\kappa^{(\alpha)dn}_{st}$ Variability metric of total renewable generation power plants, namely wind and solar plants, connected in the subsystem s at period t, considering positive variations.

$\kappa^{\sigma,up}_{it}$ Variability metric of generating unit i at period t, considering negative generation variations of power plants.

$\kappa^{\sigma,dn}_{it}$ Variability metric of generating unit i at period t, considering positive generation variations of power plants.

ϵ^{up}_{it} Factor of standard deviation relative share, considering negative generation variations, of generating unit i.

ϵ^{dn}_{it} Factor of standard deviation relative share, considering positive generation variations, of generating unit i.

$\overline{\kappa}^{up}_{it}$ Mean of variability metrics, considering positive generation variations, of generating unit i at period t.

$\overline{\kappa}^{dn}_{it}$ Mean of variability metrics, considering negative generation variations, of generating unit i at period t.

List of Abreviations

ABEEólica	Brazilian Wind Energy Association
ACO	Ant Colony Optimization
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AHPF	Approximated Hydro Production Function
ANEEL	Brazilian Electricity Regulatory Agency
ARIMA	Autoregressive Integrated Moving Average
APC	Active Power Curtailment
ARO	Adjustable Robust Optimization
BM	Balancing Mechanism
BDU	Bidirecional Unit
BESS	Battery Energy Storage System
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CAG	Automatic Generation Control
CCEE	Brazilian Chamber of Electric Energy Commercialization
C&CG	Column and Constraint Generation
CMO	Marginal Operating Costs
CMSE	Electrical Sector Monitoring Committee
CMP	Constraint Management Pathfinder
CMIS	Constraint Management Intertrip Service Information
CO_2	Carbon Dioxide
C-off	Constrained-off
CREZ	Competitive Renewable Energy Zone
CSP	Concentrating Thermal Solar Power
DC	Duration curve

DDU Decision-dependent uncertainty

DIR Dispatchable Intermittent Resource

DER Distribution Energy Resources

DLR Dynamic Line Rating

DNO Distribution Network Operator

DSO Distribution System Operator

EDF Empirical Distributed Function

EKS *Erneuerbaren-Energien-Kennzahl* (Renewable Generation Indicator)

ERCOT Electric Reliability Council of Texas

ESRE Portugal's Energy Services Regulatory Authority

EES Electric Energy Storage

ESG Environmental, Social and Governance

ESS System Service Charges

FACTS Flexible Alternating Current Transmission System

FCF Future Cost Function

FERC Federal Energy Regulatory Commission

FRCC Florida Reliability Coordinating Council

FTR Financial Transmission Rights

GA Genetic Algorithms

GCS Grid Connection Study

HPP Hydroelectric Power Plants

HUC Hydroelectric Unit Commitment

HVDC High-Voltage Direct Current

ISO Independent System Operators

ISO-NE Independent System Operator New England

ISP Private Social Investment

KCL Kirchhoff's Current Law

KDE Kernel Density Estimation

KVL	Kirchhoff's Voltage Law
LCM	Local Restrictions Market
LCA	Life Cycle Assessment
Li-ion ESS	Lithium-Ion Energy Storage System
LMP	Locational Marginal Price
LR	Lagrangian relaxation
LVRT	Low Voltage Ride Through
MCC	Marginal Congestion Component
MCMC	Markov Chain Monte Carlo
MILP	Mixed-Integer Linear Programming
MMDG	Micro and Mini Distributed Generation
MISO	Midcontinent Independent System Operator
NEM	National Electricity Market
NERC	North American Electric Reliability Corporation
NESO	National Energy System Operator
NGESO	National Grid Energy System Operator
NYISO	New York Independent System Operator
NWPP	Northwest Power Pool
OFGEM	Office of Gas and Electricity Markets
ONS	Brazilian Independent System Operator
OPF	Optimal Power Flow
OOME	Out-Of-Merit-Energy
PDF	Probability Density Function
PJM	Pennsylvania, Jersey, Maryland Interconnection
PMO	Monthly Operational Program
PTDF	Power Transfer Distribution Factor
PSH	Pumped Storage Hydro
PSO	Particle Swarm Optimization
PTDF	Power Transfer Distribution factor

PHS	Pumped Hydro Storage
PV	Photovoltaic
RC	Resource Cost
REC	Renewable Energy Credits
REE	Red Eléctrica de España
REZ	Renewable Energy Zones
RMPA	Rocky Mountain Power Area
RO	Robust Optimization
RTCA	Real Time Contingency Analysis
RTTR	Real-Time Thermal Rating
RTO	Regional Transmission Operators
RUC	Residual Unit Commitment
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SERC	Southeastern Electric Reliability Council
SIN	National Interconnected System
SISOL	Isolated Systems
SO	Stochastic Optimization
SPP	Southwest Power Pool
SWIS	South West Interconnected System
TL	Transmission Line
TPP	Thermal Power Plants
TSO	Transmission System Operators
TUC	Thermal Unit Commitment
UC	Unit Commitment
US	United States
VG	Variable Generation
VPP	Virtual Power Plant
VRB	Vanadium Redox Battery

VRE	Variable Renewable Energy
WECC	Western Electricity Coordinating Council
WEM	Wholesale Electricity Market
WPP	Wind Power Plant

1

Introduction

1.1

Motivation

The global electricity sector is currently undergoing an energy transition to reduce the impact of energy production on the environment. The impact is measured mainly by the use of energy sources that emit greenhouse gases into the atmosphere. As a result, the growth of wind and solar energy has been encouraged through public policies, reduced equipment costs, and their rapid implementation periods.

Figure 1 shows the worldwide growth in renewable generation capacity by energy source, mainly wind and solar photovoltaic (PV), from 2010 to 2023, and the expected growth of 5,520 GW in capacity from 2024 to 2030 (IEA, 2024c). Photovoltaic solar energy, centralized and distributed, is the renewable source that is expected to grow the most in the coming years, accounting for almost 80% of all predicted expansion of renewable energy.

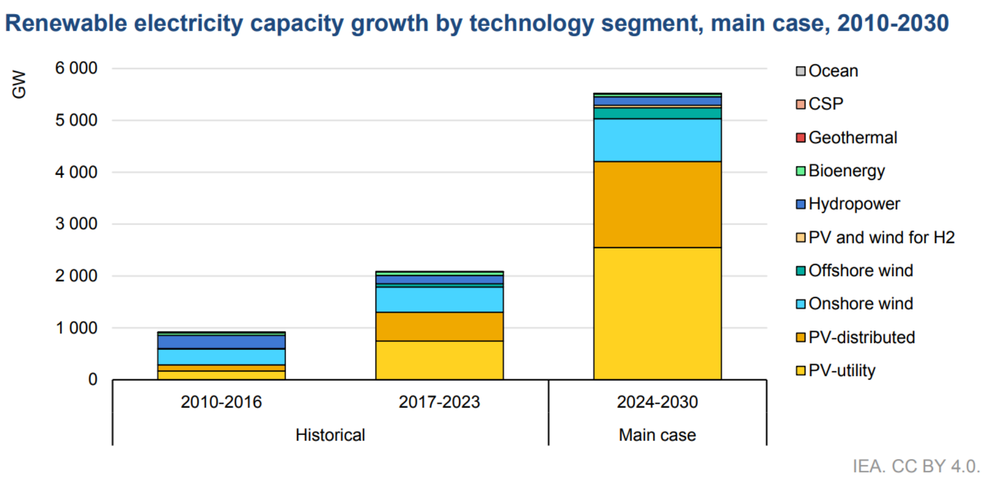


Figure 1: Renewable generation capacity historical and predicted growth worldwide (IEA, 2024c).

The increase in wind and solar connections in electrical systems is characterized by high levels of intermittency and variability, and it is bringing significant impacts on the operation of systems around the world.

For instance, the high penetration of wind turbines in the system can cause voltage instabilities. As detailed in (MULJADI, 2014), multiple variations in wind power output can result in voltage fluctuations outside safe ranges, making the network unstable and susceptible to uncontrollable cascading events that could lead to load outages. In addition, severe weather scenarios, such as high wind speeds or sudden changes in solar irradiance on a cloudy day, may result in unplanned overgeneration that can result in excessive power flows in system interconnections (FILIPPOV; DILMAN, 2019). Additionally, (BORODULIN, 2022) elaborates on the intermittency and high fluctuations of wind and solar generation, proposing new definitions of extreme contingencies in stability analysis which may cause significant disturbances in large power systems with high Variable Renewable Energy (VRE).

Faced with new challenges, system operators are pursuing new resources and methods to improve system's flexibility. Nevertheless, in many cases, it is imperative to curtail generation as a last resource to ensure security and reliability in energy supply.

Figure 2 illustrates the behavior of annual renewable energy curtailment rates in conjunction with the share of Variable Renewable Energy (VRE) connected to the system, with data from 2000 to 2022 (IEA, 2023). The variable energy sources can include wind, solar, biomass and Concentrating Thermal Solar Power (CSP), and the generation curtail rates refer to those caused by electrical restrictions and not those motivated by economic incentives or market rules.

Figure 2 shows that there is no unique standard behavior related to the rates of renewable energy curtailment with their growth in the country's energy mix. This relationship and the treatment of renewable curtailment depends

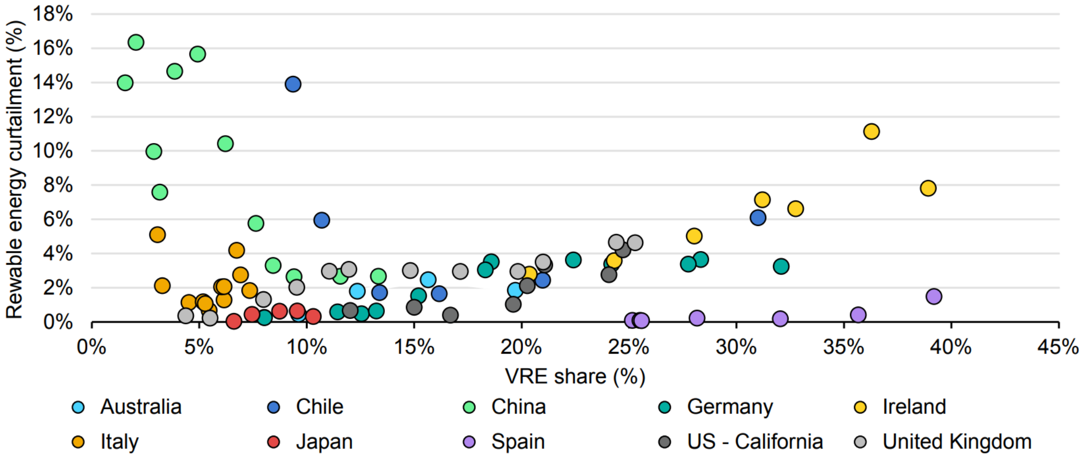


Figure 2: Variable renewable energy (VRE) shares in generation and technical curtailment for selected countries (IEA, 2023).

on other variables besides the connections in the system and shares in energy mixes, including as follow:

(i) renewable power plants and load centers' electrical distance;

(ii) regional and international transmission energy interconnections;

(iii) load growth and renewable generation forecasts;

(iv) economic signals for generators and consumers related to market designs;

(v) transmission and distribution systems modernizations and expansions;

(vi) public policies to promote energy transition indicators targets; and

(vii) available ancillary services, distributed energy resources, demand response, among others products and services to increase system flexibility, controlability and security.

To illustrate the public policies influence, in the case of China, it is verified that the beginning of its energy transition was a period with high renewable power curtailment. Although China has a significant installed capacity for wind and solar generation and reaching all global renewable energy indicators, this did not necessarily mean greater renewable generation consumption due to the high rates of curtailment presented during these years. Recently, a shift in worldwide renewable energy metrics can be observed from installed capacity to the percentage of energy consumption coming from these sources.

In general, in Figure 2, it can be noted an oscillatory non-uniform pattern through the years in several countries. This can be attributed to the pursuit of more flexibility resources and generation absorption to accommodate the expected growth of wind and solar generation connections to the grid.

Therefore, in the scenario of networks with high VRE connections, system planners must analyze the benefits of investing in transmission grid infrastructure and other innovative resources to provide system operators with tools to deal with these challenging power sources in short periods and in real time operation.

In conclusion, renewable generation curtailment constitutes an ongoing characteristics of the energy transition situation and it is expected to increase if no action is taken. For this reason, it is essential that the renewable curtailment is indicated in the most predictable, optimal and transparent manner for all parties involved, considering the existing system resources and their uncertainties characteristics.

1.2
Objective

The main objective of this work is to propose an integrated methodology to co-optimize the renewable energy curtailment and the day-ahead energy and reserve scheduling to support the Brazilian system operator in its decision-making process. To achieve this goal, a new reserve-requirement sizing is proposed, considering:

(i) *the impact of intermittent renewable energy curtailment* – enabling the energy and reserve scheduling to be adjusted by an uncertainty reduction due to a curtailment action; and

(ii) *curtailment discrimination by reserve cost causation* – enabling the curtailment discrimination among renewable generators based on their variability and its induced opportunity cost with additional reserve requirements.

Despite the advantages of increasing the share of renewable generation in energy mix, the Operator must ensure the inclusion of their variability characteristic in the day-ahead planning decisions and in real-time operation.

Therefore, the development of a tool to support the Operator's decision-making to optimally distribute and allocate generation curtailment aims to balance the costs allocated to reserves with the uncertainties inherent in wind and solar energy.

1.3
Contributions

The contributions of this dissertation are listed below.

(i) Detailing the challenges of renewable energy curtailment in other countries and Brazil, presenting the current curtailment rates, action plans, and projects that are being implemented and studied by system operators and regulators;

(ii) Presenting an alternative renewable curtailment criterion integrated in the Brazilian day-ahead scheduling energy and reserves considering:

» the reserves requirement opportunity cost and the contribution of each renewable generator to the final reserve requirement size;

» the transmission system restrictions; and

» the thermal and hydro *unit commitment* constraints.

(iii) A new integrative framework that approximate the generation and reserves day-ahead planning with the real-time operation comparing the verified generation, reserves and variable renewable power curtailment with the scheduled dispatch; and

(iv) Proposition of new methods to access hourly reserve requirements for frequency control related to renewable variability, including wind and solar photovoltaic energy sources, subsystems and individual power plants' intermittencies with and without correlation.

These contributions are proposed considering the increase of uncertainty in the electrical systems of Brazil and the worldwide due to intermittent renewable energy sources, along with discussions about renewable curtailment allocation and optimization in a more equitable way considering the accurate assessment of the service provided by hydroelectric plants. The model also includes thermal and hydroelectric unit commitment constraints, in addition to the balance and grid restrictions to indicate curtailment that ensure system security and energy supply.

1.4 Organization

This dissertation is organized in the next chapters, structured as follows:

(i) *Chapter 2* – presents an overview of the renewable generation curtailment metrics, challenges and solutions found in other countries and system operators. This Chapter exemplifies how this issue is currently being faced in countries in Europe, systems in United States and Australia.

(ii) *Chapter 3* – covers the amounts and reasons for wind and solar curtailment in the Brazilian energy sector. This chapter also details the regulatory discussions associated with the curtailment distribution criteria, financial compensation for wind and solar constrained-off and other flexibility resources that are being studied.

(iii) *Chapter 4* – presents a literature review on models and optimization algorithms for renewable generation curtailment including distribution methodologies, action plans to minimize them and additional aspects regarding market rules and alternative solutions for curtailment.

(iv) *Chapter 5* – proposes the methodology for the optimization model that considers the renewable generation curtailment. This chapter details the model equations, including the Objective Function and constraints in different cases, in order to analyze the results and compare them with the expected outcomes.

(v) *Chapter 6* – provides the results obtained from the implemented case studies. A medium-sized and a large-sized case are modeled and simulated with similar characteristics. This Chapter shows and discusses the results of the case studies, with qualitative and quantitative comparative analyses.

(vi) *Chapter 7* – presents the conclusions by summarizing the objective, contributions and the main results of this dissertation. Furthermore, the chapter also suggests future work related to the generation curtailment optimization problem.

Finally, *Chapter 8* lists all the references and relevant documents cited in this dissertation. *Appendix A* presents a summary table of the international cases that were detailed in *Chapter 2* and *Appendix B* defines the complete proposed optimization model with the Objective Function and equations constraints as explained in *Chapter 5*.

2

International Benchmarking

Variable renewable energy curtailment is a global challenge associated with the rapid increasing penetration of these renewable sources in electrical systems. Figure 3 shows the annual expansion of power capacity between 2003 and 2023 for renewable and non-renewable energy sources (IRENA, 2024). From 2014 onwards, the annual renewable energy expansion exceeded the growth of conventional energy and this difference has been increasing in the following years.

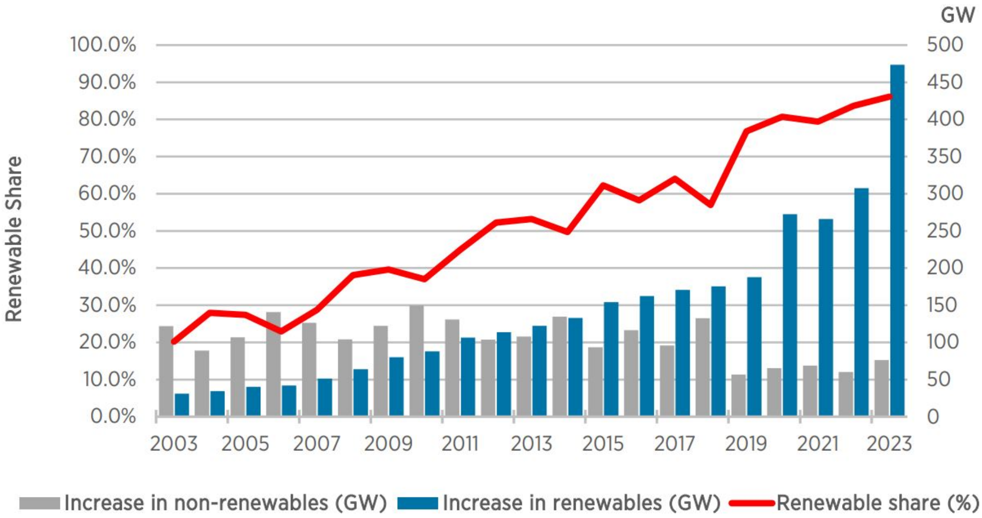


Figure 3: Annual Power Capacity Expansion and renewable share in world energy mix from 2003 to 2023 (IRENA, 2024).

According to (IEA, 2024a), the global energy mix will continue to develop the renewable energy capacity up to 7,300 GW until 2028, leading by 95% of wind and solar energy sources. Hence, the rapid expansion of renewable generation may lead to a greater renewable curtailment, as network expansion and load growth are generally outpaced by the accelerated deployment of variable renewable power plants.

The means of addressing the renewable curtailment depends on resources available in the system and electricity networks' configurations. Some aspects influencing the increase of curtailment are regional or international transmission interconnections' capacities, distance between renewable power plants and load centers, growth of country's economy and load prediction, renewable generation forecast, energy market designs, transmission expansion modernization, system expansion planning and available ancillary services, distributed energy resources, demand response, among others flexibility products, to the system operator.

As an example, Figure 4 shows the VRE generation shares and curtailment rates due to grid limitation in different countries around the world. In some countries, as Australia, Ireland, Italy and United Kingdom (UK), it can be verified the oscillatory behavior of curtailment rates over the years.

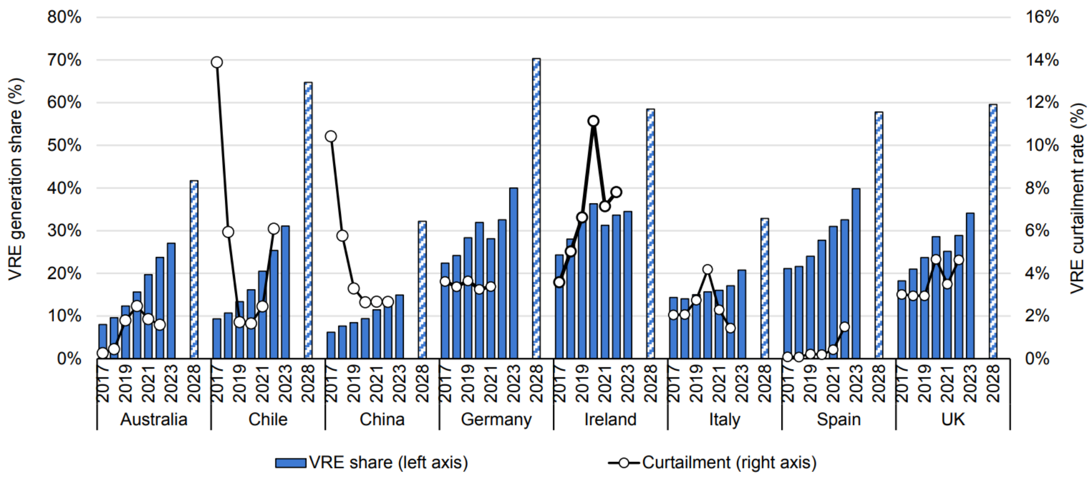


Figure 4: Variable renewable energy generation shares and curtailment rates (IEA, 2024a).

Certain solutions to minimize renewable curtailment may include transmission system modernization, distribution energy resources remote control or storage systems to alleviate power flow through lines when the main cause is grid congestion, and flexibility resources such as demand-side response, energy storage systems to reallocate the generation-demand balance, capacity markets, when the main cause is oversupply. Nevertheless, despite the cause of the restriction, it should be emphasized that renewable energy curtailment is an highly likely consequence of the energy transition considering the accelerated growth of wind and solar photovoltaic power plant projects, associated with renewable energy subsidies and lower supply chain costs.

For that reason, the key point for dealing with the renewable curtailment trend is to make these restrictions as predictable as possible and implement an optimal and objective criteria to distribute them considering the high intermittent and real-time variability of wind and solar generation.

The details of the measures, requirements and processes implemented by operators and regulators worldwide are described in the next sub-items. The international benchmarking for renewable curtailment in this work includes Europe in general, specific European countries as Great Britain, Germany, Spain and Portugal, electrical systems in United States as the Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Midcontinent Independent system operator (MISO), and finally, Australia.

2.1 Europe

Europe has an active participation in the global energy transition. The growth of renewable energy, wind and solar, has been considerable in recent years, with around 50 GW in 2022 and 60 GW in 2023, amounting to 480 GW of wind and solar capacity (EC, 2024). Furthermore, the predicted growth of renewable generation is more than 532 GW until 2028 (IEA, 2023).

In July 2023, the European Union increased goal of the renewable energy share in final energy consumption from 32% to 42.5% until 2030 (PARLIAMENT; COUNCIL, 2023b). For this reason, European countries are accelerating their investment plans in networks and connection processes in order to facilitate the integration of more renewable projects into the grid.

The European electrical system has as great advantage their international interconnections lines which allows the harnessing of renewable energy from other countries, such as offshore wind generation and hydroelectric energy, to serve energy for load centers in locations that lack renewable resources. According with (ENTSO-E, 2023), Europe had 93 GW of cross-border transmission capacity in 2022 and more 23 GW of cross-border capacity in construction or in advanced stages of permitting until 2025.

Figure 5 shows the estimated 88 GW cross-border capacities and additional opportunities for an increase of 41 GW storage system around 2040 in Europe, amounting to €5.6 billion/year of investments in the grid (ENTSO-E, 2023).

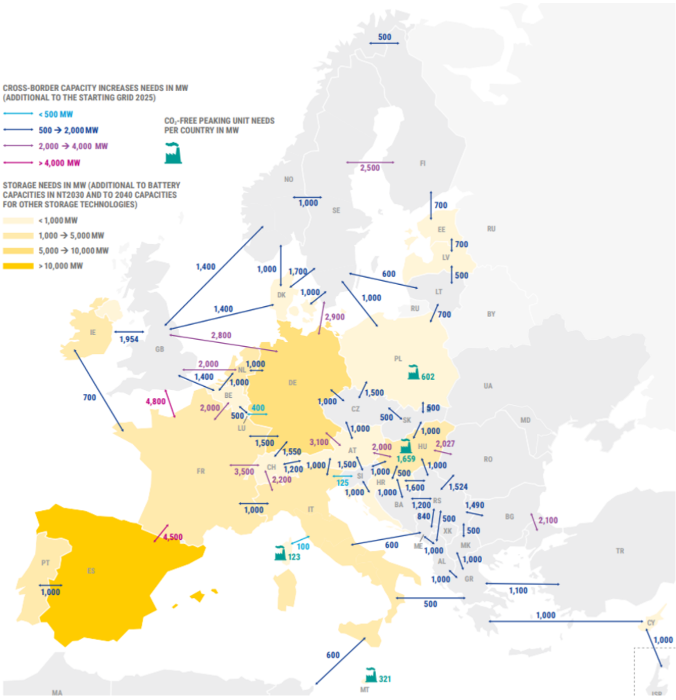


Figure 5: Opportunities for increases in cross-border transmission, storage and peaking units capacity in 2024 in Europe (ENTSO-E, 2023).

Nevertheless, besides the cross-border energy exchanges, the renewable curtailment is still a challenge in European countries. As detailed in the (ENTSO-E, 2023), in case Europe stops investing in the grid after 2025, it is estimated an increase of renewable curtailed energy of 17 TWh/year and an increase of 14 Mton/year CO_2 emissions by 2030. As a result, international transmission interconnections investments are one of the main strategies to deal with renewable curtailment in Europe, along with Energy Storage Systems (ESS), coordination with the Distribution System Operators (DSO), modernization of transmission system and others measures detailed in this Chapter.

Regarding ESS, in 2023 the European Commission published a recommendation (PARLIAMENT; COUNCIL, 2023a)(PARLIAMENT; COUNCIL, 2023c) regarding the new *consumer-producer* classification, with regulatory and tariff guidelines. The recommendations include the need for European countries to adapt their regulations to consider this new context and avoid double taxation, facilitating its integration into the system. In addition, the document also recommends that the services provided by storage systems be appropriately remunerated and that competitive procedures be considered in order to provide flexibility and capacity to the network. Currently, the following classifications are considered in the European data for storage systems (SYSTEMS, 2025c):

1. Mechanical: systems that use physical infrastructure to store energy, including Pumped Hydro Storage (PHS), Compressed Air Energy Storage (CAES) and flywheel. Currently, this type covers the majority of storage systems in operation, as shown in Figure 6.

2. Electrochemical: These include batteries that store energy through chemical reactions. Some examples are lithium-ion, sodium-sulfur, lead-acid, and redox flow batteries. This type of storage system has the largest number of projects with ongoing system access requests, as shown in Figure 6.

3. Thermal: This storage captures and stores heat for later uses, such as molten salts, used in concentrated solar power plants, and Sensible Thermal Energy Storage (STES), which involves storing energy in water or rocks for heating or cooling; and

4. Chemical: This involves converting electricity into chemical energy for storage and later reconverting into electricity. The main system is hy-

drogen centers, which convert electricity into hydrogen by electrolysis and are used as fuel cells.

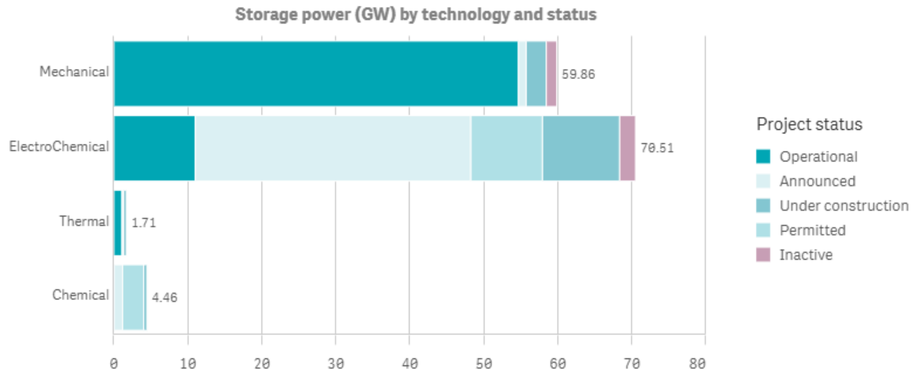


Figure 6: Storage power capacity by technology and projects' status (SYSTEMS, 2025b).

Figure 7 shows the total power capacity of battery systems in operation, totaling approximately 66.83 GW (SYSTEMS, 2025b) by country, with a focus on the UK, Germany, Italy, Spain and France. In addition, the chart also presents the amount of power capacity of storage projects announced, permitted, under construction and inactive, highlighting almost 20 GW of storage system projects announced in the UK and over 8 GW already permitted.

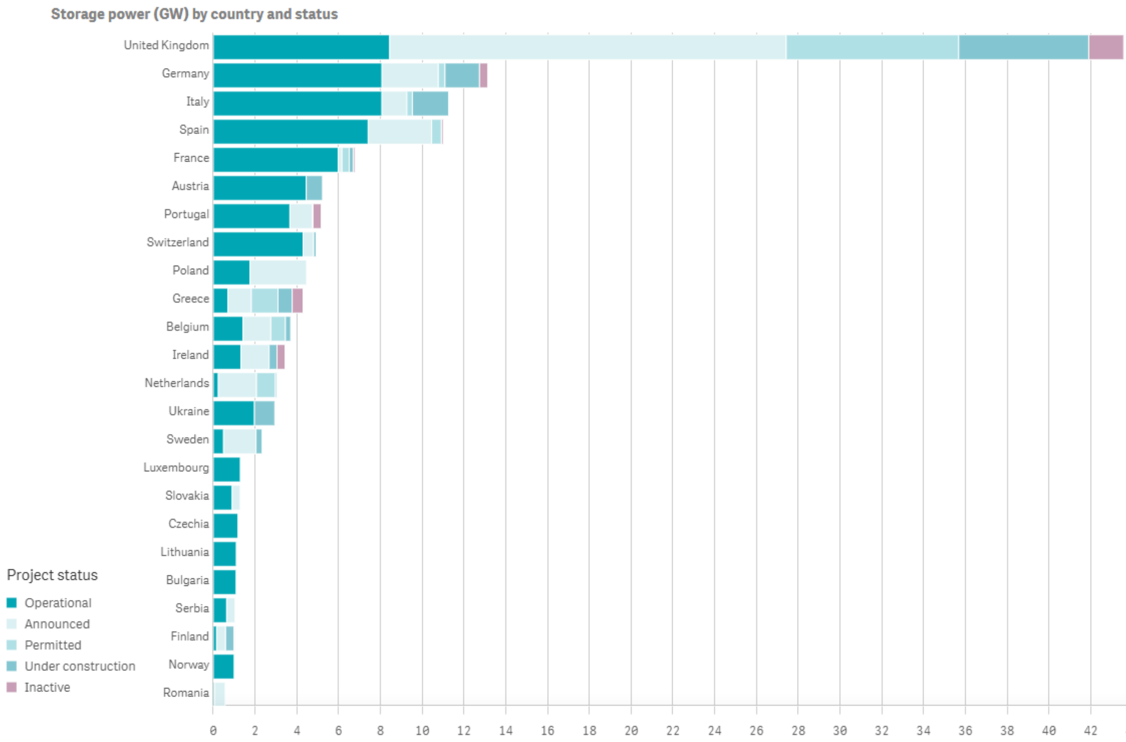


Figure 7: Storage systems capacity by technology and projects' status (SYSTEMS, 2025b).

Furthermore, an important stakeholder in the energy transition context regarding the increase of renewable generation in the system are the DSO. According to (MELETIOU A.; VITIELLO, 2022), up to 70% of future renewable energy capacity is expected to be connected to the distribution grid by 2030.

In Europe, the establishment of DSO took place in 2009 with the definition of its responsibility to *'ensure the long-term ability of the system to meet reasonable demands for the distribution of electricity, for operating, maintaining and developing under economic conditions a secure, reliable and efficient electricity distribution system in its area with due regard for the environment and energy efficiency'* (PARLIAMENT; COUNCIL, 2009). Then, in 2018 (PARLIAMENT; COUNCIL, 2018) and 2019 (PARLIAMENT; COUNCIL, 2019a), further details of DSO's duties are included in the context of the *Clean Energy for All Europeans Package* considering the new global targets for reducing greenhouse gases. In 2021, the European Union DSO Entity (SYSTEMS, 2025a) was created with the aim of unifying DSO's responsibilities, sharing innovative solutions and analyzing emerging trends in the face of the growth of intermittent renewable generation.

Distribution system operators must ensure the safety of resources connected to their network through voltage controls, smart metering, supervision systems and, mainly, implement a coordinated procedure with the Transmission System Operators (TSO). In 2022, around 75% of DSO in Europe share data with the TSO's considering real-time requirements and around 86% of DSO share data with TSO in the post-operation stage (MELETIOU A.; VITIELLO, 2022). As shown in Figure 8, more than 70% of the data shared between DSO and TSO in real time has a granularity of 15 minutes, facilitating the management of transmission and distribution grid restrictions due to intermittent renewable generation and distributed energy resources.

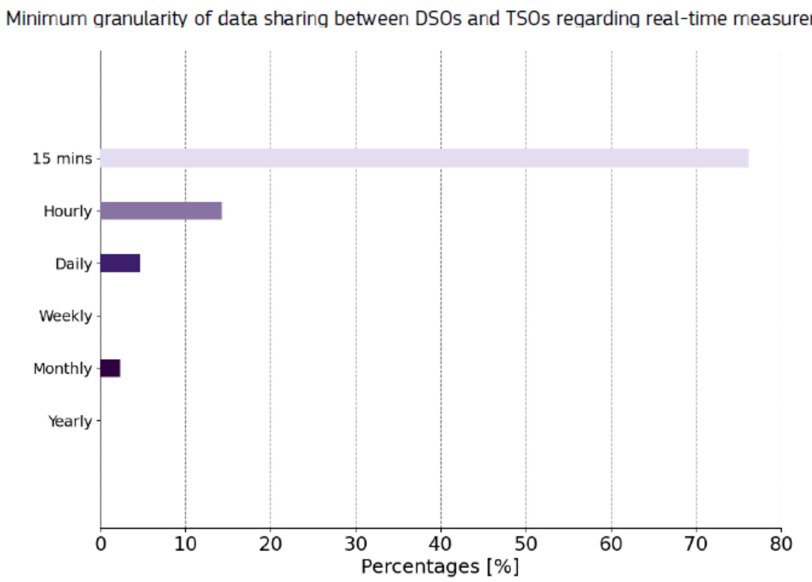


Figure 8: Data granularity sharing between DSO and TSO in Europe in real-time operation (MELETIOU A.; VITIELLO, 2022).

In addition to these investments and measures to deal with intermittent renewable generation, the European Union also defines regulatory commands to be followed by European countries in the generation curtailment processes, as detailed in the following subsection.

2.1.1

Curtailment Regulation

The generation curtailment is included in the definition of *redispatching* which is regulated by Article 2 and detailed in Article 13 of the European Regulation 2019/943 (PARLIAMENT; COUNCIL, 2019b). According to this normative, the redispatch is a measure activated by the system operator and it must be executed based on transparent rules and non-discriminatory criteria.

As stated by (PARLIAMENT; COUNCIL, 2019b), redispatch command is related to generation or load restrictions that occur in order to relieve physical congestion in the grid or to ensure system security. Moreover, the generation curtailment must be justified and conducted by the operator using a transparent and a non-discriminatory criteria based on market mechanisms. In case there is no market rules implemented, the curtailment must be financially compensated by energy sales price, or in case of cogeneration facilities, it must be compensated by backup heat provision additional costs. The payment for the curtailment reimbursement must be provided by the system operator, except in the case of generators with a flexible connection agreement which do not guarantee firm energy supply.

Moreover, European regulation requires operators to publish generation curtailment data, including curtail reasons, quantities and the energy source. operators also must report analyzes on the efficiency of the market mechanisms used to prioritize generation curtails and information about the action plans to reduce the curtailment amounts of renewable or cogeneration energy sources.

In case market mechanisms are not implemented or utilized to define energy curtailment, the system operator must deprioritize the following energy sources:

1. Renewable energy sources;

2. Self-production from renewable sources, when there is no injection into the grid; and

3. High-efficiency cogeneration plants.

From this definition, it can be verified that renewable curtailment must be the last source for generation restrictions by European system operators. Based on (PARLIAMENT; COUNCIL, 2019b), this order must by followed unless there is no other alternative, or costs are disproportionate or there are severe risks to system security.

Finally, the cited regulation also determines that the renewable generation or high-efficient co-generation curtailment should be the minimum possible and should not exceed a rate of 5% of its total annual generated electricity in installations which use renewable energy sources. That indicator must be adhered, except in cases where the renewable energy production is more than 50% of annual gross final electricity consumption.

2.1.2
Great Britain

The operator of Great Britain's electrical system is the National Grid Energy system operator (NGESO), recently renamed as National Energy system operator (NESO)(NESO, 2024a), and it is regulated by the Office of Gas and Electricity Markets of Great Britain (OFGEM). As shown in Figure 4 in Chapter 2, the share of VRE generation is increasing, but the rate of renewable curtailment is in a *zig-zag* movement close to 5%, which is an usual behavior as preventive and corrective measures are implemented.

Great Britain's transmission system is separated in two subsystems, the *Scottish Electricity Transmission System* in the North and the *English and Welsh Electricity Transmission System* in the South region (NGESO, 2023). The region between Scotland and England has accounted for most of the transmission restrictions, namely as *B6 boundary*. There is an intense power flow from the North, due to the anticipated growth of renewable generation in Scotland, to the South region where the largest load centers are located, which cause the majority of the wind generation curtailment. Figure 9 shows the map of Great Britain highlighting the regions where energy curtailment occurs in the island.

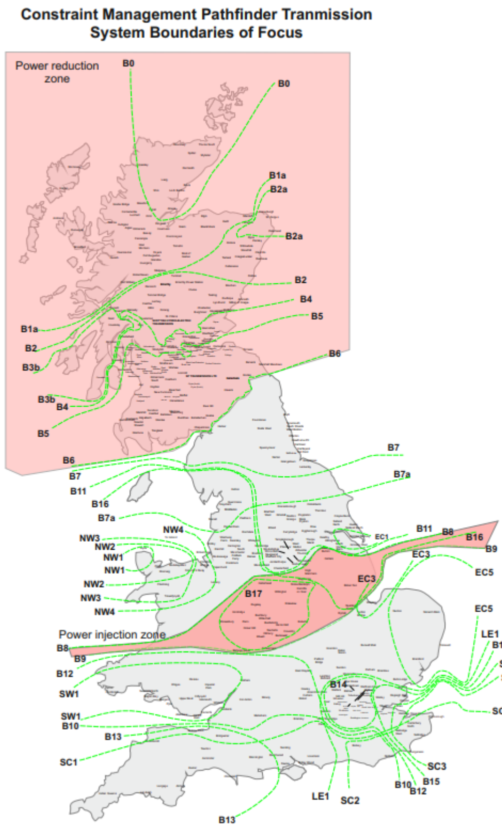


Figure 9: Great Britain network route maps and curtailment regions in light red color (NGESO, 2019b).

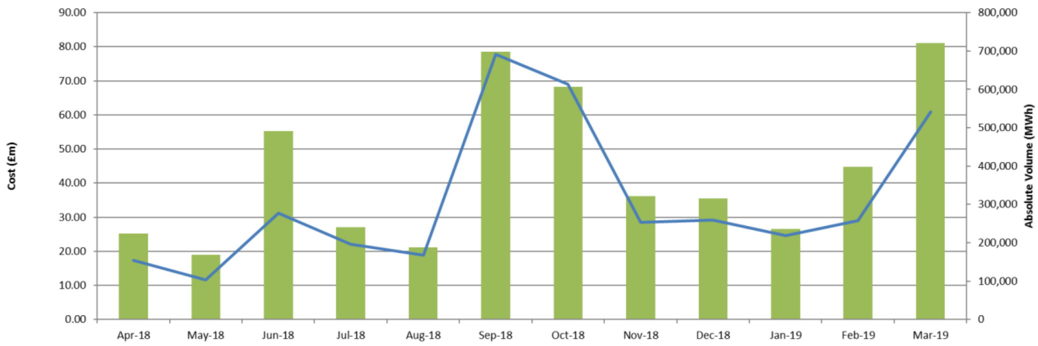
In 2021, as a result of the increase of wind power plants in the system and aiming to access new flexibility resources in these constrained boundaries, NESO held a project called *Constraints Management Pathfinder* (CMP). The CMP, recently renamed as *Constraint Management Intertrip Service Information* (CMIS)(NESO, 2024b). This project had the objective to contract post-fault and fast-acting services for system operating, for the following years, mainly during periods of restrictions on North-South interconnection lines. The requirements of these services are described below:

1. Total of 800 MW of generation connected to the transmission system;
2. Ability to shut down in 150 ms after fault occurring; and
3. Located in the power exporting region, in this case, Scotland.

This service will be payed for arming according to the quantity (MW) and period requested by NESO and also, for tripping in a single fee when total disconnected from the grid.

The requirement for additional flexibility service in system operation became first evident with the rise in operating costs in the Balancing Mechanism (BM). The BM is the British primary tool to balance energy supply and demand in real-time operation, additionally to the day-ahead generation dispatch every half-hour.

The prices in BM can be negative, which means in case of transmission restrictions, the operator pays them to reduce its power generation. Figure 10 shows the increase in BM costs for NESO in 2018 and 2019, reaching almost £80 million per month (NGESO, 2019a).



	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19
BM - Volume	223525	169041	490530	240083	188415	697941	606953	321460	315936	235331	398487	719805
BM - Costs	17.32	11.61	31.11	22.02	18.85	77.83	68.93	28.49	29.17	24.66	29.07	60.83

Figure 10: Monthly costs on Balancing Mechanism in 2018 and 2019 (NGESO, 2019a).

In March 2022, as a result of the CMP, NESO procured 1.7 GW of generation services. These energy amounts allow instantaneous shutdown of up to 800 MW to manage transmission restrictions and, as consequence, reduce renewable generation curtailment on that border and minimize operating costs. These additional flexibility products are estimated to save from consumers around £20 million to £40 million annually (NGESO, 2022a).

The call for additional flexibility services in the CMP was part of a larger NESO project called *5-Point Constraint Management Plan* (NGESO, 2021). The NESO made studies about transmission constraints caused by the increase of renewable energy and analyzed several solutions such as energy storage systems, improvements in BM costs' predictions, development of local specific market to manage restrictions on the Anglo-Scottish boundary and expansion of transmission network capability.

According to (NGESO, 2022c), energy storage systems used exclusively for constraint management are not an economical flexibility mechanism for the system operator. The use of battery for the exclusive purpose of solve transmission restrictions results in a usage time of around 23%, which causes higher costs than the costs related to restrictions. Furthermore, the region of transmission lines limitations are not ideal locations for battery installations, because these same restrictions limit the services provided from storage system. Therefore, NESO decided not to hold specific auctions for this technology and purposes, considering that there are no benefits to the operation costs, however, it will keep its participation in neutral technology contracts open for decision-making and business studies by interested parties.

The development of a local market to manage specific restrictions on the Anglo-Scottish boundary is called the *Local Constraint Market* (LCM) and its main objective is to reduce the annual costs of the border restrictions (NGESO, 2022b). The particularity of this market is the use of Distribution Energy Resources (DER) to provide cheaper flexibility products, by reducing generation or increasing demand, independently the technology. The main characteristics of this project are defined as follow:

1. Participants must be connected to the distribution network below the

Anglo-Scottish boundary and must not be in the BM.

2. There is a 1MW minimum limit and participants will be aggregated by grid supply point and half-hourly metered.

3. Participants bid for maximum energy volumes and prices up to 6pm in day-ahead planning and up to 10am in intra-day operation.

4. Participants have one hour to accept or refuse a command from the operator until 9pm in day-ahead planning and until 1pm in intra-day.

5. Participation starts to provide flexibility services after 10 hours from acceptance in the day-ahead planning (at 7am), and in intra-day operation after 6 hours from operator's acceptance (at 7pm).

6. The volume of energy required by operator depends on the conditions of the transmission system and renewable generation.

7. The participant cannot have remote operation and control contracts with the Distributor.

8. Payment is a single quantity based on the bid and the power reduced or load delivered.

9. Visibility, possibility of review and control must be integrated by Distributor (ESO and DSO Coordination).

To illustrate the steps described in (NGESO, 2022b), Figure 11 shows a workflow diagram of this market in day-ahead planning and intra-day operation.

In 2023, LCM opened for tests with voluntary participants and the most contracted service was to turn up the demand (NGESO, 2024). In 2024, NESO contracted a third party platform to support the process.

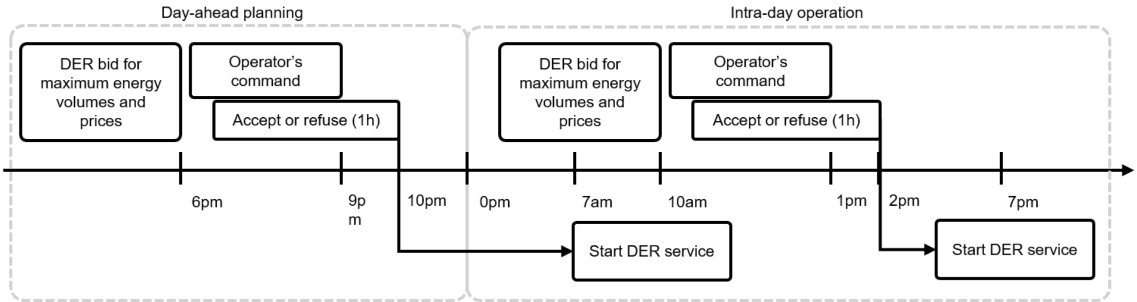


Figure 11: Day-ahead and intra-day workflow of local constraint market with Distributed Energy Resources (DER) in Great Britain (elaborated by author).

Finally, as additional measure, Great Britain has invested in significant international interconnections to avoid renewable curtailment as illustrated in Figure 12. According to (NG, 2022), without the ability to export excess energy via international interconnections, the renewable curtailment in Great Britain would be six times greater by 2030. To demonstrate this, the *Viking link* is the longest land and submarine interconnection line in the world. It is a High-voltage Direct Current (HVDC) transmission line with 765 km, which connects the United Kingdom to Denmark and began commercial operation on December 29, 2023 (NG, 2023). With an estimated capacity of 1.4 GW, it is predicted that Great Britain will import electricity from Denmark up to 60% of the time by 2030. And during export periods, it is predicted that more than 75% of Great Britain's demand will be supplied by renewable energy (NG, 2022).

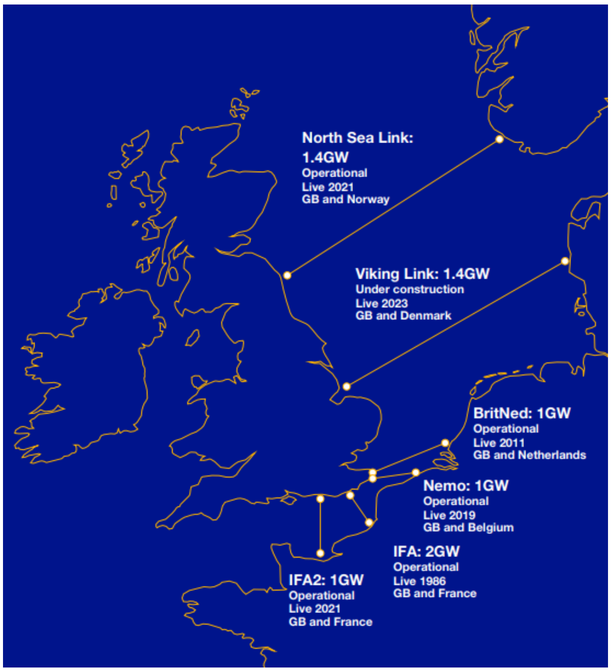


Figure 12: Examples of Great Britain's international subsea electricity international interconnectors and their maximum capacities (NG, 2022).

In conclusion, it is verified that Great Britain is taking several measures to reduce transmission lines congestions, that causes VRE curtailment. Since 2012, the renewable generation curtailment rate in Great Britain has remained below 4% even with more than 14% growth of renewable generation capacity (NG, 2022). As detailed previously, the implemented measures included new flexibility products for real-time operation, new local markets and new transmission system expansions through cross-border interconnection lines.

2.1.3 Germany

As reported by (ENTSO-E, 2023), Germany and Spain will be the European countries most affected by energy curtailments in 2030 due to their energy mixes with high share of VRE and in case transmission network investments are not made or additional flexibility products are not implemented during the following years.

Germany has four Transmission system operators (TSO), as shown in Figure 13. Amprion operates the Western network, TenneT is responsible for the North, Central and Southeast systems where Munich is located. The 50Hertz system operator coordinates the Northeast grid where Berlin is located, and finally, TransnetBW operates the Southwest region.

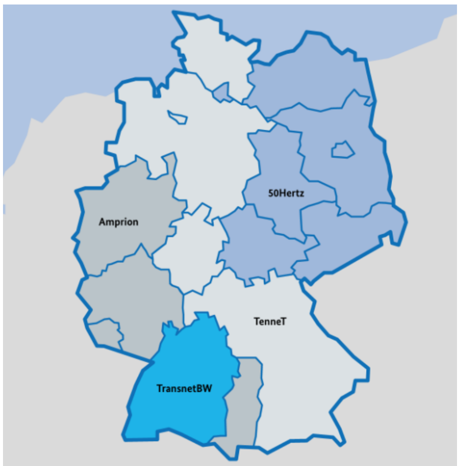


Figure 13: German electricity network control areas and TSO (BNETZA, 2023c).

The highest rates of generation curtailment are observed mainly due to the power flow from the North region, where wind farms are concentrated, to the South where large industrial centers and Munich are located (BNETZA, 2021b). Figure 14 presents the increase of generation curtailment in Germany from 2011 to 2020 by source. It can be observed that power restrictions are mainly occurred to intermittent renewable sources, such as onshore wind energy. According to (BNETZA, 2022a) and (BNETZA, 2022b), the total volume of renewable energy curtailment in 2021 was 5,818 GWh, a lower rate than 2020, likely as a result of the transmission system expansion, and increased again to 8,063 GWh in 2022, which is equivalent to 3.3% of total annual estimated renewable generation.

The recent growth in renewable energy curtailment can be attributed to both the increase of wind power capacity and specific policy reasons. The reduction of nuclear generation in France and Germany in the Southern part of the country has led to an increase in the use of North-South interconnection transmission line, and several storms and strong winds in early 2022 have resulted in an increase of wind generation, and as consequence, wind overgeneration (BNETZA, 2022b). Finally, the escalation in renewable curtailment after 2021 may also be associated with the implementation of the *Redispatch 2.0* program, detailed below.

In Germany, there is no day-ahead or intra-day markets for generators to participate in redispatch process, which means it is a cost-based definition rather than a market-based design. According to the German Federal Ministry for Economic Affairs and Energy (BMWK, 2017), a redispatch market could have distorted effects on operating costs, as power plants closer to a transmission congestion can take advantage of their greater influence and demand higher prices than other power plants located further away from the system constraint. Therefore, the EU Electricity Market Regulation determines exceptions to permit cost-based redispatch. These cases include when there is insufficient competition and easily foreseeable transmission congestion that could lead to a strategic congestion-worsening behavior by market participants (BMWK, 2019)(PARLIAMENT; COUNCIL, 2019b). Figure 15 presents the results of a study (HIRTH; SCHLECHT; TERSTEEGEN, 2019), commissioned by the

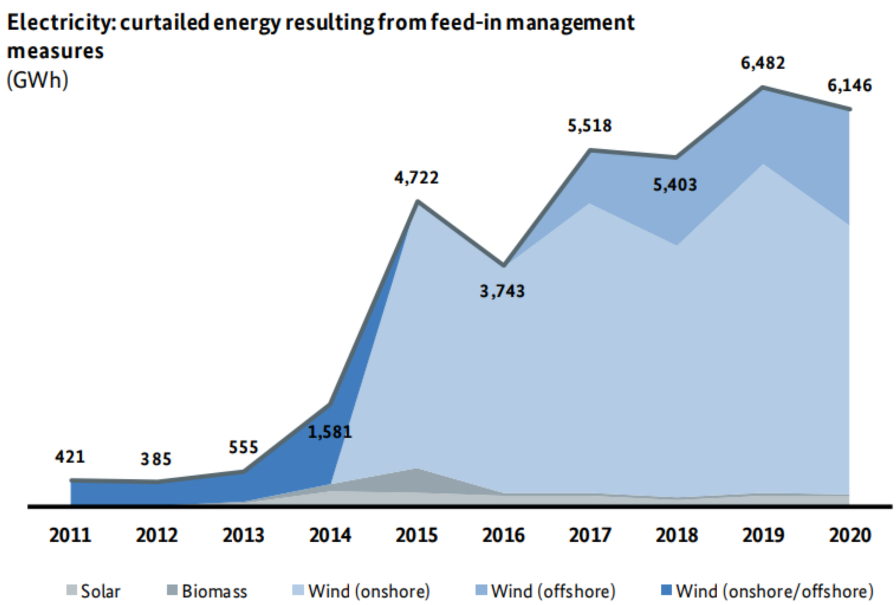


Figure 14: Renewable curtailed energy amounts in German (BNETZA, 2021b).

German government, that simulated redispatches in German electricity system in 2030, considering cost and price mechanisms. An increase of up to three times in the amount of restrictions (MW) and four times in the operating cost (€) was observed in the case of price or market mechanisms compared to the use of cost mechanisms.

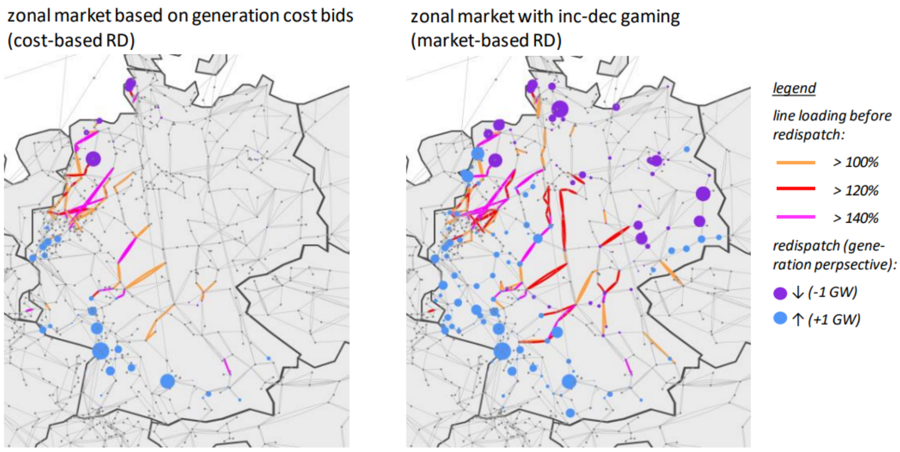


Figure 15: Restricted transmission lines in German grid and generation redispatch in cost-based and market-based simulations (HIRTH; SCHLECHT; TERSTEEGEN, 2019).

The Program *Redispatch 2.0* was launched in 2020 by the German Energy Regulator and was implemented in October 2021 (BNETZA, 2021a). In this program, all generators, including energy storage systems, above 100 kW must participate in the redispatch process when requested by system operators. TSO must use optimization algorithms to make redispatching decisions such as penalty costs and the following criteria:

1. Renewable energy curtailment can only be carried out if its reduction cost is 10 times lower than the conventional generation reduction cost; and

2. High-efficiency cogeneration power curtailment should only be carried out if its reduction cost is 5 times lower than power curtailment from standard cogeneration plants.

The average generation curtailment prices for priority and non-priority energy sources are defined by the TSO in accordance with the Regulator's guidelines, considering several parameters such as savings in Carbon Dioxide (CO_2) emitted, fuel prices, impacts on consumer tariffs, costs of activating other plants, costs for exporting and importing energy and even contractual aspects. These prices are published annually on the Energy German Regulator website, at least one month before implementation by the operator. As stated by (BNETZA, 2021a), the published curtailment prices are not exactly reproducible and do not determine which power plants will be curtailed; however, they provide sufficient information and transparency for the redispatch process without disclosing sensitive commercial data.

Additionally, in order to better signal the locations where there is a greater risk of generation curtailment due to network restrictions, in April 2024, the Federal Network Agency (*Bundesnetzagentur*) conducted a public consultation to discuss the distribution of additional costs in electricity grids due to renewable energy connections (BNETZA, 2023b). In August 2024, the conclusion was published, which entitles grid operators to receive financial compensation due to high penetration of renewable energy generation into the network. The compensation criterion follows a *Renewable Energy Index* or *Erneuerbaren-Energien-Kennzahl* (EKZ) in German, which calculates the relation between maximum generation and maximum load at each substation. Based on this provision, the operator can charge the renewable energy producer *grid fees* taking into account their impact on the connected network (BNETZA, 2024).

Figure 16 shows the growing gap between grid expansion fees in Germany over the years 2015 to 2023 for the commercial user (*Gewerbekunde*), especially in the Northern region where most of the wind farms are located.

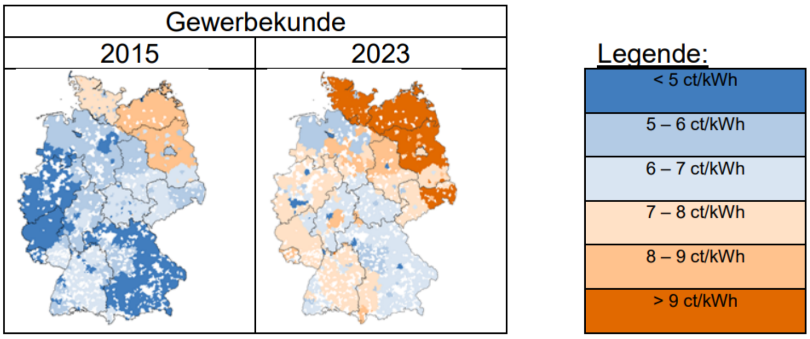


Figure 16: Energy transition-related grid expansion costs for the commercial user (BNETZA, 2023a).

Moreover, the regulator published a report with reference to the German Network Development Plan 2035 with the following actions in the transmission system to reduce system congestion and renewable generation curtailment (BNETZA, 2023d):

1. expansion of 28 transmission lines;

2. construction of two additional corridors for High-Voltage Direct Current (HVDC) transmission lines (namely Schleswig-Holstein to Mecklenburg-Vorpommern and Lower Saxony to Hesse);

3. implementation of moderns tools in transmission system, such as dynamic monitoring of overhead lines that allow increase of the carrying capacity of line conductors depending on the weather (Dynamic Line Rating - DLR);

4. implementation of additional phase-shifting transformers that can influence power flows by changing voltage angles and reduce redispatch and remote generation control (Feed-in Management mechanism);

5. implementation of reactive network management, which involves actions that can be quickly activated in the event of a line outage to counteract potential overloads; and

6. implementation of multi-terminal converters for High-Voltage Direct Current (HVDC) transmission system, instead of individual point-to-point converters, integrated with metallic return conductor to reduce unavailability. In the event of a fault, half of the transmission capacity remains available in the DC system.

Furthermore to these measures to increase the flexibility and capacity of the transmission network, investments are also planned for optimization, reinforcement, and expansion of distribution networks, including increasing cable cross sections and capacity of transformers, installation of metering technology and voltage regulators, changes in network topology and constructions of parallel systems (BNETZA, 2021b).

Therefore, it is expected that these several measures in the German electricity grid enhance the flexibility, controllability and resiliency of the system, in order to allow greater power flow of wind and solar generation, and thus, reduce the transmission congestions and renewable curtailment rates.

2.1.4 Spain

The Spanish electrical system is operated by the TSO called *Red Eléctrica de España* (REE). Spain's energy matrix has already reached its sustainable goal of 68% renewable energy of the total installed generation capacity, including 19% of solar PV, 32% of wind, 16% hydro and 1% of others renewable energy sources. Furthermore, in 2022, the renewable generation curtailment was around 3,600 GWh/year, being 2.4% of the total renewable energy generation (REE, 2022).

System connection requests in locations with transmission restrictions on the grid must contract a flexible connection agreement that does not guarantee a firm energy supply. After the power plant starts operation, the distribution of the generation curtail occurs in two ancillary services markets, during day-ahead planning and during real-time operation (CEER, 2022).

In the day-ahead process, based on the prediction of wind and photovoltaic generation, load forecast and scheduled maintenance, the TSO executes the system's security analysis and allocates power curtailment, if necessary, to avoid transmission congestion or line overloading. The criterion for selecting the candidate plants to curtail is the maximum contribution to solving the technical restriction, namely the power plant's sensibility. In this step, there is no offers from generators and no financial compensation to the energy curtailment (AURORA, 2023). In case the power plants' sensibility are the same, a curtailment distribution proportional (*Pro-rata* criteria) to the power plant scheduled generation is carried out considering the following priority (HUCLIN et al., 2022):

1. Dispatchable conventional power plants (thermal);
2. Dispatchable renewable power plants (with more than 5 MW of installed capacity); and
3. Non-dispatchable renewable and thermal cogeneration power plants, de-prioritizing those with better safety and quality conditions for the system such as voltage control resources.

After the security criteria have been satisfied, the generation-load balance is analyzed. If a new power redispatch is necessary, the TSO allocates the restrictions according to the cheapest bids given by the generators. In this process, all dispatched power plants, including renewable generators with installed capacity or aggregators above 1 MW, are required to bid a price to the TSO. In this stage, the energy curtailment are financially rewarded based on the generators' bid prices in the balancing services (MINTUR, 2015).

In real-time operation, the REE implemented a control and operation room exclusively dedicated to the renewable energy generation, called *Renewable Energy Control Center* (*Centro de Control de Energías Renovables* - CECRE, in Spanish). This operation room has the objective to be a worldwide reference in the operation and remote control of variable energy generation above 5 MW and in the observability of renewable plants above 1 MW (REE, 2025).

Regarding generation redispatch, in the intra-day ancillary service market, the TSO can use generator's bids to restrict generation based on the lowest cost criteria, for electrical and energetic reasons.

As an incentive for technological improvement, generators with *automatic disconnection* mechanism are de-prioritized by TSO to energy curtailment. This mechanism allows the TSO to remotely control the power plant's generation in real time. It is used by most thermal power plants, at their own risk of not being constrained-off on the following day (CEER, 2022).

To illustrate the steps described in (MINTUR, 2015), Figure 17 shows a workflow diagram of the redispatch markets in day-ahead planning and real-time operation.

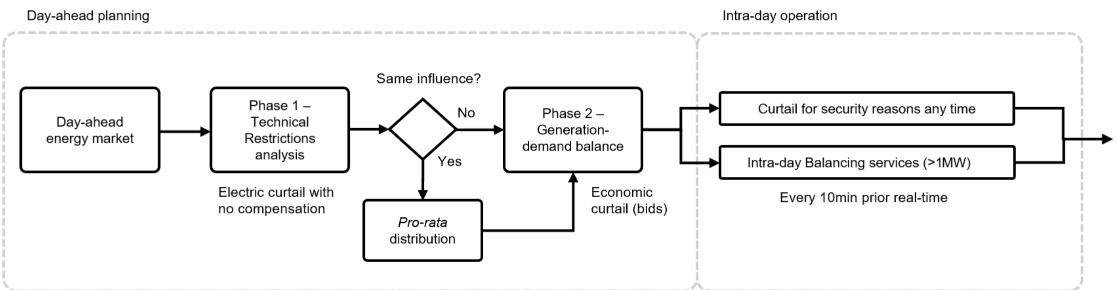


Figure 17: Day-ahead and intra-day workflows of restriction and balance markets in Spain (elaborated by author), based on (MINTUR, 2015).

Finally, as indicated by the Spanish transmission network development plan (REE, 2022), the TSO is investing in the modernization of the existing transmission system in order to increase the flexibility of the system and minimize renewable generation curtailment. Transmission modernization contributes to a system with more information and control and replace reinforcements or system expansion which are more expensive. The upgrades alternatives are described below:

1. Dynamic Line Rating (DLR) or Real-Time Thermal Rating (RTTR) in around 200 lines until 2026. This solution estimates the capacity of the transmission line in real time based on weather conditions, conductor temperature or line deflection identified, transmitted and calculated by sensors, telecommunications and processing data;

2. Flexible Alternating Current Transmission System (FACTS) which is a power control equipment according to power electronics;

3. Phase Shifters, which are transformers that can modify the energy flows that circulate through them;

4. Synchronous condensers, which, unlike synchronous generators, do not inject active power into the network and contribute to increasing the system's inertia and continuous voltage control; and

5. Energy storage systems, including batteries and Pumped Storage Hydro (PSH) units (HUCLIN et al., 2022).

These new elements for the system were indicated in the mid-term planning based on a cost analysis, comparing the renewable energy curtailment that could be avoided and, hence, the minimization of energy from conventional plants. In addition to the cost analysis, the REE network planning (REE, 2022) also considered energy public policies, security of supply, economic sustainability, environmental commitment and strength of international interconnections for renewable energy integration, including interconnections to Portugal, through French border, and to North Africa (REE, 2023).

2.1.5

Portugal

Portugal's electricity grid is presented in Figure 18 and it is operated by a single Independent system operator (ISO) called *Rede Elétrica Nacional* (REN), which acts as Global Manager of the National Electricity System, or *Gestor Global do Sistema Elétrico Nacional, GGS* in Portuguese. The GGS is regulated by the Portugal's Energy Services Regulatory Authority (ERSE) and the normative procedures of the system operation is detailed in the Network Operation Regulation (ROR), the Network Access and Interconnections Regulation (RARI) and the Commercial Relations Regulation (RRC) (ERSE, 2023b)(ERSE, 2024a).

Figure 18: Portugal's electrical transmission grid (REN, 2024).

In Portugal, the renewable curtailment rates are considerably low compared to the high penetration of renewable generation with over 20% of its energy matrix. In 2020, the renewable curtailment rate was nearly 0.3% (YASUDA et al., 2022) and 0.4% in 2023 (CASTRO, 2024), even with 50% of electricity volume coming from green sources (REN, 2024). These low metrics were a consequence of a set of measures implemented in the system (YASUDA et al., 2022), such as:

1. Dynamic Line Rating (DLR);
2. Implementation of Pumped Storage Hydro (PSH) units;
3. Expansion, modernization of the electricity grid, based on investments of more than €3 bi (REN, 2024); and
4. Increase of international interconnections.

Additionally, in the connection process, the system operator verify different forecast scenarios regarding the availability of renewable generation and the related connection costs, the firm energy capacity which is the equivalent to the guaranteed power injection during the year and, if necessary, the possibility of renewable curtailment. In 2023, the ERSE established that the restrictions indicated in the Connection Agreements must be detailed by the operator including probability of occurrence, duration, dimension and the estimated date for updating this information (ERSE, 2023a). These connection agreements are temporary until the constraints are resolved and in the meantime, generators with more than 1 MW of installed capacity and with restricted Grid Connection Study are required to participate in the Technical Constraints Resolution Market to provide services and flexibility to the system operation (ERSE, 2024a).

In the day-ahead planning, the generator reports the renewable generation forecast and the operator performs the day-ahead dispatch scheduling based on the information and results of the Day-Ahead Market and bilateral contracts. In case there are system restrictions, in day-ahead and intra-day operation, the operator uses the Technical Restrictions Resolution Markets to obtain capacity products that were offered and defined by the operator annually. In this regard, the operator prioritizes maximizing renewable generation, but the main criterion is network security, followed by the lowest price and, finally, electrical distance. If there are equivalent situations in these requirements, the operator uses the *Last-in First-out* criterion to prioritize the curtail until its maximum restricted generation, i.e. the last generator connected to the grid with similar influence in solving the network restriction or overgeneration has priority in power curtailment (ERSE, 2023b).

Finally, in real-time operation, the generator that does not comply with the operator's limitation commands may have its connection contract suspended for up to six months or more (ERSE, 2025). As a last resource to maintain network security, the operator has the possibility, without financial compensation to the generator, to control the power of plants greater than 1 MW of installed capacity that do not participate in the Balance and Restrictions Markets. Furthermore, the activation of this order must be justified and equitable in the distribution network security (ERSE, 2024b).

2.2 United States

The United States (US) has 10 transmission systems operated by several ISO and Regional Transmission operators (RTO) as shown in Figure 19. The systems include California Independent system operator (CAISO), Midcontinent Independent system operator (MISO), ISO New England (ISO-NE), New York ISO (NYISO), Northwest area which includes the Northwest Power Pool (NWPP), the Rocky Mountain Power Area (RMPA) and the Western Electricity Coordinating Council (WECC), Pennsylvania, Jersey, Maryland Interconnection (PJM), Southeast area that consists of Florida Reliability Coordinating Council (FRCC) and Southeastern Electric Reliability Council (SERC), Southwest network and energy market as part of WECC, Southwest Power Pool (SPP) and finally, Electric Reliability Council of Texas (ERCOT) as an isolated electrical system located in Texas (FERC, 2022).

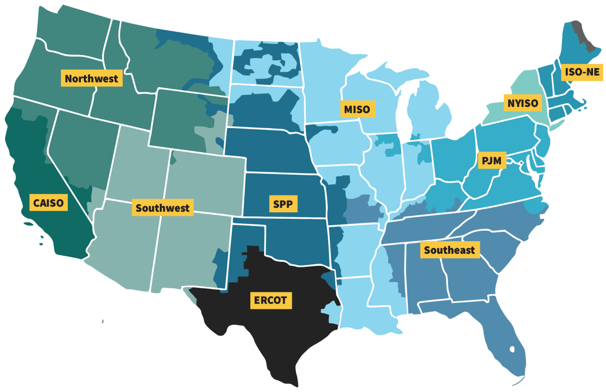


Figure 19: United States' systems operated by ISO and RTO (FERC, 2022).

The system operated by RTO typically covers more than one state and ISO covers mainly one state of US such as CAISO, NYISO and ISO-NE. ERCOT is the only system completely disconnected from the transmission systems of other US states and is not regulated exclusively by the Federal Energy Regulatory Commission (FERC), but directly by the North American Electric Reliability Corporation (NERC).

In relation to renewable curtailment numbers, Figure 20 presents the curtailed wind power rate and the percentage of wind power penetration in the system of seven RTO and ISO. Note that the presented wind penetration percentage is related to the load capacity of the system in the US. The curtailment percentage is calculated by the relation between the amount of renewable energy reduced and the total amount of renewable energy that could have been produced in case there were no restrictions.

ERCOT is the ISO with the highest annual wind generation curtailment rate during the period of 2007 and 2022, followed by SPP and MISO. These systems are located in the central region of the US, which is an area with the highest wind speed rates in the country, as shown in Figure 21. The high levels of wind speed result in greater wind power generation that may lead to curtailments due to energy oversupply specially during low demand periods. Nevertheless, as shown in Figure 20, these curtailment rates vary over the years for each system which emphasizes the broad range of variables and solutions applicable

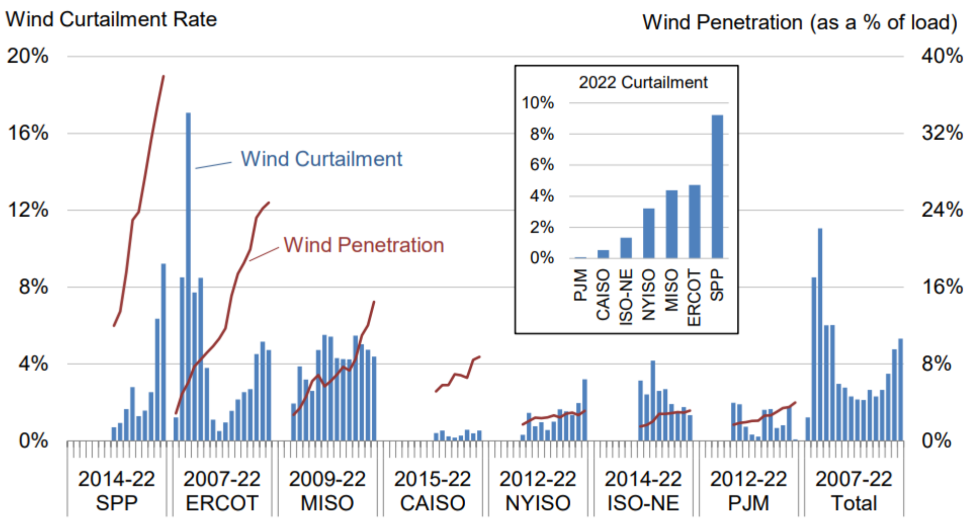


Figure 20: Wind curtailment and penetration rates (as % of load) in US electrical systems (DOE, 2023).

to dealing with the variable renewable expansion and curtailment.

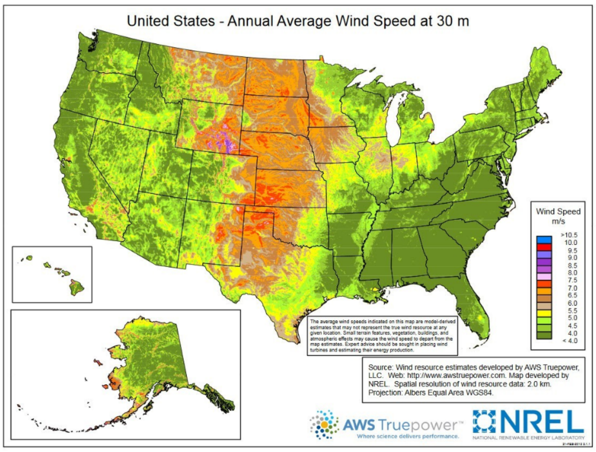


Figure 21: Annual average estimates of wind speed in United States (NREL, 2024b).

In relation to ESS, batteries can help to reduce renewable generation curtailment by storing surplus energy at periods with overgeneration. In US, until 2010, the vast majority of energy storage systems were related to PHS. After this period, short-duration batteries emerged to provide auxiliary services and recently, with the fall in the prices of lithium-ion batteries, large-scale storage systems have seen a surge in the US and worldwide (NREL, 2024a). The Figure 22 presents the installed capacity of battery projects that are in the queue for access the systems of US by state. By the end of 2024, the total power capacity of storage systems in the US was approximately 26 GW with an additional 20 GW expected to be added in 2025 (EIA, 2025).

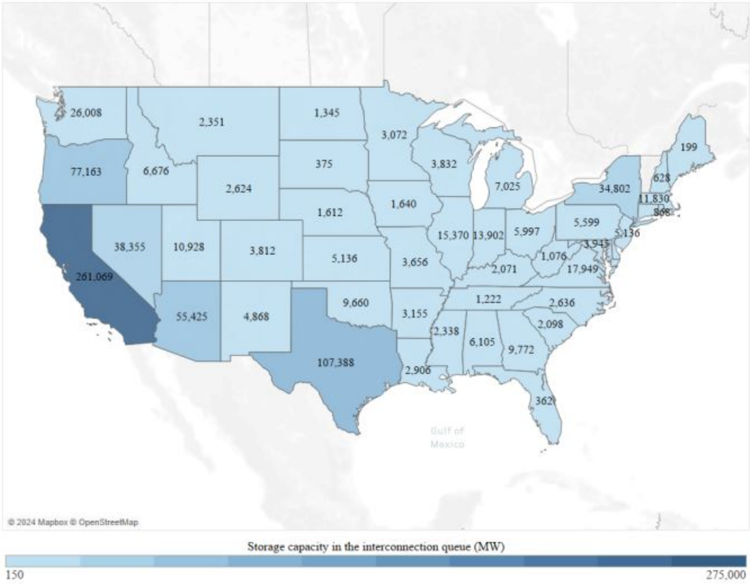


Figure 22: Storage power capacity (MW) in the interconnection queue by state in US (NREL, 2024a).

(NREL, 2017) presents a study that verifies the potential for reducing renewable curtailment using storage systems in the US. This study considered three scenarios regarding load supply by renewable generation, namely: *Wind Vision* with 44% wind and 11% PV, *Minimum curtailment* with 37% wind and 18% PV and *Equal mix* with 27.5 of wind and PV. Figure 23 shows the results of the study considering a storage system with a fixed duration of 4 hours and the different variable generation (VG) scenarios. It is possible to verify the reduction in generation curtailments as storage capacity increases.

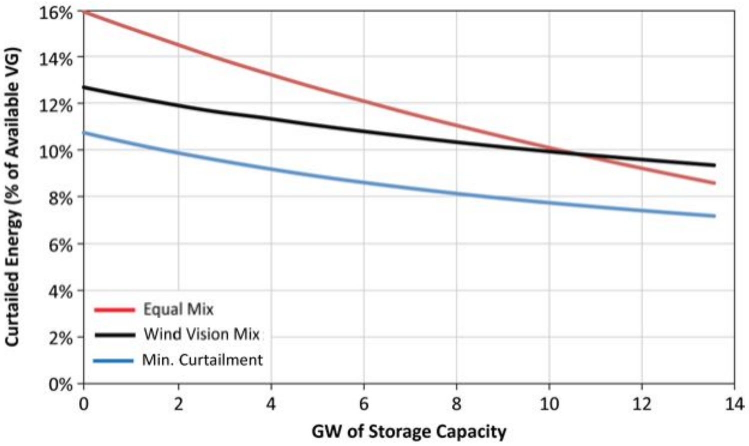


Figure 23: Variable renewable generation curtailment compared to storage capacity (NREL, 2017).

In addition to storage systems, the growth of renewable energy in the distribution grid and the complexity of dispatching these renewable resources to support system operation brings innovations for distributors. In this new scenario, the traditional roles of utilities changed from Distribution Network Operator (DNO) to Distribution System Operator (DSO). Currently, more than half of the states in US have market designs that enable the provision of flexibility services by DER to contribute to distribution and transmission systems as shown in Figure 24.

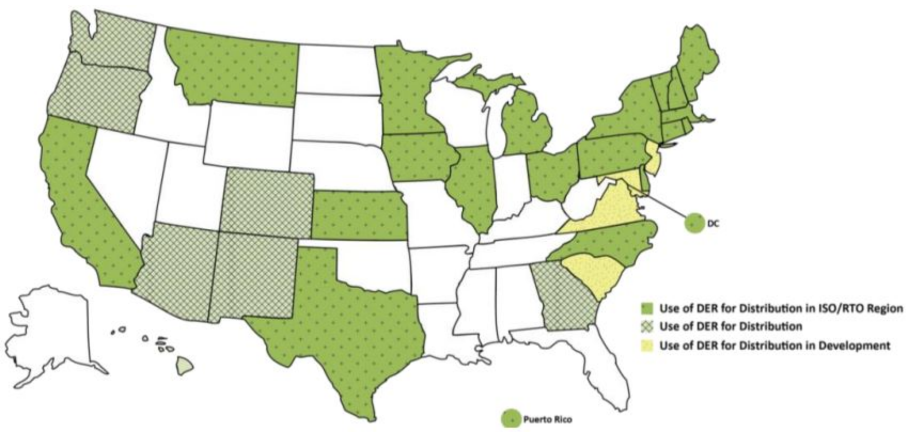


Figure 24: Distributed Energy Resources (DER) services in US states (DOE, 2024).

The use of DER in a coordinated manner between the DSO and the RTO/ISO in the US was regulated by (FERC, 2021). This regulation established the responsibility for operators to implement real-time coordination mechanisms throughout distribution and transmission systems and aggregators. To this end, the use of communication, control, measurement, telemetry data sharing systems and protocols for responding to the conditions of the DER and the systems are defined. In addition, the regulation also guides the establishment of financial compensation for the aggregators and the guarantee that there is no double remuneration for the service provided by the DER. Figure XX presents different conceptual models for implementing the DSO-TSO coordination. In practice, this relationship is much more complex and involves several actors and interfaces between processes, markets and operations, as detailed in (EAC, 2021).

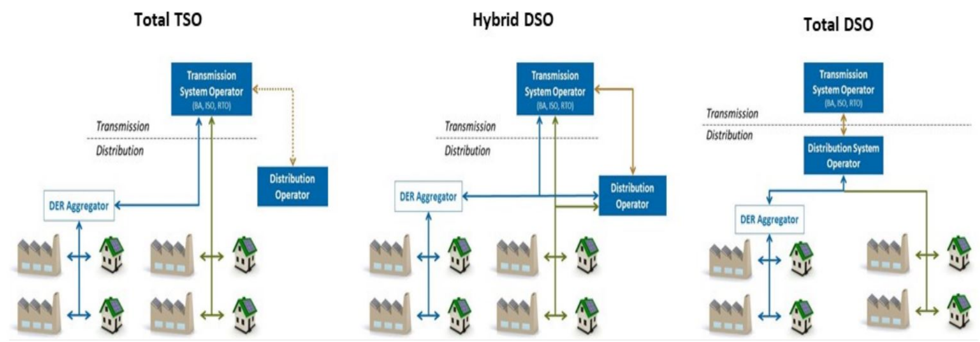


Figure 25: Conceptual illustration of DSO-TSO coordination models (EAC, 2021).

In addition to these resources, other measures are being implemented to deal with the growth of intermittent renewable generation and the increase in its curtailment in system operation. In the next subsections, the treatments given by ERCOT, SPP and MISO will be detailed, considering their highest curtailment rates over the last decade.

2.2.1
ERCOT

ERCOT energy system serves more than 23 million customers in Texas in US and it has specific characteristics in relation to other North American regional systems. It is not regulated by FERC and does not have synchronous connections with other electrical systems. Therefore, ERCOT relies exclusively on its internal resources to balance the load with variations in intermittency renewable generation (DU et al., 2020).

To operate the system, ERCOT uses Security-Constrained Economic Dispatch (SCED) markets. The dispatch is discretized every 15 minutes in day-ahead and every 5 minutes in real-time operation considering the lowest cost while ensuring grid reliability within the safe limits of the transmission system (DU et al., 2020).

In 2022, ERCOT's wind generation represented 24% of total US wind generation with 37.5 GW of installed capacity, and ERCOT solar generation represented 15% of total US solar generation with 16.5 GW of installed capacity (EIA, 2023).

Regarding annually renewable curtailment rates, ERCOT achieved 5% for wind energy and 9% for solar energy source in 2022 (EIA, 2023). In prospective studies for 2035, these renewable curtail indicators are predicted to increase up to 16% and 26% for wind and solar energy, in case significant investments are not made in the transmission network. In case a battery storage system of 30 GW is considered, power curtailment in 2035 are projected to be 13% for wind and 19% for solar energy sources respectively. The majority of these restrictions, around 64%, is predicted to come from oversupply of renewable energy in periods of low demand (EIA, 2023).

As shown in Figure 20, ERCOT achieved the highest U.S. renewable generation curtailment rate of 17% in 2009. However, these numbers dropped dramatically in the following years, reaching 1% in 2013 and 2015. These significant changes over a period of more than ten years are due to several changes in the operation of the ERCOT system and in the configurations of the energy market, such as:

1. In December 2009, renewable energy generators' ramp rate requirement changed from 10% of nominal power plant capacity per minute to 20%

per minute (ERCOT, 2017)(EIA, 2023).

2. In December 2010, ERCOT transitioned from the zonal market with 5 zones to a nodal market with more than 4,000 load and resources nodes, resulting in a more efficient generation dispatch and less transmission system congestions (EIA, 2023).

3. Government subsidies, such as Renewable Energy Credits (REC) for wind and solar generators, have brought distortions to the ERCOT's balancing-energy market. Given these incentives, generators continued to produce energy even with negative energy prices (NREL, 2010). The end of renewable subsidies in the US has seen several deadline extensions, but since 2020 they have been gradually reduced, especially for wind energy (FILHO; DWIVEDI, 2018).

Furthermore, in recent years, ERCOT invested in improving the renewable generation forecasts; improving the performance of measuring equipment for variable renewable power plants; defined new methodologies for ancillary regulation services based on the historical variability of wind and solar resources; established new requirements for intermittent renewable generators as voltage support service for plants with installed capacity greater than 20 MW (ERCOT, 2017), and invested in transmission expansion with more than $6.8 billions as part of a initiative called *Competitive Renewable Energy Zone* (CREZ). This initiative identified regions with high potential for wind power generation and anticipated expansions and reinforcements in the local transmission system (NREL, 2014).

Despite significant reductions in generation curtailment rates since 2007, the rapid expansion of intermittent renewable energy in the ERCOT system to date continues to be a challenge for the operator when compared to the growth of more flexibility resources for the system, and as a result, curtailment rates have begun to increase slowly from 1% in 2013 and 2015 to 5% in 2020 and

2021.

In medium-term planning studies, throughout the estimated generation curtailment in 2035, illustrated by month and curtail reason in Figure 26, it is observed an increase in wind generation restrictions from February to April. During this period, the demand is lower due to milder temperatures and wind generation levels are higher. As a result, the generation curtailments increase and are mostly due to energy oversupply. As summer begins in June, July and August, energy demand increases due to high temperatures and the transmission system is unable to flow all available wind and solar generation, which causes lower curtailment rates mainly caused by transmission system congestions.

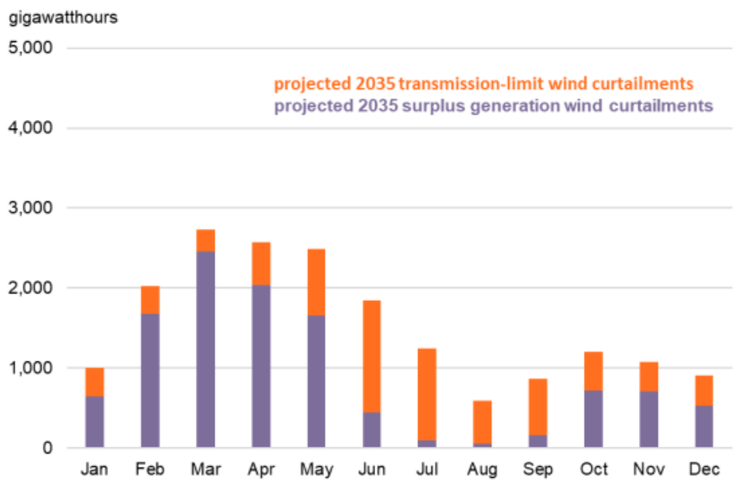


Figure 26: Projected 2035 wind curtailments monthly in ERCOT system (EIA, 2023).

In Figure 27, a summer day in June 2035 is shown comparing the wind curtailment and hourly energy prices. Oversupply restrictions begin at 9 am and last until 1 pm due to increase of wind generation and low demand. During this period, the zonal and system energy prices are equally zero. After 2 pm, generation curtailments are reduced and are caused by transmission system restrictions. During this period, as load begins to increase, wind generation connected in the South region of the system struggles to flow through the transmission lines to meet load centers in the North of Texas. Hence, the zonal price remains low because there is more generation than demand in the South region. When the low price signal are not enough to reduce generation, the wind curtailment occurs and wide-system prices increase due the dispatch of more expensive power sources needed as consequence of transmission congestions (EIA, 2023).

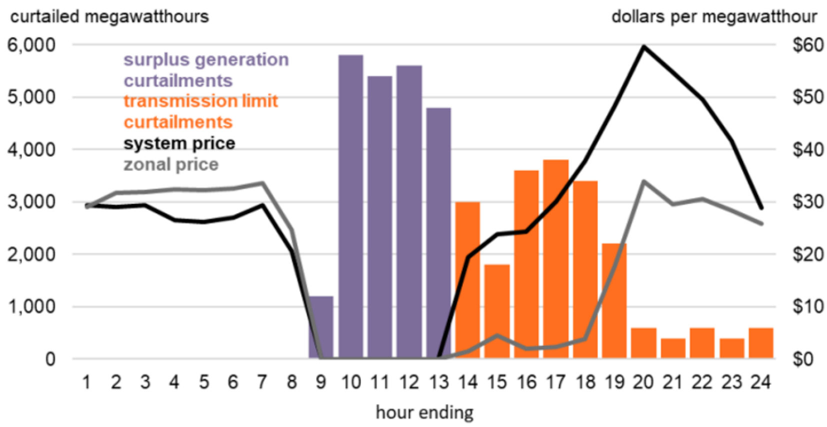


Figure 27: Projected June 2035 wind curtailments and energy prices hourly in south ERCOT region (EIA, 2023).

Detailing the reasons for power curtailment during the day and throughout the year is essential to understanding the behavior of these restrictions in the system and defining specific action plans to reduce them. Furthermore, energy market prices are a good measure for classifying the curtail reason and thus determining mechanisms to minimize the impact on operating costs.

2.2.2 SPP

SPP is an RTO located in the central US, covering 17 states, and is regulated by FERC to ensure energy supply to approximately 19 million consumers. In addition, it is responsible for maintaining a reliable transmission system and competitive prices in its integrated markets. Since 2014, SPP has a day-ahead and real-time energy markets, as well as operational reserves and transmission congestion management markets (SPP, 2023).

In 2023, SPP had more than 30 GW of wind generation installed capacity and 9 GW of solar installed capacity, which corresponds to 37% and less than 1% of the energy matrix in the region, respectively. In recent years, the grid connection queue increased considerably with a total of 135 GW of proposed power plants projects. From these access requests, more than 80% corresponds to wind plants, solar plants and storage systems, and others refer to hybrid systems and gas power plants (MMU, 2024).

From 2020 to 2022, average hourly wind generation curtailment increased substantially from 244 MW to 1.3 GW, a five-fold growth in 3 years (MMU, 2023). According to Figure 20, total wind generation restrictions in 2021 reached more than 6% and, in 2022 (NBER, 2023), this rate rose to more than 10%. In 2023, the reduction rate began to decrease mainly due to transmission expansion and lower wind generation (MMU, 2024).

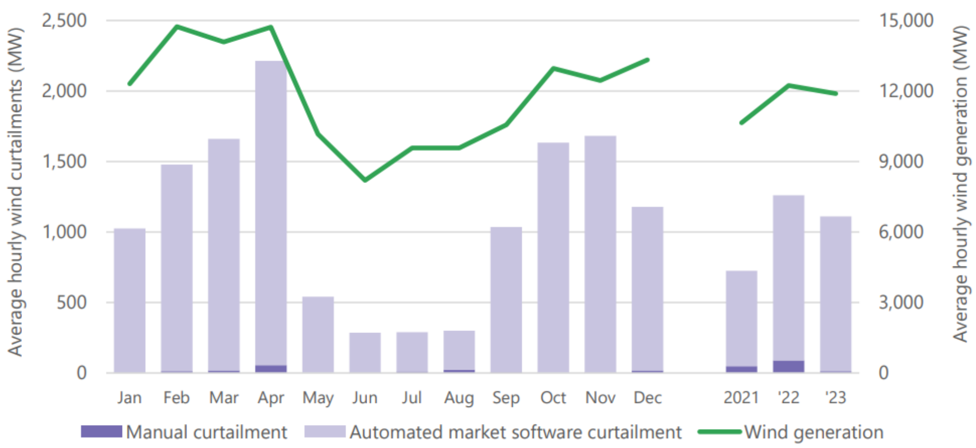


Figure 28: Average hourly curtailments for wind resources (MMU, 2024).

During 2020 and 2022, the substantial increase in generation curtailments was associated with the following factors (MMU, 2023):

1. Growth in wind generation compared to transmission system expansion;
2. Wind generation curve not compatible with load curve, where periods of higher wind generation generally occurs in periods with low loads when renewable generation competes with inflexible thermal plants; and

3. Change of classification of VRE sources from non-dispatchable plants to dispatchable plants by operator.

In 2021, the change in dispatchability classification of VRE plants included power plants with more than 10 MW of installed capacity and for all power plants with more than 10 years of commercial operation. This proposal was approved by FERC and did not included run-of-river hydroelectric plants (FERC, 2020a). According to SPP reports (MMU, 2023)(MMU, 2024), in 2014 only 27% of the total installed capacity of wind farms was dispatched and this value has increased to 97% in 2023. Figure 29 presents the dispatchable and non-dispatchable wind generation by month in 2023.

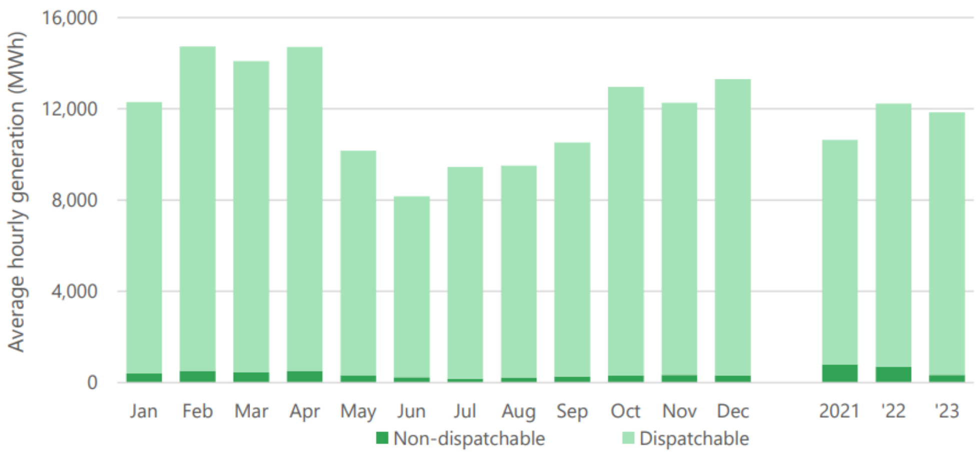


Figure 29: Dispatchability of wind power plants in 2023 (MMU, 2024).

The power plant's dispatch classifications have different responsibilities in real-time curtailment process. Dispatchable sources are included in the *Automated Curtailments* which are performed before *Manual Curtailments*. Automated curtailments were implemented in 2013 to automate and shorten the duration of generation restrictions and are based on pricing signals in real-time markets to mainly mitigate transmission congestion (MMU, 2023).

The non-dispatchable sources are only enabled for manual curtailment and they are used by operator as last resource when there are reliability issues that cannot be addressed by market-driven curtailments. The manual curtailment has the obligation of three verbal communications between the parties (NREL, 2014). In these situations, the SPP issue an *Out-Of-Merit Energy* (OOME) instruction for all non-dispatchable generators that contributed to at least 5% to the system constraint indicating the market has not sufficient resources or incentives to solve the transmission congestion. Then, the total curtailed energy is divided equally among all generators involved (NREL, 2014)(MMU, 2023).

As a final point, it is worth mentioning that the dispatchability reclassification brought a lot of pressure and resistance from renewable generators, arguing the high cost and the impossibility of being dispatchable due to the communication infrastructure. Hence, SPP needed to be transparent, primarily using connection studies to clarify new requirements for intermittent renewable generators. Other communication measures were implemented as publication reports and detailed data about generation curtailment, including their causes and methodologies (GLOBAL, 2019).

2.2.3
MISO

MISO is an RTO that operates the transmission system and electricity market of 15 states in US and the Canadian province of Manitoba, with a total of approximately 45 million consumers (MISO, 2023).

MISO operates competitive wholesale markets, including products related to energy, Financial Transmission Rights (FTR), ancillary services and system capacity. MISO uses a co-optimized SCED algorithm every hour for the day-ahead market and every 5 minutes with 10 minutes in advance for real-time energy market. Linear programming algorithms determine the quantities of energy and reserves for each resource. Additionally, MISO also has an *ex-post* calculator that runs a SCED algorithm to set *ex-post* prices every 5 minutes with real-time data (MISO, 2022a).

MISO's energy matrix is mainly formed by natural gas thermal power plants with a share of 42%, followed by coal thermal plants with 25%, wind plants with 16% and an installed capacity of 21 GW, nuclear plants with 7%, hydroelectric and solar power plants with 4% each energy and others, including diesel, biomass, storage and demand response resources, with a share of 2% (MISO, 2024). By 2041, MISO projects that wind and solar energy will meet 60% of MISO's annual energy consumption (MISO, 2022b).

As shown in Figure 20 in section 2.2, MISO had a 4.7% wind curtail rate in 2021, with a wind generation share of 12% and, in 2022, the curtailment rate was reduced to 4.4% with wind power penetration increase to 14.5%.

The report (IMM, 2023) highlights causes that impact the wind curtailment rate, such as errors in forecasts sent by generators and failure to comply with operator commands in real time. In MISO, the renewable forecasts are provided by the generators in the day-ahead planning and its dispatch is defined by MISO also considering the offer prices, which is usually very low and less decisive compared to the forecast. It been verified that generators usually under-scheduled wind generation in the day-ahead due to penalties for over-scheduling. The day-ahead under-scheduled wind output is on average 1.2 GW lower compared to the real-time generation. Additionally, in real-time operation, it was verified that wind generators do not followed scheduled dispatch, leading to serious problems of transmission violations and causing out-of-market actions. As a result, MISO is exploring new penalties and market reforms to encourage generators to delivery more realistic dispatches and follow real-time commands (IMM, 2023).

Figure 30 shows an example of a wind power plant that was requested to be curtailed during 6pm to 9h15pm but did not comply with the economic incentive of zero or negative Local Marginal Price (LMP) in MISO's real-

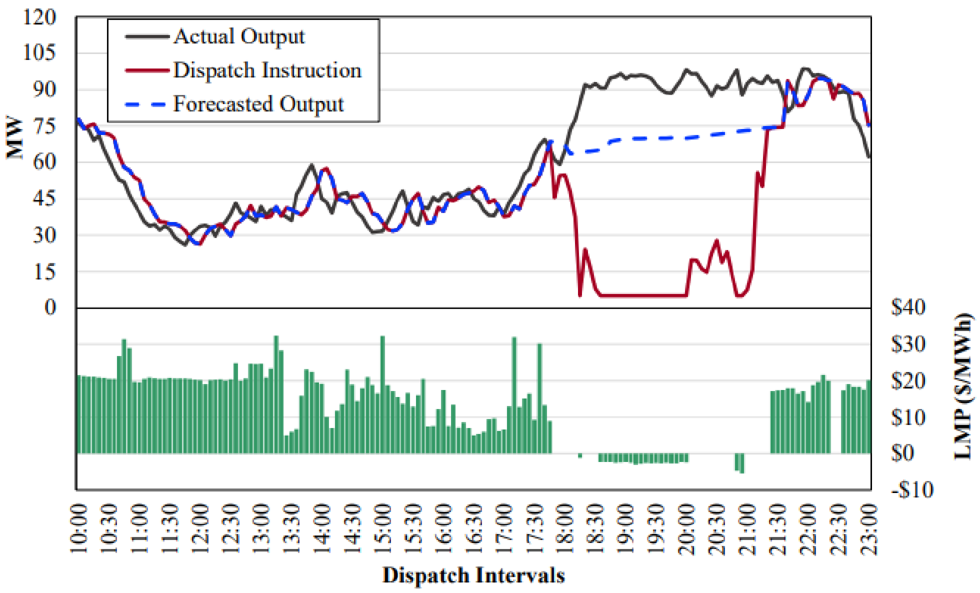


Figure 30: Example of a wind plant that not followed real-time dispatch instructions in MISO system (IMM, 2023).

time market. In this case, the transmission congestions became more serious because the generation of this unit increased the flow and violated the limit for the constraint by 9%.

According to (IMM, 2023), wind generation in 2022 contributed about 44% of the real-time transmission system congestions, specially in Midwest region where the vast majority of the wind power plants are located. These restrictions were around 726 MW per hour and reached a maximum value of 5.9 GW. These curtails led to a 30% increase in real-time prices. These costs caused by transmission congestions occurs when a higher-cost energy resource is dispatched, instead of a lower-cost resource, to avoid overloading transmission restrictions.

To deal with the challenges of the variable renewable energy power plants, MISO implemented several actions, such as:

1. Creation of registration for *Dispatchable Intermittent Resource* (DIR) to include wind and solar resources in real-time market, in other words, allows then to be dispatchable based on economic incentives;

2. Creation of a ramp product to increase system flexibility; and

3. Wind generation forecast improvements.

The DIR registration has been essential to manage congestion caused by variable renewable generation. DIR were first implemented by MISO for wind farms in 2011. Power plants registered as DIR are required to deploy additional measurement, communication and control equipments to respond to automatic real-time security constrained economic dispatch signals and can submit offers to operators based on economical signals. For power plants that are not registered as DIR, the curtailment is carried out manually and therefore they do not participate in the real-time market. In 2019, MISO requested the inclusion of solar sources in the DIR registration and FERC approved, despite arguments from solar generators, and it was implemented a transition period of 2 years until 2022, when all solar plants became dispatchable (FERC, 2020b)(IMM, 2023).

In 2023, additionally to the implemented measures, the Independent Market Monitor (IMM) recommended new actions to help MISO better manage congestions caused by intermittent energy resources (IMM, 2023), as described below:

1. Implement DLR, where transmission owners can adjust the capacity of transmission lines according to ambient temperatures or temporarily after a contingency (*emergency ratings*);

2. Implement *Economic Transmission Reconfiguration* in real-time operation which open circuits rather than altering generation output to manage system congestion, when network security is not affected;

3. Define and contract *uncertainty products* to reward the flexible resources that can meet the real-time needs when conditions are uncertain or unpredictable, during a proposal period of four hours;

4. Integrate DER to satisfy reliability and efficiency objectives of the system;
5. Define a reliability-based demand curve to improve capacities products;
6. Remove wind resources from ramp product eligibility due to the lack of capability; and
7. Improve wind forecast with the incorporation of recent wind direction, based on studies that shows substantial reduction in wind forecast errors by more than 40%.

To illustrate the *Economic Transmission Reconfiguration* recommendation, (IMM, 2023) details a simulation in a transmission line that flows the wind energy from the Northern region which has an alternative configuration that can reduce line congestion by more than 60% and consequently, reduce the volumes of wind power curtailment.

All of these measures are preparing MISO for the increased penetration of intermittent renewable energies in the system and consequently, the potential increase of renewable curtailment, especially when the renewable share exceeds 30%, which is expected to occur by 2026 (IMM, 2023).

According to (MISO, 2021), when the share of renewable generation reaches between 30% and 40% in energy mix, an inflection point appears, characterized by a relevant increase in the complexity of the electrical system and by more complex processes due to the greater variability and intermittency of these renewable sources. Considerable and more restricted changes will be necessary in transmission infrastructure and operation systems to guarantee the security and reliability of the grid.

2.3

Australia

Australian electricity systems and wholesale markets are operated by Australian Energy Market operator (AEMO) and regulated by Australian Energy Regulator (AER). Additionally, Australia also has the Australian Energy Market Commission (AEMC), which is an independent statutory institution whose objective is to administer the regulatory and Grid Code changes based on proposals from AEMO and AER, focusing on long-term benefits for the consumers (AEMC, 2023).

AEMO operates two independent electricity systems and markets, namely the National Electricity Market (NEM) which operates in eastern and southeastern Australia, and the Wholesale Electricity Market (WEM) which operates the South West Interconnected System (SWIS) in Western Australia (AEMO, 2023b), as shown in Figure 31.

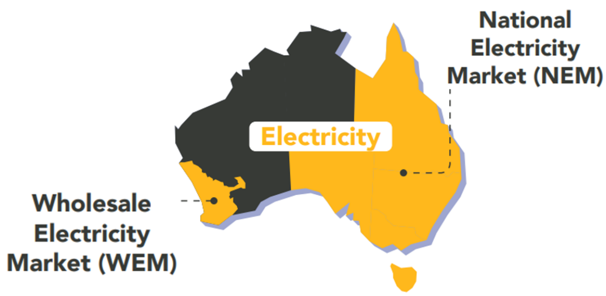


Figure 31: Electrical systems and energy markets in Australia (AEMO, 2023d).

NEM serves around 9 million consumers and its energy matrix is made up of 32.4% coal, 19% gas, 17% wind, 13.8% solar, 12% hydropower, and 2% battery systems (AEMO, 2023c). And WEM has a energy matrix formed by 38.5% gas, 27.4% coal, 16.3% wind, 1.9% grid solar, 15.5% from small-scale solar and 0.4% of landfill gas produced by the decomposition of solid waste, and it serves around 1.2 million homes (AEMO, 2023f).

In these Australian systems and markets, generation dispatch is carried out through a process based on bid prices, renewable generation forecasts and energy sources availabilities. The renewable forecasts are provided by generators and AEMO (AEMO, 2023a). In 2008, for wind and solar power plants, AEMO created the classification of *semi-scheduled generating units* and includes all variable renewable power plants above 30 MW of installed capacity. The dispatch of these plants is defined based on the lowest value between the system's unrestricted generation forecast and its maximum availability (AEMO, 2023a).

During the dispatch scheduling, AEMO informs confidentially each generator or aggregated generators about its *Dispatch Target*. This value is the plant's generation limit and must be obeyed when the operator activates the *Semi-Dispatch Flag*, which may be below or above the indicated generation forecast, regardless of the energy availability or energy prices, and at intervals defined by AEMO. The operator activates this flag when any network or ancillary service restriction is violated or there is a risk of violating system limits (AEMO, 2023a) and it is crucial to control their generation. Figure 32 presents an workflow of this process.

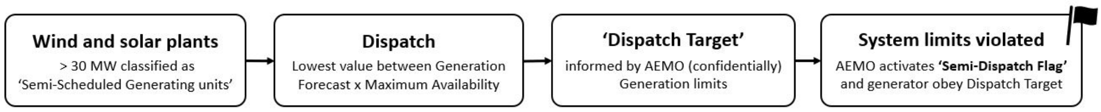


Figure 32: Variable renewable energy dispatch process workflow in Australia (elaborated by author), based on (AEMO, 2023a).

The *Target Dispatch flag* was established by AEMC, in 2021, due to cases where wind farms reduced their generation to zero in negative price intervals without any instructions from AEMO or rebid for redispatch, causing relevant security risks to the network. Additionally, the inadvertent reduction of intermittent generation in large amounts in real time operation can make a more constrained and limited power system and consequently, increase the costs of ancillary services, redispatch, making the market less efficient and generation forecast less accurate (AEMC, 2021).

AER understood this amendment was necessary to bring greater predictability and security in market price, generation forecast and real-time operation. At the time of this regulatory discussion, in 2021, the NEM system had around 11 GW of intermittent energy source capacity, corresponding to around 20% of the system's total installed capacity (AEMC, 2021).

In relation to the renewable curtailment, AEMO had a curtailment rate of approximately 7% in 2024, and a energy matrix with 50% renewable energy, including solar, wind, hydro, biomass and grid-scale storage. In 2050, the total annual curtailment rate is estimated to be more than 20% with a renewable share in energy mix of more than 90% and approximately 135 GW of total installed capacity (AEMO, 2022c)(AEMO, 2025b).

In AEMO's systems, the main reason for renewable curtailment is the oversupply generation. However, this type of restriction in Australia is called as *spilled energy*, and *curtailment* is related exclusively to system's constraints such as operational limits. Figure 33 detailed the average quarterly curtailment rates during 2022, 2023 and 2024 (AEMO, 2025b) when it is observed an increase in warmer periods (summer and spring), and Figure 34 presents the curtailment or spilled energy rates estimation from 2024 to 2049 (AEMO, 2022c).

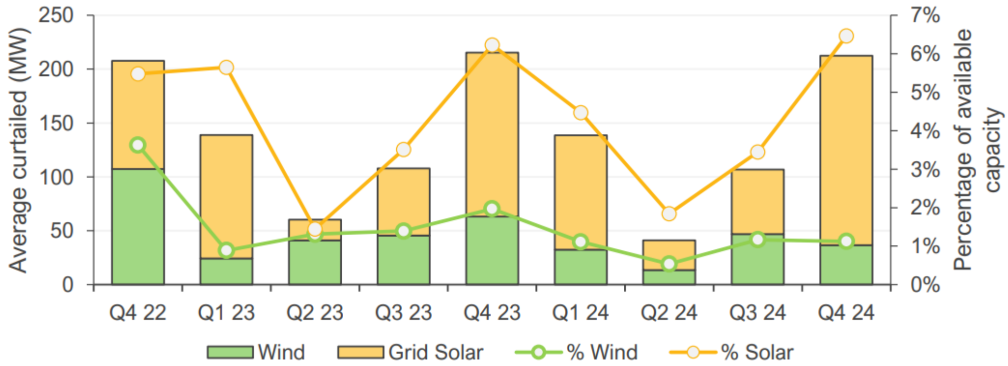


Figure 33: Quartely average renewable energy curtailment in NEM (AEMO, 2025b).

To address the significant increase in renewable energy grid connections and consequently estimated increase in renewable curtailment, AEMO created the *Renewable Energy Zones* (REZ) which aims to coordinate network expansion

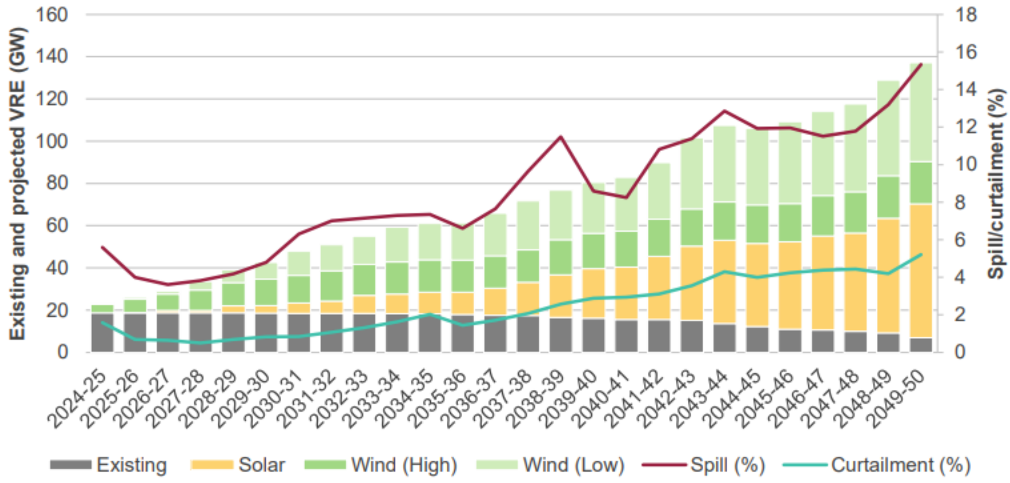


Figure 34: Variable renewable energy curtailment and spills futures scenarios (AEMO, 2022c).

and renewable generation investments, considering technical, environmental, social and economic requirements. These regions are characterized by high-quality renewable generation resources, strong community support and network capacity.

Figure 35 presents an example of a current REZ region called *Central West Orana REZ* in green. It is electrically close to the Sydney load center. This area has moderate wind and solar resources and it is intended to have 3,000 MW of additional transmission grid capacity and new transmission lines connecting to 500 kV and 330 kV levels(AEMO, 2022b).

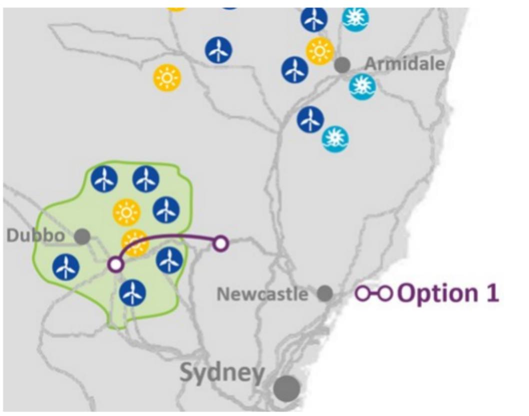


Figure 35: Central-West Orana *Renewable Energy Zone* (REZ) in NEM electrical system in Australia (AEMO, 2022b).

Wind and solar resources in REZ areas have generally high grid utilization and low curtailment rates, which improve grid reliability and security. Other benefits for investors, generators and consumers include co-location of infrastructure and weathers monitors, sharing of costs and risks between multiple linked parties, and development of the region by incorporating social license into the planning process (AEMO, 2022d). In 2022, AEMO created the *Social License Advisory Board* to better understand community challenges and opportunities presented by building new energy infrastructure. The Board has members of landholders and agricultural groups, rural and regional communities, First Nations people, energy consumers and environmental groups (AEMO, 2022a).

The transmission expansion costs to transport renewable energy from REZ to load centers more efficiently is expected to increase annually by 5% to 15% until 2050, depending on scenarios for meeting national or global net zero emission goals (AEMO, 2023e). In conclusion, the point of network connection is determined by the generators, however the REZ characteristics endeavors to guide them for a beneficial decision that satisfied all stakeholders and society.

Regarding the potential of ESS to deal with the increase of intermittent renewable generation, AEMO concluded, in June of 2024, the Integrating Energy Storage Systems (IESS) Project. The aim of this project was to facilitate the connections of storage and hybrid systems into the NEM network and it had a transition period until March of 2025 (AEMO, 2024b).

From June 2024, AEMO changed the classification of market participants from *consumer* or *generator* to *sent out* and *consumed*, regardless the type of the system connection. In addition, by March 2025, it will be changed the classification of Battery Energy Storage System (BESS) to Bidirectional Unit (BDU) (AEMO, 2025a). These changes were intended to standardize the categories and to be adaptable to the range of services provided by the storage systems.

In 2024, the total power capacity of storage systems in Australia, including batteries and pumped hydroelectric power plants, were 3 GW and the estimation is more than 22 GW by 2030 (AEC, 2024). As presented in Figure 36, batteries systems, as well as renewable energy plants, are estimated to increase substantially in the distribution systems, namely as *rooftop* solar, other distributed solar plants and Consumer Energy Resources (CER) storage systems. Therefore, to deal with the impacts of intermittent renewable energy generation on the system, including renewable curtailment, also includes new responsibilities for distributors, in a coordinated and cooperative manner with the transmission system operators. According to (AEMO, 2024a), CER batteries have the potential to avoid more than $4 billions, if well coordinated between DSO and TSO, of investments in large-scale storage systems.

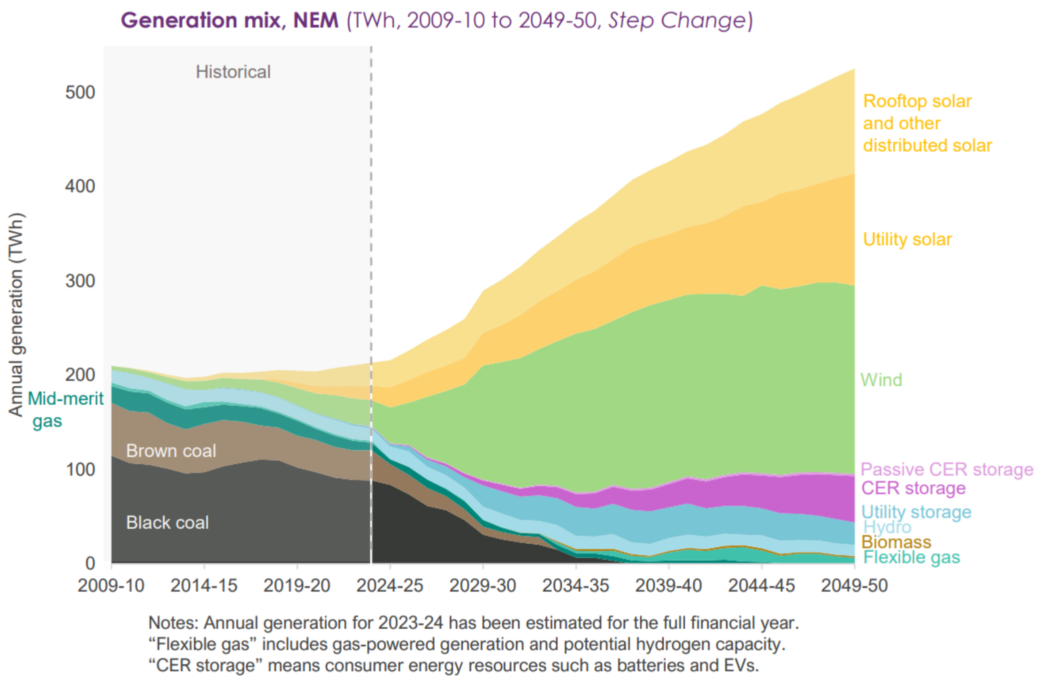


Figure 36: Generation mix growth from 2009 to 2050 in Australia (AEMO, 2024a).

For that reason, AEMO plans modernizations and investments in the distribution system infrastructure to enable the use of capacity in the low-voltage network to support the system operation (AEMO, 2024a). In June 2024, a pilot project called *Project Symphony* was completed to test the participation of DER in the energy market of the Western Australia's power system, highlighting the following results (AEMO, 2024c):

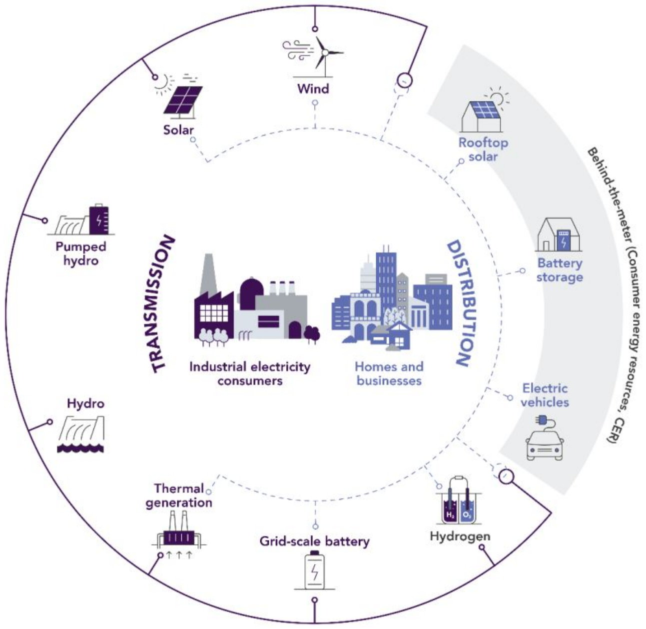


Figure 37: An schematic of power system with resources connected in the transmission and distribution networks (AEMO, 2024a).

1. The inclusion of aggregators or Virtual Power Plants (VPP) of DER in the market will reduce system costs and help alleviate local grid constraints;

2. Storage systems connected in the distribution system are essential resources for prioritizing and evolving VPP;

3. Regulatory improvements are needed to reduce entry barriers for DER as an integral part of VPP; and

4. The proposed action plans include technology, customer, value and policy aspects and they are estimated to be implemented in the next four years, as detailed in (ARENA, 2024).

In conclusion, Figure 37 presents a schematic of the resources connected to the transmission and distribution network considering the new system operation scenario, given the growth of intermittent renewable energy, as well as the estimate increase in storage systems and distributed energy resources.

2.4

Summary and conclusions

In this Chapter, it was analyzed the increase of wind and solar energy in the systems of Europe, United States and Australia and the challenges faced by operators and regulators with high rates of renewable curtailment. From this analysis, it can be verified that curtailment is a global challenge and it is almost an inherent characteristic of the energy transition goals due to the intrinsic aspects of these variable renewable resources which result in accelerated power plants employment and greater unpredictability and variability in very short periods of time.

Implemented measures to mitigate, but not eliminate, these curtail events are various and depend usually on day-ahead and operation dispatchability classification, grid configuration and load centers locations, energy market design, system expansion and available flexibility products and services.

In summary, after analyzing these international cases related to variable renewable energy curtailment, the main points are highlighted below.

(i) *Intermittent renewable energy curtailment is common* - operators use curtailment as a measure to maintain the security of systems with high penetration of wind and solar generation. However, restricting large amount of renewable generation is not recommended due to inefficiency and energy waste. It is important to verify the evolution of the curtailment rates over the years and the actions that have been taken to minimize or stabilize them;

(ii) *Curtailment rate should be accompanied by energy consumption rate* - Curtailment rates for wind and solar generation should be analyzed considering the share of these sources in energy consumption, since they can cause risks to the system security. European regulation recommend an annual redispatch rate of maximum 5% of the expected generation, provided that the energy consumption from renewable generation is up to 50% and does not pose serious risks to network security;

(iii) *Increasing the share of renewable energy can increase system cost* - Increasing the penetration of intermittent renewable energy can increase the cost of system operation due to curtailment, as demonstrated in the case of Great Britain, which verified a considerable rise in the charges paid by the operator in the balancing markets, and in the Germany case in relation to the market-based curtailment reports;

(iv) *Market-based mechanisms may not be adequate* - Mechanisms based exclusively on markets are not always the most appropriate means of allocating renewable generation curtailment. It is necessary to assess whether these products are equally competitive for all participants. In Germany, the redispatching and curtailments are often carried out at predictable locations and therefore do not create competitive signals for markets participants, posing risks to system security and increasing operating costs;

(v) *Curtailment priority can be used as an incentive measure* - Prioritization criterion for power curtailment can be implemented as an mechanism to support system operation and increase the network controllability. As an example, in Spain, the curtailment priority is given to power plants that do not have automatic curtailment mechanisms integrated into the operator's systems;

(vi) *Reduction of minimum dispatchability capacity* - It is observed that, in most countries, the minimum installed capacity for dispatchability by the operator has been reduced, ranging from 100 kW in Germany, 1 MW in UK, Spain, Portugal and MISO (US), to 10 MW in Italy, ERCOT (US) and SPP (US). In Australia, a semi-dispatch mechanism has been implemented, where wind and solar plants above 30 MW have the possibility of being controlled by the operator, depending on the conditions verified in real-time operation;

(vii) *Local economic signaling can direct renewable connections* - Locational signaling is important to encourage connections of wind and solar generators at points in the grid that are most suitable and safe for operation. In Germany, additional connection charges have been implemented in locations requiring grid reinforcements, and in Australia and ERCOT (US), they mapped the most appropriated regions in the grid for renewable energy connections, considering, for example, progress of system expansion and modernization, distance to load centers, co-utilization of infrastructure and sensors, and agility in the assessment of social licenses;

(viii) *Transmission system expansion and modernization are a traditional solution but expensive and less efficient* - Transmission expansion is a conservative solution implemented in most countries with high curtailment rates; however, it is not seen as an unique solution, due to the high investments and considering the seasonality of wind and solar energy sources, which do not power flow at full capacity through transmission lines in all periods. Alternative transmission solutions include DLR, which increases the capacities of existing lines according with the ambient temperature, and international interconnections which allows power flows during different load and generation profiles. These are measures widely used in Europe, where an additional 88 GW of cross-border capacity is expected by 2040;

(ix) *Renewable energy subsidies can distort markets and impact real-time operation* - Subsidies for renewable energy can create market distortions and risks to the system, as verified in ERCOT and MISO (US) cases, where the generators did not follow price signals in real-time, even in periods with negative prices due to the guarantee of government subsidies;

(x) *New flexibility products, mainly energy storage systems* - To support the system operation with high penetration of intermittent generation, new products and new requirements for connected generators can be established and procured by the operator, such as the instantaneous shut-down services contracted in UK, ramp products and stricter requirements implemented in ERCOT (US) and MISO (US); and energy storage system in Portugal, ERCOT (US), MISO (US) and Australia. Specifically in UK, storage systems have been found to be not a cost-effective solution to minimize curtailment caused by transmission congestion;

(xi) *Distributed Energy Resources are an alternative* - Distributed Energy Resources (DER), such as distributed generation and demand response, can be considered in the solution to increase the controllability and security of the grid. New roles and responsibilities for distributors to deal with DER and their impact on transmission system operation led to the creation of the DSO. The UK and Australia have been developing pilot projects to analyze the inclusion of DER in local markets; and

(xii) *Penalties for non-compliance in real-time operation* - In addition to markets and models to define generation dispatch and curtailment, it is also relevant to implement penalty measures considering cases of non-compliance with operator commands in real-time system operation, as observed in MISO in US and in Portugal.

Based on these main points, it is verified that some actions are being discussed or already implemented in the Brazilian energy sector, involving the Brazilian National Electrical System Operator (ONS), Energy Regulator (ANEEL) and generators, as shown in the Table 2.1.

Benchmarking international highlights	Brazilian energy sector context
Curtailment rate should be accompanied by energy consumption rate	The ONS publishes on its website records of intermittent renewable curtailment (ONS, 2024b), however does not consolidate this data with the renewable energy consumption rates.
Increasing the share of renewable energy can increase system cost	Intermittent renewable curtailment can increase the costs of the Brazilian energy sector in cases curtailment is classified as *electrical reason*, which is paid by consumers to generators, as detailed in the next Chapter 3.
Market-based mechanisms may not be adequate in highly predictable restrictions	In Brazil, most wind power curtailment are due to meet reliability requirements, mainly in restrictions on Northeast-Southeast interconnections, as explained in the next Chapter 3.
Curtailment priority can be used as an incentive measure to support Operator	In the draft resolution on the criteria for generation curtailment, Regulator ANEEL proposed prioritizing plants with restrictions in their Grid Connection Studies and plants with pending integration requirements, in order to encourage generators to comply with these obligations (ANEEL, 2024).
Reduction of minimum dispatchability capacity	ONS plans to review the Grid Code that defines the operating mode classification of power plants in 2025 (ONS, 2025a). This document also defines the minimum capacity for power plants dispatchable.
Local economic signaling can direct renewable connections	ANEEL carried out a Connection Reform in 2023 including stricter financial guarantees for connection requests and contract signing (ANEEL, 2023b).
Transmission system expansion and modernization is a traditional solution but expensive	ONS predicts an investment in transmission system of approximately R$ 50 billions until 2027 (ONS, 2023j).
Renewable energy subsidies can distort markets and impact real-time operation	In 2021, the Brazilian government published the Law No. 14,120 (PR, 2021), which determined the gradual elimination of discounts on transmission usage tariffs for renewable generators.
New flexibility products	A Capacity Auction is planned for contracting power (MME, 2024), with 327 projects and more than 74 GW of installed capacity already registered (EPE, 2024b).
Distributed Energy Resources (DER) are an alternative	ONS is conducting a study that aims to defines the action plans to create the Distribution System Operator (DSO), in order to deal with the increase of DER, mainly rooftop solar systems, and its impacts on the transmission system (ONS, 2025b).
Penalties for non-compliance in real-time operation	The regulation (ANEEL, 2022b)(ANEEL, 2023c) establishes that generator will not receive payment for the curtailment in case of failure to send real-time data to ONS. Additionally, Submodule 1.3 of the Brazilian Grid Code (ONS, 2021b) defines the identification and treatment of non-compliance by generators .

Table 2.1: Summary of the benchmarking international highlights that are in discussion or implemented in the Brazilian energy sector.

Furthermore, the Appendix A presents a table describing the renewable curtailment process of several countries, including the mechanism to financial compensate the generators for curtailment actions and, finally, the summarized measures implemented to deal with the renewable generation curtailment amounts. The Table presents the mentioned countries in this Chapter and additional information about Italy and other US systems, such as PJM and CAISO, which were not detailed in this Chapter in the interest of conciseness.

The next chapter will analyze the energy transition in Brazil, specifically for wind and solar energy sources, the day-ahead dispatch process, and the data and actions involved in addressing variable renewable energy curtailment.

3

Brazil Energy Sector

Brazil has a privileged position in the global energy transition. According to reports from (EPE, 2023b)(EPE, 2024a), shown in Figure 38, approximately 90% of the Brazilian energy mix is from renewable energy sources, while the world had on average less than 30% of renewable energy in its energy mixes, including hydroelectric, wind and solar energies.

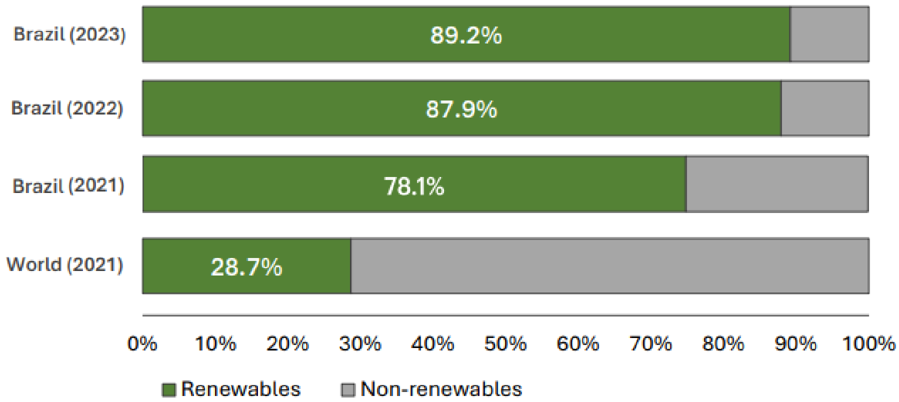


Figure 38: Renewable energy share in Brazilian mix (EPE, 2023b)(EPE, 2024a).

The Brazilian electrical system is divided into 2 independent subsystems, the National Interconnected System (SIN) and the Isolated System (SISOL). SIN is the significantly larger grid that connects all regions of Brazil and it is illustrated in Figure 39. SISOL has no electrical connection with the rest of the country and it consists of less than 1% of total Brazilian consumers. The Brazilian Independent system operator (ONS) operates the SIN and a portion of SISOL corresponding to the city of Boa Vista in Roraima State along with its smaller connected locations (ONS, 2023e). The ONS' responsibilities and procedures are regulated by the Brazilian Electricity Regulatory Agency (ANEEL).

The SIN connects a total of 78,814 MW$mean$ of electrical load (ONS, 2024c) and has approximately 170,000 km of transmission lines between 230kV and 800kV (ONS, 2023a). The installed capacity of power generation plants connected to SIN at the end of 2024 was 230.5 GW and it has a total generation projection of 251.6 GW in 2028 (ONS, 2024d). Figure 40 details the energy sources in Brazilian installed capacity in December 2024, namely 43.7% hydro, 15.2% distribution generation (below 3 MW of installed capacity for hydro plants and 5 MW for other energy sources mainly solar rooftop systems), 9.8% thermal, 14.0% wind, 7.2% biomass, 7.0% solar and 3.1% small hydroelectric plants which have between 3 MW and 30 MW of installed capacity. The Figure also shows the expectation generation growth until 2028 with more than 250 GW, mainly due to solar energy centralized and distributed power plants. In 2028, the renewable share in the Brazilian energy mix is estimated at approximately 92.7% or 232.7 GW of installed capacity, with 46% of this renewable share coming from wind and solar energy sources.

Figure 39: Illustration of Brazilian National Interconnected System (SIN)(ONS, 2019).

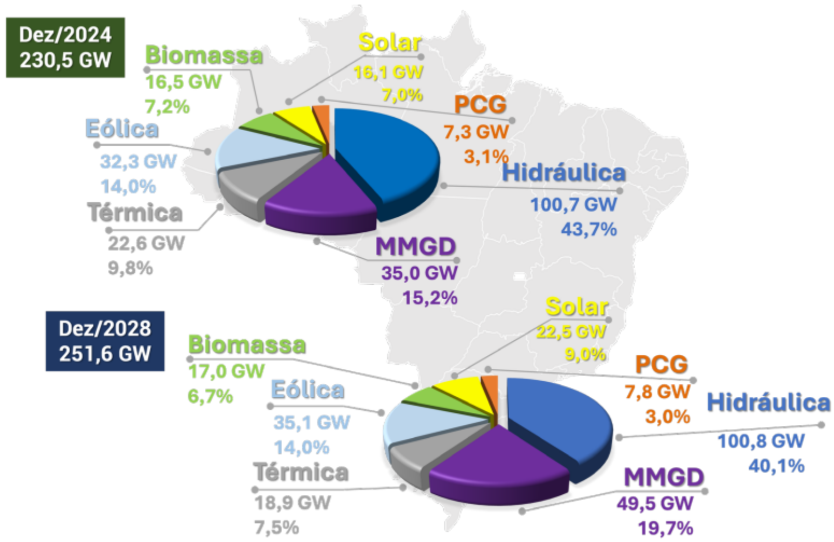


Figure 40: Brazilian installed generation capacity in 2024 and estimated generation for 2028 (in Portuguese)(ONS, 2024d).

As reported by (ONS, 2023i), the expansion of intermittent energy sources into the grid, specially wind and solar power plants, occurs mainly in the free energy market and therefore centralized transmission auctions face challenges in keeping pace with the rapid renewable plants' time deployment. Since 2016 until 2022, transmission auctions have encouraged early construction and observed a fourfold increase, compared to the previous period of 2013 and 2016. By 2026 (ONS, 2024d), the classification with the highest number of projects in the transmission system is related to the power flow restrictions.

Furthermore, for the 2023-2027 horizon, it was expected approximately 10,000 km of transmission lines expansion which corresponds to an increase of 5.8% in relation to the existing transmission network. Total investments in the Brazilian transmission system are estimated to be around R$ 50 bi (ONS, 2023j).

The next section presents the day-ahead dispatch process including the definition of generation dispatch and indication of renewable curtailment generation.

3.1

Optimization Models for Energy Generation Planning

The energy generation dispatch planning in Brazil are defined by a chain of centralized optimization models, namely by a *tight pool* energy market design. These optimization models are utilized by ONS and the CCEE from medium-term horizon of five years, by a model called *NEWAVE*, through short-term horizon of up to 12 months, model *DECOMP*, until the very short-term planning with a horizon of up to one week where day-ahead generation scheduling is segregated every half-hour, *DESSEM*. The CCEE defines the energy price using the *DESSEM* model without grid electrical restrictions. Figure 41 shows the chain of centralized optimization models used in Brazil.

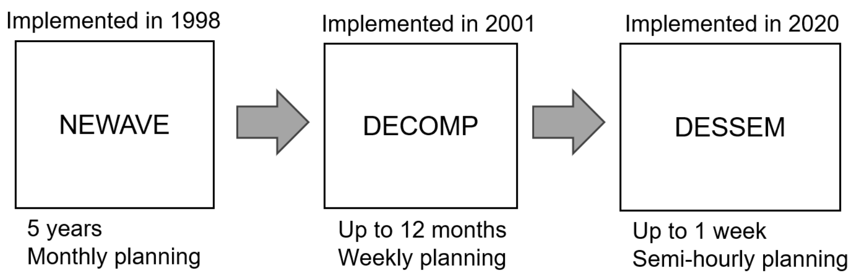


Figure 41: Brazilian optimization models to energy generation planning (elaborated by author).

Intermittent renewable generation, wind and solar energy sources, is represented in optimization models by blocks of energy deducted from load demand and the renewable generation forecast is defined based on historical average of generation from monthly data of the last five years or based on specific methodology by source and power plant's classification, as described in the Brazilian Grid Code (ANEEL, 2022c)(ONS, 2022e).

The process of scheduling generation for the next day operation consists of two steps carried out by ONS (ONS, 2023g)(ONS, 2023f). The first stage is the very short-term optimization model, *DESSEM*, which it is a mixed integer programming with linear static and dynamic models and an iterative process with nonlinear functions and power flow constraints (CEPEL, 2024). The *DESSEM* model defines the Marginal Operating Costs (CMO) on a semi-hourly basis and the optimal scheduling of hydroelectric and thermal generating units considering electrical system restrictions, operation of river cascades, and thermal unit commitment constraints such as *on/off* status, minimum and maximum *on/off* periods and upward and downward ramps restrictions.

The second step, between day-ahead hydrothermal defined dispatch and real-time operation, is called a *post-DESSEM* stage. At this moment, the Operator makes adjustments in the day-ahead scheduling from *DESSEM* in order to guarantee the safety and integrity of the equipment in the system considering regulatory, computational model development, public and operational policies and other aspects, as detailed below according to (ONS, 2024a):

1. *excess thermal inflexibility*: Addition of excess inflexibility of thermo-electric plants when the total sum of weekly inflexibility declared by generators is greater than the value declared in the medium-term model (ANEEL, 2019a);

2. *hydroelectric unit commitment (HUC)*: The Operator checks the feasibility of the proposed generation curves resulting from the optimization model with the hydraulic operation restrictions registered for the generating units and interacts with the generators. Currently, the *DESSEM* model does not consider the hydroelectric unit commitment constraints which may include *on/off* status of generating units, individual productivity and efficiency of turbines, pressure losses and others operational restrictions;

3. *operational energy policy*: ONS analyzes the assumptions previously considered in the Monthly Operational Program (PMO) (ONS, 2021c)

and the model results for the current operating week. Then, it is defined, if necessary, refinements in generation dispatch to ensure efficiency of existing system resources mainly to preserve headwater hydroelectric water reservoirs;

4. *water flows forecast*: After the optimization model results which considered different water flow forecast modelings, the ONS interacts with hydroelectric generators to confirm the registered data and update the flow forecasts;

5. *out of merit order*: Additional thermal generation outside the order of cost merit from optimization model result according with determinations from the government and energy institutions in the Electrical Sector Monitoring Committee (CMSE). These additional dispatches are made in an extraordinary manner and with the aim of ensuring compliance with the energy demand when there is a critical energy supply-demand scenario;

6. *real-time operation feedback*: Operator receives real-time reports verifying the occurrence of relevant facts during system control and operation that may impact the day-ahead dispatch planning. Thus, ONS interacts with generators, if necessary, to make adjustments to their generation and exchange energy schedules based on these reports;

7. *export and import*: International energy exchanges between Brazil, Uruguay, Argentina and in some specific cases, with Venezuela. Energy exports and imports occur in scenarios that do not affect the electrical and energy security of the SIN nor increase the costs in Brazilian electrical sector (ONS, 2023h);

8. *operational reserves*: Definition of operational energy reserve values for each network subsystem in accordance with the Brazilian Grid Code

electrical studies requirements (ONS, 2022d); and

9. *wind and solar energy curtailment*: Based on the changes in hydrothermal dispatch from optimization model, there is a need to reduce the VRE generation to accommodate all system constraints and meet the predicted load demand.

Generation curtailment criteria are not yet fully regulated in Brazil, but several regulatory discussions are underway, as detailed in the Section 3.3. Hence, ONS develops specific planning studies and uses the operational policy to define the generation restriction order in the day-ahead dispatch process. In addition, the Operator uses several computer systems to support real-time operations in the curtailment distribution and to convey information rapidly and effectively with wind and solar generators.

In this dissertation, a day-ahead planning single model is proposed and implemented with electrical and energy restrictions considering thermal and hydroelectric unit commitment constraints and a co-optimized dispatch of operational reserves and intermittent renewable power curtailment distribution, in order to support Operator's decision-making process considering the intrinsic uncertainties of wind and solar energy sources and their impact on the system reliability.

To better illustrate the challenges of intermittent renewable generation in Brazil, the next section details the renewable generation and curtailment data and ongoing regulatory discussions on the topic.

3.2
Wind and Solar Energy

The first MW of wind power capacity installed in Brazil was recorded in 1994, but it only began to have relevance in the Brazilian energy matrix from 2009 onwards, when it reached 600 MW or 0.5% of the country's total installed generation capacity (EPE, 2023a). In the following years, wind energy continued to grow rapidly and, in less than 10 years, reached 14% of Brazil's total installed capacity, with around 32 GW in 2024 (ONS, 2024d).

Regarding solar energy, the first power plant was implemented in 2010 and its growth began to be more pronounced from 2017 onwards when it reached 932 MW and 0.6% of total Brazil's installed capacity (EPE, 2023a). In 2024, solar energy occupies 7% of Brazilian energy matrix with around 16 GW. This number corresponds to grid solar, excepting distributed generation which already has 35 GW of installed capacity, mainly by solar rooftop systems, and corresponds to 15% of the total energy mix (ONS, 2024d).

Figure 42 shows the evolution of the Brazilian energy mix by source since 1974, highlighting the majority share of hydraulic energy since the 1970's and the growth of wind and solar energy after 2009. After 2024, the forecast for the next five years, until 2028, indicates that wind energy will continue to maintain 14% of installed capacity with 35 GW, grid solar energy will occupy 9% and 22 GW, and distributed generation will have around 20% and 50 GW (ONS, 2024d).

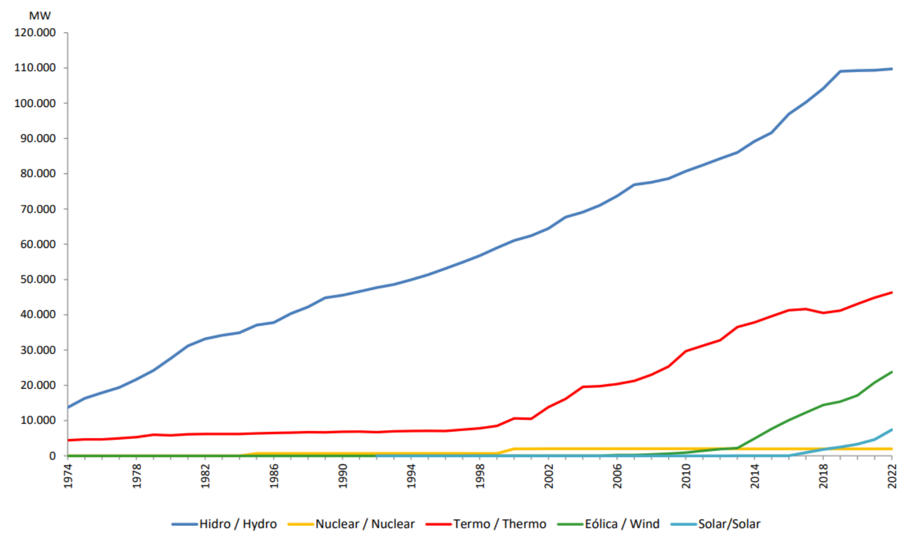


Figure 42: Evolution of installed capacity of electric energy generation in Brazil (EPE, 2023a).

As a result, it is predicted that the Brazilian energy mix in 2028 will have 42.7% of its total installed capacity made of intermittent renewable energy sources connected in transmission and distribution networks. This scenario brings major challenges to system planning and real-time operation considering the high variability and unpredictability of wind and solar energy sources, adding the short time to adapt and modernize the existing grid and communication infrastructures to ensure system security and stability.

In July 2023, the Northeast region of the country verified an instantaneous wind generation record of 18,401 MW which corresponded to 150% of the region's demand at the time and on another day, an instantaneous solar energy generation of 6,597 MW which corresponded to 53.5% of the region's demand (ONS, 2023c). During the period of July and September, Brazil's river basins are going through the dry season. Hence, the generation of wind and solar energy, concentrated mainly in the Northeast region, is complementing the hydraulic energy source to serve the large load centers in the Southeast region.

On the other hand, excess supply of renewable generation far away from load centers can present risks to the operational limits of the network specially in the regional interconnections between the Northeast and Southeast regions. According to electrical planning studies (ONS, 2023j), it was estimated that excess energy would reach 30 GW in 2024 and 50 GW from 2026 onwards in the dry season.

To analyze the current variable renewable energy curtailment rates, the next section will present historical data in graphs and present the ongoing regulatory discussions on generation curtailment priority criteria in the day-ahead, system operation and post-operation processes in Brazil.

3.3

Intermittent Renewable Generation Curtailment

The VRE curtailment allocation is first indicated in the day-ahead post-model step, considering the results of the day-ahead dispatch model, detailed in section 3.1. After day-ahead dispatch and Before real-time operation, the Operator verifies the curtailed energy at different locations of the subsystem and prepares specific normative documents. In addition, the operation center uses real-time tools to calculate and distribute wind and solar energy reductions based on sensitivity factors and available generation of operating power plants.

After real-time operation, financial reimbursement can be applied to wind and solar generators based on regulatory requirements. For wind generation, the constrained-off payments was regulated by (ANEEL, 2022b) with effect from October 2021. And for solar generation, the curtailment financial payment was regulated by (ANEEL, 2023c) with the same definitions and very similar process of wind energy, with effect from April 2024.

The wind and solar generation constrained-off regulations established the following main definitions and procedures:

1. Causes for wind and solar power curtailment from system operator (ONS)'s command:

   (a) *Reliability*: Generation curtail due to system reliability requirements;

   (b) *Electrical*: Generation curtail due to system reliability needs after a contingency in transmission system's installations not belonging to generator's assets; and

   (c) *Energetic*: Generation curtail due to the impossibility of allocating energy generation to meet load demand, i.e., overgeneration caused by high renewable output and low demand or frequency control requirements.

2. ONS must calculate a reference generation and publish the productivity curve that reports the plant's energy production with meteorological measurements such as wind speed and solar radiation.

3. The restrictions indicated in the Grid Connection Studies (GCS) of connected power plants must be disregarded in the reference generation values.

4. Financial reimbursement is applied to generators or electricity utilities, depending on the energy contract, and is proportional to the generation curtailed that is classified exclusively as resulting from the *electrical reason*.

5. Financial reimbursement is valid when the curtailed power are calculated considering a system unavailability above the average of the previous five years.

6. Meteorological measurement data and power availability must be provided by generators to ONS in real-time in accordance with the Grid Code requirements (ONS, 2022c)(ONS, 2022e), under penalty of not receiving the estimated financial compensation.

For wind and solar power curtailments, financial payments to generators or utilities are made through System Service Charges (ESS). These fees are paid by consumers and are intended to maintain the reliability of the system (CCEE, 2023). The payment is calculated by the Brazilian Chamber of Electric Energy Commercialization (CCEE), after the real-time operation, considering the amount of curtailed generation and the energy price in the free market of the subsystem at the time of the generation restriction (ANEEL, 2022b)(ANEEL, 2023c).

Data on variable renewable energy curtailment in Brazil were released from June 2020, starting with wind generation. Solar generation curtailment data was released from April 2020 through December 2023 and then from April 2024 through December 2024. Figure 43 presents published data on renewable energy curtailment separated by regulated constrained-off reasons (ONS, 2022a).

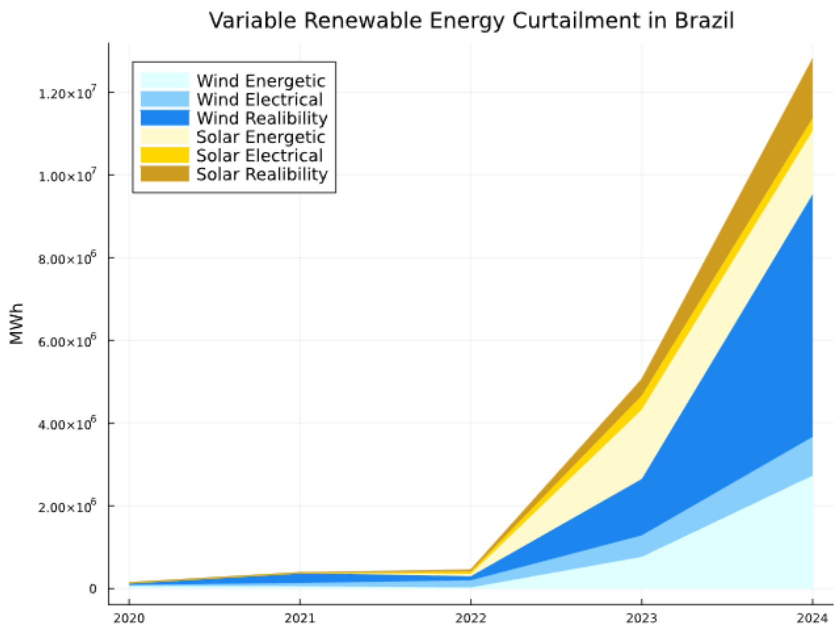


Figure 43: Intermittent renewable generation curtailment data published by ONS (elaborated by author).

The main reason for the wind power curtailment in Brazil from 2020 to 2024 was the need to meet system reliability requirements, a reason that have no financial compensation. This cause occurs when the limits of the transmission lines are not sufficient to flow energy through the system. This restriction is occasionally aggravated by the concentrated location of wind farms in the Northeast region of the country, while most of the load centers in Brazil are located in the Southeast region. As a result, there is an increase in transmission system violations, especially in inter-regional interconnections, also causing an increase in generation curtailment. For solar energy, most of the curtails were due to the *energetic reason* that may be caused by the rapid expansion of solar energy in Brazil's mix during the last years.

An important on the renewable curtailment nowadays is the rapid growth of distributed generation. These systems, connected in the distribution network, are not controlled by ONS and reduces the net load during the day which lead to an increase in solar and wind curtailed generation that are connected in the transmission system (ONS, 2024d). Figure 44 shows the impact of Micro and Mini Distributed Generation (MMDG), mainly rooftop solar photovoltaic systems of up to 3 MW of installed capacity, on the restrictions of centralized wind and solar power generation.

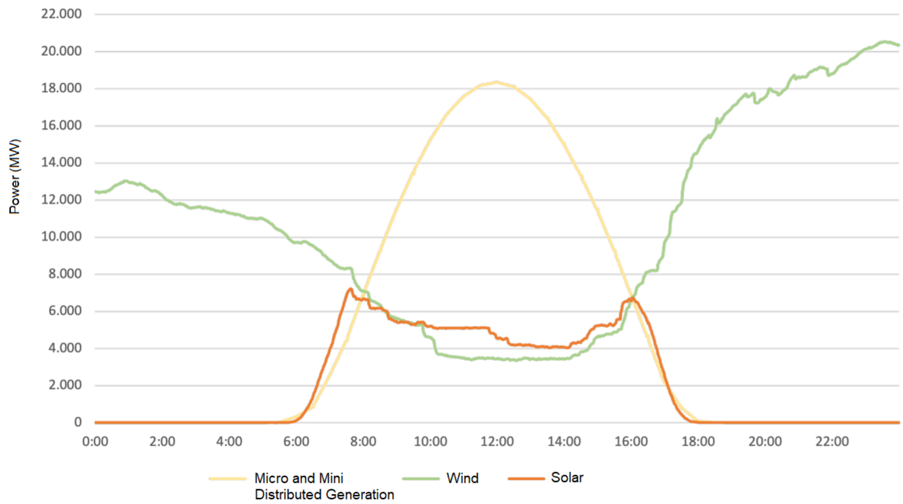


Figure 44: Modulation of centralized wind and photovoltaic generation based on micro and mini distributed generation (ONS, 2024d).

To better analyze the amounts of annual wind and solar generation curtailment rates, Figure 45 and Figure 46 present respectively the restricted generation data by month and reason from June 2020 for wind energy and for solar generation from April 2022 to December 2024.

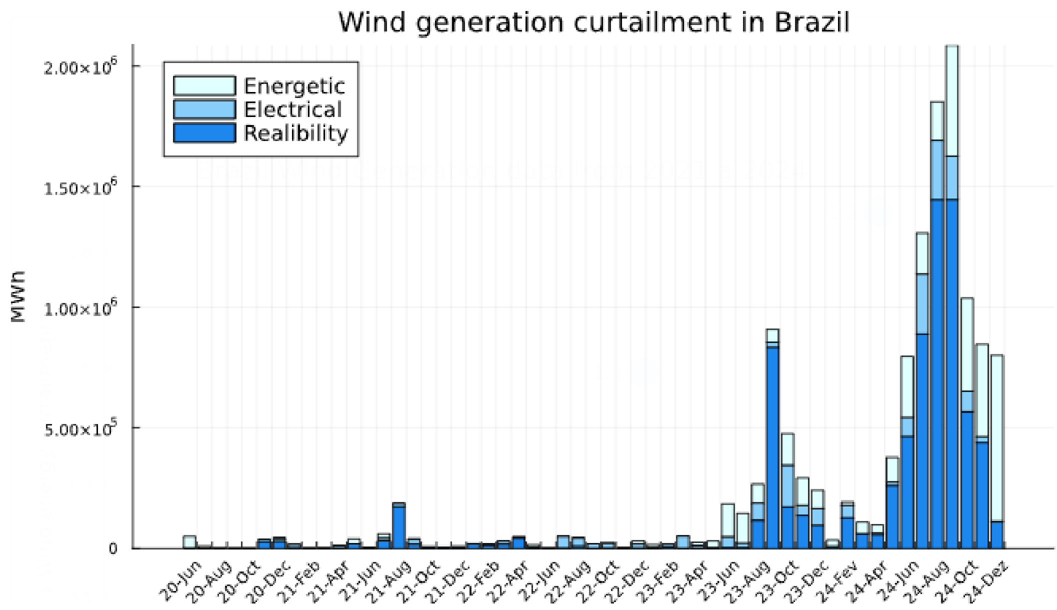


Figure 45: Wind generation curtailment in Brazil (elaborated by author), data from (ONS, 2024b).

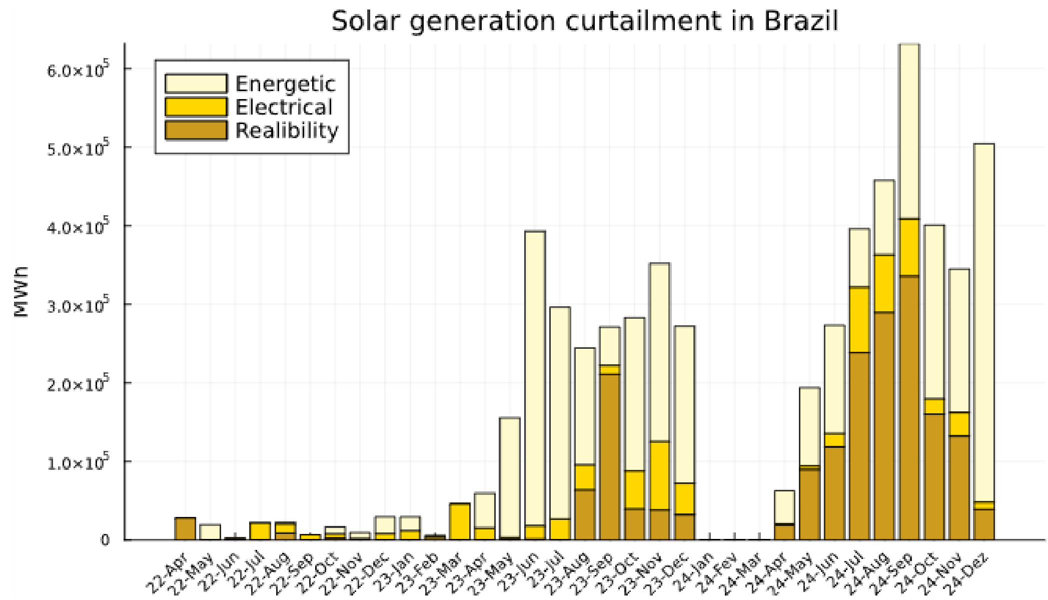


Figure 46: Solar generation curtailment in Brazil (elaborated by author), data from (ONS, 2024b).

According to Figure 45 and Figure 46, it is verified a peak increase in wind and solar power curtailment due to reliability requirements in August and September of 2023. Following a system disturbance in the Northeast region in mid-August, more restrictive operating limits were established that affected the interconnection transmission lines between the Northeast and Southeast regions, and additionally, the requirements related to commissioning models and reports had to be reassessed for both operating and new renewable power plants. These restrictions and reassessments, among other factors such as the continued increase in installed capacity of more than 6 GW of centralized wind and solar energy and 6.7 GW of distributed generation in the system, caused variable renewable curtailment in 2024 to increase by more than 250% compared to 2023.

Based on the estimated and verified generation data (ONS, 2024b), the annual curtailment rates are presented in Figure 47 along with the wind participation in energy mix (ONS, 2021a)(ONS, 2022b)(ONS, 2023d)(ONS, 2024d).

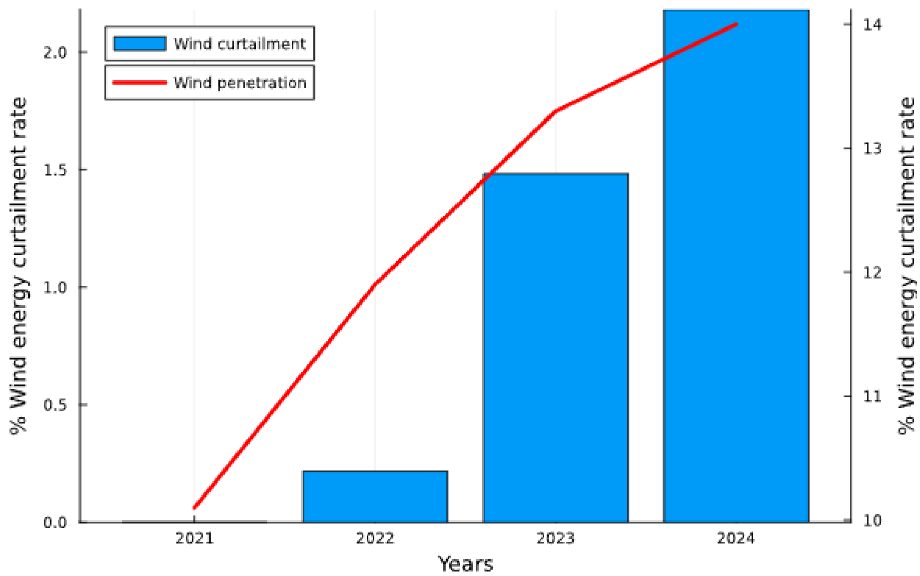


Figure 47: Annual wind energy curtailment rates and energy mix shares in Brazil (elaborated by author), data from (ONS, 2024b).

In relation to solar generation, estimated and verified generation data are only available from the year 2024 (ONS, 2024b), where an annual curtail rate of 8.48% was calculated with a share of 7% in Brazil's energy matrix (ONS, 2024d). Therefore, considering the restrictions in wind and solar generation in 2024, there is a VRE curtail rate of 3.26% with a VRE share of 21% of total Brazilian energy mix.

Therefore, when comparing these curtailment rates with other countries (IEA, 2024b) shown in Figure 2, depending on the data made available in the period of 2000 and 2022, it is observed that Brazil follows the trend of most countries along with the growth of variable renewable generation participation in the energy matrices, as presented in Figure 48 below. Note that the VRE share is related to the total generation installed capacity of the system.

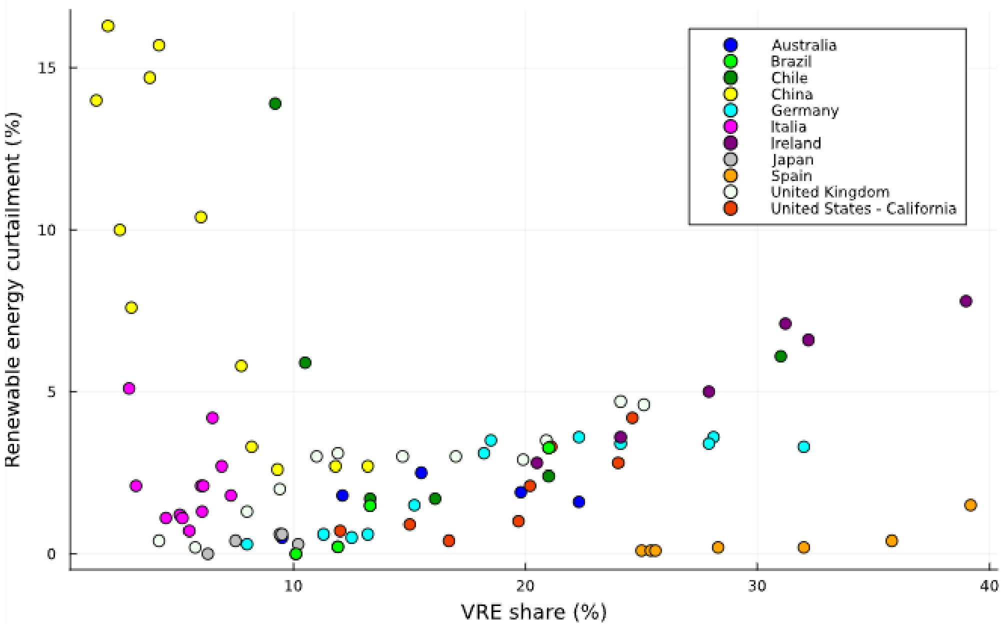


Figure 48: Annual renewable energy curtailment rates and energy mix shares (elaborated by author), data from (ONS, 2024b)(IEA, 2024b).

As mentioned, the Brazilian Grid Code and regulation (ANEEL, 2022b)(ANEEL, 2023c) define the procedures and requirements for *ex-post* payment for wind and solar generation curtailments. Moreover, the Brazilian Energy Regulator (ANEEL) is discussing a criteria for generation curtailment in day-ahead dispatch, real-time operation and after operation, considering all energy sources and their commercial effects.

In 2019, ANEEL opened the *1st Phase of Public Consultation No. 45* presenting a conceptual proposal of curtailment criteria (ANEEL, 2019b) for the system operator and CCEE. According with the Regulator, the generation curtailment criteria is important because it involves different costs to different stakeholders depending on the energy source and previous rules. Hence, ONS must consider these commercial and financial impacts on consumers, generators and others, after evaluating the system's operational security, to distribute the power curtailment. In the *2nd Phase of Public Consultation No. 45 of 2019*, ANEEL proposed a draft normative regulated with a curtailment order taking into account charges paid by utilities and consumers. This phase received several divergent contributions from the electricity sector, including generators, consultancies firms and sector institutions, including ONS, CCEE and EPE.

In December 2024, ANEEL opened the *3rd Phase of Public Consultation No. 45 of 2019* along with the Technical Report (ANEEL, 2024) and a new normative proposal for curtailment criteria. Figure 49 presents a summary of ANEEL's proposal in this phase.

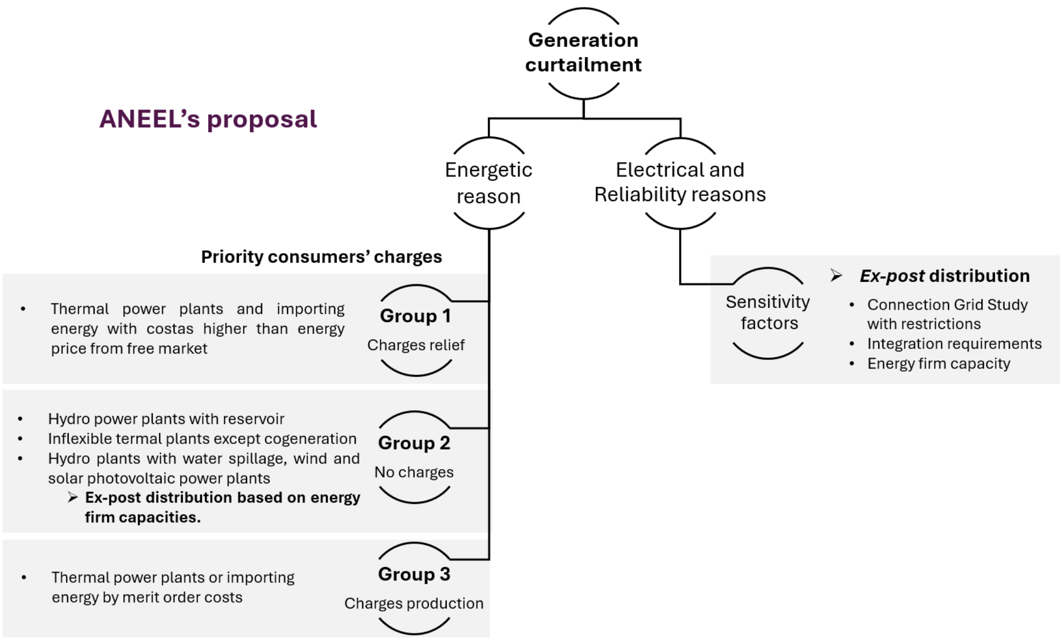


Figure 49: Brazilian Energy Regulator's proposal for generation curtailment criteria in the 3rd Phase of Public Consultation No. 45/2019 (elaborated by author), based on (ANEEL, 2024).

The normative proposes a *ex-post* proportionally curtailment distribution, made by ONS and CCEE, based on the Firm Energy of the reduced power plants. Besides that, for curtailment due to electrical reasons, ANEEL suggests first a curtail priority considering power plants with restrictions in their Connection Grid Studies and then, with power plants pending requirements in the effective operation. According to ANEEL's Regulatory Agenda for 2025-2026 (ANEEL, 2025), the conclusion of this Consultation, with a new published regulation, is scheduled for the end of July 2025.

In addition to the regulatory discussions relating to generation curtailment, the medium-term electrical system planning, that indicates the implementation of reinforcements and improvements in the Brazilian transmission system, also raised concerns about the generation curtailment rates for the next five years, up to 2028. According to (ONS, 2023j), a significant generation oversupply in the Brazilian electrical system is expected during the day, specially at 1pm which is the period of greatest solar radiation. The analysis showed that the total estimation of spilled generation by all energy sources could reach approximately 30 GW in 2024, with growth prospects for around 50 GW at 2026, driven by the projected increase in wind and solar generation.

In order to prepare the system and network operation for this new renewable reality, Brazil's institutions are studying news mechanisms to increase system flexibility and manage the growth of VRE into the grid. ANEEL opened the *1st Phase of Public Consultation No. 39/2023* to receive contributions to Regulatory Impact Analysis on Electric Energy Storage (EES), including pumped-storage hydroelectricity (ANEEL, 2023a). In this document, ANEEL underscores that storage resources can reduce renewable curtailment, specially wind and solar which are less controllable sources, as shown in Figure 50.

According to (ONS, 2021d)(ANEEL, 2023a), a battery storage system could charge during wind and solar generation curtail periods which occurs frequently in the Northeast region to control power flow, frequency control and due to transmission system outages. In December 2024, the Regulator opened the *2nd Phase of Public Consultation No. 39/2023* with an adjusted proposed norma-

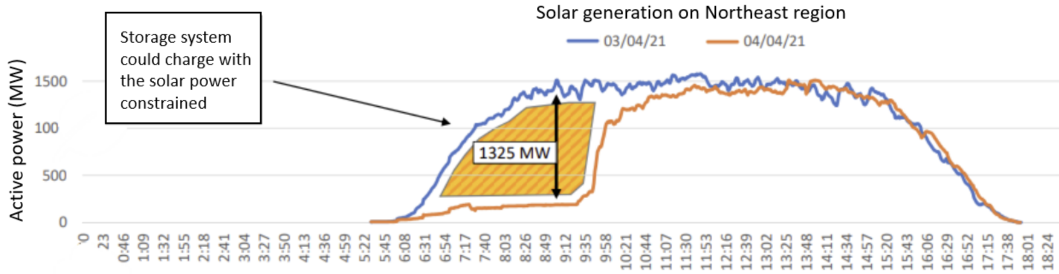


Figure 50: Solar generation and solar curtails with an estimated storage system. Translated from (ONS, 2021d).

tive including aspects such as definitions, tariffs, contracts and remuneration aspects. Similarly with the curtailment criteria regulatory discussion, the conclusion of this Consultation, with a new published regulation, is scheduled for the end of July 2025 (ANEEL, 2025).

Other measures to deal with intermittent renewable overgeneration and to increase system flexibility are being implemented and studied by ANEEL and ONS, including the Connection Process Reform which increased the contributions of financial guarantees by generators and defined quarterly updates of Transmission System Utilization Map by ONS (ANEEL, 2023b). The Brazilian Connection Reform aimed to reduce the access queue that has increased considerably with the growth of wind and solar energy projects. Additionally, it was regulated a pilot (ANEEL, 2022a) and a definitive (ANEEL, 2022d) Demand Response programs, and new ancillary services that provide reactive support for power voltage control through a competitive mechanism are being discussed by ANEEL, ONS and Brazilian energy sector (ANEEL, 2023d). Finally, ONS is carrying out a Project called ONS-Distribution System Operator (DSO) Integration with the aim of including new attributions to distributors and increasing the controllability of Distributed Energy Resources (DER) considering their impact on the transmission network (ONS, 2025b).

To summarize, there are many actions that have been implemented, and many others programs still being studied to be further explored in Brazil. All these programs and prospective regulations have great potential in the short and medium-term to increase system's flexibility and support system operation with more efficiency and security.

The SIN is a continental-sized interconnected electrical system with available natural resources with high amounts of generation and high capacity factors for wind and solar generation, with no similarity in the world. Therefore, it is important that the Brazilian Independent system operator and Brazilian Energy Regulator create a safe environment for evolution of new technologies and flexibility products and services, together with modernization of electrical and communication infrastructure systems, ensuring the delivery of renewable generation to consumers with robustness, efficiency and at the lowest costs.

The following Chapter presents an summary of articles and reports published on the topic of generation curtailment and related aspects in the literature over the last decade.

4

Related Literature

This chapter presents and summarizes articles and research regarding intermittent renewable power curtailment optimization and related topics. The objective of this bibliographical analysis is to discover previous contributions of the subject to knowledge the developments made and possible future trends.

As the total installed capacity of wind and solar power plants increases in the world's electrical networks, researching topics and publishing articles on the treatment of renewable curtailment becomes substantially important for Systems operators, energy generators, investors, consumers and regulators.

In light of the diverse impacts of these renewable generation restrictions on the energy sector, the studies and reports cover a wide range of expertise including electrical engineering, statistics, economics and regulatory disciplines. Topics related to renewable energy curtailment range from concepts such as transmission system power analysis and sensitivity factors, generation probability forecasting, optimization, energy design markets and regulatory settings regarding system operating cost minimization, and their appropriate incentives.

Thus, the following sections describe some of these published research regarding three main subjects: renewable generation curtailment optimization in day-ahead dispatch, action plans to minimize renewable generation curtailment and additional aspects for renewable power curtailment. Additionally, at the end of the chapter, Table 4.1 presents a summary of more than thirty reviewed articles related to renewable energy curtailment with the main topics covered checked for ready reference.

4.1

Renewable Generation Curtailment Optimization in Day-Ahead Dispatch

Regarding this primary subject, (YANG et al., 2021) is related to a Chance-Constrained Economic Dispatch (CCED) model which considers the renewable generation limits amounts as decision variables to define renewable energy curtailment. The article proposes a two-stage co-optimized day-ahead planning model. The first stage is a relaxed linear programming model which aims to identified infeasible system constraints and the time periods when these constraints occurs. The objective function in this stage minimizes the fuel cost of conventional generating units.

After the first-stage, the Objective Function of the second part of the model includes a renewable energy curtailment penalty. This penalty is proportional to the curtailed energy decision value and it models the upper limit generation as decision variable in the Probability Density Function (PDF) of the renewable generation forecasting. Therefore, the second-stage model result is the renewable curtailment optimization, solved by the Mixed-Integer Linear Programming (MILP). Figure 51 shows the proposed methodology flowchart (YANG et al., 2021).

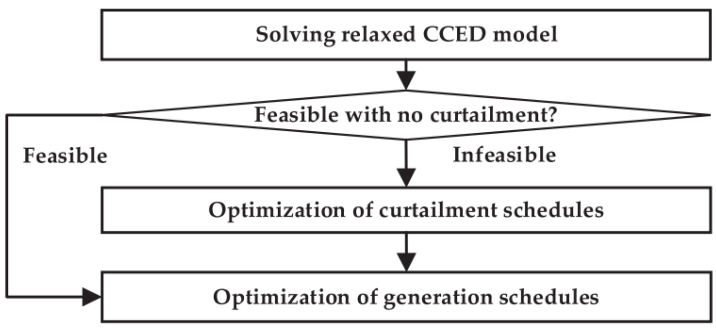


Figure 51: Flowchart of the co-optimized model with day-ahead dispatch and renewable curtailment proposed by (YANG et al., 2021).

In another article, regulatory and technical aspects are considered in the day-ahead dispatch model to optimize wind power curtailment (ALVES; REIS; SHEN, 2016). The author uses the evolutionary Particle Swarm Optimization

(PSO) algorithm to provide a robust power curtailment solution at minimal cost. The renewable curtailment model prioritizes wind farms that have flexibility features to the system operation, such as Low Voltage Ride Through (LVRT) capability. This resource is valuable for system operators as it allows intermittent renewable plants to continue operating in a secure way even in severe grid voltage drop events. Furthermore, the curtailment optimization model also priorities the restriction of over-equipment plants when generation is higher than the maximum authorized injected power into the grid, based on Portugal's energy regulation and as illustrated in Figure 52. Then, the renewable overgeneration is curtailed considering it has no cost to the system.

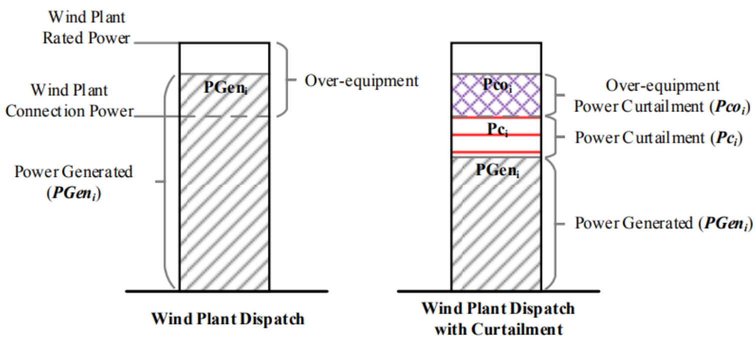


Figure 52: Wind power plants' generation over-equipment and associated wind power curtailment amounts (ALVES; REIS; SHEN, 2016).

Another curtailment criteria considered in the day-ahead optimization model is proposed in (MEIER; TöBERMANN; BRAUN, 2019). This article presents a model with a time-variant penalty term on the Objective Function. The aim of the model is to minimize the curtailed energy considering the past curtailed energy amount of each renewable power plant. The author discusses the fact that, depending on the grid configurations, the same geoelectric region may be frequently congested and the same generator may be curtailed repeatedly, which may cause high costs to the generator and lead to a discriminatory system operation.

Therefore, to avoid this behavior without substantially compromising the minimization of the operating cost, the article considers the past curtailed energy amounts of each generator and redistributes the curtailment per area in order to achieve a *lower discriminating grid operation*. As expected, the results showed that a reduction in discrimination on real-time operation leads to an increase in overall curtailed energy. In that way, it is inferred that the goal of reducing discrimination in power curtailment management is contrary to minimizing the total amount of power restrictions. For that reason, the authors discuss a financial compensation when the curtailment are not distributed equally among the generators up to a percentage limit. Figure 53 summarizes the analysis and conceptual conclusions presented in (MEIER; TöBERMANN; BRAUN, 2019).

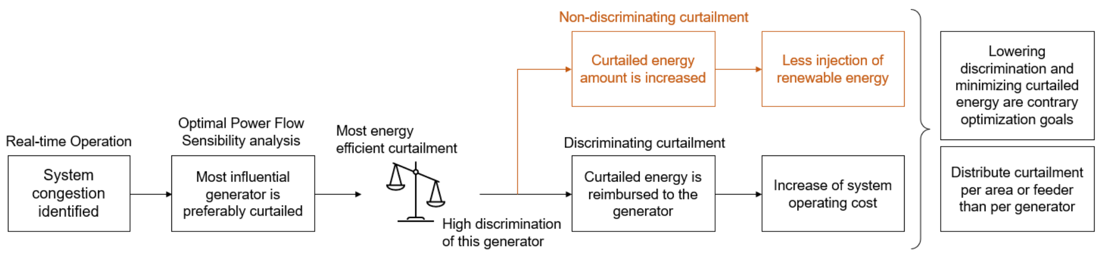


Figure 53: Flow of *discriminating operation* trade-off behavior in renewable power curtailment management (elaborated by author), based on (MEIER; TöBERMANN; BRAUN, 2019) .

Regarding the relationship between system operating reserves allocation and renewable generation curtailment, (YANG; CHING, 2021) presents a methodology to optimize reserves considering scenarios that include intermittent renewable generations, unit generating failures, and energy not supply probabilities for day-ahead scheduling. The model results the day-ahead generation and renewable curtailment dispatch. By using different predefined thresholds for renewable curtailment, the author confirmed the inverse correlation between the renewable curtailment amounts with the system reserves allocation and hence, the system operating cost. In light of this, the article reinforces the need to find a balance between the participation of renewable generation sources in the grid and the impacts on system reliability and operating costs.

In another article about reserves allocation considering a system with renewable generation, (CHEN; MATHIEU; SEILER, 2024) proposed a two-stage optimization model to examine the reserves allocation of conventional power plants considering the variability of renewable generation plants. It was verified the relationship between these parameters in cases with and without restrictions on the electrical grid, even with smaller renewable generation forecast errors. The results showed the importance of optimizing the allocation of reserves, renewable generation curtailment and the solution of grid restrictions considering renewable generation forecasting in a single model, as proposed in this dissertation.

Lastly, (MEHDIABADI; ZHANG; HEDMAN, 2015) demonstrates a dispatch model with renewable generation curtailment penalty in the Objective Function aiming to allocate complementary systems reserves from wind power plants based on below-expected renewable generation scheduling. The author related this as an *flexible wind dispatch margin* based on probability forecasting in order to support system operation with renewable uncertainties at minimum cost. The Figure 54 shows the model results for different levels of renewable penetration in the system.

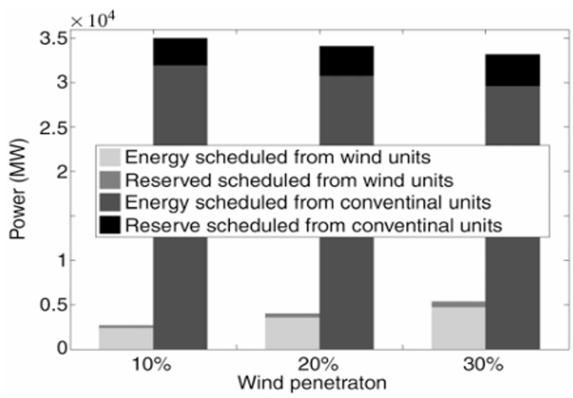


Figure 54: Scheduled energy and reserves in wind and conventional power plants per wind penetration level (MEHDIABADI; ZHANG; HEDMAN, 2015).

In conclusion, it is noticeable that there are different strategies to consider renewable energy curtailment in system operation, including day-ahead models with multiple sequential stages and generation curtailment priorities considering technical and regulatory aspects. These definitions are impacted by the generation forecasting methods, and moreover, have an effect on other system sources and parameters, such as operating reserves and costs. Hence, it is essential to take into account these technical, regulatory and probability factors in the decision-making process of renewable curtailment, considering their influence on the complexity and reliability of the network. The model proposed in this work aims to cover all these aspects in a single-stage model for day-ahead generation with no curtailment penalty in the Objective Function of the model and, considering reserves allocation costs and transmission system, hydroelectric and thermal power plant unit commitment restrictions.

In the following sections, research related to other topics on renewable generation curtailment is presented. In addition to day-ahead optimization models, the stakeholders, operators and regulators also should consider actions to minimize the curtailment amounts and to increase the system absorption of renewable generation regarding grid flexibility. And in conclusion, innovative published discussions and studies are cited concerning how to address the increasing values of renewable generation curtails in the markets and system operation, given the continued prediction of growth of renewable generation in the energy mixes worldwide.

4.2

Action plans to Minimize Renewable Generation Curtailment

As discussed in previous chapters, significant amounts of renewable power curtailment is not desirable and it is generally considered as a last resource by system operators. If the power plant does not have a energy storage system, the renewable curtailment is a waste of free and renewable energy and goes against the energy transition targets. Several studies have been published to proposed methods of reducing renewable curtailment by increasing system flexibility and better accommodate intermittent renewable energy in the grid.

First, (RAMESH; LI, 2020) presented a model that considers transmission system reconfiguration as a resource to be used by the operator to reduce transmission congestion and consequently, minimize renewable curtailment. The optimization model is a stochastic *N-1* security-constrained unit-commitment with corrective network reconfiguration considering multiple probability distribution scenarios. *N-1* denotes the contingency of a single element of the system.

The study results indicated a reduction in transmission system congestion and renewable curtailment, by using network reconfiguration and increasing transmission system flexibility. Additionally, the implemented method reduced the CO_2 emissions due to fewer renewable curtailments cause by transmission congestions.

The corrective network reconfiguration method can be considered by operators as cheaper solution comparing with transmission expansion and other advanced flexibility technologies for line power flows such as FACTS. Nevertheless, it is important to highlight the risks of this method to the system security in real-time operation.

Another measure to increase system flexibility and reduced renewable curtailment is proposed in (MANAKARI et al., 2020). This paper presents a minimization of wind power curtailment by using the Dynamic Line Rating (DLR) resources. These tools are implemented to increase transmission line capacity in real-time operation according to lines' temperatures. The temperature is calculated considering the conductors' parameters, such as thermal conductivity of air and conductor diameter, and real-time meteorological measurements collect by local sensors, for instance, wind direction, conductor's surface temperature and ambient temperature. The results shows that the renewable curtailment amounts is reduced, specially during periods of greater wind generation, relieving transmission congestions.

Other actions to mitigate renewable curtailment includes improvement of renewable forecasting methodology, as proposed in (LEE; HUR, 2023). The article presents an accurate short-term forecasting methodology for intermittent renewable power in order to minimize curtailment and improve system reliability in real-time operation. The wind power forecast is defined by estimating transmission congestions in steady state power flow analysis and considering probabilistic seasonal hourly scenarios in critical system contingency cases. Annual data for wind generation and load demand were utilized to generate these scenarios classified by season and by specific periods of daytime such as overnight, morning, afternoon and evening. Figure 55 presented the workflow of the presented methodology using Kernel Density Estimation (KDE) and Markov chain Monte Carlo (MCMC) sampling algorithm to define the wind power and demand forecasts and critical system contingencies scenarios.

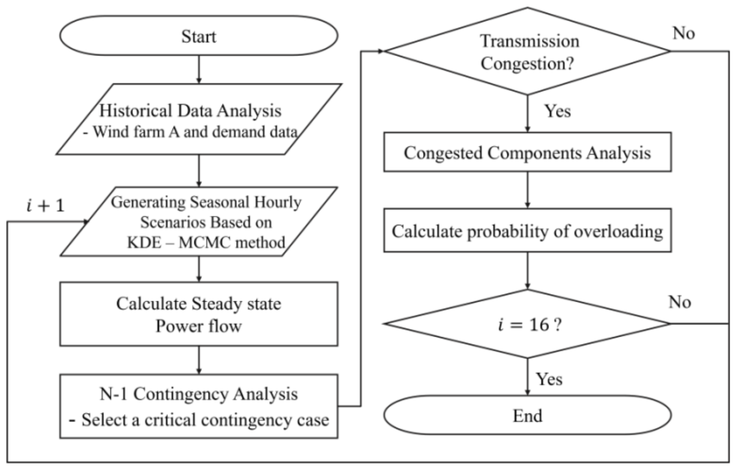


Figure 55: Workflow of the model to calculate transmission congestion probability using seasonal hourly scenarios to mitigate wind curtailment (LEE; HUR, 2023).

Finally, several papers discuss about Energy Storage Systems (ESS) and its characteristics to mitigate system congestions and reduce renewable power curtailment. (DUI; ZHU; YAO, 2018) shows a two-stage optimization model to determine power and capacity of battery storage system in a grid with thermal and wind power plants.

The implementation of ESS into the grid is relevant to increase system flexibility and it can add control strategies in systems with high penetration of VRE. In the first stage of the optimization proposed in (DUI; ZHU; YAO, 2018), the thermal and wind generation are optimized considering transmission system constraints. Then, the second-stage optimization model utilized a Genetic Algorithm (GA) to defines the battery's rated power and installed capacity necessary to compensate the wind variability. The results of this study showed that reasonable wind power curtailment is more economical to the system operation than no curtailment at all.

Additionally, Pumped Hydro Storage (PHS) systems are analyzed as an alternative measure to reduce renewable curtailment with adequate results in (ZANATTA; PEREIRA; FERREIRA, 2023). In a complementary manner, (YIN et al., 2022) compares different ESS technologies in order to minimize renewable energy curtailment, such as PHS, Compressed Air Energy Storage (CAES), Lithium-Ion energy storage system (Li-ion ESS) and Vanadium Redox Battery (VRB), considering an annual curtail rate reference of 5%.

The results showed that the PHS is the most cost-effective tool to reduce renewable curtailment in technical and financial aspects. Figure 56 shows the simulation results for the different ESS technologies which PHS are the ESS solution most charged during curtailment periods.

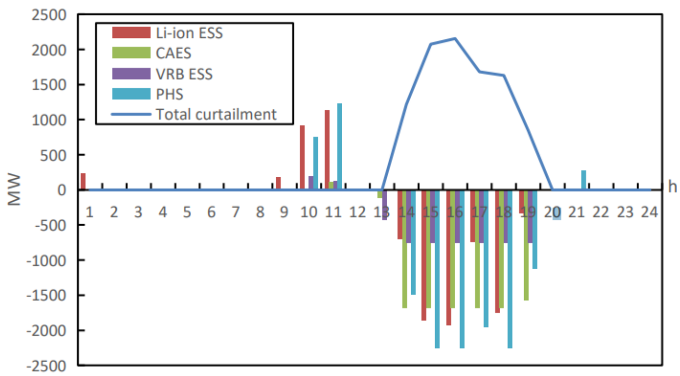


Figure 56: Results of comparative energy storage system technologies to reduce renewable curtailment (YIN et al., 2022).

4.3

Additional Aspects for Renewable Power Curtailment

In previous chapters, it is mentioned the impact of renewable curtailment in system operation regarding transmission congestions and generation oversupply. Nevertheless, the renewable curtailment also can cause market distortions considering its high generation variability and unpredictability in comparison with the conventional generation.

According to (NEWBERY, 2023), systems with high VRE penetration will have a certain amount of renewable curtailment inevitably. For that reason, VRE firm capacity must be adjusted to account its known variability in generation values, otherwise that energy could be overpaid.

The author shows that inadequate energy market rules for renewable curtailment can lead to a *Tragedy of commons* which it a concept where individual interests overcome system and social benefits. The article emphasizes that renewable generators continue to request system connection even with high rate of curtailment in the system, mainly because the real impact to the system is related to the *marginal curtailment* values, that increases over the years, and the market rules penalize *average curtailment* amounts. This cause market distortions as *marginal curtailment* can be three or four times greater than *average curtailment*.

The article proposes that wind and solar generation must be priced appropriately in the connection process due to its variability characteristics such as the increased of system reliability risks. As an example, conventional controllable synchronous generators support system inertia at no cost and intermittent renewable generators decrease system inertia and increase the need for more system reserves from other power plants. Therefore, the author suggests an additional cost of 10-20% of the annual fixed cost for intermittent renewable power plants to support system inertia.

On the other hand, besides all the implications of renewable power curtailment in the system operation and energy markets, (OLSON et al., 2014) presents an interesting study that compared two cases where in one case renewable curtail is penalized and in the other case the curtailment is used as a flexibility alternative, both in a simulated system with 40% renewable penetration.

The results are presented in Figure 57 and revealed that in the first case, where the renewable curtailment is discouraged, the system presented very relevant flexibility violations. On the other hand, in the case where curtailment is encourage, the operating cost is reduced and thermal power plants dispatch more efficiently. The optimal curtailed renewable energy reduces thermal ramp requirements and avoided unserved energy.

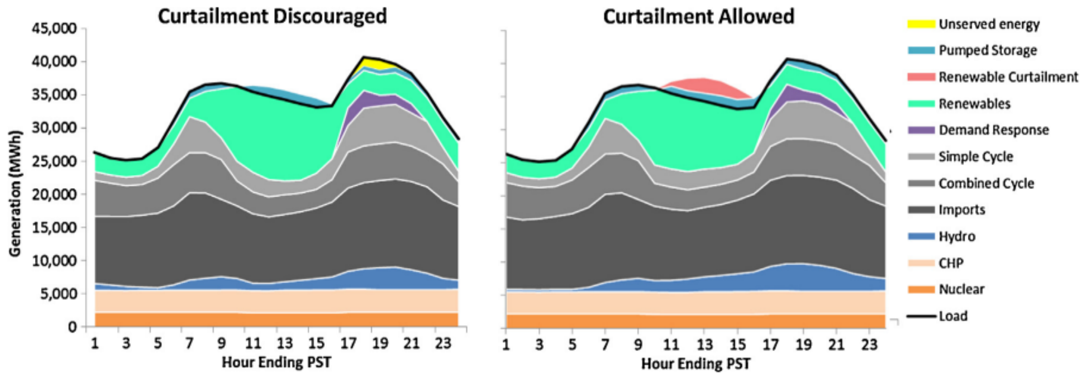


Figure 57: Results showing comparative renewable curtailment study-cases (OLSON et al., 2014).

In conclusion, the papers presented in this Chapter showed several methodologies and implementations regarding curtailment optimization, minimization and additional discussions related to market and other usages to maintain system security and reduce the system operating cost.

It is evident that system security it is criteria number one in the curtailment energy management of a system operation. However, complementary distribution rules should be discussed and defined to avoid discriminatory curtails and to produce adequate economic incentives for the generators . In case no measures to reduce renewable generation curtailment are implemented, the renewable energy mix target can still be achieved, but with a significantly higher VRE installed capacity and at the expense of high energy waste and inefficient investments, which are not desired by operators, regulators and stakeholders.

4.4
Summary and conclusions

Several studies have been conducted addressing the issue of renewable energy curtailment. These papers include topics related to the day-ahead model dispatch and real-time operation redispatch, the uncertainty of these renewable sources in generation forecasting methodologies, new aspects in transmission system configurations, reserves allocation and energy market designs.

All these relevant factors emphasizes the inevitability of intermittent renewable curtailment and the need for more grid flexibility and predictability. These aspects are fundamental to guarantee a system more resilient and secure in a intermittent renewable generation high penetration context. In addition, the importance of ESS for reducing renewable curtailment rates is widely discussed, as they are an important ally in the global energy transition. These papers presented different methodologies such as game theory, probabilistic forecasting, data-driven approaches that include artificial intelligence and neural networks models, among others methods and alternatives.

To conclude, the issue of renewable curtailment also refers to regulatory challenges, including articles that propose regulatory improvements, as an example, for an adequate distribution of curtailment, considering, historical curtailment data, flexibility available resources, including various others.

Table 4.1 presents a summary of more than thirty articles related to renewable energy curtailment research to give a overview of the variety of discussed topics. The *System Expansion* topic also includes system modernization aspects.

Reference and Country (Renewable Curtailment)	Energy Market	Fairness	Flexibility	Game Theory	Regulatory	Reserves	Statistics	Storage	System Expansion
1. (OLSON et al., 2014) United States (US)			X						
2. (VARGAS; BUSTOS-TURU; LARRAíN, 2015) Chile			X					X	
3. (ALI et al., 2015) Netherlands and Greece		X							
4. (ZHANG et al., 2015) China			X			X			
5. (MEHDIABADI; ZHANG; HEDMAN, 2015) US						X	X		
6. (KANE; AULT, 2015) UK		X			X				
7. (ROALD et al., 2016) Switzerland and US	X		X				X		
8. (ALVES; REIS; SHEN, 2016) Portugal					X				
9. (ANDONI et al., 2017) United Kingdom (UK)		X		X			X		X
10. (MASAUD et al., 2017) US			X				X		
11. (SHAO et al., 2017) China			X				X		
12. (DUI; ZHU; YAO, 2018) China							X	X	
13. (IIOKA; SAITOH, 2018) Japan		X							
14. (MEIER; TöBERMANN; BRAUN, 2019) Germany		X							
15. (IMPRAM; NESE; ORAL, 2020) UK and Turkey			X						
16. (STEINHäUSER; EISENACK, 2020) Germany	X								
17. (RAMESH; LI, 2020) US			X				X		
18. (MANAKARI et al., 2020) Sweden			X						X
19. (YANG; CHING, 2021) China						X	X		
20. (YANG et al., 2021) China							X		
21. (STRINGER et al., 2021) Australia		X						X	
22. (MORALES-ESPAñA; NYCANDER; SIJM, 2021) Netherland and Sweden	X		X		X		X		
23. (YIN et al., 2022) China								X	
24. (LEI et al., 2022) US and China						X	X		
25. (NEWBERY, 2023) UK	X								
26. (HARAG; URABE; KATO, 2023) Japan			X						
27. (PEDROSO et al., 2023) Portugal and Brazil		X			X				
28. (LEE; HUR, 2023) South Korea							X		X
29. (ZANATTA; PEREIRA; FERREIRA, 2023) Portugal								X	
30. (SOUSA; LAGARTO; FONSECA, 2024) Portugal								X	
31. (ALYAMI, 2024) Saudi Arabia		X		X					
32. (NOVAN; WANG, 2024) US	X								
33. (IULIANO; CARO; VACCARO, 2024) Italy	X		X						
34. (LIM; PARK, 2024) South Korea			X						
35. (CHEN; MATHIEU; SEILER, 2024) US						X	X		

Table 4.1: Summary of articles related to renewable power curtailment and specific topics and methodologies.

It is worth noting that the theme of renewable energy curtailment has been discussed in the academic literature since the beginning of the penetration of wind and solar energy into power systems. And that the topic *flexibility* is the major topic towards the renewable curtailment discussion. This topic includes risks from demand disruptions or line overloads, power plant ramp rates, renewable generation forecast errors, reserves requirements, and other definitions, metrics, and resources to support the system operator's ability to ensure continued secure energy supply.

Ultimately, in addition to covering several years and different topics and methodologies, as detailed and summarized in Table 4.1, the analyzed articles and reports are also verified to be distributed globally. This aspect highlights that renewable energy curtailment are a challenge worldwide in view of the accelerated growth of wind and solar sources in power systems surrounding past, nowadays and future energy transition goals.

5

Methodology

This Chapter presents the proposed methodology to define VRE curtailment for day-ahead planning considering the wind and solar energy uncertainties and co-optimization of hydroelectric reserves dispatch.

In the following sections, a description of the model will be presented, first showing an overview and a workflow of the proposed method, and then detailing the calculation of the wind and solar generation variation considering historical data and finally, the optimization model equations and the expected results.

The optimization model, including the Objective Function and constraints, considers Thermal Unit Commitment (TUC) and Hydropower Unit Commitment (HUC), restrictions related to hydropower reserves, in cases with fixed requirements and with endogenous optimization, and finally, a cutting plans method to include iteratively transmission system constraints through calculation of system sensitivity factors and worst-case transmission congestions.

This work aims to address the current challenges of high penetration of variable renewable energy in the grid, incorporating the variability of these sources into an unique model for day-ahead generation and reserves dispatch scheduling. For that reason, the proposed methodology has the potential to increase transparency and predictability of the renewable curtailment, measuring the costs associated with increased system uncertainty.

5.1

Overview

The proposed model aims to support the system operator's decision-making and approximate the day-ahead dispatch to the real-time verified generation in a context of more dynamic and complex system operation. It is relevant to consider the intrinsic uncertainty of the variable renewable energy in the generation and reserve dispatch model, along with a transparent VRE curtailment criterion.

To represent the VRE intermittency, the proposed model considers the hourly variability of wind and solar generation in the allocation of hydraulic reserve for system frequency control. This approach is improved, for each case studied, in order to provide greater representation of the wind and solar generation uncertainties by region, hourly and by power plant. In addition, it also contributes to greater predictability to generators and Operators, considering the reduced need for post-model adjustments and in real-time operation.

Furthermore, to ensure the safety of the electrical system, the model includes power flow constraints considering the worst-case scenarios of violated transmission lines. This cutting planes method, proposed by (CARVALHO, 2019), brings greater safety to the dispatch and substantially reduces the number of constraints considered in the optimization.

In this method, the power flow worst-case (wc) constraint is an *umbrella restriction* and it is created based on the results of a steady-state power flow analysis. The period of the day-ahead t_{wc} and the transmission line l^{wc} when the greatest network violation occurs is identified, then, the sensitivity factors β_{lb} are calculated considering the power flow variation on the most violated transmission line $f_{l^{wc}}$ related to the variation of generation g injected. The calculation of system sensitivity factors of transmission lines and system buses b is performed, for each iteration until the violation is less than 1%, according to the Equation 5-1.

$$\beta_{l^{wc}b} = \frac{\partial f_{l^{wc}}}{\partial g_b} \tag{5-1}$$

Additionally, the model includes a complete range of unit commitment constraints for hydro and thermal generation, and a co-optimization of hydro reserves and VRE curtailment considering the costs of the reserves and the VRE uncertainties. In Brazil, nowadays, the hydroelectric reserves for system frequency control are calculated considering a fixed requirement value based on load forecast and wind generation variations (ONS, 2016)(ONS, 2022d).

To better illustrate the methodology steps, Figure 58 presents a summarized workflow of the proposed model.

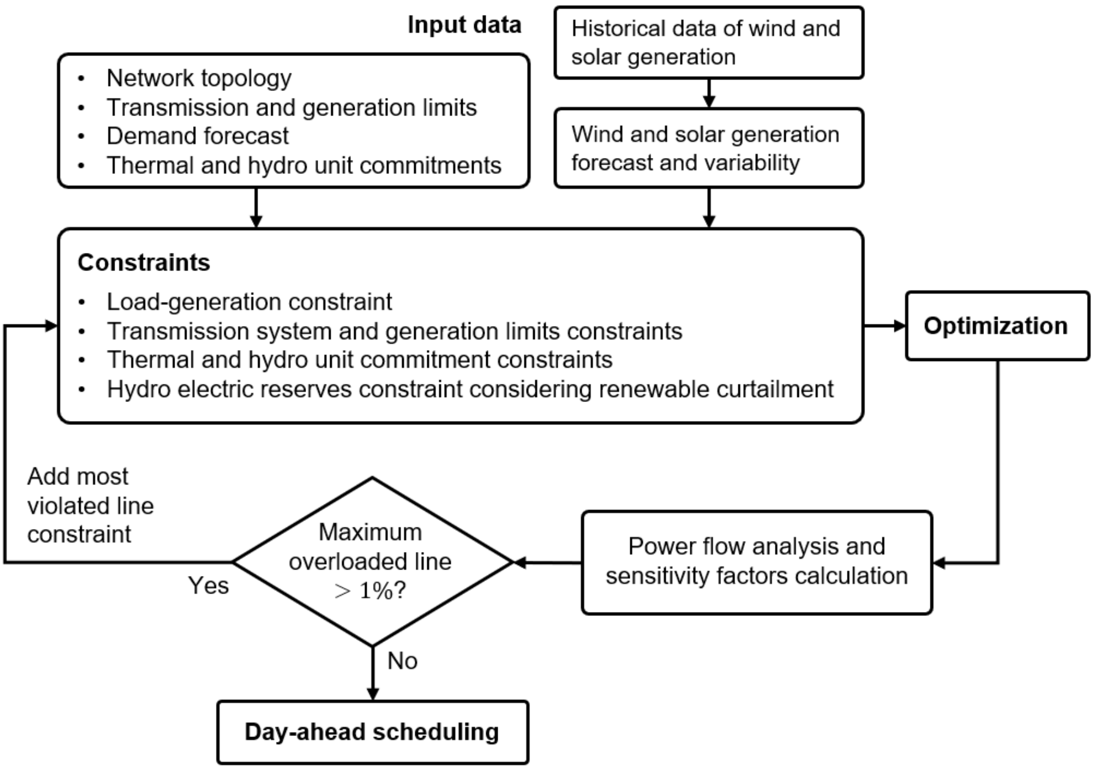


Figure 58: Workflow of the proposed model for day-ahead scheduling.

The following sections detail the optimization model, including the equations of Objective Function and constraints, and finally the expected results.

5.2
Objective Function

The Objective Function is the minimization of generation dispatch and reserves costs and it is presented in Equation 5-2.

$$\min_{\substack{g_{it}, r_{it}^{up}, r_{it}^{dn}, \\ \alpha_{FCF}, \delta_{it}}} \sum_{t \in T} \sum_{i \in I^C} \left[c_i g_{it} + c_i^{res} (r_{it}^{up} + r_{it}^{dn}) \right] + \alpha_{FCF}, \tag{5-2}$$

$$\text{where } i \in (I = I^T U I^H U I^{NC} = I^C U I^{NC}).$$

The I^C is defined as the set of controllable generators i, for instance, thermal I^T and hydroelectric power plants I^H. Then, the I^{NC} is related to the set of non-controllable generators, namely wind and solar power plants. In this model, no penalty cost or financial compensation for the intermittent renewable generation curtailment is considered. The objective of the model is to optimize the renewable curtailment endogenously, through the reserve constraints as explained in the following items.

The objective function also includes the *Future Cost Function* (FCF), α_{FCF}, which is a decision variable influenced by present decisions and with parameters linked to previous optimization models for longer horizons. Its definition is indirectly associated with the *water cost* and considers the volumes stored in the reservoirs of the system's hydroelectric plants V^T at the end of the model horizon. Thus, for n number of reservoirs, a multidimensional FCF is obtained and, it is inversely related to the reservoir amounts as shown in Figure 59.

Then, the FCF, α_{FCF}, can be defined as the minimum value greater than or equal to all segments composing the piecewise linear function, for k cuts, considering the reservoir vector V^T of each hydroelectric power plant i, as presented in Equation 5-3. The independent coefficient is represented as A

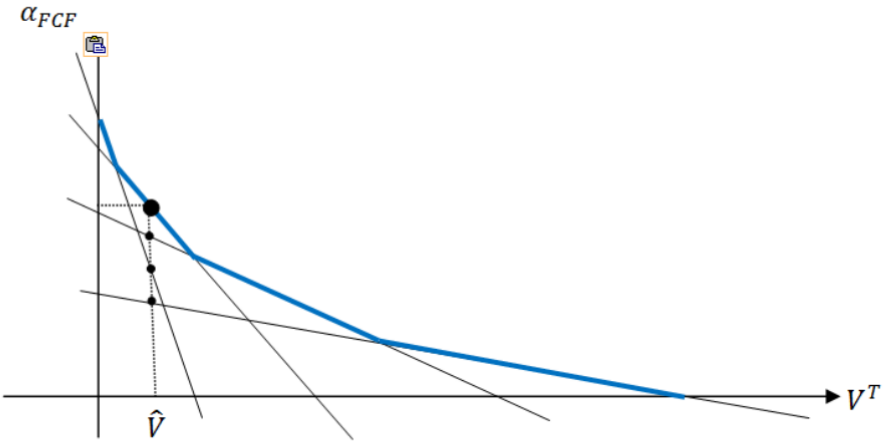


Figure 59: Illustrative example of the Future Cost Function α_{FCF} in relation to the reservoir's vector V^T (CEPEL, 2024).

and B is the coefficient related to each hydroelectric power plant (CEPEL, 2024).

$$\alpha_{FCF} \geq A_k + \sum_{i \in I^H} B_{ik}(V^T), \quad \forall k \in K, \quad \forall i \in I^H \tag{5-3}$$

The decisions variables shown in Equation 5-2 are summarized for clarity and conciseness, and include thermal and hydro generation dispatch g_i, upward and downwards hydroelectric reserves r_{it}^{up}, r_{it}^{dn} and the VRE curtailment amounts δ_{it} in every half-hour t for the following day. The complete decision variables of the model includes the unit commitment values and are fully presented in the Appendix B.

5.3
Constraints

Energy Balance

The energy balance constraint is presented in Equation (5-4) and establishes the supply of the energy net demand forecast $\hat{d}_t$ by the total generation of thermal, hydro, wind and solar power plants g_{it}, in each period of time t.

$$\sum_{t\in T}\Big(\sum_{i\in I^C} g_{it} + \sum_{i\in I^{NC}} \hat{g}_{it}\Big) = \sum_{t\in T}\Big(\hat{d}_t + \sum_{i\in I^{NC}} \delta_{it}\Big) \tag{5-4}$$

The total of wind and solar power plants' generation is defined as the difference between the hourly generation forecast $\hat{g}_{it}$ and generation curtailment δ_{it} for the non-controllable generators I^{NC}.

Generation limits

The generation dispatch of thermal and hydroelectric power plants g_{it} are limited by their minimum and maximum generation capacities for each period t, as shown in Equation 5-5.

$$G_{it}^{min} \leq g_{it} \leq G_{it}^{max}, \quad \forall t \in T, \quad \forall i \in I^C \tag{5-5}$$

Similarly, the total VRE generation, including the forecast generation $\hat{g}_{it}$ and curtailed amount δ_{vt}, are limited by the minimum and maximum generation capacities of power plants, as presented in Equation 5-6 .

$$G_{it}^{min} \leq \hat{g}_{it} - \delta_{it} \leq G_{it}^{max}, \quad \forall t \in T, \quad \forall i \in I^{NC} \tag{5-6}$$

Unit commitment and Water balance

The model considers the thermal and hydro *unit commitment* (UC) constraints, including binary variable decisions (x, y, z) that represent *on* and *off* generation units' status and minimum operating *(T-off)* and non-operating *(T-off)* periods. These values are limited by the minimum and maximum generation values along with the generators' ramps and reserves restrictions.

Additionally, for the hydroelectric power plants, it includes the constraints related to the water balance that relates the water reservoir among other hydro power plants' reservoirs. Theses restrictions contain variable decisions of reservoir volume vol, water inflows (lateral inf, turbine q and spilled s), water travel time τ, water diversion dv and spillway operation status w, as detailed in (CARVALHO, 2019)(RAMOS, 2015).

For simplicity, the *unit commitment* constraints for thermal generation, UC^T, are represented as Equation 5-7 and the hydro unit commitment constraints, UC^H, are represented as Equation 5-8.

$$(g_{it}, x_{it}, y_{it}, z_{it}) \in UC^T, \quad \forall i \in I^T \tag{5-7}$$

$$(g_{it}, x_{it}, y_{it}, z_{it}, s_{it}, s_t^{us}, q_t^{us}, vol_{nt}, inf_{nt}, dv_{nt}, w_{nt}) \in UC^H, \forall i \in I^H \tag{5-8}$$

The hydro balance constraints from Equation 5-8 are based on the relations among water reservoirs of hydroelectric power plants as shown in Figure 60.

The complete thermal and hydro *unit commitment* and water balance constraints equations are found in the Appendix B.

Power flow

The power flow restrictions are important to guarantee electrical system security when allocating generation dispatch and VRE curtailment. The power flow constraint considered in the proposed model is presented in Equation 5-9 and considers the Kirchhoff First Law (or Current Law) for each system bus b and the sensitivity factors β_{lb}, which relates the line l and bus b of the system.

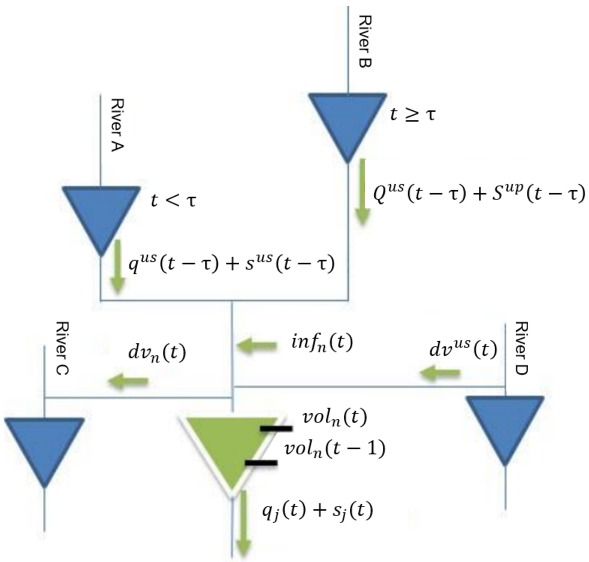


Figure 60: Composition of the reservoir of a hydro power plant n in period t. Translated from (CARVALHO, 2019).

The sensitivity factor β_{lb} is calculated considering the worst-case (wc) scenario, and the maximum F_l^{max} and minimum F_l^{min} capacities of the most violated transmission line l^{wc}.

$$F_{l^{wc}}^{min} \leq \sum_{b \in B} \left\{ \beta_{l^{wc}b} \cdot \sum_{t \in T} \left[\sum_{i \in I^C} g_{ibt} + \sum_{i \in I^{NC}} (\hat{g}_{ibt} - \delta_{ibt}) - \hat{d}_{bt} \right] \right\} \leq F_{l^{wc}}^{max}, \quad \text{(5-9)}$$

$$\forall l^{wc} \in L^{wc}$$

As described in Section 5.1 and shown in the flowchart of Figure 58, the constraint 5-9 is calculated for each model iteration and it is added to the optimization model until the system violation is less than 1% of the most violated transmission line capacity. In this cutting planes method, the number of power flow constraints is considerably reduced, and hence, the model complexity and processing time.

It can be observed that Equation 5-9 also considers the allocation of variable renewable energy curtailment δ_{ibt} considering the power flow analysis and sensitivity factors.

Hydroelectric Reserves

The upward and downward hydroelectric power plants' reserves, r_{it}^{up} and r_{it}^{dn}, are limited by R_t^{up} and R_t^{dn} respectively, as shown in Equations 5-10 and 5-11, for each period t.

$$\sum_{i \in I^H} r_{it}^{up} \geq R_t^{up}, \quad \forall t \in T \tag{5-10}$$

$$\sum_{i \in I^H} r_{it}^{dn} \geq R_t^{dn}, \quad \forall t \in T \tag{5-11}$$

The values of R_t^{up} and R_t^{dn} are defined considering the variability of demand γ and variable renewable generation κ.

The values of demand variability are defined according to the Brazilian Grid Code (ONS, 2022d), given by 4% for upward reserves requirements γ^{up} and 2.5% for downward reserves γ^{dn}.

In that instance, it is considered the opportunity cost of allocating operating reserves in a system with high variability from renewable wind and solar generation. By allocating reserves with associated costs in the day-ahead scheduling of a system with high renewable generation intermittency, the total system cost could be increased due to the need of allocating larger reserves to ensure system balance and security. Nevertheless, in a model with adequate representation of variability and reserve requirements, the reserves allocation is carried out more efficiently and reduces the reserves' opportunity costs.

Then, to calculate the different cases of reserve requirements, the following variability indexes are evaluated per subsystem s for each day d and hour t of recent historical data:

$$\Delta_{dt} = \frac{g_{d(t+1)} - g_{dt}}{g_{dt}}, \quad \forall d \in D, \quad \forall t \in T \tag{5-12}$$

$$\Delta_{dt}^{up} = -\min(\Delta_{dt}, 0), \quad \forall d \in D, \quad \forall t \in T \tag{5-13}$$

$$\Delta_{dt}^{dn} = \max(\Delta_{dt}, 0), \quad \forall d \in D, \quad \forall t \in T \tag{5-14}$$

Based on the upward and downward inter-period variability indexes (Δ_{dt}^{up} and Δ_{dt}^{dn}), we can use different strategies for calculating the reserve requirements. These strategies are presented in the following cases.

» **Case 1 - Current fixed reserves requirements:** The hydroelectric reserves requirements are calculated as presented in Equation 5-15 and Equation 5-16, considering the variability of demand and variable renewable generation.

$$R_t^{up} = \gamma^{up} \hat{d}_t + \sum_{s \in S} \kappa_s \sum_{i \in I_s^{wind}} \hat{g}_{it}, \quad \forall t \in T \tag{5-15}$$

$$R_t^{dn} = \gamma^{dn} \hat{d}_t + \sum_{s \in S} \kappa_s \sum_{i \in I_s^{wind}} \hat{g}_{it}, \quad \forall t \in T \tag{5-16}$$

The values of κ_s are established as 6% for negative and positive variations of wind power plants connected in Northeast subsystem s and 15% for negative and positive variations of wind power plants connected in South subsystem s.

These values are fixed according to the current methodology implemented in Brazil (ONS, 2022d). Figure 61 presents the calculated negative and positive generation variations in Northeast and South subsystems, published by (ONS, 2016) to define the wind power variabilities for reserves requirements.

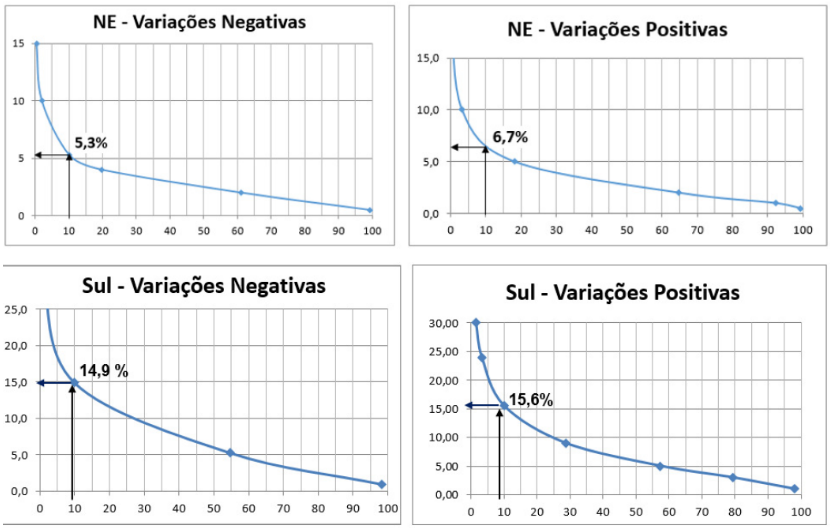


Figure 61: Negative and positive wind generation variations per subsystems in Brazil (ONS, 2016).

» **Case 2 - Incorporation of variable renewable curtailment:** The reserves constraints are improved to consider, in addition to the variable renewable generation forecast, the generation curtailment δ_{it}, as presented in Equation 5-17 and 5-18. This improvement aims to co-optimize VRE reductions in relation to the hydroelectric reserves allocation.

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{s \in S} \kappa_s \sum_{i \in I_s^{wind}} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \qquad (5\text{-}17)$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{s \in S} \kappa_s \sum_{i \in I_s^{wind}} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-18}$$

The values of κ_s are fixed as Case 1, being 6% for negative and positive variations of wind power plants connected in Northeast subsystem s and 15% for negative and positive variations of wind power plants connected in South subsystem s.

» **Case 3 - Incorporation of updated variable renewable generation variabilities:** The reserves requirements, considering variable renewable curtailment, are improved to consider updated wind and solar variabilities (non-controllable power plants), I^{NC}, as Equation 5-19 and Equation 5-20.

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{s \in S} \overline{\kappa}_s \sum_{i \in I_s^{NC}} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-19}$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{s \in S} \overline{\kappa}_s \sum_{i \in I_s^{NC}} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-20}$$

The values of $\overline{\kappa}_s$ are calculated as Equation 5-21 considering the hourly variation from historical generation and, as shown in Equation 5-22 which calculates the average of the quantiles α of the negative and positive generation variations of the aggregated power plants connected in the system region s.

$$\Delta_{dt} = \frac{g_{d(t+1)} - g_{dt}}{g_{dt}}, \quad \forall d \in D, \quad \forall t \in T \tag{5-21}$$

$$\overline{\kappa}_s = \frac{\Delta^{up}_{[(DT)\alpha]} + \Delta^{dn}_{[(DT)\alpha]}}{2}, \quad \text{where } \alpha = 90\%, \quad \forall s \in S \tag{5-22}$$

The value of $\Delta_{[(DT)\alpha]}$ is equivalent to the number located in the $(DT)\alpha$-th element of the total calculated generation variations values, for upward and downwards contributions, considering each day d of the total D historical days and each period t of the total $T = 24$-hours of the day.

In the simulation of the medium-scale system, the variability of wind power plants in Northeast and South subsystems are updated. In the simulation of the large-scale system, the variability of solar generation and other subsystems, such as North and Southeast, are also incorporated.

» **Case 4 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions:** The reserves' limits constraints are incremented by renewable variability metrics considering the generation variations per hour and per separated contributions for upward and downward reserves allocation, as presented in Equation 5-23 and Equation 5-24.

$$R^{up}_t = \gamma^{up}\hat{d}_t + \sum_{s\in S} \kappa^{(\alpha)up}_{st} \sum_{i\in I^{NC}_s} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-23}$$

$$R^{dn}_t = \gamma^{dn}\hat{d}_t + \sum_{s\in S} \kappa^{(\alpha)dn}_{st} \sum_{i\in I^{NC}_s} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-24}$$

The upward and downward variability metrics $\kappa^{(\alpha)up/dn}_{st}$ are defined as the truncated results of the calculated positive and negative generation variations as explained below. The hourly negative renewable generation variations contributes to the allocation of upward reserves for system frequency control. Similarly, the positive generation variation contributes to the downward hydro reserves allocation, as presented in Equation 5-25, Equation 5-26 and Equation 5-27.

$$\Delta_{dt} = \frac{g_{d(t+1)} - g_{dt}}{g_{dt}}, \quad \forall d \in D, \quad \forall t \in T \tag{5-25}$$

$$\Delta_{dt}^{up} = -\min(\Delta_{dt}, 0), \quad \forall d \in D, \quad \forall t \in T \tag{5-26}$$

$$\Delta_{dt}^{dn} = \max(\Delta_{dt}, 0), \quad \forall d \in D, \quad \forall t \in T \tag{5-27}$$

Then, the $\kappa_{st}^{(\alpha)up/dn}$ are defined considering the quantile distribution, with $\alpha = 90\%$, of the calculated truncated values, per subsystem s and hour t, as presented in Equation 5-28 and Equation 5-29.

$$\kappa_{st}^{(\alpha)up} = \Delta_{[D\alpha]st}^{up}, \quad \forall s \in S, \quad \forall t \in T \tag{5-28}$$

$$\kappa_{st}^{(\alpha)dn} = \Delta_{[D\alpha]st}^{dn}, \quad \forall s \in S, \quad \forall t \in T \tag{5-29}$$

The value of $\Delta_{[D\alpha]st}$ is equivalent to the number located in the $D\alpha$-th element of the calculated generation variations values for each subsystem s and hour t considering the calculated values for all the D historical days.

» **Case 5 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions, and individual power plants variabilities:** The reserves requirements are enhance to implement renewable variability metrics for each power plant, considering the individual standard deviation contribution in relation to the total standard deviation, as presented in Equation 5-30 and Equation 5-31.

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{i \in I^{NC}} \kappa_{it}^{\sigma,up}(\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-30}$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{i \in I^{NC}} \kappa_{it}^{\sigma,dn}(\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-31}$$

In this case, it is calculated a factor ϵ_{it} for each power plant i at each period t in order to distribute the total generation variation metric κ_{st}, calculated in Case 4, for a quantile of $\alpha = 90\%$, proportionally to the individual power plants' uncertainties, as presented in Equation 5-32 and Equation 5-33.

$$\kappa_{it}^{\sigma,up} = \epsilon_{it}^{up}\kappa_{st}^{(\alpha)up}, \quad \forall i \in I^{NC}, \quad \forall s \in S, \quad \forall t \in T \tag{5-32}$$

$$\kappa_{it}^{\sigma,dn} = \epsilon_{it}^{dn} \kappa_{st}^{(\alpha)dn}, \quad \forall i \in I^{NC}, \quad \forall s \in S, \quad \forall t \in T \tag{5-33}$$

The factor ϵ_{it} is calculated as the share of individual standard deviation $\sigma_{it}^{up/dn}$ in relation to the total sum of standard deviation of the wind and solar power plants, as shown in Equation 5-34 and Equation 5-35.

$$\epsilon_{it}^{up} = \frac{\sigma_{it}^{up}}{\sum_{i \in I^{NC}} \sigma_{it}^{up}}, \quad \forall i \in I^{NC}, \quad \forall t \in T \tag{5-34}$$

$$\epsilon_{it}^{dn} = \frac{\sigma_{it}^{dn}}{\sum_{i \in I^{NC}} \sigma_{it}^{dn}}, \quad \forall i \in I^{NC}, \quad \forall t \in T \tag{5-35}$$

The standard deviation $\sigma_{it}^{(\alpha)up/dn}$ is related to the generation variation of each power plant i, for each day d and hour h, considering the separated contributions for upward and downward reserves, as presented in Equation 5-36, Equation 5-37 and Equation 5-38, and the mean value of the variability metrics $\overline{\kappa}_t^{up/dn}$, as shown in Equation 5-39 and Equation 5-40.

$$\Delta_{idt} = \frac{g_{id(t+1)} - g_{idt}}{g_{idt}}, \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{5-36}$$

$$\Delta_{idt}^{up} = -\min(\Delta_{idt}, 0), \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{5-37}$$

$$\Delta_{idt}^{dn} = \max(\Delta_{idt}, 0), \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{5-38}$$

$$\sigma_{it}^{up} = \sqrt{\frac{1}{D}\sum_{d \in D}(\Delta_{idt}^{up} - \overline{\kappa}_{st}^{up})^2}, \quad \forall i \in I^{NC}, \forall s \in S, \forall t \in T \tag{5-39}$$

$$\sigma_{it}^{dn} = \sqrt{\frac{1}{D}\sum_{d \in D}(\Delta_{idt}^{dn} - \overline{\kappa}_{st}^{dn})^2}, \quad \forall i \in I^{NC}, \forall s \in S, \forall t \in T \tag{5-40}$$

» **Case 6 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions, and individual power plants with no relative standard deviation contribution:** The final case considers the generation variation of each power plant based on their individual mean historical generation variation, as shown in Equation 5-41 and Equation 5-42.

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{i \in I^{NC}} \overline{\kappa}_{it}^{up}(\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-41}$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{i \in I^{NC}} \overline{\kappa}_{it}^{dn}(\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{5-42}$$

The Equation 5-43, Equation 5-44 and Equation 5-45 presented below describe the calculation of generation variation, positive and negative contribution of each power plant i, day d and hour t.

$$\Delta_{idt} = \frac{g_{id(t+1)} - g_{idt}}{g_{idt}}, \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{5-43}$$

$$\Delta_{idt}^{up} = -\min(\Delta_{idt}, 0), \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{5-44}$$

$$\Delta_{idt}^{dn} = \max(\Delta_{idt}, 0), \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{5-45}$$

The variability metrics $\overline{\kappa}_{it}^{up/dn}$ of the reserves requirements constraints are defined as the historical mean value of the positive and negative contributions of the truncated values of generation variations, as presented in Equation 5-46 and Equation 5-47.

$$\overline{\kappa}_{it}^{up} = \frac{1}{D} \sum_{d \in D} \Delta_{idt}^{up}, \quad \forall i \in I^{NC}, \quad \forall t \in T \tag{5-46}$$

$$\overline{\kappa}_{it}^{dn} = \frac{1}{D} \sum_{d \in D} \Delta_{idt}^{dn}, \quad \forall i \in I^{NC}, \quad \forall t \in T \tag{5-47}$$

For complete reference, all model equations detailed in this Chapters are listed in the Appendix B. In the next Section, it is implemented the proposed methodology for the cases in a medium and large-scale power system and the obtained results are analyzed.

5.4

Expected Results

This work has the objective to present, through the proposed methodology and model detailed in this Chapter, a transparent, efficient and secure procedure to supports system operator's decision-making for hydro-thermal generation, hydro reserves and renewable generation curtailment dispatch in the day-ahead planning process.

The model incorporates operational constraints criteria (*unit commitment* restrictions), in addition to the grid constraints based on system sensitivity factors, and uncertainty metrics of intermittent renewable generation. Therefore, the main contribution of the model is to optimize renewable curtailment considering load-generation balance, power flow restrictions and hydro reserves allocation through the wind and solar uncertainties.

Furthermore, for a complete analysis of the case studies, detailed in the following Chapter, a simulation of the real-time operation is also performed with an optimization model considering verified data and the results from the day-ahead optimization model, as explained below:

» Thermal generation is the scheduled dispatch from the day-ahead optimization model results;

» Hydro generation is limited between the dispatched upward and downward hydro reserves from day-ahead optimization model results;

» Wind and solar energy sources are the verified generation from historical data of the following day; and

» The Objective Function includes the penalization of the intermittent renewable generation curtailment and load shedding.

Therefore, in the next Chapter, it will be presented a medium and a large study-cases, which considers real data from Brazilian Electrical System, to verify the adequacy of the proposed methodology for generation, reserves dispatches and intermittent renewable generation curtailment optimization.

The proposal to study methodologies for improving reserve allocation in a comprehensive model that considers renewable curtailment for electrical and energy reasons aims to present a greater representation of the uncertainties of intermittent renewable energy and, consequently, to adequately measure system costs in a more dynamic and complex scenario, while bringing day-ahead dispatch closer to real-time operation. These performance criteria will be evaluated in the results of the case studies.

6

Cases Studies

In this chapter, the proposed model is implemented in a medium-sized system of 30-buses and in a larger system with 6,181-buses. Six cases are simulated to represent the daily programming process, as detailed in the Section 5.2, and summarized as follow:

» Case 1 - Current hydro reserves methodology;

» Case 2 - Incorporation of variable renewable curtailment;

» Case 3 - Incorporation of variable renewable curtailment and updated generation variability;

» Case 4 - Incorporation of variable renewable curtailment, updated generation variability hourly, and separated upward and downward contributions;

» Case 5 - Incorporation of variable renewable curtailment, updated generation variability hourly, upward, downward contributions, and individual power plants variabilities; and

» Case 6 - Incorporation of variable renewable curtailment, updated generation variability hourly, upward, downward contributions, and individual power plants with no relative standard deviation contribution.

The results found are detailed and analyzed comparing with the expected objectives. Furthermore, the day-ahead scheduling results are performed with verified load and intermittent renewable generation to simulate the real-time operation of the following day.

The hourly wind forecasts, and generation variation are calculated in *R* programming language and the day-ahead planning optimization model and real-time verified load and generation are implemented in *Julia* programming language.

6.1
30-Bus System

6.1.1
Characteristics of the system

The characteristics of the 30-bus system, the wind power forecast and generation variation, and the results obtained are detailed below.

The electrical system of this medium-sized case study consists of 30 buses, 45 lines, 10 thermal power plants (TPP), 8 hydraulic power plants (HPP) and 9 wind power plants (WPP), as shown in Figure 62.

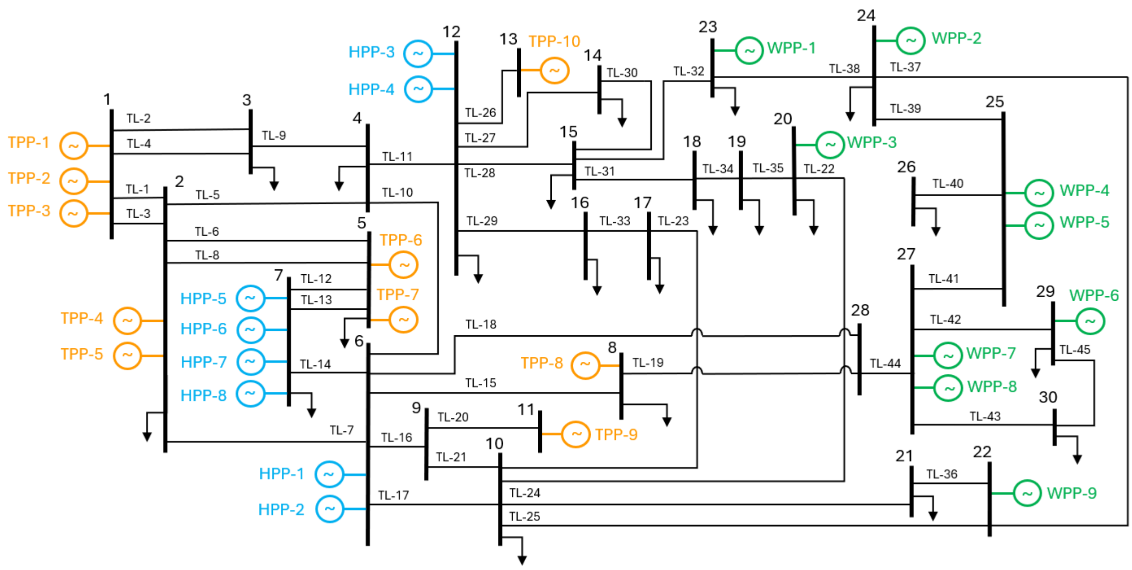


Figure 62: Diagram of 30-bus system.

The installed capacities of each energy source, load demand and energy matrix of the system are shown in Figure 63. The characteristics of TPP, coal or gas combined cycled (CC), are presented in Table 6.1, the characteristics of HPP are presented in Table 6.3 and the installed capacities of WPP are presented in Table 6.2. Furthermore, in this medium-sized case study the future cost function is not considered.

	MW	%
Total Installed Capacity	754	100
Wind Installed Capacity	302	40.0
Hydro Installed Capacity	235	31.2
Thermal Installed Capacity	217	28.8
Load Demand	228 MW	

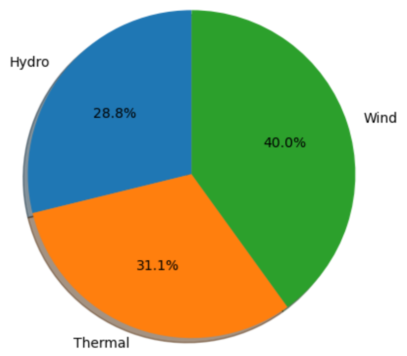


Figure 63: 30-bus system installed capacity and energy mix.

TPP	Gmin (MW)	Gmax (MW)	Ramp Down (MW)	Ramp Up (MW)	Time-off (half-hour)	Time-on (half-hour)	Fuel	Fuel Cost ($)	Bus
1	23.4	23.4	5	5	0	48	Coal	119.28	1
2	23.3	23.3	5	5	48	0	Coal	119.28	1
3	23.3	23.3	5	5	48	0	Coal	72.63	1
4	8.5	33.5	25	25	2	0	Gas-CC	64.06	2
5	8.5	33.5	25	25	2	0	Gas-CC	64.06	2
6	2.5	10.0	7	5	2	0	Gas-CC	12.79	5
7	2.5	10.0	7	5	2	0	Gas-CC	12.79	5
8	2.5	10.0	7	5	2	0	Gas-CC	12.79	8
9	2.5	10.0	7	5	2	0	Gas-CC	12.79	11
10	10.0	40.0	20	20	2	0	Gas-CC	63.00	13

Table 6.1: Thermal power plants data for 30-bus system.

The historical wind generation data of the following nine wind power plants (WPP) were obtained from real wind generation data in Brazil (ONS, 2024b):

1. WPP-1 Curva dos Ventos (BA);
2. WPP-2 Areia Branca (BA);
3. WPP-3 Caetité (BA);
4. WPP-4 Baixa do Feijão (CE);
5. WPP-5 Faísa (CE);
6. WPP-6 Xangri-lá (RS);
7. WPP-7 Santa Vitória do Palmar (RS);

HPP	Gmin (MW)	Gmax (MW)	Ramp Up/ Down (MW)	Time-off (half-hour)	Time-on (half-hour)	Reserves Cost ($)	Bus
1	4.6	25.2	11	0	8	20	6
2	4.6	25.2	11	0	8	20	6
3	16.48	39.2	10	0	8	177	12
4	15.48	39.2	10	0	8	408	12
5	10.88	26.6	10	0	0	10	7
6	10.88	26.6	10	0	0	10	7
7	10.88	26.6	10	0	0	10	7
8	10.88	26.6	10	0	0	10	7

Table 6.2: Hydro power plants data for 30-bus system.

WPP	1	2	3	4	5	6	7	8	9	Total
Installed capacity (MW)	54	25	29	15	15	32	58	13	61	302

Table 6.3: Wind power plants installed capacities for 30-bus system.

8. WPP-8 Água Doce (SC); and

9. WPP-9 Casa Nova (BA).

The WPP-1, WPP-2, WPP-3 and WPP-9 are located in the state of Bahia (BA), in the northeast region of Brazil. WPP-4 and WPP-5 are located in the state of Ceará (CE), also in the Northeast region. Then, WPP-6 and WPP-7 are located in the state of Rio Grande do Sul (RS), in the extreme South of the country. Finally, WPP-8 is located in the state of Santa Catarina (SC), also in the Southern region.

These plants were chosen considering the geographic distribution of wind farms in Brazil, where most of them are located in the Northeast and a minority in the Southern region. To illustrate, Figure 64 shows the detailed historical data obtained for WPP-2, WPP-4, WPP-6 and WPP-8. Different behaviors can be observed in the history data of wind generation. Wind farms located in the Northeast region have more seasonal generation, while the plants connected to the South of the system has more intermittent wind generation. As will be seen in the calculations of generation variations, the South region actually has greater intermittency compared to the plants in the Northeast region.

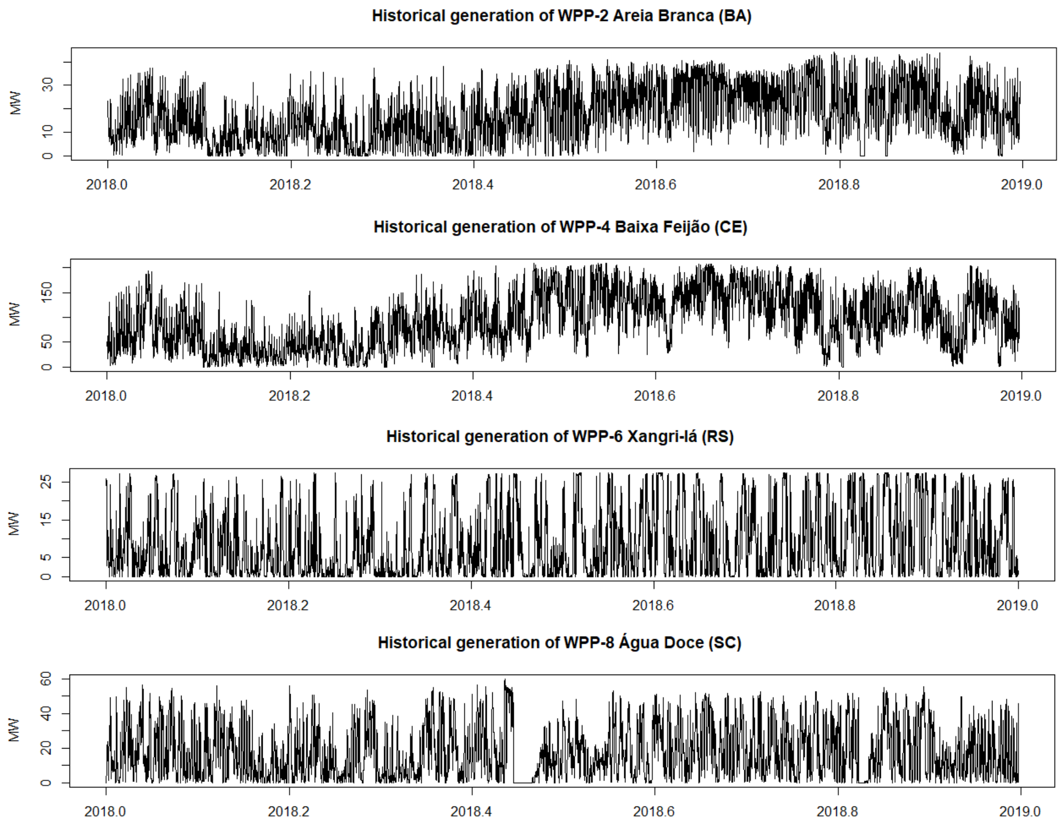


Figure 64: Historical annual generation of WPP-2, WPP-4, located in the North region, and WPP-6, WPP-8 located in the South region of Brazil.

6.1.2

Wind and solar generation forecast and variability

Wind generation forecasting is calculated using an Autoregressive Integrated Moving Average (ARIMA) method based on historical generation. ARIMA is a widely known and implemented model for time series forecasting, including wind generation forecasts (ELDALI et al., 2016)(ZHANG et al., 2021)(LI; SABAS; MENDéZ, 2022).

Figure 65 shows the total forecasted wind generation for the day-ahead scheduling and the verified generation for the 30-bus system operation. Additionally, Figure 66 detailed the wind power forecasting and the verified generation for each power plant.

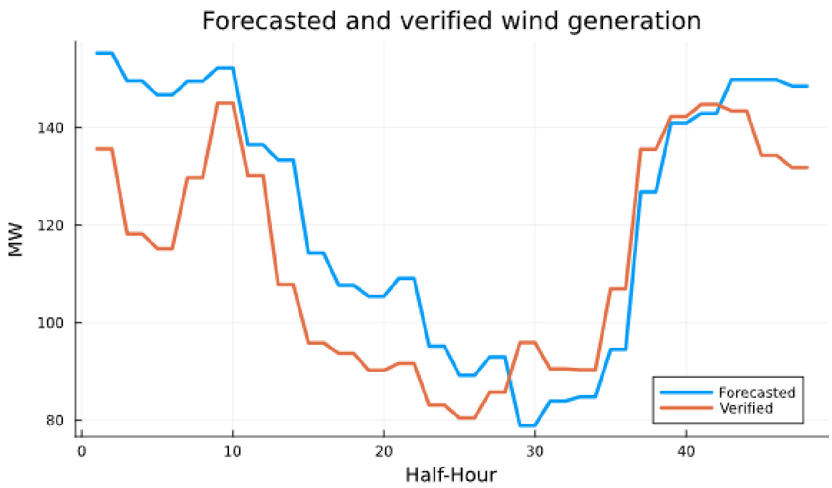


Figure 65: Total forecasted compared with total verified wind generation for 30-bus system.

Figure 66: Individual forecasted and verified wind generation of the 30-bus system power plants.

For Case 1 and 2, the generation variation defined in the Brazilian Electric Grid Code is implemented, as being $\kappa_{NE} = 6\%$ of the predicted wind generation connected in the Northeast region and $\kappa_S = 15\%$ for the predicted wind generation connected in the South region as detailed in Section 5.3.

For Cases 3, 4, 5 and 6, it is calculated the generation variation based on the historical hourly wind generation data. Firstly, to simulate Case 3, it is verified the median value of the wind generation variability for a quantil of $\alpha = 90\%$ considering the positive and negative contributions to upwards and downwards reserves. As shown in Figure 67, the mean generation variation in the Northeast region is approximately equal to $\overline{\kappa}_{NE} = 10\%$ and for the South region it is equivalent to $\overline{\kappa}_{S} = 31\%$, which is the region with much more intermittent daily wind generation as observed in the historical data.

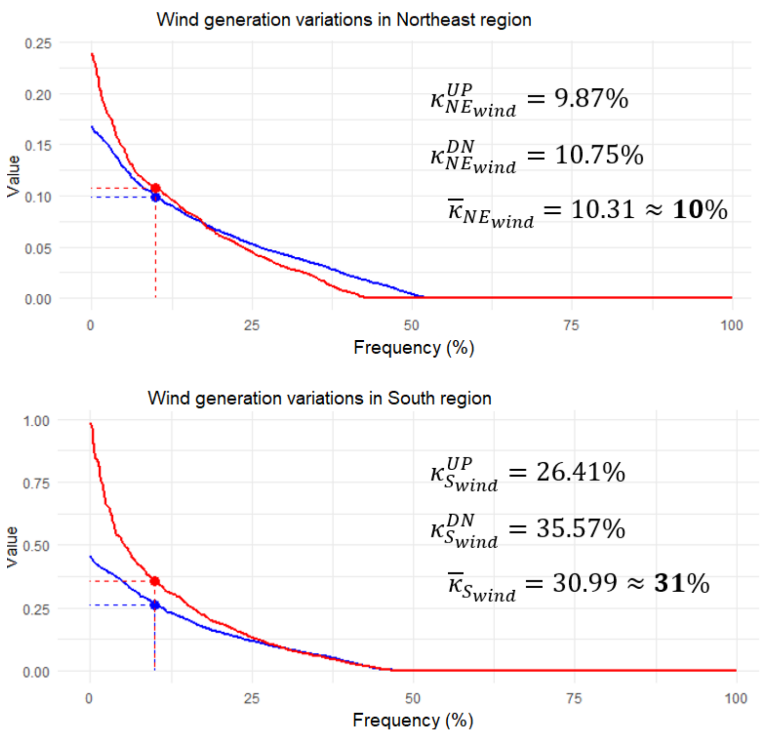


Figure 67: Quantil of 90% for wind generation variability per region of 30-bus system - Case 3.

In Case 4, it is calculated the generation variation hourly for a quantile of 90% for positive and negative contributions and per region, as presented in Figure 68.

It can be verified that the positive variation in generation increases at the end of the day for the Northeast and South regions, both at 7pm, reaching 46.42% in the Northeast and 98.48% in the South, and additionally during the day in the South region with the second highest variation of 71.52% at 12pm. For negative generation variation, a minimum value of 43.66% is verified in the

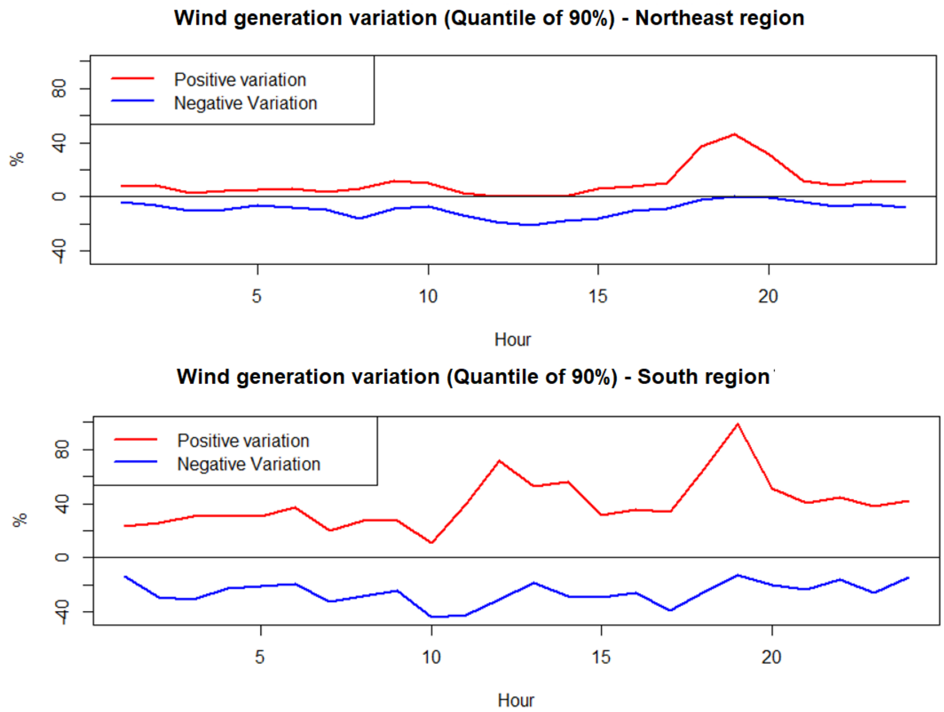


Figure 68: Positive and negative generation variability of the 30-bus system - Case 4.

South region at 10am and a minimum value of 20.89% in the Northeast region at 1pm.

For Case 5, in order to distribute the variability of total generation among the wind power plants per region, the proportion of the standard deviation of each plant is calculated as detailed in Section 5.3, presented in Figure 69. The sum of total hourly wind plants generation variation is equivalent to the generation variation metric presented in Figure 68 for Case 4.

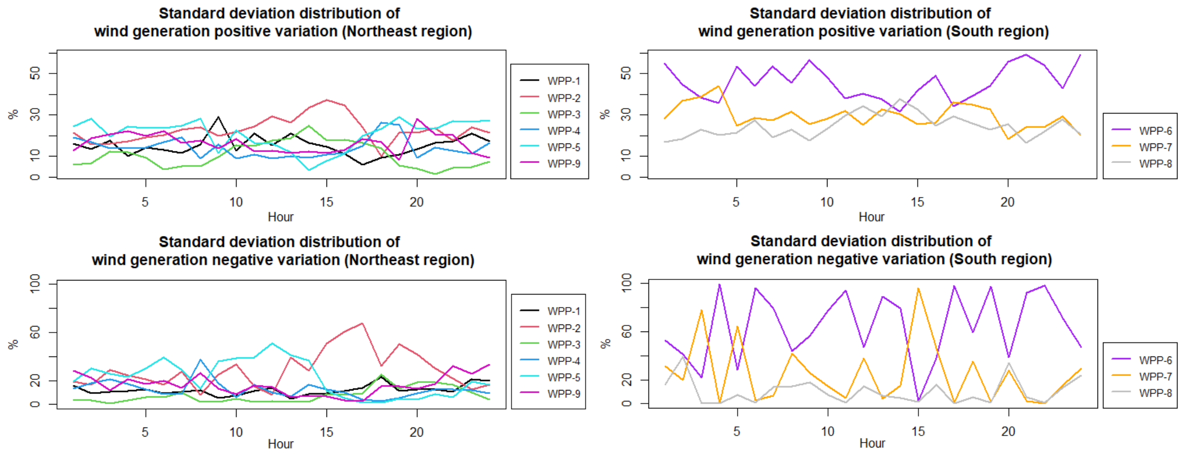


Figure 69: Standard deviation proportion of generation variability of 30-bus system's wind power plants - Case 5.

Finally, for the Case 6, it is calculated the generation variability considering the historical generation of each wind power plant as shown in Figure 70.

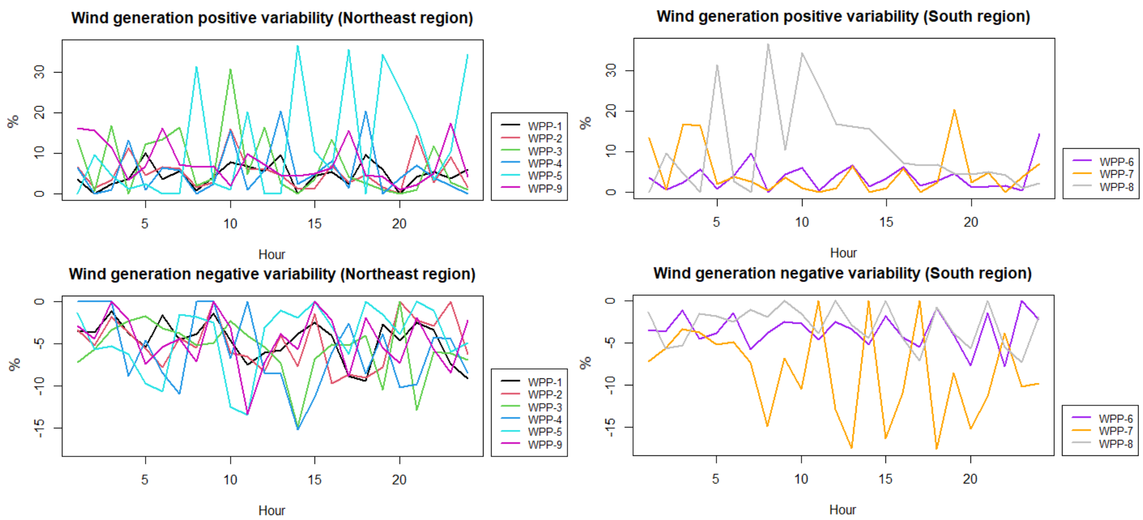


Figure 70: Individual generation variability of the 30-bus system's wind power plants - Case 6.

From the uncertainty metrics for each case, the results obtained for the simulations of the case studies for day-ahead dispatch and real-time verified generation are presented as follow.

6.1.3

Day-ahead Optimization results

The day-ahead scheduling model results for the 30-bus system with no hydroelectric reserves costs are shown in Figure 71 and the detailed results are presented in Table 6.4.

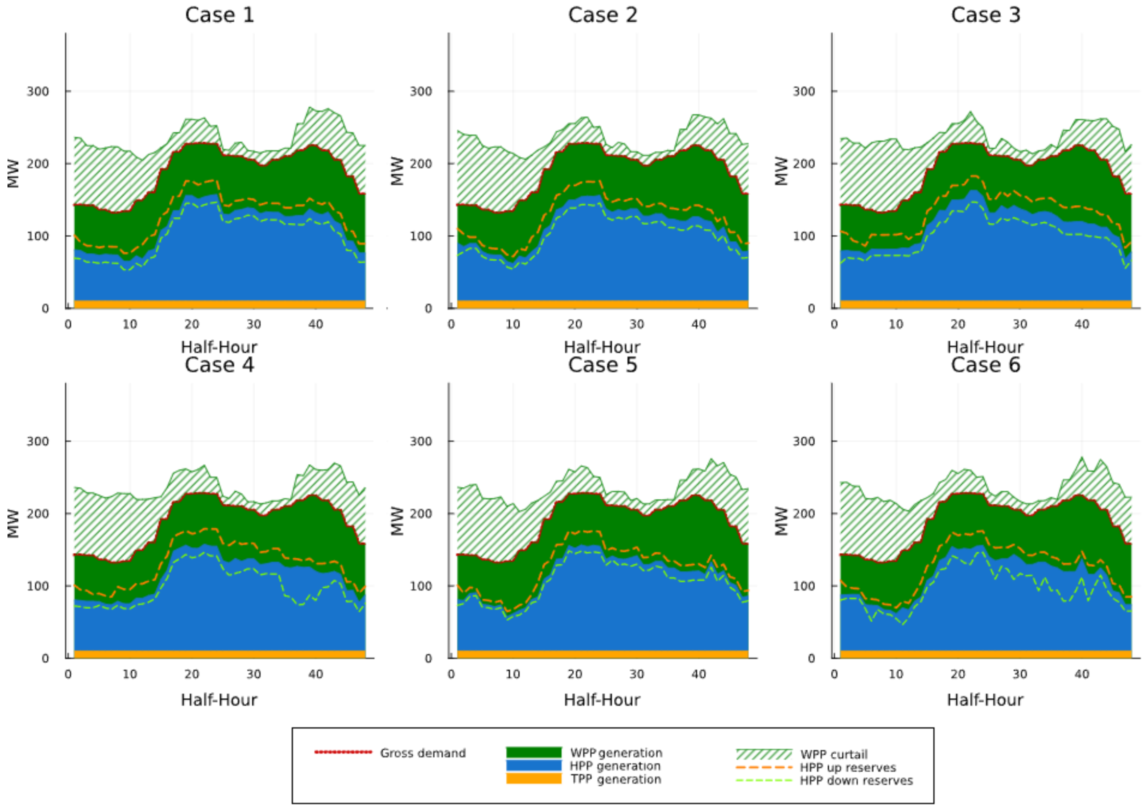


Figure 71: Day-ahead planning dispatch results for 30-bus system with no hydroelectric reserves costs.

Day-ahead Reserves Results	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Hydro up reserves (MWh)	354.40	357.56	449.16	381.86	181.38	390.34
Hydro down reserves (MWh)	274.34	248.83	337.83	414.37	280.54	327.40
Total hydro reserves (MWh)	628.73	606.39	786.98	796.23	461.92	717.73
Day-ahead Generation Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Thermal generation (MWh)	240.0 (5.30% of total mix)	240.0 (5.30%)	240.0 (5.30%)	240.0 (5.30%)	240.0 (5.30%)	240.0 (5.30%)
Hydro generation (GWh)	2.468 (54.47% of total mix)	2.448 (54.04%)	2.497 (55.11%)	2.503 (55.25%)	2.477 (54.67%)	2.454 (54.17%)
Wind generation (MWh)	1,822.55 (40.23% of total mix)	1,841.88 (40.66%)	1,793.60 (39.59%)	1,787.35 (39.46%)	1,813.26 (40.03%)	1,835.92 (40.53%)
Wind curtailment (MWh)	1,115.17 (37.96% of forecasted) (15.40% of inst. capacity)	1,095.85 (37.30%) (15.13%)	1,144.12 (38.95%) (15.80%)	1,150.37 (39.16%) (15.89%)	1,124.47 (38.28%) (15.53%)	1,101.81 (37.51%) (15.22%)
Day-ahead Costs Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Total Operating cost ($)	57,254.40	57,254.40	57,254.40	57,254.40	57,254.40	57,254.40

Table 6.4: Day-ahead programming dispatch results for 30-bus system with no hydroelectric reserves costs.

According with the presented results, it can be verified the following conclusions:

» **Reserves allocation**: The results of Case 2 presented a reduction in the total allocation of hydraulic reserves compared to the results of Case 1 dispatch, considering only the inclusion of the decision variable to curtail wind generation in the reserve restriction requirement, as detailed in Equation 5-17 and 5-18. This allocation increased except in the results verified in Case 5, where the individual variabilities and the relative contributions of the standard deviation of each plant were considered. Then, Case 5 presented the lowest optimal allocation of hydraulic reserves.

» **Hydro generation**: The results of Case 2 presented the lowest value for hydroelectric generation and Case 4 resulted in the highest values of hydro generation, where it is considered the aggregated variability by hour and subsystem, but with separated positive and negative generation contributions. Nevertheless, the difference between the hydroelectric generation results among the six cases are not substantially, being between 0.8% and 2%.

» **Wind generation and curtailment:** Case 2 presented the largest amount of dispatched wind generation and, consequently, the lowest wind curtailment result. Finally, Case 4 dispatch presented the lowest wind generation and, therefore, the highest wind curtailment value compared to the other cases.

» **Thermal generation and Operating costs:** Since there are no costs associated with reserves in these scenarios, and in the 30-bus system there is no FCF, then the Objective Function of the model, according to Equation 5-2, minimizes the operating costs related only to the thermal generation which remained the same in all simulated scenarios.

Additionally, in order to analyses the results considering hydroelectric reserves costs as presented in Table 6.3, the day-ahead scheduling optimization model results are presented in Figure 72 and detailed in Table 6.5 for the same six cases.

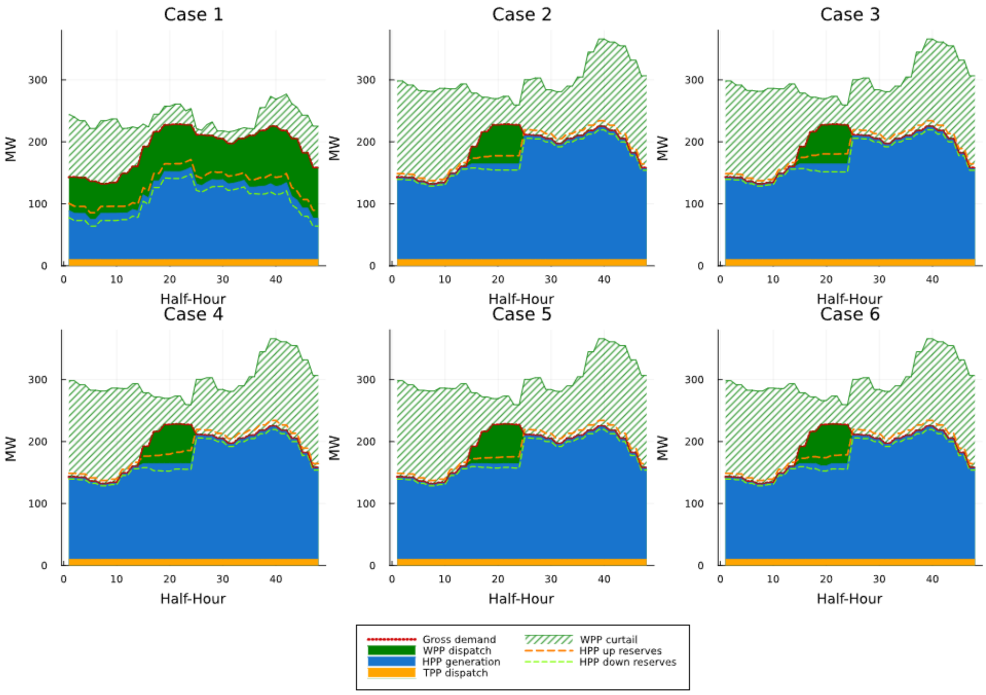


Figure 72: Day-ahead planning dispatch results for 30-bus system considering hydroelectric reserves costs.

Day-ahead Reserves Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Hydro up reserves (MWh)	298.23	198.35	210.46	217.75	187.38	198.19
Hydro down reserves (MWh)	274.34	130.40	142.51	133.75	116.08	124.47
Total hydro reserves (MWh)	572.57	328.74	352.97	351.50	303.45	322.66
Day-ahead Generation Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Thermal generation (MWh)	240.0 (5.30% of total mix)	240.0 (5.30%)	240.0 (5.30%)	240.0 (5.30%)	240.0 (5.30%)	240.0 (5.30%)
Hydro generation (GWh)	2.532 (55.89% of total mix)	4.022 (88.78%)	4.022 (88.78%)	4.022 (88.78%)	4.021 (88.76%)	4.018 (88.70%)
Wind generation (MWh)	1,179.57 (38.81% of total mix)	268.40 (5.92%)	268.40 (5.92%)	4268.40 (5.92%)	269.07 (5.94%)	272.02 (6.0%)
Wind curtailment (MWh)	1,179.57 (40.15% of forecasted) (16.29% of inst. capacity)	2,669.33 (90.86%) (36.86%)	2,669.33 (90.86%) (36.86%)	2,669.33 (90.86%) (36.86%)	2,668.65 (90.84%) (36.85%)	2,665.71 (90.74%) (36.81%)
Day-ahead Costs Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Hydro Reserves cost ($)	11,890.38	6,616.18	7,308.33	7,160.75	6,068.93	6,453.21
Total Operating cost ($)	69,144.78	63,870.58	64,562.73	64,415.15	63,323.33	63,707.61

Table 6.5: Day-ahead programming dispatch results for 30-bus system considering hydroelectric reserves costs.

According with the presented results, it can be verified the following conclusions:

- » **Renewable curtailment**: The inclusion of renewable generation curtailment in the model significantly modified the operating point, resulting in greater amounts of wind restrictions for the day-ahead dispatch. Wind curtailment reached up to 90% of the predicted generation in Cases 2, 3, 4, 5 and 6, while Case 1 indicated wind curtailment to approximately 40% of the forecasted generation. Figure 73 shows the total wind power curtailment hourly per case.

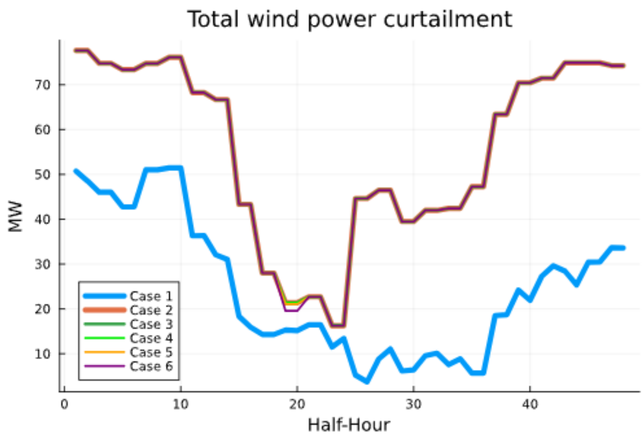


Figure 73: Wind power curtailment for day-ahead dispatch of 30-bus system per case with hydroelectric reserves costs.

- » **Operating costs**: The reserves and total operating costs are optimally reduced when the curtailment and uncertainties metrics are considered in the model in Cases 2, 3, 4, 5 and 6. The intermittent generation curtailment has no associated financial compensation in the day-ahead process, then, the model dispatched less hydro reserves to minimize the system cost, at the expense of wind generation curtailment.
  - Cases 5 and 6 presented the lowest hydro and total operating costs, with approximately 50% less hydro reserves allocation and reserves costs in comparison with Case 1. Case 5, which considered the power plant's variabilities in generation variations calculation, presented the lowest costs of all cases.

» **Reserves allocation:** Figure 74 shows the amount of hydraulic upward and downward reserves hourly dispatch for the following day. Note that the inclusion of a more detailed representation of the generation variability, per region, hour and power plants, modified the results of hydro reserves amounts. It should be emphasized the increase dispatch during the daytime hours compared to the night and morning in all cases. The model optimized the reserves allocation by increasing them during periods with greater wind power variability and decreasing them in moments of less renewable intermittency. Cases 5 and 6 presented the total lowest upward and downward hydro reserves allocation, and Case 5 resulted the lowest hydro reserves allocation of all cases. On contrary, Case 1 allocated the most amount of hydro reserves with a increase from 62% in relation to Cases 3 and 4, 77% in comparison with Case 6 and 88% in relation to the total allocated reserves of Case 5.

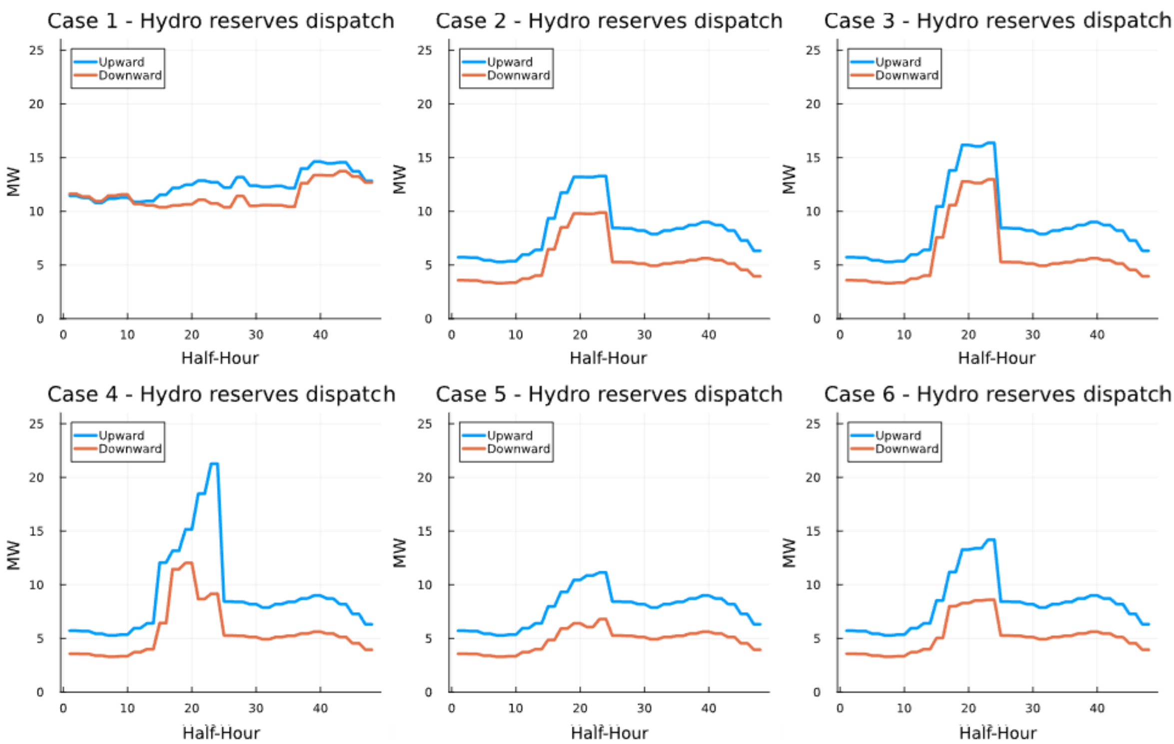


Figure 74: Day-ahead planning reserves dispatch results for 30-bus system with hydroelectric reserves costs.

Therefore, to better investigate the results obtained for the day-ahead scheduling dispatch, it is simulated a real-time operation model using the load curve of the next day and intermittent renewable verified generation considering the historical data of the wind farms (ONS, 2024b).

6.1.4
Real-time operation with verified data

The results for the real-time operation simulation considering the day-ahead dispatch model results and verified wind generation data with no hydroelectric reserves costs are presented in Figure 75 and detailed in Table 6.6, and the results considering hydroelectric reserves costs are presented in Figure 76 and detailed in Table 6.7.

In this simulation, the intermittent renewable generation curtailment and load shedding are penalized in the Objective Function. Furthermore, a total load shedding (L) of 0.05% for the following day is tolerated according to Equation 6-1.

$$\sum_{t=1}^{24} L_t \leq 0.0005 \sum_{t=1}^{24} d_t \tag{6-1}$$

By considering the day-ahead and real-time results, the following facts can be concluded:

» **Load shedding:** Only Cases 3 and 4 presented results in real-time operation without load shedding. The greatest losses were verified in Cases 5 and 1.

» **Hydro generation difference:** Cases 3 and 4 also presented the smallest differences in real-time dispatched hydraulic generation compared to the scheduled generation on day-ahead process. Overall, the differences in all cases were not substantial, with the largest difference being observed

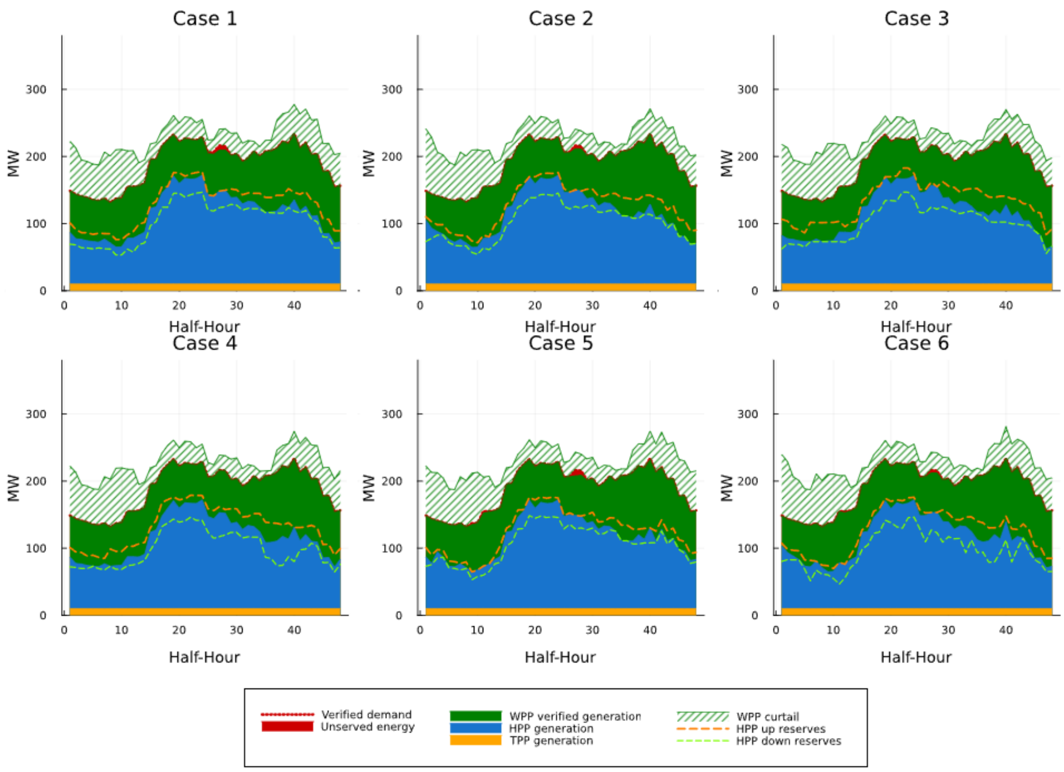


Figure 75: Verified generation dispatch results for 30-bus system with no hydro-electric reserves costs.

Verified Dispatch Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Load shedding over 0.05%?	Yes (0.19%)	Yes (0.12%)	No	No	Yes (0.26%)	Yes (0.11%)
Hydro generation difference (MWh) (Real-time and day-ahead)	+51.66 (+2.09%)	+45.64 (+1.86%)	+14.91 (+0.60%)	+23.10 (+0.92%)	+60.33 (+2.44%)	+73.81 (+3.01%)
Wind curtail difference (MWh) (Real-time and day-ahead)	-158.48 (-14.21%)	-167.77 (-15.13%)	-203.61 (-17.80%)	-195.19 (-16.97%)	-146.85.77 (-13.06%)	-139.78 (-12.69%)
Hydro upward reserves usage (MWh)	137.51 (38.80% of upward res.)	171.36 (47.92%)	145.80 (32.46%)	159.63 (38.52%)	133.97 (47.75%)	206.35 (63.03%)
Hydro downward reserves usage (MWh)	85.85 (31.29% of downward res.)	125.71 (50.52%)	130.89 (38.74%)	136.54 (35.76%)	73.64 (40.60%)	132.54 (33.95%)
Total Hydro reserves usage (MWh)	223.35 (57.39% of scheduled res.)	297.07 (77.25%)	276.69 (53.68%)	296.17 (57.25%)	207.61 (73.95%)	338.88 (75.96%)

Table 6.6: Dispatch results with verified wind generation for 30-bus system with no hydroelectric reserves.

in Case 6 with approximately 3% variation.

» **Wind curtailment difference:** The smallest difference between the wind generation curtailment indicated in the day-ahead scheduling and that verified in real-time operation was found in Case 6, followed by the results verified for Case 5.

» **Hydroelectric reserves usage:** Case 5 used the least amount of reserves dispatched in real-time operation considering the scheduling day-ahead results and Case 6 used the largest amount of them. Cases 2 and 6 obtained the highest relative use compared to the day-ahead dispatch, and followed by the results verified for Case 5.

Considering the requirement established for load shedding, it is verified that Cases 3 and 4 presented the best results for the 30-bus system simulation with no hydroelectric reserves costs. The Case 3 also had the lowest allocation of reserves in the day-ahead programming results and the smallest difference between the scheduled and verified hydraulic dispatches in real time, although it presented the greatest difference for the wind generation curtailment. Regarding the minimization of operating costs, there was no difference between the cases.

Furthermore, the analysis of the impact of hydroelectric reserves costs on the same system are verified considering the results presented in Figure 76 and Table 6.7.

Based on the findings obtained with the verified wind generation data, presented in Figure 76 and Table 6.7, a load shedding above the maximum criterion was observed in Case 1, mainly between 1pm and 2pm. In addition, it is verified that the hydroelectric and wind generation differences between real-time and scheduled was higher in Case 1 and lower in Cases 5 and 6. Finally, regarding the efficiency of the allocated hydroelectric reserves, there is

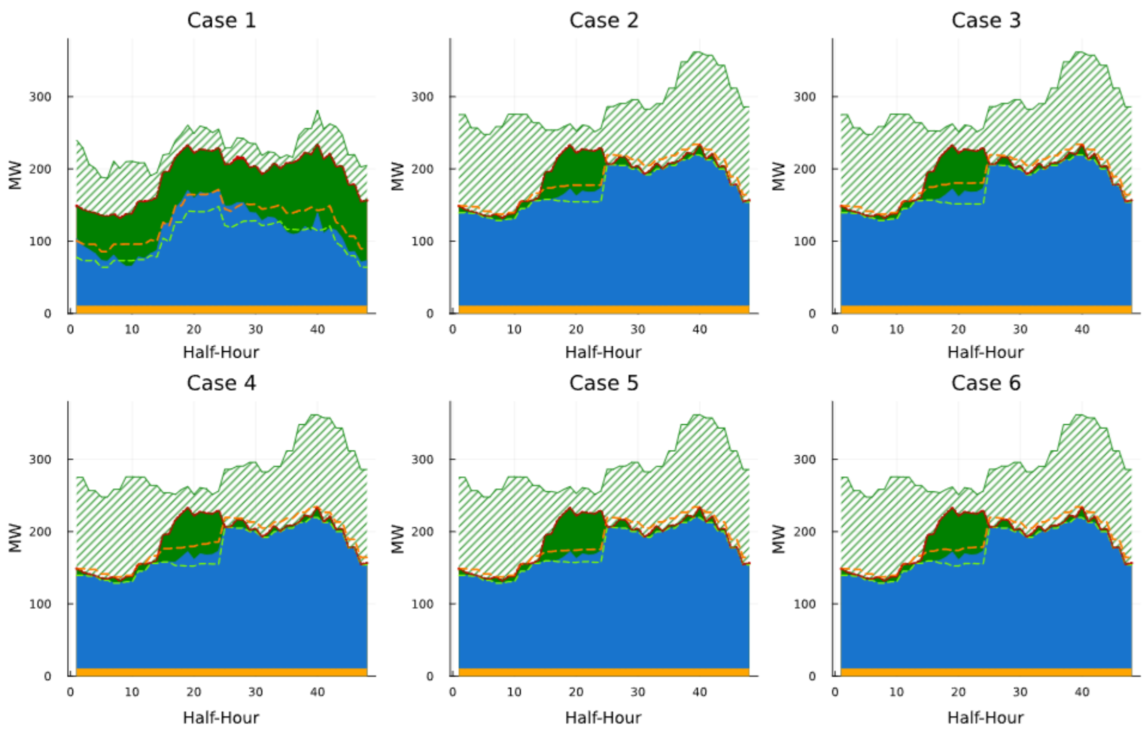


Figure 76: Verified generation dispatch results for 30-bus system with hydroelectric reserves costs.

Verified Dispatch Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Load shedding over 0.05%?	Yes (0.11%)	No	No	No	No	No
Hydro generation difference (MWh) (Real-time and day-ahead)	+73.81 (+3.01%)	-81.31 (-2.02%)	-83.54 (-2.08%)	-83.10 (-2.07%)	-79.03 (-1.97%)	-77.37 (-1.93%)
Wind curtail difference (MWh) (Real-time and day-ahead)	-139.78 (-12.69%)	-300.06 (-11.24%)	-302.54 (-11.33%)	-301.84 (-11.31%)	-297.77 (-11.16%)	-296.12 (-11.11%)
Hydro upward reserves usage (MWh)	206.35 (63.03% of upward res.)	24.70 (12.45%)	20.42 (9.70%)	20.23 (9.29%)	21.30 (11.37%)	19.95 (10.07%)
Hydro downward reserves usage (MWh)	132.54 (33.95% of downward res.)	106.01 (81.30%)	104.21 (73.13%)	103.32 (77.25%)	69.50 (59.79%)	97.33 (78.19%)
Total Hydro reserves usage (MWh)	338.88 (75.96% of scheduled)	130.71 (47.27%)	124.63 (41.10%)	123.55 (40.90%)	100.33 (86.43%)	117.28 (42.53%)

Table 6.7: Dispatch results with verified wind generation for 30-bus system with hydroelectric reserves costs.

a considerable reduction in the use of the scheduled reserves from Case 1 to Case 6, being Case 5 the lowest reserves allocation in real-time operation.

By considering the day-ahead and real-time results, the following facts can be concluded:

» **Operating costs and Load shedding:** Simplifying the representation of intermittent renewable generation variability in hydro reserve allocation can lead to increased operating costs and real-time load shedding during ramp and peak load periods, as shown in the results of Case 1.

» **Hydro reserves opportunity cost:** Case 5 presented the lowest amount of hydro reserves allocation in the day-ahead scheduling and the highest relative reserves usage, of 86%, in the real-time operation simulation comparing with the total amount of allocated reserves in the day-ahead scheduling. These results indicate a reduction in the opportunity cost for allocating hydropower reserves resulted from a day-ahead optimization model with a more adequate representation of intermittent renewable generation variability.

» **Renewable generation curtailment and differences:** The wind power curtailment was lower in Case 1, with a more simplified representation of the variability of intermittent generation, but the difference between the generation verified in real time and the scheduled generation was the largest in this case. This shows that the dispatch of the day-ahead scheduling did not present adequate results to support the Operator in real-time. On the other hand, the smallest difference was found in Cases 5 and 6 with a more discretized representation of the variability of intermittent energy sources.

» **Intermittent renewable curtailment:** The wind generation restrictions was distributed considering an transparent and secure criteria, useful for operator and predictable for generators, considering the restrictions of load-generation balance, power flow sensitivity factors, hydro reserves costs and historical generation variability.

Therefore, based on the results and analysis obtained, the results were more suitable for Case 5, which did not present load shedding, and it presented the smallest difference in hydroelectric generation and wind power curtailment amounts. In addition, Case 5 results included the largest relative use of hydroelectric reserves, considering the dispatched results for the day-ahead scheduling. In conclusion, the simulations of the 30-bus system were satisfactory in relation to the expected objectives of the proposed model and methodology.

In the next section, a large-scale case study is implemented and the results are presented and analyzed.

6.2
Brazilian National Electrical System - 6,181-Bus System

6.2.1
Characteristics of the system

A large-scale study-case is implemented with the proposed model. The power system data come from the Brazilian National Electrical System (SIN) of a Sunday in August 2018 and consist of a electrical grid with 6,181 buses and 8,983 transmission lines. The total installed capacity and energy mix are shown in Figure 77.

Installed Capacity	MW	%
Total generation	159400	100
Hydro Power Plants (HPP)	98479	61.8
Thermal Power Plants (TPP)	22290	14.0
Wind Power Plants (WPP)	17008	10.7
Solar Photovoltaic Power Plants (PPP)	1910	1.2
Other (Biomass, small hydro and solar)	19713	12.4
Load Demand	71458 MW	

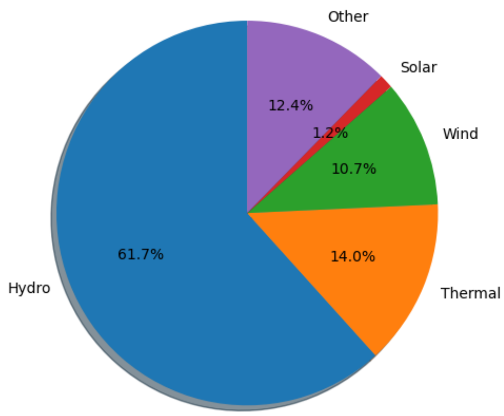


Figure 77: Installed capacity and energy mix for the 6,181-bus system.

The electrical system data, generation are based on the input data from

(CARVALHO, 2019). The intermittent historical renewable generation are from (ONS, 2024b). The reserves costs are not considered in the current day-ahead Brazilian dispatch model. Therefore, for better comparison of results, it is simulated the cases considering no hydroelectric reserves costs and considering the same random values of reserves costs for all simulated cases, on the scale up to thermal generation costs.

The intermittent renewable generation forecast, generation variation metrics calculation and the results of the model for the six cases in the day-ahead programming and in a simulation of the real-time system operation with verified generation are presented below.

6.2.2

Wind and solar generation forecast and variability

Wind and solar photovoltaic generation forecasting are calculated using the ARIMA method based on historical generation and considering the maximum wind power capacity factors of 63%, and 34% for solar generation in August (ONS, 2023b). Figure 78 shows the wind and solar forecasted and verified generation.

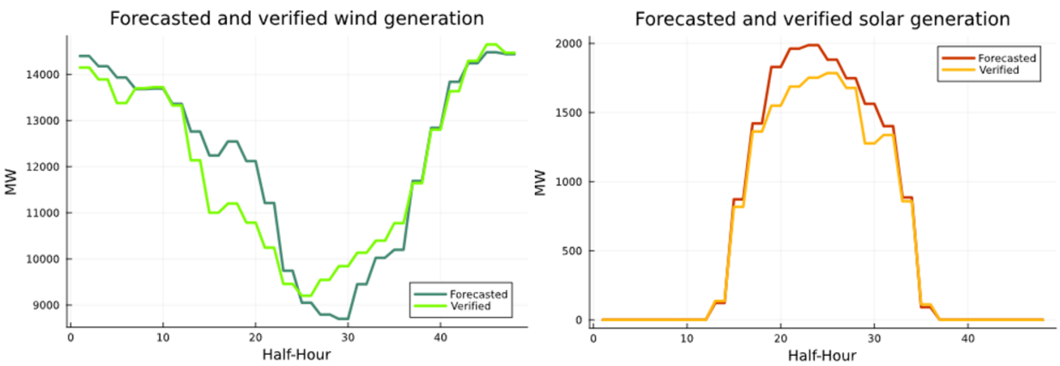


Figure 78: Total hourly forecasted and verified of wind and solar generation for 6,181-bus system.

In the following, the results of the variabilities of variable renewable generation for each case are detailed.

» **Case 1 - Current fixed reserves requirements and Case 2 - Incorporation of variable renewable curtailment:** The renewable generation variability defined in the Brazilian Electric Grid Code is implemented, as being $\kappa_{NE} = 6\%$ of the predicted wind generation connected in the Northeast (NE) subsystem and $\kappa_S = 15\%$ for the predicted wind generation connected in the South (S) subsystem, as detailed in Section 5.3.

In these cases, the generation variability of other subsystems with wind power plants connected, such as North region, and other intermittent renewable energy source, such as solar generation, are not considered based on the current hydroelectric reserves requirements for secondary frequency control (ONS, 2022d). These variabilities will be implemented in Case 3 where updated renewable generation variabilities are incremented and then, in the following Cases 4, 5 and 6.

» **Case 3 - Incorporation of updated variable renewable generation variabilities:** Figure 79 presented the updated mean wind generation variability metric $\overline{\kappa}_s$ for each subsystem s considering the quantile of 90% for positive and negative hourly variations. For wind generation, in the Northeast (NE) subsystem, the value is approximately equal to $\overline{\kappa}_{NE_{wind}} = 7\%$, for the South (S) region it is equivalent to $\overline{\kappa}_{S_{wind}} = 18\%$ and for the North (N) region it is $\overline{\kappa}_{N_{wind}} = 29\%$.

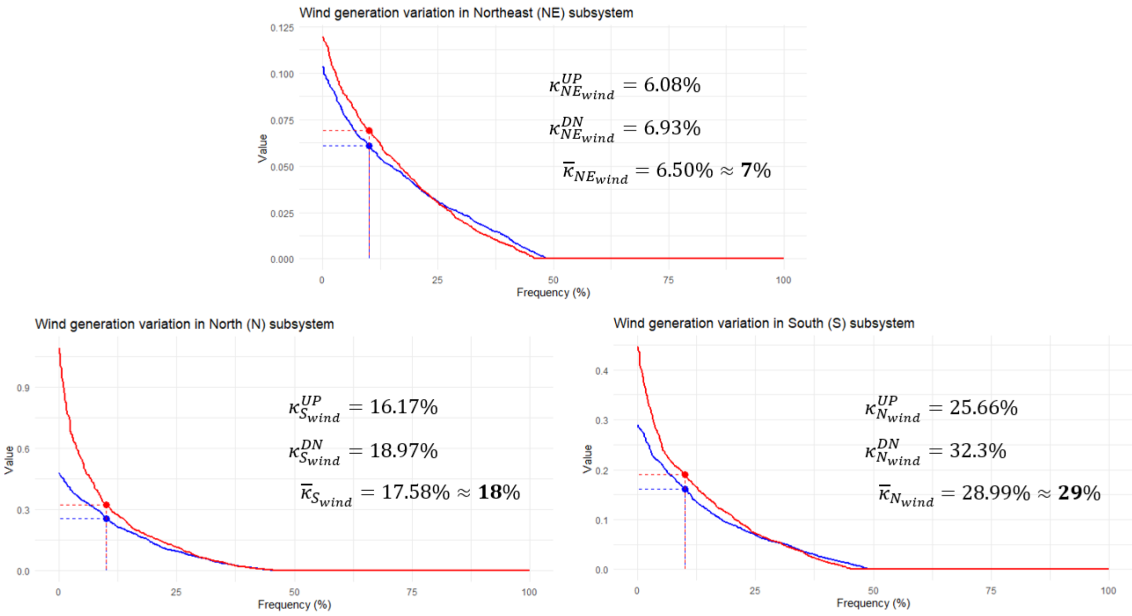


Figure 79: Wind hourly generation variations per subsystem of 6,181-bus system - Case 3.

It is worth mentioning that most wind farms are connected in the Northeast region, as shown in Figure 80. Thus, even if the variability of wind generation is high in the North region, $\overline{\kappa}_{N_{wind}} = 29\%$, it does not have a relevant impact on the dispatch scheduling due to its low relative installed capacity of 1.8% of the total wind power capacity.

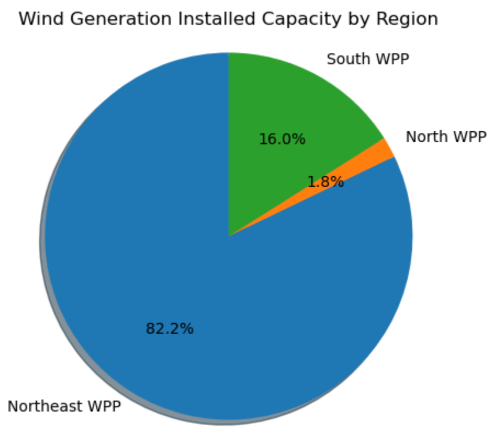


Figure 80: Wind power plants (WPP) generation installed capacity connected per subsystem of 6,181-bus system.

In relation to solar generation, the generation variation in the quantile of 90% is defined as approximately $\overline{\kappa}_{NE_{solar}} = 36\%$ for Northeast (NE) subsystem, and $\overline{\kappa}_{SE_{solar}} = 23\%$ for Southeast (SE) subsystem.

» **Case 4 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions:** The generation variation hourly is calculated for a quantile of 90% for positive and negative variations, as presented in Figure 81 for wind power plants connected in Northeast and South subsystems and 82 for North subsystem.

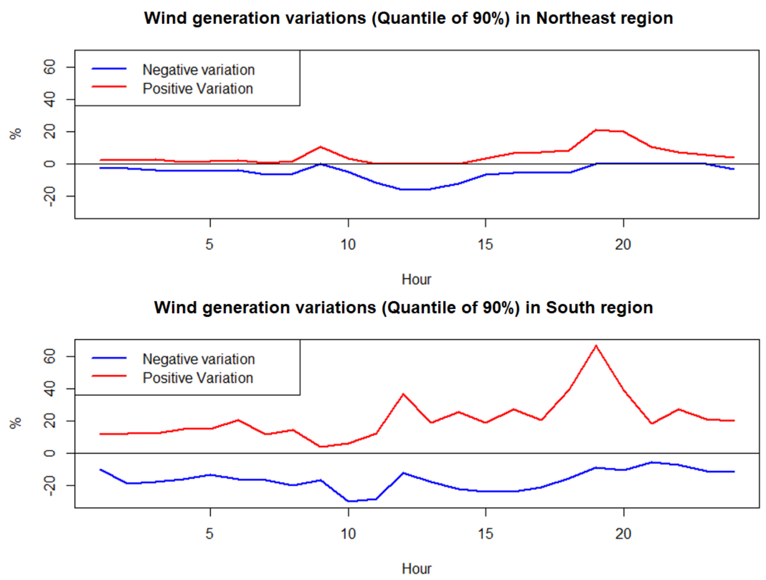


Figure 81: Hourly positive and negative wind generation variations at Northeast and South regions of 6,181-bus system - Case 4.

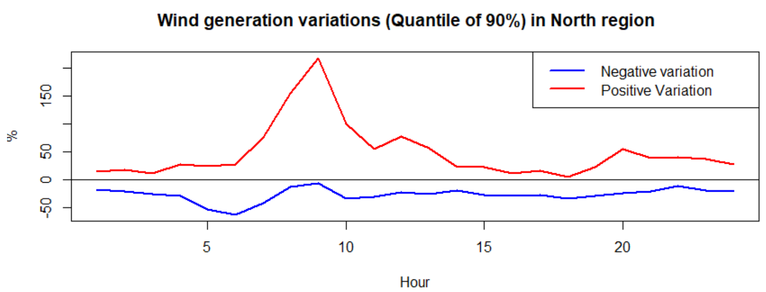


Figure 82: Hourly positive and negative wind generation variations at North region of the 6,181-bus system - Case 4.

» **Case 5 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions, and individual power plants variabilities:** Figure 83 present the distribution of the generation variation based on standard variation proportional of each wind and solar power plant considering the hourly generation variation defined in Case 4.

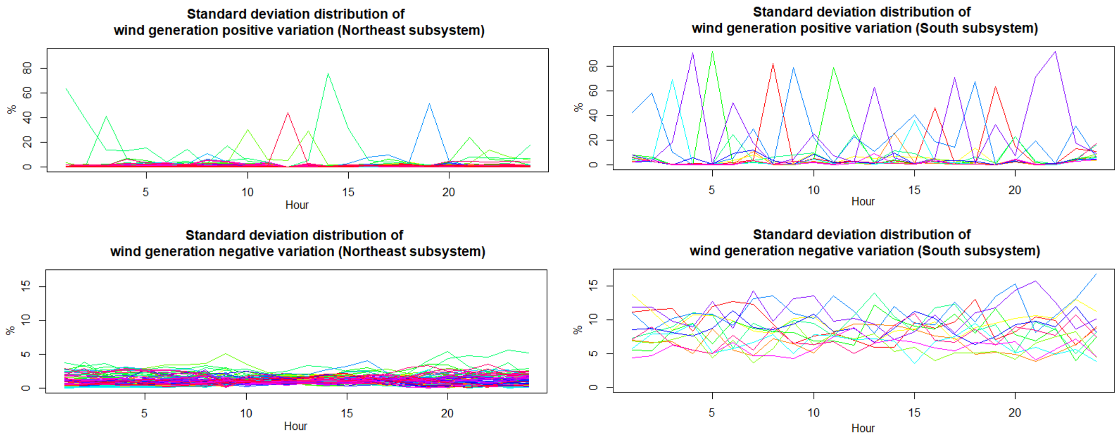


Figure 83: Standard deviation proportion of wind generation variations of the 6,181-bus system's power plants per region - Case 5.

To better illustrate the individual variabilities of wind power plants, Figure 84 presents a zoom of the standard deviation proportions of wind generation negative variability in Northeast subsystem.

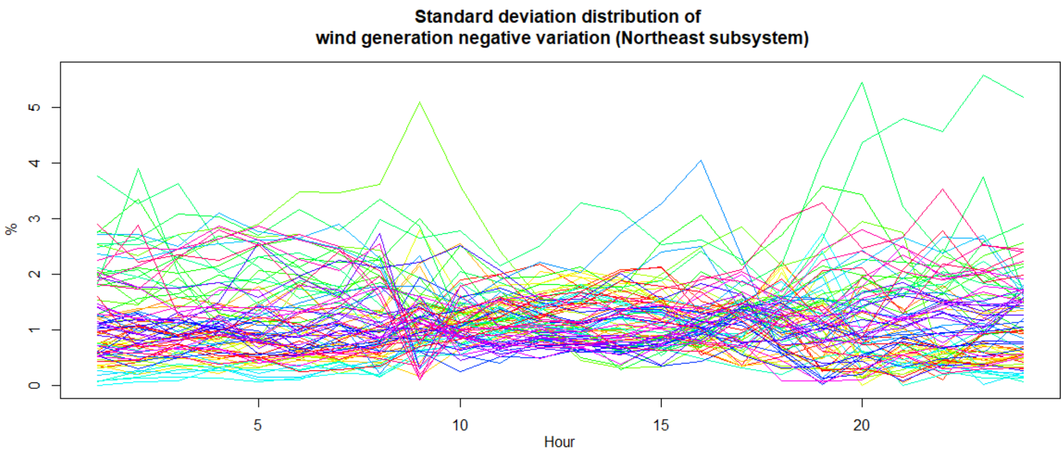


Figure 84: Zoom of standard deviation proportion of wind generation negative variability of power plants connected in Northeast region of the 6,181-bus system's - Case 5.

Finally, Figure 85 presents the standard deviations proportions of the solar generation variabilities of each solar power plant.

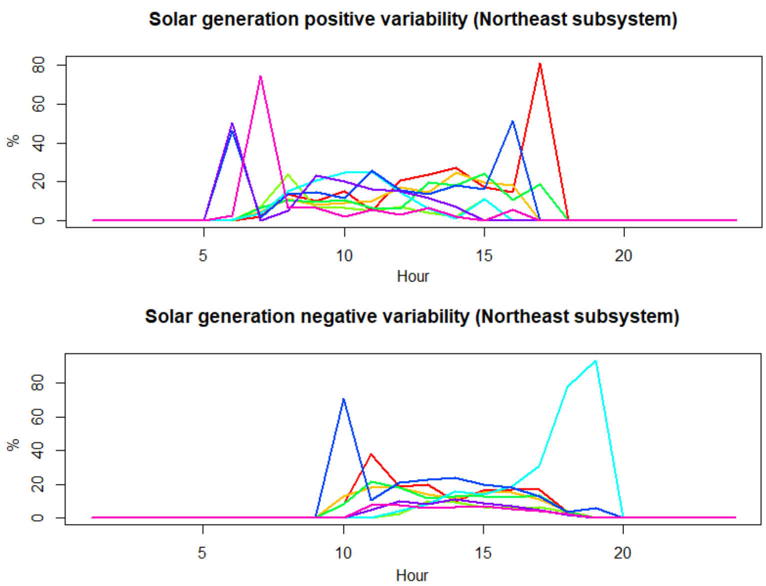


Figure 85: Standard deviation proportion of solar generation variability of the 6,181-bus system's power plants - Case 5.

» **Case 6 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions, and individual power plants with no relative standard deviation contribution:** Figure 86 presents the generation variability of each wind power plant calculated by the mean of the historical verified generation and without considering relative standard deviation contribution between them for Northeast and South subsystems.

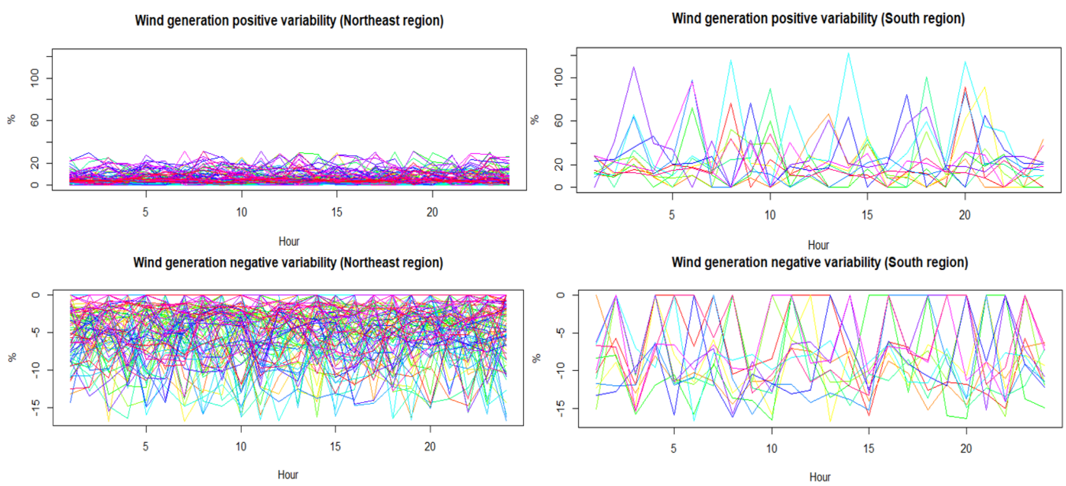


Figure 86: Hourly individual positive and negative wind generation variability per region of the 6,181-bus system - Case 6.

In conclusion, a hourly comparison of generation variability for each case is presented in Figure 87. As detailed in Chapter 5, Case 1 and Case 2 have a fixed κ calculated per subsystem according to current implemented methodology in Brazilian process, Case 3 has a updated κ considering the historical verified generation, Case 4 has a κ_t considering the generation variation hourly. Case 5 are the same of Case 4 from a hour-time perspective but with a distribution among power plants considering the individual standard deviations (sd) proportions, and Case 6 presented the mean value of the individual generation variation calculated by hour base on its individual historical hourly verified generations.

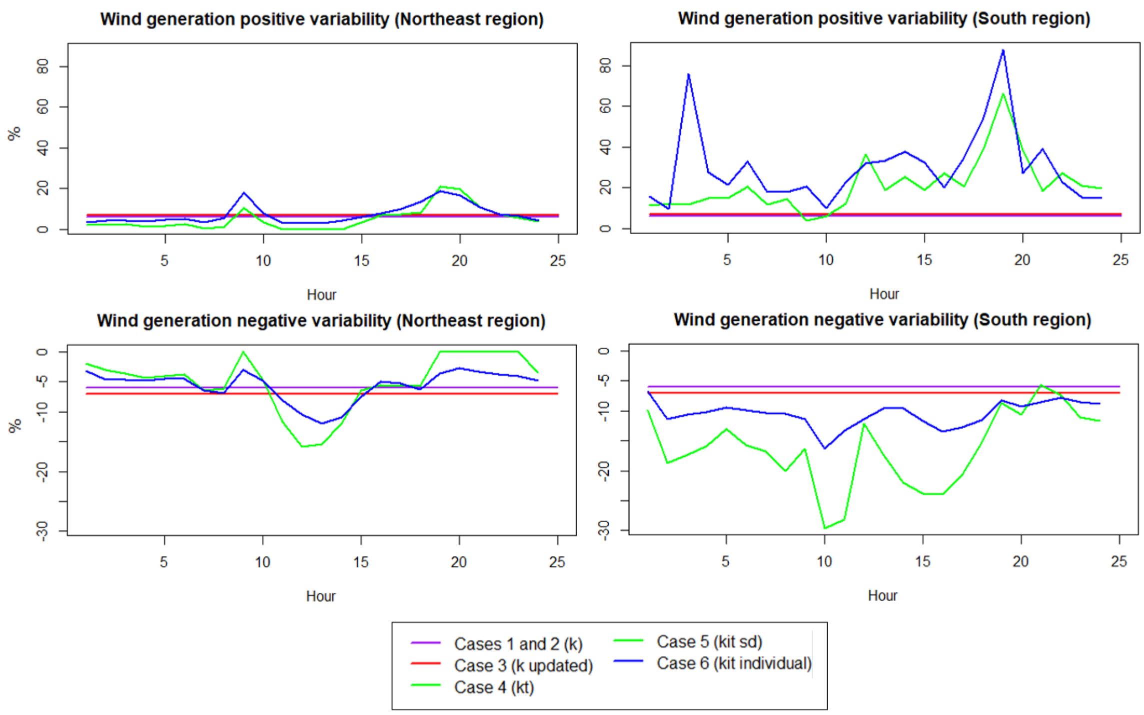


Figure 87: Comparison of positive and negative wind generation variability implemented cases per region of the 6,181-bus system.

From the comparison shown in Figure 87, it can be verified that the variabilities change hourly considerably throughout the day, especially during the afternoon and early evening in the Northeast region and during all hours of the day in the South subsystem. Furthermore, it can be seen that the fixed values implemented in the Cases 1, 2 and 3 may be underestimated in relation to the true variability of renewable generation, making it essential to analyze the a more discretized variability in the allocation of reserves for system reliability.

Therefore, considering the calculated wind and solar generation variability metrics, the results obtained for the simulations of the case studies for day-ahead dispatch and real-time verified generation are presented as follow.

6.2.3

Day-ahead Optimization results

The day-ahead dispatch results with no hydroelectric reserves costs for the 6,181-bus system of the six cases are presented in Figure 88 and Table 6.8.

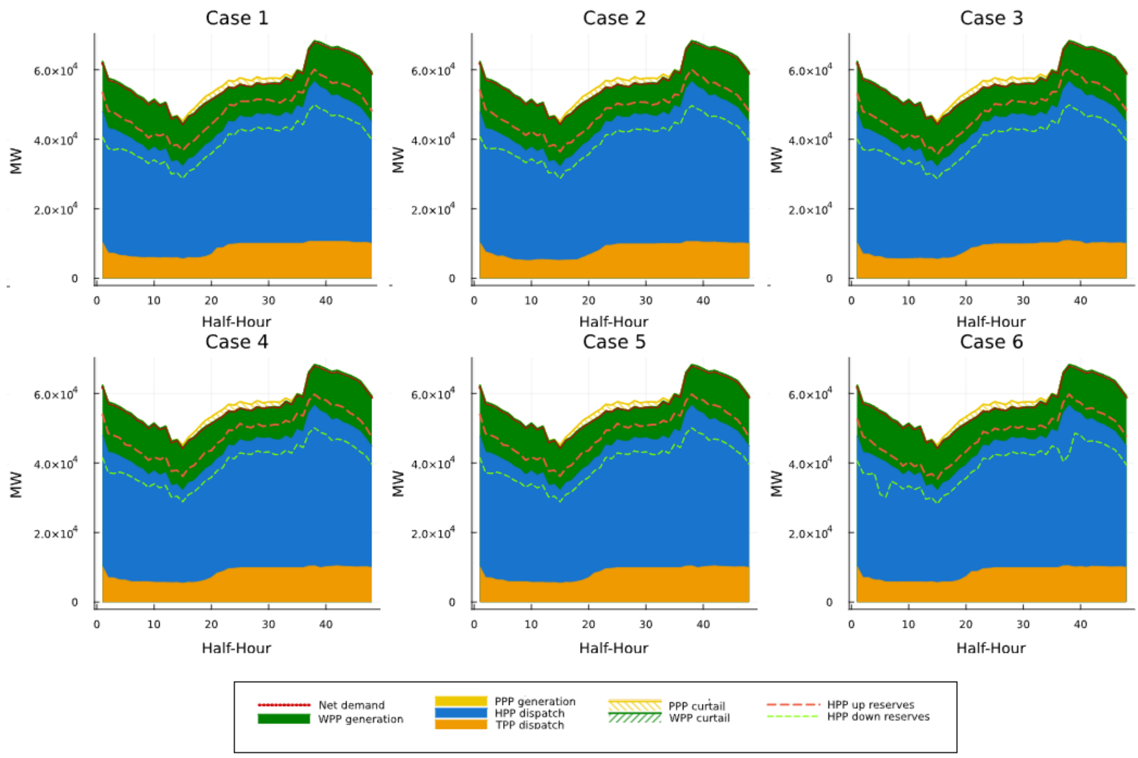


Figure 88: Day-ahead planning dispatch results for 6,181-bus system with no hydroelectric reserves costs.

Day-ahead Reserves Results	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Hydro up reserves (MWh)	102,498.12	95,473.12	93,321.95	75,604.37	101,398.90	78,535.31
Hydro down reserves (MWh)	106,311.59	108,236.96	110,280.84	113,629.71	105,683.84	125,418.22
Total hydro reserves (MWh)	208,809.70	203,710.08	203,602.79	189,234.08	207,082.74	204,953.53
Day-ahead Generation Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Thermal generation (MWh)	205,780 (15.27% of total energy mix)	198,547 (14.73%)	203,290 (15.09%)	204,966 (15.21%)	201,152 (14.93%)	202,078 (15.0%)
Hydro generation (GWh)	857.225 (63.61% of total energy mix)	864.45 (64.15%)	859.665 (63.79%)	858.075 (63.68%)	861.845 (63.96%)	860.80 (63.88%)
Wind generation (MWh)	284,543 (21.0% of total energy mix)	284,554 (21.0%)	284,595 (21.0%)	284,508 (21.0%)	284,554 (21.0%)	284,674 (21.0%)
Wind curtailment (MWh)	7,115 (2.44% of forecasted) (1.74% of installed capacity)	7,105 (2.44%) (1.74%)	7,064 (2.42%) (1.73%)	7,151 (2.45%) (1.75%)	7,105 (2.44%) (1.74%)	6,986 (2.40%) (1.71%)
Day-ahead Costs Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Thermal generation cost ($\cdot 10^7$\$)	4.04138723	3.86175936	3.99132239	4.02997291	3.87193924	3.8847308
Future Cost Function ($\cdot 10^{12}$\$)	1.1838716	1.1838628	1.1838658	1.1838630	1.1838610	1.1838653
Total Operating cost ($\cdot 10^{12}$\$)	1.1839497	1.1839463	1.1839542	1.1839466	1.1839292	1.1839489

Table 6.8: Day-ahead programming dispatch results for 6,181-bus system with no hydroelectric reserves costs.

From the results detailed in Table 6.8, the following main points were verified:

» **Hydroelectric reserves usage:** Case 4 presented the lowest total allocation of hydraulic reserves, followed by Cases 3, 2 and 6. Cases 1 and 5 presented the largest amounts of reserves allocated in day-ahead scheduling.

» **Thermal generation and costs:** Case 1 presented the highest amount of thermal dispatch and, consequently, the highest cost of thermal generation, followed by Cases 4 and 3. Then, Cases 2 and 5 presented the lowest values of dispatch and cost of thermal generation.

» **Hydro generation:** Case 1, which presented the largest allocation of hydraulic reserves, obtained the smallest amount of hydraulic generation. On the other hand, Case 4 had the smallest allocation of reserves and, consequently, the largest hydroelectric generation dispatch in day-ahead scheduling.

» **Wind generation and curtailment:** The amounts of wind power generation and curtailment were similar in all cases, with Case 4 having the lowest amount of wind generation and, consequently, the highest result of wind power curtail. Finally, Case 6 had the lowest amount of wind power curtailment, followed by Cases 3, 2 and 5.

» **Operating costs:** Case 3 had the lowest total operation cost, followed by Case 5, and Case 2 had the highest operating cost, followed by the results verified in Cases 6 and 4.

It is verified that Case 1, which does not consider the decision variable of the intermittent renewable generation curtailment in the hydraulic reserve requirement, allocates a larger amount of reserves compared to the other cases where this variable is considered. In addition, a larger amount of thermal dispatch for Case 1 is also verified compared to all other cases.

Additionally, in order to better analyses the day-ahead dispatch generation with hydroelectric reserves costs, Figure 89 and Table 6.9 presented and detailed tne obtained results for the same 6,181-bus system and six cases.

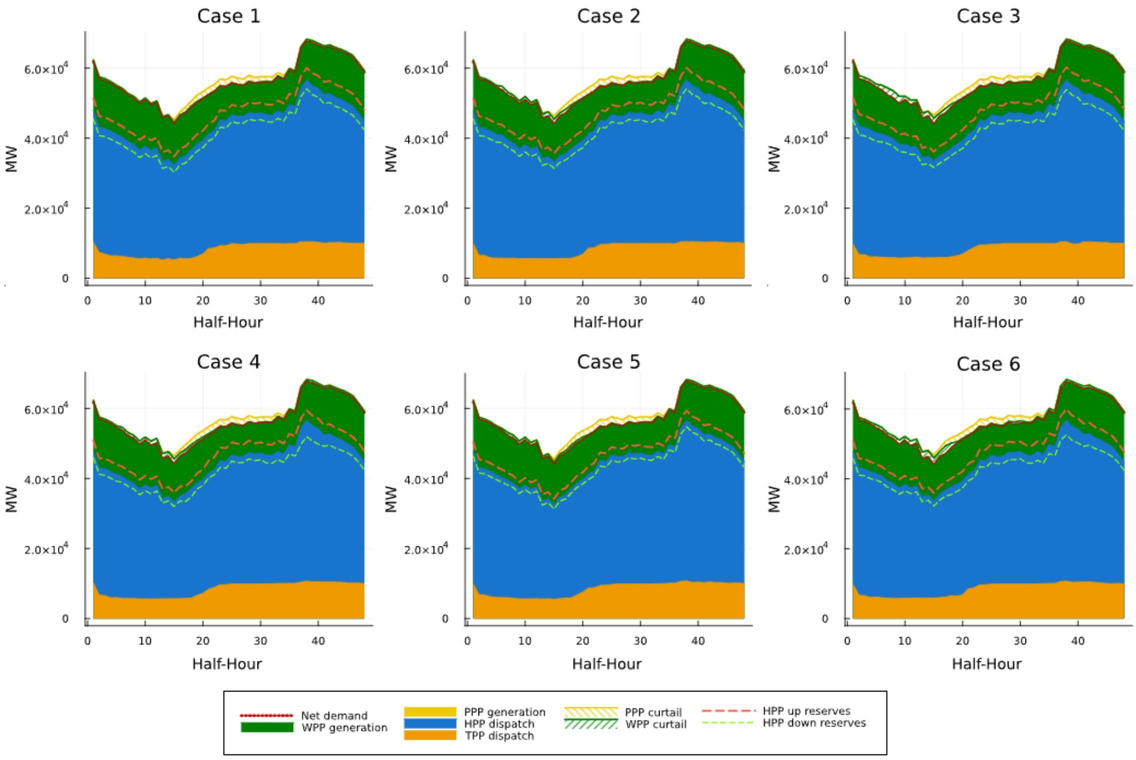


Figure 89: Day-ahead planning dispatch results with reserves costs for 6,181-bus system considering hydroelectric reserves costs.

Day-ahead Reserves Results	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Hydro up reserves (MWh)	73,439	72,704	77,043	70,256	55,247	67,729
Hydro down reserves (MWh)	53,226	52,491	56,829	53,848	35,465	55,484
Total hydro reserves (MWh)	126,666	125,196	133,872	124,104	90,711	123,213
Day-ahead Generation Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Thermal generation (MWh)	200,029 (14.84% of total energy mix)	200,013 (14.84%)	200,791 (14.90%)	201,731 (14.97%)	201,996 (14.99%)	202,639 (15.04%)
Hydro generation (GWh)	862.95 (64.04% of total energy mix)	866,49 (64.30%)	869.50 (64.52%)	866.46 (64.03%)	863.54 (64.08%)	869.31 (64.51%)
Wind generation (MWh)	284,573 (21.0% of total energy mix)	281,050 (21.0%)	277,258 (21.0%)	279,366 (21.0%)	282,013 (21.0%)	275,607 (20.0%)
Wind curtailment (MWh)	7,085 (2.43% of forecasted) (1.74% of installed capacity)	10,607 (3.64%) (2.6%)	14,400 (4.94%) (3.53%)	12,292 (4.21%) (3.01%)	9,645 (3.31%) (2.36%)	15,773 (5.50%) (3.93%)
Day-ahead Costs Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Hydro Reserves cost ($\cdot 10^7$\$)	3.9363021	4.5098135	4.9797392	4.4477855	2.8687846	4.3907904
Future Cost Function ($\cdot 10^{12}$\$)	1.1838716	1.1838628	1.1838658	1.1838630	1.1838610	1.1838653
Total Operating cost ($\cdot 10^{12}$\$)	1.1839497	1.1839463	1.1839542	1.1839466	1.1839292	1.1839489

Table 6.9: Day-ahead programming dispatch results with reserves costs for 6,181-bus system considering hydroelectric reserves costs.

From the results detailed in Table 6.9, the following main points were verified:

» **Energy mix and energy consumption**: There is no significant change in the relative share of each energy source in the total generation dispatch to meet load between the case results. Solar generation is totally curtailed in all cases, probably due to its higher variabilities in Cases 3, 4, 5 and 6, and other system restrictions in Cases 1 and 2.

» **Reserves allocation and costs:** Case 3 presented the highest amount of allocated reserves, followed by Case 1, and also, the highest reserves cost, followed by Case 2. This result demonstrates that the current methodology to calculated aggregated values of renewable uncertainties, along with renewable curtail in the reserves constraints, may sub-optimizes the reserves allocation and costs. On the other hand, Case 5 presented the lowest reserve values in quantity, around 35% and 40% lower in relation to the other cases, and an approximate reduction of 30% in reserves costs.

» **Operating cost:** Case 5 presented the lowest operating cost which considered the distribution of generation variability based on each power plant's standard deviation relative share, followed by Cases 2, 4, 6, 1 and 3.

» **Wind curtailment:** There was a significant increase in the wind generation curtailment. More than double of wind curtailed in Case 1 is verified in Cases 3, 5 and 6. Only Case 6 presented an amount of power curtailed higher than 5% of forecasted generation. Figure 90 shows the total wind curtailment per cases and hour of the day. The majority of wind curtailed is located in the morning, until 10am, which can be related to the negative demand ramp and higher wind variability.

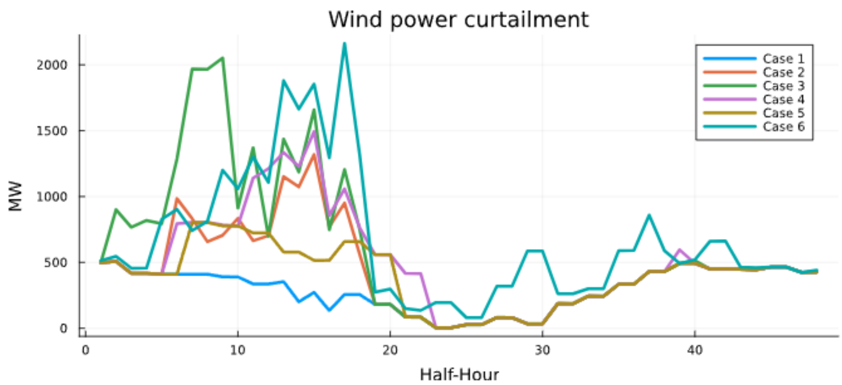


Figure 90: Wind power curtailment for day-ahead dispatch of 6,181-bus system with hydroelectric reserves costs per Case.

Moreover, the hydroelectric upwards and downwards reserves dispatch is shown in Figure 91 for all six cases.

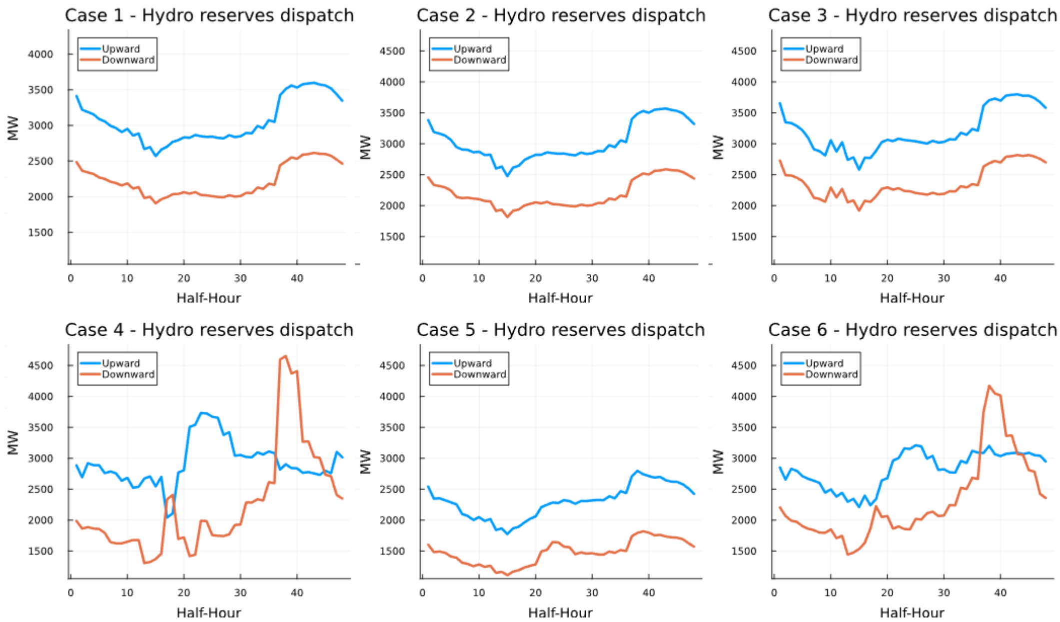


Figure 91: Day-ahead planning reserves dispatch results for 6,181-bus system with hydroelectric reserves costs.

It is verified that Cases 4 and 6 have a slightly increased of downward reserves at approximately 10am and a peak in the evening. This behavior can be associated with a higher positive wind generation variation in these periods as shown in Figure 87. Furthermore, Case 5 presented the lowest amount of dispatched upwards and downwards reserves during all times of the day and the most stable behavior, without major variations, which may be associated with the compensation of generation variation between the intermittent renewable plants. As detailed in Section 5.3, in Case 5, a metric is calculated considering the relative standard deviation contribution of each power plant in relation to the total standard deviation of the historical hourly generation variation.

Finally, to better evaluate the impact of these results on system operation, the day-ahead dispatched generation and reserves are implemented using load data of the following day and the verified intermittent renewable generation data.

6.2.4

Real-time operation with verified data

The results for the real-time operation simulation considering the day-ahead dispatch model results with no hydroelectric reserves costs and verified intermittent renewable generation data are presented in Figure 92 and Table 6.10. Additionally, the results for the real-time operation simulation, considering the same system characteristics but with hydroelectric reserves costs, are presented in Figure 93 and detailed in Table 6.11.

In the real-time operation simulations, the intermittent renewable curtailment and the load shedding are penalized in the Objective Function, being the load shedding penalization much greater than the intermittent renewable curtailment penalty.

From the results obtained for the real-time operation simulation with verified generation and no hydroelectric reserves costs, the following conclusions are verified:

» **Load shedding:** No case presented load shedding above the maximum allowed criterion of 0.05%.

» **Hydroelectric generation difference:** Case 1 have the slightly highest hydro generation difference in comparison with the other cases.

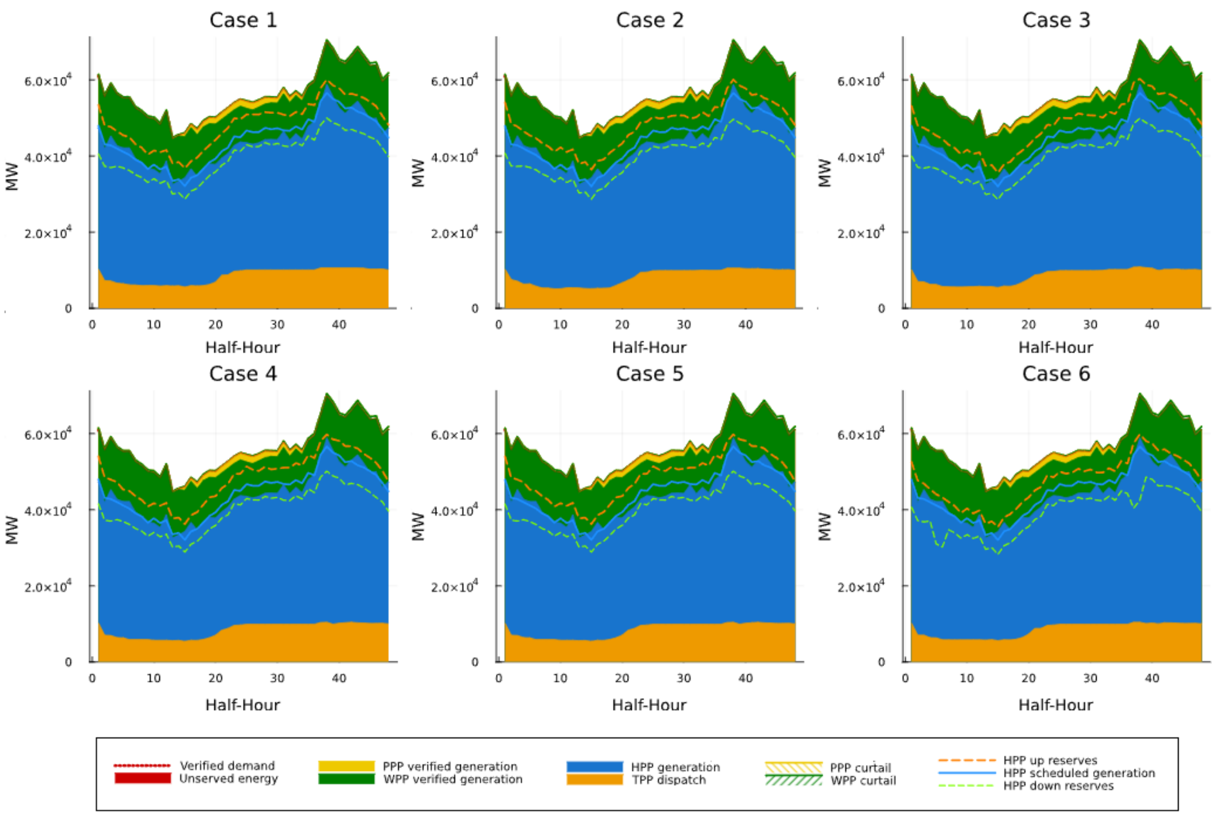


Figure 92: Verified generation dispatch results for 6,181-bus system with no hydroelectric reserves costs.

Verified Dispatch Results	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Load shedding over 0.05%?	No	No	No	No	No	No
Hydro gen. difference (GWh) (Real-time and day-ahead)	-12.160 (-1.0%)	-12.150 (-1.0%)	-12.109 (-1.0%)	-12.150 (-1.0%)	-12.150 (-1.0%)	-12.031 (-1.0%)
Wind curtail difference (MWh) (Real-time and day-ahead)	+1,404 (+19.74%)	+1,414 (+19.90%)	+1,455 (+20.60%)	+1,414 (+19.90%)	+1,414 (+19.90%)	+1.533 (+21.95%)
Solar curtail difference (MWh) (Real-time and day-ahead)	-15,758 (-99.90%)	-15,758 (-99.90%)	-15,758 (-99.90%)	-15,758 (-99.90%)	-15,758 (-99.90%)	-15,758 (-99.90%)
Hydro upward reserves usage (MWh)	47,615 (46.45% of up. reserves)	46,609 (48.82%)	47,508 (50.91%)	50,051 (49.36%)	50,051 (49.36%)	41,914 (53.37%)
Hydro downward reserves usage (MWh)	59,776 (56.23% of down. reserves)	58,760 (54.29%)	59,617 (54.06%)	62,202 (58.86%)	62,202 (58.86%)	53,945 (42.67%)
Total Hydro reserves usage (MWh)	107,391 (51.43% of scheduled)	105,569 (51.73%)	107,124 (52.61%)	112,253 (59.32%)	112,253 (54.21%)	95,859 (46.77%)

Table 6.10: Dispatch results with verified wind generation for 6,181-bus system with no hydroelectric reserves costs.

» **Intermittent renewable generation difference:** For wind power curtailment, Case 1 presented the less difference and Case 6 presented the highest difference amount, followed by Case 3. For solar curtailment, all cases presented the same amount of difference comparing real-time operation and day-ahead scheduling.

» **Hydroelectric reserves usage:** Case 6 presented the lowest amount of hydraulic reserves utilized in real-time operation simulation. Finally, Case 4 and 5 presented the highest amount of reserves usage, followed by the result verified in Case 1 and Case 2.

Furthermore, to complete the analysis, the same system is simulated with hydroelectric reserves costs and the results are presented in Figure 93 and detailed in Table 6.11.

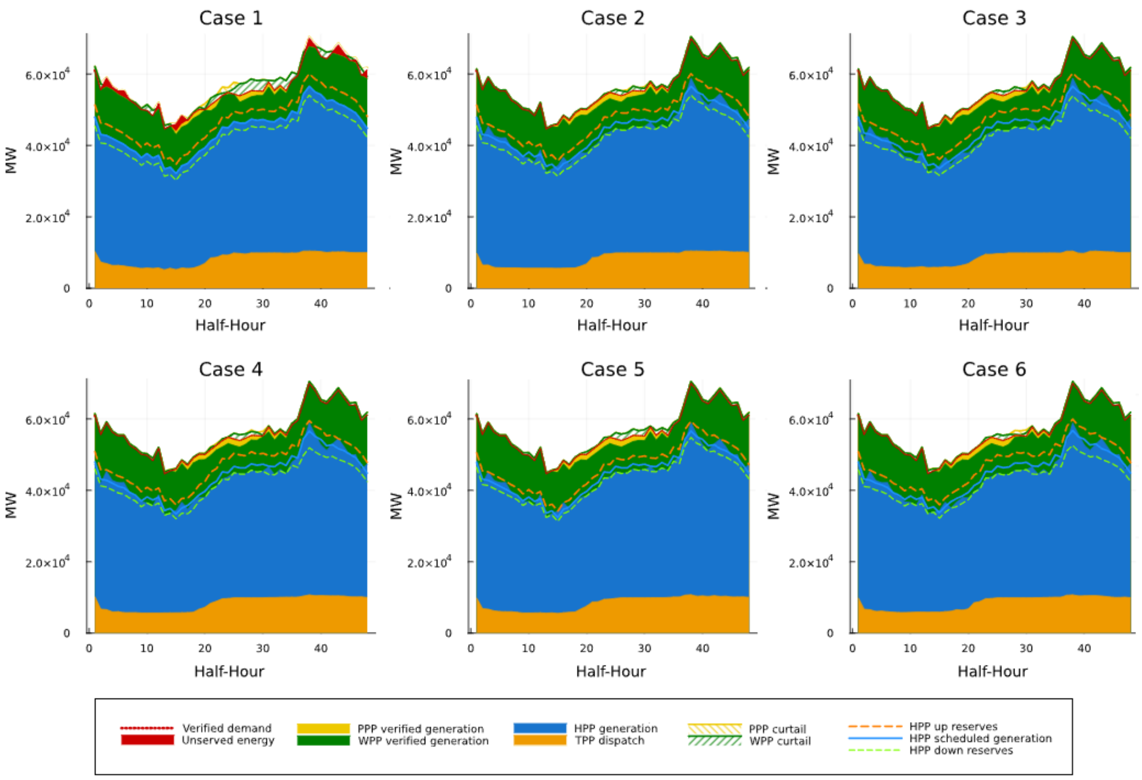


Figure 93: Verified generation dispatch results for 6,181-bus system considering hydroelectric reserves costs.

Verified Dispatch Results	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Load shedding over 0.05%?	Yes (0.85%)	No	No	No	No	No
Hydro gen. difference (GWh) (Real-time and day-ahead)	+0.00 (+0%)	+12.07 (-1.0%)	-16.69 (-2.0%)	-12.25 (-1.0%)	-7.89 (-1.0%)	-15.79 (-2.0%)
Wind curtail difference (MWh) (Real-time and day-ahead)	+21,610 (+305.0%)	+1,010 (+9.53%)	+3,538 (-24.57%)	+79.69 (+0.65%)	+5,908 (+61.26%)	-4,238 (-26.40%)
Solar curtail difference (MWh) (Real-time and day-ahead)	-12,320 (-78.11%)	-15,275 (-96.84%)	-15,349 (-97.31%)	-14,521 (-92.06%)	-15,718 (-99.65%)	-13,747 (-87.15%)
Hydro upward reserves usage (MWh)	0 (0% of up. reserves)	22,900 (31.50%)	22,485 (29.19%)	21,781 (31.0%)	16,781 (30.37%)	21,096 (31.15%)
Hydro downward reserves usage (MWh)	0 (0% of down. reserves)	34,970 (66.62%)	39,179 (68.94%)	34,031 (63.20%)	24,669 (69.56%)	36,887 (66.48%)
Total Hydro reserves usage (MWh)	0 (0% of scheduled)	57,870 (46.22%)	61,664 (46.06%)	55,812 (44.97%)	41,450 (98.11%)	57,983 (47.06%)

Table 6.11: Dispatch results with verified wind generation for 6,181-bus system considering hydroelectric reserves costs.

From the results obtained for the real-time operation simulation with verified generation, the following aspects can be verified:

» **Load shedding:** Case 1 is the only case with load shedding above the maximum allowed criterion of 0.05%.

» **Difference dispatched and verified:** Case 1 have the considerable highest wind generation difference in comparison with the other cases. For solar generation, Case 1 presented the slightly lowest difference in relation to the other cases.

» **Hydro reserves opportunity cost:** Except for Case 1, which presented load shedding, Case 5 presented the lowest amount of hydro reserves allocation in the day-ahead scheduling and the highest relative reserves usage in the real-time operation simulation. Furthermore, in Case 5, 98% of day-ahead allocated hydro reserves were utilized in the real-time operation, without verified load shedding. These results indicate a reduction in the opportunity cost for allocating hydropower reserves resulted from a day-ahead optimization model with a more adequate representation of intermittent renewable generation variability.

In conclusion, considering day-ahead dispatch and real-time operation simulation results, the inclusion of uncertainty metrics for dispatch and for indicating intermittent renewable generation curtailment in the single day-ahead dispatch model brings scheduling closer to the real-time operation. In addition, associating reserve allocation with wind and solar generation uncertainties increases the amount of wind and solar power curtailment. However, this improvement brings greater representativeness and predictability to the Operator and generators, reduces reserve allocation costs without load shedding and also reduced the total operating system cost.

It can be concluded that Case 5, in the case where hydroelectric reserves costs are considered, presented the mainly best results, for day-ahead optimization model and real-time operation simulation, considering the lowest hydro reserves and system operating costs, the lowest upward and downwards reserves allocation amounts in day-ahead dispatch and in the real-time operation without load shedding, and the lowest hydro generation differences without load shedding.

Finally, it is worth highlighting that the model addressed the optimization of intermittent renewable curtailment considering the energetic reason, in the load-generation balance restriction, and electrical reason, based on the sensitivity factors calculated for the worst cases violations of the operational capacities of the system's transmission lines.

The next section presents the final conclusions of this work and future work that can be carried out to evolve the studies presented here.

7

Conclusion and future works

This work aimed to propose a single model to support system operator in the day-ahead scheduling dispatch process considering the impact of intermittent renewable energy curtailment and the discrimantion of these curtailment in the reserve costs, with the main contributions of:

(i) Detailing the challenges of renewable energy curtailment in other countries and Brazil, presenting the current curtailment rates, action plans, and projects that are being implemented and studied by system operators and regulators;

(ii) Presenting an alternative renewable curtailment criterion integrated in the Brazilian day-ahead scheduling energy and reserves considering:

  » the reserves requirement opportunity cost and the contribution of each renewable generator to the final reserve requirement size;

  » the transmission system restrictions; and

  » the thermal and hydro *unit commitment* constraints.

(iii) A new integrative framework that approximate the generation and reserves day-ahead planning with the real-time operation comparing the verified generation, reserves and variable renewable power curtailment with the scheduled dispatch; and

(iv) Proposition of new methods to access hourly reserve requirements for frequency control related to renewable variability, including wind and solar photovoltaic energy sources, regions and individual power plants' intermittencies with and without standard deviation contributions.

These aspects are fundamental in the current energy transition context considering the increase of renewable generation curtailment rates. By adequately measuring the variability of these intermittent energy sources and allocating them co-optimally with the operational reserves, ensuring system safety, makes day-ahead scheduling and real-time system operation more predictable, with fair curtail distribution and minimum operating costs.

For future work, the following improvements are suggested:

1. Inclusion of other flexibility products in the day-ahead scheduling single model, such as Demand Response and Storage Energy Systems;

2. Increase of the study horizon to indicate wind and solar generation curtailment to better anticipate the restrictions in day-ahead scheduling and real-time operation;

3. Innovative curtailment prioritization criteria, such as Grid Connection Study restrictions, flexible contracts, controllability features available in renewable plants;

4. Real or similar hydroelectric reserves costs comparing with the Brazilian day-ahead scheduling process; and

5. Marginal cost analysis, from dual calculation in grid and reserves constraints, in order to quantify the financial impact on generators between different reserves allocation methodologies.

These future works could contribute to increasing the predictability of the intermittent renewable generation curtailment for the system operator and generators, in a more long-term approach, in order to elucidate the real impacts of these energy sources throughout the entire process of planning, programming and operation. Besides that, it is relevant to study how other flexibility products and services can be incremented in the model to minimize the costs and support system operator in a grid with high share of intermittent renewable generation. Finally, it can be detailed other curtailment distribution rules including prioritizing power plants that can provide service and tools that can be helpful to the operator in day-ahead scheduling and real-time operation.

8

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A

Summary of international benchmarking for intermittent renewable energy curtailment

Country/System	Market/Model	Curtailment financial compensation	Measures to reduce intermittent renewable energy curtailment
Great Britain	Daily and intra-day energy and redispatch market for plants larger than 1 MW.	Payment to curtailed generators for intra-day redispatches in balancing market.	Flexibility products auctions for instant shutdown services. Interconnection with Denmark of more than 1 GW capacity. Pilot markets to optimize Distributed Energy Resources.
Germany	Daily, intra-day and real-time market for energy and redispatch model for plants larger than 100 kW.	Operator pays curtailed generators based on energy price. However Operators can charge renewable connections.	Annual fees for connection that include redispatch payments. Reclassification of intermittent renewable as dispatchable power plants. Modernization of the network, namely DLR, smart metering, voltage control and reinforcement of the distribution system.
Spain	Daily offers to deal with electrical system restrictions based on sensitivity factors, and daily and intra-day markets for load-generation balance for plants larger than 1 MW.	No payment for day-ahead electric curtails. Payment for load-generation balance based on the prices offered by the generators.	Redispatch priority for plants with no voltage control and automatic curtail mechanisms. Modernization of the transmission network, including FACTS and DLR. Storage systems and expansion of international interconnections.
Portugal	Daily, intra-day and real-time market for the resolution of technical constraints for plants larger than 1 MW.	Payment in markets based on the prices offered by the generators for the flexibility services defined annually by Operator.	Operator issues Flexible Access with *firm generation* definition. Pumped storage hydroelectric power plants. Expansion of international interconnections.
Italy	Daily and intra-day market for energy and congestion resolution for plants larger than 10 MW and emergency uses for plants larger than 100 kW.	Payment for electric curtails at the zonal hourly price paid by consumers.	Generators pay fees to connect to the system. Implementation of synchronous compensators and reactors in the grid. Modernization of the transmission system with DLR. Storage systems.
ERCOT (US)	No capacity market. Energy markets and ancillary services. Markets and redispatches for plants larger than 10 MW daily, intra-day, and manual curtails in real-time operation.	Payment in markets and redispatches at cost price. No compensation for manual curtails in real time operation.	Expansion of reserves and ancillary services, and transmission system. Creation of *Renewable Energy Competitive Zones* to encourage renewable deployment in specific grid locations.
SPP (US)	Energy markets for plants larger than 10 MW, ancillary services and capacity markets. Automatic curtails based on daily and intra-day price signals for dispatchable plants and manual curtail based on real-time sensitivity factors for non-dispatchable plants.	Automatic curtails are compensated for price offers. No compensation for manual curtails (dispatch out of merit cost) in real time operation.	Generators pay connection costs to reinforce the grid. Grid Connection Study with restrictions. Reclassification of renewable plants to dispatchable for new plants and those with more than 10 years of operation.
MISO (US)	Daily and intra-day energy markets for plants larger than 1 MW, ancillary services and capacity markets. Real-time model redispatch due to network congestion based on energy price.	Payment based on zonal marginal price for electrical curtail.	Expansion and modernization, as DLR, of the transmission system. Contracting of *uncertainty* products to increase system flexibility. Transmission network reconfiguration mechanisms. Seasonal capacity markets considering source characteristics.
PJM (US)	Daily and intra-day energy markets for plants larger than 100 kW, ancillary services and capacity markets. Manual redispatch and curtails of all wind and solar plants in real-time operation.	Payment based on zonal marginal price for electrical curtails. Penalties in case of Operator's commands deviations of more than 10% in 5 minutes.	Expansion of the transmission network. Demand response. Battery storage systems and pumped storage hydropower.
CAISO (US)	Daily and intra-day markets using the Operator's renewable forecast for plants above 1 MW. Automatic curtailment in case of negative energy prices.	Payment in markets based on the prices offered by generators. Compensation for real-time redispatches.	Flexible plants and energy importation during ramps hours. New inverter technologies. Increased observability of distributed energy resources. Storage Systems and modernization of transmission system with DLR.
Australia	Daily and intra-day energy markets and *semi-programmable* indication of curtailment for plants larger than 30 MW.	Payment in market based on the prices offered by generators. Curtails due to system security are not compensated.	Classification of intermittent renewable plants as *semi-dispatchable* plants. Creation of *Renewable Energy Zones* (REZ) with reinforcement of networks, tariff and socio-environmental incentives.

B

Complete day-ahead planning generation and reserves dispatch considering variable renewable energy uncertainty and curtailment optimization model

Notation

A. Sets and Indices

T	Set of time periods t.
D	Set of historical days d.
G^T	Set of thermoelectric generating units i.
G^H	Set of hydroelectric generating units i.
I	Set of generating units i.
I^C	Set of controllable generating units i, namely thermal and hydroelectric generation power plants.
I^{NC}	Set of non-controllable generating units i, namely wind and solar generation power plants.
L	Set of transmission lines l.
L^{wc}	Set of transmission lines with worst-case power flow violations l^{wc}.
B	Set of system buses b.
S	Set of network subsystems s.
US	Set of upstream hydro generating units us.
US_τ	Set of upstream hydro generating units us with water time travel τ.
N	Set of hydroelectric plants n.
N_τ	Set of hydroelectric plants n with water time travel τ.
K	Set of Future Cost Function's cut k.

B. Constants

c_i	Generation cost of generation unit i.
c_i^{res}	Reserves cost of generation unit i.
$\hat{g}_{it}$	Generation forecast of variable renewable energy units i at period t.
$\hat{g}_{ibt}$	Generation forecast of variable renewable energy units i connected in bus b at period t.
$\hat{d}_t$	Load demand forecast at period t.
$\hat{d}_{bt}$	Load demand forecast connected in bus b at period t.
G_{it}^{max}	Maximum generation capacity of variable renewable energy units i at period t.
G_{it}^{min}	Minimum generation capacity of variable renewable energy units i at period t.
F_l^{min}	Minimum power flow capacity in system line l.
F_l^{max}	Maximum power flow capacity in system line l.
$F_{l^{wc}}^{min}$	Minimum power flow capacity in system line with worst-case overcapacity violation l^{wc}.
$F_{l^{wc}}^{max}$	Maximum power flow capacity in system line with worst-case overcapacity violation l^{wc}.
β_{lb}	Sensitivity factor relating power flow variation on line l and generation injected in bus b.
$\beta_{l^{wc}b}$	Sensitivity factor relating generation injected on bus b and power flow variation on line with worst-case overcapacity violation l^{wc}.
R_t^{up}	Maximum upward reserve capacity of hydroelectric units at period t.
R_t^{dn}	Maximum downward reserve capacity of hydroelectric units at period t.
T_i^{on}	Minimum activation time of generating unit i.
T_i^{off}	Minimum deactivation time of generating unit i.
Q_n^{us}	Water turbine flow from upstream hydroelectric plant n in a longer horizon .
Q_n	Water turbine flow of hydroelectric plant n.
Q_i	Water turbine flow of hydro generating unit i.
S_n^{us}	Spilled water flow from upstream hydroelectric plant n in a longer horizon.
S_n	Spilled water flow of hydroelectric plant n.
$\overline{S}_{nt}$	Maximum spilled water of hydroelectric n at period t.
$\overline{Vol}_{nt}$	Maximum water reservoir of hydroelectric plant n at period t.
$\underline{Vol}_{nt}$	Minimum water reservoir of hydroelectric plant n at period t.
Vol_n	Water reservoir volume of hydroelectric plant n.
Ve_n	Dead storage water reservoir volume of hydroelectric plant n.
V_n^{us}	Volume of the spillway sill of hydroelectric plant n.
$\overline{DV}_n$	Maximum water diversion of hydroelectric plant n.
$\underline{DV}_n$	Minimum water diversion of hydroelectric plant n.
GH_n	Productivity function of hydroelectric plant n.
GH_i	Productivity function of hydro generating unit i.
H_i^{us}	Upstream elevation of hydro generating unit i.

H_i^{dn}	Downstream elevation of hydro generating unit i.
h_i^{loss}	Losses of hydro generating unit i.
ρ_i^{esp}	Specific productivity of hydro generating unit i.
τ	Water travel time.
M	Big number.
A_{nk}	Angular coefficient of Future Cost Function's cut k of reservoir of hydroelectric plant n.
B_{nk}	Independent term of Future Cost Function's cut k of reservoir of hydroelectric plant n.

C. Decision Variables

g_{it}	Dispatch of generating units i at period t.
g_{ibt}	Dispatch of generating units i at period t connected in bus b.
r_{it}^{up}	Upward reserve of generating units i at period t.
r_{it}^{dn}	Downward reserve of generating units i at period t.
δ_{it}	Power curtailment of generating units i at period t.
α_{FCF}	Future Cost Function.
x_{it}	Activation status of generating unit i at period t.
y_{it}	Shutdown status of generating unit i at period t.
z_{it}	*On/off* status of generating unit i at period t.
vol_{nt}	Water reservoir of hydroelectric plant n at period t.
inf_{nt}	Water inflow given by lateral inflow forecast of hydroelectric plant n.
q_{nt}	Turbine water flow of hydroelectric plant n at period t.
q_{nt}^{us}	Turbine water flow from upstream hydroelectric plant$n$ at period t.
s_{nt}	Spillage water of hydroelectric plant n at period t.
s_{nt}^{us}	Spilled water flow from upstream hydroelectric plant n at period t.
dv_{nt}	Water diversion of hydroelectric plant n at period t.
dv_{nt}^{us}	Water diversion from upstream hydroelectric plant n at period t.
w_{nt}	*On/off* status of the spillway operation of hydroelectric plant n at period t.

C. Others

α	Quantile of the data distribution.
Δ_{dt}	Generation variation between the periods $(t+1)$ and t in relation to the generation in period t.
$\Delta^{up}_{[(DT)\alpha]}$	Generation variation value located in the $DT\alpha$-th position, considering negative variations, of the total D historical days and T periods of the day.
$\Delta^{dn}_{[(DT)\alpha]}$	Generation variation value located in the $DT\alpha$-th position, considering positive variations, of the total D historical days and T periods of the day.
κ_s	Variability metric of renewable generation power plants, namely wind and solar plants, connected in the subsystem s.
$\overline{\kappa}_s$	Mean of variability metrics, considering positive and negative generation variations, of total renewable generation power plants, namely wind and solar plants, connected in the subsystem s.
$\overline{\kappa}^{up}_{st}$	Mean of variability metric of total renewable generation power plants, namely wind and solar plants, connected in the subsystem s at period t, considering negative variations.
$\overline{\kappa}^{dn}_{st}$	Mean of variability metric of total renewable generation power plants, namely wind and solar plants, connected in the subsystem s at period t, considering positive generation variations of power plants.
$\kappa^{\sigma,up}_{it}$	Variability metric of generating unit i at period t, considering negative generation variations of power plants.
$\kappa^{\sigma,dn}_{it}$	Variability metric of generating unit i at period t, considering positive variations and variabilities between the power plants.
ϵ^{up}_{it}	Factor of standard deviation relative share, considering negative generation variations, of generating unit i.
ϵ^{dn}_{it}	Factor of standard deviation relative share, considering positive generation variations, of generating unit i.
$\overline{\kappa}^{up}_{it}$	Mean of variability metrics, considering positive generation variations, of generating unit i at period t.
$\overline{\kappa}^{dn}_{it}$	Mean of variability metrics, considering negative generation variations, of generating unit i at period t.

Model Equations

Objective Function

$$\min_{\substack{g_{it},r_{it}^{up},r_{it}^{dn},\\ x_{it},y_{it},z_{it},\\ vol_{nt},inf_{nt},q_{nt},s_{nt},dv_{nt},w_{nt}\\ qn_{nt}^{us},s_{nt}^{us},dv_{nt}^{us},\alpha_{FCF}\\ \delta_{it}}} \quad \sum_{t \in T} \sum_{i \in I^C} \quad c_i g_{it} + c_i^{res}(r_{it}^{up} + r_{it}^{dn}) + \alpha_{FCF} \tag{B-1}$$

where $i \in (I = I^T U I^H U I^{NC} = I^C U I^{NC})$.

Constraints

Energy balance

$$\sum_{t \in T} \left(\sum_{i \in I^C} g_{it} + \sum_{i \in I^{NC}} \hat{g}_{it} \right) = \sum_{t \in T} \left(\hat{d}_t + \sum_{i \in I^{NC}} \delta_{it} \right) \tag{B-2}$$

Power Flow and Sensitivity Factor

$$F_{l^{wc}}^{min} \leq \sum_{b \in B} \left\{ \beta_{l^{wc}b} \cdot \sum_{t \in T} \left[\sum_{i \in I^C} g_{ibt} + \sum_{i \in I^{NC}} (\hat{g}_{ibt} - \delta_{ibt}) - \hat{d}_{bt} \right] \right\} \leq F_{l^{wc}}^{max}, \tag{B-3}$$

$$\forall l^{wc} \in L^{wc}$$

$$\beta_{l^{wc}b} = \frac{\partial f_{l^{wc}}}{\partial g_b} \tag{B-4}$$

Generation and curtail limits

$$G_{it}^{min} \leq g_{it} \leq G_{it}^{max}, \quad \forall t \in T, \quad \forall i \in I^C \tag{B-5}$$

$$G_{it}^{min} \leq \hat{g}_{it} - \delta_{it} \leq G_{it}^{max}, \quad \forall t \in T, \quad \forall i \in I^{NC} \tag{B-6}$$

Hydroelectric Reserves limits

$$\sum_{i\in I^H} r_{it}^{up} \geq R_t^{up}, \quad \forall t \in T \tag{B-7}$$

$$\sum_{i\in I^H} r_{it}^{dn} \geq R_t^{dn}, \quad \forall t \in T \tag{B-8}$$

$$\Delta_{dt} = \frac{g_{d(t+1)} - g_{dt}}{g_{dt}}, \quad \forall d \in D, \quad \forall t \in T \tag{B-9}$$

$$\Delta_{dt}^{up} = -\min(\Delta_{dt}, 0), \quad \forall d \in D, \quad \forall t \in T \tag{B-10}$$

$$\Delta_{dt}^{dn} = \max(\Delta_{dt}, 0), \quad \forall d \in D, \quad \forall t \in T \tag{B-11}$$

Case 1 - Current fixed reserves requirements

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{s\in S}\kappa_s \sum_{i\in I_s^{wind}} \hat{g}_{it}, \quad \forall t \in T \tag{B-12}$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{s\in S}\kappa_s \sum_{i\in I_s^{wind}} \hat{g}_{it}, \quad \forall t \in T \tag{B-13}$$

Case 2 - Incorporation of variable renewable curtailment

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{s\in S}\kappa_s \sum_{i\in I_s^{wind}} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{B-14}$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{s\in S}\kappa_s \sum_{i\in I_s^{wind}} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{B-15}$$

Case 3 - Incorporation of updated variable renewable generation variabilities

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{s\in S}\overline{\kappa}_s \sum_{i\in I_s^{NC}} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{B-16}$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{s\in S}\overline{\kappa}_s \sum_{i\in I_s^{NC}} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{B-17}$$

$$\Delta_{dt} = \frac{g_{d(t+1)} - g_{dt}}{g_{dt}}, \quad \forall d \in D, \quad \forall t \in T \tag{B-18}$$

$$\overline{\kappa}_s = \frac{\Delta^{up}_{[(DT)\alpha]} + \Delta^{dn}_{[(DT)\alpha]}}{2}, \quad \text{where } \alpha = 90\%, \quad \forall s \in S \tag{B-19}$$

Case 4 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{s\in S}\kappa_{st}^{(\alpha)up} \sum_{i\in I_s^{NC}} (\hat{g}_{it} - \delta_{it}), \quad \text{where } \alpha = 90\%, \forall t \in T \tag{B-20}$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{s\in S}\kappa_{st}^{(\alpha)dn} \sum_{i\in I_s^{NC}} (\hat{g}_{it} - \delta_{it}), \quad \text{where } \alpha = 90\%, \forall t \in T \tag{B-21}$$

$$\Delta_{dt} = \frac{g_{d(t+1)} - g_{dt}}{g_{dt}}, \quad \forall d \in D, \quad \forall t \in T \tag{B-22}$$

$$\Delta_{dt}^{up} = -\min(\Delta_{dt}, 0), \quad \forall d \in D, \quad \forall t \in T \tag{B-23}$$

$$\Delta_{dt}^{dn} = \max(\Delta_{dt}, 0), \quad \forall d \in D, \quad \forall t \in T \tag{B-24}$$

$$\kappa_{st}^{(\alpha)up} = \Delta_{[D\alpha]st}^{up}, \quad \text{where } \alpha = 90\%, \forall s \in S, \quad \forall t \in T \tag{B-25}$$

$$\kappa_{st}^{(\alpha)dn} = \Delta_{[D\alpha]st}^{dn}, \quad \text{where } \alpha = 90\%, \forall s \in S, \quad \forall t \in T \tag{B-26}$$

Case 5 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions, and individual power plants variabilities

$$R_t^{up} = \gamma^{up}\hat{d}_t + \sum_{i \in I^{NC}} \kappa_{it}^{\sigma,up}(\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{B-27}$$

$$R_t^{dn} = \gamma^{dn}\hat{d}_t + \sum_{i \in I^{NC}} \kappa_{it}^{\sigma,dn}(\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{B-28}$$

$$\kappa_{it}^{\sigma,up} = \epsilon_{it}^{up}\kappa_{st}^{(\alpha)up}, \quad \text{where } \alpha = 90\%, \forall i \in I^{NC}, \quad \forall s \in S, \quad \forall t \in T \tag{B-29}$$

$$\kappa_{it}^{\sigma,dn} = \epsilon_{it}^{dn}\kappa_{st}^{(\alpha)dn}, \quad \text{where } \alpha = 90\%, \forall i \in I^{NC}, \quad \forall s \in S, \quad \forall t \in T \tag{B-30}$$

$$\epsilon_{it}^{up} = \frac{\sigma_{it}^{(\alpha)up}}{\sum_{i=1}^{I^{NC}} \sigma_{it}^{(\alpha)up}}, \quad \text{where } \alpha = 90\%, \quad \forall i \in I^{NC}, \quad \forall t \in T \tag{B-31}$$

$$\epsilon_{it}^{dn} = \frac{\sigma_{it}^{(\alpha)dn}}{\sum_{i=1}^{I^{NC}} \sigma_{it}^{(\alpha)dn}}, \text{where } \alpha = 90\%, \quad \forall i \in I^{NC}, \quad \forall t \in T \tag{B-32}$$

$$\Delta_{idt} = \frac{g_{id(t+1)} - g_{idt}}{g_{idt}}, \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{B-33}$$

$$\Delta_{idt}^{up} = -\min(\Delta_{idt}, 0), \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{B-34}$$

$$\Delta_{idt}^{dn} = \max(\Delta_{idt}, 0), \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{B-35}$$

$$\sigma_{it}^{(\alpha)up} = \sqrt{\frac{1}{D} \sum_{d \in D} (\Delta_{idt}^{up} - \overline{\kappa}_{st}^{up})^2}, \quad \text{where } \alpha = 90\%, \forall i \in I^{NC}, \forall s \in S, \forall t \in T \tag{B-36}$$

$$\sigma_{it}^{(\alpha)dn} = \sqrt{\frac{1}{D} \sum_{d \in D} (\Delta_{idt}^{dn} - \overline{\kappa}_{st}^{dn})^2}, \quad \text{where } \alpha = 90\%, \forall i \in I^{NC}, \forall s \in S, \forall t \in T \tag{B-37}$$

Case 6 - Incorporation of variable renewable curtailment, updated variabilities per hour, upward and downward contributions, and individual power plants with no relative standard deviation contribution

$$R_t^{up} = \gamma^{up} \hat{d}_t + \sum_{i \in I^{NC}} \overline{\kappa}_{it}^{up} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{B-38}$$

$$R_t^{dn} = \gamma^{dn} \hat{d}_t + \sum_{i \in I^{NC}} \overline{\kappa}_{it}^{dn} (\hat{g}_{it} - \delta_{it}), \quad \forall t \in T \tag{B-39}$$

$$\Delta_{idt} = \frac{g_{id(t+1)} - g_{idt}}{g_{idt}}, \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{B-40}$$

$$\Delta_{idt}^{up} = -\min(\Delta_{idt}, 0), \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{B-41}$$

$$\Delta_{idt}^{dn} = \max(\Delta_{idt}, 0), \quad \forall i \in I^{NC}, \quad \forall d \in D, \quad \forall t \in T \tag{B-42}$$

$$\overline{\kappa}_{it}^{up} = \frac{1}{D} \sum_{d \in D} \Delta_{idt}^{up}, \quad \forall i \in I^{NC}, \quad \forall t \in T \tag{B-43}$$

$$\overline{\kappa}_{it}^{dn} = \frac{1}{D} \sum_{d \in D} \Delta_{idt}^{dn}, \quad \forall i \in I^{NC}, \quad \forall t \in T \tag{B-44}$$

Thermal Unit Commitment

$$x_{it} - x_{i(t-1)} = y_{it} - z_{it}, \quad \forall i \in G^T, \forall t \in T \tag{B-45}$$

$$\sum_{k=t+1-T_i^{on}}^{T} z_{it} \leq x_{it}, \quad \forall t \in \{T_i^{on,inic} + 1, ..., T\} \tag{B-46}$$

$$\sum_{k=t+1-T_i^{off}}^{T} y_{it} \leq 1 - x_{it}, \quad \forall t \in \{T_i^{off,inic} + 1, ..., T\} \tag{B-47}$$

$$0 \leq y_{it}, z_{it} \leq 1, \quad \forall i \in G^T, \quad \forall t \in T \tag{B-48}$$

$$g_{i(t-1)} - g_{it} \geq G_i^{Tmin} z_{it}, \quad \forall i \in G^T, \quad \forall t \in T \tag{B-49}$$

$$g_{it}^T - g_{i(t-1)}^T \leq G_i^{Tmax} y_{it}^T, \quad \forall i \in G^T, \quad \forall t \in T \tag{B-50}$$

$$g_{it} \leq G_i^{Tmax} x_{it}, \quad \forall i \in G^T, \quad \forall t \in T \tag{B-51}$$

$$g_{it} \geq G_i^{Tmin} x_{it}, \quad \forall i \in G^T, \quad \forall t \in T \tag{B-52}$$

Future Cost Function

$$\alpha_{FCF} \geq \sum_{n \in N} A_{nk} vol_{nt} + B_{nk}, \quad \forall k \in K \tag{B-53}$$

Hydro Unit Commitment

$$x_{it} - x_{i(t-1)} = y_{it} - z_{it}, \quad \forall t \in T, \quad \forall i \in G^H \tag{B-54}$$

$$\sum_{k=t+1-T_i^{on}}^{T} z_{it} \leq x_{it}, \forall t \in \{T_i^{on,inic} + 1, ..., T\}, \quad \forall i \in G^H \tag{B-55}$$

$$\sum_{k=t+1-T_{off}}^{t} y_{it} \leq 1 - x_{it}, \forall t \in \{T_i^{off,inic} + 1, ..., T\}, \quad \forall i \in G^H \tag{B-56}$$

$$0 \leq y_{it}, z_{it} \leq 1, \quad \forall h \in G^H, \quad \forall t \in T, \quad \forall i \in G^H \tag{B-57}$$

$$g_{i(t-1)} - g_{it} \leq G_i^{min} z_{it} + RP_{it}^{dn}\, x_{it}, \quad \forall i \in G^H, \quad \forall t \in T \tag{B-58}$$

$$g_{it} - g_{i(t-1)} \leq G_i^{Hmax} y_{it} + RP_{it}^{up}\, x_{i(t-1)}, \quad \forall i \in G^H, \quad \forall t \in T \tag{B-59}$$

$$g_{it} + r_{it}^{up} \leq G_i^{max} x_{it}, \quad \forall i \in G^H, \quad \forall t \in T \tag{B-60}$$

$$g_{it} - r_{it}^{dn} \geq G_i^{min} x_{it}, \quad \forall i \in G^H, \quad \forall t \in T \tag{B-61}$$

Hydro Balance

$$vol_{nt} = vol_{n(t-1)} + inf_{nt} - (q_{nt} - s_{nt} - dv_{nt}) + \sum_{n \in N_\tau} (q_{n(t-\tau)}^{us} + s_{n(t-\tau)}^{us}) + \sum_{n \in N_\tau} (Q_{n(t-\tau)}^{us} + S_{n(t-\tau)}^{us}) + \sum_{n \in N} dv_n^{us} t, \quad \forall n \in N, \quad \forall t \in T \tag{B-62}$$

$$\underline{Vol}_{nt} \leq vol_{nt} \leq \overline{Vol}_{nt}, \quad \forall n \in N, \quad \forall t \in T \tag{B-63}$$

$$vol_{nt} \leq \overline{Ve}_n, \quad \forall n \in N, \quad \forall t \in T \tag{B-64}$$

$$\underline{DV}_n \leq dv_{nt} \leq \overline{DV}_n, \quad \forall n \in N, \quad \forall t \in T \tag{B-65}$$

$$s_{nt} \leq inf_{nt} - q_{nt} + \sum_{n \in N_\tau} (q_{n(t-\tau)} + s_{n(t-\tau)}) + \tag{B-66}$$

$$\sum_{n \in N_\tau} (Q_{nt} + S_{n(t-\tau)}) + \sum_{n \in N} dv_{nt} + [-V_n^{ss} + M(1 - w_{nt})], \quad \forall n \in N, \forall t \in T$$

$$vol_{n(t-1)} + inf_{nt} - q_{nt} + \sum_{n \in N_\tau} (q_{n(t-\tau)} + s_{n(t-\tau)}) + \tag{B-67}$$

$$\sum_{n \in N_\tau} (Q_{nt} + S_{n(t-\tau)}) + \sum_{n \in N} dv_{nt} + (-V_n^{ss}) \leq M w_{nt}, \quad \forall n \in N, \forall t \in T$$

$$0 \leq s_{nt} \leq \overline{S}_{nt} w_{nt}, \quad \forall n \in N, \quad \forall t \in T \tag{B-68}$$

Approximated Hydro Production Function (AHPF)

$$GH_n = \sum_{i \in G^H} g_i(q_i, Vol_n, Q_n, S_n), \quad \forall n \in N \tag{B-69}$$

$$GH_i = \rho_i^{esp} Q_i [H_i^{us}(Vol_n) - H_i^{ds}(Q_n, S_n) - h_i^{loss}], \quad \forall i \in G^H \tag{B-70}$$

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