Chapter

Variable Renewable Energy: How the Energy Markets Rules Could Improve Electrical System Reliability

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Abstract

In the last 10 years, significant changes have been observed in the operation of electrical systems resulting from the increasing incorporation of Variable Renewable Energy (NCRE—Solar PV, WIND) characterized by strong volatility in its energy production, due to climatic effects, which affect the reliability in the operation of the electrical system. These technologies also show a significant reduction in their capital costs, which are currently competitive compared to conventional alternatives for energy production, with the advantage of contributing to reducing the production of greenhouse gases. Therefore, increasing reliability operational problems are expected in the future, which must be resolved to supply the demand safely and at minimum cost. LATAM's countries are making slow progress in updating their regulatory frameworks for the electricity sector to include changes that improve the integration of NCRE generation without reducing the quality of service. This document describes possible regulatory changes that could be implemented to promote a system safe operation including (a) intra-hours marginal costs, (b) day-ahead/intraday energy markets, (c) incentives to better forecast the NCRE generation production profile, (d) participation of NCRE generation in the capacity market, and (e) including BESS as ancillary service for frequency/ramp power control.

Keywords: electricity markets, reserves, economic signals, marginal costs, reliability, firm capacity, ancillary services, distribution rates

1. Introduction

In the LATAM's countries, mainly during the 1990s, wholesale electricity markets were created as a means to ensure that the restructuring process of the electricity sector leads to private participation in the efficient development of the sector. The legislation and regulation of the markets establish economic signals for investment and operation decisions given by energy prices that seek to reflect the marginal cost of the system and other economical signals to promote the efficient expansion of the generation fleet.

The regulatory framework of each market (law and other regulations) establishes the objectives, criteria, and general rules that define the framework in which the market must be developed and the types of agents that can participate commercially. Likewise, they define the tariff criteria and update methodologies that result in the tariffs that are applied to energy transactions and transmission charges.

Generators have free access to the transmission network and thus to the spot market where they sell their energy production at prices that arise from competition for dispatch based on the variable production cost of each power plant. Market prices represent the short-run marginal cost of the market.

Within this conceptual framework, LATAM's electricity markets have shown great dynamism since their inception with strong private participation during the privatization processes of state-owned companies and in new generation investment projects.

The generation of electrical energy in these markets was traditionally carried out based on conventional generation (thermal, hydraulic, geothermal, and nuclear) characterized by production patterns known in advance, as a result of which the reliability of the electrical supply was high, and the events that affected the quality of electrical service limited to the unavailability of some generator/element of the transmission system due to forced unavailability resulting from an unanticipated failure.

In the last 10 years, significant changes have been observed in the operation of these electrical systems resulting from the increasing incorporation of nonconventional renewable generation NCRE (mainly solar PV and WIND) characterized by strong volatility in its energy production, due to climatic effects, which affect the reliability in the operation of the electrical system [1–5].

These technologies also show a significant reduction in their capital costs [6], which are currently competitive compared to conventional alternatives for energy production, with the advantage of contributing to reducing the production of greenhouse gases.

The electricity production based on NCRE is currently a key element in the energy transition that the electricity sectors must endure, in the following decades, toward an operation with low greenhouse gas emissions.

However, the penetration of NCRE technologies, given precisely their variability, can alter the functioning of the electricity markets. The particular characteristics of NCRE, considered non-manageable, produce technical-economic impacts on the operation of the system.

This situation, which should not prevent the development of these technologies to take advantage of their advantages, however, requires the introduction of reforms in the functioning of the market to efficiently assimilate the high levels of NCRE penetration that are forecast for the near future.

As NCRE penetration levels grow, many electricity sectors around the world are already facing new challenges and respective reforms are taking place to improve the integration of these technologies into the market.

Although the impact of renewable technologies varies according to the characteristics of the system and the regulatory environment, the main problems that arise are similar.

In recent years, a significant reduction in the cost of storage media, mainly batteries (BESS), has also been observed. The storage facilities could contribute to mitigating the volatility of the production of renewables by providing quickly managed reserves. The reduction in the development costs of BESS also makes it possible to anticipate their rapid growth, helping to mitigate the operational problems of the electrical system.

In systems with variable renewable generation, the system reserves must compensate for random variations in demand and generation. The demand has daily cycles. Variable renewable generators add variation patterns to their production. Tracking variability may require more operational flexibility and more frequent dispatch adjustments.

In the particular case of LATAM's countries, given the growing participation of NCRE generation, restrictions have been introduced that tend to limit the participation of this type of technology in the market as a way of guaranteeing security in the supply of demand.

Some countries are making slow progress in updating their regulatory frameworks for the electricity sector to include changes that improve the integration of NCRE generation without reducing the quality of service.

This document describes possible regulatory changes that could be implemented to promote a system safe operation at minimum cost with high penetration of ERNC generation. It includes (a) intra-hours marginal costs, (b) day-ahead/intraday energy markets, (c) incentives to better forecast the NCRE generation production profile, (d) participation of NCRE generation in the capacity market, and (e) including BESS as an ancillary service for frequency/ramp power control.

The document is organized into three sections, which are as follows:

Section #1: Presents a general description of the operation of the LATAMs electricity markets. It includes how the generation fleet is dispatched and how is determined the marginal cost of energy, the composition of the generation fleet, and the growth of ERNC generation.

Section #2: Presents some observed operational problems that affect the security of supply resulting from the volatility in the production of wind and solar generation.

Section #3: Describe market rules that could mitigate the adverse effects of intermittent generation, favoring its participation in the electricity markets without affecting the reliability of the electrical system. It includes: (a) intra-hours marginal costs, (b) day-ahead/intraday energy markets, (c) optimization of system reserves, (d) incentives to better forecast the NCRE generation production profile, (e) participation of NCRE generation in the capacity market, (f) including BESS as an ancillary service for frequency/ramp power control, and (g) demand participation for increasing the system reserves.

2. LATAM's market operation

2.1 Generation dispatch

Each of LATAM's electricity markets has particular characteristics concerning the mechanism used to perform the generation dispatch. Even so, there are common criteria that are summarized below.

The generation fleet is dispatched based on the variable production cost (VPC) of each generator. The VPC is equal to the sum of variable fuel cost plus O&M cost.

$$\text{VPC}\left[\frac{\text{USD}}{\text{MWh}}\right] = \text{Eficiency} \times \text{Fuel Cost} + \text{O\&M}$$

The generator with the lowest VPC is dispatched first (typically renewable generators (hydro, solar, and wind) followed by clean thermal generation (geothermal, efficient cogeneration, and nuclear) and lastly conventional thermal generation based on coal, natural gas, and liquid fuels (fuel oil and diesel). The generation dispatch order is called LIST OF MERIT.

The LIST OF MERIT may be changed due to technical requirements associated with the security of supply (reliability constraints).

Figure 1 shows (on the right) a simple example of building the LIST OF MERIT following the criteria indicated above. Each rectangle represents one particular power plant. The height is the available power of the plant, and the width is 1 hour, so the rectangle area represents the available energy of the power plant in each hour.

The generators with the lowest VPC, typically renewables (in green) are located first followed by hydro generation (in blue), and lastly, the thermal generators (T1–T5 in brown) that are ordered by their variable production costs (VPC) the cheapest first.

Figure 1 shows (on the left) the hourly demand of the system. Typically, the demand is minimum in the early morning hours and maximum in the afternoon/night hours.

The demand for 1 hour in particular (hour 23, red dot) is supplied by the generators with the lower VPC of the LIST OF MERIT: renewable generation plus hydro generation and thermal power plants T1, T2, T3, and partially T4. The T5 generator is not dispatched because it is the one with the highest VPC.

When demand is reduced, the dispatch of thermal generation is reduced. In the figure, at hour 7, only generators T1 and T2 (partial) are dispatched.

The marginal cost of generation in each hour is equal to the VPC of the generator with the highest VPC that is dispatched according to the aforementioned methodology. In the example, the marginal cost at hour 23 is equal to the VPC of generator G4, and the marginal cost at hour 7 is equal to the CVP of generator G2.

Therefore, the marginal costs are higher when the demand is higher (and therefore the lower the reserve margin), resulting in the marginal cost being an economic signal that promotes the availability of generation as a way of achieving maximum profitability of the generation business.

Figure 2 shows a typical generation dispatch by type. The figure shows the generation dispatch for each hour, for a typical day of each month (12 × 24 matrix) in the Mexican Electricity Market (MX).

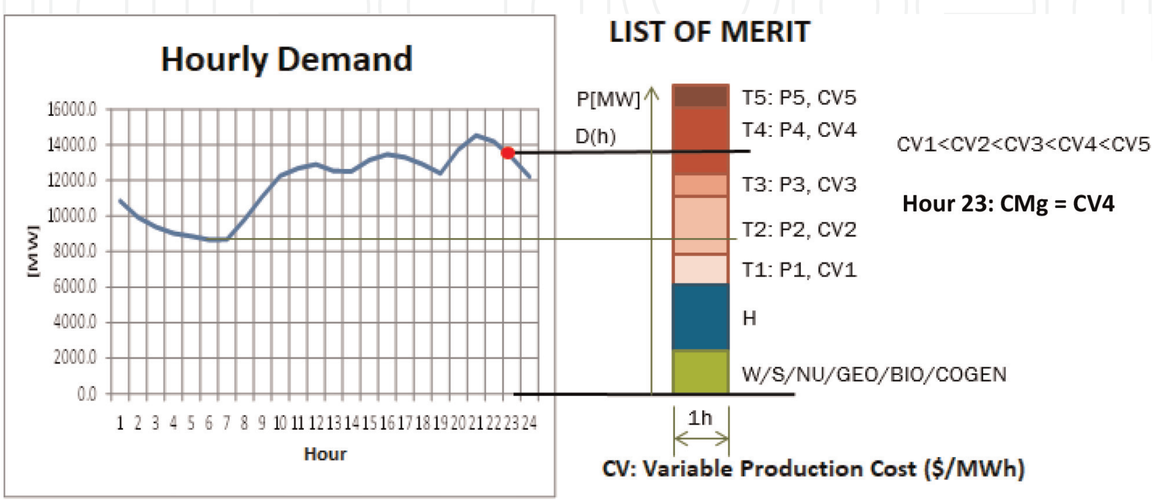

Figure 1.
Generation dispatch methodology (LIST OF MERIT).

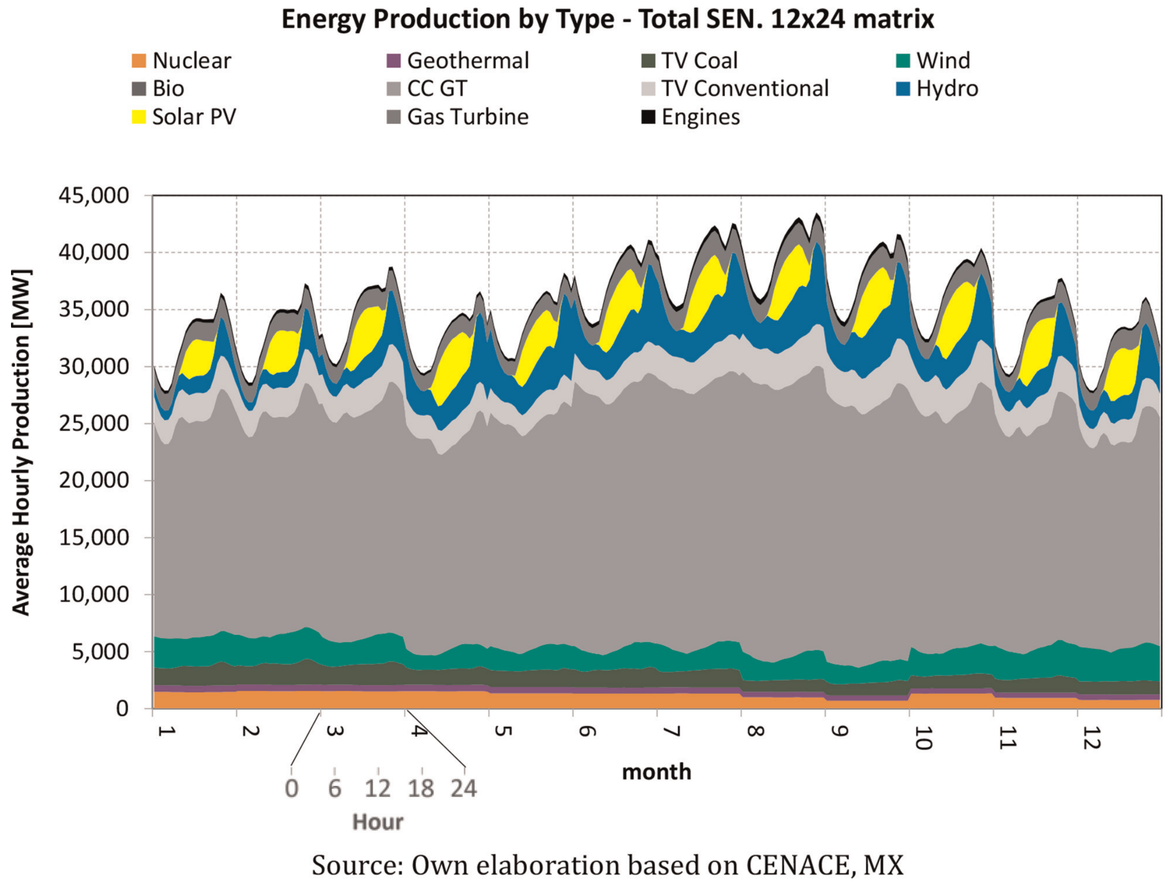

Figure 2.
Energy production by type. 12 × 24 matrix. Source: Own elaboration based on CENACE, MX.

Hydro generation is maximum at night, which compensates for the zero solar generation in those hours. Thermal generators with the lowest VPC are dispatched as baseload (typically geothermal, nuclear, combine cycle running with natural gas and coal thermal plants). High expensive thermal plants (conventional thermal running with liquid fuels) are dispatched last, as peaking units.

Generation dispatch includes the system support resources (RSS).[1] They are generators that are dispatched to maintain the reliability of the power system.

2.2 Addition of new generation capacity

In the LATAM's electricity markets, the expansion of the generation fleet that arises from the initiative of private investors is mainly based on natural gas combined cycle type thermal plants (distributed by networks or LNG type) and WIND and SOLAR PV renewable plants.

The main reason for the development of those kinds of projects is because their development cost (CAPEX + OPEX) is minimal and they allow compliance with renewable generation participation quotas imposed by governments.

As an example, **Figure 3** shows the installed generation capacity in MX by type, period 2017 to 2020. In this period, the ERNC generation increases by 9072 MW and CCGT generation by 11,490 MW. The other technologies show minimum changes (**Table 1**).

[1] For example, generators required to run out-of-merit to provide security or reliability in a given area.

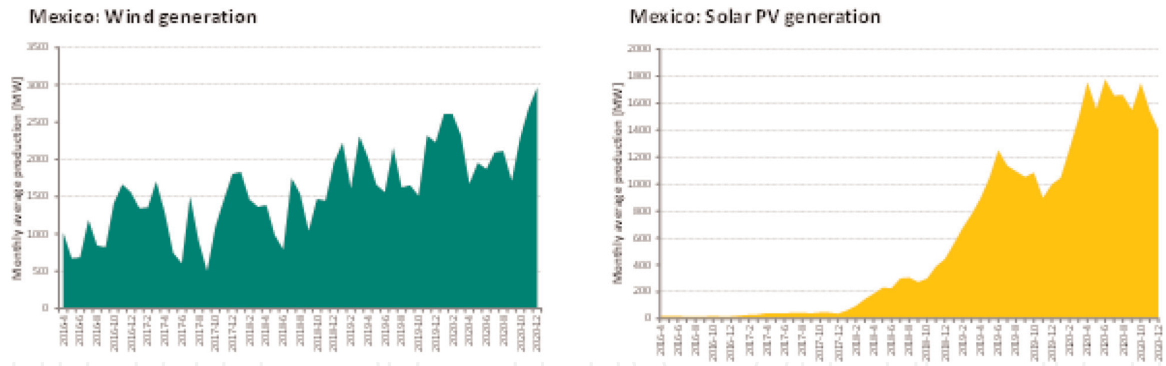

Figure 3.
Production of WIND/SOLAR PV generation. Source: Own elaboration based on CENACE, MX.

Technology	2017	2018	2019	2020
Hydro	12612	12612	12612	12614
Geothermal	899	899	899	951
Wind	3898	4866	6050	7076
Solar PV	171	1878	3646	6065
Bio	374	375	375	408
Nuclear	1608	1608	1608	1608
Cogen	1322	1709	1710	2106
Total Clean Energy	**20884**	**23947**	**26900**	**30828**
Combine Cycle	25340	27393	30402	35030
Thermal Conventional	12665	12315	11831	11831
Gas Turbine	2960	2960	2960	3793
Engines	739	880	891	949
TV Coal	5463	5463	5463	5463
Total Thermal	**47167**	**49011**	**51547**	**57066**
TOTAL	**68051**	**72958**	**78447**	**87894**
Source: PRODESEN 2020-2034				

Table 1.
MX installed capacity by type [MW].

It is expected that in the coming years the aforementioned trend in the expansion of the generation fleet in all LATAM's countries will continue, as a result of which is to be expected growing participation of WIND/SOLAR PV generation in the generation mix that supplies the demand.

3. Reliability in the operation of the electrical system

The LATAM's countries supply the demand with a mix of conventional generation plus a growing share of NCRE generation.

From the point of view of reliability in the supply of demand, countries with a high share of hydro generation (BRA, COL) use the energy stored in reservoirs to provide reserves for rapid management, contributing to the system reliability even against the high intermittence that characterizes the NCRE generation.

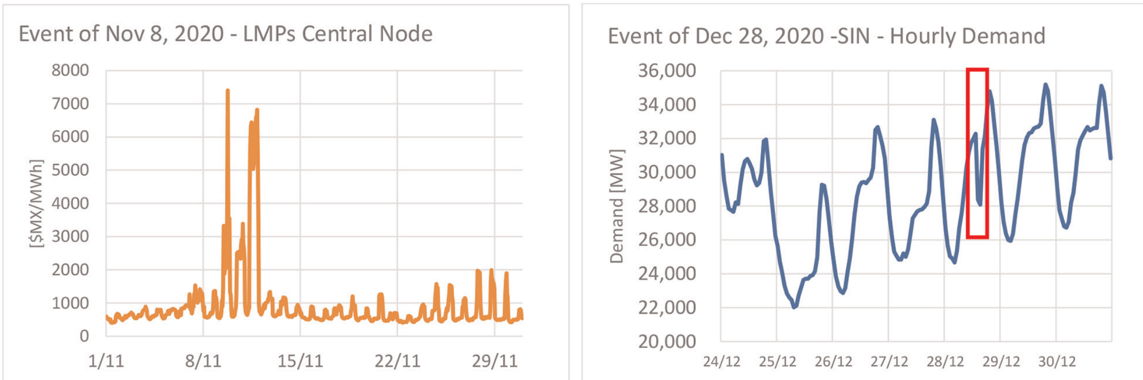

Figure 4.
Events with high volatility in the operation of the market.

On the other hand, countries with a low share of hydro generation must have another type of quickly managed reserves to guarantee the security of supply in the face of sudden changes in the production of NCRE generation.

Table 2 shows the participation of hydro, thermal, and renewables in the generation mix of LATAM's countries.

The MX electrical system has a minimum participation of hydro generation in the generation mix (9% in 2020). In this system, the reliability problems increase because thermal generation is mainly composed of conventional thermal generation (steam turbines) and the available gas turbines are very limited (3700 MW in 2020), so the dispatched thermal generation cannot follow the fast variations of ERNC production.

The aforementioned characteristics of the MX electrical system, together with the growth observed in NCRE generation, were responsible for serious reliability problems registered in two events during 2020.

1. In the week of November 8, high energy prices (LMPs) were recorded (>6000 MXN/MWh, 300 USD/MWh). They are unprecedented values in operation and were not repeated in the remaining days of the year.

2. In the afternoon of December 28, there was strong instability in the power system operation, which resulted in a severe blackout affecting over 10 million people, with a load cutoff of 8696 MW (Source: CENACE6).

Figure 4 show both events. On the left, it is observed very high marginal prices observed in the event of November 8. On the right, it is observed a sudden reduction in the demand in the event of December 28.

1. **Event of November 8.** High LMPs were recorded in the week of November 8, 2020, which are explained by a very low generation reserve, which resulted in the need to dispatch generation units with a very high VPC. It is observed very high marginal cost (LMPs) in hours with minimum wind and solar production.

2. **Event of December 28.** On the afternoon of December 28, there was strong instability in the operation of the system, which resulted in a significant load cutoff (8696 MW). The instability recorded in the power system was due to low

Country	Hydro	Thermal	Renewable	Total (GWh)
Argentina	22%	69%	9%	134,177
Bolivia	32%	63%	5%	9212
Brazil	72%	17%	11%	557,055
Chile	27%	54%	20%	77,567
Colombia	72%	27%	1%	69,323
Costa Rica	72%	0%	28%	11,534
Ecuador	89%	9%	2%	27,301
El Salvador	37%	17%	47%	5386
Guatemala	52%	21%	27%	11,122
Honduras	25%	42%	32%	9578
Mexico	**9%**	78%	13%	247,415
Nicaragua	15%	29%	55%	3748
Panama	48%	40%	12%	5420
Perú	60%	35%	5%	49,187
Uruguay	34%	7%	59%	11,596

Table 2.
LATAM's countries—generation by technology (2020).

availability of thermal generation, as a result of which, upon a fault in the transmission system, the power system had not enough generation capacity (reserve), which led to a frequency drop in the system with the subsequent load loss to restore the dynamic balance of the power system. **Figure 5** shows the production of renewables during the event of instability mentioned. The figure includes the marginal cost (local marginal prices—LMPs). During the week, it is observed high variations in renewable production (5000 MW of solar production and 3000 MW of wind generation) resulting in very high variations of marginal prices that show low reserve in the system.

As a result of the aforementioned events, the Government of President Andrés Manuel Pérez Obrador (AMLO) enacted new rules for market operation meant to preserve the power system's reliability, safety, and continuity. The most relevant are as follows:

1. Include limits for the integration of NCRE into the electric system.

2. Restrictions on the dispatch of the NCRE generation (curtailment).

3. To provide Ancillary Services, the ISO is enabled to include in the generation dispatch some proportion of mandatory generation (must-run).

4. NCRE generators must be able to control the voltage at their connection node at all times.

5. NCRE generators do not provide firm energy to the electrical system.

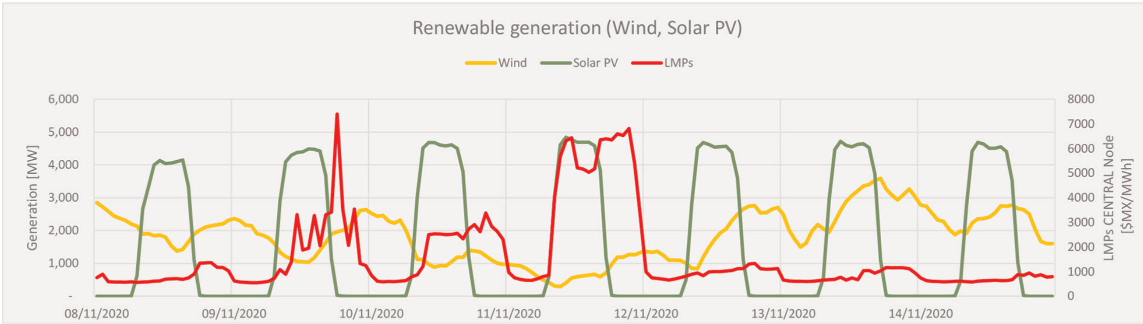

Figure 5.
Hourly NCRE generation (wind, solar PV). Source: Own production based on CENACE, MX.

The new rules introduce severe restrictions to the integration of NCRE generation in the system, resulting in higher energy prices and higher greenhouse gas production as a result of increased production of thermal generation replacing NCRE generation.

4. Market rules to incentive NCRE integration together with a safe system operation

4.1 Generation dispatch programming

The determination of the hourly production of each generator that participates in the market results from an operation programming that covers different time intervals from 1 day, 1 week, and the medium/long term. This makes it possible to guarantee that the programming of the operation meets the objective of supplying the demand with adequate quality service at a minimum cost within the time horizon covered by each program [7].

In electrical systems with high participation of hydro generation in the generation mix, the energy that is stored in the reservoirs is used to supply the demand, thus avoiding fuel costs in the thermoelectric units. However, the availability of hydro energy is limited by the storage capacity in the reservoirs, which also affects the operational safety of the system.

This introduces a dependency between today's operating decision and future operating costs, including possible costs due to insufficient generation capacity resulting in demand cuts (non-supply energy).

If the existing hydro reserves are used in the short term to minimize thermal costs and a severe drought occurs in the future, high-cost rationing could occur, affecting the quality of service.

If, on the other hand, the hydro reserves are not used in the short term, through more intense use of thermal generation, and the future hydro inflows to reservoirs are high, water spill may occur, which represents a waste of energy and, consequently, an increase in the operating cost of the electrical system.

The optimal use of the water stored in the reservoirs corresponds to the point that minimizes the sum of the total costs incurred (present plus future costs). As shown in **Figure 6**, the hydro production that minimizes total cost is where the derivatives of the present cost (FCI) and future cost function (FCF), with respect to the volume of water stored in the reservoirs, are equal with opposite signs.

$$\frac{\partial(Total\,Cost)}{\partial V} = 0$$

where
V [m^3]: Stored volume of water in the reservoir.
Then

$$\frac{\partial}{\partial \mathrm{V}}\mathrm{FCI} = -\frac{\partial}{\partial \mathrm{V}}\mathrm{FCF} = \mathrm{Water\ Value}$$

The last equation says that minimum total cost is achieved when the reservoir reaches a level where the marginal immediate cost of using water is equal to the marginal future cost of using water now (with a different sign).

Any of both derivatives are known as WATER VALUE [$/Hm^3] and represent the "opportunity variable cost" of the stored water.

Immediate cost function (FCI) is directly calculated as the least-cost thermal complement to hydro energy production. The future cost function (FCF) is conceptually calculated through the simulation of future system operation and the calculation of corresponding operating costs.

Due to the variability of inflows to reservoirs, which fluctuate seasonally, regionally, and from year to year, this simulation is carried out on a probabilistic basis, that is, using a large number of hydrological scenarios (historical data; dry, medium, and wet years).

SIMULATION = > FUTURE COST FUNCTION.

FUTURE COST FUNCTION = > HYDRO OPERATION POLICY FOR SHORT TERM.

The optimization of generation resources in a hydrothermal system, such as the ones existing in LATAM's countries, requires the use of mathematical optimization models that simulate the hierarchical decision-making process that must be carried out (strategy, tactics, and operation).

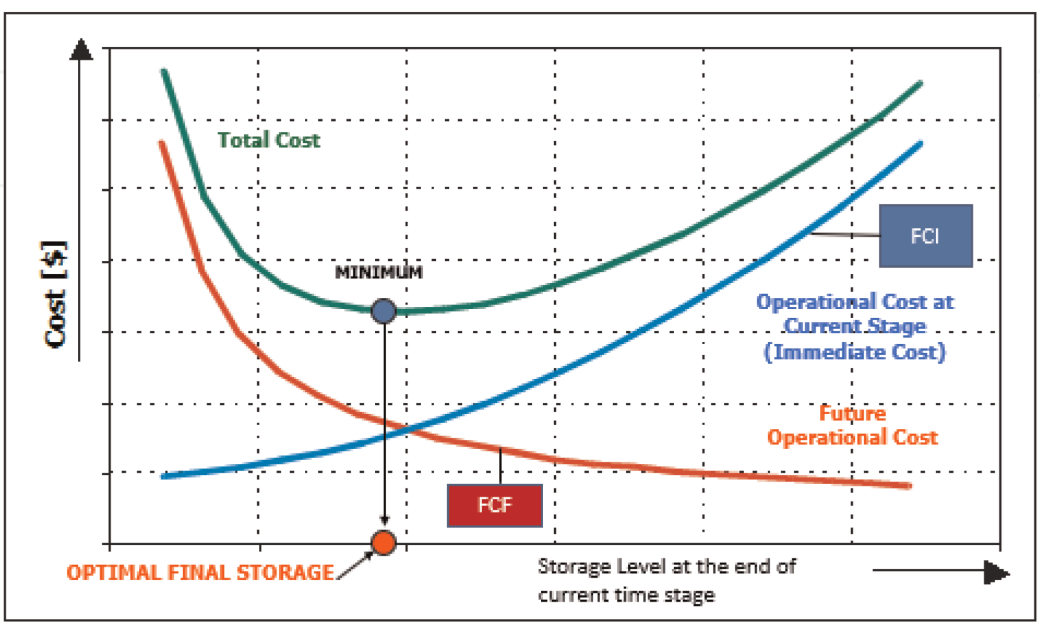

Figure 6.
Hydro production optimization.

The generation dispatch is the result of sequential processes of calculation that divide the total problem, in time and space (multiples reservoirs), based on solvable models in reasonable computational times, which are coupled to each other through the conditions of the border that joins them [8].

The level of detail of the modeling, in time and space, is a compromise between the information required, the complexity of the mathematical problem, and the computational resources available.

Thus, planning the operation of hydrothermal systems can be divided into two major steps, which are as follows:

- **Planning:** Related to the simulation of the "optimal operation" in the coming months/years. For planning, it is used an **LTP** model.

- **Programming:** Related to the programming of the "optimal operation" in the short term (next few hours, typically on a week)**.** For programming, it is used an **STP** model.

The optimization models related to both processes are quite well-known and are generally used in one way or another by electricity system operators around the world [9–11].

Given the differences between the LTP and STP models, each one of them is executed and solved independently (at different times) (**Figure 7**).

The short-term optimization is carried out using the boundary conditions established by the LTP model for the $\mathbf{T_{ST}}$ time, which determines the end of the period for which you want to schedule operations with the STP model, called short-term scheduling that covers period {1, $\mathbf{T_{ST}}$}; the LTP model covers the period {$\mathbf{T_{ST}}$ + 1, **T**} that needs to be analyzed to determine the future implications of decisions made in the present, {1, $\mathbf{T_{ST}}$}.

Frontier conditions between both models can be established at least in one of the following ways:

- **Through economic variables (dual/prices):** Based on the setting, the opportunity price of the stocks at the end of period {1, TCP}, in this case, the hydro resource (water stored); it also applies to other storable resources such as the unused amounts of previously purchased fuel (take or pay contracts).

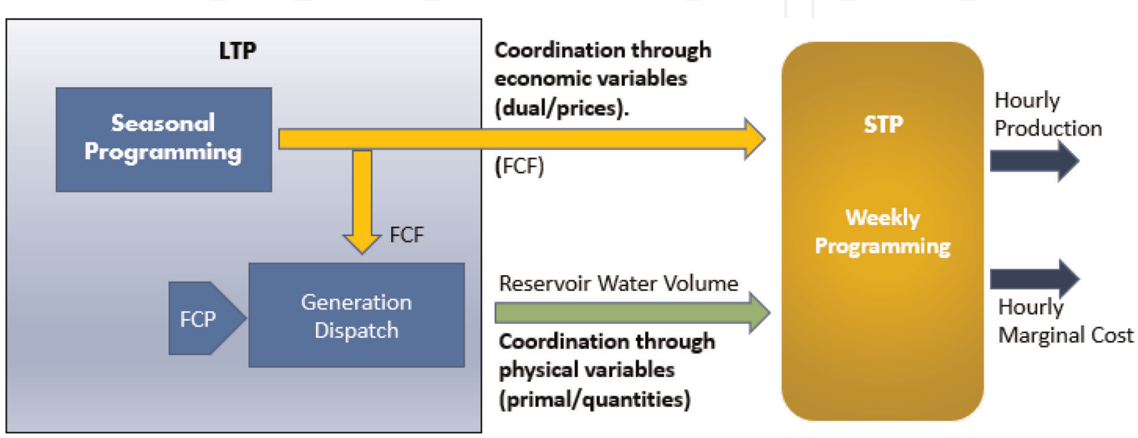

Figure 7.
STS and LTS models coordination.

- **Through physical variables (primal/quantities):** Based on the setting, the amounts of resources available to be used during the operating period {1, TCP}.

Then, the minimum simulation period for the long-term programming is different for each system, according to their total water regulation capacity:
Brazil => 4 years
Chile => 4 years
Colombia => 2 years
Argentina => 1 year
Ecuador => Seasonal

4.2 Energy marginal cost

The generation economic dispatch results in the production of each power plant in each time interval (1 hour).

In each hour, the energy marginal cost is equal to the VPC of the generator with the highest VPC that, in each hour, is producing energy according to the results of the economic dispatch. The energy prices in the spot market are equal to the energy marginal cost [12].

Figure 8 show historical energy prices for MX Market (Local Marginal Prices (LMPs) in the Day-Ahead Market (DAM)) at the Hermosillo node.

The marginal costs of energy have intraday and seasonal variations. The intraday variations, with a time step of 1 hour, are mainly due to (i) the hourly variations of the system demand (typically, the system demand is maximum in the evening/night hours and minimum demand in the early morning hours), (ii) the production of solar generation that reduces the energy prices at solar hours, and (iii) any time, by the effect in the power balance resulting from the forced outage of a generation unit or a transmission line.

Within the year, the average marginal costs of energy vary mainly due to the added effect of (i) seasonal variations in demand (in MX typically the demand in the summer months is greater than that of the winter months), (ii) due to the effect of

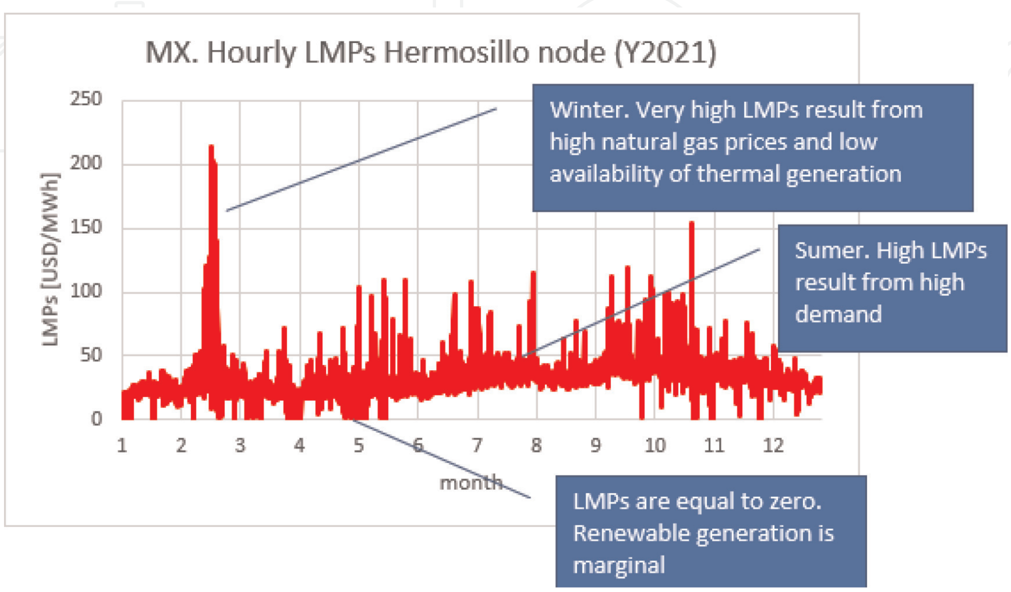

Figure 8.
Hourly LMPs at Hermosillo node (Y2021).

rainfall that modifies the water inflows that reaches the reservoirs of the hydro plants, and (iii) seasonal changes in fuel prices.

If at some moment there is not enough generation availability to supply the demand, including the reserve margin for frequency regulation, the energy marginal cost result equal to the cost of not-supply energy (CNSE). This results in a strong economic signal toward improving the availability of generating units and thereby improving the security of the system.

The growing addition of new intermittent generation capacity (wind and solar) will produce variations in the generated power that can be significant in time intervals of less than 1 hour. In these operating conditions, for the marginal cost of energy to produce efficient economic signals to promote the availability of generation, it will possibly be necessary to determine the marginal costs of generation in time intervals of less than 1 hour [13, 14], mainly in markets with low hydro participation (like Mexico).

As a result, greater volatility is expected at energy prices in the spot market due to variations in the marginal costs of energy resulting from the intermittency in the production of NCRE generators.

To mitigate the risks of high prices in the spot market, supply contracts, with freely agreed conditions between generators and consumers, are efficient commercial instruments that allow:

- Stabilize prices (price hedging)
- Facilitate investment in generation
- As a mechanism for long-term supply guarantee
- Promote adequate generation availability

Note: In LATAM's electricity markets, the supply contacts are **financial contracts** (not physical contracts). This means that the generator supplies, each hour, the contracted energy with its production, if it is dispatched, or by buying the contracted energy in the spot market if it is not dispatched, so financial contracts do not modify the economic generation dispatch.

4.3 Day-ahead markets and intraday markets

At the international level, there are several examples of wholesale energy markets with two or more settlement instances. An example is the wholesale electricity market of Mexico, where a day-ahead market (DAM) and a real-time market (RTM) operate. The other LATAM's markets are all markets that operate only in real-time.

In markets that operate only in real-time, the income of the generators in each hour ($GEN(h)) results from valuating the energy generated (EG(h)) at the marginal cost of the hour (CMgR(h)).

$$\$GEN(h) = EGR(h) \times CMgR(h)$$

In the markets that operate with two or more settlement instances, for example, MX where there is the DAM and the RTM, the income of the generators is determined by the following expression:

$$\$GEN(h) = \underbrace{EGA(h) \times CMgA(h)}_{\{1\}} + \underbrace{[EGR(h) - EGA(h)] \times CMgR(h)}_{\{2\}}$$

In this case, the income of the generators has two terms, which are as follows:

- The term {1} corresponds to the income resulting from selling the energy expected to be generated (EGA) at the marginal cost of the DAM (CMgA).

- The term {2} corresponds to valuing the error of the forecast generated energy (EGR-EGA) at the marginal cost in the RTM (CMgR).

Therefore, in markets where there are at least two settlement instances (DAM and RTM), the generators are exposed to the uncertainty of the marginal costs in the RTM due to the difference between the expected energy to be generated (offer to the DAM) and the energy real generated in the RTM.

This exposure generates risks that generators seek to mitigate by improving their production forecasting tools for the following day. This helps to mitigate the adverse effects of the volatility of the production of NCRE generators on the security of supply. In markets with multiple intraday settlements (like European electricity markets), this is improved due to the probable production in real-time being better known.

In summarizing, the advantages of multiple settlements are: (i) allows generators to hedge the risks associated with real-time price volatility; (ii) reduces operating costs by allowing the market operation to be better scheduled to meet the demands at a minimum cost; and (iii) allows programming the operation of resources to deal with the uncertainty of large-scale variable renewable generation.

Given the existing structural differences between the different electricity markets (e.g., due to the generation mix that supplies the demand), the implementation of the multiple settlements scheme requires special attention to analyze the effect that these have on the generators' incentives to have high-precision forecasts, the opportunities for better coverage of risks due to price variability in the real-time market, and the incentives to install flexible generation resources that are capable of adjusting their dispatches at short notice. Other aspects to be evaluated are the number of settlements that it considers in the short-term market, the products that are traded in the multiple settlements (energy, ancillary services), and the sophistication of its matching models.

By way of background, it should be noted that markets in the United States are typically characterized by a day-ahead market and a real-time market (i.e., two-settlement markets), with co-optimization of energy offers and frequency reserves, and with matching algorithms from the previous day's market that consider unit commissioning restrictions and their associated costs, in addition to transmission system restrictions, based on a so-called Security Constrained Unit Commitment (SCUC). On the other hand, wholesale markets in Europe are characterized by the sequential acquisition of reserves and energy, where energy is traded in auctions the day before and multiple instances of intraday auction markets or continuous bilateral transactions [15]. In this case, the daily and intraday market instances do not consider security restrictions and transmission corridor congestion, which are evaluated and managed by each system operator, generating deviations in the real operation for market matching.

4.4 Forecast of the NCRE generation production profile

To schedule the market operation, the market operator needs to forecast the probable production of NCRE generators. NCRE generation forecasting is a rapidly evolving field [16, 17].

With the expected increase of NCRE generation, including generation within the distribution networks, the problem of forecasting the production is complicated since usually there is no information on the NCRE produced within the distribution networks. In these cases, the net demand of the distribution system must be forecast, which is equal to the consumed demand minus the existing NCRE generation in each distribution system.

To increase reliability in the operation of the market, regulatory changes should therefore be introduced to improve the quality of information on the expected production profile of NCRE generators. Improving the forecasts should be the combined responsibility of the system operator and the market agents. Departures between forecast and actual values should give rise to economic incentives to improve forecasts, for example, via intraday markets above described.

4.5 System reserves

The generation resources that provide flexibility to the electrical system are typically the following:

- Conventional generators (quick start thermal, hydro),
- Spin reserves (primary, secondary)/ramp,
- Load reduction,
- Energy storage systems,
- FACTS equipment as a means of controlling transmission capacity that improves the ability to share reserves between areas of the electrical system,
- Interconnections with neighboring systems (other countries).

The development of the aforementioned technologies/schemes in the electricity market may result from the economic signals produced by the market. When this is not possible (lack of competition, oligopoly), regulated mechanisms (Ancillary Services) are created to make the development of the necessary technologies economically viable to achieve a safe and minimum-cost operation of the electrical system.

The amount of reserve (i.e., for frequency regulation) required in the system results from a trade-off between the cost of the reserve and the resulting quality of service.

The determination of the required reserve is carried out through reliability studies [18–20] that result in reliability indices (e.g., energy not supply) associated with insufficient generation for different values of power reserve. Based on the results, the cost of the reserve and the cost of the quality of service are determined. The optimal reserve is the one that allows minimizing the sum of the costs of the reserve plus the costs of the NSE due to insufficient generation.

4.6 Optimal reserve power determination

The optimal reserve power required by the electrical system is determined through reliability studies that allow knowing the quality of the supply of the demand based on the reserve power in the electrical system.

For example, the quality index could be the ratio between the NSE and the total energy supplied, or the probability of loss of load, both due to the effect of forced contingencies in the generation fleet. In what follows, these quality indices are identified as RE (**RE**liability Index).

Electrical systems are composed of a large number of generating units, each with its own technical and availability characteristics, including the availability of primary resources in the case of renewable power plants (inflow water, wind speed, and solar radiation levels), and where demand varies from time to time following generally known and repetitive patterns. In these kinds of systems, and considering a very low allowed NSE (in the range of 1×10^{-3} to 1×10^{-5} of the served energy), the system quality index RE is typically an exponential function of reserve power (PRES) required to control the quality of the supply. The NSE is proportional to RE index.

$$RE \equiv e^{-k \times PRES}$$

$$NSE = k_1 e^{-k \times PRES}$$

where

k, k1: Constant that results from system reliability studies.

PRES [MW]. System reserve power.

The total cost incurred in the electrical system results from the sum of the cost of the energy not served that results in a certain quality index RE, plus the cost of providing the reserve power that allows obtaining said quality level.

$$Total\ Cost\ [\$] = CNSE\left[\frac{\$}{MWh}\right] \times NSE[MWh] + CRES\left[\frac{\$}{MW}\right] \times PRES[MW]$$

where

CNSE: Unitary cost of the NSE.

NSE: Not supply energy resulting from reliability analysis.

CRES: Unitary cost of the reserve power.

PRES: Reserve power.

In the optimum

$$\frac{d\ (Total\ Cost)}{dPRES} = 0.0$$

That allows to obtain the optimum value of System Reserve Power (PRESopt):

$$\frac{d\ (NSE)}{dPRES} = \alpha = -\frac{CRES}{CNSE}$$

$$PRES_{opt} = \frac{\ln\left(kk_1 CNSE/CRES\right)}{k}$$

Figure 9 shows the described optimization process. The red curve shows the variation of the non-supply energy (NSE) as a function of the reserve power (PRES). The higher the reserve, the lower the NSE. The optimal PRES is the one that meets the condition that the derivative of the NSE, with respect to PRES, is equal to alpha (α).

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4.7 The cost of non-supply energy (CNSE)

As demonstrated in the previous point, the reserve power (PRES) required by the electrical system depends on the cost of not supply energy (CNSE), with the reserve power being greater the higher the CNSE.

The CNSE concept includes a group of economic costs that can affect society, as a whole, when the supply of electricity cannot be provided to the extent required by consumers. The NSE is the amount of energy potentially demanded (presumed energy) that cannot be supplied.

In the commodity markets, in the absence of enough supply, the price of the product increases and the quantity demanded adjusts automatically (elasticity), first withdrawing those consumers with lower utility or consumer surplus, which is economically efficient, thus minimizing the reduction in societal benefit.

However, the electricity sector has certain special characteristics, due to which the CNSE concept is used, instead of the more natural idea of balance between supply and demand:

- Electrical energy, as cannot be stored, if there is not enough supply available in the electrical system, and the excess demand is not interrupted, the system runs the risk of collapsing.

- Electricity demand is very inelastic, which is why price signals maybe not be enough to return the system to a situation of supply/demand balance.

The valuation that consumers make of the NSE, in general, needs to be estimated. The economic costs that can affect society as a whole when electricity supply is not enough are of various kinds. The main difficulties that arise in estimating the CNSE are:

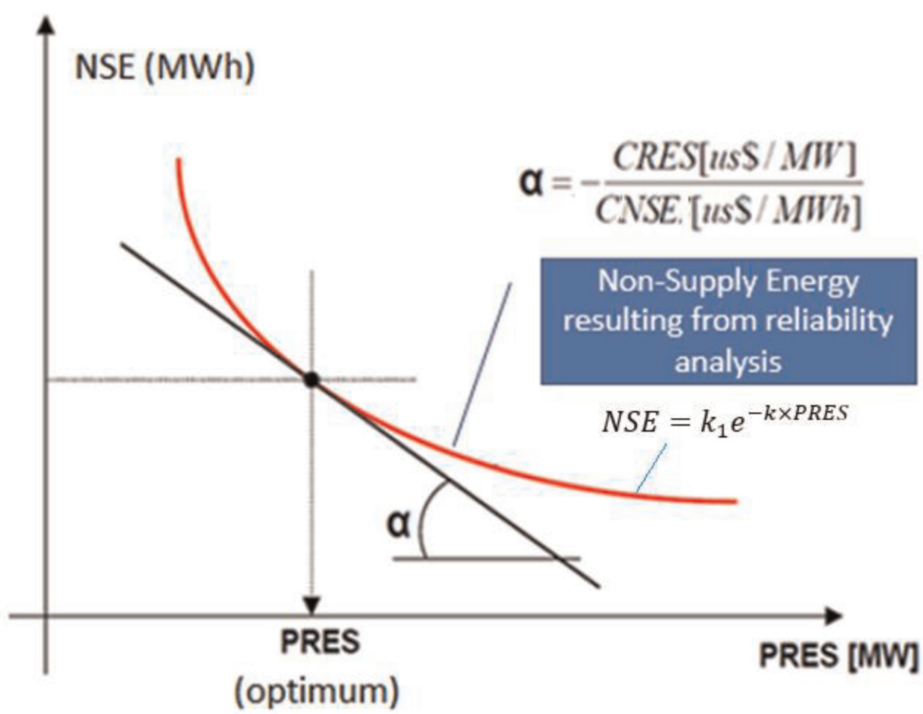

Figure 9.
Optimal power reserve.

- The complexity of modeling the link between the not enough supply and the impact on people's well-being, as well as on the economic activities that are affected, depends on the type of interruption.

- The CNSE varies depending on the existence or not of selectivity in the cuts, or whether they affect all consumers equally or not.

- The complexity of establishing the acceptable limits of deterioration in the quality of supply compared to the alternative of interrupting demand.

There is a wide variety of methods that can be used to calculate the CNSE. There are two large families of approaches, which are as follows:

- **Indirect methods:** Aggregated data are used, for example, the relationship between energy demand and GDP, or based on the cost of self-generation, or through the Leisure Work Exchange Theory [21].

- **Direct methods:** They are based on conducting surveys or interviews with consumers to inquire directly about the economic and noneconomic effects linked to the interruption of electricity service.

The CNSE is significantly reduced if the interruption condition can be anticipated by the consumer in such a way that they can take precautions in the event of a probable supply interruption. To take this aspect into account, the CNSE is determined for short-term failures (when the failure condition is not prevented) and long-term failures (when the failure is scheduled and known by the consumers).

4.8 Capacity balance market

The purpose of the **Capacity Market** is to provide an economic signal to incentivize the installation of enough generation capacity to supply demand while satisfying defined reliability criteria [22].

If the generation fleet was designed and operated to supply the system demand at a minimum total cost (the sum of investment costs (CAPEX) plus OPEX operating costs), it is fulfilled that all generators cover all of their investment costs and operation (sufficiency principle) if all generators receive as remuneration: (i) a payment for energy ($ENE), which results from valuing their production at the Marginal Cost of the Energy in the market, and (ii) payment for firm capacity ($POT), which results from valuing their firm capacity at the price of capacity (PPOT) in the power balance market.

The value of PPOT is determined in most of LATAM's markets as the annual fixed costs (CAPEX, fixed O&M costs) of a Turbo Gas-type power plant with an installed capacity approximately equal to the annual growth of the maximum demand of the system.

The payment for capacity that generators receive has a direct effect on the reliability of the electrical system.

With capacity payments, generators require lower marginal rent (spark spread) to cover their capital costs (CAPEX). So, for the same demand, lower marginal rent results from lower market marginal costs that result from a higher generation availability and consequently lower non-supply energy (NSE) probability.

The firm capacity of the generating units depends on their technology. For hydroelectric plants, firm capacity is determined typically as the power generated in the hours of maximum demand (or minimum reserve) for a very dry hydrological condition.

For thermal power plants, firm capacity is usually equal to their average available capacity. Large thermal power plants, compared to the supplied demand, produce large disturbances in the operation of the electricity market when they go out of operation due to an unscheduled event (failure). When the power of the failed plant exceeds the reserve margin for frequency regulation, a load cut will be necessary to balance supply/demand, a situation that could lead to a massive load cut. In such a situation, the firm capacity of large thermal plants could be reduced as an economic signal that shows the impact on the quality of service of the system.

As an example, **Table 3** shows the installed capacity and forced output rate (FOR) of a fictitious generation fleet made up of 10 generating units (G#1 to G#10). One of the generators (G#3) has an installed capacity (300 MW) equivalent to 25% of the total installed capacity of the generation park.

Figure 10 shows the total power available for a given probability of exceedance resulting from considering all the possible operating states (2^{10}) of the generation park considering the operating states of each generation unit.

Generator	G#1	G#2	G#3	G#4	G#5	G#6	G#7	G#8	G#9	G#10
Installed Capacity [MW]	100	150	300	50	20	80	120	200	20	180
Forced Output Rate	20%	15%	20%	30%	50%	35%	15%	10%	20%	25%
Available Capacity [MW]	80	127.5	**240**	35	10	52	102	180	16	135

Table 3.
Example of the generation fleet.

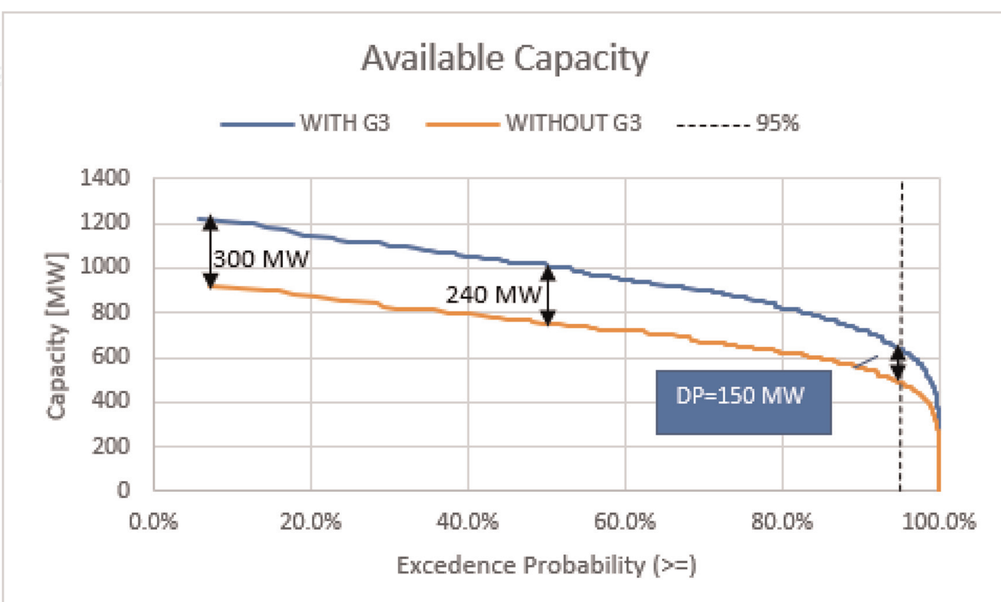

Figure 10.
The firm capacity of thermal plant.

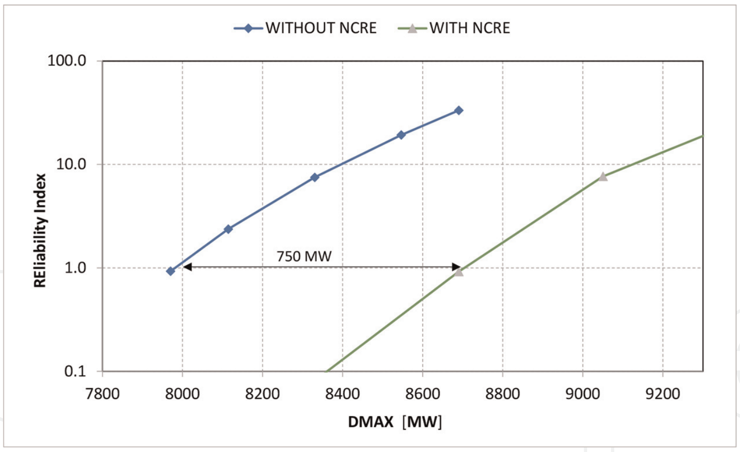

Figure 11.
Effective load carrying capability of NCRE.

Two curves are presented, the blue curve considering the entire generation park and the red curve WITHOUT generator G#3.

It is observed that for a probability of exceedance of 95%, generator G#3 contributes only 150 MW, while its average available power is 240 MW, so the firm capacity of generator G#3 should be reduced to 150 MW.

Up to now, in the LATAM's markets, there is no consensus on the firm capacity of NCRE plants. The main reason is that it cannot be guaranteed that this type of generator will produce energy during the hours of minimum reserve of the system, which are typically at night hours.

In markets with a significant share of hydro generation in the generation mix that supplies demand, such as most of the LATAM's markets, it is observed through reliability studies that with NCRE generation, a greater demand can be supplied without compromising the quality of service. This is justified because the production of NCRE generation allows a greater volume of water to be stored in the reservoirs, which allows a greater hydro generation in hours of minimum reserve.

As an example, **Figure 11** shows the evolution of a reliability index for different levels of demand in the Peruvian market. Two curves are presented, WITH and WITHOUT NCRE generation (installed capacity 1100 MW). It is observed that WITH NCRE generation, demand can be increased by 750 MW without reducing the reliability index, which shows that in the Peruvian system, NCRE generation effectively contributes to improving the quality of service in supplying the demand [23–25].

In electrical systems with high participation of hydro energy, the hours where there is a greater risk of not being able to supply the demand is at evening/night hours when the demand is usually maximum. In these systems, the firm capacity result from the generation available in this hour range.

On the other hand, in systems with low participation of hydro generation, the supply risk is at any time of the day and even more so with significant participation of NCRE generation in the generation mix, as occurs in the MX electrical system [26].

For this reason, in the MX electrical system, the firm capacity of an NCRE generator results from the generator production in the so-called critical hours, the 100 hours of minimum reserve of the year. **Figure 12** shows the system generation reserve, in MX, in each hour of 2019, in red the 100 critical hours. The firm capacity of the NCRE generators is measured in these critical hours.

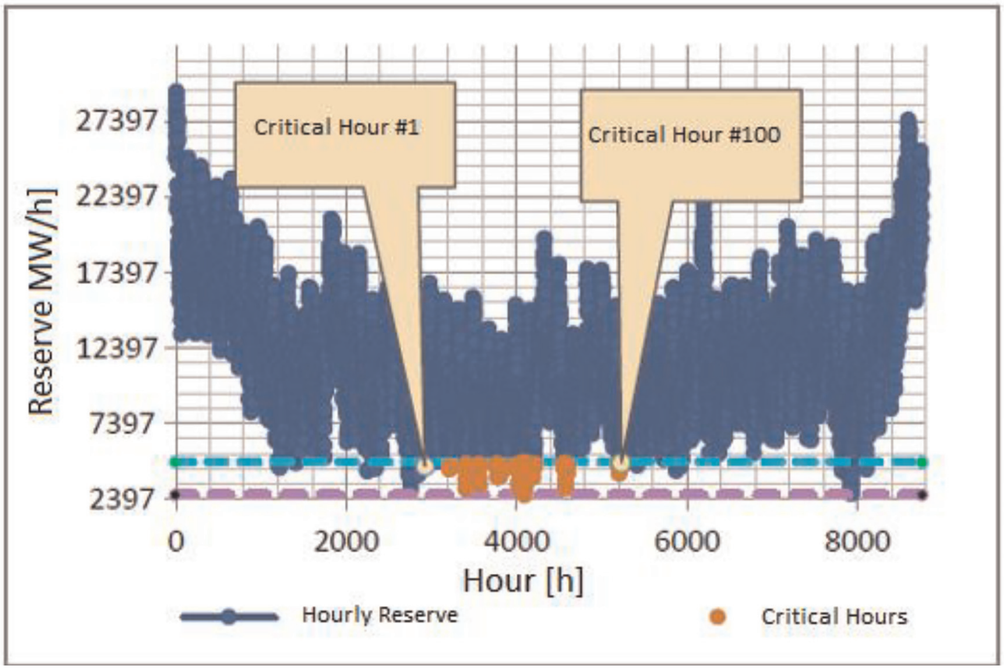

Figure 12.
MX capacity balancing market – 100 critical hours, 2019 year.

4.9 Storage energy systems

Storage energy systems are a set of technologies and operating methods that allow energy to be conserved for later use (similar to what happens with hydro plants). Energy storage is currently based on a broad set of technologies, many of which already have a solid state of maturity, while others are less consolidated, which require progress in some aspects and improve their performance, costs, and competitiveness.

Examples of existing storage systems in LATAM's countries are (i) batteries (BESS), in which the charging phase is carried out by storing chemical energy in the batteries, and (ii) pumping hydro plants in which during the charging phase it accumulates water in the reservoir (potential energy) by pumping, which is transformed into electrical energy during the discharge phase. The charging phase is usually fed with energy withdrawn from the same network into which the accumulated energy will be injected.

Of the storage technologies, it is worth highlighting the high potential for the development of BESS, which constitutes an effective complement to NCRE generation for the safe supply of demand at a minimum cost. Other possible uses of BESS concerning the safety and quality of the energy supply are as follows:

1. Frequency control reserves to manage contingencies, especially with a relatively large proportion of NCRE in the system;

2. Voltage stability in the power system;

3. Provide peaking capacity, deferment of new generation capacity, and displacement of thermal generation;

4. Enhanced system security by supplying energy during shortages in electricity generation.

The NCRE generation technically today can offer operating reserves for frequency regulation. However, it must be taken into account that since NCRE generation has zero production opportunity cost (the energy that is not produced is lost) by requiring a power reserve margin to offer the regulating band, the provision of reserves normally has a high operating cost results from the difference between the price of spot energy and the variable cost of the generator, which is zero. This margin is usually much lower in other technologies, so from the economic point of view, it is better to assign the frequency regulation reserve to conventional power plants or storage systems.

Storage generators, particularly batteries, can be a lower-cost alternative for NCRE generators to provide power reserves for frequency regulation.

NCRE generators can also increase their firm capacity by adding batteries to their installed generation capacity, charging the batteries with their generation at hours when there is a high reserve margin (low marginal energy prices), and injecting the stored energy into the electrical system at hours of the day when the reserve is minimal (high marginal prices). This configuration is called a "hybrid generator."

The storage generators can also operate in the electricity markets independently of other generators in the system, under the so-called "stand-alone" configuration. In this case, the owner of the storage media (battery) covers the investment costs via the marginal rent that results from the storage process in hours of low marginal cost and the sale of the energy stored in hours of high marginal cost. The difference between the marginal costs during loading and unloading of the storage medium must cover at least the losses in the process of loading/unloading the storage medium.

A stand-alone storage generator can also be remunerated by its firm capacity. In this case, system operation studies must demonstrate that it will be economically convenient to charge the storage system when the electrical system is in a critical situation with a minimum reserve margin. The economic feasibility will depend on the difference between the marginal costs between the loading and unloading processes when the electrical system has a minimum reserve. If the difference in marginal cost does not cover the cost of losses in the storage system, so the firm capacity will be equal to zero.

4.10 Demand participation

The demand can participate directly in the spot market via offers to withdraw demand if the price of energy in the spot market exceeds the offered price. To this effect, loads should have the technical capacity to respond to the ISO instructions to reduce the load in real time. From the point of view of the economical minimum cost dispatch, the demand withdrawal offers are similar to a thermal plant with negative capacity and a VPC equal to the offered price.

Consumers can also play an active role in the system's security of supply via their response to the electricity rates paid to the distribution company from which they buy energy. In many cases, the rates include high charges if the time in which the consumer has his maximum demand coincides with the time of day in which the aggregate demand of the distribution company is maximum. In these cases, the consumers, mainly industries, reduce their consumption, so, their demand is elastic to electricity rates. This can be seen in **Figure 13**, which shows the hourly demand of a typical day for large consumers in the Peruvian market. In the hours where rates are high, 6–10 pm, demand is significantly reduced. This lower demand, at times when the system

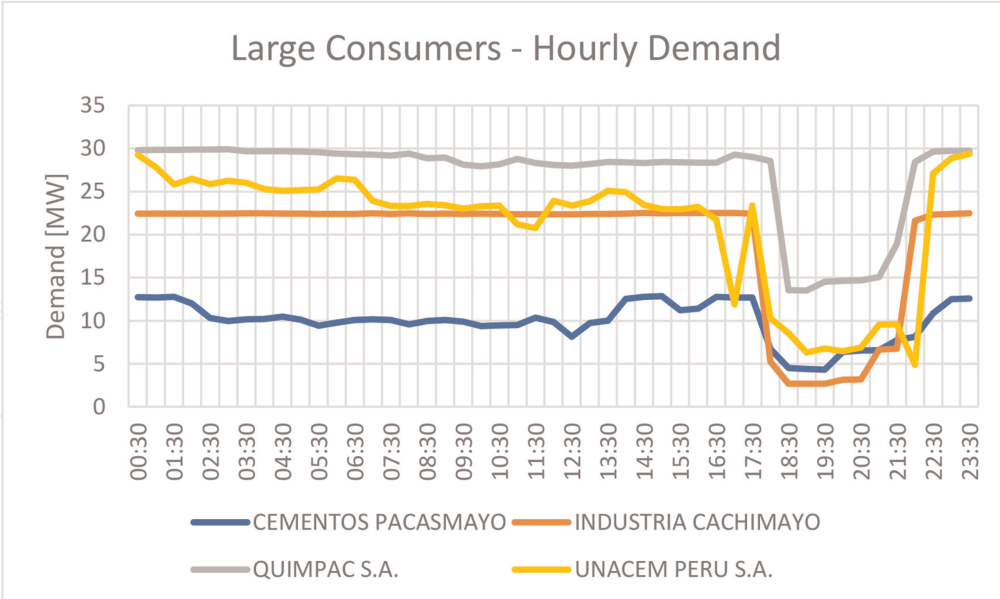

Figure 13.
Peruvian electricity market. Hourly demand of large consumers.

typically has minimal reserves, contributes to increasing system reserves and thus improving the security of supply.

5. Conclusions

In the 1990s, wholesale electricity markets were organized in the LATAM's countries to introduce competition in the supply of electricity as a way of supplying demand with an adequate quality of service at a minimum cost.

The initial design of these markets mainly considered that the demand would be supplied with a mix of hydro and thermal generation.

In recent years, the growing participation of NCRE energies, mainly wind and solar-PV, in the generation mix has been observed, promoted by a significant reduction in the capital costs of these technologies and the need for countries to advance in the replacement of thermal generation, mainly the generator based on coal, to mitigate the effects of climate change and thus move toward a production matrix-based mainly based on clean energy (energy transition).

The greater participation of solar and wind energy, characterized by variable generation depending on climatic conditions (wind level and solar radiation), introduced a strong instability in the electrical systems that put at risk the normal supply of demand in safe conditions.

To mitigate these effects, the rules of the wholesale electricity markets of the LATAM's countries include, or their implementation is being evaluated soon, strong economic incentives that seek to maximize the availability of energy at times of minimum generation reserve. In this sense, the following stand out:

- Generation dispatch, based on reliability constraints and minimum cost.
- Systems reserves (frequency regulation and voltage control) are dimensioned to supply the demand at minimum cost including CNSE.

- Energy prices are equal to the generation short-term marginal cost including the CNSE when there is not enough energy to supply the demand.
- Anticipated energy markets (day ahead), to promote better information of expected ERNC production for the generation economic dispatch.
- Supply contracts, to mitigate the risks of high prices in the spot market and to promote generation long-term expansion that improves system security.
- Firm capacity market, to promote a reliable operation by remunerating the contribution of the power plants based on their contribution to the security of supply.
- Distribution rates that promote consumer participation reduce its demand in hours of minimum reserves.

The electricity markets of LATAM's countries showed strong dynamism from the beginning, mainly due to private participation in the electricity generation segment.

It is estimated that this behavior will continue in the future, for which it will be necessary for market regulations to evolve to allow the integration of new technologies efficiently, thus contributing to achieving the objectives of the energy transition without compromising the secure supply of demand.

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