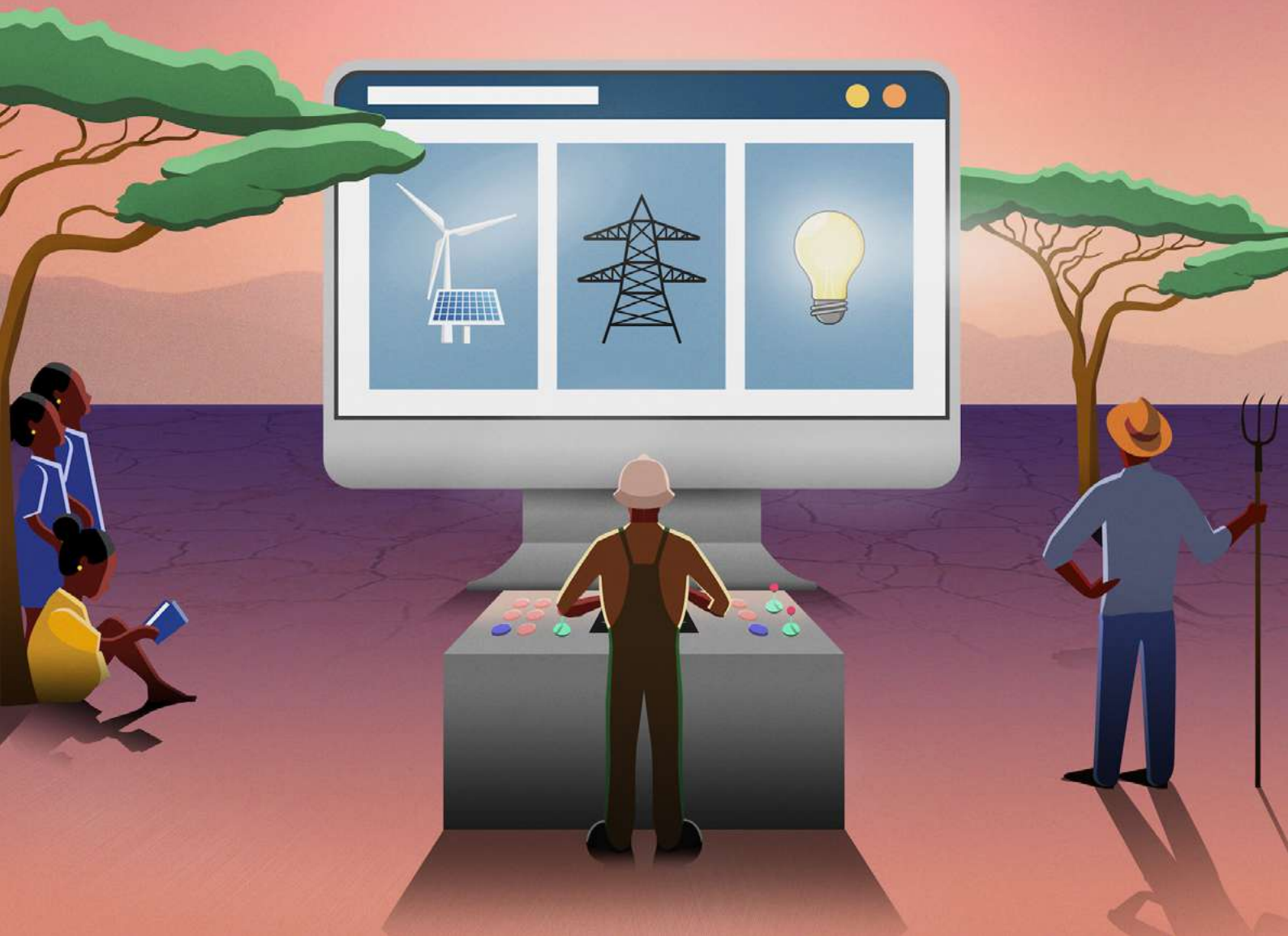
Fostering Renewables within an Independent Network System scenario for South Africa

RES4AFRICA FOUNDATION

In partnership with: CESI Shaping a Better Energy Future



Fostering Renewables within an Independent Network System scenario for South Africa

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ACRONYM LIST

Acronym	Definition
ACER	Agency for Cooperation of Energy Regulators
AS	Ancillary Services
BEE	Black Economic Empowerment
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CSP	Concentrated Solar Power
DAM	Day-Ahead Market
DER	Distributed Energy Resources
DLR	Dynamic Line Rating
DSM	Demand Side Management
DSO	Distribution System Operator
DSR	Distributed System Resource
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators
ESO	Electricity System Operator
EU	European Union
FCR	Frequency Containment Reserve
FDI	Foreign Direct Investment
FIT	Feed-in-Tariff
FRR	Frequency Restoration Reserve
GDP	Gross Domestic Product
GME	Gestore Mercati Energetici (Italian Electricity Market Operator)
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operators
ITO	Independent Transmission Operators
MO	Market Operator
MSD	Mercato per il Servizio di Dispacciamento (Italian A/S Market)
NDC	Nationally Determined Contribution
NEMO	Nominated Electricity Market Operator
NERC	The North American Electric Reliability Corporation
NERSA	National Energy Regulator of South Africa
NRA	National Regulatory Agency
O&M	Operation & Maintenance
PAB	Pay as Bid
PPA	Power Purchase Agreement
PST	Power System Transformation
PV	Photovoltaic
R&D	Research and Development
REIPPPP	Renewable Energy Independent Power Producers Procurement Programme
RES	Renewable Energy Sources
REFIT	Renewable Energy Feed-in-Tariff
RR	Replacement Reserve
RoCoF	Rate of Change of Frequency
RTO	Regional Transmission Organization
SCADA	Supervisory Control And Data Acquisition
SWOT	Strengths, Weaknesses, Opportunities and Threats
SMO	System and Market Operator
SNSP	System Non-Synchronous Penetration
SO	System Operator
T&D	Transmission and Distribution
TPA	Third Party Access
TSO	Transmission System Operator
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital
WEC	World Energy Council

FOREWORD

South Africa has a well-developed electricity network and one of the highest rates of electricity access in sub-Saharan Africa. Electricity generation in South Africa is reliant on coal (over 70% of the energy consumption), but efforts are ongoing to diversify the energy mix, as the coal-fired fleet is ageing and new projects will not fully compensate for the decline of the existing fleet. The government is focussing on diversifying the power mix by introducing natural gas and renewables.

The National Development Plan 2030 [1] envisages a decommission of 35 GW (of 42 GW currently operating) of coal-fired power capacity and to supply at least 20 GW of the additional 29 GW of electricity needed by 2030 from renewables and natural gas.

According to the Integrated Resource Plan (IRP) 2010–2030 (2019 edition [2]) 6,000 MW of new solar PV capacity and 14,400 MW of new wind power capacity will be commissioned by 2030. Such amount of variable renewable generation needs to be integrated into the power system by implementing adequate actions aimed at assuring the system security and reliability.

Moreover, a process of reforming and restructuring of the South African electricity public utility Eskom is ongoing, aimed at strengthening the reliability of the power system, supporting increased industrialisation and helping efforts to diversify the energy mix.

Successfully phasing out coal while rapidly deploying RES and smart grids requires a different and more open market framework. **Renewables and reforms are the two crucial pillars of a positive energy transition.**

CESI, as an active member of RES4Africa Foundation, is proud to offer its support in RES4AFRICA project to deliver a secure and reliable operation of the South African power system. This study aims at analysing and discussing international case studies and best practices on market reform and RES integration. The objective of the study is to provide South African decision-maker with clear insights and lessons learnt that will provide insightful contributions to the energy transition.

The report is structured in five chapters. Chapter 1 gives a comprehensive overview of the current South African power system and its major challenges. Chapter 2 presents the theory and practice of market reforms and transmission unbundling. Chapter 3 discusses the principles of transmission and ancillary services regulation and then it presents application in the European context. Chapter 4 presents the core challenges and the state-of-the-art solutions to integrate VRE into the power system. Chapter 5 concludes the study with a possible roadmap for the energy transition.

EXECUTIVE SUMMARY

South Africa has a well-developed electricity network and one of the highest rates of electricity access in sub-Saharan Africa. Electricity generation is reliant on coal (over 70% of the energy consumption), but efforts are ongoing to diversify the energy mix, as the coal-fired fleet is ageing and new projects will not fully compensate for the phase out of the existing fleet. The government is focussing on diversifying the power mix by introducing natural gas and renewables.

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At present, the electricity sector is dominated by Eskom; the vertically integrated public utility encompasses all the phases of the electric supply chain: generation, transmission, distribution, organised into three divisions. Eskom operates 30 power plants with a nominal capacity of 44 GW, roughly equivalent to 86% of total capacity, divided into thermal coal (36 GW), nuclear (2 GW), gas fired (2.5 GW), hydro (3.3 GW) and wind (100 MW). The public utility currently generates approximately 95% of the electricity consumed in South Africa. The company owns South Africa's transmission grid and 60% of the country's distribution grid and it serves more than 6 million direct customers. As exclusive large-scale vendor, Eskom also exercises a monopsony of power, performing the role of buyer in the main VREs promotion frameworks.

In order to favor an efficient and effective energy transition the Government of South Africa (GoSA) is envisaging to reform Eskom. It is clear that successfully phasing out coal while rapidly deploying RES and smart grids require a different and more open market framework. **Renewables and reforms are the two crucial pillars of a positive energy transition.**

Hence, the objective of this study is to present and discuss the most emblematic case-studies of power sector reform and renewable integration. This critical review is aimed at supporting the decision-making process that is currently undergoing in South Africa.

Worldwide experiences on power sector reform and transmission unbundling

Massive RES deployment is likely to attract new market participants and new players. **As experience shows, the most successful countries in attracting new players and adding considerable generation capacity are the ones with the most transparent and indiscriminatory third-party access (TPA) rules**. TPA is the pillar of all market reforms. As market players have access to the transmission network on a transparent and non-discriminatory basis, confidence grows, projects pile up and competition flourish. TPA entails clear access and dispatching rules, clear and transparent transmission and connection tariffs and a trustworthy transmission system operator.

One of the key aspects of TPA is unbundling. Unbundling is defined as the separation of production and supply of vertically integrated activities where the transport (or transmission) assets constitute a natural monopoly. As the case studies show, there are different degree of unbundling, from a mild ring-fencing to the more extreme option of full ownership unbundling. As Countries open up their markets, they tend to address transmission unbundling aggressively: transmission is either legally or proprietarily unbundled from generation and distribution. **Best practices show that the bigger the generation fleet of the incumbent, the stricter the level of unbundling must be in order to provide trust and transparency to newcomers.**

This is particularly true for electricity systems of continental size such as India or Brazil, described in this report, where the unbundling process also entailed the creation of several transmission companies, at national and regional level. Dimension also represents a challenge for market operation and dispatching, and sometimes several load dispatch centres are established at regional level, such as in India.

At the same time, the case studies show that transmission unbundling is a gradual process that can be planned over a relatively long horizon. Accounting separation and ring-fencing are the first necessary steps; the real policy choice comes afterwards, when the Government has to decide between legal unbundling and ownership unbundling, which also means opting for the Transmission System Operator (TSO) model, where all-integrated energy companies sell off their electricity networks to an independent company, or the Independent System Operator (ISO), where energy supply companies may still formally own electricity transmission networks but must leave the entire operation, maintenance, and investment in the grid to an independent company.

Italy for instance transitioned from an initial ISO to a full TSO model, due to inefficiencies exhibited by the former in tackling the underlying market conditions. The fully unbundled TSO currently operates the totality of the Italian transmission grid and expanded its range if activities to foreign countries and non-regulated activities. In the United Kingdom, given the existing framework, England and Wales opted for the TSO model, while Scotland and Northern Ireland pursued the ISO.

The degree of unbundling and non-discrimination is also related to how the Government intends to structure its supply market. As experience show, there are three broad models for securing efficient power generation: single buyers with competitive auctions, where newcomers bid for the right of a long-term power purchase agreement with a buying authority; wholesale market competition, where generation companies sell through the intermediation of a market operator via some kind of trading platform and distribution companies act as suppliers, and the full-fledged liberalized market, where retail activity is completely liberalized with the right for all consumers to freely choose a supplier.

As our case studies show, fully liberalized market requires a TSO or an ISO model; on the other hand, **single buyers may easily go hand in hand with ring-fencing and milder separation.**

Economic and tariff regulation of transmission system operators

Unbundling and renewable integration require an efficient and cost-reflective pricing system able to provide the correct economic signals to all market operators. In particular, sector reform must allow the transmission system operator to:

1. Provide a high-quality service at an efficient cost;
2. Maintain and develop infrastructures;
3. Promote innovations.

Transmission tariff regulation is the most important tool to achieve all these objectives. The regulator must define a clear tariff mechanism allowing the transmission operator to be efficient while fully recovering its costs. As a first choice, regulators have to decide how much they want to push on cost efficiency. If the regulator opts for a "Rate-of-return" regulation, it reduces the financial risks faced by the TSO, but it does not provide enough incentives for cost efficiencies. On the other hand, if the regulator opts for a "Price-cap" regulation is providing the TSO with more incentives to cost reductions, while exposing it to higher financial risks. **Best practices show that regulators opt for some form of rate of return regulation to protect the TSO from adverse financial effects.** In this case, incentives for cost efficiencies can be provided by a forward-looking approach, where the regulator approves on paper the investment that the TSO has yet to make, allowing him to reap all possible cost efficiencies. Forward looking approach is particularly important in developing countries, as it gives TSO more financial strength.

Tariff regulation also entails the following choices:

1. Determination of what is included in the transmission tariff;
2. Determination of who is going to pay the transmission tariff;
3. Determination of how the tariff is calculated.

The first question relates particularly to the definition of the regulated services that the TSO has to provide and for which it has to receive a cost-reflective remuneration. Ancillary services are a crucial aspect of this.

The Pricing Mechanism for the Ancillary Services (AS) varies according to the type of service, i.e., if the Ancillary Service under procurement has a monopolistic nature, then the Pricing Mechanism should be different in comparison with a market-oriented situation. In general, the reserve AS could be classified as Competitive Services, while the Voltage and Black Start Services could be considered as a monopoly or oligopoly service because of their strong locational dependence.

The competitive AS are Market Driven and can be procured in the market by any competitive procurement mechanism compatible with the design of the Day Ahead Market. The monitoring of the competition is required in the competitive market in order to avoid anticompetitive practices and the use of market power.

The **regulated Ancillary Services are Regulatory-Driven** and their tariffs should be set by the Regulatory Authority on a regular basis, in order to better reflect the new conditions of the service.

Moreover, for power systems that are experiencing a growing integration of VRE **new specific AS can be introduced** (e.g. fast frequency reserve, fault ride through, etc.).

The second point, instead, requires the regulator to decide if the transmission tariff is charged to the generators, to the load or to both. As the case studies show, most European countries tend to charge only the load. At the same time, some countries still charge a part of the transmission costs to generators. If the transmission tariff is charged to the load, it is a standard practice that distribution companies collect the transmission tariff on behalf of the TSO and then they pay it back to it. On the other hand, generators pay the tariff directly to the TSO. **In the case of possible payment issues from consumers, the regulators might consider charging part of the transmission costs to generators.**

As for the third question, transmission tariffs can be charged with a variety of methods, as our case studies show. The most relevant choice for the regulator is to opt for an energy charge or a capacity charge. Energy charges expose the TSO to volume risks which should properly be addressed. On the other hand, capacity charges might penalize those who consume little. **The fixed cost nature of the activity requires the regulator to set up a tariff mechanism that protects the TSO from the demand risk.**

VRE Deployment

RES deployment requires not just economic support schemes, such as feed-in-premiums or auction mechanisms, but a coherent market design in which:

1. Dispatch rules allow for the accommodation VRES into the power system;
2. Balancing rules do not penalize VRES generators which in turn have to be a balancing responsible party;
3. Grid development costs are properly addressed.

Changes required for the VRES integration can be managed in the process of Power System Transformation (PST), that includes the activities that facilitate and manage changes in the power sector. It is a process of **creating policy, market and regulatory environments**, and **establishing operational and planning practices** that accelerate investment, innovation and the use of smart, efficient, resilient and environmentally sound technology options.

The IEA has developed a categorization into six different phases to capture the evolving impacts that VRE may have on power systems, as well as related integration issues. This framework can be used to prioritize different measures to support system flexibility, identify relevant challenges and implement appropriate measures to support the system integration of VRE, that is mainly advanced through:

- appropriate design of the operations, regulations and markets that govern energy systems;
- infrastructural improvements or enhancements that aid access to renewables or facilitate their uptake;
- increased flexibility in energy demand and supply to accommodate VRE.

The European countries can be considered as a benchmark, becoming leaders in driving the deployment of renewable technologies and adopting significant targets of share of renewable energy in energy consumption. Experiences gained in the early 2000s demonstrated the **importance of enabling frameworks for renewables**, and such frameworks remain at the heart of the EU's policy process.

Among the European countries that experienced a fast and sharp increase of VRE, the cases studies of Italy, Spain, Ireland and Denmark have been considered, highlighting the main challenges and the VRE integration implemented measures, according to the specific characteristics of each power system. Among the considered VRE integration measures and flexibility options it is worth to mention use of **interconnectors** to other countries, the increase of the **flexibility of thermal power plants**, the **demand-side flexibility**, the installation of **Storage Systems** and/or **Synchronous compensators**, the **establishment of a dedicated tools for VRE monitoring and forecasting**, the implementation of **new ancillary services from virtual units or distributed resource**.

Among the experiences in **emerging markets** it is significant the case of Brazil, that implemented during the last 20 years a **regulatory framework designed to incentive customers and investors** with the scope to achieve the projected target of expansion of alternative renewable generation capacities and Uruguay, that faced a dramatic growth of VRE share in the energy mix with strong cross-border interconnection and a flexible grid, as well as a clear decision making, a **supportive regulatory environment** and a **strong partnership between the public and private sector.**

Possible Roadmap for the transition

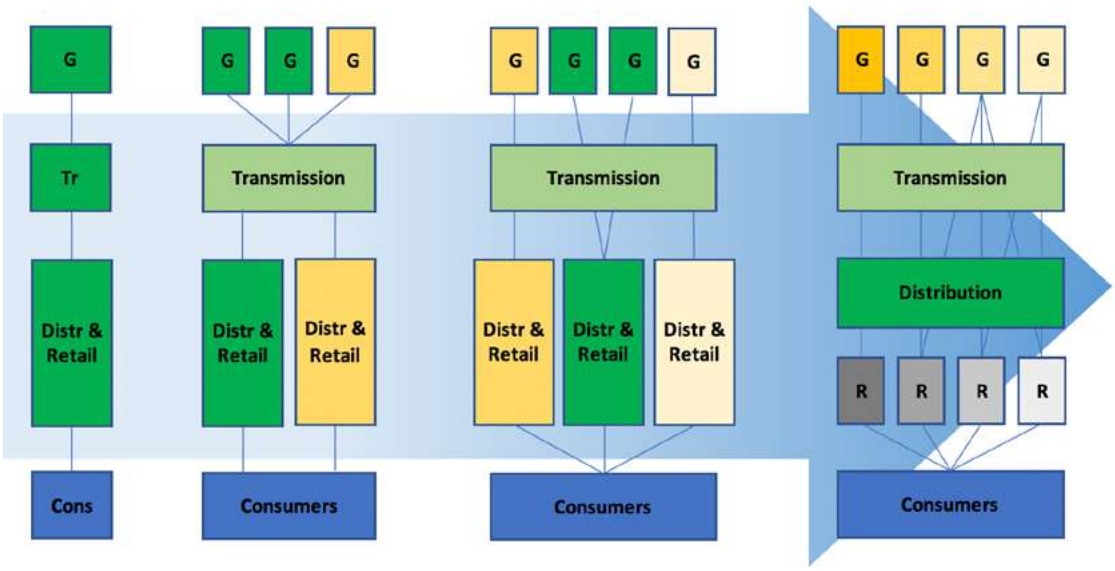
There is no definite best practice or preferable route to implement the process of liberalization in electricity markets. The main steps towards opening markets to competition are generally dictated by existing conditions and characteristics at country level. Some of the aspects taken into consideration are the following:

- Status of market incumbent, if any (state-owned company, public company), investment and expansion policies;
- Degree of market concentration and power, with focus on generation and supply/retail;
- Presence of regional or historically motivated distribution networks;
- Characteristics of customers and demand (share of domestic, commercial and industrial consumers, demand seasonality, presence of relevant interruptible loads, assessment of existing bargaining power);
- Cross border trading, interconnections and long-term arrangements in place;
- Status of available technology (generation mix, transmission / distribution, metering);
- Existence of regulated wholesale prices, PPAs and bilateral agreements;
- Overall system adequacy and reliability (dispatching, ancillary services, generation capacity);
- Current national regulation and participation to international frameworks, markets or systems of rules (energy pools, associations of markets or countries, e.g. "Acquis Communautaire").

It is relevant to highlight how the unbundling process is intrinsically associated with market liberalization, notwithstanding the two concepts do not necessarily coincide. In every electricity market, transmission and distribution are considered natural monopolies, either at national or local level, therefore the allocational efficiency is to be maximized under a monopolistic regime. Liberalization usually entails the protection of consumers, by opening the market to competition in order to achieve better consumer surplus, generally via lower electricity prices.

As previously discussed, there are different models of unbundled systems, such as the competition wholesale market, the single buyer market and the fully liberalised market, and different ways in which they are integrated with the establishment or reorganization of a market operator and/or a system operator.

The chart below describes a possible path to address liberalization. This process is likely to be triggered by the need to expand generation capacity (i.e. economic growth, need for diversification of generation mix or adequacy issues) by gradually opening the market to competitors beyond the current incumbent. The need to dispatch different generators usually arises concerns regarding i) the reliability of transmission assets and ii) the opportunity to offer a fair treatment by granting Third Party Access. Hence, the need for unbundling, i.e. separating the transmission, via a "mild" approach such as ring fencing, or a more "radical" one such as the ITO or TSO models, is generally perceived as the most suitable solution to address transmission issues. Distribution might be more fragmented due to historical reasons bound to geography or local markets, but it is equally considered a local natural monopoly and regulated accordingly. At the same time, measures of protection of final consumers are also enforced, with the gradual shift from captive customers to eligible ones, who can freely choose their supplier. This bottom-up change of mindset, paired with the top-down opening of generation, might pave the way to the creation of a liquid market place for electricity spot prices, for instance in the form of a power pool or a power exchange, managed by an entity called the Market Operator, which consistently enjoys a different degree of separation from the incumbent. The new market is steadily opened to a variety of players, such as traders and new suppliers, not necessarily owned or controlled by an integrated utility, while new contractual forms and sophisticated operational procedures are envisaged (e.g. day-ahead and intra-day markets, ancillary services market). The natural end of the process is a fully liberalized, unbundled electricity market, where only transmission and distribution operate under a regulated natural monopoly regime, while the other phases along the supply chain are open to competition.



• Initial vertically integrated market, with transmission and distribution under market incumbent (same color indicates the same company performing different activities) • Regulated and centrally set prices • No choice of supplier for end consumers • Gradual opening of generation to additional players • Addressing Third Party Access (TPA) • Set-up of Market Operator and System Operator with acknowledged dispatch rules • Potential adoption of Single Buyer model to aggregate generation and /or load	• First step of unbundling of transmission and distribution (ring fencing, licensing) • Set-up of regulation of networks • Generators are obliged to provide ring fencing for captive distribution and retail companies under the same holding (in the case that generators are allowed to own or be part of a company that carries out distribution activity) • Distributors perform the supply function and can choose among non-captive generators • Designing wholesale markets (e.g. power pools, power exchanges) with day-ahead and adjustments segments • Introduction of wholesale licensed traders • First differentiation of captive and eligible clients (based on volumes)	• Full liberalized model • Full unbundling of transmission and distribution, according to suitable local framework (TSO; ISO, ITO; other available models) • Fine-tuning of regulation of networks (introduction of efficiency factors, TOTEX) • Establishment of markets for ancillary services and (where required) capacity • Generators bid on day-ahead and intra-day markets (power pools, power exchanges) • Retailers and suppliers purchase energy on the spot market or directly from generators via PPAs and bilateral agreements • Full participation of traders on wholesale markets • All consumers can freely choose their suppliers, based on market preferences

1. ESKOM AT GLANCE: STATUS AND FUTURE CHALLENGES OF A VERTICALLY INTEGRATED UTILITY

The South African electricity market is a centralised one, managed by the incumbent utility Eskom (Electricity Supply Commission), created in 1923. Eskom is the oldest and largest integrated utility in the African continent. According to the figures of the 2018 IRP (Integrated Resources Plan) [3], South Africa's total domestic electricity generation capacity is 51,309 MW from all sources. Approximately 91.2%, or 46,776 MW, comes from thermal power stations, while 4,533 MW, or 8.8% is represented by renewables.

As in 2019, Eskom operates 30 power plants with a nominal capacity of 44,172 MW, roughly equivalent to 86% of total capacity, divided into thermal coal (36,479 MW), nuclear (1,860 MW), gas fired (2,409 MW), hydro (3,324 MW) and a 100 MW wind park. Eskom serves more than 6 million direct customers connected via a transmission and distribution network of about 388 thousand kilometres of cables and power lines, for a cumulative transformation capacity of 297 GVA, and owns 60% of the country's distribution grid. Eskom generates approximately 95% of the electricity consumed in South Africa. As exclusive large-scale vendor, it also exercises a monopsony of power, performing the role of buyer in the main VREs promotion frameworks.
Other relevant electricity assets belong to municipalities, whose generation consists of coal (64.4%) and gas fired power plants (14.66%), as well as pumped storage hydro power plants (20.91%). Some portions of the distribution grid are owned and managed by about 180 municipalities, whose current situation of financial distress triggers serious issues in maintenance and reliability of service.

In recent years, Independent Power Producers (IPPs) have been gradually entering the market, thanks to a more stable regulatory environment and the promotion of additional capacity via the REIPPPP framework.

The National Energy Regulator of South Africa (NERSA) is an independent agency established under the National Energy Regulatory Act which regulates the electricity, gas and petroleum pipeline industries. NERSA issues generation licenses and enforces their compliance, regulates all tariff increases proposed by Eskom, provides national grid codes, develops regulatory rules for relevant industries and determines the applicable standards.

As an integrated utility, Eskom's business currently encompasses all the phases of the electric supply chain: generation, transmission, distribution, organised into three divisions.

The first mention to the market liberalisation and unbundling can be found in the 1998 White Paper and reiterated in the 2011 Independent Systems and Market Operator Bill, both without substantial consequences.
The 1998 White Paper on Energy Policy endorsed ending Eskom's monopolies on generation, distribution, and transmission. The government would have supervised the creation of new Regional Electricity Distributors (REDs) to achieve better service and lower prices; as well as the unbundling of Eskom's transmission, distribution, and generation functions into separate corporate entities to advance transparency and accountability; and to promote internal competition in generation, as well to improve efficiency and ensure the continued rollout of electricity to poor urban and rural communities.

The 2011 Bill envisaged the creation of an independent entity responsible for the planning of supply of electricity by generators through the national transmission system, electricity dispatch and aggregation, and performing the role of a single buyer.

In 2019, following several years of ongoing debate, South African President Cyril Ramaphosa announced, during his State of the Nation Address on February 7th, that Eskom will be unbundled into "three separate entities – generation, transmission and distribution".

1.1 The deployment of Renewables in South Africa

Deploying renewables in South Africa is intrinsically connected to the need to tackle overall system adequacy and energy poverty in disadvantaged and rural areas. In recent years, the country has been experiencing a series of interruptions and blackouts, and Eskom is often forced to apply load curtailment and load shedding, as happened for instance during the notorious black-out in January 2008.

VREs have the potential to overcome some of the challenges currently faced by the South African power system, by:

- Providing the system with additional capacity and adequacy;
- Delivering electricity in areas poorly served by the existing transmission and distribution grids and promoting the network expansion;
- Enabling local businesses with security of supply and providing additional sources of income in disadvantaged neighbourhoods and settlements;
- Allowing the implementation of more equitable and fairer progressive electricity tariffs;
- Helping in achieving the country's targets in terms of carbon emissions and mitigation of pollutants.

In May 2009, the NERSA approved the Renewable Energy Feed-in-Tariff (REFIT) policy to generate 10,000 GWh by 2013. REFIT's proposed tariffs were initially designed to cover generation costs plus a real after-tax return on equity of 17%, fully indexed for inflation, for twenty years.

However, the mechanism proved to be unsuccessful in terms of total capacity delivered and was replaced in 2010 with the new Renewable Energy Independent Power Producers Procurement Programme (REIPPPP), which allows the private sector to bid for the right to generate and sell renewable energy to Eskom, the sole buyer under the program, for the injection of this power into the national grid. Its realization implied a strict coordination among the Department of Energy, the National Treasury, the Departments of Trade and Industry and of Environmental Affairs, NERSA, and Eskom, as well as financial institutions and project developers. [4]

The Integrated Resource Plan for Electricity 2010–2030 aimed to supply 42% of the new additional capacity over the 2010–2030 period, or 9% of the total generated electricity by 2030, from VRE producers, with an initial goal set at 17.8 GWp. In the period 2011–2018, the REIPPPP has awarded 102 projects to the private sector, articulated in 5 Rounds, with a projected generating capacity above 6 GWp. The scheme also contributed to bring generating prices down. Over the first three bidding phases lasting 30 months, average solar PV tariffs decreased by 68% in nominal terms and those for wind by 42%. Over the subsequent two bidding phases lasting 27 months, PV tariffs decreased a further 47%, and those for wind, a further 29%. Unlike REFIT, the tendering or bidding system allows the government to control the amount of VRE generation.

The framework has proved to be a flexible one, and in 2014 Eskom used the same bidding system to introduce the "Coal Baseload IPP Programme", with plant size capped at 600 MW. The winning bidders under the first bid window, Thabametsi (557 MW) and Khanyisa (306 MW) are meant to provide short-term capacity increases in thermal generation. [5]

IPPs companies eligible to bid for REIPPPP could have the following shareholders:

- Black Industrialists (increasing shareholding with projects to be signed having an average of 40% shareholding);
- Other South African shareholders;
- Community Trusts representing the local communities where the projects are located;
- Foreign shareholders bringing foreign direct investments (FDI).

The selection follows a multi-stage bidding process, where bids are evaluated according to two main criteria: 1) Economic Development (30%) and 2) Price per kWh (70%). Bidders with the highest combined Price and Economic Development scores are selected as the preferred bidders within the technology MW allocation to supply the capacity allocation for the bid round.

Much attention is paid on the overall social purposed vested on the REIPPPP framework, as it is focused also on the promotion of job growth, domestic industrialization, community development, and Black Economic Empowerment (BEE) goals. To meet the economic development requirements of REIPPPP, projects must meet minimum thresholds of a 12% for BEE shareholding and 2.5% for community shareholding. This is the vision promoted by the "One Million Climate Jobs" campaign, an alliance of trade unions, social movements and community organizations campaigning for policies that combine the imperative of reducing emissions and pollutants with the energy and socio-economic mandate to improve livelihoods through employment creation.

Another, more state-of-the-art proposed approach is the decentralized model that uses "smart grid" technology to integrate small scale distributed generation with actively managed demand. Dispatchable renewable sources, with typically much lower (indeed, close to zero) operating costs, serve to flatten peak prices. The standard merit curve that favours 24/7 baseload supply running as close to 100% capacity as possible, is inverted, since, wind and PV—although not continuous—are already 40% cheaper than new coal plants and can bid well below. VREs are also much more modularly scalable. A potential option would be to implement a progressive FIT together with universal net metering. Net metering enables grid-connected renewable systems to be credited for the electricity that they provide to the grid.

The CSIR Energy Centre has proposed a master plan combining net metering and FIT policies—the NETFIT—via a "Central Power Purchasing Agency (CPPA)". This would provide a FIT for all surplus generated energy, while compensating municipalities and Eskom Distribution for reduced sales resulting from households' self-generated energy consumption. [5]

1.2 Uncertainties, Priorities and SWOT framework in the South African energy system

The electricity system of South Africa is currently facing a series of dynamic choices and options on the way to modernization. Many of the foreseeable changes will be driven by market dynamics as well as new regulation policies. Therefore, envisioning a clear strategy and selecting achievable objectives is fundamental in achieving positive, long-term results. South African institutions are focusing the efforts on reliability and adequacy of the power system, access to electricity and inclusion of previously disadvantaged people, and overall reduction of emissions and pollutants.

In its assessment of strategic objectives to be pursued, the NERSA lists the following items:

- Promote energy supply that is certain and secure for current and future user needs;
- Create a regulatory environment that facilitates investment in energy infrastructure;
- Promote competition and competitiveness within the energy industry;
- Promote regulatory certainty within the energy industry;
- Promote accessible and affordable energy for all citizens.

The World Energy Council (WEC, "Issues Monitor 2020" [6]) proposed a framework of analyses to assess the status of South Africa's power market after the publication of IRP 2019 [2]. WEC evaluates two categories of elements, Critical Uncertainties and Action Priorities, according to two dimensions, Uncertainty and Impact.

The individuated Critical Uncertainties are:

- Exchange Rates. Due to changes introduced by the announced unbundling of Eskom into separate generation, distribution and transmission entities, there is concern regarding the promotion of competition as a driver for energy affordability. As the programme is at an early stage, uncertainty remains high, given also the persisting economic stagnation. Electricity and liquid fuel prices have been rising and various mechanisms to reduce electricity costs are under consideration.
- Capital Markets. The main concern revolves around the restructuring of Eskom's debt, as well as the possibility to attract relevant foreign direct investments from IPPs and institutional investors alike.
- Decentralised Energy Systems. The IRP2019 aims for 20.4 GW of power capacity to be generated via solar and wind between 2022 and 2030. Investment in renewable energies has risen due to the REIPPPP and the opportunity for rooftop solar. At the same time, Eskom unveiled its Distributed Battery Storage Programme, committing to solar-plus-storage and energy storage projects totalling 1,400 MWh. Uncertainty also revolves around medium-term grid prices.
- Corruption. The 2019 Corruption Perception Index of Transparency International ranks South Africa 70th out 180 observed countries. There is a widespread sentiment that both the political and administrative systems must undergo severe scrutiny and reforms.

The individuated Action Priorities are:

- Economic Growth. Private sector participation in the economy is being promoted as a strategy to enable growth. The strategy was proposed by Finance Minister Tito Mboweni in an attempt to improve business confidence. However, it faces challenges from opposition parties and social groups concerned about job losses as a result of privatisation.
- Coal. The IRP 2019 forecasts that by 2030 almost 60% of electricity in South Africa will still be generated from coal, dropping from today's 77% share. Significant increases in VREs, primarily in wind and solar, are expected to replace some coal capacity by 2030. Any new coal projects will be designed to be more efficient and with lower emissions.
- Energy Efficiency. This is defined in terms of both improvement of the overall energy mix and reduction in transmission and distribution losses. Effective parameters of evaluation are represented by the overall quality of supply and the total number of load curtailment / shedding episodes along the year.

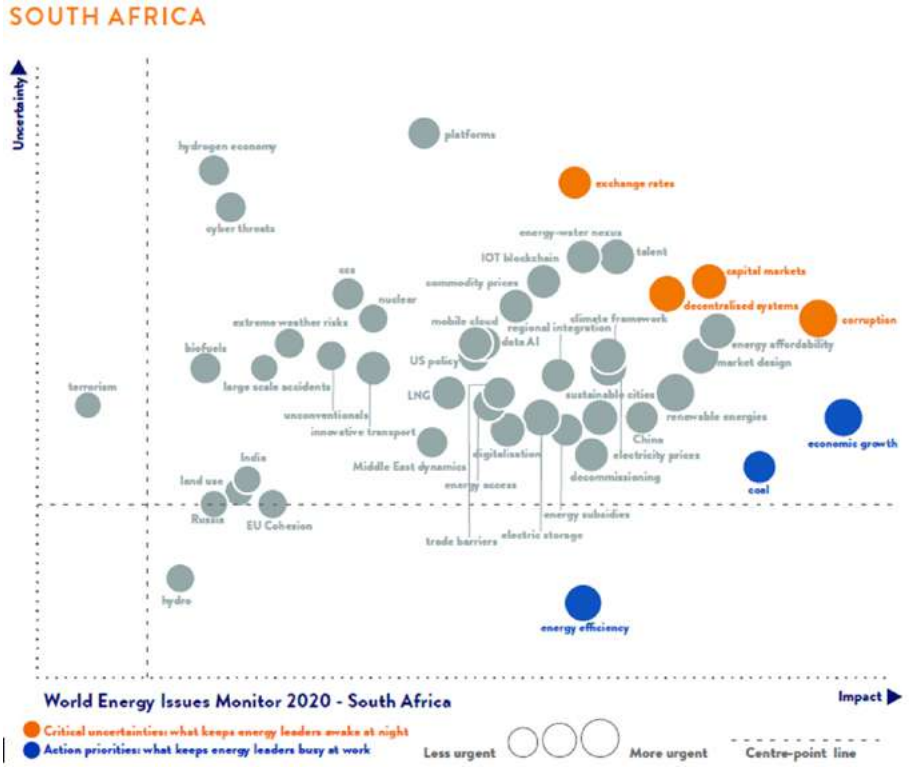


Figure 1: World issues monitor 2020 – South Africa (Source WEC [6])

A tool currently used in planning energy strategies at national level is the Strengths, Weaknesses, Opportunities and Threats (SWOT) analysis, which originates from the business management literature and was adopted in the 80s by public administrations. Specifically, there is ample literature concerning the successful application of SWOT analyses in the fields of regional energy planning and municipal solid waste management. A number of mature markets countries used SWOT analysis to select policy priorities and ensure horizontal policy coherence in their national strategies for sustainable development.

The two main components of SWOT are the indicators of the internal situation (existing Strengths and Weaknesses) and the indicators of the external environment (existing Opportunities and Threats). Here below a framework of analysis is proposed, tailored on the South African electricity market.



Figure 2: SWOT Analysis

Strengths:

- Available Technology. State-of-the-art generation technology allows for a rapid roll-out of adaptive solutions. VREs are modular and easily deployable in disadvantage and rural areas, and their cost is steadily decreasing towards full grid parity. Likewise, flexible thermal generation, such as gas-fuelled mid-merit and peak plants are being planned. The nuclear power plant of Koeberg will undergo a refurbishing and lifetime extension. In IRP 2019 the emphasis is on High Efficiency Low Emission (HELE) facilities, already commercially available, and supercritical and ultra-supercritical power plants with Carbon Capture Use and Storage, whose technology is currently under development.
- Regulation. The NERSA is taking advantage of the previous REFIT experiences in designing effective measures to harness the potential of renewables within the country, such as the REIPPPP. The same framework and bidding system proved to be equally suitable to develop and commission conventional thermal capacity. Moreover, a dynamic and thriving civil society is contributing in steering the attention of policy makers to address objectives of social inclusion and energy poverty.
- Geographic Location. South Africa is a vast country abundant with natural resources. A net exporter of coal resources and other minerals, the country lacks relevant reserves of hydrocarbons, but the proximity to gas-rich Mozambique provides the possibility of supply via pipelines. There is some unlocked potential for additional hydro generation (IRP 2019 targets extra 2500 MW capacity by 2030) [2]. Geography also allows for the increasing deployment of VREs such as wind and solar: the country receives a yearly average solar radiation 7 kWh/m2 and an average wind speed of over 7 m/s in coastal areas. It is estimated that South Africa has wind generating potential at over 2,500 TWh, concentrated solar power (CSP) potential at over 4,000 TWh, and solar PV potential at over 3,000 TWh.

Weaknesses:

- Generation Mix. Eskom currently owns and operates a varied mix of generation plants: baseload, mid-merit and peak load ones. However, there is a track-record of reliability and safety issues, such the accidents at the Duvha coal-fired station in 2011 and in 2014, or the 2014 silo collapse at Majuba power station, that lead to significant outages. The heavy reliance on centralized thermal generation does not provide an adequate degree of flexibility when disruptions occur. Moreover, there is some environmental concern regarding the realization of the Thabametsi and Khanyisa IPP coal-fired plants, that can potentially delay or hamper those capacity expansion projects.
- Transmission / Distribution. There is evidence that the current power grid is not adequate to foster energy access, social development and economic growth. South Africa's distribution network has been in severe difficulty, primarily due to financial distress at both municipal level and at Eskom level which has led to a maintenance backlog of distribution assets. The deployment of distributed VREs also presents serious safety concerns for grid operators and line workers confronting potentially large numbers of technically non-compliant PV installations.
- Payment Collection and Theft. Non-payment and forced disconnections have been frequent in the past years. There is social concern about a degree of discrepancy towards disadvantaged settlements where systems of pre-paid metering were implemented. Cable theft is another relevant issue, in 2018 it was estimated to cost R5–7 billion a year.
- Political Stability. The country does not enjoy political stability due to the widespread allegations of mismanagement and corruption against the leading party, the ANC. The common label used by media is that of "state capture" or corruption on a grand scale. General elections were held in South Africa on May 8th 2019 to elect a new National Assembly and provincial legislatures in each province, following the 2018 resignation of former President Zuma after a sentence of the Constitutional Court. The incumbent interim President Cyril Ramaphosa secured a full term in office.

Opportunities:

- Renewables. VREs like wind and solar, represent the greatest opportunity to modernize and make the South African system flexible and adequate. There are challenges to integrate new renewable resources into a traditionally centralised energy system. By positioning renewables as a priority area, the IRP 2019 envisages the reduction of uncertainty around large scale and grid connected renewable energy projects. VREs, wind and solar, are expected to provide the lion share of additional generation capacity by 2030, with 9,200 MW and 6,500 MW, respectively.
- Distributed Generation. The new paradigm to deliver energy access and social inclusion is the emerging decentralized model that uses "smart grid" technology to integrate smaller-scale distributed generation with actively managed demand. Measures to be taken in order to allow the integration of VREs comprise optimisation techniques such as: minimisation of power losses, voltage deviation and cost of generation, maximisation of system reliability and renewable energy penetration, simulation of the overall behaviour of the network and subsequent implementation of optimal results.
- Regional Market Integration. The electricity markets in the Southern African region are already substantially integrated, also thanks to the closely linked extractive industries: Eskom historically has both imported power from and exported it to Mozambique and Zambia; it is a major supplier for Botswana, Lesotho, Namibia, Eswatini, and Zimbabwe; and it has imported hydro power from the Democratic Republic of Congo. The cooperation is framed by the Southern African Power Pool (SAPP), currently consisting of 13 members and aiming at further exchange and market integration.

Threats:

- Economic Outlook. As an emerging market, the economic outlook of South Africa is not a positive one. Real GDP grew at an estimated 0.7% in 2019, down from 0.8% in 2018, and it is projected to rise to 1.1% in 2020 and 1.8% in 2021 amid domestic and global downside risks. Concerns over a sustained economic growth can potentially hamper investments targeting the modernization of the electricity sector.
- Commodity Prices. South Africa is heavily reliant on export of commodities (coal, gold and diamonds among others) and the contraction in mining activities drove slow growth in 2019. Prices can therefore affect economic growth and state budget, as well as the electricity sector, almost completely based on thermal generation and therefore heavily dependent on fuel prices. Variability in fuel prices might even deter the implementation of the energy transition to renewables, notwithstanding all negative externalities associated with this type of generation.
- Environmental Impact. Pollution in South Africa is becoming an ever-alarming issue. The main drawback of depending on coal as a source of energy is the increase in carbon emissions in the atmosphere, along with SOx and NOx and particulate matter. This mix of pollutants triggers environmental and health impacts, thereby causing damages represented as external costs. Coal mining activities also hold a huge negative impact on the land's water, air and soil quality.

2. WORLDWIDE EXPERIENCES ON TRANSMISSION UNBUNDLING

This chapter will focus on the different approaches towards market liberalization in the electricity transmission sector. Evidence and case studies will be provided regarding mature and emerging markets alike, with the aim of disclosing country-specific paths to unbundling. Regulatory periods and tariff scheme models will be discussed in detail in Chapter 3.

2.1 General Models of Unbundled Systems

The concept of "unbundling", starting from a technical notion since its origin, has entered the vocabulary of a broader public. The debate over the opportunity for a separation of vertically integrated industries spans across a variety of sectors, from telecoms to railways as well as energy markets and captures the attention of legislators, operators and technicians alike. The rationale of widening economic opportunities and competition often clashes with issues regarding technical frameworks and operational flows, and balancing these two requirements is pivotal to achieve benefits for consumers, investors and enterprises.

Unbundling is defined as the separation of production and supply of vertically integrated activities where the transport (or transmission) assets constitute natural monopolies. Unbundling may occur in different ways: from the setting up of transportation system operators, also called legal unbundling, which means the legal separation of enterprise and the grid operator, to the Independent System Operator (ISO), and or the "full" model of Transmission System Operator (TSO), which has been labelled "expropriation" by some operators But even simple ownership unbundling occurs through different forms: from a common shareholding of the grids by different producers, who own the network, to minority shareholding of the enterprise in the grid, and then to the most radical version, that completely excludes generation companies. Unbundling means also that the network operators cannot possess the goods they transport. In all cases, unbundling aims at introducing more competition into the market and at putting an end to potential discrimination exercised by the holder of the natural monopoly. It is also considered that a high level of market concentration, vertical integration and supply leads to a lack of equal access as well as insufficient investment in infrastructures, and every process of unbundling comprises the creation of stable set of rules to guarantee the third-party access to the grid and promote investment on new transmission assets.

The rationale for unbundling is based on the following questions:

- Does ownership unbundling really improve competition in the internal market? In economic terms, does the total welfare surplus increase?
- Is it possible to guarantee the necessary investments in infrastructure, once the enterprises and the grid have been unbundled?
- How to guarantee access to the grid for all market players?
- How to solve the trade-off between more competition and the security of supply, if unbundling weakens potentially strong, national champions?
- Are there any alternatives to ownership unbundling? What is the best way or strategy in order to open a market, according to the local features and requirements?

The figure below represents the traditional flows according to a vertically integrated, market incumbent scheme, where generation, transmission, distribution and supply are comprised within the perimeter of a single enterprise.

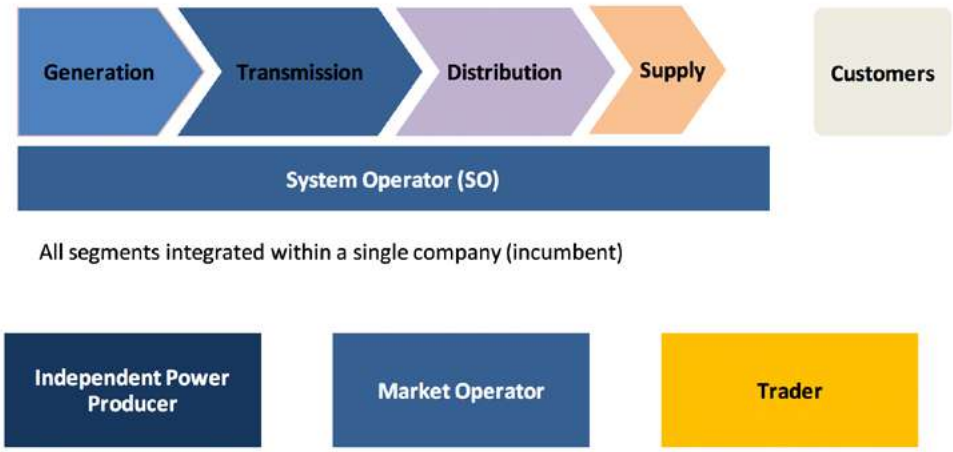


Figure 3: Vertically Integrated Company

Unbundling uses ring-fencing rules, setting requirements for accounting separation, functional, or legal separation, or providing for full ownership unbundling.

It is also relevant to consider how the unbundling process has to be harmonized with the existing market players, such as Independent Power Producers (IPPs), other regional distributors and traders. The liberalization phase often goes along with the creation or further implementation of new models affecting the wholesale power market. In case a new wholesale market is also envisaged, it is pivotal to understand how IPPs, traders and suppliers will have access to it. Likewise, regional distributors must enjoy equal treatment compared to the incumbent distributor, according to a clear framework of rules.

Another aspect to be assessed is the entity in charge of the activity of dispatching, i.e. the management of energy flows along the grid so that supply and demand are always balanced, guaranteeing the continuity and safety of the service provided. As general rule, two models may be applied, the central dispatch and the self-dispatch model.
Central dispatch models typically occur in electrical systems where the impact of locational market imbalances is a material threat to the security of the system. The main distinguishing feature of central dispatch systems is that balancing, congestion management and reserve procurement are performed simultaneously in an integrated process.

Conversely, in self-dispatch model, the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those facilities. Chart below displays a model of central dispatch, as represented by the Italian TSO Terna.

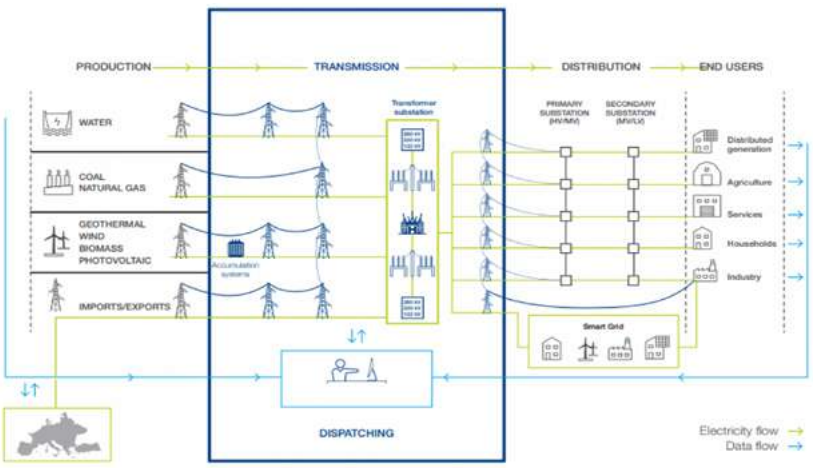


Figure 4: Central dispatch model of the Italian TSO [7]

There are different degrees of market liberalisation that it is possible to pursue. The function of operating the market can either be carried out by an entity separated from the system operator (transmission system operator plus market operator model), or by a market operator.

In a competition wholesale market (see left figure below), generation companies sell through the intermediation of a market operator via some kind of spot-trading platform, where participation is frequently mandatory, and the resulting wholesale electricity prices are passed through to consumers by the distribution companies, acting as suppliers.

In a full-fledged liberalized market (see right figure below), retail activity is completely liberalized, with the right to freely choose a supplier for all consumers; in this case distributors work as regulated local monopolies and do not sell directly. In some countries this possibility has been progressively introduced, starting from the largest consumers to the smallest residential ones.

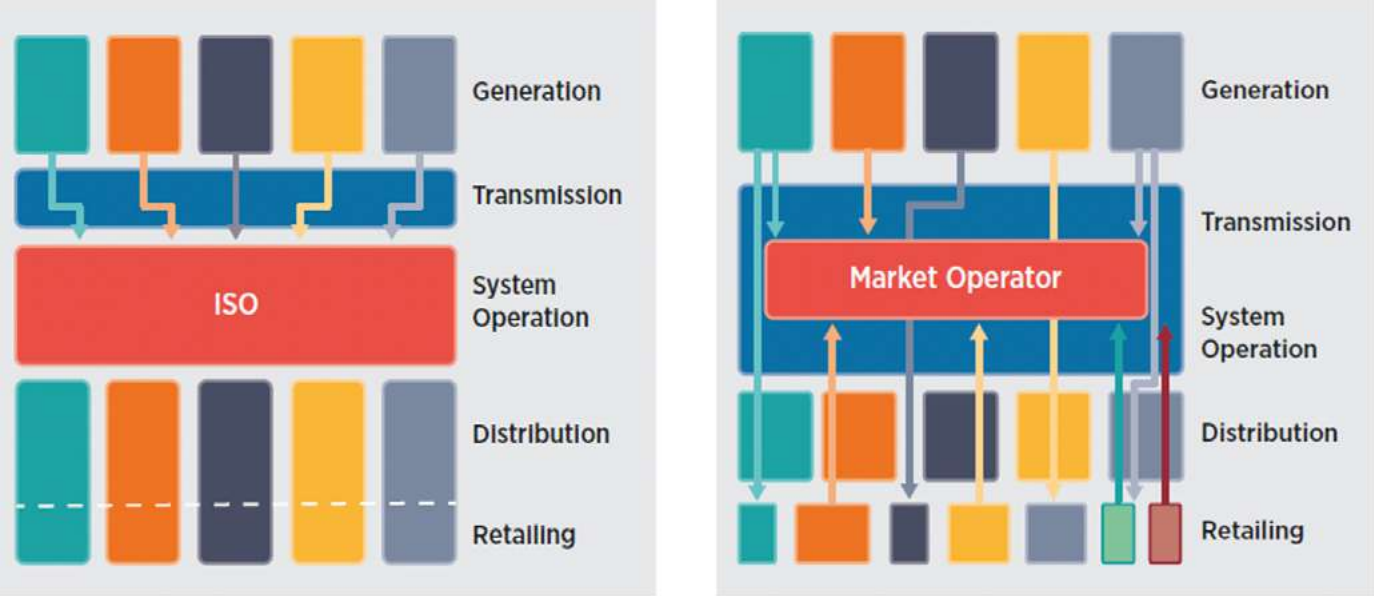


Figure 5: Competition Wholesale Market and Fully Liberalised Market [8]

The Single Buyer Model may be considered a transitional phase towards a fully liberalized market. The rationale behind this model is to ensure equal treatment to market participants, requiring all generators to sell their output to an entity (the Single Buyer), thus ruling out direct (bilateral) contracts with distributors, which may unfairly favour some plants over others.

The rational for the adoption of Single Buyer Model is given by the following:

- Often the single buyer role is represented by the entity responsible for real-time dispatch. By balancing the differences between the planned and actual output of individual generators and between the planned and actual loads of individual distributors, the single-buyer model facilitates this balancing;
- It preserves a key role for the sector ministry in decisions on investments in generation capacity, and facilitates centralized planning;
- It helps to stabilize wholesale electricity prices, simplifying price regulation and enabling the permanence of default regulated retails tariffs for non-eligible customers;
- It allows for the protection of developers of generation projects from market risk and regulatory risk at retail level, by reducing financing costs or making the investment commercially bankable.

However, this model is also prone to induce misallocation of resources, given the centralized nature of planning, and biased transmission of supply-demand price signals. The chart below represents the structure of the Single Buyer Model.

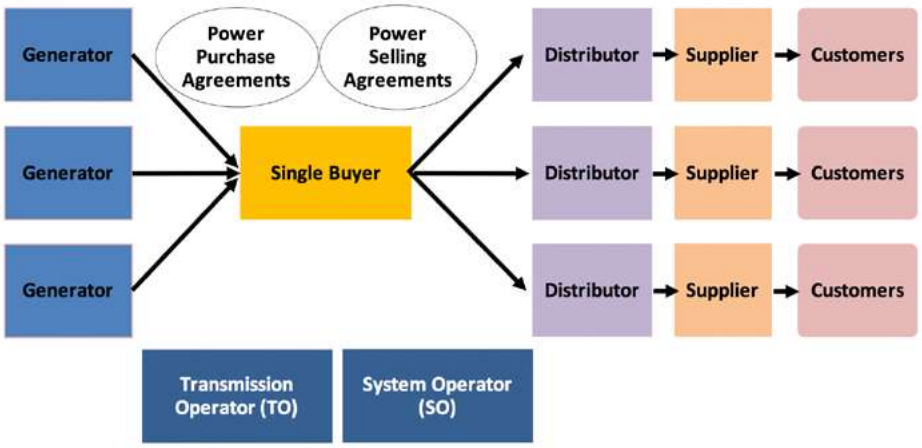


Figure 6: Single Buyer Model

2.1.1 The Power Pools

The Power Pool Model is a specific implementation of the competition wholesale markets. A mandatory Power Pool Model partially smoothens the backside effects of a Single Buyer Model, of which it can be considered an evolution. In a Power Pool. the private sector makes decisions about new generation capacity, and the pool agreements and market rules replace power purchase agreements. Likewise, generators are not protected from market risks.

The main characteristics of the Power Pool Model are the following:

- All electricity is traded over the pool (mandatory);
- The generators offer price-quantity pairs for the supply of electrical energy for each generating unit during a specific time interval;
- The pool operator forecasts demand and dispatches generating units to meet the forecast demand (one-sided pool);

or

- The pool operator dispatches on the basis of a demand curve created from price-quantity bids made by buyers (two-sided pool);
- Final production schedule of all producers is centrally determined by the pool operator.

A simplified scheme of a Power Pool Model is represented in the chart below.

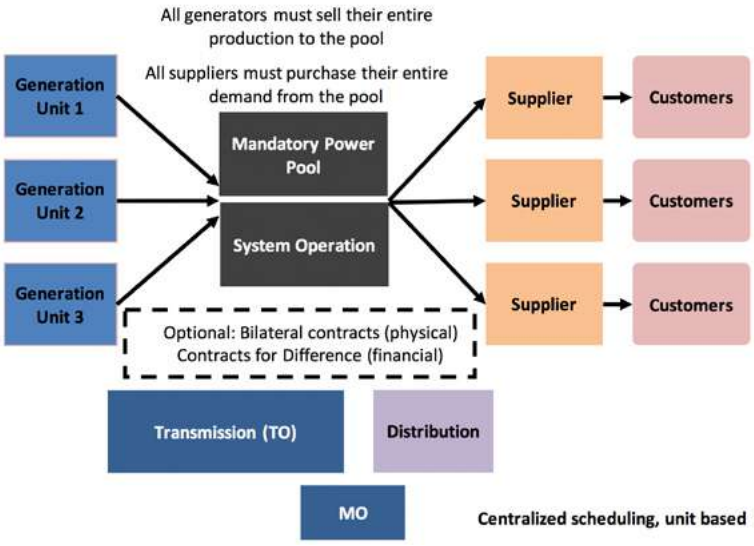


Figure 7: Mandatory Power Pool

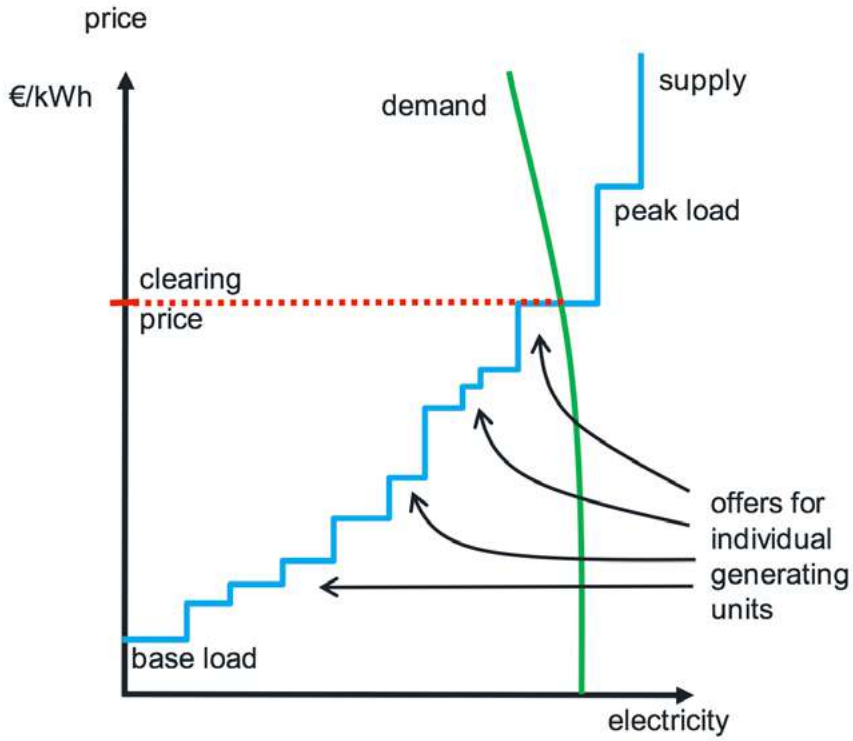


Figure 8: Clearing Price in Power Pools

The Power Pools are also cost-based and price-based. Several Latin American countries have cost-based Power Pools, meanwhile the USA Power Pools are generally price-based.

The differences are presented in the summary table as follows:

Cost-based Power Pool	Price-based Power Pool
• Generators submit offers for their individual units at their actual or estimated variable production costs • Pool operator ranks generating units from least to most expensive production costs (merit order) • Clearing price is determined by the short-run marginal costs (fuel, operating and maintenance costs) of the generating unit that clears the market • Cost-based pools require regulatory audits of costs • Example: Latin American wholesale markets	• Generators submit offers for their individual units based on their willingness to offer • Offers include start-up costs and minimum and maximum MW • Pool operator ranks generating units based on offer prices • Clearing price is determined by the most expensive bid offered which is needed to satisfy demand in each time interval • Example: England and Wales (1990-2001)

Table 1: Cost-Based and Price-based Power Pools

2.2 First Privatization Processes and Unbundling

Latina America is a pioneering continent in the process of liberalization of electricity markets. The earliest was carried out by Chile, the first country in the world to unbundle and deregulate its electricity market in 1982.



Figure 9: Liberalization of electricity markets in Latin America

The drivers that were considered in taking the decision to unbundle were the following:

a. Need for a sustainable energy sector with competitive prices for economic growth;
b. Need to develop infrastructure: transmission system and distribution; and
c. Expand electrification and access to energy.

The transmission companies also were privatized and were not held as public companies. Some of the countries established by regulations to have just one transmission operator, like Ecuador, Panama, Nicaragua, El Salvador, but other countries allowed several transmission companies, such as Argentina, Bolivia, Colombia, Brazil and Peru.

The general features of transmission companies in Latin America are summarized below:

- Transmission companies are independent from market participants;
- Open, or third party access is guaranteed;
- Competitive expansion is envisaged to develop the transmission system;
- Nodal pricing and marginal methodologies are adopted as better signals towards efficiency;
- Effort is spent towards ensuring a strong service quality.

2.3 The EU Energy Packages and approaches towards transmission unbundling

In the European Union, the process of liberalization started in the 1990s (First Energy Package, 1996) and continued in 2003 with Second Energy Package and in 2009 with Third Energy Package. These directives progressively introduced rules on consumer protection, as well as accounting, legal and ownership separation between transmission assets and functions and activities related to generation, market operation and trading. Common detailed rules for electricity markets were established later, with the aim of coupling markets and improving cross-border trading, whose final goal is the creation of a pan-European single electricity market.

With the launch of Directive 96/92/CE of 19th December 1996 on common rules for the electricity market (the "First Package"), a new phase of European energy policy started, and liberalisation processes finally began. The most important general principles envisaged in the Package were to set up common rules across the EU to ensure a single playing field for all those expressing supply and demand; and to progressively proceed to the opening of markets. [9]

The main provisions of the First Energy Package are:

- Freedom to build power plants to sell electricity to eligible customers, and to access transmission and distribution networks;
- Competition in generation: the construction of new plants can be done through authorisations or procurement procedures. There are two options. One is the authorization, according to which every company can build new power plants, when and where it wants, subject to the new procedures that every industrial plant is required to comply with. The other option is a tendering process, whereby the need for new power plants is fixed by some form of planning and companies compete for the awarding to build the necessary capacity;
- Competition in sales: possibility for eligible customers to be free to conclude supply contracts to cover their own needs with generators and/or suppliers, and, at the same time, envision of a single buyer to protect captive customers;
- Access to the transmission networks: it can be negotiated or regulated:
  - The regulated option is called Third Party Access (TPA), in which generators and suppliers have guaranteed access to the network at prices made public by the System Operator and on non-discriminatory terms;
  - The negotiated option, in which the indicative prices are made public, but customers can negotiate the precise price and conditions with the System Operator;
- Obligation of public service: the directive itself does not impose any obligation to public service. It accepts the general idea that liberalisation can be restricted by Member States by the imposition of public service obligations, but this must be explicitly provided for.
- The First Energy Package takes also the first steps towards unbundling, by providing for:
- Accounting Separation between generation, transmission, and distribution activities for companies operating at all stages of the market;
- Functional Separation of transmission from other market activities;
- Independence of the transmission system. To ensure non-discriminatory access to the transmission network, there are rules that aim to ensure the independence of network management. Integrated companies are at least compelled to have separate management of the transmission and to publish separate accounts of network activity.

Directive 2003/54/EC of June 2003 (the "Second Energy Package") produced further enhancements towards market liberalization, tackling the dissatisfaction with the uncertain progress of market opening expressed by some countries. At the same time, the Lisbon European Council (spring 2000) had called for the rapid completion of the internal energy market as an important step in revitalizing the competitiveness of the European economic system, employment and higher standards of service for citizens.

The first and most significant change of the Second Energy Package was the introduction of certain «public service» obligations which must be respected by all Member States. States must ensure 'universal service', and 'a high level of consumer protection' must be guaranteed. Special forms of protection (social tariffs) were

provided and a new category of users was defined, the «vulnerable customers», e.g. corporate consumers in financial distress, that can benefit from appropriate measures to avoid supply disruption. [10] The directive also includes:

- Freedom of choice of the electricity supplier, for all consumers other than household ones in 2004 and for all consumers, including household ones, starting from 2007;
- Legal separation of transmission and distribution from production and supply;
- Non-discriminatory access to networks based on transparent and published tariffs (no longer negotiated option);
- Establishment in each Member State of a Regulatory Authority, appropriate to the local regulatory framework, in order to ensure effective control of the conditions of access to networks;
- Allocation of cross-border electricity transmission capacity according to market mechanisms.

Further elements of novelty are:

- Adoption of several measures to ensure fair conditions on the supply side, in order to reduce the risk of dominant positions and predatory behaviour, and protection of small consumers also through the increase of negotiating power with their supplier counterparts;
- Access to the network without discrimination, in a transparent way and at prices proportionate to the costs incurred;
- Promotion of investments in new infrastructure, to benefit the security of the system and procurement, and introduction of public service obligations on issues of supply, regularity, quality and price;
- Need to establish methodologies for setting tariffs in a transparent and non-discriminatory manner (via publication);
- Environmental protection; promotion of efficiency and energy-saving measures through incentives and emphasis on research and development;
- Creation by the Regulatory Authorities of transparent market mechanisms for the supply and purchase of balancing electricity based on the liquidity levels of the national electricity and gas market.

Directive 2009/72/EC of July 2009 (the "Third Energy Package) coherently completed the process of liberalization. The main provisions included in the Package are related to the role of national Regulatory Authorities, the establishment of the EU Agency for Cooperation of Energy Regulators ("ACER"), stricter definitions and rules for the unbundling, cross border cooperation and protection of consumers. [11]

The requirements for national Regulators have undergone several changes, specifically:

- Independence from both industry interests and government. Regulators must be an independent legal entity and have authority over their own budget. National governments must also supply them with sufficient resources to carry out their operations;
- Issuing of binding decisions to companies and imposition of penalties on those that do not comply with their legal obligations;
- Collection of compulsory data from electricity generators, gas network operators, and energy suppliers;
- Cooperation among Regulators from different EU countries to promote competition, the opening-up of the market, and an efficient and secure energy network system.

The Agency for Cooperation between National Energy Regulators was established to increase cooperation between states and remove cross-border barriers to natural gas and electricity. The Agency is granted several powers, including:

- Drafting guidelines for the operation of cross-border gas pipelines and electricity networks;
- Reviewing the implementation of EU-wide network development plans;
- Deciding on cross-border issues if national Regulators cannot agree or if they ask it to intervene;
- Monitoring the functioning of the internal market including retail prices, network access for electricity produced from renewables, and consumer rights.

Unbundling is the separation of energy supply and generation from the operation of transmission networks. If a single company operates a transmission network and generates or sells energy at the same time, it may have an incentive to obstruct competitors' access to infrastructure and infringe the Third Party Access. This prevents fair competition in the market and can lead to higher prices for consumers.

According to the Third Package, unbundling must take place in one of three ways, depending on the preferences of individual EU countries [3]:

- Ownership Unbundling or Transmission System Operator (TSO) - all-integrated energy companies sell off their electricity networks. In this case, no supply or production company is allowed to hold a majority share or interfere in the work of a Transmission System Operator;
- Independent System Operator (ISO) - energy supply companies may still formally own electricity transmission networks but must leave the entire operation, maintenance, and investment in the grid to an independent company;
- Independent Transmission Operator (ITO) - energy supply companies may still own and operate electricity networks but must do so through a subsidiary. All important decisions must be taken independent of the parent company, who guarantees the full functional independence of the transmission company.

Operators that comply with the unbundling rules can apply for certification with their national energy regulator, stating which of the three above-mentioned models is to be applied. Every operator in Europe must be certified and the Commission provides its opinion on the certification procedure. These opinions are published by the Commission, and regularly updated.

Regarding Cross-border interconnection, the directive states that securing common rules for a true internal market and a broad supply of electricity accessible to all should be one goal. To that end, undistorted market prices would provide an incentive for cross-border interconnections and for investments in new power generation while leading, in the long term, to price convergence towards a single electricity market. National Regulatory Authorities shall provide for the framework to improve congestion management and facilitate the integration of isolated systems forming electricity islands. The Third Package includes rules designed to benefit European energy consumers and protect their rights. It includes the right to choose or change suppliers without extra charges, receive information on energy consumption, and quickly and cheaply resolve disputes. The provision also allows for direct cross-border supply competition, as explicitly states that contracts for the supply of electricity with an eligible customer in the system of another member state shall not be prohibited if the customer is considered as eligible in both systems involved.

2.4 Transmission Activity in a Vertically Unbundled Environments

In the electric industry there are several elements that erect entry barriers that proscribe electricity transmission to be characterized as a perfectly competitive or contestable market. Those elements that characterize the transmission industry are:

- large sunk and specific investments;
- lumpy investments;
- need for redundancies to meet security requirements;
- economies of scale in the construction cost in terms of the capacity of the transmission line; and
- economies of scope given by the interconnection of electric systems.

The role of the transmission company in a vertically unbundled environment could be:

a. active role
b. passive role

If the transmission company has the active role, generally has the following characteristics:

- Responsibility for expansion and management of network, including losses, ancillary services and congestion;
- Risk-taking approach and remuneration according to each risk:
  - System planning or indicative planning
  - Expansion of the transmission system
  - Operation and maintenance
  - System Operation
- Need to have decision and control on expansion, Operation & Maintenance (O&M) and System Operation, and to be able to manage risk.

Examples of an active role of transmission companies are the European countries and Panama in Latin America.

On the other hand, the passive role of the transmission company generally has the following characteristics:

- Responsibility for its O&M performance (availability targets);
  - Minor expansions and upgrades;
  - Operation and maintenance, with regulated availability standards;
- No decisions about design and expansion;
- Obligation to inform about expected constraints;
  - Indicative planning: provision of information about expected constraints and best localization of new load or generation;
- Obligation for minor expansions and upgrades.

Examples of this role are Argentina and Brazil.

2.5 Transmission Operator, System Operator & Market Operator

In a vertically integrated company, besides the typical roles of the generation, transmission and distribution activities, there are other important roles which impact the market structure, the operation of the grid and the expansion of the system.

These roles are the Transmission Operator (TO), the System Operator (SO) and the Market Operator (MO).

Transmission Operator (TO)	System Operator (SO)	Market Operator (MO)
• Transmission grid owner • Plan, construct and maintain transmission grid	• Operate the system, ensure reliability and security • Real-time dispatch to balance supply and demand • Manage ancillary services to maintain system reliability • Manage congestion (internal and cross-border)	• Market Operation and development • Market administration • Registration of market participants • Receive bids/offers from market participants • Market clearing • Settlement and invoicing

Figure 10: Transmission Operator, System Operator and Market Operators

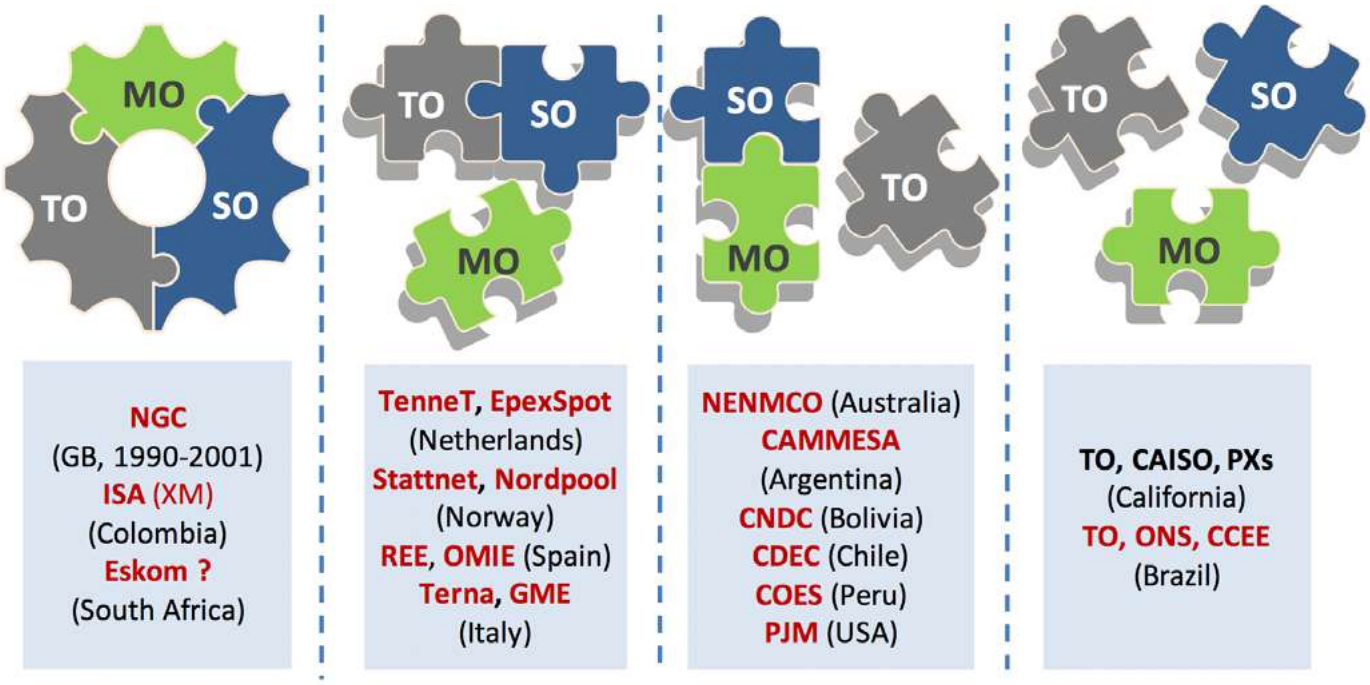


Figure 11: Transmission Operator, System Operator and Market Operators

In the case of EPEX SPOT, it is a Power Exchange that operates for the German, French, British, Dutch, Belgian, Austrian, Swiss and Luxembourgian markets.

Nordpool is also a NEMO (Nominated Electricity Market Operator) in Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Great Britain, Ireland, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland and Sweden.

2.5.1 System Operators

The System Operator is an entity responsible for operating the electricity system, ensuring reliability and security, performing a real-time dispatch in order to balance the supply and demand; managing ancillary services to maintain system reliability and solving the internal and cross-border congestion.

The System Operator can be part of a Transmission Operator, then it is called Transmission and System Operator (TSO), very common in European countries, or it could be an Independent System Operator (ISO), common in North American markets.

As an independent entity, it avoids conflict of interest with the transmission company(ies). An important case of the analysis of the independence or ring-fencing of the SO is presented in section 2.5.1.1.

An ISO is defined as a neutral, independent, and (typically non-profit) organization with no financial interest in generating facilities, that administers the operation and use of the electricity system. ISOs exercise final authority over the dispatch of generation to preserve reliability and facilitate efficiency, ensure non-discriminatory access, administer transmission tariffs, ensure the availability of ancillary services, and provide information about the status of the transmission system and available transmission capacity.

In the USA, additionally to the ISOs, there are the Regional Transmission Organizations (RTOs), which are non-profit, public-benefit corporations that were created as a part of electricity restructuring in the USA, beginning in the 1990s. The RTO coordinates, controls and monitors a multi-state electric grid, as the transfer of electricity between states is considered interstate commerce and electric grids spanning multiple states are therefore RTOs regulated by the Federal Energy Regulatory Commission. Some RTOs, such as PJM in the Mid-Atlantic states, were created from existing "power pools" dating back many decades. They are based on FERC Orders 888 and

889, which suggested the concept of the "Independent System Operator" (ISO) to ensure non-discriminatory access to transmission systems.

Finally, it is important to note that the System Operator requires a Control Center to perform its activity as well as signals from the SCADA system from most of the generators, transmission operators, distribution companies and big customers participating in the wholesale market.

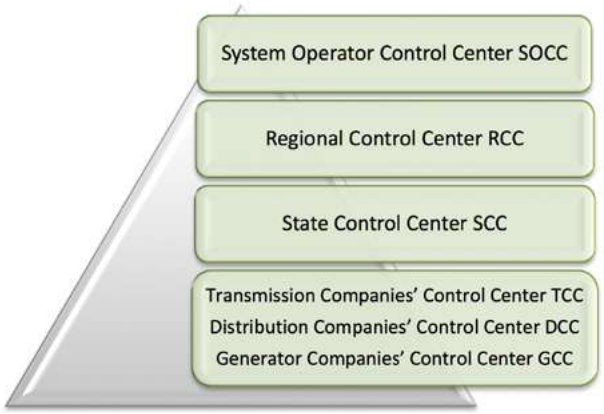


Figure 12: Hierarchy of the Control Centers

The System Operator is the "brain" of the electricity system and generally does not operate the physical assets, but issues dispatch instructions to the Control Centers of the market participants. According to the market structure, there are several participants, for example, in Brazil there are near 1584 generation market participants, 156 transmission operators and 63 distribution companies.

2.5.1.1 System Operator Ring Fencing

The major focus of conflict of interest in the short term is the System Operator. The SO must have complete control over the short-term operations of the generating plant and keep the interface with the transmission system.

The SO may have many subtle ways of influencing access to transmission, which are hard to monitor, because the SO's judgment relies on very short notice to resolve problems on the transmission system by providing commands/instructions to generators and transmission companies.

If the SO were controlled by a company that also owns generation or transmission assets, it would not be independent, being a competitor, and it would not be trusted. In a competitive world, the SO needs to be independent by all involved stakeholders/actors, namely all generators, and indeed all traders, buyers, and sellers.

The independence of the System Operator is always a central objective of restructuring.

A second source of conflict is the responsibility for expanding the transmission system—i.e. the short-term problem of transmission access translated into the long term.

If a generation company or utility in a competitive context owned the transmission system and had responsibility for maintaining and expanding it, there would be many opportunities to thwart competitors by being dilatory about construction and maintenance of the transmission assets.

This is not so immediately apparent, since the bad results could appear in longer term, not day by day.

Competitive producers may also complain on possible delays and costs involved in connecting their generating units to a transmission system under the control of a competitor.

Possible solutions to this situation are:

- Separate legal ownership;
- Ring-fencing.

In performing their functions, the SO and MO should ensure their operation according to the rules, by avoiding to act in a manner that unreasonably discriminates against any other participant.

To provide transparency to the operation, the SO and MO should develop a set of non-discriminatory processes which have to be published in their respective websites.

Meanwhile the SO and MO should identify those circumstances that may rise to a conflict of interest or have impact on free competition in the electricity market and implement the proper ring-fencing procedures.
The ring-fencing should touch many areas, such as:

- Accounting;
- Working place and access;
- Information;
- Internal corporate meetings;
- Procedures.

Examples of ring-fenced SOs are: India (2017), Malaysia (2016), and UK, whose ring-fencing was proposed and completed from August 2017. Some details can be seen in ANNEX 1.

2.5.2 Market Operator

The Market Operator is generally an independent entity that provides a service whereby the offers to sell electricity are matched with bids to buy electricity [1] . In European countries, the market operator is generally an independent organisation, but in other contexts, for example in Latin American countries, the MO can be attached to an independent System Operator as presented in Figure 11.

The Market Operator can manage all types of electricity markets, in general these can be distinguished not only by timeframes and trading windows, but also by their properties. There are three common types of markets: power exchange, over-the-counter (OTC) and an organized OTC which is cleared continuously.

Power Exchanges

Power Exchanges are used for anonymous and transparent trading. A multilateral trading platform is set up, where market participants submit demand or supply bids. Typically, the day-ahead and intraday-market are considered power exchanges but there are also power exchanges for long-term future products. Typically, the MO aggregates all the demand bids and all supply bids and clears the market. For the day-ahead market this happens based on the principle of the merit order curve. Or, as in the case of the intraday market, the platform allows direct anonymous contracts between the market actors by clicking on the demand or supply bid of the counterpart. The products offered on the power exchanges are standard products for which the demand is high enough to ensure liquidity and an adequate price.

[1] Article 2(7) of the Regulation (EU) 2019/943 of the European Parliament

OTC markets

OTC markets are used for bilateral trading. Often brokers (intermediaries) bring trading parties together to trade electricity, mostly via framework contracts, however direct trading between two parties is equally possible. Any type of electricity product (e.g. block contracts, only during certain hours, for a few days or a specific period, specific constraints and conditions, etc.) can be negotiated and traded. Prices are confidential and not transparent to other market parties. However, the transparent market prices from the Power Exchanges are mostly used as a reference. The main volumes of long-term contracts are typically traded on OTC market.

Organised OTC markets

In an organised over-the-counter market, market participants submit supply and demand bids to a market platform just like a power exchange. It is cleared continuously though, which means that supply and demand bids are matched on a continuous basis. Interested parties can click an offer to agree on it and make the deal.

2.6 Case Study Italy

Objectives of Unbundling	Necessity to liberalize the market and unbundle transmission from market incumbent Enel. Bersani Decree 1999.
Transmission Model	TSO (Transmission System Operator). Initially ISO (Independent System Operator)
Outcomes	Fully independent legal entity, owning almost totality of the National Transmission Grid. Central dispatch model. Public company, with expansion plans abroad, and activities spanning from regulated to non-regulated business.

The Legislative Decree 16th March 1999, N 79 ("Bersani Decree"), implementing Directive 96/92/CE, liberalised the electricity market from the previous integrated model managed by the state utility Enel Spa. The former framework envisaged:

- Government and centralised energy planning (CIPE, PEN);
- Prices set by the ministerial Pricing Committee (CIP) to cover operational costs;
- Presence of municipal companies (emanations of municipalities, usually multi-utility)
- Self-producers (large industries);
- Regulatory safeguards for autonomous regions and provinces;
- Enel mission was to ensure service was delivered at a certain quality and at the lowest possible cost;
- Legal monopoly regime (government concession).

Regarding generation, the Bersani Decree imposed energy production thresholds on the former market incumbent, which cannot produce more than 50% of the electricity created in Italy. To this end, Enel was required to sell part of its production capacity (power plants for at least 15 GW) to other operators, so that new electricity companies could step in the market.

Regarding distribution, the Bersani Decree designed the area of low voltage network management on a territorial basis, creating several regional distributors: hence each region (or, sometimes, province) has a distribution company, awarded in a concession regime. Finally, as concerns the sale of electricity, many operators were allowed to enter the market as supply companies.

In the transmission sector, the Decree envisaged the model of the Independent System Operator (ISO), i.e. the separation between the management of the national transmission network, entrusted to a public entity controlled by the Ministry of Economy and Finance (GRTN Spa – Gestore Rete Trasmissione Nazionale), and the activities associated with the ownership of network infrastructure, which remain in the hands of the operator (Terna Spa, as legally unbundled subsidiary of market Incumbent Enel Spa).

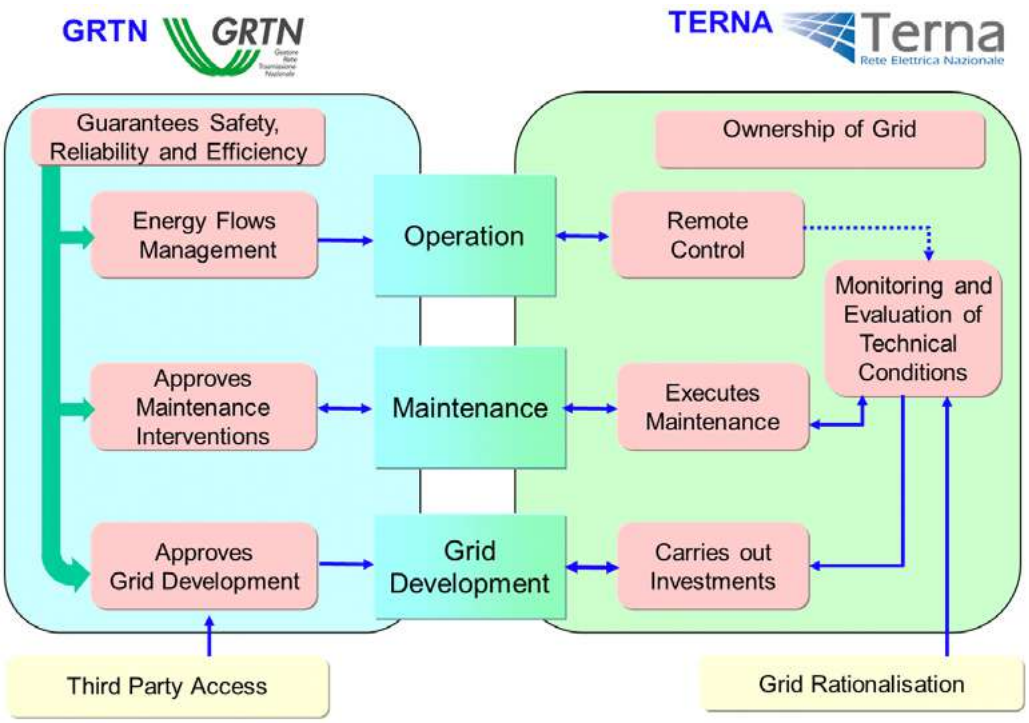


Figure 13: Unbundling of the Italian electric power system

This model showed inefficiencies and difficulties in coordinating between the network operator and the network owners, prompting the government to propose the unification of ownership and management, effectively shifting to a TSO model. This reorganization was then effectively introduced by Law 27th October 2003, N 290, and by the subsequent Decree of the President of the Council of Ministers 11th May 2004 and became operational in November 2005 with the birth of Terna – National Electricity Network Spa. [12]

The transition from an Independent System Operator (ISO) to a Transmission System Operator (TSO) followed these steps:

- The GRTN transferred assets, functions, active and passive legal relations relating to transmission and dispatching activities to Terna;
- On the date of the effectiveness of the transfer, Terna assumed the ownership and functions of GRTN and GRTN Spa and Terna Spa changed their respective social denominations;
- GRTN was required to prepare the Grid Code containing, among others, objective and non-discriminatory technical rules for access and use of the national transmission electricity network and for the delivery of the dispatch service;
- The Regulatory Authority considered the adoption of tariff-related mechanisms to promote the complete unification of the national transmission power grid.

The entity resulting from the unification between ownership and management of the transmission network is managed according to principles of neutrality and impartiality, without discrimination of users or categories of users. also provides for the integration between ownership and management of the national transmission network – From 1st July 2007, it prevents companies that carry out production, import, distribution and sale of electricity or natural gas and, in any case, each publicly controlled company, to directly or indirectly hold more than 20% of the capital of the companies that own and operate national electricity and natural gas transport networks.

The new regulatory arrangement initiated the process of unifying the national transmission network. In the following years, while Terna acquired ownership of Enel's transmission networks (with the last major third-party purchase), Enel itself reduced its stake in Terna; At present, a 29.85% share of the company's shares is

owned by the company Cassa Depositi e Prestiti Spa (financial institution controlled by the Italian Ministry of Economy and Finance), while Enel no longer holds shares.

Key figures and details of the Italian electricity market can be found in ANNEX 2.

2.7 Case Study UK: the National Grid

Objectives of Unbundling	Necessity to liberalize the market and unbundle transmission from market incumbent CEGB. Electricity Act 1989.
Transmission Model	TSO (Transmission System Operator) for the National Grid in England and Wales. ISO (Independent System Operator) in Scotland and Northern Ireland.
Outcomes	Fully independent legal entity, owning the majority transmission grid in England and Wales. Central dispatch model. Coexistence with several other transmission licenses in the UK. High degree of adaptability to local autonomies within UK and to grid expansion plans, including merchant transmission.

The United Kingdom was the first country in Europe to move the first steps towards the privatization of the electricity sector in the early 1990s. The prior market incumbent was the Central Electricity Generating Board (CEGB), whose duty was to develop and maintain an efficient, coordinated and economical system of supply of electricity to England and Wales, and for that purpose to generate or acquire supplies of electricity, with 12 area boards acting as local distribution monopolies.

CEGB had also interconnections to France and Scotland, the latter maintained its historical degree of autonomy, with two vertically integrated and geographically distinct utilities, combining generation, transmission and distribution, serving northern Scotland (and the islands) and southern and central Scotland, respectively. Northern Ireland, given its physical separation from Great Britain, was supplied by a locally integrated state-owned company, Northern Ireland Electricity.

In generation, the Electricity Act 1989, with the subsequent breakup of CEGB in 1990, divided its assets, 74 power stations into 3 companies: National Power (29,486 MW of conventional capacity), PowerGen (19,802 MW of conventional capacity), Nuclear Electric (7,973 MW of nuclear capacity). [13]

In distribution, the 12 area boards were vested as public limited companies and labelled as Regional Electricity Companies (RECs). Shortly after the privatization, almost all RECs became joint investors with Independent Power Producers (IPPs) in building new and fuel-efficient CCGT plants. Competition was also enhanced in supply, with about 5,000 consumers with more than 1 MW of demand free to choose any supplier or to buy electricity on the Electricity Pool. In 1994 the franchise limit was lowered to 100 kW, thus releasing other 45,000 eligible customers. From 1998, all customers became eligible to freely choose supplier. At the beginning of 2020, there are 14 licensed Distribution Network Operators (DNOs) in Great Britain each responsible for a distribution service area, as well as 13 Independent Distribution Network Operators (IDNOs) that mainly serve new housing and commercial developments.

The high-voltage grid and pumped-storage generation assets in England and Wales were passed to National Grid Company plc, whose initial shareholders were the RECs, later to become National Grid Transco, and now National Grid plc. In Scotland the grid was already split into two separate entities, one for southern and central Scotland and the other for northern Scotland, joined by interconnectors, and privatized in 1991. The first is owned and maintained by Scottish Power Transmission (SPT), a subsidiary of Scottish Power, and the other by Scottish Hydro Electric Transmission (SHE). Northern Ireland was liberalized between 1992 and 1993. National

Grid plc continues to be the transmission system operator for the whole grid in the island of Great Britain, with overall control powers.

The model adopted by the UK is that of ownership unbundling (TSO). At the beginning of 2020, there are 22 UK transmission licence holders. Under the UK electricity market trading regime, introduced through the British Electricity Trading Transmission Arrangements (BETTA), National Grid Electricity Transmission plc (NGET) was nominated as the sole operator of NETS – i.e. the onshore transmission network of Great Britain. Later NGET was split into two separate legal entities, with National Grid Electricity System Operator (NGESO) taking over the operation of NETS, the single Great Britain national electricity transmission system, whereas NGET remains owner of the onshore transmission network in England and Wales. SHE and SPT own the portions of the grid in their respective geographical areas in Scotland. In Northern Ireland the grid ownership belongs to Northern Ireland Electricity Limited and the TSO is System Operator for Northern Ireland (SONI), which in coordination with EirGrid, holds the Single Electricity Market operator licence for the all-island market. The remainder of transmission licence holders are primarily Offshore Transmission Owners (OFTOs), which own and operate the transmission lines between offshore generators and NETS.

Currently, the majority of National Grid shareholders is represented by institutional investors, the company is listed on the London and New York stock exchanges. The company manages electricity and gas network alike, with important assets in the US. The UK electricity transmission assets currently comprise 7,212 kilometres of overhead lines, 2,280 kilometres of underground cables and 347 substations.

2.8 Case Study France: RTE

Objectives of Unbundling	Necessity to liberalize the market and unbundle transmission from market incumbent EDF. Law 10th February 2000.
Transmission Model	ITO (Independent Transmission Operator). Initially ring fencing.
Outcomes	Partially independent entity, managing the national transmission grid, the largest in Europe. Central dispatch model. Electricity market is still one of the most concentrated in Europe. Greater level of coordination within the perimeter of EDF but lack of autonomy.

The historical electricity market incumbent in France is Electricité de France (EDF), a vertically-integrated utility that was set up after the Second World War as a way to nationalize the sector and address the delivery of electricity as a social purpose.

The European Directive 96/92/CE imposed a separation of management of the entities responsible, on the one hand, for the development of operations and, on the other hand, for the maintenance of the transmission network. Law 10th February 2000, N 1008 transposed this obligation into French law by establishing the Réseau de Transport d'Électricité (RTE) as the manager of the EDF independent network from a financial and managerial accounting point of view. Moreover, the law provided for a partial privatization, with up to 30% of the shares to be traded on the market, but internal political debate allowed only for limited trading.

The generation sector is completely open to competition, but in practice only few companies beyond EDF are involved in this business: essentially Engie (formerly GDF Suez) and Uniper (spin-off from E.ON), thus making France one of the most concentrated markets in Europe for electricity generation.

There are about 160 electricity Distribution System Operators (DSOs) in France of various sizes, called local distribution companies (ELDs). These ELDs can take different legal forms (e.g. SICAE and semi-public companies). Distribution is dominated by Enedis (formerly ERDF), which operates 95% of the electricity distribution network, representing 1.3 million kilometres of lines and 35 million customers. Six other DSOs serve more than 100,000

customers (Gérédis, SRD, SER, GEG, URM and EDF SEI) and the remaining DSOs are local companies that serve less than 100,000 customers. Between the medium and low voltages networks are some 700,000 distribution substations. The Decree of August 30, 2005 opened the market for Small and Medium enterprises as eligible customers from 1st July 2004, and for all customers (industrial, commercial and households) from 1st July 2007.

In transmission, RTE is legally entrusted as operator of the French public transmission system by the French Law of February 2000. RTE was set up on 1st July 2000, as an EDF department with independent accounts, management and finances.
The subsequent Law of 9 August 2004, N 803 led to a legal separation between RTE and EDF, in order to avoid cross subsidies between regulated and non-regulated activities. Later RTE has become, in September 2005, a public limited company with a supervisory board and a management board, a fully owned subsidiary of EDF.

On 26th January 2012, CRE (French Regulatory Authority) certified RTE under the ITO (Independent Transmission Operator) model. Revisions were carried out for RTE after changes in their shareholding (decrease of EDF's shares down to 50.1%). RTE's certification was renewed by decision on 11th January 2018. RTE covers in its activities the management:

- network infrastructure (construction, operation and maintenance);
- electrical system (forecast management of the production-consumption balance at all time intervals, from annual to real time).

In addition, RTE contributes to the definition of mechanisms to ensure consistency between the wholesale market and management constraints of the electricity system.

According to Article 9(8) Electricity Directive, the ITO model may be applied in cases where the transmission system belonged to a Vertically Integrated Undertaking (VIU).

A VIU means *an electricity undertaking or a group of electricity undertakings where the same person or the same persons are entitled, directly or indirectly, to exercise control, and where the undertaking or group of undertakings perform at least one of the functions of transmission or distribution, and at least one of the functions of generation or supply of electricity* (Article 2(21) of the Directive 2009/72/EC).

The alleged advantages of the ITO would be:

- greater ease of implementation by circumventing the question of ownership of infrastructure;
- greater coordination between the system manager, sponsor of network developments and the infrastructure manager supposed to ensure project management.

Currently, the shareholders of RTE are EDF (50.1%), Caisse des Dépôts et Consignations (29.9%), CNP Assurances (20%). The network managed by RTE is the largest in Europe, with 105,857 km of lines and 2,770 substations.

2.9 Case Study Spain: REE

Objectives of Unbundling	Necessity to liberalize the market and unbundle transmission from market incumbent Instituto Nacional de Industria. Law 27th November 1997.
Transmission Model	TSO (Transmission System Operator). Initially ring fencing from 1985
Outcomes	Fully independent legal entity, sole system and transmission system operator Central dispatch model. Public company, with expansion plans abroad (Red Electrica Internacional), and activities spanning from regulated to non-regulated business. Wholesale market is unified with Portugal.

In Spain the process of unbundling followed a different trajectory compared to other main European markets: Red Eléctrica de España (REE) was already founded in 1985, way before the EU-inspired privatization process, in application of the Law 26th December N 49, 1984. It was the first company in the world dedicated exclusively to the transport and operation of the electrical system.

Law 27th November 1997, N 54 of the electricity sector established the different categories of participant to the market, and confirmed the role of REE, and Law 4th July 2007, N 17 which amended this legislation to adapt it to European Directive 2003/54/EC, ratified REE as the sole carrier and operator of the Spanish electrical system. The new Law 26th December 2013, N 24 (Electricity Act) establishing the main piece of legislation set the rights and duties of operators and authorities, which authorizations and permits are required, the legal framework for activities and the applicable offences and sanctions.

The generation sector is open to competition, but dominated by few players: Endesa, Iberdrola, Gas Natural Fenosa, Hidroeléctrica del Cantábrico and E.On España.

Regarding distribution, key players are Endesa Distribución Eléctrica, S.L.; Iberdrola Distribución Eléctrica, S.A.; Unión Fenosa Distribución, S.A.; Hidrocantábrico Distribución Eléctrica, S.A.; and E.ON Distribución, S.L. There are also smaller distribution companies that are undertakings or co-operatives of consumers and users (cooperativas de consumidores y usuarios) that distribute electricity to end consumers. Distribution is arranged according to a local monopoly scheme.

REE is the system operator and the sole and exclusive transmission system operator in Spain. Unbundling was carried out in line with the 2009 Directive and Spanish implementing regulations opted for the Transmission System Operator (TSO) regime. The alternative Independent System Operator (ISO) regime was not deemed necessary because the high voltage power transmission grid (except for very few facilities that are in fact part of the distribution grid) already belonged to REE. In practice, ownership unbundling has been in place for the high voltage transmission network in Spain since 2010.

REE was certified as TSO by the National Markets and Competition Commission on 19th July 2012.

REE must carry out the following key functions to balance the supply and demand of electricity in Spain:

- Forecast the short and medium-term generation capacity of the system to determine an electricity generation programme and analyse whether to introduce more generation capacity;
- Anticipate the short and medium-term demand for electricity and use of generation equipment, particularly hydroelectric reserves;
- Schedule the functioning of generation plants along with the information provided by market operator OMI Polo Español and private parties that have bilateral agreements for the direct supply of electricity;
- Order generation plants to carry out the adjustments necessary to respond to a potential change in electricity consumption or generation that causes an imbalance in the supply of the electricity programme.

The network managed by REE comprises 44,207 km of lines and 5,865 substations. The shareholders of the company are made up of a 20% ownership of the Sociedad Estatal de Participaciones Industriales (SEPI) and a remaining 80% publicly traded

2.10 Case Study Brazil

Objectives of Unbundling	Need to open the market and adapt it to the continental size of the country. Laws 10,847 and 10,848, dated March 15th 2004.
Transmission Model	Several transmission companies (156 as February 2020) operating under a revenue cap mechanism for 30 years, with expansion carried out through periodical auctions.
Outcomes	Extensive transmission network implemented, covering a geographical distance equivalent to Europe. Central dispatch model. Coexistence of two wholesale markets (regulated and not regulated).

In 2019 the Brazilian installed capacity was 168.3 GW (Table 2) and generated near 593.6 TWh in 2019, this is near 58% of the generation of all South America.

The territorial extension is 8,514,876 km² (6th largest country after Russia, Antarctica, China, USA and Canada) with a population of more than 209 million people. The GDP in 2019 amounted USD 1.86 trillion and the GDP per capita was USD 8,959.

Main Sources	Installed Capacity (MW)	%	No. of Power Plants
Hydro	114,116	67.8%	1,189
Thermal	34,466	20.5%	2,802
Nuclear	1,990	1.2%	
Wind	15,273	9.1%	273
Solar	2,445	1.5%	25
Total	**168,290**	**100%**	**4,209**

Table 2: Installed capacity of the Brazilian generation system in 2019

The main characteristics of the system are:

- Long distances;
- Regional or Area different characteristics;
- Electric restrictions (Technical and stability limits);
- Predominant Hydroelectric System.

Brazilian markets began to operate in 1997 with a competitive structure in wholesale and retail. Nevertheless, the model, like many early models, suffered some drawbacks in the practice. Generally, they are due to the flaws in the design and the government intervention to control the tariffs for the final consumers according to values that are considered "acceptable" by the government.

The problems detected in the first model according to the Ministry of Energy of Brazil in 2003 were the following:

- Black-out in 1999;
- Black-out in 2001;
- Electricity rationing in 2001-2002;
- Economic and financial crisis of the companies in the sector in 2001-2003;
- Pendulum effect: need to ration energy;
- Need to include 12 million Brazilians access to electricity;

- Previous Regulatory Framework:
  - Instability;
  - Lack of energy;
  - rationing of 25% of the market.
- During the economic crisis the Auction for Power Purchase yielded a high premium: 3090%, near USD 2,1 Billions.

Finally, another problem detected in the model was the self-dealing: distribution companies could buy energy from the generation companies belonging to the same holding, direct or indirectly. The self-dealing increased the prices to the final consumer near 30%, according the Ministry of Energy of Brazil.

Then, the new structure proposed was aimed to:

- Reasonable tariff:
  - End of «self-dealing»;
  - Efficient mechanism for promoting energy investments -> Auctions;
- Security of supply:
  - All contracts should be supported by physical production capacity;
  - All consumers must be fully covered by electricity contracts;
  - Creation of the Electricity Industry Monitoring Committee (CMSE);
- Risk reduction for the Investor:
  - Long-term contracts (30 years), with the existence of a spot market;
  - Need for prior environmental licences;
- Restructuring of the energy planning;
- Promoting social integration -> Universal use and access to energy for more than 12 million people.

For the main key figures of this market and the complete case description, please see ANNEX 3.

2.11 Case Study Argentina

Objectives of Unbundling	Need to open the market and adapt it to the continental size of the country. Laws 10,847 and 10,848, dated March 15th 2004.
Transmission Model	Several transmission companies (8 in 2020). Transmission of the Argentinian Interconnected System (Sistema Argentino de Interconxion -SADI). This is a monopolistic activity remunerated via tariffs regulatory approved. Transmission companies are not allowed to generate or distribute electricity and are not allowed to have any share in any generation and/or distribution company.
Outcomes	Steady expansion of the transmission grid. Central dispatch model.

Argentinian territorial extension is 2,736,690 km² (9th largest country in the world) with a population of more than 45 million people. The GDP in 2019 amounted USD 445 billion and the GDP per capita was USD 8,959.

Regarding the electricity sector, the Argentinian installed capacity in 2019 was 39.7 GW (Table 3), for a net generation of 131.2 TWh and a peak demand of 26.1 GW.

Argentina has 34,919 km of transmission lines in the Interconnected System (SADI) and an installed a transformation capacity of 43.2 GVA.

Main Sources	Installed Capacity (MW)	%
Hydro	10,812	27.2%
Thermal	24,547	61.8%
Nuclear	1,755	4.4%
Renewables	2,590	6.5%
Total	**39,704**	**100%**

Table 3: Installed capacity of the Argentinian generation system in 2019

The main characteristics of the system are:

- Long distances;
- Concentrated demand in Buenos Aires Province;
- Different regional characteristics;
- Electric restrictions (Technical and stability limits) due to long-distance transmission lines from the generation to the concentrated load.

In Argentina, the electric sector, originally vertically integrated, was separated into its three stages: generation, transmission and distribution, with well-differentiated structures.

Due to its intrinsic and natural characteristics, the generation sector was conceived as a competing market, while transmission and distribution, being natural monopolies, were given in concession and subjected to regulation by incentives and results.

The Argentine power sector was one of the most competitive and deregulated in South America until 2001. The expansion mechanism at the beginning was purely based on market rules. If the market foresaw high prices (high marginal costs), then companies decided to invest in the sector autonomously. The expansion was carried out by market forces until 2001, when the big crisis occurred in the country and the end-user tariffs were frozen and the spot price capped by the Ministry.

In order to mitigate the losses of the generation companies, who bought the fuel at international market prices, the difference between the spot price and the regulatory cap, were accrued in a special Fund to pay the generation companies in the future.

Due to government intervention, the investments in the energy sector were frozen and this initially successful market took advantage of the overcapacity installed by competitive forces to avoid rationing. The government intervention was again required in order to create parallel market environments to foster investments, but with poor success.

In 2004, the Kirchner government created a national company named Energía Argentina Sociedad Anónima (ENARSA), a company managed by the national state of Argentina for the exploitation and commercialization of oil and natural gas, as well as for the generation, transmission and commercialization of electricity. This was a consequence of poor or null investments of the private sector and the several government interventions in the economy and the electricity sector.

In August 2006, the Argentine government officially announced the decision to reactivate nuclear activity, which included the establishment of a nuclear program for the short and medium term. Because of lack of investments, the government decided in 2006 to launch the Energy Plus Program, to stimulate private investors to build and expand medium and high-power thermal power plants, guaranteeing the purchase of electricity to be supplied at a price above the spot price cap, and passed the Law N ° 26,190/06 implementing the renewable (GENREN) Program.

Accelerated economic growth imposed the need to quickly expand the offer again. As of 2007, the Argentine electricity market recovered the path of growth interrupted by the 2001 crisis, supplying the needs of a growing economy. A strong investment program was implemented public articulated with the private sector for the new economic model.

Nevertheless, the Energy Plus program did not give the expected results from the public and private sectors. The lack of investments forced the government to push the private sector for investment. The government decided to invest the accrued amount in the special Fund in new generation capacity on behalf of the companies. In 2008, Siemens began the construction of two thermal power plants that provided a capacity of 1,660 MW, approximately 10% of the energy available at that time. These plants required an investment of USD 1,097 million accrued in the Fund to pay the difference between the spot price and the regulated cap. This represented an unprecedent intervention of the government in both the market and private funds.

Nowadays, the government is performing the expansion via open public tenders. Tenders delivering renewable generation capacity are also competitive and are aimed at complying with the diversification of the energy matrix through the contribution of renewable energy that replaces the thermal generation and consequently modifies the variable costs incurred by generators.

For the main key figures of this market and the complete case description, please see ANNEX 4.

2.12 Case Study: India

Objectives of Unbundling	Necessity to liberalize the market and unbundle transmission from market incumbent. Central Electricity Act of 2003.
Transmission Model	Interstate and state-based transmission companies. Transmission is carried out under a license regime.
Outcomes	Regional dispatch model, divided into 5 main areas of operation. Heavy reliance on PPAs. Wholesale market is currently under consideration.

India envisages a decentralized market-based approach where many players, both public and private, are involved in generation, transmission, trading, and distribution. The Central Electricity Act (CER) of 2003 introduced the concept of market mechanism on the different phases of the supply chain of electricity in India. The main objectives of the Act are to (i) protect the interest of consumers (ii) promote competition (iii) ensure electricity to all and (iv) enforce transparency.

The Central Energy Authority (CEA) is the statutory body that advises Government of India on establishing policies, safety requirements and technical standards. The Government of India (in consultation with the single states and the CEA) sets policies (such National Electricity Policy) as a guideline for the Central Electricity Regulatory Commission (CERC) and the State Electricity Regulatory Commissions (SERCs) to steer their regulation assessment.

India adopted a delicensed regime, where generation (except hydropower) is completely open to competition, with about 45% of capacity in the hands of private players, while essentially three activities operate under a license regime: transmission, distribution and trading of electricity (purchase of electricity for resale).

As in 2019, in India there are 600+ generating stations, 30+ transmission licensees, 70 distribution licensees, 2 power exchanges, 40 trading licensees, load dispatchers at the centre, in each of the five regions and in each of the 29 States. The total installed generation capacity is about 350 GW. Thermal dominates the generation, contributing 64% of the total share (55% coal), whereas VREs (solar and wind) and hydro contribute 21% and 13%. Nuclear makes the remaining 2%. The Government of India has set a target of additional 175 GW from renewable energy sources by 2022, as follows: 100 GW from solar energy, 60 GW from wind, 10 GW from biopower and 5 GW from small hydropower.

Power generation in India is dominated by long-term PPAs. For thermal and hydro power projects, long-term power is procured either via a negotiated procedure or a competitive procedure. Under the former, a distribution company's power procurement tariff is determined by the regulatory commission, by considering various factors such as return on equity, interest on loans and working capital, depreciation, O&M expenses and renovation allowances. Under the latter, tariffs are set via a competitive bidding process and procurement is ruled by standard bid documents including PPAs, which are issued by the government. Another widely adopted mode of installing generation is through captive power plants, generally owned by an industrial player, where the captive power user owns a minimum of 26% of such power plant and consumes at least 51% of the annual aggregate electricity generated by such power plant.

Guidelines have been introduced for medium-term power procurement (i.e. 1-5 years) of electricity from coal, gas or hydro-based power stations on a finance, own and operate basis. For VREs projects, power is typically procured via contracts at a determined feed-in tariff or at a tariff individuated through competitive bidding process. All distribution utilities, captive-power users and open-access consumers are obliged to procure a fixed amount of electricity from renewable energy sources. The regulatory framework gradually seeks to incentivise renewable energy, with favourable tariff regimes established by SERCs. Starting from 2017, solar and wind power projects were integrated with tariff based competitive bidding guidelines for the procurement of power. The feed in tariff regime continues to be applicable for solar and wind plants with a capacity lower than 5 MW and 25 MW respectively. Benefits such as accelerated depreciation for wind power projects, and exemptions from payment of electricity duties are also provided to renewable power generators.

The major licensed actors undertaking transmission activity include Power Grid Corporation of India Limited, Adani Transmission Limited and Sterlite Power Transmission Limited. In addition to these companies, each state has its own state transmission utility. No transmission licence is required for the construction of dedicated transmission lines, such as electric supply lines for point-to-point transmission that connect generating stations or load centres to the main grid.

The major distribution and supply companies in India include CESC Limited, Tata Power Delhi Distribution Limited, Adani Electricity Mumbai Limited, and BSES Rajdhani Power Limited. Many states have state-owned power distribution companies. There are two power trading platforms in India: Indian Energy Exchange and Power Exchange of India Limited.

For optimum scheduling and despatch of electricity, load despatch centres are established at national, regional and state level. The National Load Despatch Centre (Power System Operation Corporation Limited – POSOCO) is responsible for ensuring the integrated operation of the national power system. It supervises 5 Regional Load Despatch Centres (RLDCs) and the underlying State Load Despatch Centres (SLDCs). There is the necessity for coordination among a generating company, state load dispatch centres and regional load dispatch centres. The generating company declares its capacity for the next day and informs the concerned regional load dispatch centre. The regional load dispatch centre validates the capacity and other information and informs the concerned state load dispatch centre.

Most of the generating companies sign 25-year PPAs with the distribution companies. As in 2019, about 87% of volume transactions take place via these long-term contracts, while the remaining are negotiated through bilateral contracts, power exchanges and demand side management.

The map below displays the partition into the five regional grids in India [14]

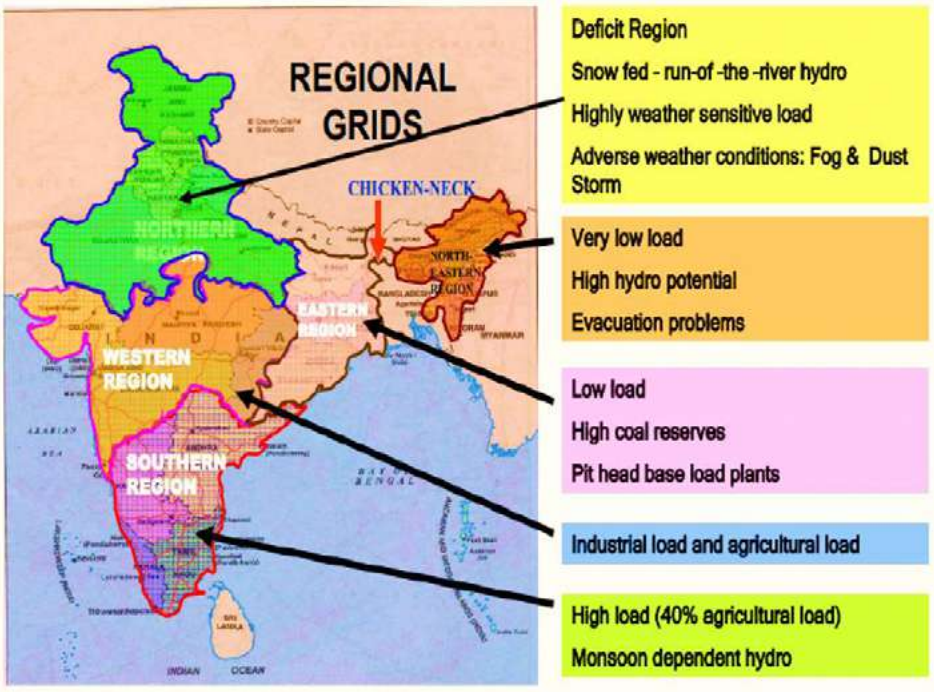


Figure 14: Regional Grids in India

The energy sector is facing multiple issues like fuel shortages, cost escalations and unviable long-term PPAs. Several state-owned distribution companies are in financial distress. India also has approximately 66 GW of financially stressed power assets (including largely coal, gas, and hydro), also due to delayed payments by distribution companies and the current system of power procurement. There is no effective transmission of price signals and/or merit order effect, so that relatively cheaper generation might not be always able to produce over more expensive plants.

Also, the necessity to tackle the illiquidity of the market, to eliminate cross-subsidies (such as in the agriculture sector) and to pave the way for 100% rural electrification as well as deployment of VRE, is prompting several proposed market reforms [15], such as:

- A day-ahead market to enhance liquidity, communicate correct price signals and help least-cost generators to sell their power across state lines to distribution companies that could source unmet power needs outside their existing generation portfolio;
- A real-time market to ensure timely dispatch of scheduled power from generator to distribution company, also allowing generators to sell surplus power that is not purchased to another entity somewhere else in the country;
- A sound ancillary services mechanism to manage an increasing amount of VRE. Synchronizing these services with real-time day-ahead markets would ideally allow additional power producers to optimally dispatch their resources;
- A shift of cross-subsidies from the electric system to general taxation; and the lowering of costs for manufacturers without a privileged access to a PPA, that would boost electricity demand and improve capacity utilization;
- A reduction of theft in transmission and distribution, currently averaging 20%.

3. REGULATION OF TRANSMISSION AND ANCILLARY SERVICES

3.1 Regulation and Third-Party Access

Electricity requires a fixed network to deliver its services and it can be considered a natural monopoly that could preclude efficient competition, conferring potentially exploitative powers to its owner. At the same time, because this network needs access to rights of way which requires community or government approval, the durable, costly and irrecoverable nature of the network raises the fear that curbs on prices will prevent the investor recovering a fair return on his investment. Therefore, regulation evolved to balance the interests of investors, those of generators and those of consumers. Where a satisfactory balance can be achieved, network operators can remain under regulated private ownership. If private investors lack confidence that they can earn an acceptable return, the outcome is public ownership.

Hence, whenever the network operator is privatized, the task of the regulator is to create a harmonious set of rules that allows the pursuit of these three objectives:

1. The provision of a high-quality service at an efficient cost;
2. The maintenance and development of infrastructures, promoting innovations;
3. Non-discriminatory third-party access (TPA).

Regarding the first objective, effective regulation must first be able to promote cost efficiency without affecting the quality of the service. Subsequently, regulation must provide mechanisms to transfer to consumers the benefits deriving from higher levels of efficiency and quality.

Regarding the second objective, the regulator must guarantee an adequate return on investments by reducing the risk of the regulated service provider, while avoiding unnecessary investments.

The third and final objective is the third-party access. Non-discriminatory third-party access to transportation infrastructures in electricity - transmission and distribution networks - is essential for open and effective competition in wholesale and retail electricity markets. In a nutshell, TPA requires network operator to:

- apply transparent and non-discriminatory technical rules to all parties willing to connect to the grid (meaning that no party can be denied access insofar it respects the technical standards set in the Grid Code);
- charge a transparent and non-discriminatory tariff for connection and use of the grid, a tariff set by the regulator.

A major consequence of TPA is that a third party compliant to all technical requirements cannot be denied access to the grid because of constraints on the grid. The grid owner will have to connect the third party and solve any constraint.

Clearly, the presence of these three objectives leads to the emergence of numerous trade-offs and consequent possible distortions.

The main tool with which the regulator (or national regulatory authority – NRA) tries to pursue the various objectives while considering the various constraints is the tariff instrument: it is, in fact, the regulator's task to define the allowed revenues, which should allow attaining a certain level of quality, while promoting efficient spending and innovation, without discriminating market participants.

Any tariff regulation can be measured and analysed along these five criteria.



Figure 15: Tariff regulation criteria

In the next paragraphs, we will discuss the main principles of tariff design.

3.2 Principles of tariff regulation

Tariff regulation has three main steps:

1. Determination of the return on the transmission activity. What do we pay for?
2. Determination of who is going to pay. Who is paying to guarantee those returns?
3. Determination of how the returns are charged to those who have to pay for the service.

The figure below summarizes the main elements.

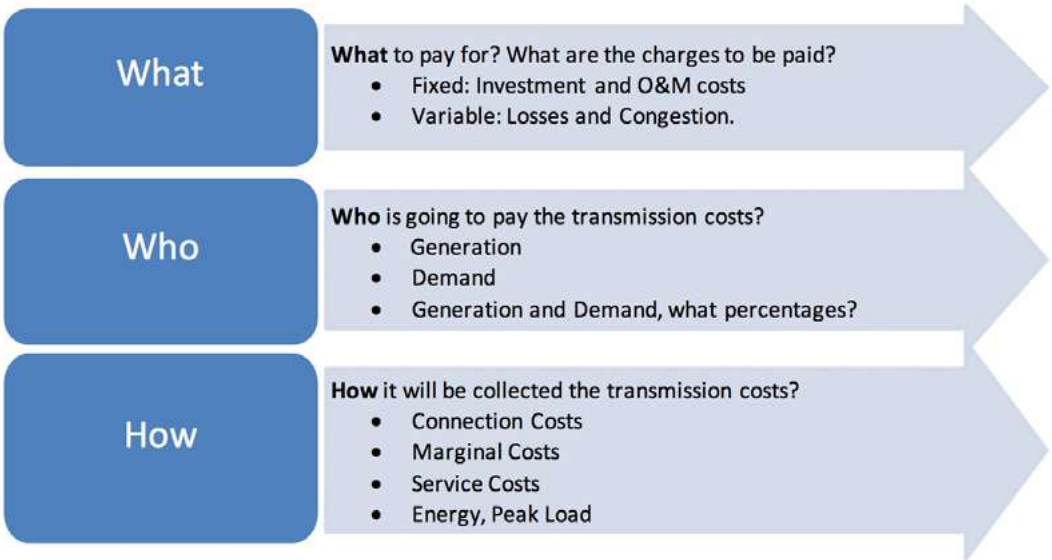


Figure 16: Principles of tariff regulation

3.2.1 What to pay

When it comes to the first element, the what can be remunerated is summarized in the graph below.

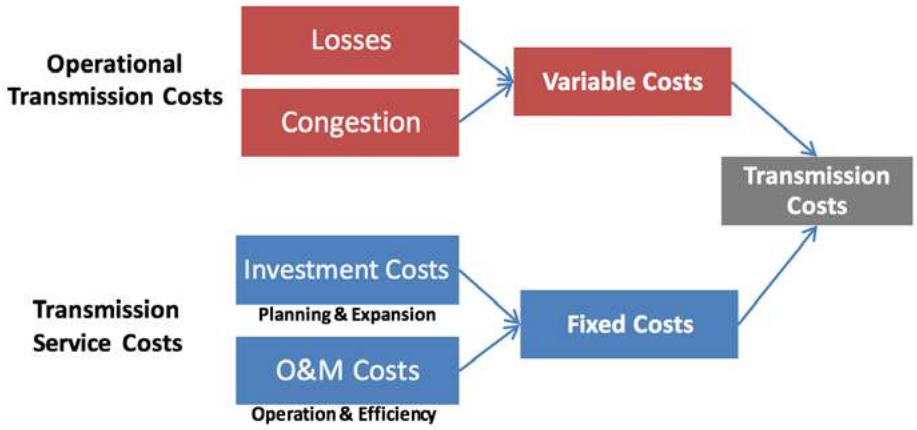


Figure 17: What can be remunerated

Broadly speaking, there are two families of revenue-setting regulation: cost-based regulation and incentive-based regulation.

In the past, cost-based regulation approaches (rate-of-return regulation or cost-plus regulation) were widely used for tariff regulation purposes. The rate-of-return model guarantees the regulated company a certain pre-defined rate of return on its fixed and variable costs. Another approach is cost-plus regulation, in which a pre-defined profit margin is added to the costs of the company. Evidently, the regulated company has no incentive to minimise its costs under a cost-based regulation framework, because it can increase its profits by simply expanding the asset or cost base. Under cost-plus regulation a company may have an incentive to signal incorrect costs to the regulator or to even opt for wasting resources in order to increase the cost base ("gold-plating").

As a response to the major drawbacks of the cost-based regulation, incentive-based approaches to tariff regulation were first developed in Great Britain (GB) and are currently applied in many other countries.

Incentive-based regulation can be characterised by the use of financial rewards and penalties to induce the regulated company to achieve the desired goals (generally in form of an efficient cost base) whereby the company is allowed some discretion in how to achieve them. Rewards and penalties replace a 'command and control' form of regulation and provide incentives to the company to achieve the goals by allowing it to share the 'extra profit' in case it over-fulfils the targets set by the regulator. In general, incentive-based regulation aims at cost control – so that grid users later could benefit from lower costs in a quantitative way through lower tariffs in the future.

Each of these two forms of regulation be a special solution to the general problem of designing a system of regulation in which the regulator has imperfect information about the costs and opportunities facing the regulated utility. The regulator specifies rules that determine the utility's allowable revenue, R, in which

$$R = b\bar{R} + (1 - b)C$$

where $\bar{R}$ is independent of the utility's total cost, C. The term b is the power of the regulatory incentive scheme, with b = 0 (the lowest power) corresponding to cost-of-service or rate-of-return regulation, and b = 1 to a high-powered scheme such as price regulation in which the utility receives all the benefit of cost reduction.

Depending on the level of b, different regulatory schemes are obtained and, of course, it is also possible to design regulations that touch the two extremes. If, in fact, all costs are remunerated, it falls within the scope of a rate of return regulation; on the other hand, if all costs are efficient, it falls under a revenue cap regulation.

Clearly, the larger the number of cost items subject to efficiency, the greater the incentive to reduce costs even beyond any regulatory level of efficiency. In such a regulatory scheme, the operator will bear a greater risk in the event of an uncontrollable shock.

Conversely, the larger the number of items included in the allowed costs, the higher the return on investments, compared to a lower risk borne by the operator in the event of uncontrollable shocks.

In European countries, it is customary to adopt building-block approaches, where some costs, usually the operational ones – OPEX, are subject to efficiency, while the fixed costs – CAPEX, are subject to a rate of return regulation. For example, this is the case for Belgium, France and Italy.

This approach seeks to balance the risks and benefits associated with the two objectives: in particular, the recognition of an integral remuneration of capital costs has the objective of preventing the company from being too exposed to exogenous shocks.

Germany, the Netherlands and the UK are closer to the concept of pure revenue-cap regulation, where all incurred costs (TOTEX), including the cost of existing assets, are subject to efficiency improvement. New investments can be excluded from these efficiency rules, if they are approved in advance by the regulator.

While pushing more on the concept of efficiency, in this case the regulators try to mitigate the risk on capital costs both by excluding new investments from automatic efficiency logics, and by agreeing ex-ante with the operator CAPEX and OPEX necessary to achieve satisfactory levels of quality.

The meaning of capital remuneration differs slightly under the revenue-cap approach with respect to the rate-of-return approach. In the former, capital remuneration is used to define the level of revenues recognized at the beginning of each regulatory period; revenues will then be subject to efficiency. In the latter, capital remuneration represents the pure expected return of the assets.

In both cases, the regulator must define a level of return on invested capital that is able to allow the achievement of the second objective, that is to attract capital that allows the stability and quality of the assets, ensuring a constant flow of investments and promoting the necessary development of innovation.

Obviously, the regulator must avoid both the risk of under-investment, determined by a too low remuneration rate, and the risk of gold-plating, linked to a too generous remuneration rate.

In defining the return on capital, each regulator must necessarily define its approach to some fundamental questions:

1. Is a regulated activity an investment or a set of investments?
2. What kind of investments will be made? Replacement investments and/or innovative investments?
3. If it is a set of investments, do they have different risks and therefore different expected returns?
4. Should the regulatory approach be forward looking or backward looking?

Depending on the basic decisions on these strategic issues, the regulator will decide how to set the most appropriate capital remuneration.

3.2.1.1 Rate-of-return regulation

RoR is used to determine a stream of revenues that allows recovering the investment. Each year, the utility can recover part of its capital expenditures (CAPEX) and its operating expenditures (OPEX).

Revenues are then defined as the sum of OPEX, charges, amortization and capital remuneration. Capital remuneration is obtained by multiplying all assets' value (that is the sum of existing assets and capital additions) by a defined interest rate.

Below, we show a graphical representation of this revenue setting mechanism.

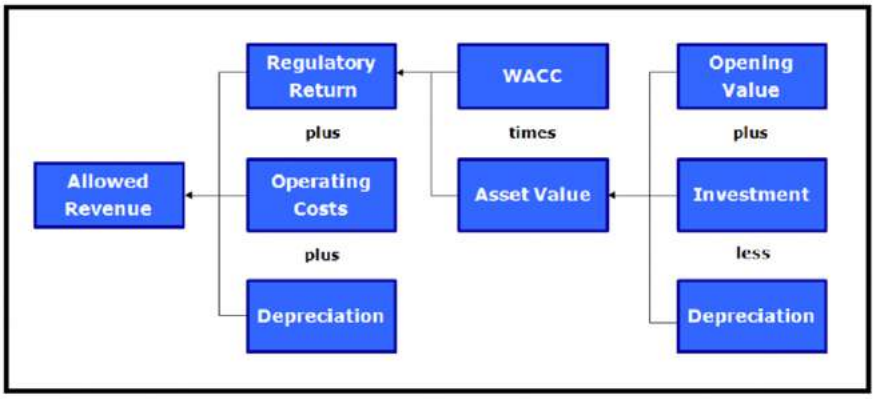


Figure 18: Regulated revenues.

Hence, within this regulatory framework, each year the regulated utility has to provide all its accounting data to the regulator, in order to allow him to set the revenues for the subsequent year.

3.2.1.2 Revenue-cap (price-cap) regulation

Price-cap regulation adjusts the operator's prices according to the price cap index that reflects the overall rate of inflation in the economy, the ability of the operator to gain efficiencies relative to the average firm in the economy, and the inflation in the operator's input prices relative to the average firm in the economy. Revenue cap regulation attempts to do the same thing, but for revenue rather than prices.

Under this regulatory framework, the regulator has to set an initial R (or P) and then an adjustment formula. Hence, contrary to any cost-plus approach, there is no need to review annually OPEX and CAPEX.

Some regulators choose a general measure of inflation, such as a gross national product price index. In this case, the X-factor reflects the difference between the operator and the average firm in the economy with respect to the operator's ability to improve its productivity and the effect of inflation on the operator's input costs. Other regulators choose a retail (or producer) price index. In these cases, the X-factor represents the difference between the operator and the average retail (or wholesale) firm. Lastly, some regulators construct price indices of operator inputs. In these cases, the X-factor reflects productivity changes of the operator.

3.2.1.3 Rate-of-return vs revenue-cap: some considerations

The main difference between rate-of-return and price regulation is that the former is based on actual costs, whilst in principle the latter is based on projected efficient costs, that is, costs that the utility should be able to achieve (possibly after some reorganization) if it were efficient.

Where there are many comparable utilities (for instance distribution companies within the same country), the regulator can estimate the efficient frontier cost function using information about costs from all companies,

and can then determine how far from the frontier any individual utility is, and how rapidly it might be expected to reach the frontier. Yardstick regulation in which the target for one utility depends of the performance of other comparable utilities has the advantage of using relevant cost information while preserving incentives for cost reduction.

Where there is only one utility, such as in the case of transmission networks, such yardstick regulation is not directly possible (though international benchmarks are sought and used). Instead, the regulator may need to employ consultants to assess the efficient level of costs and investment required to meet performance standards.

In the regulatory practice, this difference is less of an issue. Most tariff regulations around the world have a predefined duration, after which there is a review. At each review, the regulator has to reset the price control for a set period, typically 4-5 years, based on information about operating costs, investment plans, and the Regulatory Asset Base (RAB).

The acts and laws under which each utility is regulated require that the utility be allowed to earn a return sufficient to attract funds for future investment. The regulators make essentially the same calculation any investor would do in order to determine the cost of capital for an enterprise of comparable risk, based on market evidence.

In case of a price/revenue-cap regulation, at each review, the regulator has to reset the price index and the new value of X. The trajectory of prices implied by the initial price level and value of X must be such as to generate a revenue stream leading to a terminal asset value (equal to the opening value less depreciation plus investment) whose present discounted value at the allowed rate of return is at least equal to the opening value of the RAB, assuming that the operating costs and investment are efficiently undertaken. Hence, at least at each review, the regulator requires the utility to submit its accounting books in order to determine the initial R (or P), similarly to what a regulator would do under the rate-of-return framework.

3.2.2 Who is going to pay for it? How is he going to pay for it?

Once revenues are set, another topic that the regulator has to define is who is going to pay the transmission charges. It is important to determine if the transmission charges will be paid by the following market participants:

- Generators;
- Demand (Distribution Companies and Big Consumers);
- Both.

Moreover, the regulator has to determine which unit of measure will represent the basis of the transmission tariff:

- Energy;
- Annual Peak Demand;
- Monthly Peak Demand;
- Use of the lines (Influence Area).

Regarding how the transmission charges or cost will be paid, there are the following methodological options:

1. Proportional Division methods: they allocate the total cost of a transmission system among participants based on proportions of Peak Demand or Transmitted Power. Belonging to this group are the pro-rata techniques (Postage Stamp);
2. Incremental methods: they calculate the difference between the costs in the presence and absence of a bilateral transaction, trying to determine its responsibility over the costs of a transmission system. This modelling allows to consider long or short-term costs (i.e. investments in reinforcements and network expansions);
3. Marginal methods: they valuate the change in the transmission cost caused by the marginal variation of

the active power injection into a bus. The growing interest in marginal procedures has been justified by their ability to promote an allocation consistent with the efficient use of the network. The economic signals provided by the marginal tariffs have justified the application of such methods in several countries.

Apart from network usage and system operation charges, consumers and generators might be subject to specific connection charges. These charges can be:

- "Shallow", whereby the developer of generation or consumption project pays simply for the cost of the equipment to make the physical connection to the grid network at the chosen connection voltage. The developer pays no contribution towards any upstream network reinforcements that are needed because of the generator/load being connected;
- "Deep", whereby the developer of generation or consumption project pays for all costs associated with the connection, including all network reinforcement costs.

3.3 Regulatory practice: the EU experience

Most European countries use incentive-based regulation in the form of a revenue cap. The table below contains a summary of the type of regulation adopted in different European countries. In general, most countries use a mixture of a cap regulation (revenue or price) and a guaranteed rate of return. A revenue cap regulation can thereby be seen as an indirect price cap regulation, where the revenue is the result of price multiplied with the quantity. Nowadays, a cost-plus regulation is an exception and is only used in a few countries.

Electricity transmission is regulated by incentive methods in 19 out of 25 countries. Revenue caps are set by 15 NRAs.

Country	What regulatory system is in place? (Cost-plus/ Rate-of-Return Regulation, Incentive-based Regulation [Price-Cap/ Revenue-Cap, mixture])
AT	Price Cap
BE	Revenue cap
CZ	Revenue Cap
DE	Revenue Cap – incentive based
DK	Revenue Cap
EE	Rate-of-Return
ES	Revenue Cap
FI	Revenue Cap
FR	Revenue Cap, incentive based with pass through
GB	Revenue Cap based on Rate-of-Return with Incentive-based Regulation
GR	Revenue Cap
HR	Revenue Cap
HU	Incentive-based Regulation (mixture of price cap, revenue cap and quality regulation)
IE	Revenue Cap based on Rate-of-Return with Incentive-based Regulation
IT	Combined model of Price Cap (OPEX) and Rate-of-Return (CAPEX)
LT	Revenue Cap
LU	Revenue Cap
LV	Cost-plus/Rate of return
NL	Price Cap
PL	Cost of service (with elements of revenue cap)
PT	Combined model of price cap (OPEX) and rate of return (CAPEX)
RO	Price Cap
SE	Revenue Cap
SI	Revenue Cap

Table 4: Type of regulation. Source: CEER, 2020 [16].

The table below shows which costs are included in the network tariff. C indicates if a given cost item is included in the calculation of the Unit Transmission Tariff. C/B and B/C indicate a given activity that can be a cost or a source of revenue for the TSO. N indicates a cost item that is not considered in the calculation of the Unit Transmission Tariff. Those marked as "estimated" indicate that the cost item is not invoiced by the TSO and estimated values are provided for comparability purposes by ENTSO-E.

	Infrastructure				System services								Losses
	OPEX (except system-services,losses and ITC)	Depre-ciation	Return on capital invested	ITC	Primary reserve	Secondary reserve	Tertiary reserve	Congestion management (internal)	Congestion management (cross border)	Black -Start	Voltage Control Reactive Power	System Balancing	
Albania	C	C	C	C	N	C	C	N	B/C (estimated)	N	N	N	C
Austria	C	C	C	B/C	N	C	N	C	C	C	C	N	C
Belgium	C	C	C	B/C	C	C/B	C/B	C	C/B	C	C	N	C (estimated)
Bosnia & Herzegovina	C	C	C	B/C	C	C	C	N	B/C	C	N	C	C
Bulgaria	C	C	C	C/B	C	C	N	N	B/C	C	C	N	C
Croatia	C	C	C	B/C (estimated)	N	C	C	N	C	C	C	C/B	C
Cyprus	C	C	C	N	C	C	C	N	N	C	C	N	C
Czech Rep.	C	C	C	C/B	C	C	C	C	C	C	C	C/B	C
Denmark	C (estimated)	C (estimated)	C (estimated)	B/C (estimated)	C (estimated)	C (estimated)	C (estimated)	C/B (estimated)	B/C (estimated)	C (estimated)	C (estimated)	B/C (estimated)	C (estimated)
Estonia	C	C	C	B/C	N	N	C	N	C	C	C	N	C
Finland	C	C	C	C/B	N	N	C	C	C	C	C	C	C
France	C	C	C	C	C	C	C	C	C	C	C	N	C
Germany	C/B	C	C	C/B	C	C	C	C	C	C	C	N	C
Great Britain	C	C	C	C/B	C	C	C	C	C	C	C	C	N
Greece	C	C	C	C/B	C (estimated)	C (estimated)	N	N	B/C	C (estimated)	N	N	C (estimated)
Hungary	C	C	C	C/B	C	C	C	N	B/C	C	C	B/C	C
Iceland	C	C	C	N	C	C	C	N	N	C	C	C	C
Ireland	C	C	C	C	C	C	C	C	C	C	C	C	C
Italy	C	C	C	N	C	C	C	B/C	B/C	C	C	C	C (estimated)
Latvia	C	C	C	C/B	C	C	C	N	N	C	C	C/B	C
Lithuania	C/B	C	C	B/C	N	C	C	N	N	C	C/B (estimated)	N	C
Luxembourg	C	C	C	C	C	C	C	C	C	C	C	C	C
North Macedonia	C	C	C	B/C	N	C	C	N	B/C	C	C	C/B (estimated)	C
Montenegro	C	C	C	B/C	N	C	C	N	B/C	N	N	C	C
Netherlands	C	C	C	B/C	C	C	C	C	B/C	C	C	B/C	C
Northern Ireland	C	C	C	C	C	C	C	C	C	C	C	N	C
Norway	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	B/C (estimated)	B/C (estimated)	C (estimated)	C (estimated)	N	C (estimated)
Poland	C	C	C	N	C	C	C	C	B/C	C	C	C	C
Portugal	C	C	C	C/B	N	C/B (estimated)	N	N	B/C	N	N	N	C (estimated)
Romania	C (estimated)	C (estimated)	C (estimated)	C/B (estimated)	N	C (estimated)	C (estimated)	C (estimated)	N	N	C (estimated)	N	C (estimated)
Serbia	C	C	C	B/C	C	C	C	C	C/B	C	C	C	C
Slovakia	C	C	C	B/C	C	C	C	C	N	C	C	N	C
Slovenia	C/B	C/B	C/B	C/B	N	C	C	C	C/B	C	C	N	N
Spain	C	C	C	C	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)
Sweden	C	C	C	B/C	C	N	N	N	N	C	C	N	C
Switzerland	C (estimated)	C (estimated)	C (estimated)	B/C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)	B/C (estimated)	C (estimated)	C (estimated)	C (estimated)	C (estimated)

Table 5: Cost items included in the network tariff: Source: ENTSO-E, 2019 [17].

	Sharing of network operator charges	
	Generation	Load
Albania	0.0 %	100.0 %
Austria	8.0 %	92.0 %
Belgium	5.6 %	94.4 %
Bosnia and Herzegovina	0.1 %	99.9 %
Bulgaria	0.0 %	100.0 %
Croatia	0.0 %	100.0 %
Cyprus	0.0 %	100.0 %
Czech Republic	0.0 %	100.0 %
Denmark	4.3 %	95.7 %
Estonia	0.0 %	100.0 %
Finland	18.6 %	81.4 %
France	3.0 %	97.0 %
Germany	0.0 %	100.0 %
Great Britain	16.1 %	83.9 %
Greece	0.0 %	100.0 %
Hungary	0.0 %	100.0 %
Iceland	0.0 %	100.0 %
Ireland	25.0 %	75.0 %
Italy	0.0 %	100.0 %
Latvia	0.0 %	100.0 %
Lithuania	0.0 %	100.0 %
Luxembourg	0.0 %	100.0 %
North Macedonia	0.0 %	100.0 %
Montenegro	37.5 %	62.5 %
Netherlands	0.0 %	100.0 %
Northern Ireland	25.0 %	75.0 %
Norway	29.0 %	71.0 %
Poland	0.0 %	100.0 %
Portugal	9.1 %	90.9 %
Romania	3.0 %	97.1 %
Serbia	0.0 %	100.0 %
Slovakia	3.1 %	96.9 %
Slovenia	0.0 %	100.0 %
Spain	10.0 %	90.0 %
Sweden	36.0 %	64.0 %
Switzerland	0.0 %	100.0 %

As the table above show, the main differences can be found in the charges related to system services. In most of the countries where there are wholesale markets for ancillary services, system balancing is not included in network charges as these costs are borne directly by those responsible for unbalances.

ITC costs refer to a specific European compensation mechanism for electricity transit that is normally remunerated with a specific component of the transmission tariff.

As for who is paying, the table 6 shows that in most of the European countries, the load pays for most of the transmission costs. Only in 16 out of 39 surveyed countries, the generation has to pay for transmission charges. In these cases, the burden on generation goes from 0.1% in Bosnia up to 37.5% in Montenegro.

When it comes to the unit of measure, European countries differ greatly. Only the Netherlands allocates costs based on capacity, five countries allocate 100% of transmission costs on energy, while all others split costs on capacity and energy, with different percentages.

Table 6: Sharing of network charges: Source: ENTSO-E, 2019.

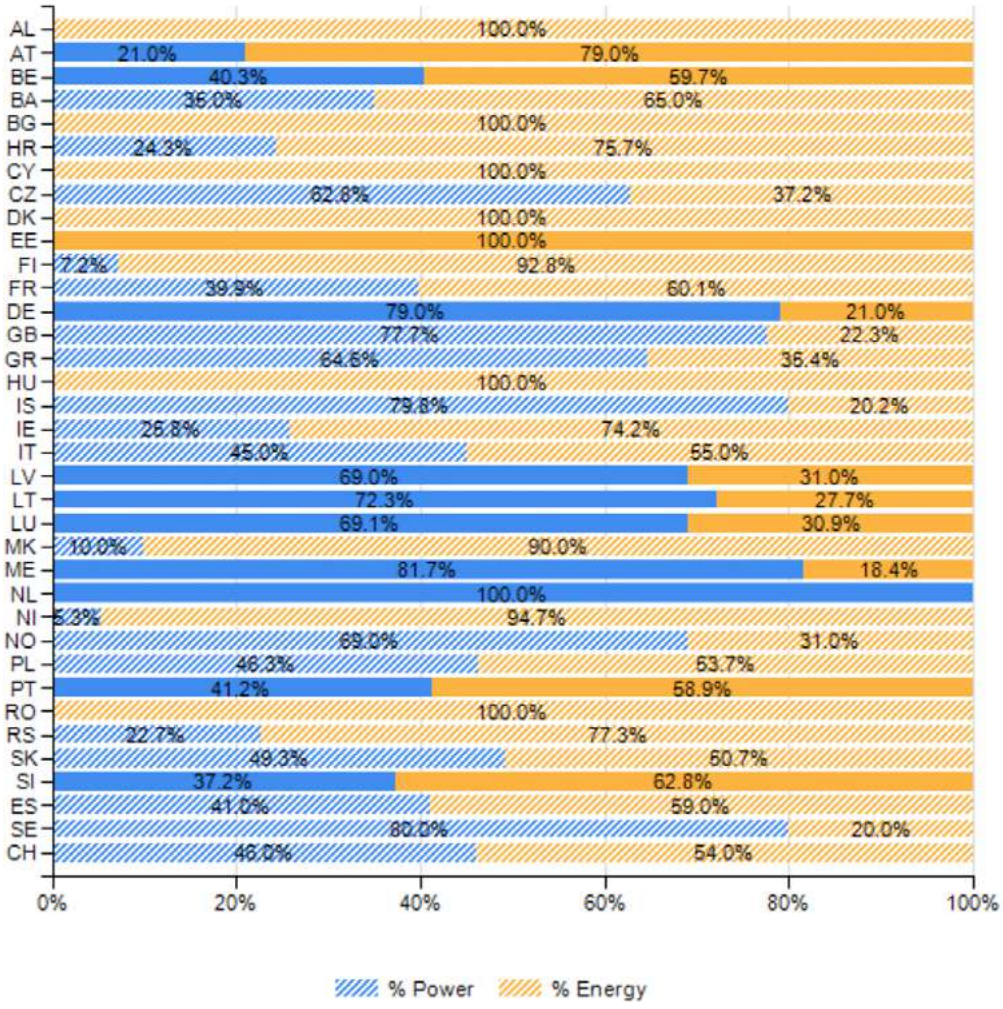


Figure 19: Energy-related and power-related components of the TSO components of the Unit Transmission Tariff. Source: ENTSO-E, 2019.

3.3.1 Calculation of the rate of return in the European experience

The cost of capital depends on the mode of financing used. It refers to the cost of equity if the project is financed solely through equity, or to the cost of debt if it is financed solely through debt. Many projects are financed through a combination of debt and equity, and for such projects, their overall cost of capital is derived from a weighted average of all capital sources, widely known as the weighted average cost of capital (WACC).

For electricity network regulation, the most popular approach is to use nominal WACC before taxation. The calculation of the nominal pre-tax WACC takes into consideration both the cost of equity (ke) and the cost of debt (kd), with weights represented by the optimal debt-to-equity (or gearing) ratio, as shown in the formula below:

$$WACC = \frac{E}{(E+D)\times(1-T)} \times K_e + \frac{D\times(1-T)}{(E+D)\times(1-T)} \times K_d$$

Where:

- K_e is the cost of debt applied by lenders;
- K_d is the cost of equity;
- D is the amount of debt;
- E is the amount of equity;
- D+E is the sum of debt and equity, and in general it is equal to the total capital value of the investment;
- T is the tax rate;
- (1-T) expresses the tax shield.

The cost of debt (kd) is typically the sum of a reference rate plus a floating spread (premium), which reflects the financial market's perception of the project's inherent risk as well as the intensity of competition on the financial markets. The values of debt premiums used by the regulators are in most cases between 0.40% and 2.00%. Portugal uses a debt premium of 2.5%. Greece has a debt premium for electricity network operators of 2.3%.[2]

The cost of equity (ke) is the expected return by equity providers. There are a number of models that are used to estimate the cost of equity. All European NRAs use the Capital Asset Pricing Model or CAPM. The CAPM distinguishes two components of risk: the part that can be diversified away, called non-systematic risk and systematic risk that is unavoidable.

Under CAPM the opportunity cost of equity is equal to the return on risk-free securities plus an Equity Risk Premium, which is the price of risk of an average Equity investment. The ERP estimates the difference between the expected return on the stock market overall versus the risk-free rate and is the product of two variables:

- Beta of the investment – the weighted covariance of the forecast excess return on the project with the average excess return on the whole market; and
- Equity Market Risk Premium (EMRP) – the average premium above the risk-free rate on equities, reflecting the amount of risk in the equity market portfolio.

The risk-free rate is the return on an investment with no variance around the expected return. Most NRAs evaluate the risk-free rate based on government bonds' interest rates. The risk-free rates are usually evaluated on the basis of their own national government bond interest rates. Some regulators, however, use the interest rates based on the government bonds of selected foreign countries (AA or higher rated) or OECD averages.

Most of the countries use a gearing between 40% and 60%.

The WACC is then applied to an asset volume to calculate a rate of return. The asset volume is called the regulated asset base (RAB). In general, the RAB provides for remuneration of both historic and new investment. The RAB should be formed by the assets necessary for the provision of the regulated service in their residual (depreciated) value. The RAB can be comprised of several components such as fixed assets, working capital or construction in progress. Other elements such as capital contributions of customers, government (e.g. subsidies) and third parties, on the contrary, are usually excluded.

The RAB may be valued according to different methods (e.g. historical costs, indexed historical costs or actual re-purchasing costs), which will have an influence on the determination of the CAPEX. A RAB based on indexed historical costs would, therefore, require the use of a "real" instead of a "nominal" WACC. As a result, it is important to understand the relation between the RAB definition and the WACC structure.

In general, the role of the RAB is very important for the tariff calculation. Most of the countries use the RAB as one component (multiplied with the WACC) for calculating the allowed revenue. With a determined revenue, the necessary tariffs can also be calculated.

[2] All the figures in the present paragraph are taken from: CEER, Report on Regulatory Frameworks for European Energy Networks 2019.

Fixed assets, also known as a 'non-current asset', is a term used in accounting for assets and property which cannot easily be converted into cash. Fixed assets normally include items such as lines, land and buildings, motor vehicles, furniture, office equipment, computers, fixtures and fittings, and plant and machinery.

Assets under construction are a special form of tangible assets. They are usually displayed as a separate balance sheet item and therefore require a separate account determination in their asset classes. Cost includes all expenditures incurred for construction projects, capitalised borrowing costs incurred on a specific borrowing for the construction of fixed assets incurred before it has reached the working condition for its intended use, and other related expenses. A fixed asset under construction is transferred to fixed assets once it has reached the working condition for its intended use.

At the EU level, about half of the NRAs responded that electricity transmission and distribution assets under construction are included in the RAB.

Contributions from third parties such as connection fees, contributions from public institutions, EU funding under cohesion/structural funds, or EU grants are deducted by the NRAs from the RAB.

The value of the assets included into the RAB could be expressed either in terms of historical costs or re-evaluated values. Whilst the historical cost approach values the RAB with reference to the costs that were actually incurred by the company to build or acquire the network, the re-evaluated values represent the costs that would hypothetically be incurred at the time of re-evaluation of the assets.

The method of valuation of the RAB in historical costs is applied in regulatory regimes where the assets of regulated companies were not re-evaluated or in the regimes where NRAs keep a regulatory database of the historical values of the assets. As the historical costs do not reflect a decrease in the real value of the assets caused by the inflation, some NRAs make use of the indexed historical cost method.

In electricity and transmission regulation, most of the NRAs (72%) surveyed by CEER in 2019 base their RAB exclusively on historical value of assets.

The re-evaluation of fixed assets is a technique that may be required to accurately describe the true value of the capital goods a business owns. The purpose of a re-evaluation is to bring into the books the fair market value of fixed assets. This may be helpful in order to decide on selling one of its assets or inserting part of the company into a new company. Re-evaluation of assets was conducted in many countries following the unbundling of vertically integrated companies where separate network companies were established.

3.3.2 Tariff incentives

Incentives are one of the central elements of the regulatory regimes in European countries. Due to the absence of a competitive environment for network operators, regulation has been introduced. Instead of defining all the working processes of the regulated network operators, most regulatory regimes only constitute a certain framework that aims to give incentives to network operators in a certain direction.

The pace of technological changes has intensified in recent years. These changes should be taken into account at the transmission network level. Therefore, NRAs are introducing specific incentives for the installation and operation of smart grids and smart meters.

In Europe, at the distribution level, there are also some incentives established for the integration of renewable distributed generation. In general, more incentives are implemented at the DSO level than at the TSO level.

The Spanish regulatory regime includes, at the TSO level, incentives for:

1. maximising the transmission grid availability;
2. accomplishing the investment plan approved by the NRA;
3. being more efficient in the cost of new assets and their operating and maintenance costs, by trying to get lower costs than the approved reference values.

At the DSO level, Spain, like Italy, is one of the countries which has implemented several additional incentives such as a grid losses incentive, a power supply quality incentive and a fraud incentive. Spanish network operators are, therefore, able to get a higher remuneration by achieving the given criteria.

3.4 Ancillary Services

Considering the traditional perspective of the centralized approach towards power systems, Ancillary Services (AS) can be grouped into four classes: (1) Frequency control, (2) Voltage control, (3) System restoration, (4) Demand-side services.

Nevertheless, nowadays power systems are experiencing a growing integration of VRE. In this situation, beside new technological solutions (e.g. storage), also new specific AS can be introduced. To provide mention to this trend, Table 7 summarizes AS according to "widespread today", "emerging" (i.e. it refers to services that are currently implemented in certain countries while in others are not) and "expected in the future". ref TECNALIA, "SmartNet - D1.1 Ancillary service provision by RES and DSM connected at distribution level in the future power system," EU, 2016.)

	Widespread today	Emerging	Future
Frequency Control	Frequency Containment Reserve, Frequency Restoration Reserve, Replacement Reserve*		Fast frequency reserve Ramp margin
Voltage Control	Primary, Secondary	Fault ride-through	
System Restoration	Black start capability		
Other	Demand-side services	Compensation of power losses	Injection of negative sequence V Damping of low-order harmonics Mitigation of flicker Damping of power oscillations Power factor control

Table 7: Ancillary Services classification [18]

* The reserves classification is indicated according to the ENTSO-E guidelines, respectively equivalent to the Instantaneous Reserve, Regulating Reserve and Ten-minute Reserve defined in the SAPP Agreement Between Operating Members [19].

- **Widespread AS** such as (1) Load Frequency Control, (2) Voltage Control and (3) Black-start are mandatory services to be implemented as pre-requisite to allow a stable power system.
- **Demand side services** require to be clearly distinguished between (1) interruptible loads, (2) load shedding, (3) demand-side management.
- **Fault-ride through** refer to the generator capability to maintain connection during voltage dips following a fault on transmission grid and it is more a RES generator requirement.
- **Future AS** such as fast frequency reserve, ramp margin and fast reactive current injection are services required to increase the flexibility and accommodate high shares of VRE both at T&D level. These are currently at the stage of R&D / pilot projects.
- **Other future AS** (injection of neg. V sequence, damping of low-order harmonics, etc.) are services required to guarantee high quality of the supply with high shares of VRE both at T&D level.

3.4.1 Pricing mechanism and models for AS

The Pricing Mechanism for the Ancillary Services varies according to the type of service, i.e., if the Ancillary Service under procurement has a monopolistic nature, then the Pricing Mechanism should be different in comparison with a market-oriented situation.

In order to better classify the Ancillary Services according to their nature from the pricing perspective, the following criteria are considered: (i) Locational service, (ii) Sources for providing the service, (iii) Competitiveness from the sources and the service itself, (iv) Specialization of the service.

Considering the abovementioned criteria, Table 8 is presented:

Ancillary Service	Locational Characteristics	Source	Competitiveness of the source and service	Specialization of the service	Conclusion
Frequency Containment Reserve / Instantaneous Reserve	No	Generator Units	Competitive activity	No	Competitive service
Frequency Restoration Reserve / Regulating Reserve	No	Generator Units	Competitive activity	Requires AGC	Competitive service
Replacement Reserve / Ten-minute Reserve	No	Generator Units	Competitive Activity	No	Competitive Service
Voltage support	Yes	Generator Units; transmission equipment	Generators Competitive Activity; Transmission Regulated Activity	Yes	Regulated Service
Black start	Yes	Generator Units	Competitive Activity	Yes Requires specialized equipment	Regulated Service
Interruptible demand	Yes	Loads	Competitive Activity	Yes Requires specialized equipment	Regulated Service

Table 8: Ancillary Services: Market driven or Regulatory Driven

As can be observed, in general, the reserve Ancillary Services could be classified as Competitive Services based on the main activity and market where the generator unit participates. On the other hand, the Voltage and Black Start Services could be considered as a monopoly or oligopoly service because of their strong locational dependence and the specialized additional equipment required (Black Start). By these reasons, those AS should be regulated and the prices should be set by the regulatory authority of the country, based on the cost of the service plus a reasonable and fair rate of return according to the regulatory policy.

Therefore, the competitive AS are Market Driven and can be procured in the market by any competitive procurement mechanism compatible with the design of the Day Ahead Market. Their prices are market driven. The monitoring of the competition is required in the competitive market in order to avoid anticompetitive practices and the use of market power.



Figure 20: Ancillary Services General Procurement Schemes

The regulated Ancillary Services are Regulatory-Driven and their tariffs should be set by the Regulatory Authority of each country (or equivalent: like Ministry of Energy for example). Their tariffs (not prices) should be set regularly, yearly or every six months in order to better reflect the new conditions of the service. These services are mandatory and require a strong monitoring and quality control by the System Operator and penalties to be imposed by the Regulatory Authority for non-compliance.

3.4.2 AS procurement

The electricity wholesale market is composed of all the commercial transactions of buying and selling of energy and also other services related to the supply of electricity, the so-called ancillary services, which are essential for this to occur in adequate conditions of security and quality. These transactions are organized around a sequence of successive markets where first market agents trade energy, and then, the system operator acquires from these agents the above mentioned ancillary services products related to the supply of electricity in periods closer to real-time.

The overall trading timetable covers a number of timescales:

- months or years before a trade is to be implemented;
- real-time when the transaction takes place;
- post-transaction settlement.

The generation and load parties must notify the system operator of their expected physical schedules at real time by market gate closure (one day, one hour, or possibly less before real time).

3.4.2.1 Frequency Containment Reserve (or Instantaneous Reserve) Procuring

Scheme with mandatory offers
The TSO establishes a set of technical parameters that define the condition of mandatory Frequency Containment Reserve (FCR) for plants connected to the grid. All the power plants with suitable technical parameters are obliged to offer FCR.

The FCR obligations can be referred to the total available capacity starting from scheduled set point or can concern only a part of the total available capacity. In the latter case, the amount of FCR obligation is typically defined as a percentage of the maximum output of the plant. In this way the operators are not allowed to offer at their minimum/maximum output on the energy market since enough room for FCR must be kept. An adequate framework of penalties should be set up for providers that do not comply with the obligations. FCR with a mandatory offer can be remunerated as follows: (i) No remuneration, (ii) Fixed price remuneration, (iii) Market price remuneration.

Scheme with free offers

In a scheme with free offers, each power plant is free to offer or not FCR. Also, the offered quantity is freely selected by the power plants. This scheme clearly only makes sense if a FCR market is established.

Advantages and disadvantages of different procuring schemes

A mandatory offer scheme has the main advantage to allow a complete exploitation of the available FCR sources. In systems with a limited number of power plants with FCR -providing capabilities, the mandatory offer scheme generally allows to ensure the possibility to fulfil the FCR requirements.

The general disadvantage of a mandatory scheme without remuneration is related to the absence proper price signals to investors. In this way the possible technologies of FCR provision that do not participate to energy market (e.g. storage systems) are discouraged.

A mandatory scheme with a fixed price remuneration can provide both adequate exploitation of the available FCR sources and proper price signals to investors.

The fee to be paid to FCR providers shall be correctly identified and periodically revised by the TSO. The fee has to be calculated taking into account the actual average costs to be sustained for FCR provision.

The most appropriate scheme for encouraging effective investments in FCR if a free offer scheme in the framework of a liberalized market. However, this kind of solution need a proper liquidity of the market; it means that the FCR supply should be much greater of the FCR demand. If this condition is not fulfilled, it may emerge significant market distortions.

3.4.2.2 Frequency Restoration Reserve (or Regulating Reserve)

The provision of Frequency Restoration Reserve (FRR) is typically optional, since this service requires dedicated equipment and dynamic performances. The quantity of FRR offered by each provider is usually free, and it depends on plant technical capabilities. For these reasons the procurement of FRR is usually market based.

Dedicated power market provision

The FRR can be provided by the mean of a dedicated market in which the SO is the only counterpart of the FRR providers. The main characteristics are:

- a defined time resolution for which the market is settled (from 1 hour to more than a year);
- for each block, each FRR provider makes offers consisting of pairs price/quantity;
- for each block the SO defines the requested FRR and selects the offers in order to fulfil this requirement at the minimum system cost;
- the market can adopt a marginal price or a pay-as-bid auction scheme;
- once a provider's offer is selected, the provider has the obligation to provide FRR for the selected quantity. It is up to the provider the responsibility to operate on the scheduling phase in order that the scheduled set point ensures enough room for FRR provision.

A feature of the FRR is the possibility to remunerate also the activated FRR in terms of energy. The energy price paid to the selected providers is typically defined ex-ante by SO/NRA as a fixed tariff (distinguishing upward and downward FRR activation).

Implicit provision in the Ancillary Market

The FRR can be procured by the SO also within the resolution of the Ancillary Market. In this procurement scheme, the FRR required to operate the system is ensured by a dedicated constraint in the Ancillary Market.

The FRR providers submit to the Ancillary Market the quantity of FRR (in terms of MW) that they are available to provide in each hour. The criterion for the FRR offers selection in each hour is based on the upward/downward offered price in each hour. Since these prices are considered to re-dispatch the system considering the whole set of requirements in a single optimization process, it is not generally possible to identify the reason why a upward/downward offer is selected.

Given that there is not an explicit remuneration of secondary reserve in terms of offered capacity (MW), the main remuneration scheme is based on the actually activated FRR during the operation of the system. The SO/NRA shall define ex-ante proper tariffs for upward and downward activation of FRR.

Advantages and disadvantages of different procuring schemes

The dedicated power market provision allows the provision of explicit price signals to investors for what regards the FRR. However, this kind of provision overlaps its mechanism with the general Ancillary Market with potential inefficiencies and the possibility of market distortion.

For these reasons it should be preferred the implicit provision of FRR even if the signal prices for investors (defined by the activated energy tariffs) are more indirect. An integrated Ancillary Market is generally more efficient in the selection of the different ancillary service providers.

3.4.2.3 Replacement Reserve (or Ten-minute Reserve) Procuring

The provision of the Replacement Reserve (RR) is typically optional, since this service requires dedicated equipment and dynamic performances. The quantity of RR offered by each provider is usually free, and it depends on plant technical capabilities. For these reasons the procurement of RR is usually market based.

Implicit provision in the Ancillary Market

The RR can be procured by the SO also together with the resolution of the Ancillary Market in a similar way as it was described for FRR.

3.4.2.4 Voltage control procuring

Voltage control is always mandatory, all power plants connected to the transmission grid are obliged to provide voltage control service according their technical possibilities.

In principle this service given to the grid could be charged through a dedicated spot market for reactive power. This would be a complex and expensive market to run although reactive power is usually almost costless to produce (providing voltage control does not really affect active power production).

System Operators and researchers have been looking for appropriate mechanisms for reactive power provision in the context of deregulation and liberalization. However, the debate is still ongoing, there are several issues concerning the existing provision policies and payment mechanisms for reactive power services that delay the full development of a competitive market around the world.

In Europe voltage control, payments are often based on long contracts, but some auctions are used (E.g. England, where basic payment for capacity and operation with auction/ offer mechanism operated on a semester base).

Provision by means of long term contract

In general, many of the aforementioned issues can be resolved if reactive power services are optimally procured through long-term agreements between the SO and the service providers. These long-term contracts (annual, or monthly) would likely reduce the possibility of exercising market power by generators, and at the same time could solve the problem of price volatility that arises when reactive power services are priced on a real-time basis.

Implicit provision in the Ancillary Service Market

The ancillary market is a security constrained UC program, able to provide the optimal scheduling respecting the voltage stability limit. Remuneration for this service is implicitly provided by the operation of the Ancillary Service Market, by the selection of the offers in each hour, based on the upward/downward offered price.

3.4.2.5 Procurement of Black Start capabilities

The set of black-start units are defined by the TSO on the basis of technical requirements of the system. In this way there is not a real procurement scheme for this kind of ancillary service.

However, the selected plants should be remunerated for providing capabilities. A fair and transparent remuneration scheme should be then established.

- A remuneration should be paid to each selected plant for the availability.
- A remuneration should be paid for each real black out events in which a selected plant correctly operated its black start capability.
- A penalty should be requested to a selected plant if during a periodical real test, a critical technical and/or organizational failure has taken place.

4. VRE DEPLOYMENT

In 2018, at least nine countries supplied more than 20% of their electricity generation from variable renewable energy (VRE), as shown in Figure 21.

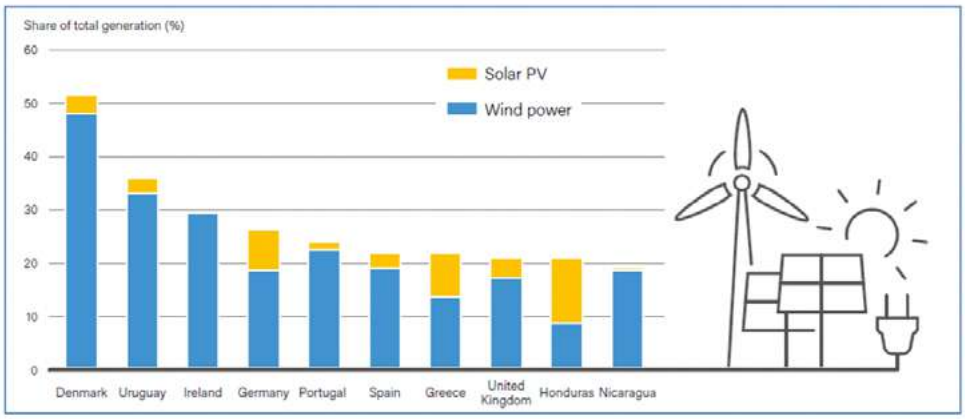


Figure 21: Share of Electricity Generation from Variable Renewable Energy, Top 10 Countries, 2018 (Source REN21 [20])

As shares of renewables grow in energy systems, additional challenges may emerge that require systems-focused approaches and strategies for the VRE integration, that is mainly advanced through:

- appropriate design of the operations, regulations and markets that govern energy systems;
- infrastructural improvements or enhancements that aid access to renewables or facilitate their uptake;
- increased flexibility in energy demand and supply to accommodate VRE.

4.1 General economic and regulatory aspects of VRES integration

Different instruments can be used to support renewables production: the most commonly used ones are feed-in tariffs, feed-in premiums, quota obligations, tax exemptions, tenders, and investment aid. Instrument choice also depends on the market technology, scale, timeframe and location. The choice of the support instrument often determines the price exposure that renewables producers face. This range of market price risk in turn affects the expected rate of return, which is function of the project risk and capital costs.

As a general rule, support schemes that give more market exposure to renewables producers drive energy production and investment decisions more efficiently and more cost effectively. At the same time, though, market design should be adapted so that VRES producers can participate on a level-playing filed with all other producers.

As we briefly discuss in the next paragraph, many of the instruments can be designed on the basis of costs calculated ex ante by a competent national authority or via genuinely competitive tendering or auctions, to let the market decide the most competitive bid for the specified source of energy.

Experience shows that the level of support alone does not necessarily determine success in terms of renewables production. A well-designed support scheme needs to be embedded in a coherent policy framework that allows the definition of a well-functioning market design. Support schemes work best when they are part of a long-term predictable and stable policy/strategic framework with clear objectives.

In particular, balancing, grid connection and dispatch influence on what degree renewable electricity producers are and can be integrated effectively into the power markets. Good administrative practice is relevant for all support schemes to bring costs down and ease market entrance also for new and smaller players.

4.2 Support mechanisms

4.2.1 Quota Obligations

Obligations that require energy suppliers to purchase a quota of renewables (or green certificate representing the production of such energy) are one of the first instruments to be developed for the promotion of VRES. Such instruments create a market between renewables producers and suppliers of energy which can trade energy or certificates at a price determined by them and other possible market players. In particular, such instruments expose the energy producer to market prices, since they must market and sell the energy itself on the relevant market and, if its renewable characteristic is identified separately with a green certificate, also sell and receive a market price for its «greenness». In most countries which have introduced quota obligations, a penalty is applied for non-compliance that effectively sets a ceiling on the price of the certificate/greenness.

4.2.2 Feed in tariffs

Feed in tariffs is a fixed payment guaranteed for a certain number of years on the energy produced, coupled with an obligation by a national authority or a buyer to purchase and dispatch the electricity produced. This mechanism insulates new market entrants from price risk, thus lowering their cost of capital and enabling private investment. Feed in tariffs are also amongst the simplest of schemes to implement, making them suitable for markets with a large number of less commercial participants (e.g. households or local community-based initiatives).

This support scheme is ideal at the early stage of development of VRES. As VRES penetration grows and the technology becomes more mature the advantage of simplicity is outweighed by disadvantages: feed in tariffs exclude producers from actively participating in the market and thus hinder efforts to develop large liquid electricity markets as the share of renewables grows.

4.2.3 Feed in premiums

Premium systems are an evolved version of feed in tariff system with varying degrees of market exposure for producers. Premium systems have several advantages compared to other instruments: they oblige renewable energy producers to find a seller for their production on the market and make sure that market signals reach the renewable energy operators through varying degrees of market exposure. A well-designed premium scheme will also limit costs and drive innovation by granting support based on a competitive allocation process or including automatic and predictable adjustments on cost calculations, giving investors market signals coupled with foresight and the necessary confidence to invest.

4.2.4 Auctions

A well-designed auction can lead to significant competition between bids revealing the real costs of the individual projects, promoters and technologies, thus leading to cost-efficient support levels, and limiting the support needed to the minimum. Tender/auction designs need to ensure there is sufficient competition to incentives lower prices and have low regulatory costs to avoid becoming a barrier to market entry, as well as avoid strategic bidding, and contain penalties for non-delivery. Auctions may still require some ex ante calculation of energy costs by the agency preparing the scheme, partly to help avoid strategic bidding, and often include floor or ceiling prices.

4.2.5 Investment support

Upfront investment support generally covers capital costs and is distinct from operating support which covers operating or production-based costs. Investment support takes various forms, the main types being grants, preferential loans and tax exemptions or reductions.

Whilst operating or production based financial support is viewed critically because it maximises production irrespective of price, investment support decouples production from the sales price and can be appropriate when production incentives are not necessary or where the market provides an adequate and efficient production signal – for instance for more mature technologies with high up-front investment costs. In practice, limits on the availability of short-term financial resources can be a constraint on the use of such upfront investment support for large scale energy investments, particularly when government budget financed.

4.2.6 Tax exemptions

Tax exemptions and reductions are used extensively in the energy sector. In the VRES sector, in Europe they are used to encourage household investments (e.g. rooftop PV), while in the US are the main support scheme for all types of investments.

Tax exemptions are financed indirectly by all taxpayers, since public revenues are reduced, rather than by energy consumers. They are therefore subject to the political and economic currents that shape fiscal policy in general.

4.3 Market design for VRES

4.3.1 Electricity dispatching rules

To help access the market, VRES are normally granted priority dispatch rights. This helps new technologies and market players enter the market dominated by centralized large power producer incumbents because it insulates renewable power from volume risk. As markets evolve and as grid operations become more neutral, such priority may become unnecessary.

When renewables producers are able to take part in offering power to the market directly, they, like other producers, seek a power purchaser and sell their power accordingly. Moreover, when renewables producers have equal access to the market, their low operating costs (particularly for wind and solar power production) place them before conventional power producers in the merit order. As such, systems with centralized dispatch fade and priority dispatch rules become less relevant for renewable energy technologies active in the market.

Of course, to take full advantage of VRES participation into markets and power pools, policymakers and regulators have to possibly review the functioning of the market to see if it is convenient to:

- Review gate closure times;
- Review bidding formats;
- Review the locational granularity of prices and schedules (zonal vs nodal).

4.3.2 Responsibility for electricity grid balancing

The majority of existing electricity grid infrastructure and wholesale markets were designed to accommodate centralized and dispatchable national power output from conventional thermal and hydro-electric plants.

Initially when wind and solar electricity started, it had no balancing obligations, which were borne by transmission system operators (TSOs) or other entities. This was because such producers constituted a small share of the market and because system operations and market structures could not support such obligations at low cost.

As their share is growing, VRES must participate take responsibility for grid balancing as all market players have an implicit responsibility to balance the system and become "Balance Responsible Parties" or BRPs. In this respect, the BRPs are financially responsible for keeping their own position (sum of their injections, withdrawals and trades) balanced or to help restore system imbalance over a given timeframe.

Hence, there is a growing consensus on the need to make RES increasingly responsible for their imbalances. This is an important step towards the greater integration of variable RES. The graph below shows the different levels of balancing responsibilities in selected EU countries.

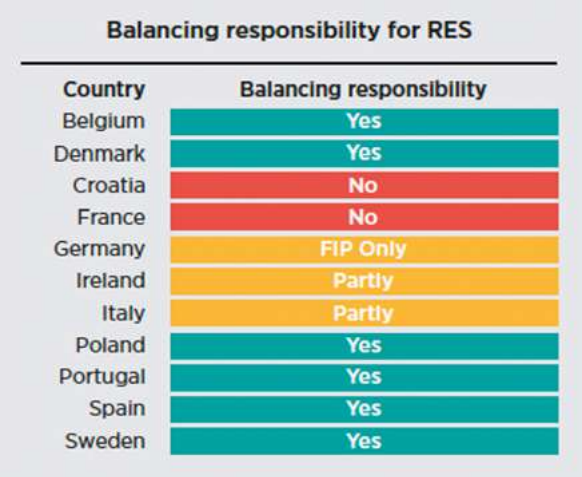


Figure 22: Balancing responsibilities in different EU countries. (Source IRENA [8])

At the same time, it is clear that in order for VRES to become BRPs, balancing products need to be updated. In particular, new balancing products must unlock the potential of new, flexible resources, by:

- Give different price signals to resources performing differently;
- Separate the procurement of balancing energy, upwards reserves and downwards reserves;
- To the extent possible, avoid limiting participation based on size or technology.

4.3.3 Responsibility for grid costs

Grid connection fees are a crucial element for power system development. Therefore, imposing high costs of connection to RES producers might reduce the incentives to locate production where the resource is optimal («wind where the wind blows», «sun where the sun shines»). On the other, not taking into account locational aspects might inefficiently increase transmission investments.

As VRES deployment increases, there is the need to find a way to take into account locational issues. This does not need to be done by charging specific network tariff for those investing in remote but resourceful locations, but by understanding the impact of different market designs (zonal vs nodal) and of different support schemes (based on capacity or on energy).

Below, we report a brilliant example from Newbery et al. [21].

"The wind and the sun vary over time and space and so will the cost per MWh from these sources. But to that cost must be added the transmission and balancing costs. Distant wind farms may have higher capacity factors, but they incur considerably higher transmission costs—and it is that total cost that matters. In the case of a feed in tariffs (FiT) or feed in premiums (PFiT), if the support price is set high enough to even encourage the least-favored location, then it will over-reward those in favored locations. This raises the cost of procuring a given amount of capacity investment (and RES learning benefits).

By contrast, if RES is supported per MW of capacity rather than per MWh of output delivered, there will be less inducement to locate in distant locations in response to a higher incentive per MWh. That has the benefit that it does not over-reward RES in favorable locations, while with locational pricing it discourages excessive connection in constrained locations. This would make better use of the existing network and reduce the effect of current subsidies in exaggerating power flows when the network is congested. Assuming that a plant delivers at least the specified

number of MWh, the only remaining (minor) distortion towards windier but less efficient locations is earning the subsidy more rapidly.

A simple example illustrates how most existing RES support schemes lead to inefficient location decisions even with nodal pricing. Suppose that the nodal price in a distant windy location is €20/MWh (averaged over hours of wind generation) while it is €40/MWh near a major demand centre. The windy location has a capacity factor of 3,000 hrs/yr (i.e. produces 3,000 MWh/MW capacity) while the demand centre has a wind capacity factor of 2,000 hrs/yr. So, the value of the windy location is €60,000/MWyr and at the demand centre is €80,000/MWyr and so more valuable. If a wind investor receives a FiT of €80/MWh in both locations, then it would choose to locate in the windy place – where it produces more output but less value to society.

A PFiTs responds to local wholesale prices; it is less distorting than a FiT—but the premium element still creates a distortion. If wind is paid a PFiT, say with a premium of €40/MWh, then the windy farm earns €(20+40) x 3,000 = €180,000/MWyr and the demand-centred farm earns €(40+40) x 2,000 = €160,000/MWyr, so incentives still point to the wrong location. If the demand centre instead had 2,500 windy hours, the FiT would still favour the windy location. But the PFiT would now earn €60 x 2,500 = €150,000/MWyr in the windy location, less than the €160,000/MWyr at the centre, and so would locate in the right place."

4.4 Challenges and solutions to integrate VRE

This section deals with the main challenges and solution to integrate VRE in the power system, with a focus on Transmission and mainly considering the following aspects:

- State-of-the-art mechanisms of VRE deployment in mature and emerging markets;
- Current technology and market options for mitigating risks associated with VRE.

Many power systems around the world are experiencing significant changes, mainly caused by the increasing availability of low-cost variable renewable energy, the deployment of distributed energy resources (DER), advances in digitalisation and growing opportunities for electrification.

According to the IEA [22] these changes can be managed in the process of Power System Transformation (PST), that describes the processes that facilitate and manage changes in the power sector in response to these novel trends. It is a process of creating policy, market and regulatory environments, and establishing operational and planning practices that accelerate investment, innovation and the use of smart, efficient, resilient and environmentally sound technology options.

The increasing prominence of VRE, and its associated "system integration" issues, is among the most important drivers of PST globally, and different levels of VRE penetration require an evolving approach to providing power system flexibility.

The IEA [23] has developed a categorisation into six different phases to capture the evolving impacts that VRE may have on power systems, as well as related integration issues. This framework can be used to prioritise different measures to support system flexibility, identify relevant challenges and implement appropriate measures to support the system integration of VRE as shown in Figure 23 and Figure 24.

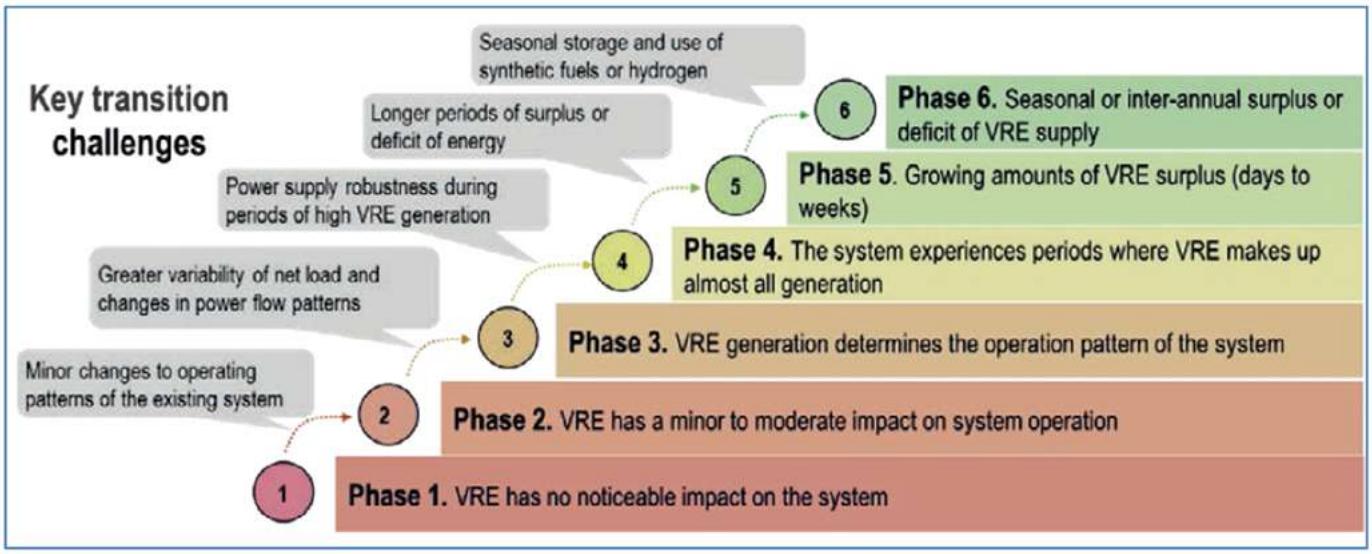


Figure 23: Key characteristics and challenges in the different phases of system integration (Source IEA, 2018)

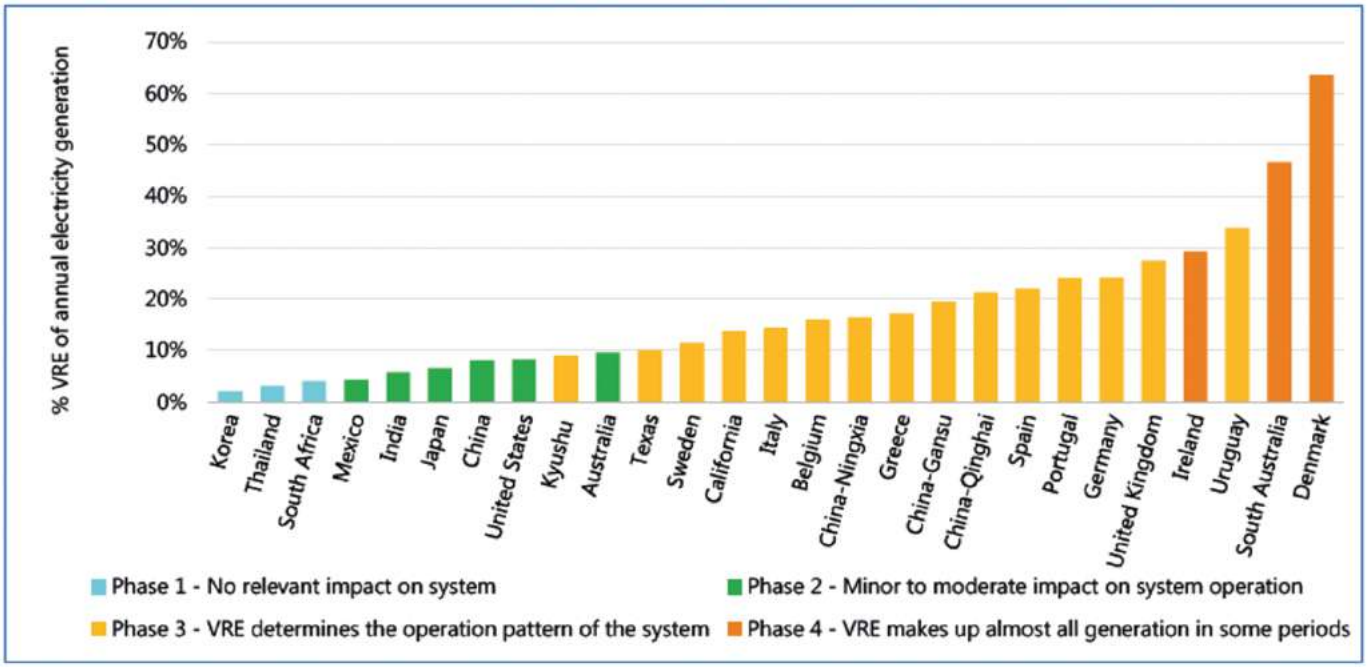


Figure 24: Annual VRE share and corresponding system integration phase in selected countries/regions (Source IEA, 2018)

A key aspect recognised as a global priority to properly manage the integration of the VRE into a power system is the Power system flexibility, defined as "*the ability of a power system to reliably and cost effectively manage the variability and uncertainty of demand and supply across all relevant timescales, from ensuring instantaneous stability of the power system to supporting long-term security of supply*".

There is a variety of options for policy, market and regulatory instruments that can boost system flexibility. These options can be grouped into several categories of interventions for policy makers to consider and are depicted in the blue boxes in Figure 25 ([22]).

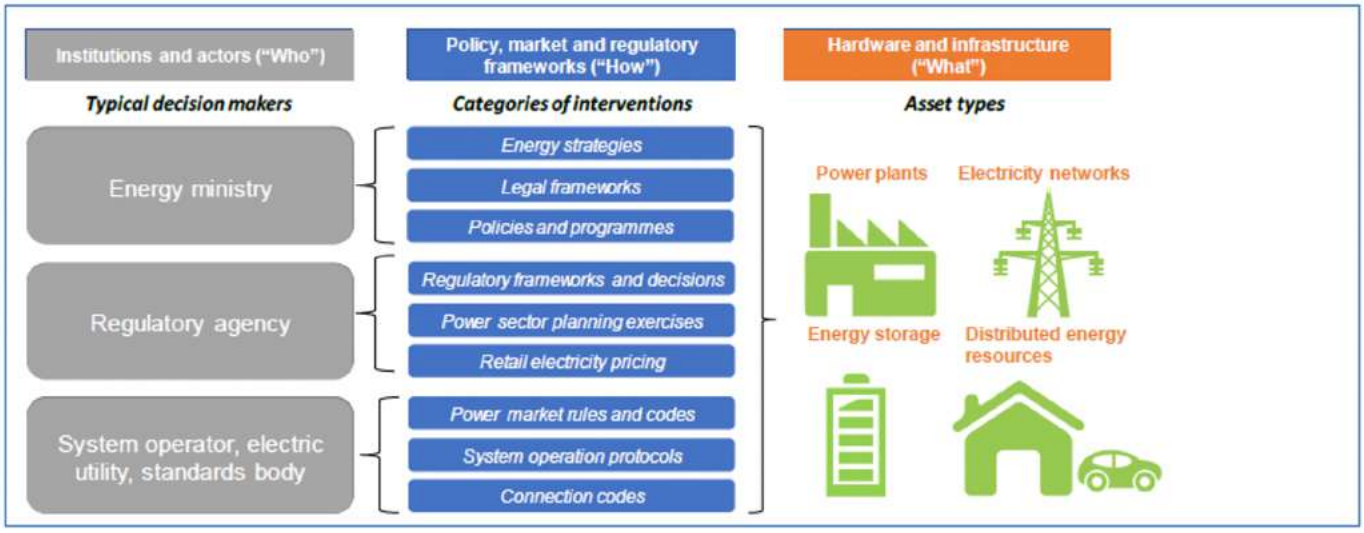


Figure 25: Layers of power system flexibility at different levels of decision making (Source IEA, 2018)

In transitioning from evaluating to increasing flexibility, regulators and system operators can draw from a suite of options, as illustrated in Figure 26. The types of intervention span physical (e.g., storage, transmission), operational (e.g., cycling thermal fleets, forecast integration), and institutional (e.g., new market designs, integration of demand response). Country experiences demonstrate a wide range of approaches to addressing flexibility, reflecting system-specific contexts. These experiences also demonstrate that while system operators might be cautious about increasing variability based on valid concerns about feasibility, experience suggests that system operators have been very innovative in discovering new approaches once they take up this challenge.

Although options and associated costs to increase flexibility are very system-specific, in general tools that help access existing flexibility through changes to system operations and market designs are cheaper than those that require investments in new sources of flexibility. While requiring less capital investment, changes to system operation and market design do have implementation costs and may entail changes to institutional relationships.

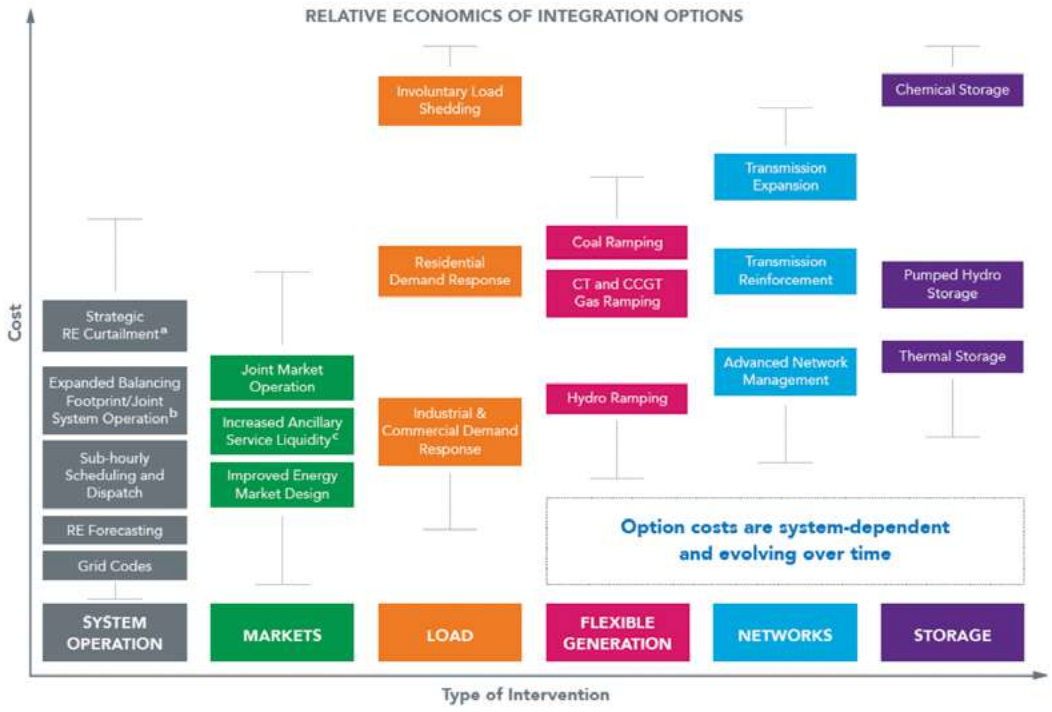


Figure 26: Example integration options. Relative costs are illustrative, as actual costs are system dependent (Source [24])

4.5 Criticalities with relevant shares of VRE generation: experiences in the EU

Europe has an abundance of renewable energy sources, and its countries in recent years have become leaders in driving the deployment of renewable technologies. The EU has adopted targets to achieve a 20% share of renewable energy in energy consumption by 2020, and 32% by 2030 [25]. Experiences gained in the early 2000s demonstrated the importance of enabling frameworks for renewables, and such frameworks remain at the heart of the EU's policy process.

Figure 27 shows the significant increase (from 6% to around 30%) of Wind and Solar PV in the power mix of the EU countries in the last 10-15 years.

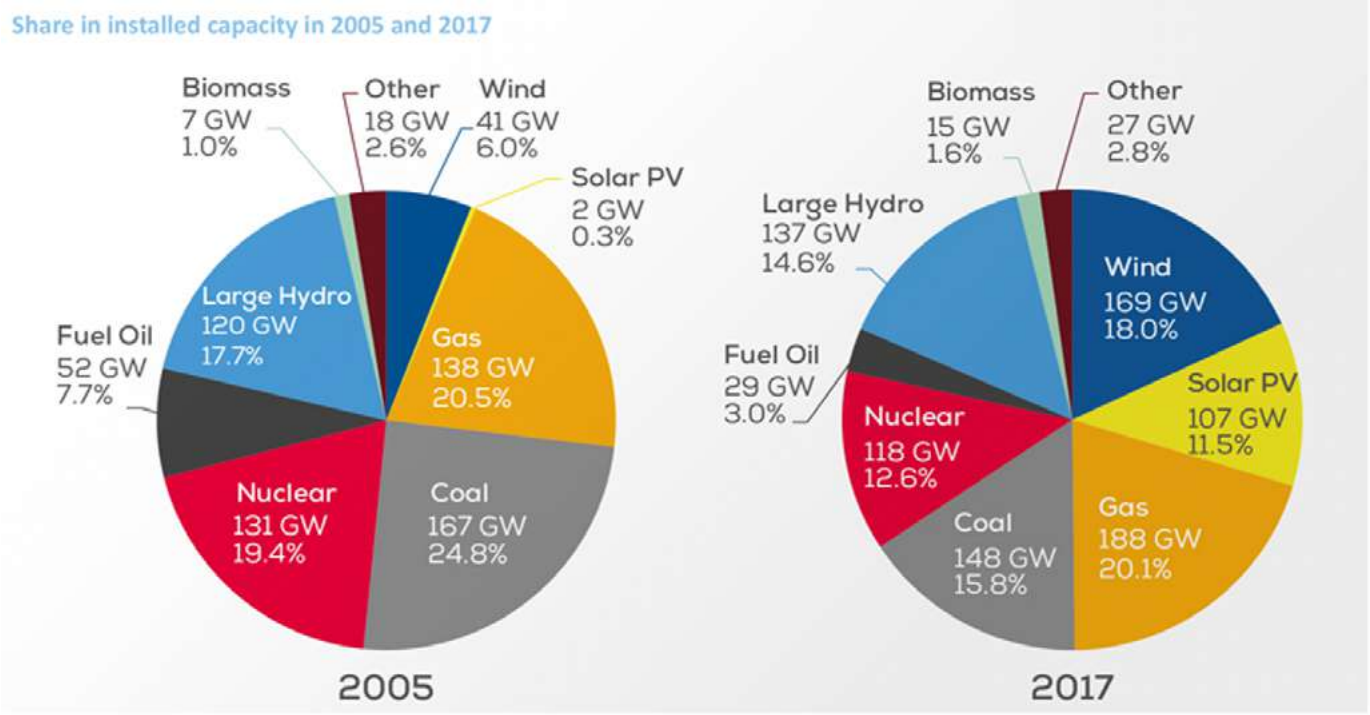


Figure 27: Share in installed capacity in the EU (Source: WindEurope)

The original renewable energy directive (2009/28/EC [25]) establishes an overall policy for the production and promotion of energy from renewable sources in the EU. It requires the EU to fulfil at least 20% of its total energy needs with renewables by 2020 – to be achieved through the attainment of individual national targets. All EU countries must also ensure that at least 10% of their transport fuels come from renewable sources by 2020.

In December 2018, the revised renewable energy directive 2018/2001/EU [26] entered into force, as part of the Clean energy for all Europeans package, aimed at keeping the EU a global leader in renewables and, more broadly, helping the EU to meet its emissions reduction commitments under the Paris Agreement. The new directive establishes a new binding renewable energy target in the EU for 2030 of at least 32%, with a clause for a possible upwards revision by 2023.

Under the new Governance regulation, which is also part of the Clean energy for all Europeans package, EU countries are required to draft 10-year National Energy & Climate Plans (NECPs) for 2021-2030, outlining how they will meet the new 2030 targets for renewable energy and for energy efficiency. Member States needed to submit a draft NECP by 31 December 2018 and should be ready to submit the final plans to the European Commission by 31 December 2019.

Most of the other new elements in the new directive need to be transposed into national law by Member States by 30 June 2021.

4.5.1 Case Study Italy

Italy experienced a fast and sharp increase of VRE, mainly PV connected to the distribution grid (**DER**).

Among the implemented VRE integration measures it is worth to mention the development and implementation of a roadmap of **Storage Projects** and installation of **Synchronous compensators**, the implementation of **DLR system** to reduce network congestions and associated VRE curtailments and the implementation of **grid services from virtual units or distributed resources.**

The Italian 2019-2023 Strategic Plan intends to take the country through a complete energy transformation with the aim of completely integrating renewables. With this aim, Terna, the Italian TSO, has implemented the Directive 2009/28/EC [25] and the Italian Ministry of Economic Development's National Action Plan. At the end 2018, 35% of the Italian public's electricity needs were covered by renewables sources (and around 12% from solar PV and wind).

VRE capacity rose from roughly 4 GW to 30 GW within ten years (2008–2018), with a significant increase over 2 years (9 GW to 25 GW from 2010 to 2012), as shown in Figure 28.

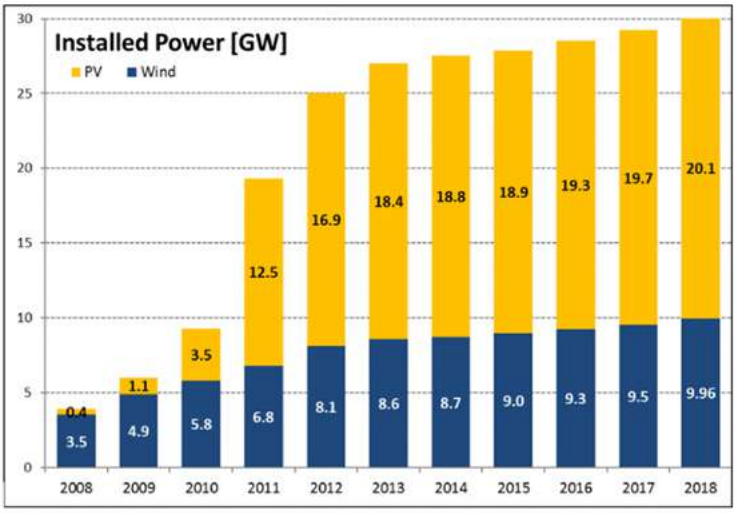


Figure 28: VRE installed capacity evolution in Italy (Source: Terna)

The main challenges faced during the different phases of increasing VRE in the system are:

- Changed load profiles and energy flow patterns (since VRE are largely installed in southern regions, while main load centres remain in mid-northern cities), which led to energy congestion and VRE curtailment.
- Reduction of utilization hours of conventional power plants (mainly CCGT), subjected to tougher load ramps (e.g. in the evening), with implication on the system operation and the electricity market.
- Power flow inversion between transmission and distribution network (since, at the end of 2018, around 94% of the solar PV installed power was connected to the distribution system), changing the traditional structure of the power system and requiring more coordination between the transmission system operator and distribution companies.
- Reduction of power reserve margin, system inertia, short circuit power and reactive power resources (mainly in some network areas, like the Sardinia Island, and under particular operating conditions), affecting the system security and stability.

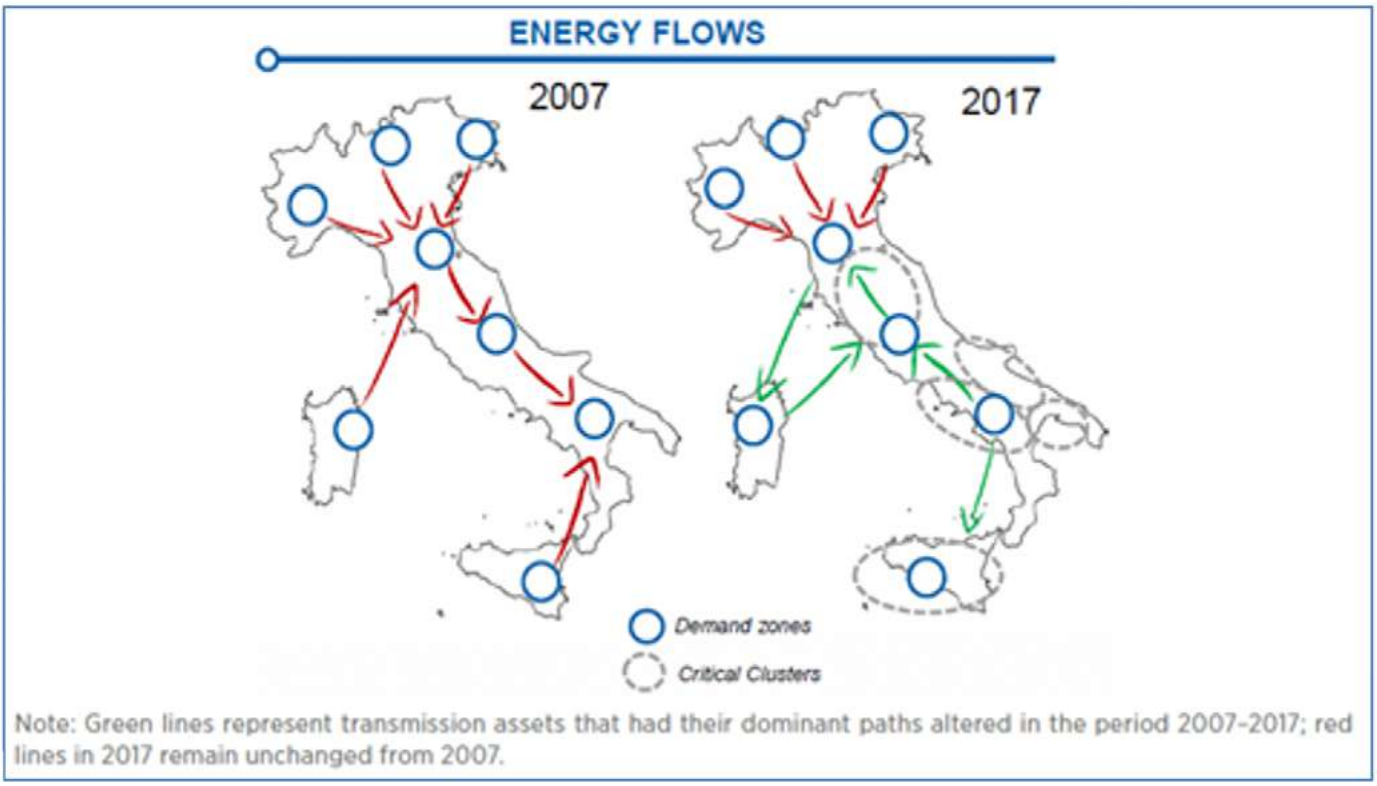


Figure 29: Evolution of energy flow dominant paths in Italy (Source: Terna, 2018)

Initial measures for VRE integration usually comprise better operational practices and grid code improvements and this has been also the case in Italy. Since then, a set of measures has been applied in the country, such as:

Forecasting: since the initial development of the VRE, the TSO equipped his control rooms with wind and solar forecasting tools, based on accurate weather forecasts and neural networks algorithms, aimed at providing forecasts of the VRE plants connected to the transmission grid.

Grid Codes: specific Grid Code annexes have been issued over the last years to implement requirements and procedures for VREs (including DER), mainly to cover the following aspects:

- Frequency regulation;
- Voltage control;
- Protection settings;
- Fault Voltage ride through capability;
- Data Exchange between TSO and DSOs;
- Power Quality;
- System strength (short-circuit power) and Inertia support.

Storage. Since 2012, Terna has started several pilot projects to test the use of storage for providing grid services. Additionally, following the Regulatory Authority resolution (300/2017), Terna has launched new projects allowing new resources to participate to the balancing market. Figure 30 and Figure 31 show the related roadmap and implemented pilot projects.

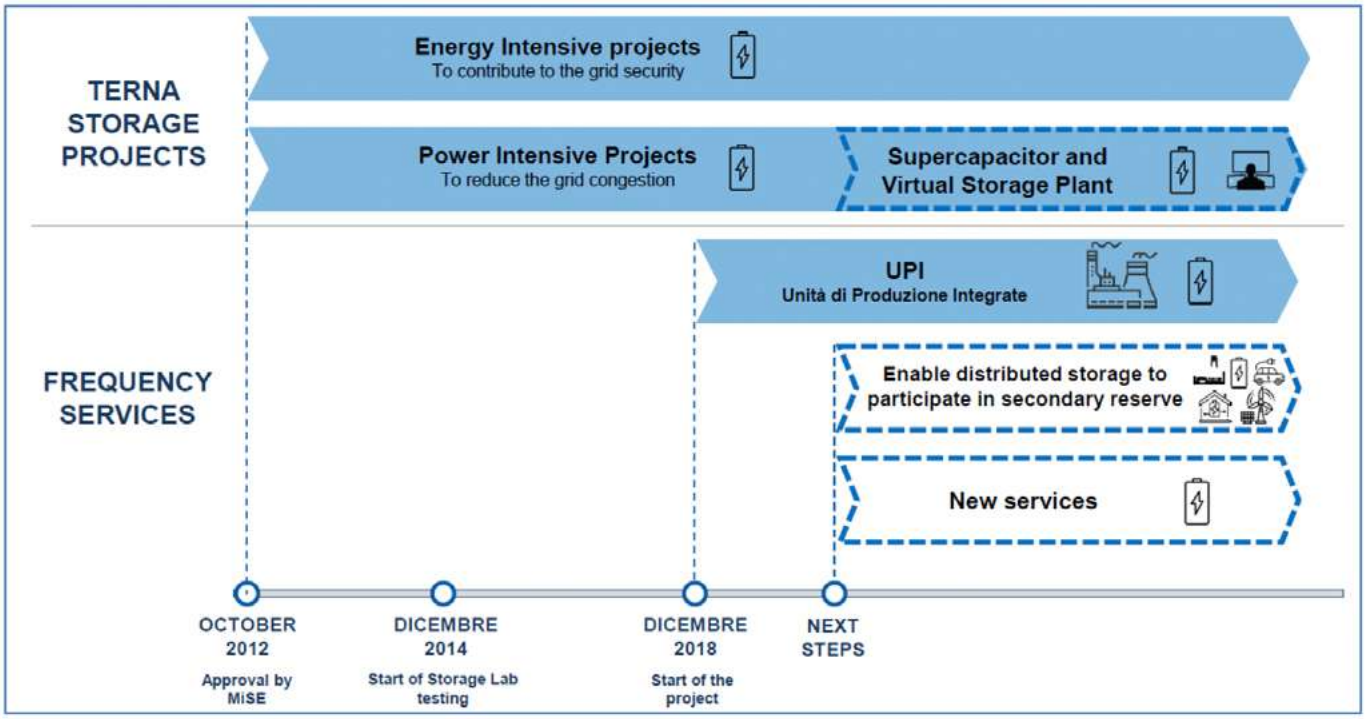


Figure 30: Roadmap of the TSO Storage Projects in Italy (Source: Terna)

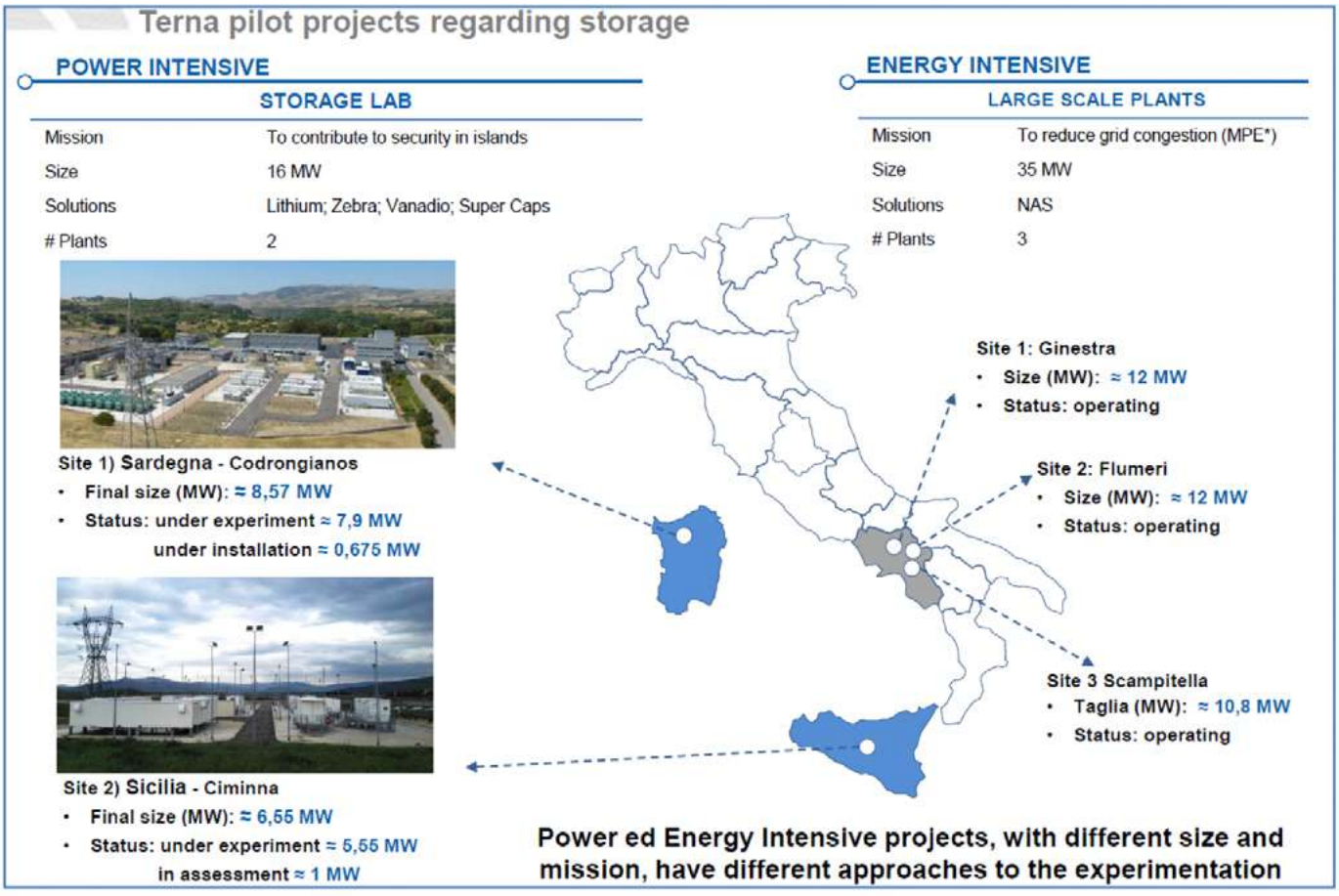


Figure 31: Implemented Storage Pilot Projects in Italy (Source: Terna)

Monitoring tools: the TSO equipped his control rooms with tools, aimed at monitoring the security operation of the grid, considering also the presence of the VRE. Among these tools, usually integrated in the SCADA/EMS system, it is worth to mention:

- DSA – Static and Dynamic Security Assessment;
- Advance dispatching – short time analysis of reserve adequacy.

Dynamic Line Rating (DLR): contributing greatly to easing curtailment due to transmission constraints. DLR is a relatively low-cost measure with a short lead-time that has been instrumental in significantly reducing curtailment levels down to 1-2% in Italy in a very short period. Such levels have remained almost unchanged since then, with the help of other measures that have followed, such as transmission expansion and the current development of smart grids in the region of Puglia.

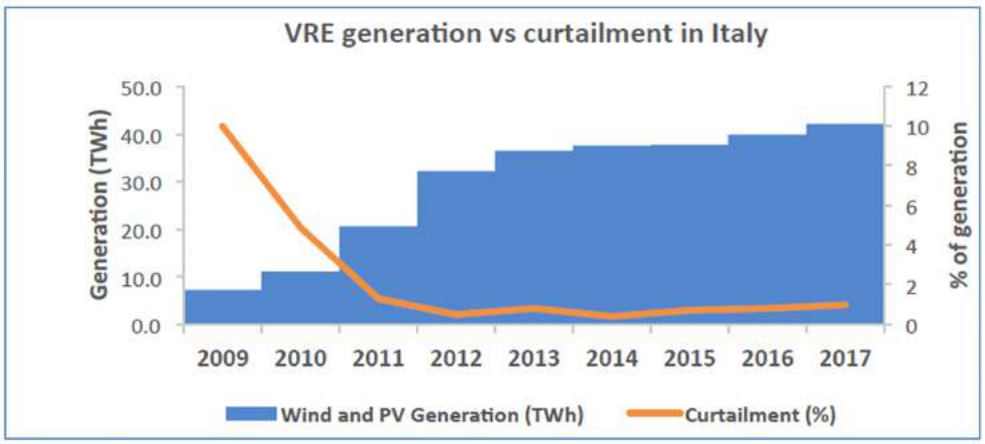


Figure 32: VRE generation and curtailment in Italy (Source: Terna, 2018)

Synchronous Compensators. Within the context of increasing amounts of distributed solar PV generation and Wind farms and the near-term phasing out of large coal power plants, in the regions of Sardinia and Sicily synchronous compensators have been installed, reducing the number of plants considered essential for the security of the grid, providing ancillary services such as: inertia, short-circuit power and voltage control.

Distributed System Resources. Balancing and congestion management services in Italy are market -based and traded on the same platform. The traditional providers of ancillary services are Large-scale generation (& pumped storage) units. Starting from 2017 some pilot projects have been launched to test the performance of distributed generation and the demand-side in order to enable DSR (Distributed System Resources) to provide grid services. Since November 2018 the UVAM (Enabled Virtual Mixed - generation and load - Unit) were introduced as possible service provider in the balancing market, allowing to increase and diversify the available resources in the market.

Functioning	UVAM is an aggregate of consumption, production and storage units that can participate in the Ancillary Services Market through the Balancing Service Provider (BSP) offering: congestion resolution, tertiary rotating and replacement reserve, balancing.
Participants	• Non-Relevant Production Units (**UPNR**) • Consumption Units (**UC**) • Stand-alone storage units or combined with a UPNR and/or UC, including Vehicle-to-Grid (V2G) • **Relevant Production Unit** not already prequalified for MSD
Remuneration	The **ordinary mechanism** of remuneration of the quantities accepted in the MSD is applied; the **strike price** is set at **€ 400/MWh**. In the case of forward contracting, a fixed premium (capacity contract) is applied to remunerate the capacity offered on the MSD with a **CAP** of **€ 30,000/MW/year** (pay-as-bid).
Available quantity	• **800 MW** per le zone Nord e Centro-Nord • **200 MW** per le restanti zone di mercato

Figure 33: Main characteristics of the UVAM (Enabled Virtual Mixed Unit) in Italy (Source: Terna)

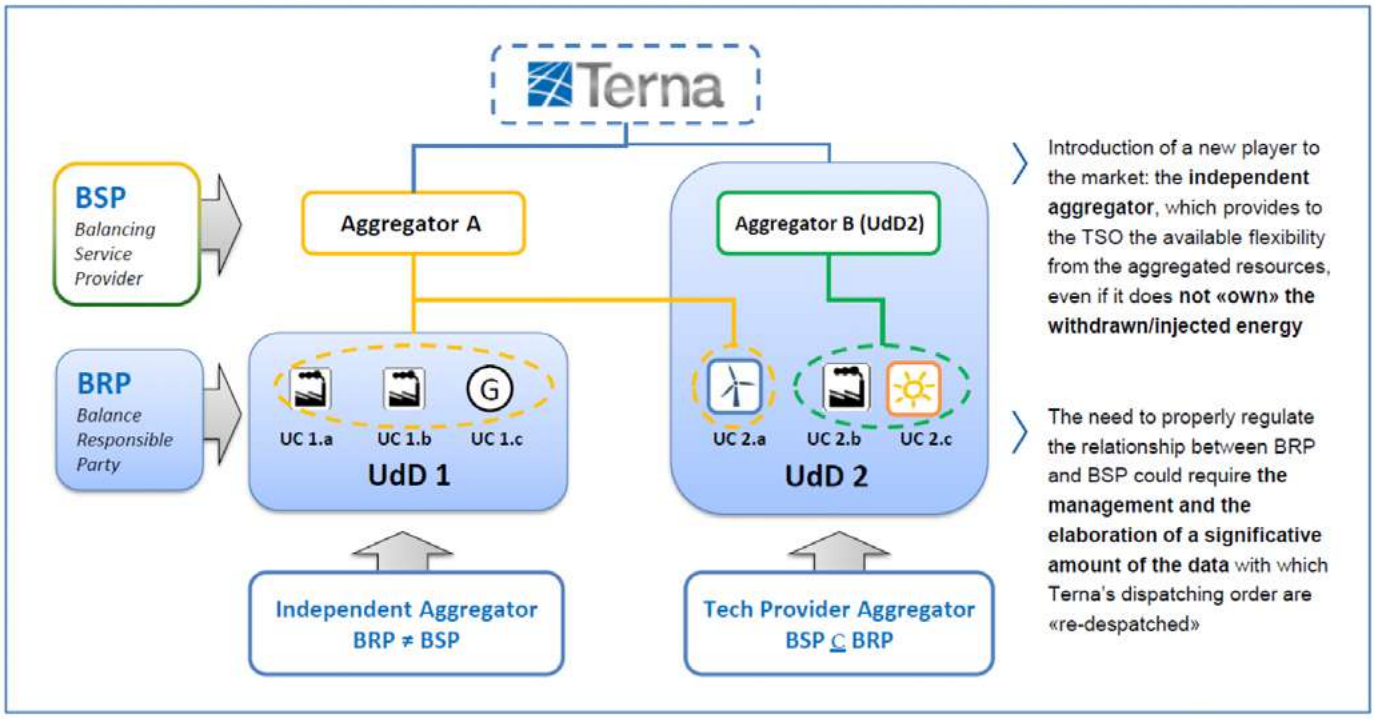


Figure 34: Concept of grid services from distributed resources in Italy (Source: Terna)

4.5.2 Case Study Spain

Spain is among the countries with the **highest share of electricity generation from VRE** (mainly Wind Power) and **one of the first country which integrated significant amount of VRE** in its power system.

A key success milestone of the VRE integration was the **establishment of a dedicated control center for VRE within the main system operation center**, aimed at constantly analysing the current scenario and predict the operation measures necessary for the system security and, when it is not possible to integrate into the system all the wind/solar power production available, issuing orders to reduce the production of wind/solar energy facilities.

As shown in Figure 35 Spain has a significant amount of VRE in its system, with a predominance of Wind Generation (19% of the electricity needs covered by wind in 2018).

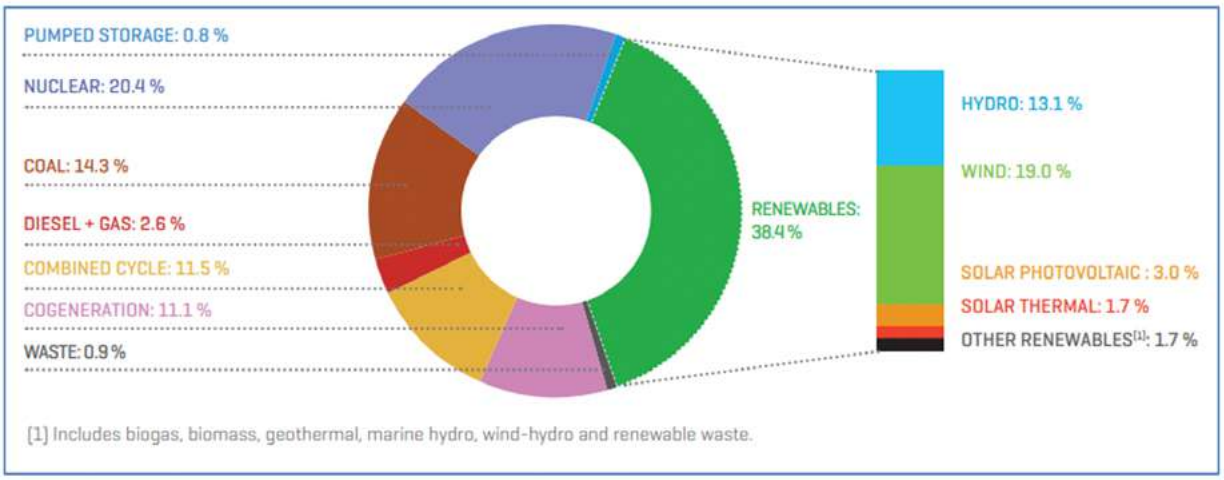


Figure 35: National electricity system and Renewable energy generation structure in Spain in 2018 (Source: REE)

The Spanish Transmission System Operator REE (Red Electrica de Espana) highlighted the following challenges and solutions for VRE integration.

- Challenges:
  - Insufficient power capacity interconnection with Europe;
  - Demand coverage;
  - Control and supervision of distributed generation;
  - Variability in renewable generation and difficult to predict;
  - Behaviour of the electricity system when faced with weather disturbances;
  - Contribution of renewable generation to the system's ancillary services;
  - Situations in which there is a surplus of renewable generation which cannot be integrated into the system.

- Solutions:
  - Development and strengthening of international interconnections;
  - Increase of flexible generation and development of demand-side management tools (storage and the electric vehicle);
  - Development and adaptation of the Control Centre of Renewable Energies (Cecre);
  - Development and improvement of predictability tools;
  - Technological adaptation of the aerogenerators;
  - Regulatory and technological development for the provision of adjustment services.

A very distinctive integration action undertaken by REE is the establishment of a control centre within its main system operation centre, in 2006, initially to better manage a swift rise in wind capacity, and later to manage also solar PV and CSP. The CECRE (Control Centre of Renewable Energies) is the first centre in the world used for controlling and managing the electricity generation obtained from renewable energy producers. Its objective is to integrate into the electricity system the greatest quantity of renewable energy possible whilst maintaining the levels of quality and guaranteeing the security of supply. CECRE plays a significant role in the integration of renewable generations, considering the significant share of installed renewable energy (mainly wind) and the specific characteristic of the Spanish system, with limited interconnection capacity with neighbouring systems (around 3% with France at the current maximum demand). The work of the CECRE has made it possible for renewable energy generation to have represented nearly 40% of the annual energy production in the Spanish peninsular electricity system in recent years, reaching in some cases hourly coverage values greater than 80%. This is allowing local energy sources to have an increasingly prominent role in the coverage of demand, thereby reducing our dependence on foreign energy.

The information sent by the generators is received and monitored by the control system of Red Eléctrica, making it possible for CECRE operators to use and view it 24 hours a day, 365 days a year. By means of 23 control centres of the generation companies, which act as interlocutor, CECRE receives, every 12 seconds, real time information about each facility regarding the status of the grid connection, production and voltage at the connection point. The main tasks undertaken at CECRE are:

- Constantly analyse the current scenario and predict the operation measures which will be necessary so that the system remains in a secure state.
- When it is not possible to integrate into the system all the wind power production available, CECRE can issue orders to reduce the production of wind energy facilities which must be complied with in under 15 minutes. In this way, in the event that inadmissible situations are detected in the system due to the high production of wind energy, they can be corrected quickly.

The main information collected and processed at CECRE are:

- Real-time wind energy generation (updated every 12 seconds) and relation with the total installed wind capacity (total and per region) and scheduled curtailment order, if any;
- Wind energy production throughout the day (actual and forecasted);
- Wind power generation maps, showing the areas in which wind power energy is being generated (from real-

time data) and the disturbance in the system that would cause the greatest loss in wind power generation at that moment;

- Solar PV generation maps, showing the areas with installed solar PV capacity with real-time (estimated) data on the generated power;
- Solar thermal generation maps, showing the areas with installed solar thermal capacity with real-time data on the generated power;
- Cogeneration maps, showing the areas with installed cogeneration capacity with real-time data on the generated power;
- Dashboard showing real-time the share of generation of the four main technology in renewable energy and the daily demand coverage using renewable energy generation.



Figure 36: Overview of the CECRE - Control Centre of Renewable Energies (Source: REE)

4.5.3 Case Study Ireland

Ireland is among the countries with the **highest share of electricity generation from VRE** (mainly Wind Power) and a **critical System Non-Synchronous Penetration (SNSP) level.**

The VRE integration was achieved through the **implementation of a multi-year programme**, called DS3 "Delivering a Secure, Sustainable Electricity System", launched in 2011 and aimed at developing solutions to the challenges associated with increasing levels of renewable generation, particularly with regards to secure power system operations, through the three pillars of: (i) System Performance, (ii) System Policies and (iii) System Tools.

The island of Ireland has two Transmission System Operators (TSO) and one Market Operator (MO): Eirgrid plc is the licensed TSO in the Republic of Ireland (ROI) but is also the owner of the System Operator Northern Ireland (SONI Ltd) the TSO in Northern Ireland (NI). Since 2005 the two jurisdictions operate under a single wholesale electricity market (SEM) and with dual currencies that is managed in cooperation between Eirgrid plc and SONI Ltd by a joint venture known as SEMO (the Single Electricity Market Operator).

As the main source of electricity on the island of Ireland is thermal power, the transmission network is characterised as "centralised" with the main transmission lines connecting the large electricity production plant to areas where end users are concentrated. This has been a main concern for wind farms but also for other renewable generators. The reason is that wind farms are being built in areas that are not well connected in terms of the transmission network. Nevertheless, as shown in Figure 37, Ireland has a significant amount of VRE in its system, with a predominance of Wind Generation (32% of the electricity needs covered by wind in 2019).

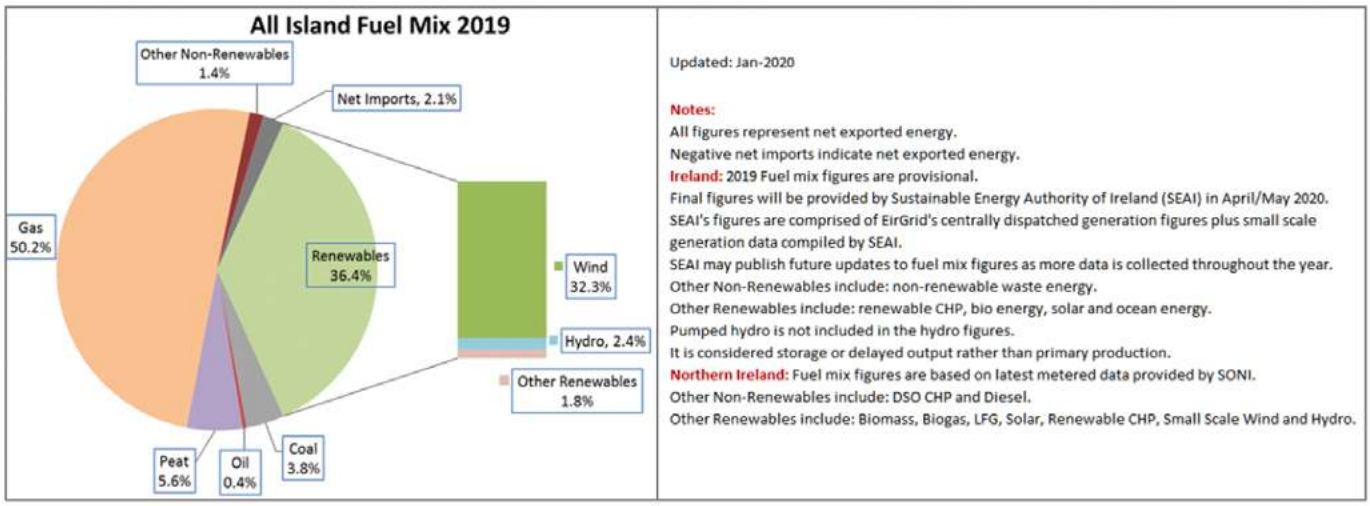


Figure 37: National electricity structure in Ireland in 2019 (Source: Eirgrid)

Ireland's EU target is for 16% of the country's total energy consumption to come from renewable energy sources and 40% of electricity to come from renewable sources by 2020.

In response to binding national and European targets, EirGrid Group began a multi-year programme, called DS3 "Delivering a Secure, Sustainable Electricity System", launched in 2011 and aimed at developing solutions to the challenges associated with increasing levels of renewable generation, particularly with regards to secure power system operations.

The 2020 renewable electricity target means to increase the amount of non-synchronous generation on the Irish power system in a safe and secure manner. The aim of the DS3 Programme is to meet this challenge.

According to the 2018 update the DS3 programme has enabled EirGrid to increase levels of renewable generation on the system from 50% to 65% (world-first), with the goal to increase this gradually to 75% over the coming years.

The DS3 Programme is made up of 11 workstreams, which fall under the three pillars of: (i) System Performance, (ii) System Policies and (iii) System Tools (as shown in Figure 38). Each pillar is fundamental to the success of the programme and to achieving the 40% renewable electricity target. The programme brings together many different strands, including development of financial incentives for better plant performance, and the development of new operational policies and system tools to use the portfolio to the best of its capabilities. Standards for wind farms and conventional plant are also being reviewed to give enhanced operational flexibility for the future. The programme involves many different stakeholders, including the Distribution System Operators (DSOs), Regulatory Authorities, Conventional Generators and Renewable Generators, as well as Government Departments.

Each pillar of the DS3 is vital to the success of the programme and the delivery of the renewable electricity targets. Together with the on-going grid infrastructure development (Grid25 in Ireland and a similar programme which is under development in Northern Ireland) and the addition of renewable generation capacity, the DS3 Programme is critical to meeting those targets by 2020.



Figure 38: Three main pillars of the DS3 program (Source: Eirgrid)

Since 2011 the focus has been on creating the correct technical and commercial mechanisms to incentivise and improve system performance and capability. Later on, since 2014, the main focus has moved towards the implementation of increased performance capability for the generation portfolio and developing the required system policies and tools needed to meet the 2020 targets. Finally, future work to be accomplished by the DS3 Programme will include:

- Adapting and refining system operational policies to assist in securely managing the voltage and frequency on the Irish and Northern Irish power system;
- Design, development and implementation of enhanced system tools in order to manage the increased organisational complexity. For example, the inclusion of a ramping tool and a voltage trajectory tool;
- The development of a long-term Operational Policy for largescale Demand Side Management penetration;
- The implementation of an enhanced Performance Monitoring system.

The main activities performed within the three pillars of the DS3 Programme are following summarized.

System performance, that mainly refers to the performance of all plant connected to the power system:

- Approval of a number of Grid Code modifications regarding wind farm power stations in Ireland and Northern Ireland The Distribution Code modifications for wind farm standards have been agreed by the Distribution Code Review Panel.
- Demand Side Management (DSM) implementation. Demand Side Units (DSU) and Aggregated Generator Units (AGU) currently operate commercially within the electricity market (SEM) and are centrally dispatched. The wider DSM space is also evolving rapidly with significant work being carried out in developing storage solutions, integrating electric vehicles, etc.
- Rate of Change of Frequency (RoCoF) modification, to move to a RoCoF standard of 1Hz/s over 500ms. However, the decisions outline the need for the implementation of the new RoCoF standard to be linked to the completion of generator studies over a period of 18 to 36 months.
- System Services review, carried out to identify the new products that are needed to complement the transition towards a power system with high levels of wind generation. In December 2014, the Regulatory Authorities in Ireland and Northern Ireland published a decision paper endorsing DS3's ground breaking

approach, changing the commercial focus of generation towards better performance and greater flexibility. The significant elements of the decision are:
  - An increase in the annual budget cap from €60M to €235M;
  - Doubling the number of System Service products from 7 to 14;
  - Movement to a hybrid regulated tariff / auction procurement mechanism;
- Performance Monitoring, including both commissioning and on-going testing of generators to allow the TSOs to understand the capability and compliance of the generation portfolio with respect to the Grid Codes, their registered technical operating characteristics and their capability to provide the contracted levels of System Service provision. Performance monitoring in turn helps to flag non-compliances, so that the generating units can remedy these issues, submit derogations or revise their contracted values. Work completed to date includes:
  - Standardisation and documentation of existing processes on an all island basis;
  - Development of a detailed design specification for the enhanced performance monitoring IT system;
  - Engagement with industry through workshops presenting proposed business processes and working examples;
  - Publication of draft test procedures for industry comment;
  - Development of the business case and scope for the roll out of high speed data recorders.

System policies, as the level of renewable generation increases, the TSOs will be required to update and develop new system operational policies. In particular, operational polices will need to be developed to support frequency control and voltage control. The Irish power system currently has a maximum System Non-Synchronous Penetration (SNSP) level of 50%. This level is based on the results of detailed technical studies, and represents a secure operational level given the current plant portfolio and system capability. The DS3 Programme aims to address the various factors that influence the SNSP limit, with the ultimate aim of increasing the limit from 50% to 75%. This target will be reviewed as the DS3 Programme progresses, depending on the progress of various workstreams. Each year the TSOs publish the Operational Capability Outlook – this briefing paper sets out their view of how operational capability metrics for the Irish and Northern Irish power system are expected to change between now and the target years. The DS3 Programme collates various system statistics and regular reports on key system indices. This provides clear information to the industry and to the general public on the progress being made in integrating renewables into the power system. It also allows broad trends to be identified and acted upon. For example, EirGrid analyses the High Wind Speed Shutdown of wind turbines to help determine operational policy for high wind situations.

System Tools, the evolving power system requires new principles and operational practices, and this also means the need to develop and implement new and updated system tools:

- The most important tools used in the Control Centres are:
  - The Wind Forecast tool estimates the level of wind power production over the coming hours and days. At present, forecasts are supplied by two external providers while a project has been completed to improve forecast accuracy and Grid Controller user interface.
  - The online SNSP, system inertia and RoCoF monitoring within the existing Energy Management System (EMS) is complete. Furthermore, an EMS Integration project for Ireland and Northern Ireland is underway. This will deliver enhanced operational flexibility to the Control Centres.
  - When there is high wind generation, especially during times of low demand, wind generation may need to be dispatched down (e.g. to maintain system security). This is done using the wind dispatch tool, which sends out instructions electronically to wind farms. To aid tracking of dispatch instructions, the tool will also provide downstream reporting systems with reasons for each wind dispatch.
- The stability of the power system is affected by wind generation. To study this in real-time, an online Wind Security Assessment Tool (WSAT) was introduced into the Eirgrid Control Centres. WSAT provides a real-time assessment of the transient and voltage stability of the power system, allowing Grid Controllers to take appropriate actions if necessary. Further extensions of WSAT may include assessment of frequency stability, calculation of security based regional wind curtailment amounts and enhanced look-ahead capability.

Other work areas will include: i) the continued development of the Reserve Constrained Unit Commitment (RCUC) tool, which will take account of new operational metrics; ii) the development of a tool to present power system data recorded by Phasor Monitoring Units (PMUs); iii) the provision of the necessary training for Control Centre staff on any new tools or policies.

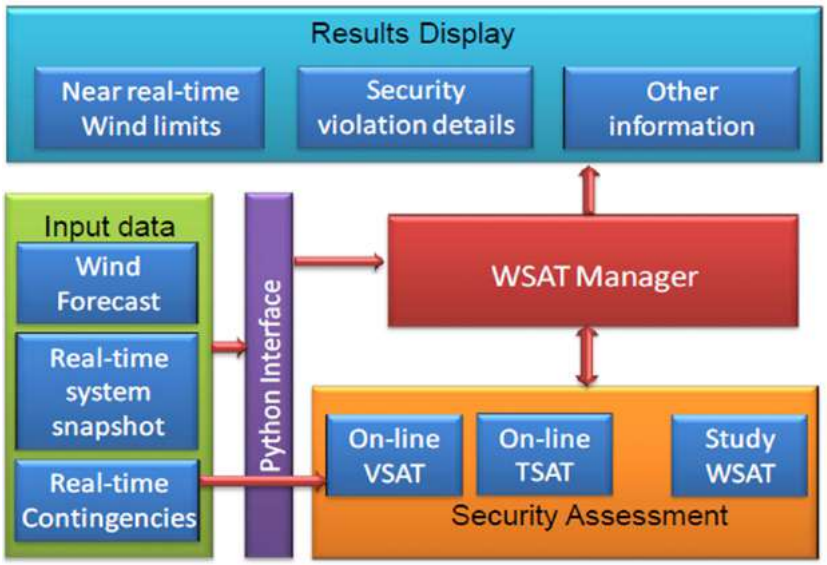


Figure 39: WSAT functional scheme (Source: Eirgrid)

4.5.4 Case Study Denmark

Denmark is the country with the **highest share of electricity generation from VRE** (mainly Wind Power). This outstanding result was feasible through the development of several flexibility options, such as: use of **interconnectors** to other countries, increasing of the **flexibility of thermal power plants**, and **demand-side flexibility**

Denmark is the world's leader in the deployment of wind power, about with 46% of electricity consumption supplied by wind in 2018. Denmark aims to supply half of its electricity consumption with wind by 2020 towards the goal of achieving a 100 per cent fossil-free energy system by 2050.

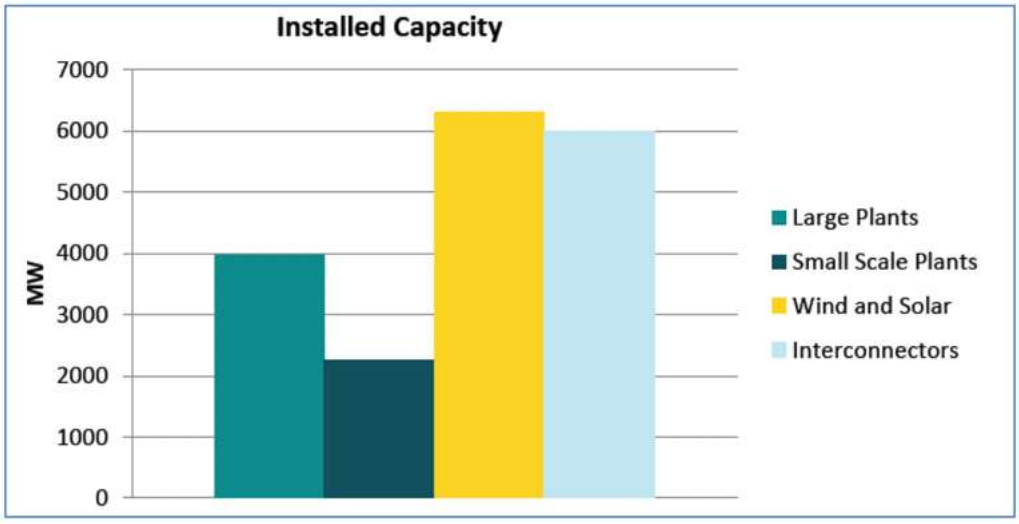


Figure 40: Overview of the present Danish power system (2018). Installed generation capacities, and capacity of interconnectors to neighbouring countries (Source Energinet)

The challenge of integrating a high share of wind power led Danish institutions and market participants to develop several flexibility options, such as:

Use of interconnectors to other countries: Denmark is one of the countries in Europe with the strongest power system interconnections. The total capacity of interconnectors to Norway, Sweden and Germany amounts to about 6,000 MW (and new interconnections are planned with Netherland and UK), which is close to 50% of the total installed generation capacity and close to the peak load of about 6,500 MW (2018). Therefore, a market-based power exchange with neighbouring countries is one of the most important tool for dealing with high shares of wind power in Denmark, that is able to sell electricity during times of high wind production, and to import electricity in times of low wind production.

Within the Nordic power exchange Nord Pool, there has been implicit market coupling of Denmark with Norway and Sweden since 1999/2000, whereas an explicit day-ahead auction was used for the connections to Germany. The market-based exchange with Denmark's neighbouring countries is one of the most important means of integrating wind power production. The electricity market ensures that the cheapest generators are prioritised for electricity production. For example, it allows Nordic hydropower stations to function as cheap and effective energy storage for wind power. When electricity prices are low due to high levels of wind power in the system, hydropower stations withhold their production. Alternatively, when electricity prices are high, they increase their production.

Increasing the flexibility of thermal power plants: A great deal of attention has been devoted in recent years to the flexibilization of conventional power plants. When there is a renewable power shortage (i.e. when load exceeds renewable electricity generation), there is an increasing demand for steep positive ramp rates at running plants as well as a need for fast start-ups at hot, warm and cold thermal plants. Conversely, steep negative ramp rates at running power plants and the lowest minimum stable generation possible are required when there is a renewable power surplus. Between these two extremes, rapid fluctuations in residual load require large positive/negative ramp rates.

Danish coal and gas power plants have been optimised to allow very steep ramp-up gradients, shorter start-up times and low but stable minimum generation levels. Flexibility in providing ancillary services has further reduced must-run capacity.

The Danish experience furnishes a number of best-practice examples that should be considered in efforts to make power systems in other countries more flexible. The organisational integration of the optimisation procedure is illustrated in Figure 41.

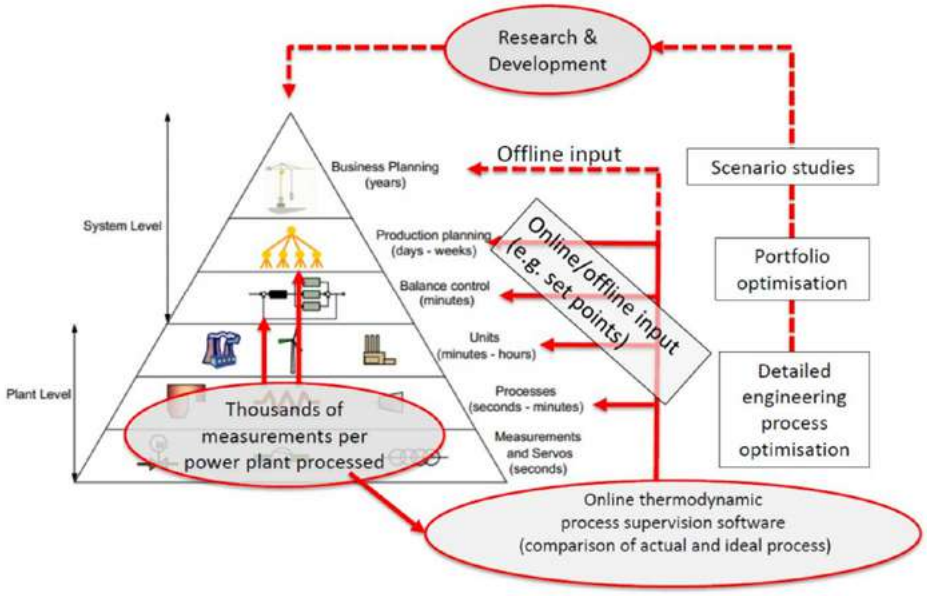


Figure 41: Optimization of power plant flexibility at different organizational levels (Source Blum & Christensen 2013) [27]

Making district heating more flexible, Regulation has been reshaped to reduce heat bound electricity generation in situations with high wind energy feed-in. In the future district heating systems are envisioned to become electricity consumers rather than producers in times of high wind power production. In spite of changes already adopted to the energy tax system, further regulatory measures are still needed to tap the full potential of using power for heat.

Implementing demand side flexibility. To reach the ambitious energy targets in the Danish system, the demand side will need to become flexible. Electricity consumers simply move any demand, that is less important at any given time, to a time with more electricity generation – which also happens to be when electricity is expected to be the cheapest and most environmentally sustainable. This also means that flexible consumers may choose not to use electricity at times when generation is low and the price presumably high. Thus, flexible consumers reduce their electricity bills while simultaneously contributing to the green transition.

The introduction of **flexible or hourly settlement in Denmark** is the first step towards flexible demand (known as demand-side response), because flexible settlement allows consumers to react to prices in the electricity market. This means that, going forward, consumers will need to be aware of when they use electricity and not just how much they use. Energinet has launched various pilot projects, collaborating with both consumers and market participants across the entire value chain, to ensure that the electricity market's framework can accommodate this change in the electricity system. Basically, the purpose is to create a market that makes demand-side response possible and reduces transaction costs to a minimum. At the same time, this work allows new market participants to test products and business models, making demand-side response not only possible, but also manageable.

Case Study: North Sea Wind Power Hub is a proposed energy island complex to be built in the middle of the North Sea. One or more "Power Link" artificial islands will be created in a relatively shallow area in the North Sea. Dutch, German, and Danish electrical grid operators are cooperating in this project to help develop a cluster of offshore wind parks with a capacity of several gigawatts, with interconnections to the North Sea countries. Undersea cables will make international trade in electricity possible. The principle of the project is the "Modular Hub-and-Spoke Concept" to Facilitate Large Scale Offshore Wind, central to the vision is the construction of modular hubs in the North Sea with interconnectors to bordering North Sea countries and sector coupling through power-to-Hydrogen conversion. The concept coordinates the international development of wind farm connections and interconnections to minimise the need for onshore grid reinforcements. This is a cost-effective way to transport offshore wind energy whilst securing energy supply, providing a robust market outlook. The project is to be completed around 2050.



Figure 42: Overview of the North Sea Wind Power Hub (Source Energinet)

4.6 Criticalities with relevant shares of intermittent RES generation: experiences in selected emerging markets

4.6.1 Case Study Brazil

Brazil implemented during the last **20 years a regulatory framework** designed to incentive customers and investors with the scope to achieve the projected target of expansion of alternative renewable generation capacities.

Brazil's main commitments concerning the decarbonisation (from the Nationally Determined Contribution, NDC, ratified by the government in 2016 following the Paris Agreement in December 2015) indicate for the electricity sector the country's intention to increase the overall proportion of renewable energy sources (other than large hydro) to at least 23% by 2030.

In 2017, alternative renewable energy sources (i.e. small hydropower, wind, solar, and biomass) accounted for 16 per cent of national electricity generation.

Figure 43 presents the projected expansion of alternative renewable generation capacities in the 10-year plan's reference scenario (PDE 2027 [28]).



Figure 43: Installed and expected generation capacity of alternative renewable energy sources in Brazil (Source PDE [28])

The evolution of the renewables energy in the country mix (mainly dominate by large-hydro) has been highly influenced by the regulatory programs implemented in the last years.

In 2002, the two-stage programme PROINFA (Programa de Incentivo às Fontes Alternativas de Energia – Incentive Programme for Alternative Sources of Electric Power) was created to encourage power matrix diversification with other energy sources such as wind, solar and biomass. The goal of the first stage was to install 3300 MW of renewable energy, using subsidies and other incentives. PROINFA has awarded 20-year PPAs to a total of 144 biomass, wind, and small hydropower projects with a combined capacity of 3.3 GW. These PPAs include a stipulated feed-in tariff for each technology and an additional subsidy scheme for investments via special BNDES (National Bank) financing mechanisms.

The second stage target was to increase the renewable energy generation (excluding hydro) to 10% of annual consumption within 20 years. The second stage did not occur and was later replaced by the regulator ANEEL's energy auctions. More in details since 2007, the government has used auctions to increase the share of alternative

renewables in the power mix. Until 2017 projects totalling more than 14 GW awarded through long-term PPAs via renewable energy auctions – either via reserve energy auctions (LER), where the government decides which technologies and volumes should be contracted to the system, specific renewable energy auctions (LFA) or regular new energy auctions (LEN), which can also be exclusive for specific technologies.

The Brazilian model is designed to incentive, both sides: government & customers (adequacy and availability of energy) and investors (long-term auctions through competitive auctions).

The main incentives can be summarized as:

- Long-term contracting auctions:
  - Hydro 30 years;
  - Wind 20 years;
  - Solar 20 years;
  - Biomass 15-20 years;
- Reduction of minimum requirement for demand: 0.5 (reduced from 3 MW) for contracting from renewable sources.
- Discount in the transmission charges: 50%, 80% or 100% for sellers and buyers of renewable sources.
- Finance: subsidy rates by BNDES (National Bank)
- Tax Incentives: reduction of taxes for certain goods

The auctions are the main mechanism for generation expansion. There is a compulsory obligation for Distribution Co. to buy energy from the regulated market (consumers).

The auctions have 3 types of incentives:

- Auctions with specific products (hydro, wind, solar, biomass)
- Designed auction to prioritize renewables.
- Long-term supply contracts.
- Variable Cost cap for thermoelectric participation.

The Sellers in the auctions are the Generators technically approved by EPE or ANEEL. The Contracts signed after the auctions are for 30 years for hydro and 20 or 25 years for Thermal, Wind, PV and Biomass.

The energy supply contracts in ACR may vary only between two modalities:

- Quantity: It is a standard financial forward contract, where generators bid an energy price of R$/MWh for their FECs. In this case, the risk of physical delivery led by ONS's central dispatch is assumed by generator. The Contracts for delivering energy, all risks are taken by generators to supply the energy contracted.
- Availability: It is a typical call option. Generators receive an option premium in R$/year (fixed cost paid in 12 monthly instalments, like capacity payment) to remain available to the dispatch and receive an operational cost every time it is dispatched. The Contracts for availability, all risks of production deviations relative to assured energy are assigned to the pool and passed through to captive consumers.

4.6.2 Case Study Uruguay

Uruguay experienced a **dramatic growth of VRE share in the energy mix**, becoming a showcase for what is possible with **strong cross-border interconnection** and a **flexible grid**, as well as a **clear decision making**, a supportive regulatory environment and a strong partnership between the public and private sector.

Electricity from variable wind energy and solar PV achieved a very high share of 36% in Uruguay in 2018.

The share of generation from wind energy rose more than five-fold in just four years, from 6.2% in 2014 to 33% in 2018.

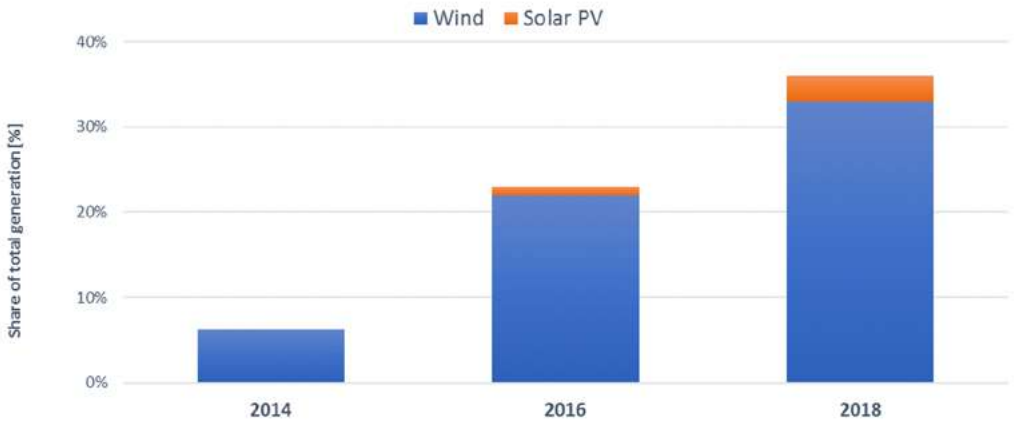


Figure 44: Share of wind and solar PV power in Uruguay (evolution 2014-2018)

The growth in variable renewable power market share in Uruguay has been dramatic, and the country has become a showcase for what is possible with strong cross-border interconnection and a flexible grid.

Grid operators have various operational mechanisms at their disposal to smooth the grid integration of high levels of variable renewables such as wind and solar.

Such steps included:

- incentivizing flexible back-up generation to balance the variability of wind power and
- using cross-border interconnection to export generation surpluses when wind and solar power are fully available.

Uruguay has both excellent flexible hydropower, and good interconnection into Argentina and Brazil, contributing to the country's extraordinary growth in wind and solar market share.

Moreover, in Uruguay the key to success was a clear decision making, a supportive regulatory environment and a strong partnership between the public and private sector.

Uruguay has a comprehensive, long-term energy plan, the National Energy Policy 2005-2030, with the overall objective to diversify the energy mix, reduce dependency from fossil fuels, improve energy efficiency, and increase the use of endogenous resources, mostly renewables.

All these aspects allowed the country to change from having virtually no wind generation in 2007 to become a double world-record holder in less than a decade.

5. HIGHLIGHTS AND ROADMAP

The South African electricity market faces a pivotal challenge on the way to modernization: the country is heavily reliant on thermal generation based on domestic coal resources and needs to tackle severe issues of system adequacy and reliability, as well as energy access.

In order to favor an efficient and effective energy transition the Government of South Africa (GoSA) is envisaging to reform Eskom. It is clear that successfully phasing out coal while rapidly deploying RES and smart grids require a different and more open market framework. **Renewables and reforms are the two crucial pillars of a positive energy transition.**

Eskom at glance: status and future challenges of a vertically integrated utility

Renewables can help South Africa in achieving ambitious goals in terms of capacity flexibility and deployment: the country is currently planning to add 6,000 MW of new solar PV capacity and 14,400 MW of new wind power capacity by 2030. Such amount of variable renewable generation needs to be integrated into the power system by implementing adequate actions aimed at assuring system security and reliability. There is evidence the current REIPPPP scheme proved to be successful in commissioning increasing levels of VRE capacity, but some more tasks are to be addressed, from the implementation of demand-response mechanism via local smart grids, to net metering and social inclusion projects linked to capacity deployment.

According to the World Energy Council, South Africa faces some unfavourable conditions that might slow or hamper its energy transition, such as the dependence on external prices and an unfavourable currency exchange, as well as difficult access to capital markets and corruption. As the political and macroeconomic situation evolves, these issues might be relaxed.

Similarly, we proposed a SWOT framework of analysis, and focused on some points of weakness, and potential threats affecting the electricity sector. The former comprises an inflexible and risk-prone generation mix, an insufficient and undermaintained transmission and distribution, difficulties in collecting payment and in curbing the theft of electricity assets and the abovementioned framework of political instability. For the latter, we highlighted external threat elements represented by the stagnant economic outlook, the reliance on internationally-set commodity prices to GDP growth (not only coal and gas for thermal generation, but also the different mineral materials that the country exports) as well as the ever pressing issue of environmental impact, exacting a toll in terms of lives and quality of living especially in disadvantaged areas.

Worldwide experiences on transmission unbundling

The main opportunity to enhance the South African electricity system and foster the deployment of VREs comes from the expected market liberalisation and unbundling of the state utility Eskom. Unbundling is defined as the separation of production and supply of vertically integrated activities where the transport (or transmission) assets constitute natural monopolies. We presented two possible models that can be pursued by South Africa on the way towards liberalisation: the competition wholesale market, where generation companies sell through the intermediation of a market operator via some kind of spot-trading platform and distribution companies act as suppliers, and the full-fledged liberalized market, where retail activity is completely liberalized with the right for all consumers to freely choose a supplier.

The concepts of Single Buyer and Power Pool are both somehow relevant to the South African market: the former is currently applied via monopsony conditions exercised by Eskom, while the latter has been successfully introduced in emerging Latin America countries that present many similarities with South Africa.

We further corroborated our analysis by introducing some best practices from more mature European electricity markets (Italy, the United Kingdom, France, Spain) and from emerging markets alike (Brazil, Argentina and

India), by showing the way different systems have been arranged once the process of liberalization started. For each of them, we highlighted the initial and current regulatory framework and gave a short description of the process of unbundling. For European markets, three options are available, depending on the preferences of single countries: the ownership unbundling or Transmission System Operator (TSO) model, where all-integrated energy companies sell off their electricity networks to an independent company; the Independent System Operator (ISO), where energy supply companies may still formally own electricity transmission networks but must leave the entire operation, maintenance, and investment in the grid to an independent company; and the Independent Transmission Operator (ITO), where energy supply companies may still own and operate electricity networks but must do so through a subsidiary or ring fencing rules.

Clarifications were added on the definitions and roles of the Transmission Operator, System Operator and Market Operator, and the way these market players can be blended and integrated according to each country's requirements. Examples are also provided.

Best practices show that:

- ***the most successful countries in attracting new players and adding considerable generation capacity are the ones with the most transparent and indiscriminatory third-party access (TPA) rules;***
- ***Best practices show that the bigger the generation fleet of the incumbent, the stricter the level of unbundling must be in order to provide trust and transparency to newcomers.***

Conditional to the specific features of South Africa's electricity sector, it will be possible to assess which of the abovementioned models is best suited for delivering value to consumers and reliability to the system.

Economic and tariff regulation of transmission system operators

For a well-functioning energy sector, network development and system operations must facilitate overall sector development. Hence, the regulator has to create and implement a harmonious set of rules that allows the pursuit of these three objectives:

1. The provision of a high-quality service at an efficient cost;
2. The maintenance and development of infrastructures, promoting innovations;
3. Non-discriminatory third-party access (TPA).

Tariff regulation is the most important tool to achieve all these objectives and has two answers to three key questions:

1. Determination of the return on the transmission activity. What do we pay for?
2. Determination of who is going to pay. Who is paying to guarantee those returns?
3. Determination of how the returns are charged to those who have to pay for the service.

As for the first question, it is important to understand the level of cost efficiency that the regulator wants to push:

- Rate-of-return regulation allows the company to be less exposed to financial risks, but it is not properly stimulated to achieve cost efficiencies;
- Price-cap regulations provide more incentives to cost reductions, but they expose network operators to more financial risks.

Ancillary services are a crucial aspect of the regulated services that the TSO has to provide and for which it has to receive a cost-reflective remuneration. The Pricing Mechanism for the Ancillary Services (AS) varies according to the type of service, i.e., if the Ancillary Service under procurement has a monopolistic nature, then the Pricing Mechanism should be different in comparison with a market-oriented situation. In general, the reserve AS could

be classified as Competitive Services, while the Voltage and Black Start Services could be considered as a monopoly or oligopoly service because of their strong locational dependence.

The **competitive AS are Market Driven** and can be procured in the market by any competitive procurement mechanism compatible with the design of the Day Ahead Market. The monitoring of the competition is required in the competitive market in order to avoid anticompetitive practices and the use of market power.

The **regulated Ancillary Services are Regulatory-Driven** and their tariffs should be set by the Regulatory Authority on a regular basis, in order to better reflect the new conditions of the service.

Moreover, for power systems that are experiencing a growing integration of VRE **new specific AS can be introduced** (e.g. fast frequency reserve, fault ride through, etc.).

As for the second question, EU experience shows high levels of heterogeneity: generators and consumers pay the transmission tariff.

As for the third question, transmission tariffs are charged with a variety of methods, again showing that there are different experiences, particularly in the European context.

In the end, best practices show that:

- ***regulators should opt for some form of rate of return regulation to protect the TSO from adverse financial effects;***
- ***the fixed cost nature of the activity requires the regulator to set up a tariff mechanism that protects the TSO from the demand risk;***
- ***All ancillary services should be duly and timely remunerated.***

VRE Deployment

VRES deployment requires not just economic support schemes, such as feed-in-premiums or auction mechanisms. A well-designed support scheme needs to be embedded in a coherent policy framework that allows the definition of a well-functioning market design. Support schemes work best when they are part of a long-term predictable and stable policy/strategic framework with clear objectives.

Hence, as shares of renewables grow in energy systems, policymakers need to address three issues:

1. How to change electricity dispatch rules in order to accommodate VRES;
2. How to change grid balancing rules in order for VRES to become balancing responsible parties;
3. How to optimize grid development and how to allocate grid costs.

Changes required for the VRE integration can be managed in the process of Power System Transformation (PST), that includes the activities that facilitate and manage changes in the power sector. It is a process of **creating policy, market and regulatory environments**, and **establishing operational and planning practices** that accelerate investment, innovation and the use of smart, efficient, resilient and environmentally sound technology options.

The IEA has developed a categorization into six different phases to capture the evolving impacts that VRE may have on power systems, as well as related integration issues. This framework can be used to prioritize different measures to support system flexibility, identify relevant challenges and implement appropriate measures to support the system integration of VRE.

Europe has an abundance of renewable energy sources, and its countries in recent years have become leaders in driving the deployment of renewable technologies. Therefore, it can be considered as a reference for other countries, like South Africa, that are currently experiencing a limited impact of VRE, but shall face the integration challenges soon. Significant case studies of VRE integration are:

- **Italy**, where the most significant implemented VRE integration measures include: forecasting and monitoring tools adopted by the TSO, adoption of grid codes for VRE and DER, development and implementation of a roadmap of Storage Projects and installation of Synchronous compensators, implementation of DLR system to reduce network congestions and associated VRE curtailments, demand-side management and implementation of grid services from virtual units or distributed resources.
- **Spain**, where a key success milestone of the VRE integration was the establishment of a control center for VRE within the main system operation center, aimed at constantly analysing the current scenario and predict the operation measures necessary for the system security and, when it is not possible to integrate into the system all the wind/solar power production available, issuing orders to reduce the production of wind/solar energy facilities.
- **Ireland**, that implemented a multi-year programme, called DS3 "Delivering a Secure, Sustainable Electricity System", launched in 2011 and aimed at developing solutions to the challenges associated with increasing levels of renewable generation, particularly with regards to secure power system operations, through the three pillars of: (i) System Performance, (ii) System Policies and (iii) System Tools.
- **Denmark**, that is the world-champion in terms of integrated share of wind power, through the development of several flexibility options, such as: use of interconnectors to other countries, increasing of the flexibility of thermal power plants, flexibility of district heating, development and implementation of demand side flexibility.

Among the experiences in emerging markets it is significant the case of **Brazil**, that implemented during the last 20 years a regulatory framework designed to incentive customers and investors with the scope to achieve the projected target of expansion of alternative renewable generation capacities. Another significant case study is **Uruguay**, that experienced a dramatic growth of VRE share in the energy mix, becoming a showcase for what is possible with strong cross-border interconnection and a flexible grid, as well as a clear decision making, a supportive regulatory environment and a strong partnership between the public and private sector.

Possible Roadmap for the transition

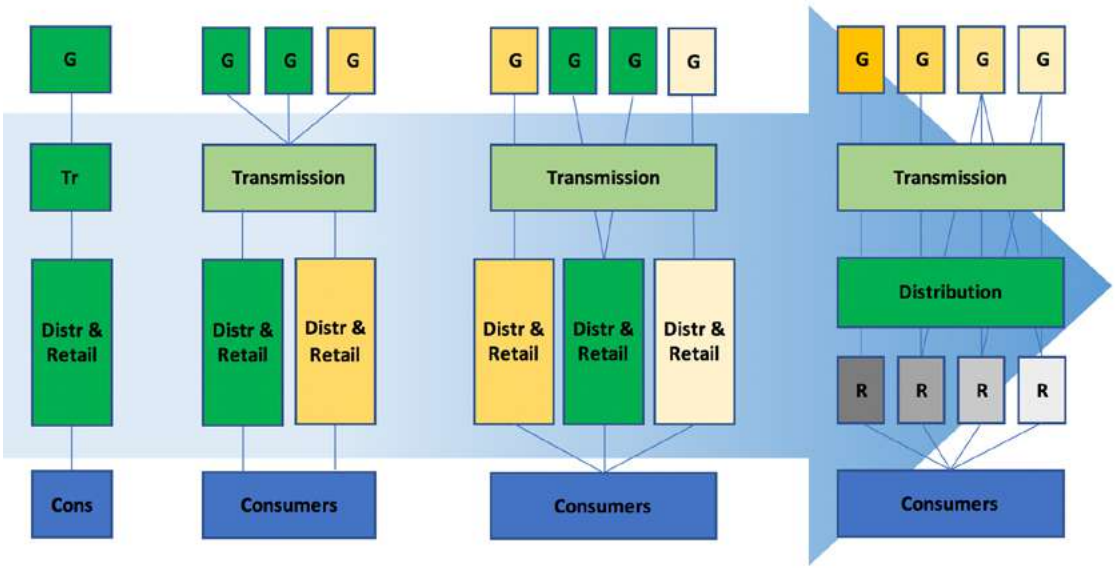
There is no definite best practice or preferable route to implement the process of liberalization in electricity markets. The main steps towards opening markets to competition are generally dictated by existing conditions and characteristics at country level. Some of the aspects taken into consideration are the following:

- Status of market incumbent, if any (state-owned company, public company), investment and expansion policies;
- Degree of market concentration and power, with focus on generation and supply/retail;
- Presence of regional or historically motivated distribution networks;
- Characteristics of customers and demand (share of domestic, commercial and industrial consumers, demand seasonality, presence of relevant interruptible loads, assessment of existing bargaining power);
- Cross border trading, interconnections and long-term arrangements in place;
- Status of available technology (generation mix, transmission / distribution, metering);
- Existence of regulated wholesale prices, PPAs and bilateral agreements;
- Overall system adequacy and reliability (dispatching, ancillary services, generation capacity);
- Current national regulation and participation to international frameworks, markets or systems of rules (energy pools, associations of markets or countries, e.g. "Acquis Communautaire")

It is relevant to highlight how the unbundling process is intrinsically associated with market liberalization, notwithstanding the two concepts do not necessarily coincide. In every electricity market, transmission and distribution are considered natural monopolies, either at national or local level, therefore the allocational efficiency is to be maximized under a monopolistic regime. Liberalization usually entails the protection of consumers, by opening the market to competition in order to achieve better consumer surplus, generally via lower electricity prices.

As previously discussed, there are different models of unbundled systems, such as the competition wholesale market, the single buyer market and the fully liberalised market, and different ways in which they are integrated with the establishment or reorganization of a market operator and/or a system operator.

The following chart describes a possible path to address liberalization.



• Initial vertically integrated market, with transmission and distribution under market incumbent (same color indicates the same company performing different activities) • Regulated and centrally set prices • No choice of supplier for end consumers • Gradual opening of generation to additional players • Addressing Third Party Access (TPA) • Set-up of Market Operator and System Operator with acknowledged dispatch rules • Potential adoption of Single Buyer model to aggregate generation and /or load	• First step of unbundling of transmission and distribution (ring fencing, licensing) • Set-up of regulation of networks • Generators are obliged to provide ring fencing for captive distribution and retail companies under the same holding (in the case that generators are allowed to own or be part of a company that carries out distribution activity) • Distributors perform the supply function and can choose among non-captive generators • Designing wholesale markets (e.g. power pools, power exchanges) with day-ahead and adjustments segments • Introduction of wholesale licensed traders • First differentiation of captive and eligible clients (based on volumes)	• Full liberalized model • Full unbundling of transmission and distribution, according to suitable local framework (TSO; ISO, ITO; other available models) • Fine-tuning of regulation of networks (introduction of efficiency factors, TOTEX) • Establishment of markets for ancillary services and (where required) capacity • Generators bid on day-ahead and intra-day markets (power pools, power exchanges) • Retailers and suppliers purchase energy on the spot market or directly from generators via PPAs and bilateral agreements • Full participation of traders on wholesale markets • All consumers can freely choose their suppliers, based on market preferences

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ANNEX 1 RING-FENCING

Following are described two examples of implementation of ring-fencing arrangements, namely the cases of Malaysia and UK.

Malaysia issued in 2016 a Ring-fencing Guidelines in order to ring-fence the System Operator of the peninsular Malaysia. The guidelines, principles, rules and mechanism for implementation considered:

- Ring-fencing of the SO within the vertical integrated company TNB. This set requirements in order to perform its functions in a non-discriminatory manner and outlined the measures to be adopted in undertaking its daily activities.
- Ring-fencing of Operation, which outlined the operational requirements for the SO in a ring-fenced environment and requests of the procedures to operate in a ring-fenced environment.
- Ring-fencing of Infrastructure and ICT, which sets the arrangement to be developed for the management of the SO's operational systems and the development of the systems shared with the Single Buyer and other entities inside TNB.
- Ring-fencing of Information and data-flow which establish the access and controls for SO data on shared systems and rules for the transfer of data between market participants, including the Single Buyer and other Dept of TNB.
- Ring-fencing of Accounts, which sets the requirements for unbundling the accounts from TNB and the framework of the regulatory accounts.

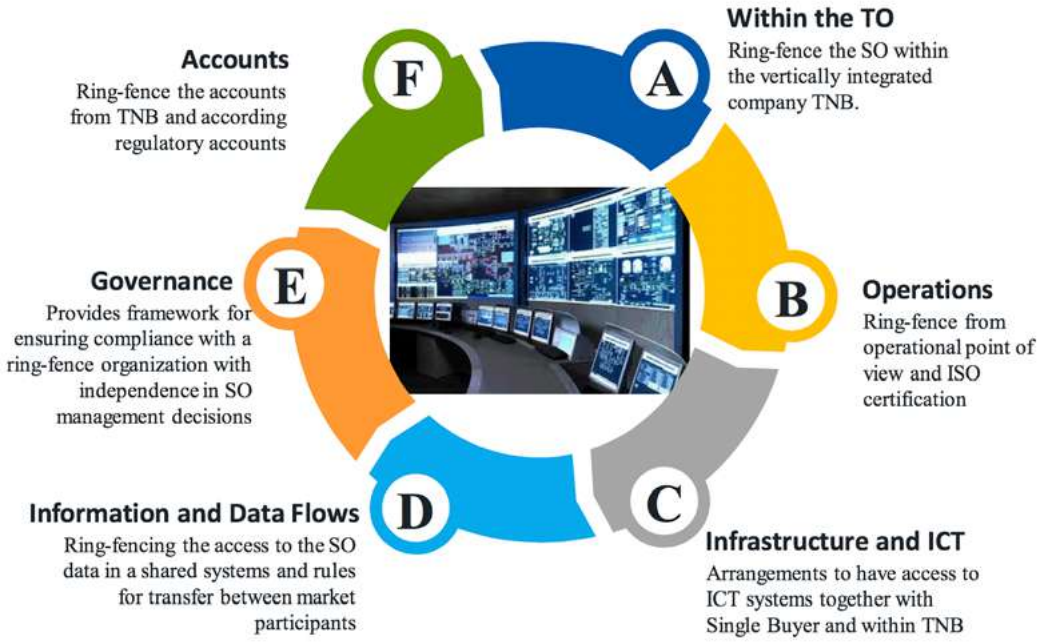


Figure 45: Ring-Fencing of the Malaysian System Operator

After a long consultation process in UK, the regulator (OFGEM - Office of Gas and Electricity Markets) recognised that it may not completely resolve the issues (in the competitive market) of conflict and that risks remain that the TSO (NGET - National Grid Electricity Transmission) could continue to exert undue influence over the SO.

The OFGEM decision was not the ring-fencing (a type of separation), but the complete separation of the SO from NGET:

- Implementing the legal separation of the ESO from NGET on the basis of the appropriate licence changes to underpin the separation requirements;
- Closely monitoring the separation and undertaking a review in 2020-21 to assess the effectiveness of the measures in delivering the benefits of separation; and
- Considering the implementation of additional appropriate separation arrangements that could ensure the effectiveness of separation. These include potential additional licence requirements and/or other policy options.



Figure 46: Ring-Fencing of the UK System Operator

ANNEX 2 ITALIAN CASE

A2.1 Introduction

Italy is regarded a successful example of a fully unbundled, liberalized electricity market. Already a mature market since the start of the liberalization process in the early 2000s, Italy currently enjoys a complete opening in the generation, trading and supply phases, while transmission and distribution are operated according to a regulated monopoly regime, as set up by the Regulator (ARERA- Autorità di Regolazione per Energia Reti e Ambiente). The wholesale market, though not the biggest or the most liquid among European countries, has grown steadily since its beginning, and operational procedures have been fine-tuned and adapted to the specific features of the country's electric Market Zones, as individuated by existing transmission bottlenecks.

A brief overview of the key figures of the market is presented, as well as the main measures taken under government intervention, with specific focus on the regulation of transmission and how the grid expansion is being carried out.

A2.2 Overview of the Italian Market Structure

A2.2.1 Introduction – Key Figures

Italy is 302,000 km² wide with a population more than 60 million people. The GDP in 2019 amounts to USD 2,001,290 million and the GDP per capita is USD 33,156.

Regarding the electricity sector, the Italian installed capacity in 2019 is 115.2 GW, with a net generation of 283.7 TWh and a peak demand of 26.1 GW.

Italy has 74,442 km of transmission lines in the National Transmission Grid (Rete Trasmissione Nazionale – RTN) and an installed transformation capacity of 150 GVA, thus representing the largest fully unbundled TSO in Europe-

Voltage (kV)	km	%
<132	50,031	67.2%
220	11,915	16%
380	12,496	16.8%
Total	**74,442**	100.0%

Table 9: Transmission lines in the National Transmission Grid (Italy)

Two simplified maps of the Italian 380 and 220 kV networks are presented below:

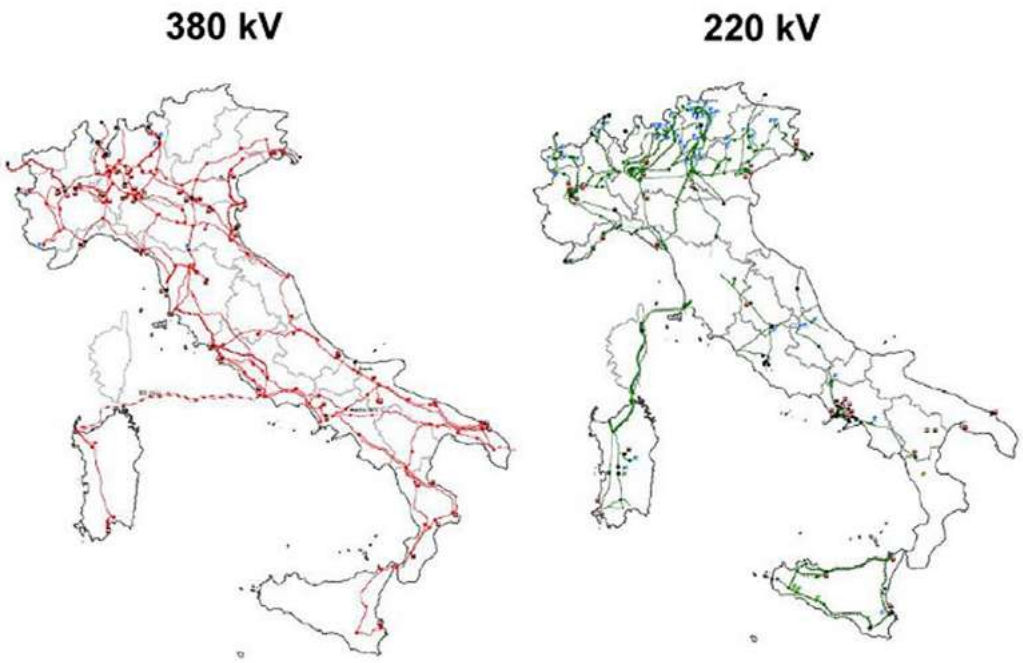


Figure 47: 380 kV and 220 kV networks in Italy

The installed generation capacity in 2019 is detailed in the following table:

Main Sources	Installed Capacity (GW)	%
Hydro	22.9	19.9%
Thermal	61.0	52.9%
Solar PV	20.2	17.5%
Wind	10.3	8.9%
Geothermal	0.8	0.8%
Total	**115.2**	**100.0%**

Table 10: Installed capacity of the Italian generation system in 2019

The main characteristics of the Italian system are the following:

- Mountainous territory, with the presence of several bottleneck along the North – South direction. Geography enables the creation of different electricity zones with different zonal prices ("market splitting"). The Italian system is the most relevant case of market splitting in Europe, together with the Nordpool market;
- Demand is mainly concentrated in the northern area, where much of the industrial production is located, while there are different regional characteristics in terms of generation capacity (renewables are mainly located in the South) and loads
- Presence of two great islands, Sardinia and Corsica, interconnected with the mainland, whose zonal prices have gradually aligned to the National System Price (PUN – Prezzo Unico Nazionale);
- Presence of several interconnection lines with bordering countries (France, Switzerland, Austria, Slovenia) and nearby systems (Malta, Greece and the commissioning interconnection with Montenegro). As in 2019, Italy is a net importer of electricity (38.1 GWh in 2019, corresponding to 12% of total electricity demand);
- Inversion of the traditional North to South electricity flows, thanks to the infeed of priority dispatching renewables from the South.

The Italian power generation mix has undergone a profound change in recent years, both in terms of overall consistency and in terms of the installed capacity. In terms of total consistency, gross installed power has progressively grown to a peak in 2012, only to shrink in recent years. This phenomenon is explained by analyzing the trends that have driven the installations of RES plants and the phase-out of traditional thermal plants.

The main trend that has characterized the last decade has been the unprecedented development of renewables. In particular, between 2008 and 2018, wind power capacity tripled to over 10 GW (3.5 GW in 2008), while the Italian photovoltaic capacity reached a total of 20 GW in 2018, starting from a share of just 0.5 GW in 2008. Overall, installed wind and photovoltaic capacity has increased by more than 26 GW in the last decade, reaching a total installed value of more than 30 GW. The evolution of the installed capacity is presented in Figure 48.

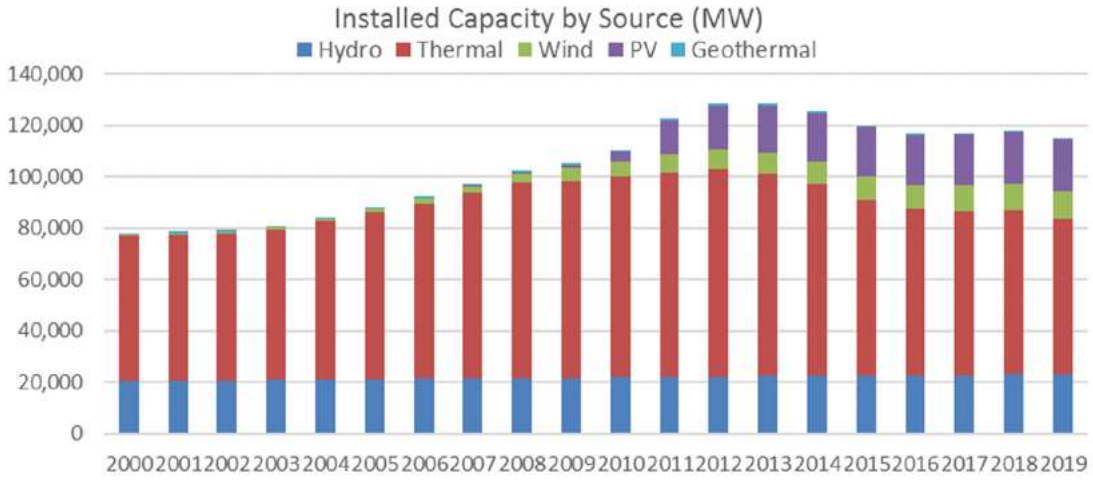


Figure 48: Evolution of the Installed Capacity in Italy (2000-2019)

The mix of resources contributing to national electricity production has varied greatly in recent years. While renewables accounted for about 16% of net production in 2005 (mainly associated with hydroelectric plants), in 2018 this percentage more than doubled, with renewable sources now covering about 40% of national production (113 TWh out of a total of 280 TWh in 2018). Expanding the analysis to also consider foreign exchange, the RES share of total electricity demand (321 TWh in 2018) amounted to more than 35% in 2018. The maximum RES coverage value of 39% was recorded in 2014, a year characterized by an exceptional water supply. The share of production from non-renewable plants on national production has decreased from 84% in 2005 to 60% in 2018 In absolute terms, this reduction is even more evident with the thermal generation that has gone from a value of 236 TWh in 2005 to 167 TWh in 2018(about -30%).

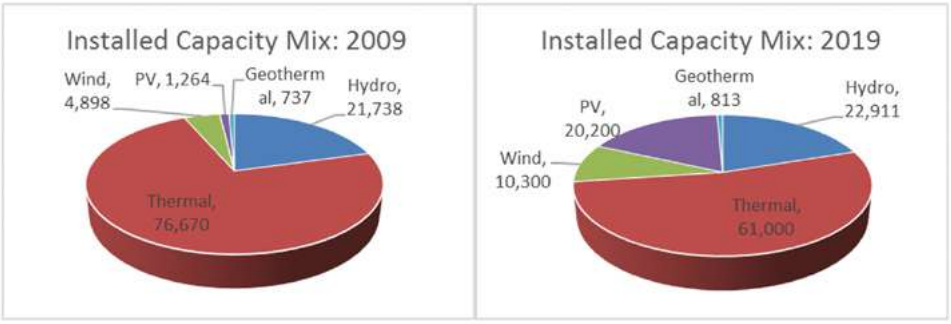


Figure 49: 2009 and 2019 Installed Capacity in Italy

A detailed analysis shows that the growth of renewable generation between 2005 and 2018 (+140%) has been strongly influenced by the increase in production from photovoltaic and wind power plants. In particular, photovoltaic production, almost nothing in 2005, grew at an average annual rate of 95%, reaching the value of about 23 TWh in 2018, equivalent to more than 7% of electricity needs. Wind production and bioenergy production also increased, growing with a CAGR of 17% and 11% respectively, covering a similar share of the demand in 2018, amounting to about 5.5% each.

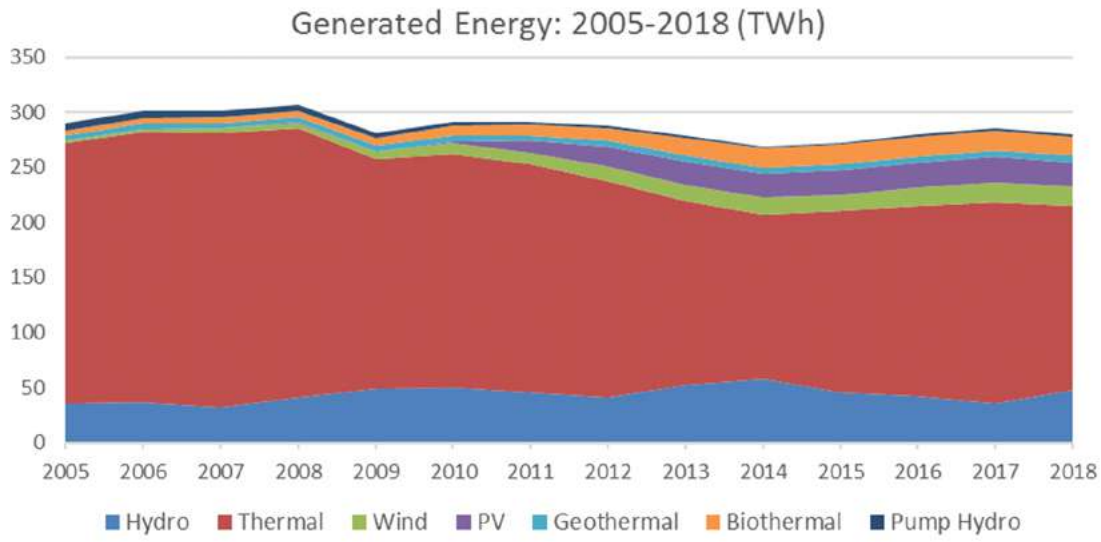


Figure 50: Evolution of the Generated Energy in Italy

The Italian electricity demand, after years of steady and significant growth until 2007 (all-time peak of about 340 TWh), has contracted considerably, reaching a low in 2014 (311 TWh), mainly due to the negative economic situation. The evolution of the demand of the Italian system is represented in Figure 51:

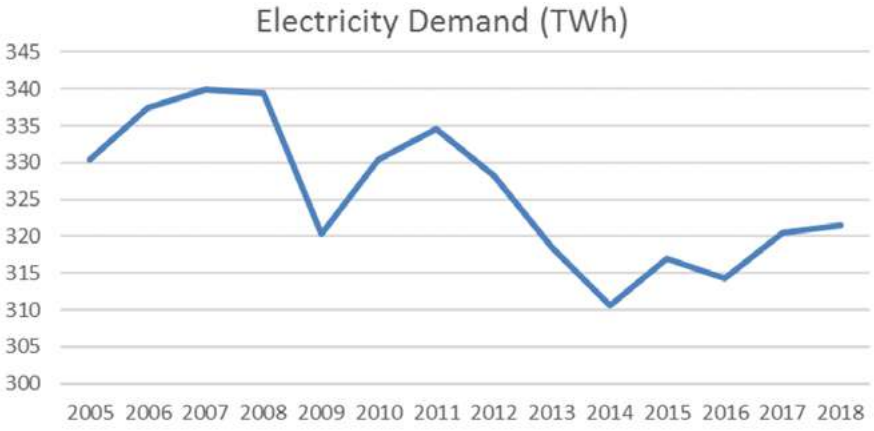


Figure 51: Electricity Demand Evolution in Italy

In the Italian electricity market, a geographical or virtual area is a significant part of the grid in which the balance between supply and demand is determined, for the purposes of safety, by taking into account the physical limits of energy exchange with other neighbouring geographical areas. These limits are determined by using a system security assessment model. The identification of the zones arises from the analysis of the structure of the transmission network at 380 and 220 kV, as well as the power flows, which in the most frequent operating situations affect these connections. Other factors are the location of production plants on the national territory and the energy imports from abroad. This assessment is carried out by considering different scenarios of the electricity grid and different seasonal periods of the year. Italy is currently divided into six market zones.



Figure 52: Electricity Market Zones in Italy

The share of demand not covered by domestic generation, amounting to 14% in 2018, is guaranteed by imports from bordering countries, for a substantially constant percentage share in recent years. Historically, Italy is a net importer of electricity, with an exchange predominantly associated with the Swiss and French borders (over 80% in 2018), where the interconnection capacity is greater. In the two charts below the Scheduled Exchange for a typical summer and winter day is reported.

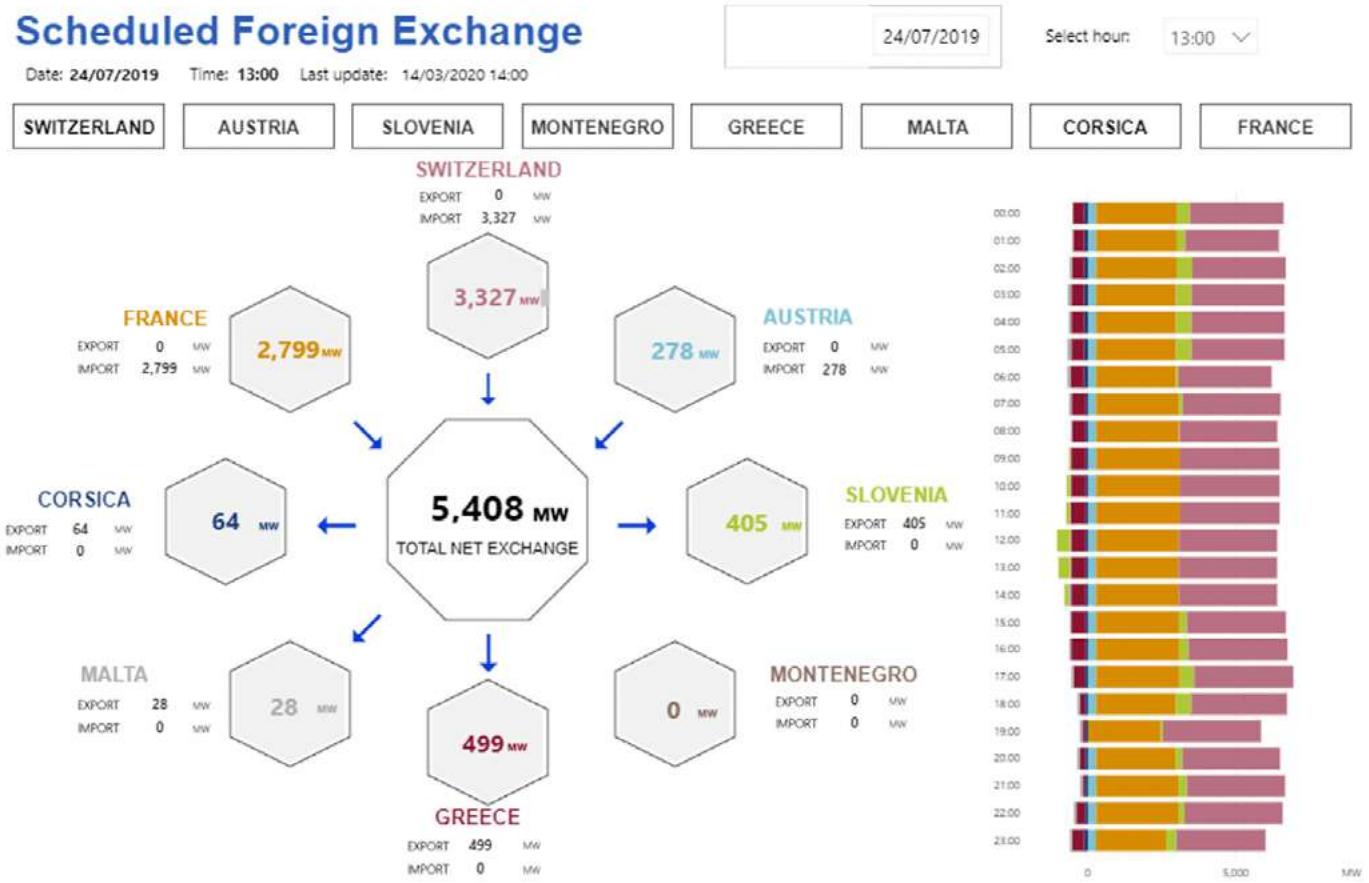


Figure 53: Typical Summer Day: Imports and Exports of Italy

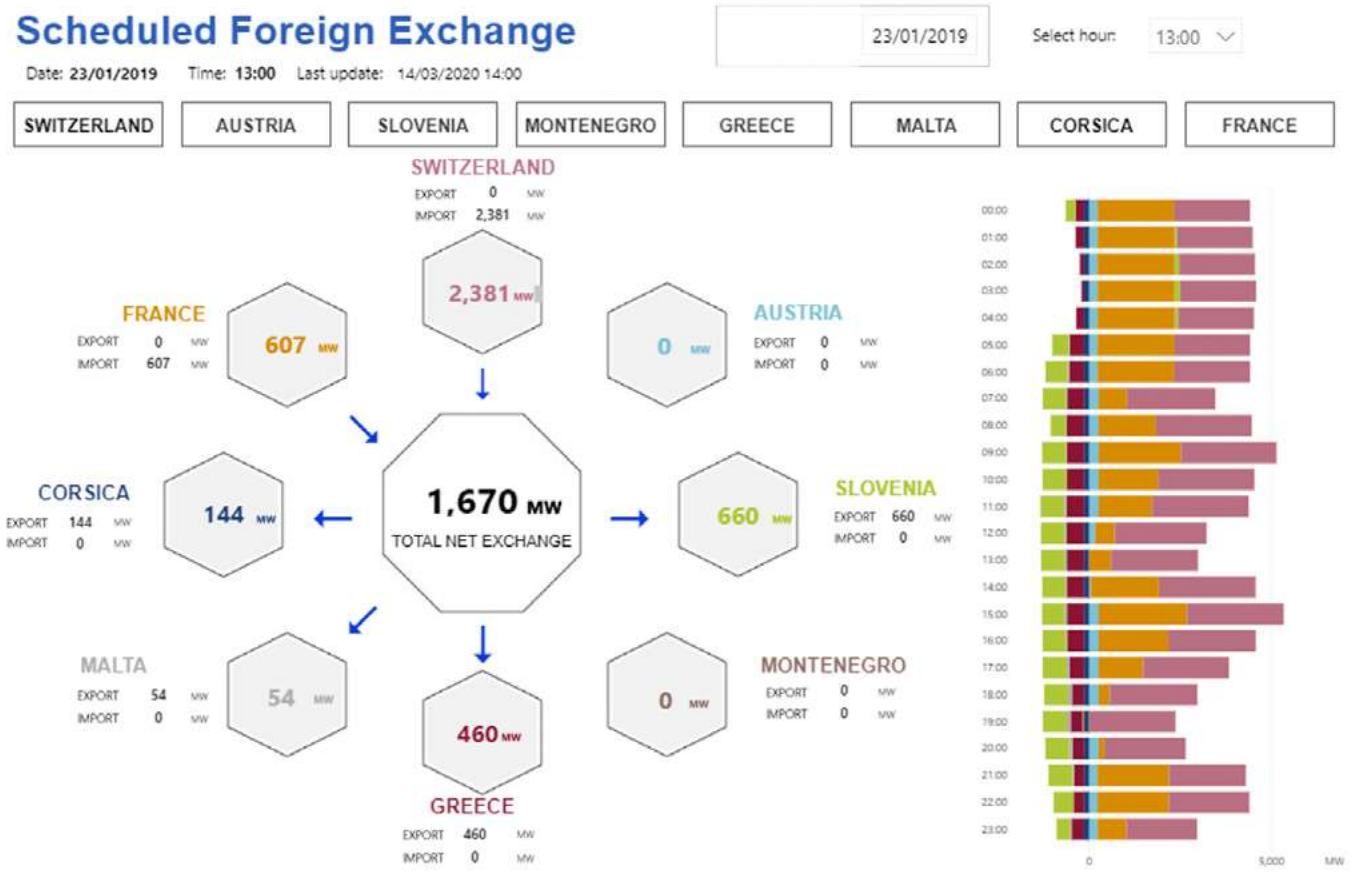


Figure 54: Typical Winter Day: Imports and Exports of Italy

A2.2.2 Structure

A2.2.2.1 Organization and Actors

With the Legislative Decree 16 March 1999, N 79 ("Bersani Decree"), implementing Directive 96/92/CE, the electricity industry, originally vertically integrated under the former market incumbent Enel, was separated into its stages: generation, transmission, distribution and sale, with well-differentiated structures. At the same time, the wholesale market, structured according to a power exchange model, was introduced, in order to enhance and develop trading activity and liquidity.

The main actors in the Italian electricity market are the following:

Ministry of Economic Development (Ministero dello Sviluppo Economico)

The Ministry of Economic Development deals with production, economic activities, energy and mineral resources, telecommunications, consumers, tourism, internationalisation and business incentives. It was formed in 2006 after the reorganization of the Ministry of Productive Activities (called Ministry of Industry, Trade and Handicraft until 2001) to which were merged the Ministry of Communications and the Ministry of International Trade in 2008.

National Regulatory Authority (ARERA: Autorità di Regolazione per Energia Reti e Ambiente)

The National Regulatory Authority was set up with the aim to ensure the promotion of competition and efficiency in the energy sectors. The Authority's action is directed, for all regulated sectors, to ensure the dissemination of services in a homogeneous way throughout the country, to define adequate levels of quality of services, to prepare the transparent tariff systems, to promote the protection of users and consumers. These functions are

carried out by harmonizing the financial economic objectives of service providers with the general objectives of social, environmental protection and efficient use of resources.

System and Market Operator (GME: Gestore dei Mercati Energetici)

The Italian Power Exchange (IPEX) was created in Italy on 31st March 2004 following the approval by the Government and the Regulator of the implementation measures of Legislative Decree 79/99 (cd «Decreto Bersani») which envisaged the structural reform of the electricity sector.

In particular, two companies were incorporated within the Gestore Servizi Energetici (GSE, 100% owned by the Ministry of Economy and Finance): the Market Operator (Gestore Mercati Energetici - GME), with the scope to organize and manage the electricity, natural gas and environmental markets and the Single Buyer (Acquirente Unico - AU) entrusted with the role of guarantor of the supply of electricity to households and small. GME is the NEMO (Nominated Electricity Market Operator) for the day ahead and intraday markets in Italy.

Transmission Operator (Terna)

The Legislative Decree 16 March 1999, N 79 ("Bersani Decree"), implementing Directive 96/92/CE, liberalized the electricity market from the previous integrated model managed by the state utility Enel Spa. In the transmission sector, the Decree originally envisaged the model of the Independent System Operator (ISO), i.e. the separation between the management of the national transmission network, entrusted to a public entity controlled by the Ministry of Economy and Finance (GRTN Spa – Gestore Rete Trasmissione Nazionale), and the activities associated with the ownership of network infrastructure, which remain in the hands of the operator (Terna Spa, as legally unbundled subsidiary of market Incumbent Enel Spa).

Generation

The generation is open to competition and only moderately concentrated. No electric utility is allowed to produce or import, directly or indirectly, more than 50% of the aggregate electricity demand of the system. At the end of 2018, 13,749 electricity producers were registered: operators with the largest share of capacity, equal to 307 subjects, have both thermal and renewable capacity for a total of 50,600 MW. The bulk of this capacity (52.3%) is held by 89 operators, for which renewables account between 30% and 60% of gross capacity.

Distribution

Distribution is based on low voltage network management on a territorial basis, with the creation of several regional distributors: hence each region (or, sometimes, province) has a distribution company, awarded in a concession regime. Companies serving at least 100,000 customers are obliged to separate distribution activities from supply activities. This led to a process of rationalization and merging of operators at regional and local level, with a steady decrease over time. Al 31 dicembre 2018 risultavano registrati 130 distributori elettrici, quattro in meno rispetto ai 134 iscritti al 31 dicembre 2017.

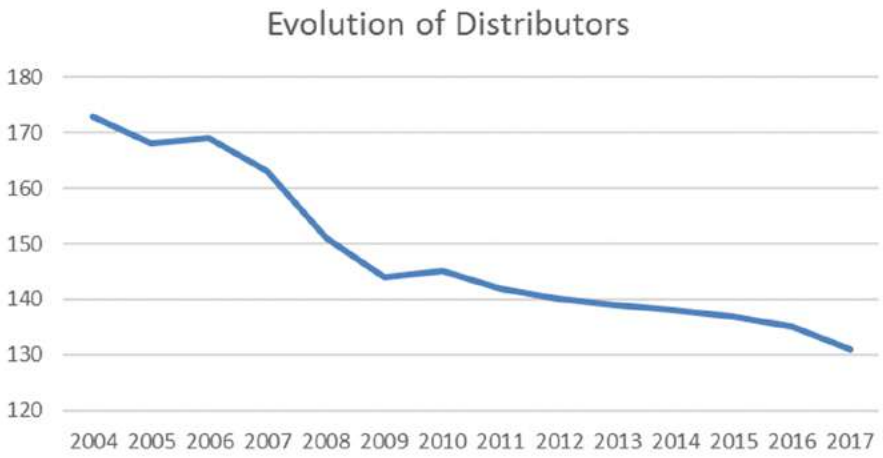


Figure 55: Evolution of Distributors in Italy

Suppliers

With the liberalization many operators were allowed to enter the market as supply companies. Starting from July 2007, all clients were allowed to freely choose their electricity supplier. The end of the market for captive customers (Mercato di Maggior Tutela), whose prices are set in advance by the Regulator, has been delayed several times in the past, and it is due to end in January 2022. Captive customers steadily declined as the market gradually opened to competition, but still represent a relevant share of the market.

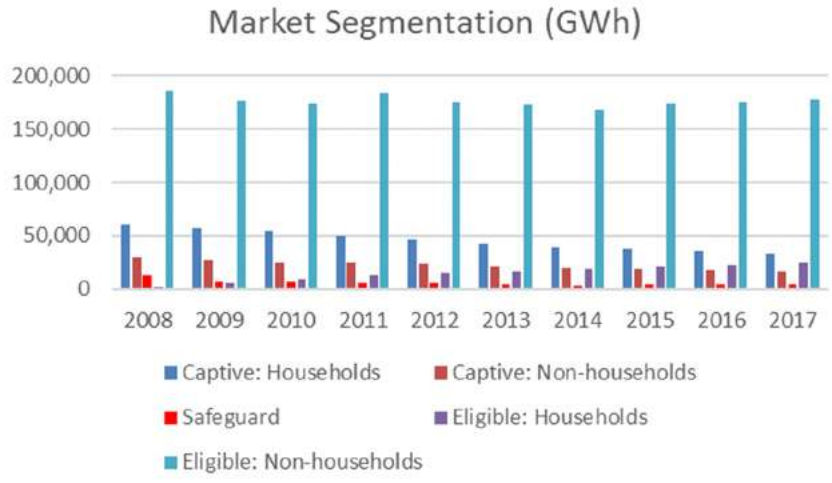


Figure 56: Evolution of Market Segmentation by Type of Customer

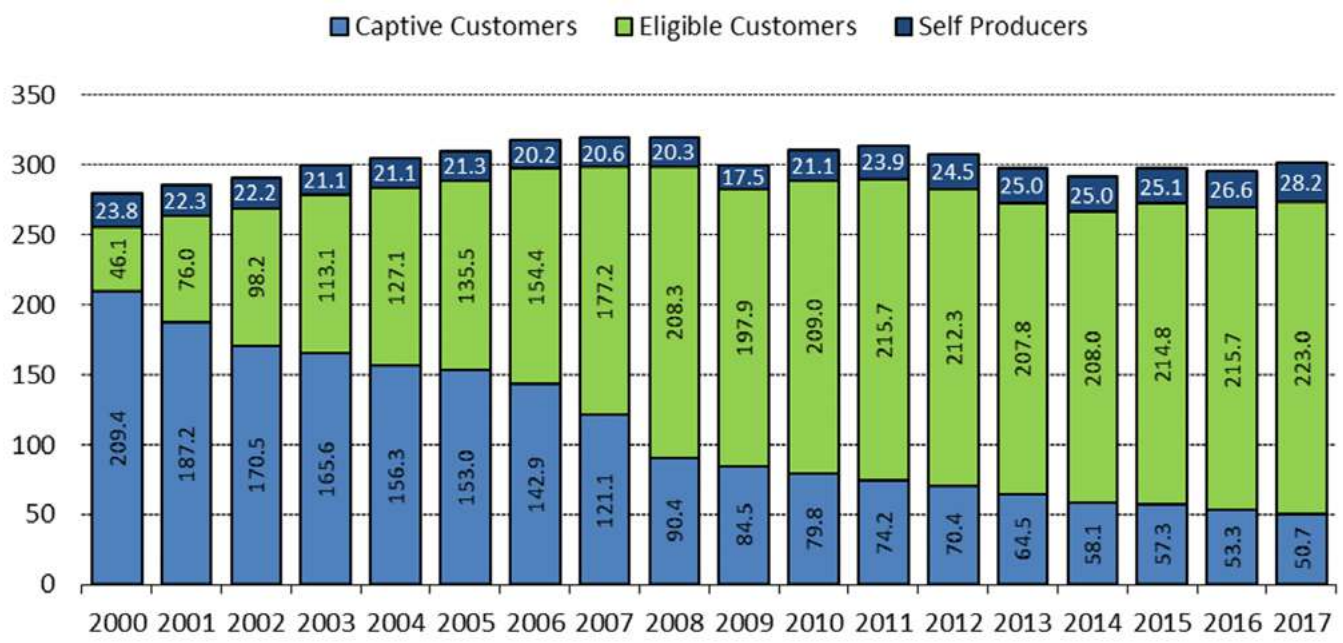


Figure 57: Evolution of Captive vs Eligible Customers

A2.2.2.2 The Italian Markets

The Italian electricity markets are managed by GME and are divided into the Spot (wholesale) Electricity Market and the Forward Electricity Market.

The Spot Market defines electricity prices and the entry and withdrawal programmes for each time of day. It is divided into the Day-Ahead Market (Mercato del Giorno Prima – MGP) and Intraday Market (Mercato Infragiornaliero -MI]), which host most of the electricity trading transactions. On MGP, the sales offers are valued at the marginal (pay-as-clear) price of the market area to which they belong. Purchase offers, excluding those submitted by pumping plants, are valued at the national single price (PUN), equal to the weighted average of area prices.

The Dispatching Services Market (Mercato dei Servizi di Dispacciamento -MSD), operated by Terna, is the trading platform through which Terna supplies the resources necessary to manage and control the electrical system, to keep the production and consumption of electricity in constant balance. On MSD, offers are accepted on the basis of economic merit, compatible with the need to ensure the proper functioning of the system, and are remunerated at the price presented (pay-as-bid). The Dispatching Services Market is divided into a programming phase (MSD ex-ante), in which Terna accepts bids to modify the resulting programmes for the resolution of network constraints and the supply of the reserve, and a phase of real-time balancing (MB) in which Terna procures resources to carry out the regulatory services and maintain the real-time balance between supply and demand.

The Forward Electricity Market (Mercato a Termine dell'Energia – MTE)) is the venue where forward electricity contracts with delivery and withdrawal obligation are traded. In the Italian system, MTE is an illiquid market.

The Energy Accounts Platform (Piattaforma dei Conti Energia - PCE) is GME bilateral contract registration platform. The PCE allows the registration of five types of contracts including four standard (Base-load, Peak-load, Off-peak, Weekend) and one Non-Standard. Operators can record quantity and delivery time data for futures contracts two months ahead of the physical delivery date.

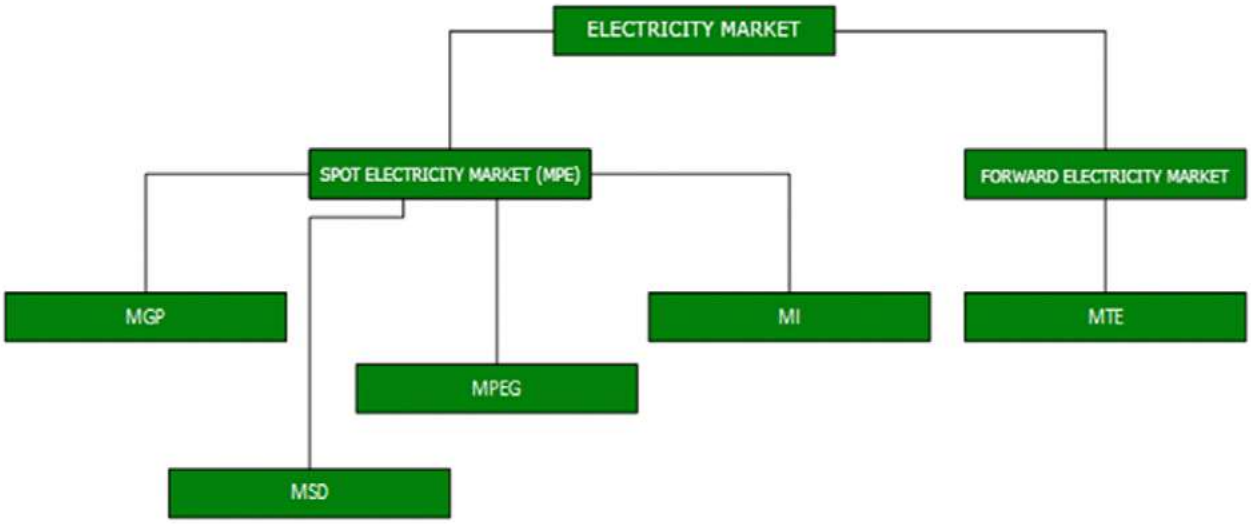


Figure 58: Electricity Markets in Italy

There are currently 284 registered market participants on the Italian Power Exchange.

The clearing price generally identifies the price that is set in the MGP, MI, MPL and MGS at the intersection of demand and supply curves, so as to balance demand with supply, maximise social welfare and perform efficient transactions. In the Electricity Market, the clearing price is determined in each hour and, if the market is split into 2 or multiple Zones, both in the MGP and in the MI, it may be different in each Market Zone (Zonal Price). In the MGP, the zonal clearing price may be applied to all supply offers, to demand bids in respect of mixed units and to demands bids in respect of consuming units belonging to Virtual Zones. Demand bids in respect of consuming units belonging to Geographical Zones are always valued at the National Single Price (PUN). In the MI, in case of market splitting into 2 or multiple zones, the zonal clearing price is applied to all supply offers and demand bids.

The National Single Price (Prezzo Unico Nazionale - PUN) is the average of Zonal Prices in the Day-Ahead Market, weighted for total purchases and net of purchases for Pumped-Storage Units and of purchases by Neighbouring Countries' Zones. Each Zonal Price is the clearing price in each geographical zone.

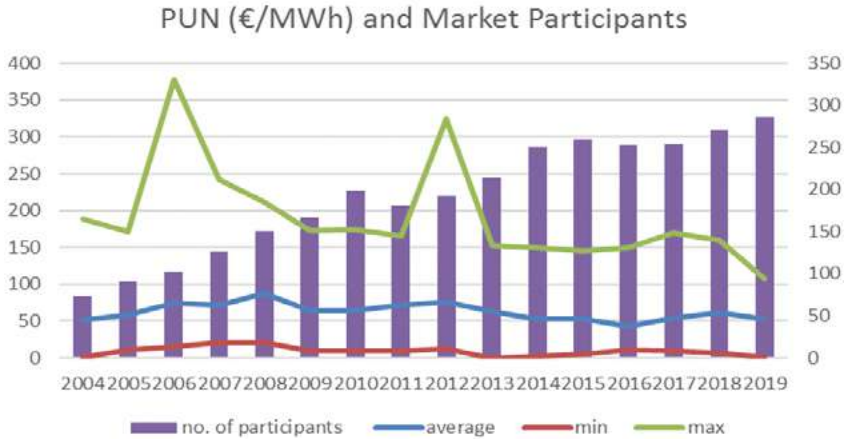


Figure 59: Evolution of PUN and Market Participants

The overall market liquidity, i.e. the share of electricity traded on the day-ahead segment of the Power Exchange over the total volumes traded on the Italian System, has gradually increased since the inception, reaching 72% in 2018, with a main share represented by non-institutional participants. The quantities purchased by the Single Buyer (see below) are about 20% of the total traded on the Exchange, while priority dispatching sales for Renewables managed by GSE (Gestore Servizi Energetici) are slightly lower in terms of volumes.

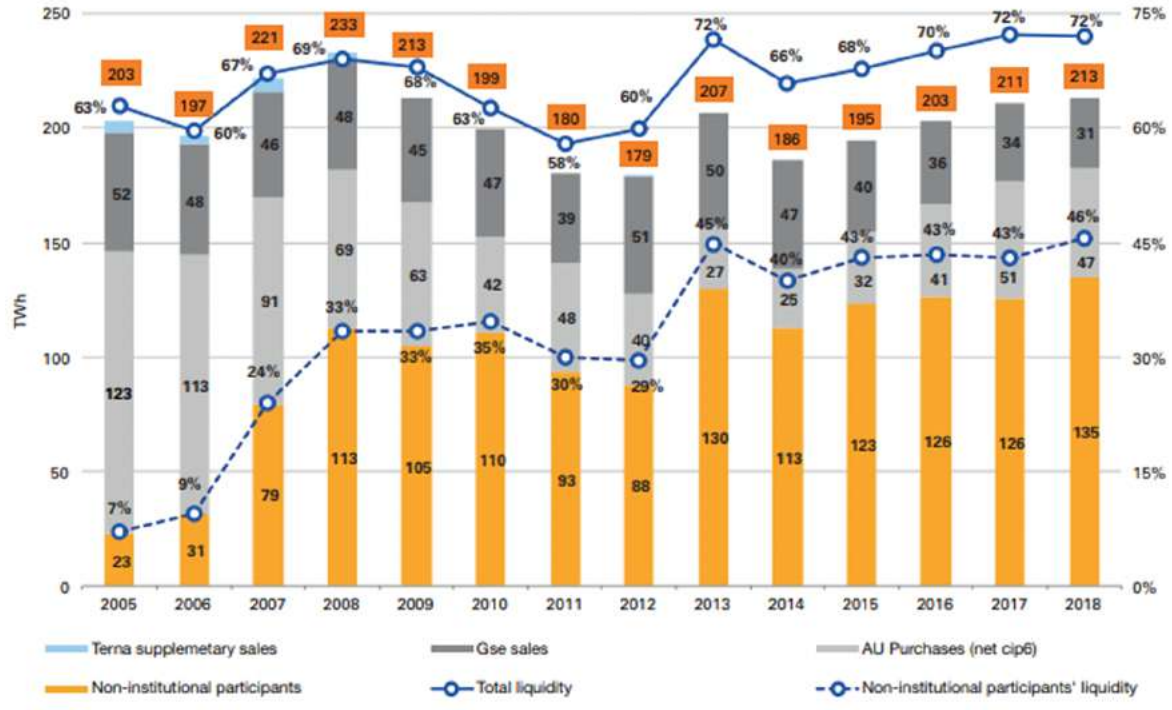


Figure 60: Liquidity, Market Participants and Single Buyer

Single Buyer

The Single Buyer (Acquirente Unico – AU), a public company wholly owned by energy services manager SpA, was created with the aim of ensuring the supply of electricity to captive customers in the protected market (Mercato di Maggior Tutela). In the current market environment, AU is sourcing electricity for the protected market (for domestic consumers and small businesses, with fewer than 50 employees and 10 million euros in turnover, which did not opt to move to the free market). Based on AU's procurement costs, an average energy price is defined monthly, then transferred to the companies that supply electricity to the protected market, which is therefore derived from the meeting of supply and demand on the wholesale markets.

Activities of the Single Buyer:

- forecasting the protected market demand to minimise the burden of imbalance
- forecasting purchase prices so that the Authority can determine the tariff of protected customers
- buying energy on the wholesale market and formulating offers
- contracting energy and/or capacity contracts with producers (bilateral contracts and imports)
- risk coverage through contracts to differences and/or other derivative contracts
- contracting sales contracts with distributors (according to ARERA directives)
- selection of suppliers for the Safeguard Service

In the chart below, the regulated tariff breakdown for captive customers, as provided by ARERA, is presented:

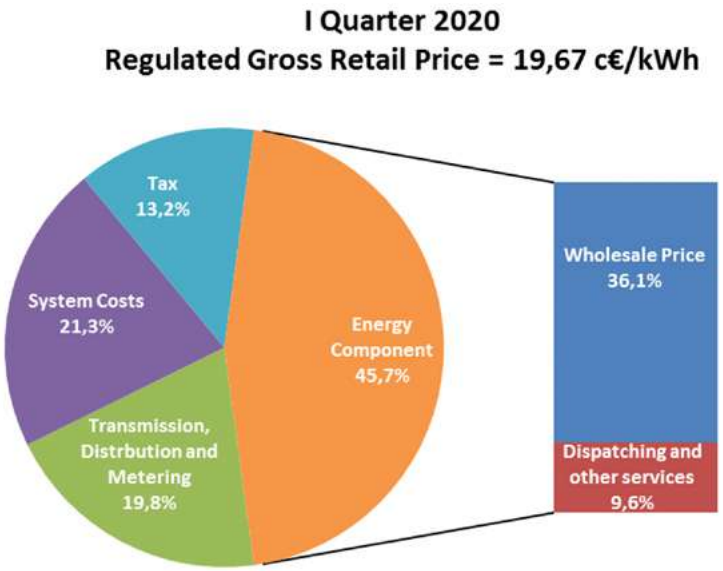


Figure 61: Regulated Gross Retail Price in Italy

A2.3 Transmission Activity

A2.3.1 Overview

The electricity sector, like in most of European countries foresees the following activities:

- Electricity Transmission. This is a monopolistic activity remunerated via tariffs approved by Regulator. The transmission company Terna is not allowed to generate or distribute electricity and is not allowed to have any interests in any generation and/or distribution company.
- The Third Party Access (TPA) is mandatory in order to guarantee the free access to the market by the Generators, Distribution Companies and Big Customers. Exceptions to TPA might be guaranteed, according to EU provisions, under specific conditions
- Distribution activity is a monopolist activity regulated and tariffs being approved by the Regulator ARERA

The chart below evolution of the km of lines in 500 kV (High voltage) and in 132kV, 220 kV and 330 kV named Transmission Backbone and the installed transformation capacity is presented in the following pictures:

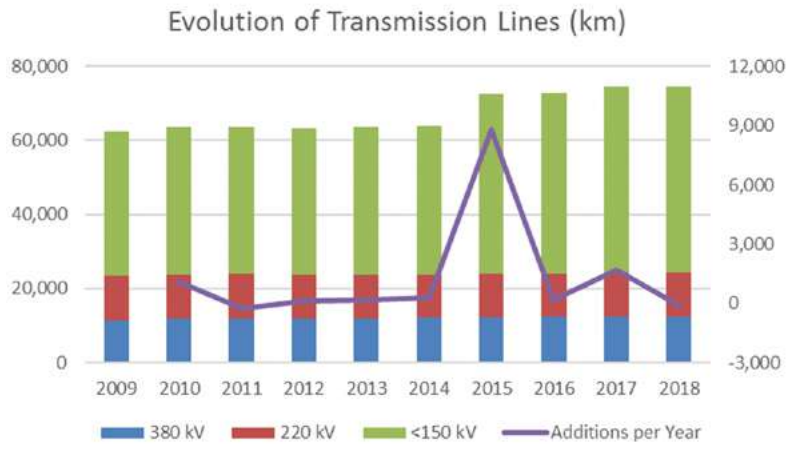


Figure 62: Transmission Lines Total (bars) and increment per year (line)

There is a clear evidence of two processes taking place since the beginning of the liberalisation:

- Expansion of the transmission grid, driven by the acquisition and merging process with existing high voltage networks, such as the lines belonging to the national railways company, or by a strategically plan of new commissioning, essentially driven by the necessity to solve existing transmission bottlenecks;
- Rationalisation of the existing network, and de-commissioning of phased-out or redundant portions of the grid

The increment of the transformation capacity follows the increment of the transmission lines extension. The evolution of the transformation capacity in MVA is presented in the following graph.

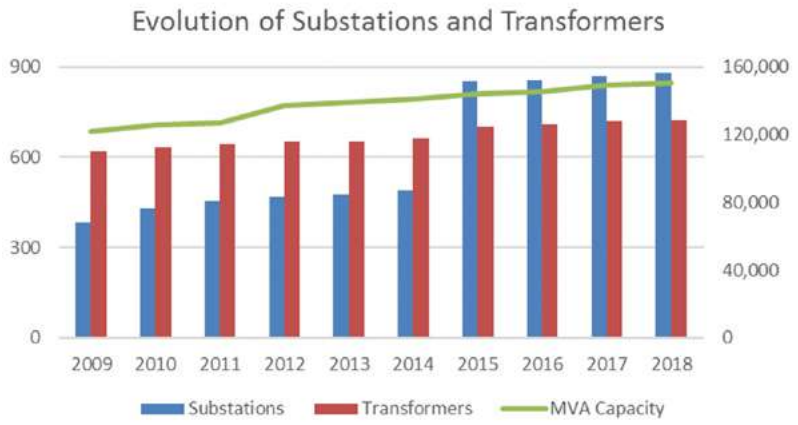


Figure 63: Substations and Transformers Total (bars) and MVA Capacity per year (line)

The figures below represent the current work in progress and the long term expansion plans, respectively, affecting the Italian transmission grid:

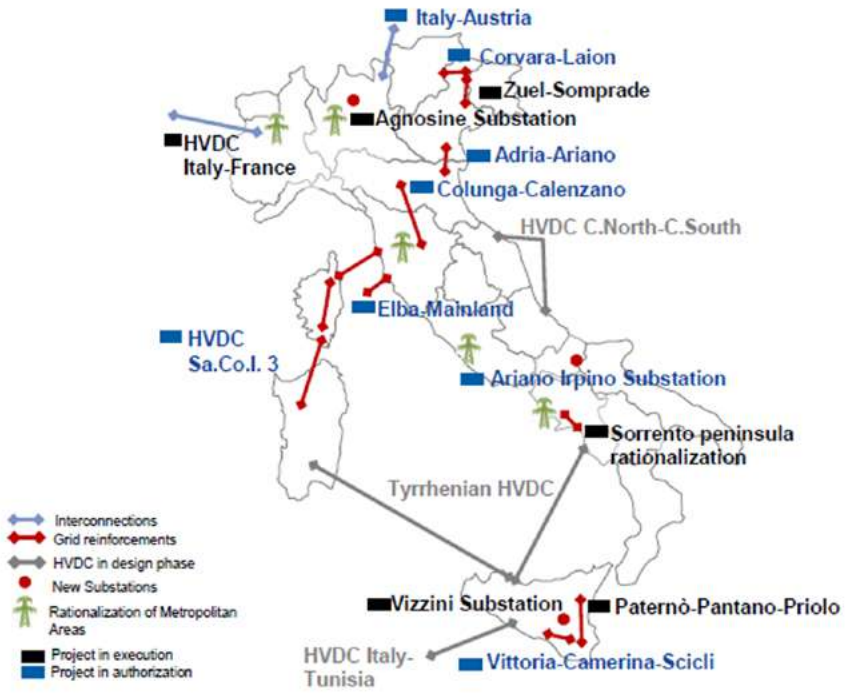


Figure 64: Long Term Expansion projects in Italian Transmission grid

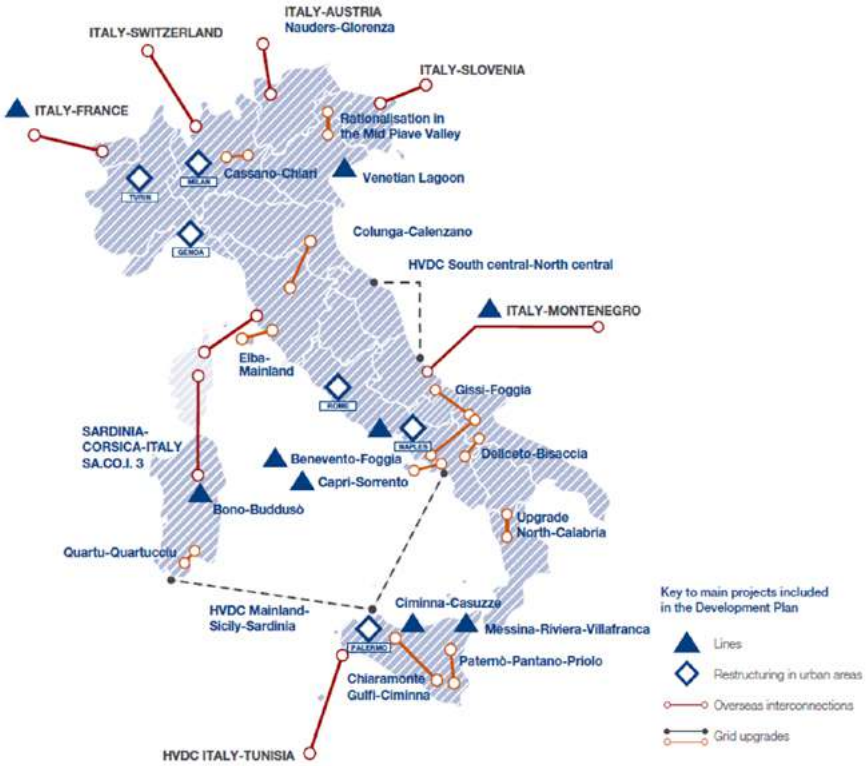


Figure 65: Current Expansion projects in Italian Transmission grid

Terna identifies four main categories of intervention, enabling to achieve national decarbonisation targets:

1. Investments on the national transmission network and foreign interconnections, aimed at strengthening the knitting of the network, reducing congestion and removing constraints;
2. Long-term price signals for the purpose of either building or converting next-generation programmable plants (e.g. flexible and efficient gas plants to replace the most obsolete and polluting thermal capacity) through mechanisms such as the market of the capacity, both to promote the construction of new RES plants and new storage capacity through tools such as power purchase agreements (PPA) and term contracting;
3. Evolution of markets to promote their integration at European level and to ensure the right balance between the push for participation of new flexible resources (demand, distributed generation, storage) and centralized and co-optimised management of services, necessary to continue to ensure the safety and efficiency of the Electrical System;
4. Investments in digitalization and innovation in an increasingly complex electrical system, both for network management and to observe and control distributed resources in real time.

Terna's 2019 Development Plan includes investments of more than 13 billion EUR, to manage the energy transition and ensure the safe integration of renewables with the development needs of the national electricity grid. Additional benefits include:

- increased overall foreign exchange capacity, estimated to be around additional 6,000 MW
- congestion reduction for about 5,000 MW
- decrease in energy losses by about 1,600 million kWh per year
- reduction of CO2 emissions amounting to about 6.3 million tonnes per year, corresponding to those produced by about 7 million medium-sized cars

In 2030, in fact, the Integrated National Plan for Energy and Climate (Piano Nazionale Integrato per l'Energia ed il Clima - PNIEC) envisages that RES will cover more than half of the gross electricity consumption (55.4% vs 34.1% in 2017), which corresponds to about 187 TWh of energy produced. Speaking exclusively of Italian

generation (excluding foreign balance and pumping energy), RES are expected to account for more than 60% of net production. Today, this share is around 39%. This implies a major transformation of the generation capacity to address a strong RES development. This expansion will mainly be driven by photovoltaic and wind power plants, whose production will have to triple and more than double by 2030, respectively.

A2.3.2 Transmission Tariff

The electricity transmission sector in Italy, as a regulated business, entered its 5th regulatory period in 2016: the period is expected to last 8 years (2016-2023). Since liberalization, the regulatory periods were scheduled as follows:

- 1st regulatory period (2000-2003)
- 2nd regulatory period (2004-2007)
- 3rd regulatory period (2008-2011)
- 4th regulatory period (2012-2015)

The 5th period consists of two 4-year subperiods: the first (NPR1), from 2016 to 2019, is characterized by substantial methodological continuity with the past; the second (NPR2), from 2020 to 2023, provides for the introduction of a new approach, based on cost recognition in relation to total spending (TOTEX), in order to avoid distortion between OPEX and CAPEX decisions.

The chart below highlights the three components of the Grid Fee tariff in 2016-2023:

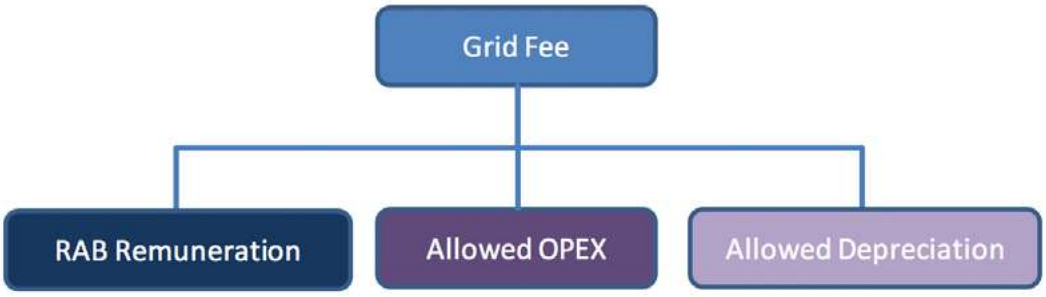


Figure 66: Components of the Grid Fee tariff in 2016-2023 (Italy)

RAB Remuneration

With regard to incentivized investments, the regulatory framework introduces a 1% incentive for specific new categories, labelled I-NPR1 and O-NPR1 investments.

The so-called time-lag, the delay with which the tariff pays for the investments made by Terna and entered into operation, is reduced by 12 months from the previous 24 months (the depreciation rate remains at 24 months) and the compensation expected in the previous regulatory period is eliminated.

The simplified formula for the calculation of RAB component is the following

$$RAB\ Rolling = [RAB_{t-1} \times (1 + Deflator) + (Capex_{t-1} - Depreciation_{t-1})] \times WACC$$

The Regulatory WACC used for the remuneration of the Regulatory Asset Base (RAB) is broken-down in the table below.

Main Sources	2016-2018
Risk-Free Rate (Real)	0.50%
Country Risk Premium (CRP)	1.00%
Beta asset (unlevered)	0.35
Total Market Return (TMR)	6.00%
Equity Risk Premium (ERP)	5.50%
Tax Shield	27.50%
Gearing = D/(D+E)	44.44%
Debt Spread	0.50%
Expected Inflation	1.50%
Tax Rate	34.4%
WACC Real Pre-Tax	**5.3%**

Table 11: Regulatory WACC used for the remuneration of the Regulatory Asset Base in Italy

Allowed OPEX

With regard to recognized operating costs (OPEX), the calculation methodology foresees the initial level of operating costs recognized in previous year to be updated every year based on inflation and with a progressive return of X-factor extra-efficiencies, valid for both transmission and dispatch.

The simplified formula for the calculation of OPEX component is the following

$$OPEX\ Rolling = OPEX_{t-1} \times (1 + Inflation - X\ Factor)$$

Allowed Depreciation

The new period increases the recognized useful life for transmission line regulators from the current 40 to 45 years. This will result in a reduction in recognized depreciation, in the face of a slower deterioration of RAB.
The simplified formula for the calculation of Depreciation component is the following

$$Depreciation\ Rolling = Depreciation_{t-1} \times (1 + Deflator) + Capex_{t-2} \times Depreciation\ Rate$$

Tariff for End Users

The tariff for end users is binomial, with a tariff energy component (CTRE) intended to cover 10% of the cost of the service and a power component (CTRP) intended to cover the remaining 90%. The overall exposure of transmission revenues to the so-called volume effect appears to be reduced overall compared to the previous adjustment.

ANNEX 3 BRAZILIAN CASE

A3.1 Introduction

The objective of analysing the Brazilian market is to present the positive and successful results after the second reform that began in 2004. The Brazilian system is dominated by hydroelectric power and because of this it suffered rationing periods for the entire population in 2001. Brazil performed remarkable reforms in its market model in order to meet the adequacy and increase the security of supply in the short and long term.

The continental dimensions of Brazil require a greater volume of investments and there is also a need to attract investors in order to meet the growing demand.

Brazil is considered one of the successful models in the Latin America region and its experiences as an emerging market may be valuable for Eskom.

A3.2 Brazilian Market Structure

A3.2.1 Introduction – Key Figures

In 2019 the installed capacity in Brazil reached 168.3 GW and the generated electricity 593.6 TWh, that is near 58% of the generation of the whole South America.

Brazil territorial extension is 8,514,876 km² (6th country after Russia, Antarctica, China, USA and Canada) with a population of more than 209 million people. The GDP in 2019 amounts USD 1.86 trillion and the GDP per capita is USD 8,959.

Brazil has a continental dimension and it is comparable to Europe.

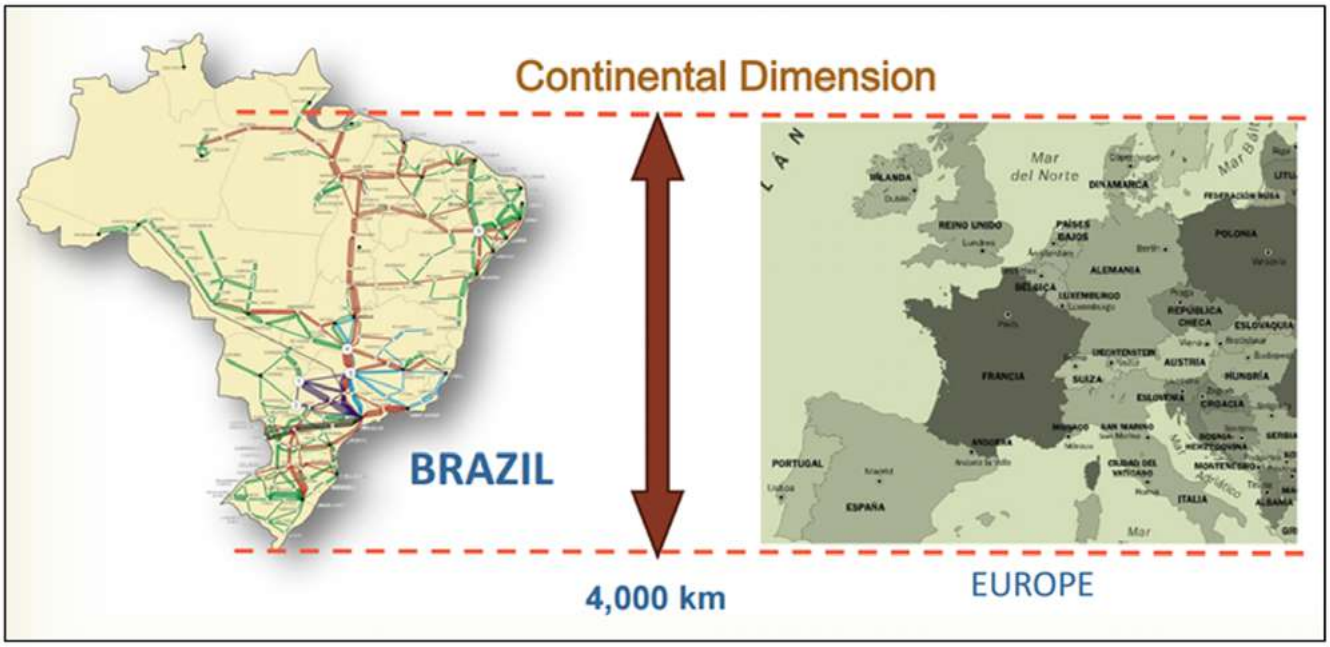




Figure 67: Brazilian Electricity Interconnected System (SIN)

Brazil has 126,764 km of transmission lines in the National Interconnected System (SIN) and an installed transformation capacity of 305 GVA (see table below).

Voltage (kV)	km	%	Capacity MVA
230	53,024	41.8%	79,390
345	10,303	8.1%	49,795
440	6,741	5.3%	23,916
500	41,197	32.5%	129,842
600 (DC)	12,816	10.1%	-
750	2,683	2.1%	22,500
Total	**126,764**	100%	**305,443**

Table 12: Transmission lines in the National Interconnected System (SIN) - Brazil

A simplified diagram of the Brazilian system and its four operative areas are presented in Figure 68.

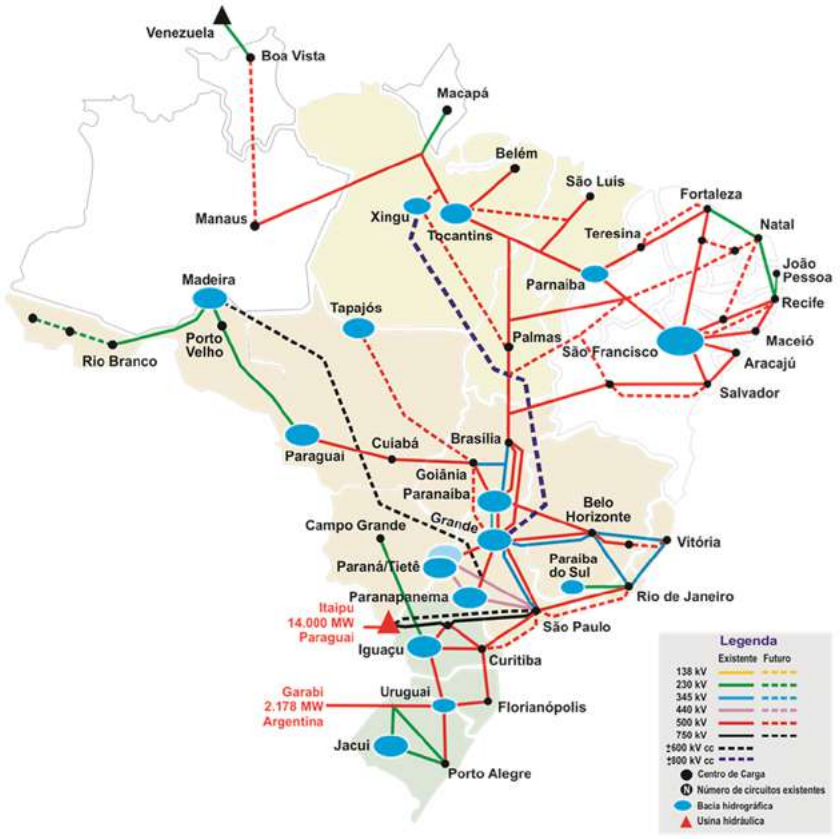


Figure 68: Simplified Brazilian Electricity Interconnected System and main Areas

The installed capacity of the Brazilian generation system is one of the largest in the world: 168,290 GW, the 6th in World after China, USA, Japan, India and Germany (Table 13).

Main Sources	Installed Capacity (MW)	%	No. of Power Plants
Hydro	114,116	67.8%	1,189
Thermal	34,466	20.5%	2,802
Nuclear	1,990	1.2%	
Wind	15,273	9.1%	273
Solar	2,445	1.5%	25
Total	**168,290**	**100%**	**4,209**

Table 13: Installed capacity of the Brazilian generation system in 2019

A comparison of the Brazilian system with the network extension in Europe is shown in Figure 69.



Figure 69: Comparison between Brazilian Electricity Interconnected System and Europe (Source: CCEE)

The main characteristics of the system are:

- Long distances;
- Regional or Area different characteristics;
- Electric restrictions (Technical and stability limits);
- Predominant Hydroelectric System.

The Brazilian demand growth is compared with the second biggest system in South America, namely Argentina:

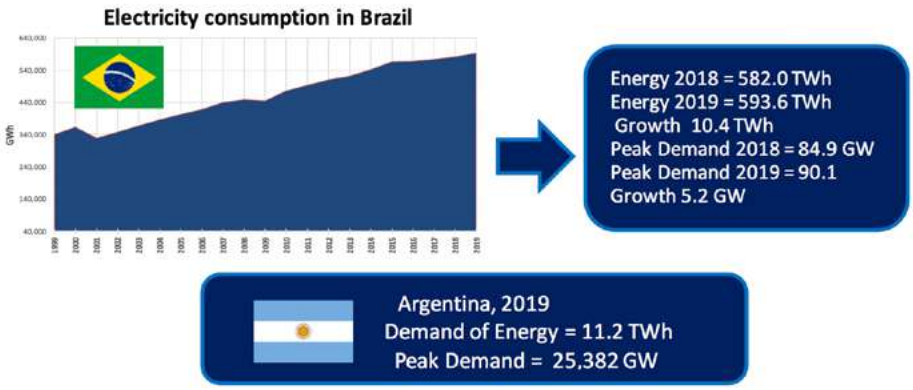
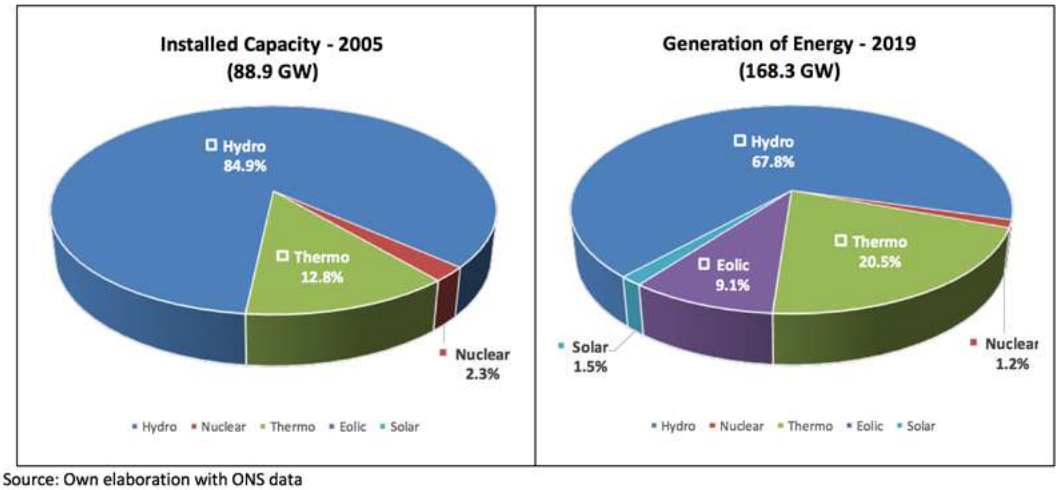


Figure 70: Comparison between growth of the Brazilian System and Argentina

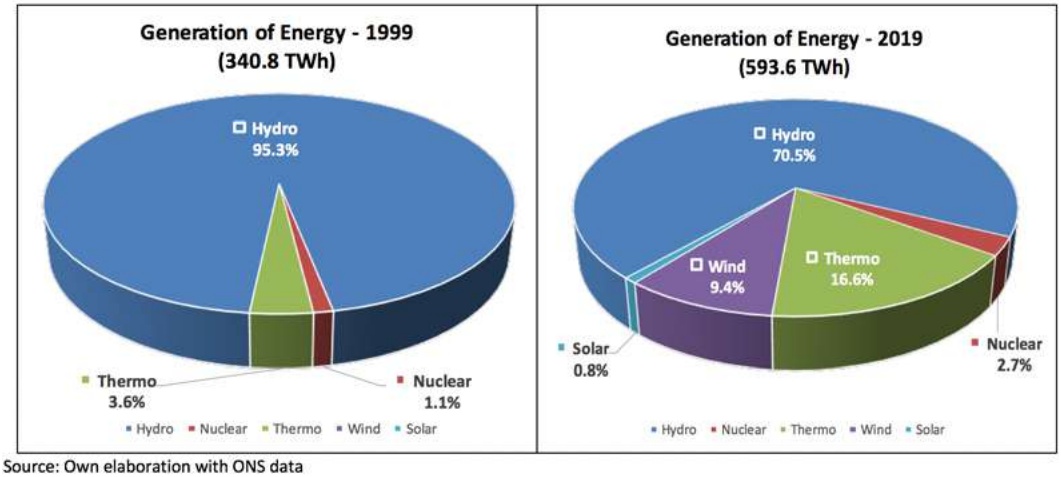
Brazil requires in terms of energy, one Argentina equivalent system every year to support the consumption growth over the next decades.

The evolution of the installed capacity is as follows:



Source: Own elaboration with ONS data

Figure 71: Evolution of the Installed Capacity in Brazilian Electricity System



Source: Own elaboration with ONS data

Figure 72: Evolution of the Generation Mix of the Brazilian System

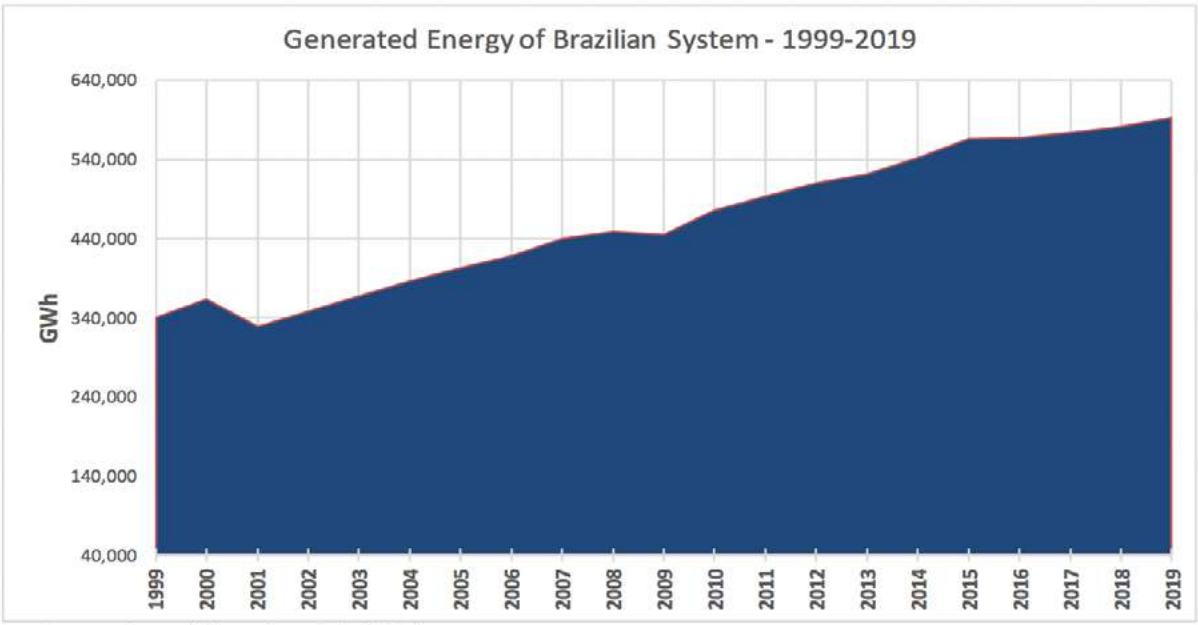


Figure 73: Evolution of the Generated Energy in Brazil

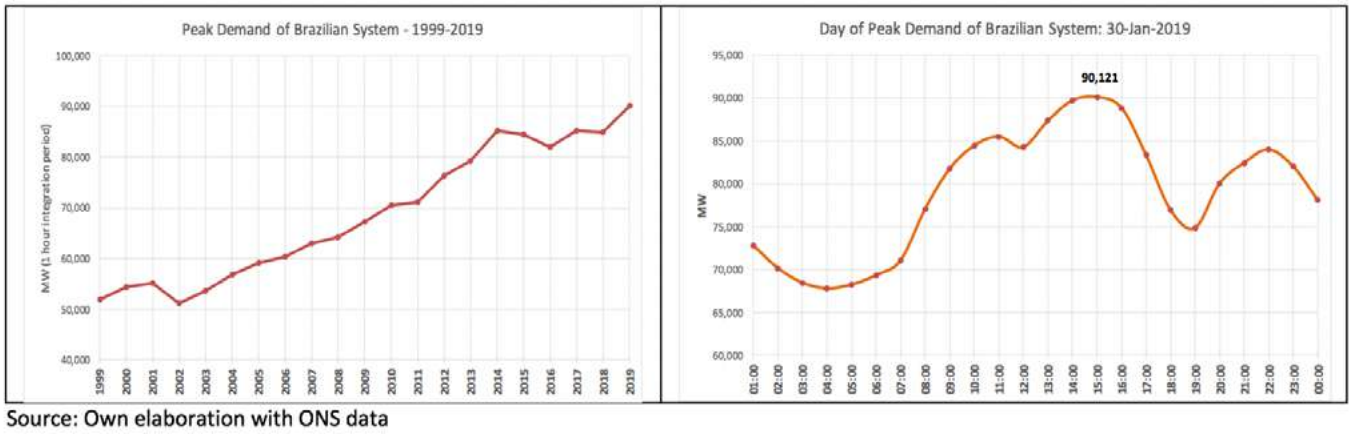
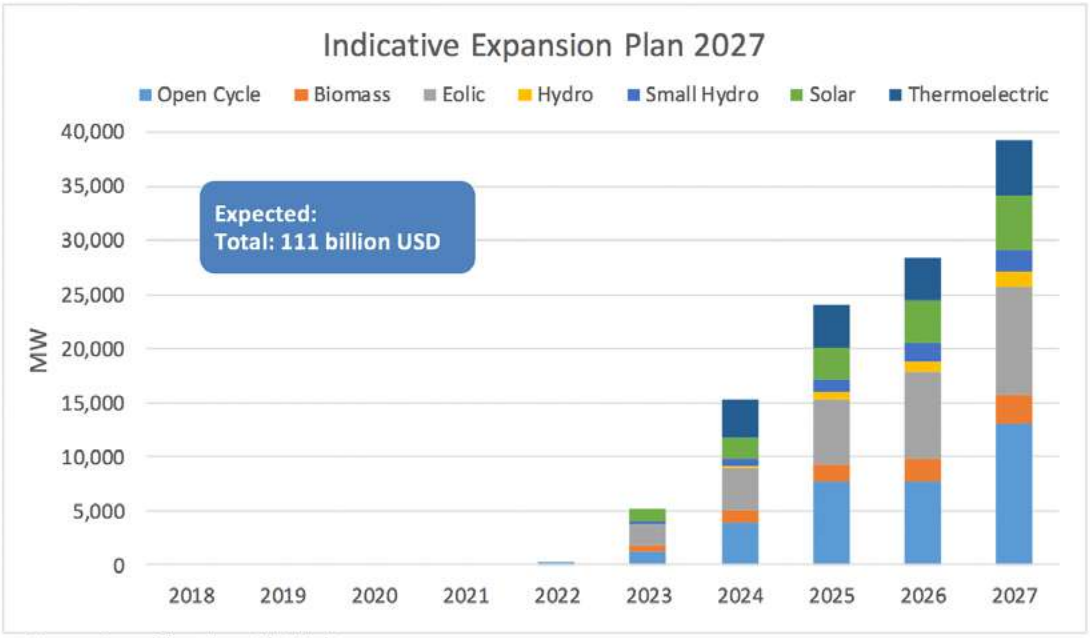


Figure 74: Evolution of the Peak Demand in Brazil and Load Curve

The investments in the Brazilian system are huge and require a strong policy and market design to support and afford this level of investments in a developing economy. The expected investments in transmission are 5.6 billion in the short-term and 3.8 in the long-term (Figure 76). This is one of the key points to analyse in this system and consider the key successful characteristics that could provide a benchmark for the South African electricity market.



Source: Own elaboration with EPE data

Figure 75: Investments in Generation of the Brazilian System



Source: Own elaboration based on EPE data

Figure 76: Investments in Transmission in the short and long-term

A3.2.2 Initial Market Structure and Problems

Brazilian markets began to operate in 1997, with a competitive structure in wholesale and retail competition. Nevertheless, the model, as most of all the first models, suffered some drawbacks in practice, due to the flaws in the design and the government intervention to control the tariffs for the final consumers on values that are considered "acceptable" by the government.

The problems detected in the first model according to the Ministry of Energy of Brazil in 2003 were the following:

- Black-out in 1999;
- Black-out in 2001;
- Electricity rationing in 2001-2002;
- Economic and financial crisis of the companies in the sector in 2001-2003;
- Pendulum effect: rationing energy to spare;
- Need to include 12 million Brazilians access to electricity;
- Previous Regulatory Framework:
  - Instability;
  - Lack of energy;
  - Rationing of 25% of the market;
- During the Crisis the Auction for Power Purchase was with high premium: 3090% near USD 2,1 Billions.

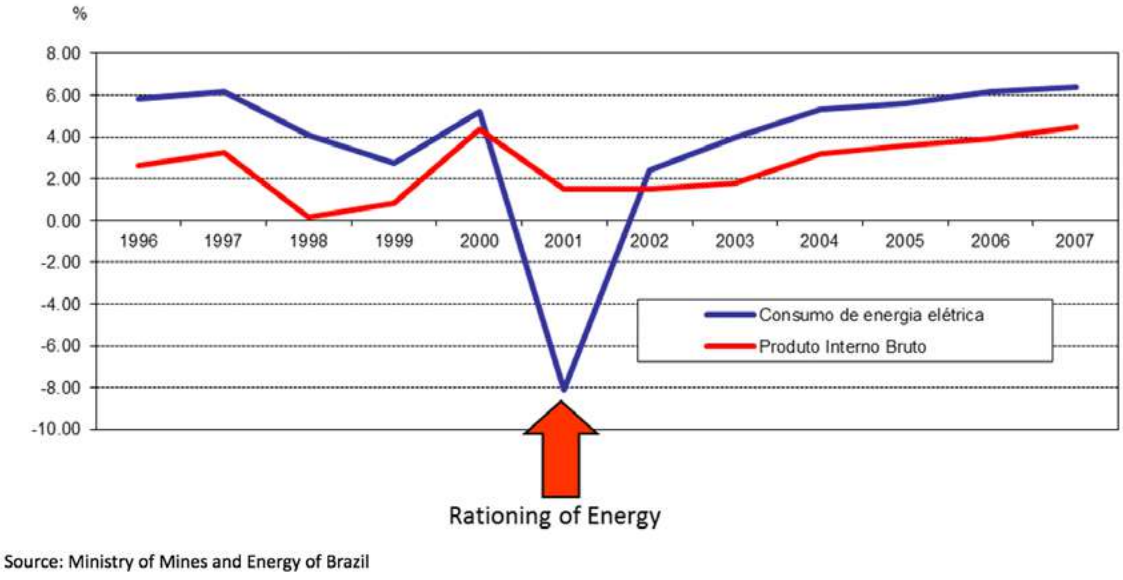


Figure 77: Crisis in the Brazilian Electricity Market

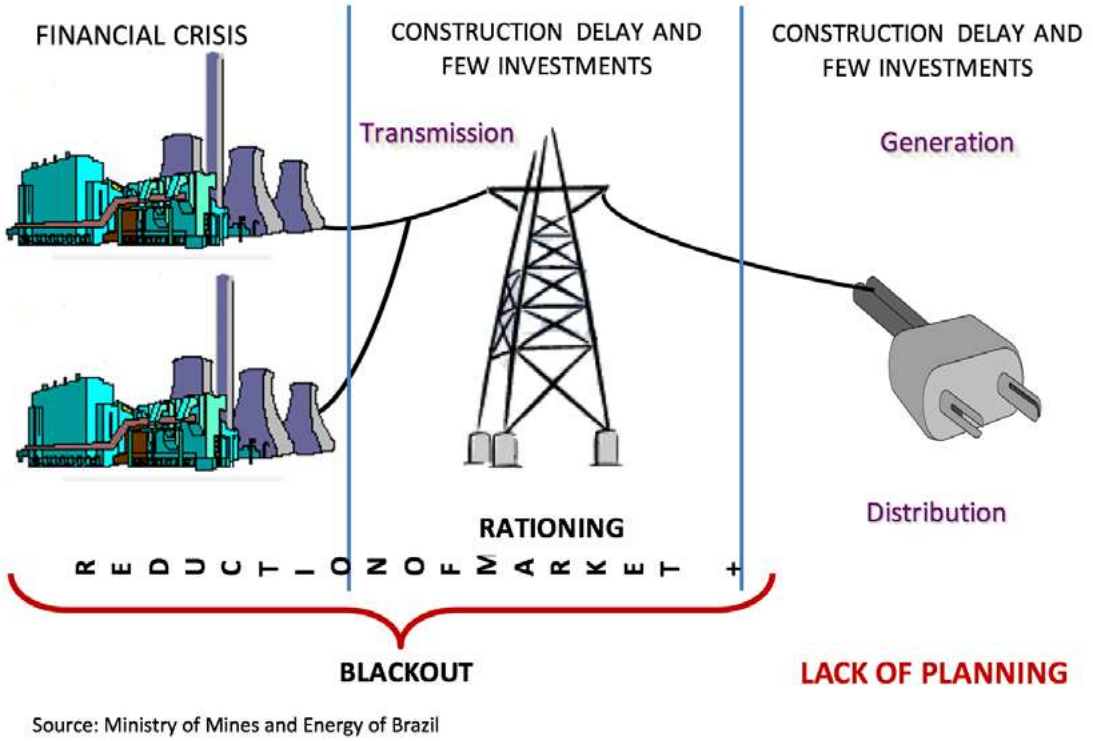


Figure 78: Causes of the Restructuring the Brazilian Market Model

Finally, another problem detected in the model was the self-dealing, meaning that the Distribution Companies could buy energy from the Generation Companies belonging to the same holding, directly or indirectly. The self-dealing increased the prices to the final consumer to nearly 30%, according the Ministry of Energy of Brazil. Then, the new structure proposed was aimed to:

- Reasonable Tariffs:
  - End of «self-dealing»;
  - Efficient mechanism for promoting -> Auctions;
- Security of supply:
  - All contracts should be supported by physical production capacity;
  - All consumers must be fully covered by electricity contracts;
  - Creation of CMSE (Electricity Industry Monitoring Committee);
- Risk reduction for the Investor:
  - Long-term contracts (30 years), with the presence of a spot market;
  - Need for prior environmental licences;
- Restructuring of the energy planning;
- Promoting social integration -> Universal use and access to energy for more than 12 million people.

The next sections present the results of this reform and how this new model solved the detected problems.

A3.2.3 Market Structure and Actors

A3.2.3.1 Organization and Actors

The general structure of the current Brazilian market after the reform conducted in 2004 is the following:

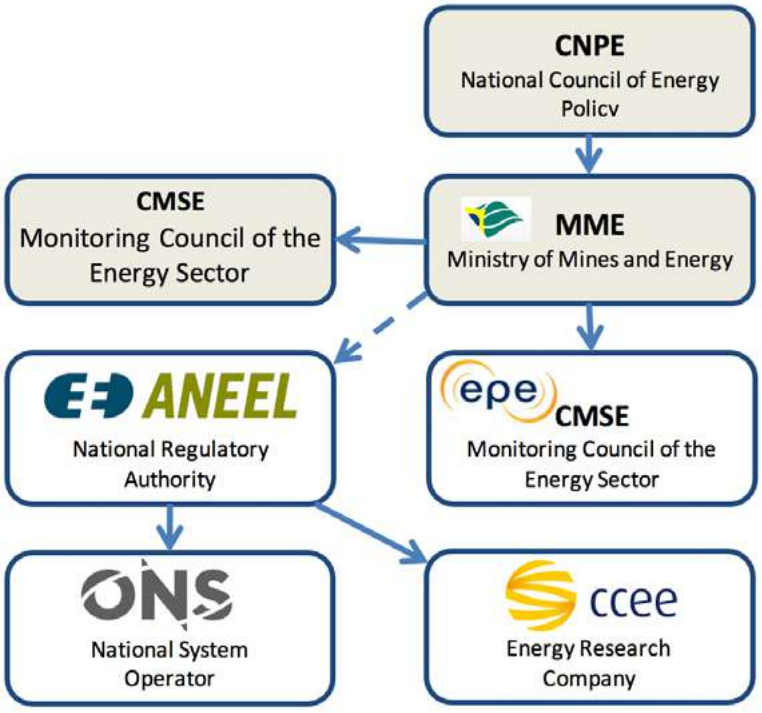


Figure 79: Organization of the Brazilian Sector

National Council of Energy Policy (CNPE: Conselho Nacional de Politica Energetica)
The CNPE defines the Energy Policy with the objective to guarantee the energy supply in the country.

Ministry of Mines and Energy (MME: Ministerio de Minas e Energia)
The MME is responsible for planning, development of the energy sector legislation. MME perform the Supervisory and Control of the execution of policies for energy development.

Monitoring Council of the Energy Sector (CSME: Comite de Monitoramento do Setor Elétrico)
The CSME supervises the continuity and reliability of supply of electricity.

Energy Research Company (EPE: Empresa de Pesquisa Energetica)
The Energy Research Company performs the generation and expansion planning. EPE provides services to the Ministry MME and technical support to the auctions.

National Regulatory Authority (ANEEL: Agencia Nacional de Energia Elétrica)
ANEEL regulates and supervises generation, transmission, distribution and Commercialisation of electricity. Defines tariffs for transport and consumption and assure the economic-financial equilibrium of the Concessions.

National System Operator (ONS: Operador Nacional do Systema)
ONS controls the National Interconnected System operation, centrally optimizing the resources.

Commercialisation Chamber of Energy (CCEE: Camera de Comercializacao de Energia Elétrica)
CCEE handles the transactions in the Energy Market and performs the official auctions.

- Established according to the art. 4º of Law nº 10.848/2004, Decrees nº 5.163 and 5.177/2004.
- Private non-profit organization;
- It is under the regulation and supervision of the Regulatory Authority;
- Main Functions:
  - Registers the supply Contracts;
  - Collects the measurements of generation/consumption;
  - Settlement and;
  - Reports of the results;
  - Electrical Energy Auctions.

The main actors (and numbers at February 2020) of the Brazilian electricity markets are the following:

a. Generators, with three different types under this category:
   - Public Generation Service Concessionaires (44)
   - Independent Electricity Producers (1463)
   - Self-producers (77)
b. Distributors (47)
c. Marketers in the following categories:
   - Traders (346)
   - Free Consumers (942)
   - Special Consumers (6374)
   - Importers (0)
   - Exporters (0)
d. Transmission Companies (156)

A3.2.3.2 The Brazilian markets

Brazil has implemented two market environments:

1. **ACR or Regulated Contracting Environment**. This is a regulated environment, where a pool of distributors buys power from generators in public auctions under set prices
2. **ACL or Free Contracting Environment**, where the marketers and generators can freely negotiate their own bilateral contracts

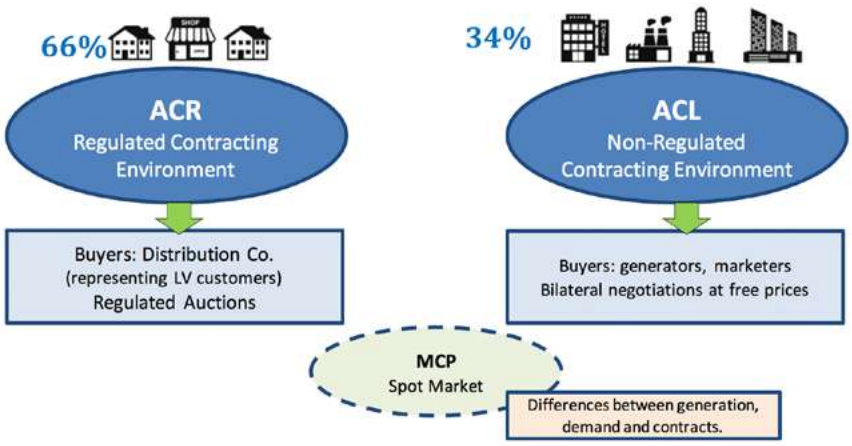


Figure 80: Markets of the Brazilian Power Sector

The general overview of the entire commercial and financial activity and structure is presented next:

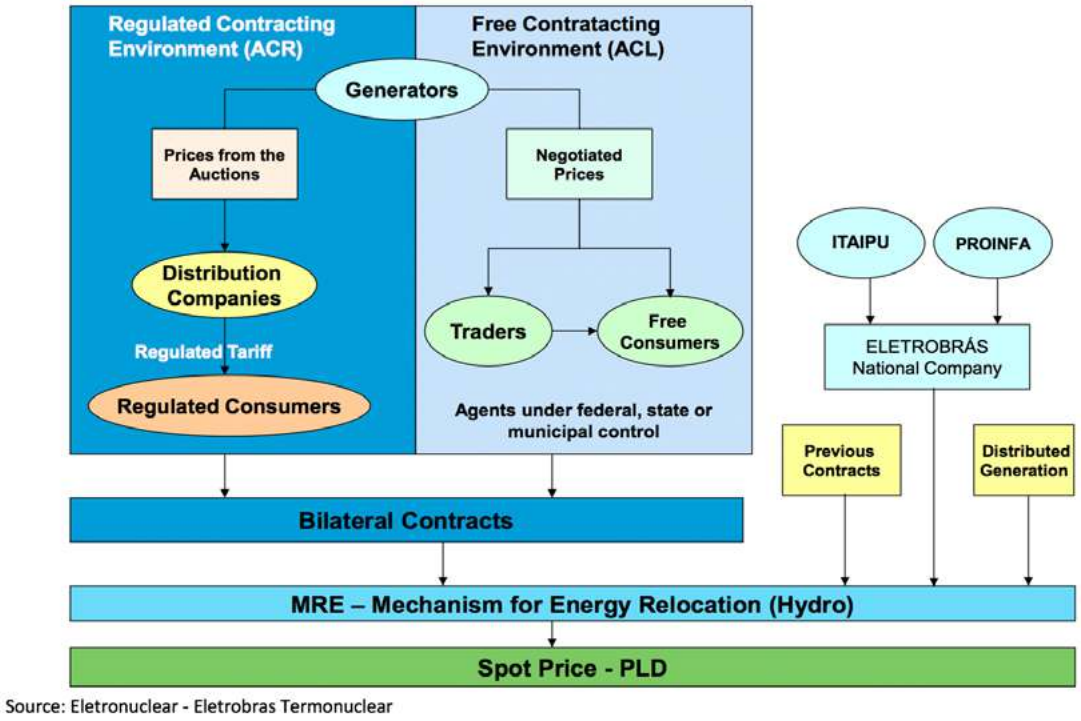


Figure 81: Structure of the Brazilian Sector after the Reform (2004)

In the pool system (ACR) all sellers perform contracts with all distribution companies. The electrical energy contracting in the RCE is formalized by means of regulated bilateral agreements called CCEAR, between selling agents (generators, independent power producers or self-producers) and purchasing agents (distributors), which participate on electric power auctions.

In the Free Environment (ACL), on the other hand, the negotiation among the generating agents, traders, free consumers, importers and exporters of electric power is freely accomplished through bilateral contracts.

Generating agents (public generation concessionaires, independent power producers or self-producers) and traders can sell electric power within the two environments, maintaining their competitive nature of the generation.

The Commercialisation Chamber (CCEE) has the following main attributions: to keep records of the contracted energy and acquire on-line measuring data of all Agents in the Brazilian interconnected electricity system, to conduct energy purchase auctions for distribution utilities under authorization of ANEEL and to determine the weekly prices and the monthly accounting and settlement of the short term market in the Free Contracting and the Regulated Contracting environments, based on a set of Commercialisation rules established by regulatory authority (ANEEL).

The legal and regulatory framework considers the Open Access to Transmission and Distribution networks in order to preserve the competition.

A3.2.3.3 ACR - Regulated Market

The Commercialisation Chamber conducts the auctions for the regulated environment. The objective is to obtain long-term contracts in order to assure the supply of energy and the proper return to investors through competitive auctions.

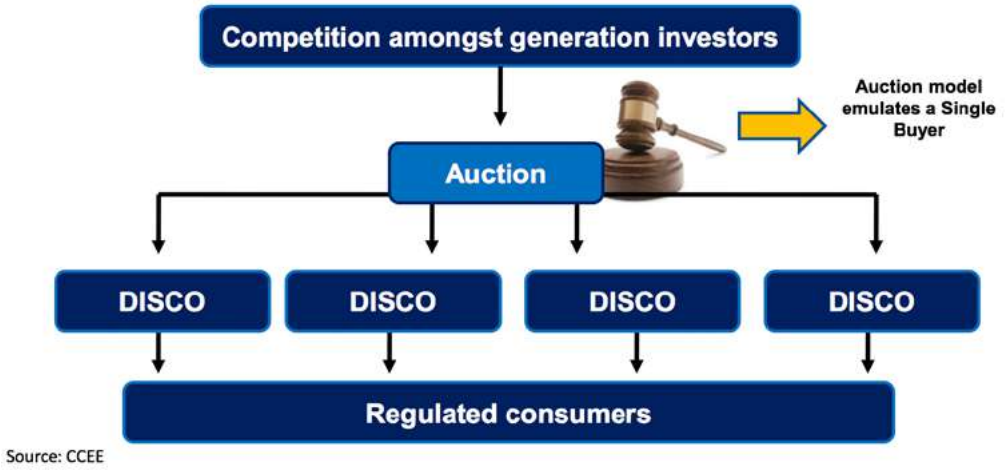


Figure 82: Auction Model in the Regulated Contracting Environment (ACR)

The auctions emulate a Single Buyer model, but under a transparent and competitive environment. The auctions are carried out for the "New Energy" or the forecasted energy for the next years and for the "Old Energy", that is the already contracted demand whose contracts are expiring.

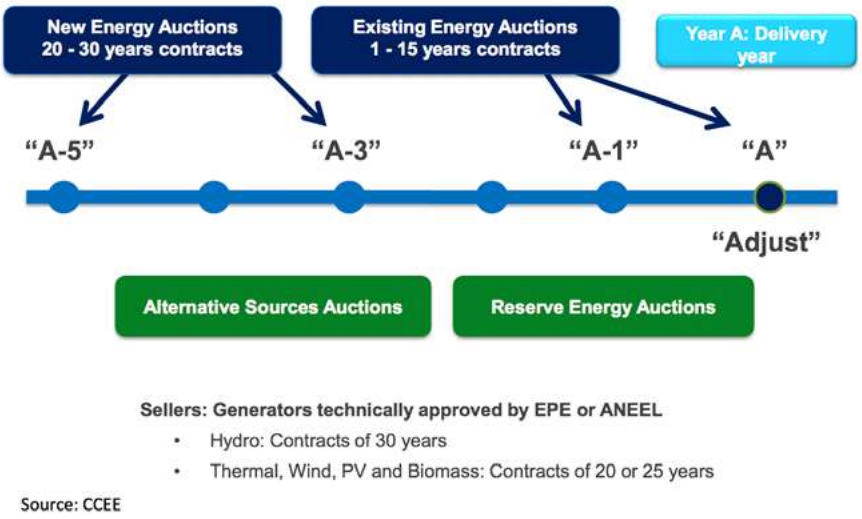


Figure 83: Regulatory obligations for long-term Contracting in ACR

There are also auctions for Reserve Energy and for the Alternative sources of Energy: Renewables other than large-hydro. The auctions are annually conducted, and the energy traded in the regulated environment is 75% of the total Brazilian market. The results of the auctions are long-term contracts, i.e., Power Purchase Agreements of two types:

1. Quantity: It is a standard Financial Forward Contract, where generators bid an energy price (R$/MWh) for their FECs. In this case, the risk of physical delivery led by ONS's central dispatch is assumed by generator.
2. Availability: It is a typical Call Option. Generators receive an option premium in R$/year (Fixed Cost paid in 12 monthly instalments, like capacity payment) to remain available to the dispatch and receive an Operational Cost every time they are dispatched. This operational cost is called Custo Variável Unitário (CVU) and works as an energy strike price.

In the Contract of Availability the generator receives fixed revenue to keep the plant available. The long-term contract signed can be used by the investors to obtain financing from the state bank of Brazil (BNDES).

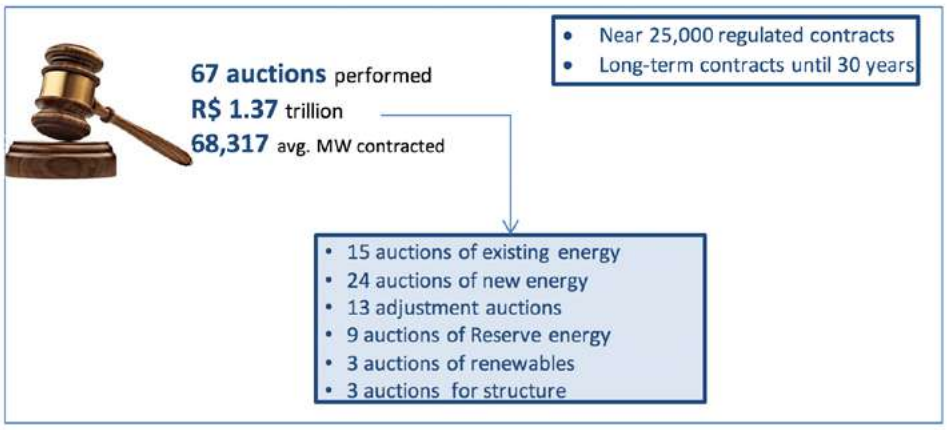


Figure 84: Auctions performed in the Regulated Contracting Environment (ACR)

There were 67 auctions conducted since 2004 and 68 avg. GW contracted in all the contracts in this period. Just in 2015 there were contracted 4.4 avg. GW under this mechanism by the pool of distributors under the Commercialisation Chamber of Energy (CCEE).

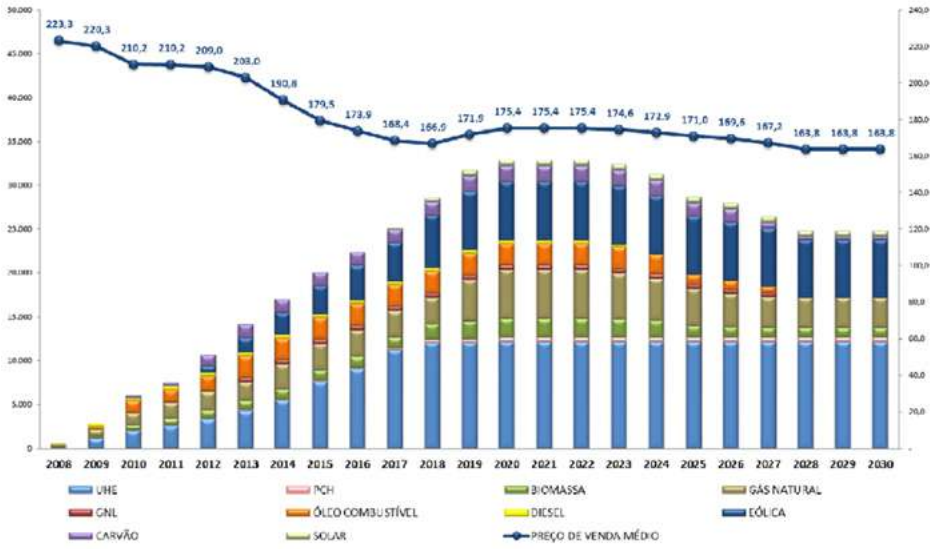


Figure 85: Evolution of the Regulated Contracting Environment and its average Prices

The evolution of the Regulated Environment, the technologies contracted, and the average prices are presented in the previous Figure.

A3.2.3.4 ACL – Non-Regulated or Free Market

The Free Contracting Environment (ACL) that allows performing bilateral contracts covers 25% of the market. The main characteristics of this market are the following:

- Bilateral contracts between parties
- Free prices and conditions
- Performed via electronic platforms

Only generators and traders can trade energy in the Free Market. The buyers in the ACL are free and special consumers, as well as generators and traders. In addition, free and special consumers can give electricity amounts to other consumers, generators or suppliers as presented in Figure 86.

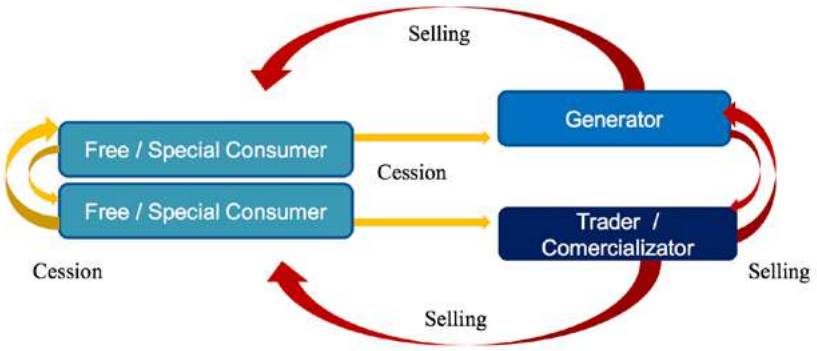


Figure 86: Free Contracting Environment Contractual Flow

The main sectors of the industry that play in the Free Contracting Environment are presented in the graph below:

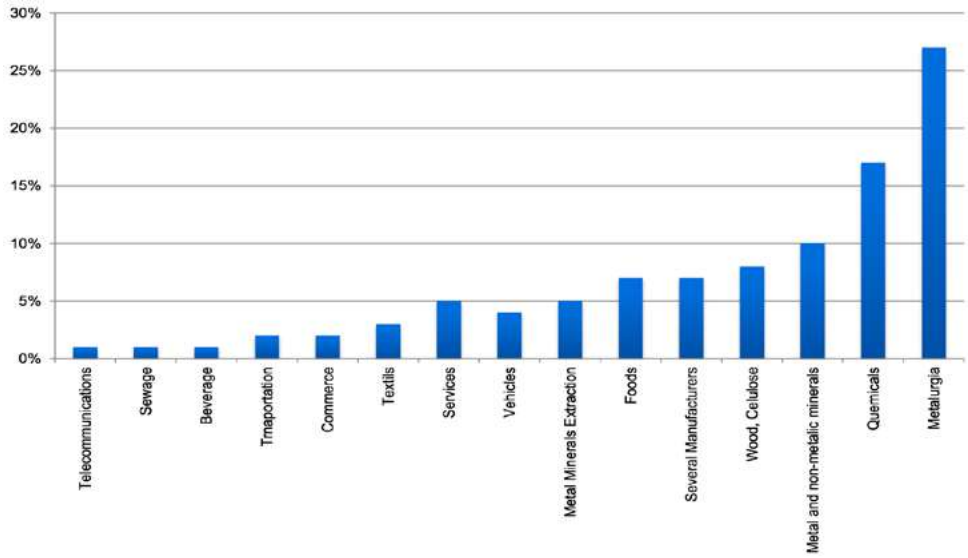


Figure 87: Sectors involved in the Free Contracting Environment

The duration of the contracts in the ACL is presented in Figure 88and near 60% have duration greater than 4 years.

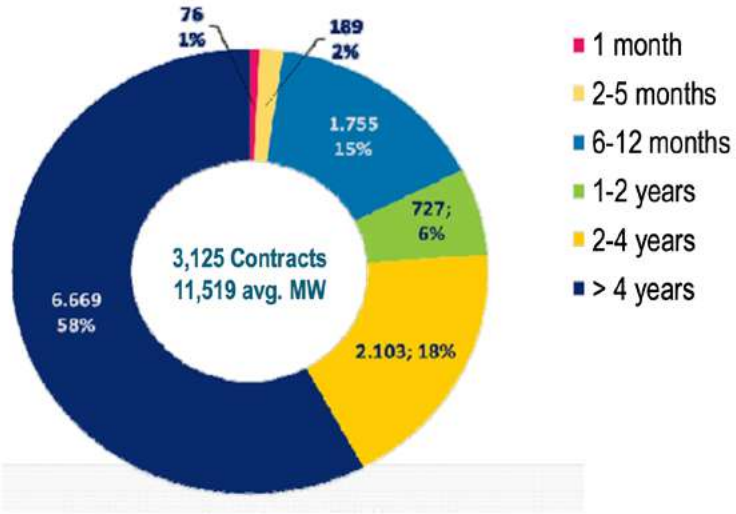


Figure 88: Duration of Contracts in the Free Contracting Environment

The Evolution of the energy traded in the Free Market is shown in Figure 89.

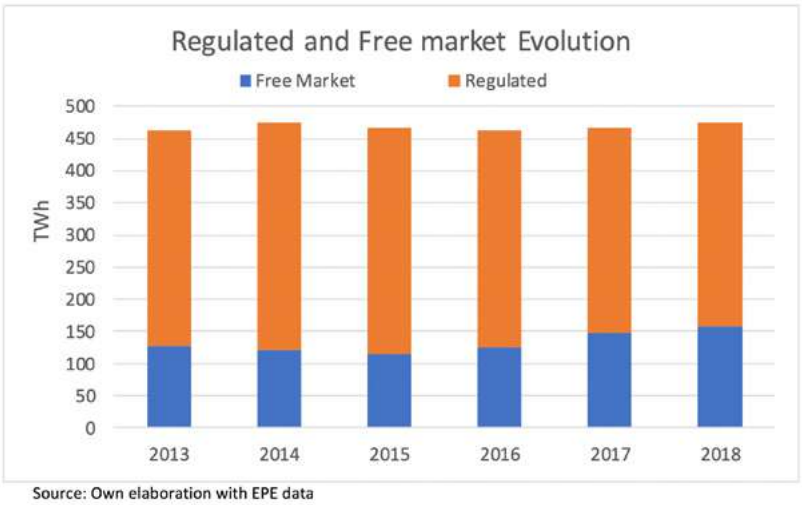


Figure 89: Evolution of Regulated and Free Markets

The share of the Free Market and Regulated environment for 2018 is presented as follows:



Figure 90: Regulated and Free Market share in 2018

Additional information about the Free Market consumers by Voltage level is following:

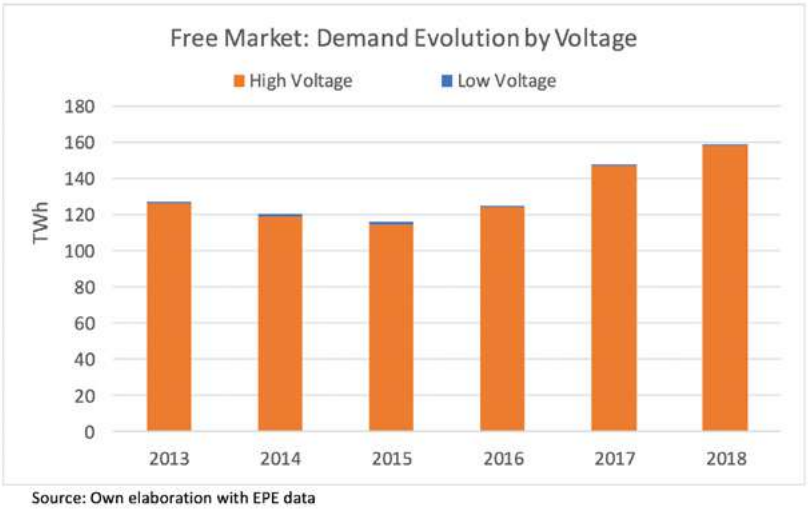


Figure 91: Evolution of Regulated and Free Markets by Voltage Level

A3.2.4 Incentive Mechanisms

The Brazilian model is designed to incentive, both sides: government & customers (adequacy and availability of energy) and investors (long-term auctions through competitive auctions).

The main incentives can be summarized as:

- Long-term contracting auctions:
  - Hydro: 30 years
  - Wind: 20 years
  - Solar: 20 years
  - Biomass: 15-20 years
- Reduction of minimum requirement for demand: 0.5 (reduced from 3 MW) for contracting from renewable sources.
- Discount in the transmission charges: 50%, 80% or 100% for sellers and buyers of renewable sources.
- Finance: subsidy rates by BNDES (National Bank)
- Tax Incentives: reduction of taxes for certain goods

A3.3 Hydrothermal Dispatch and Spot Prices

A3.3.1 Hydrothermal Programming and Dispatch

Brazil is a country with a predominantly hydroelectric generation and a multi-owned system: 31 public and private companies own 126 hydro plants (> 30MW) in 14 large basins.

There are presently 62 hydro plants with reservoirs (monthly regulation or above), 60 run-of-river plants and 4 pumping stations. There are 25 new plants under construction, adding near 25,000 MW to the system.

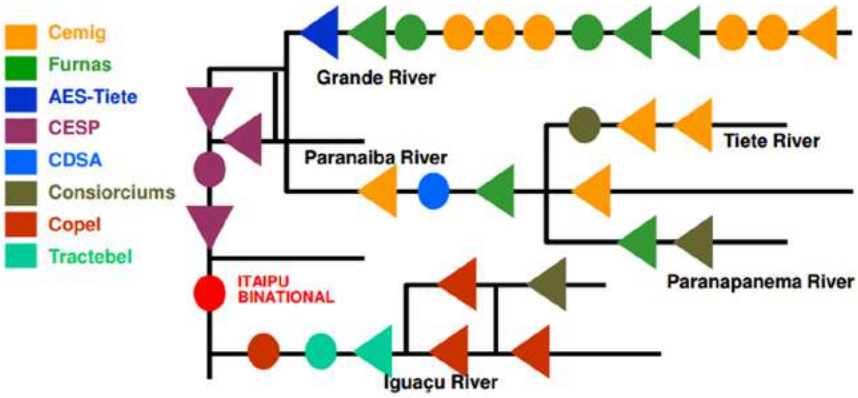


Figure 92: Hydro system of Brazil

As it can be seen from the previous figure, there are in the same basin and the same river, different owners (private, public and mix) of the hydroelectric plants. There is a complete interdependence of the generators. In order to be efficient and optimize the water resources available from different generators a **centrally coordinated operation** is required.

The hydrothermal dispatching is not a common merit order list to dispatch the available resources. There is a strong operational planning process[3] which considers long-term operational planning (generally 4 to 5 years with monthly pace) and further refinements in the short-term (1 year and hourly).

[3]As in the most Latin American countries.

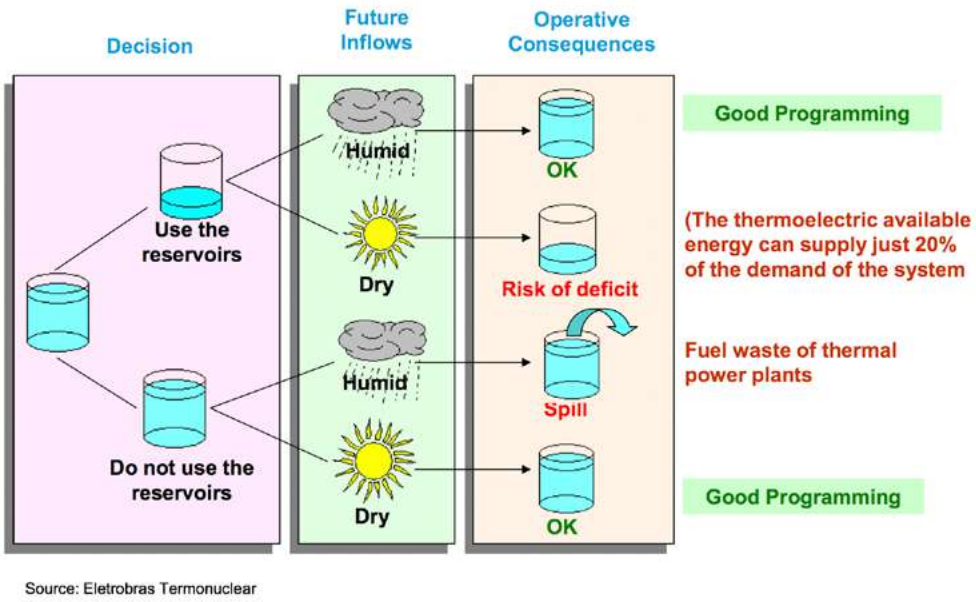


Figure 93: Hydrothermal Programming

The main concept of the hydrothermal dispatch is presented in Figure 93. In a predominant hydro system like the Brazilian, the operational programming is one of the key points to guarantee the security of the supply in the short-term. Wrong decisions in the use of the hydro resources may lead to shortages and rationings, as happened in Brazil during 2000 and 2001.

In this framework, the monitoring of the reservoir levels and the inflows has a great impact and importance. For example, Figure 94 shows the net volume of a reservoir owned by the company Furnas and it can be noted the big dry seasons in Brazil (2000 and 2001). Figure 95 also presents the levels of all reservoirs in the South-East area of Brazil.

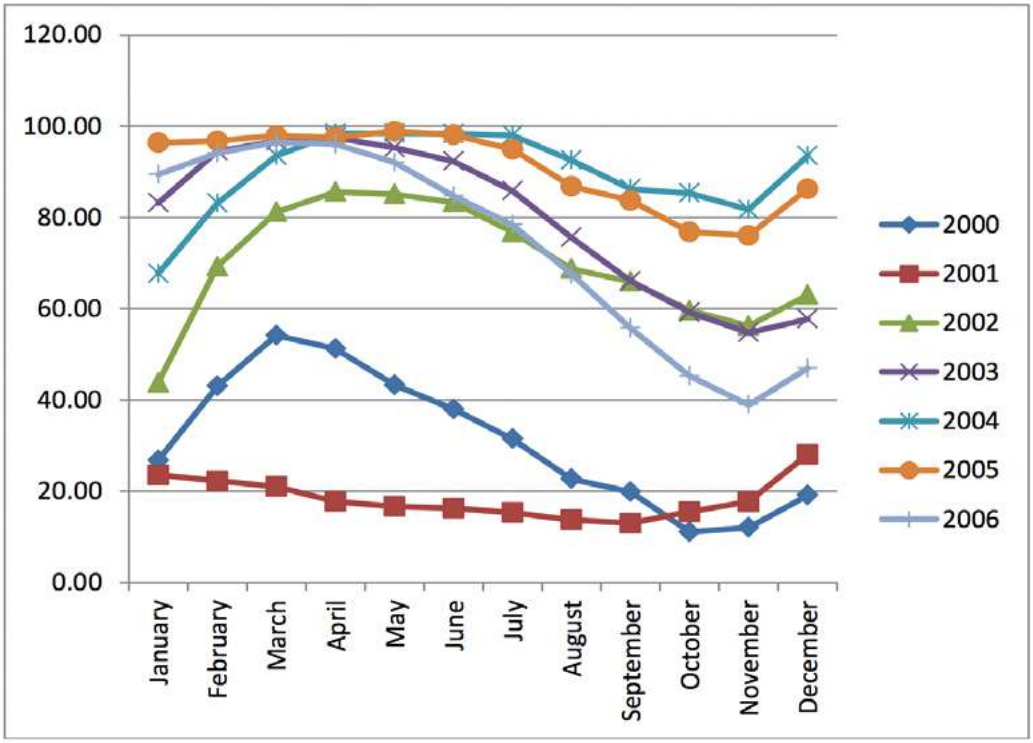


Figure 94: Furnas Reservoir levels

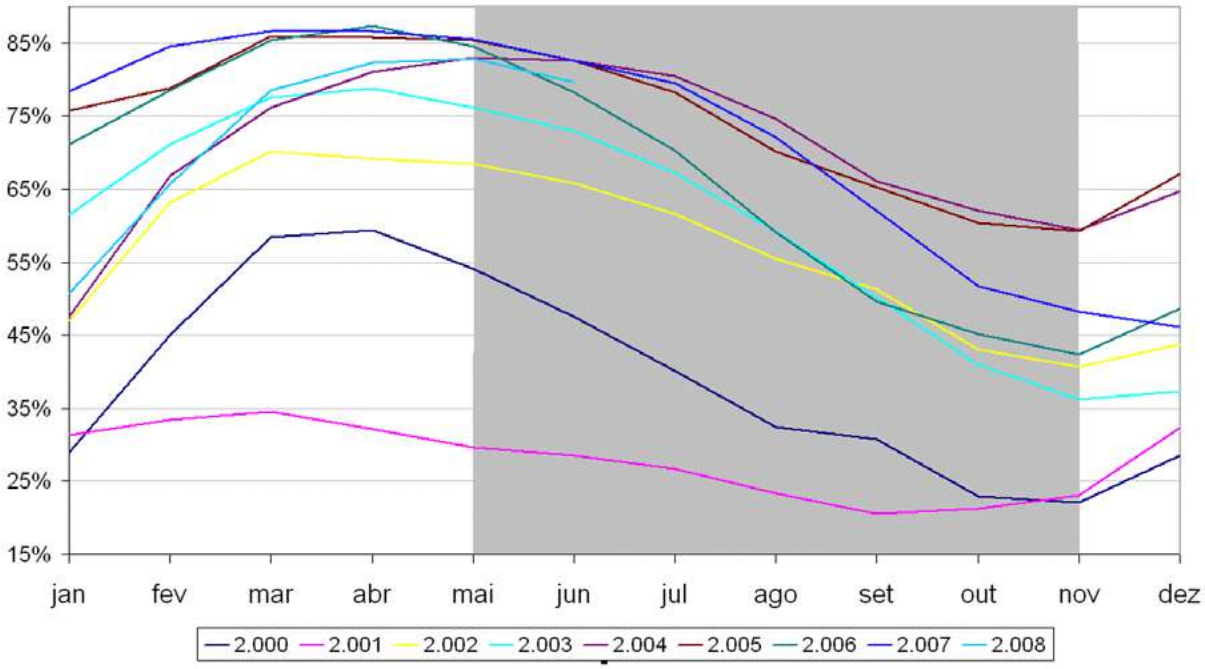


Figure 95: Reservoir levels of the South-East Area

The operational planning is performed to minimize the probability of shortages and reduce the operational costs for the system. The operational programming chain is depicted in Figure 96 and the informatics tools developed by the ONS are also an important part of the programming.

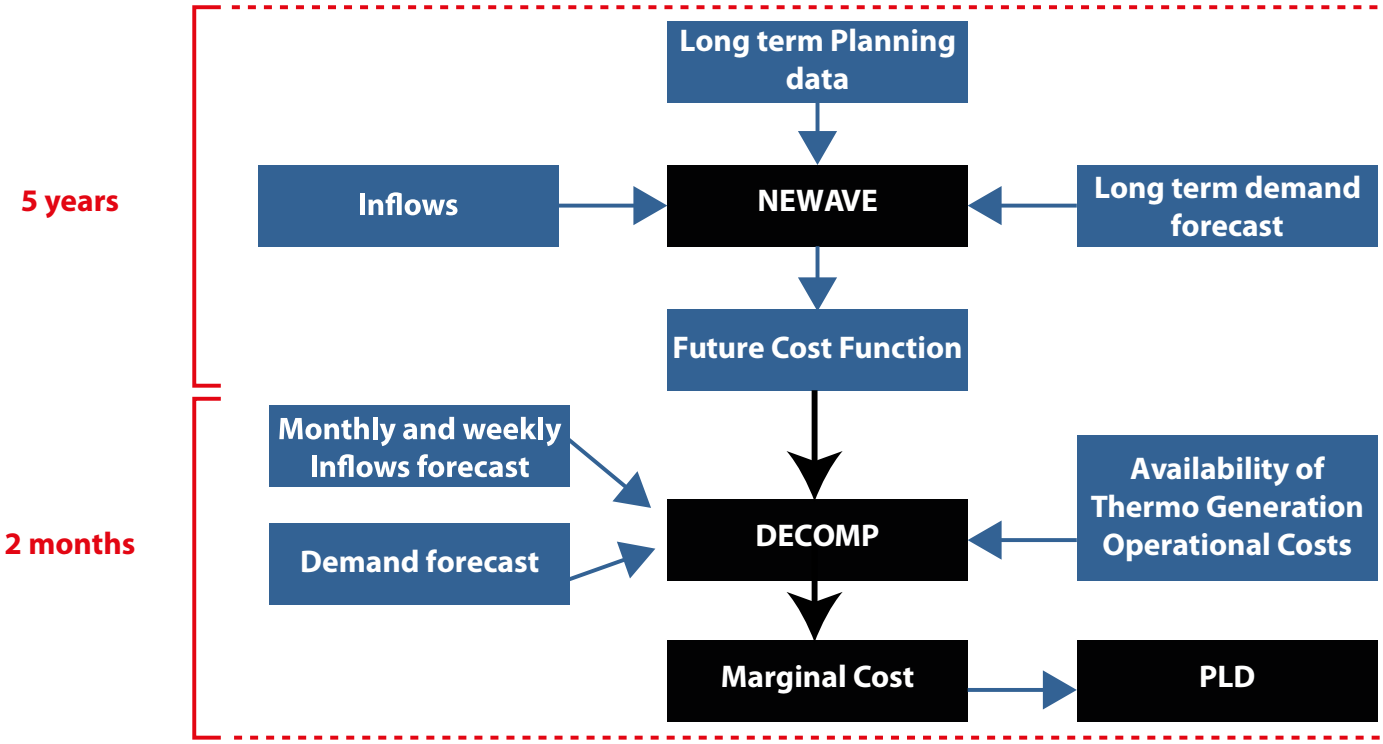


Figure 96: Operational Programming by Brazilian System Operator (ONS)

Most of the Latin American countries use informatic tools like SDDP[4] for the long and short-term programming and also in the Brazilian sector to crosscheck the results of the informatic tools developed by the ONS.

The prices obtained through the optimization process are for hourly blocks and for the Region. The congestion of the areas is also reflected in the obtained final process.

Marginal Cost USD/MWh	South-East / Central West	South	North-East	North
Heavy Load	10.43	10.43	92.53	10.43
Medium	10.16	10.16	92.53	10.16
Low	9.67	9.67	82.17	9.67
Weekly Avg.	**10.01**	**10.01**	**88.77**	**10.01**

The Marginal Prices obtained are also capped according to the limits defined by the Regulatory Authority. The resulting capped Marginal Cost is called PLD or Spot Price and it is used for settlement. An overview of the Marginal Costs of the system and the PLD is presented in Figure 97.

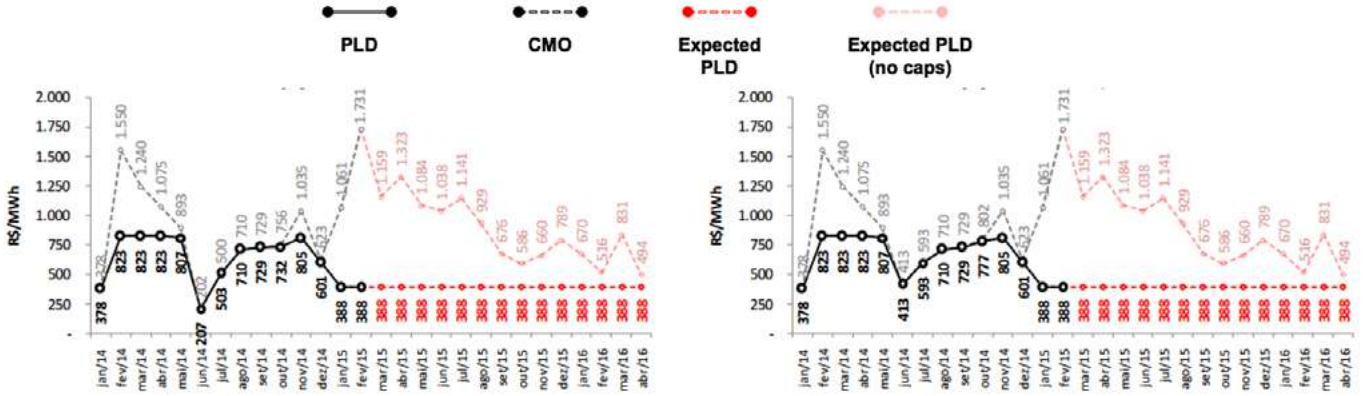


Figure 97: Marginal Costs and PLD or Spot Market prices

A3.3.2 MRE - Mechanism for Energy Relocation

The Mechanism for Energy Reallocation (MRE) is a mechanism to share the hydrological risk among the generation agents. It has the objective of mitigating the commercial risk of a hydro power plant to generate less electricity than its physical capacity, sharing the risk between all hydro participants in the mechanism.

The electrical output of a plant is directly related to the central dispatch carried out by the System Operator.

The Mechanism for Energy Reallocation (MRE) has been designed to share among its members the financial risks associated with the trading of electricity from hydroelectric plants centrally dispatched and optimized by the System Operator.

The generators must comply with their contracts. But, if the hydrological generation scenario is not favourable, generators are contractually exposed and must buy energy at a Spot Market price (PLD) in order to honour their contracts, generating an extra cost.

[4] Stochastic Dual Dynamic Programming commercial developed by PSR of Brazil 20 years ago. http://www.psr-inc.com/softwares-en/?current=p4028

The hydro plants are dispatched in order to minimize operating costs and aiming at the lowest possible Marginal Cost, keeping in view the hydrological inflows, the reservoir water storage, the prices offered by the thermal plants and the operational constraints. Thus, the owners of the hydro plants subject to centralized dispatch have no control over their generation level, regardless of their energy sales commitments made on the basis of physical guarantees.

Given the large territorial dimensions of Brazil, there are also significant differences between hydrologic regions, i.e., the dry and wet periods are not the same and therefore it is required a constant flow of electricity between the regions. A region in the dry season should store water and thus produce energy at levels below average, while a humid region shall produce above average.

The MRE mechanism is applied first between the generators in the same Regions and after, between the regions. An example of the mechanism between hydro generators in the same Region is presented in Figure 98.

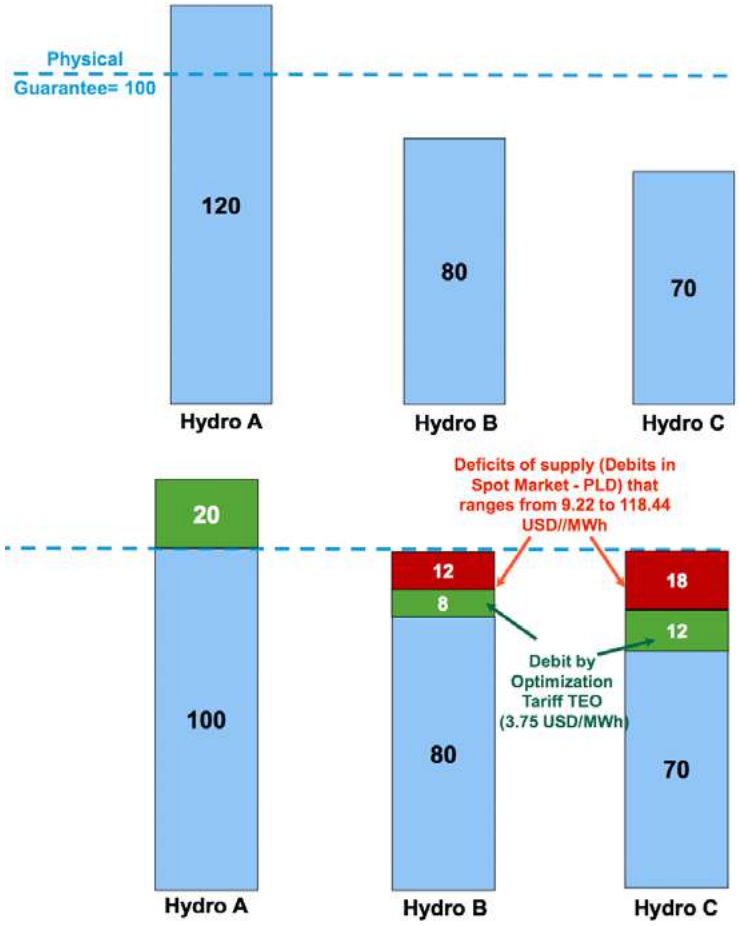


Figure 98: MRE – Mechanism for Energy Relocation between generators of one Region

The mechanism may create debits or credits that are settled in the Sport Market. During dry seasons, there are debits and a financial impact in the tariffs because of the thermoelectric generation that has to be dispatched (instead of hydro) in order to meet the demand and the physical guarantees of the hydro generators.

The transactions of the generators inside the mechanism MRE are performed at the denominated Optimization Tariff (TEO). TEO is intended to cover the incremental costs of operation and maintenance of hydroelectric plants and the payment of financial compensation relating to the energy exchanged in the Mechanism for Energy Reallocation (MRE).

The Optimization Energy Tariff (TEO) was set in a public meeting of the board of the Regulatory Agency at 3.75 USD/MWh (12.32 R$/MWh) effective from 01/01/2016.

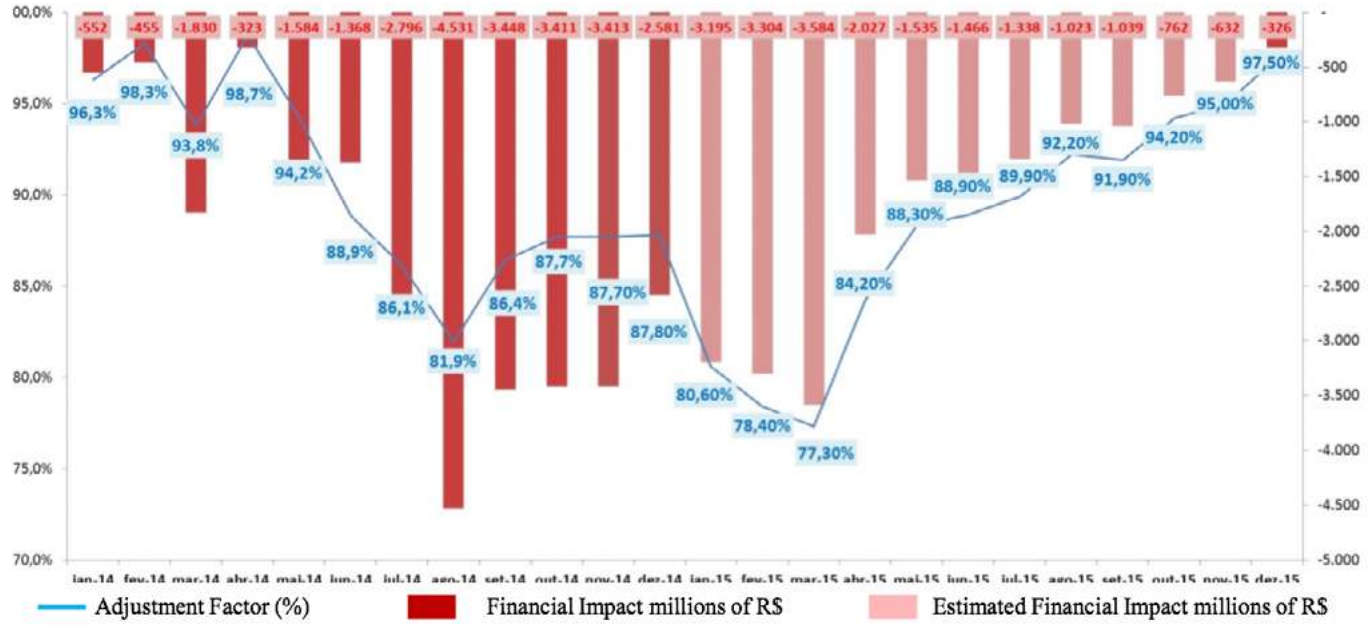


Figure 99: Financial Impact of the deficits in the MRE

The financial impacts of dry seasons and the ability to meet the physical guarantees by the hydro generators are reflected in the Figure 99.

MRE	2014	2015
Avg. Adjustment Factor of MRE	90.7%	88.2%
Financial Impact	26.3 billion R$	20.2 billion R$

Table 14: Financial impact to the electricity sector

A3.3.3 Spot Market Price – PLD

Each month, CCEE calculates and compares, for every generator, distribution company and free customer, power availability and requirements, considering consumption, production, power purchases or sales.

The differences between requirements and availabilities are settled in the spot market by the Price for Settlement of Differences – PLD

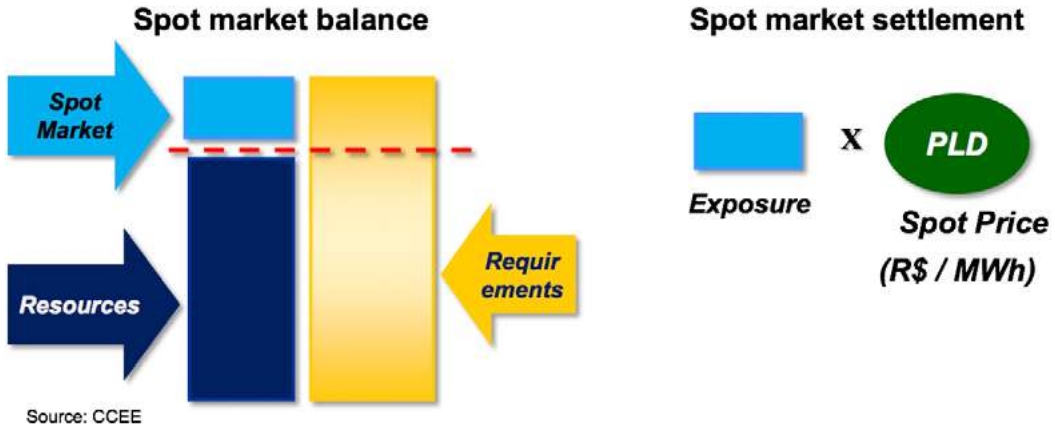


Figure 100: Spot Market Balance and Settlement

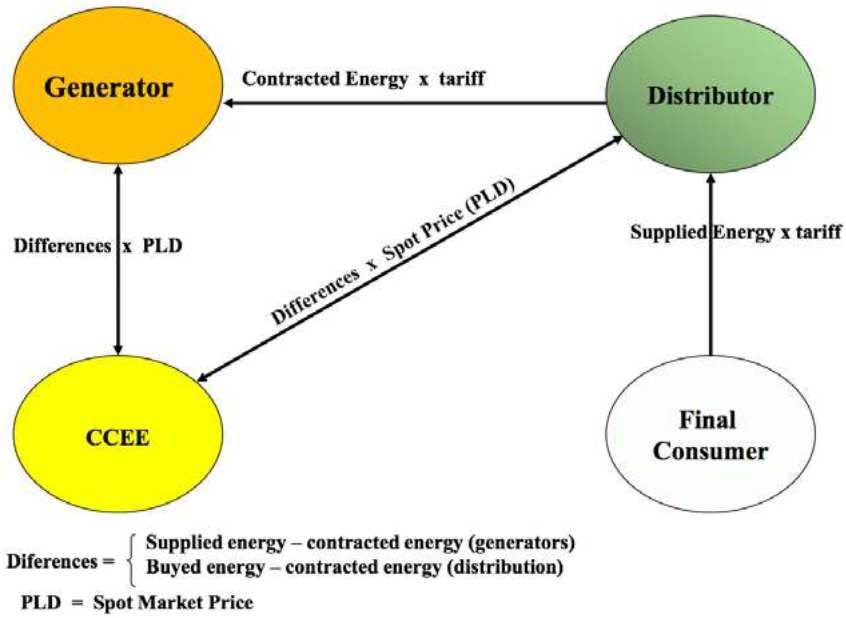


Figure 101: Spot Market price

The energy volumes settled in the Short-Term Market are valued at the Differences Settlement Price – PLD.

The Spot Price or PLD is calculated weekly by the CCEE and is valid for the entire operational next week (ex-ante). The calculation considers forecasts as the availability of generation, water inflows for reservoirs and system load.

The PLD is based on the Marginal Cost calculated by the System Operator. The difference is that the PLD is capped by the maximum and minimum prices. The regulatory authority determines the limits:

- Spot Price (PLD) minimum in 2015 is 30.26 [R$/ MWh] or 9.22 USD/MWh
- Spot Price (PLD)maximum in 2015 is 388.48 [R$/MWh] or 118.44 USD/MWh



Figure 102: Minimum and Maximum Spot Prices

A3.4 Adequacy and Generation Expansion

During the year of 2004, the Federal Government set the bases for a new model for the Brazilian Electricity Sector, supported by Laws 10,847 and 10,848, dated on March 15, 2004, and by Decree 5,163, dated on July 30, 2004.

Some mechanisms were inserted into the market to enhance security of supply, among which:

a. a requirement that distribution companies contract for 100% of their forecast demand over a five-year horizon;
b. build realistic estimates for guaranteed energy of plants;
c. contracting hydropower and thermal plants in a mix that balances guarantee and cost; and
d. permanently monitoring the security of supply, to have early detection of imbalances between supply and demand.

The auctions are the main mechanism for **generation expansion**. There is a compulsory obligation for Distribution Co. to buy energy from the regulated market (consumers).

The auctions have 3 types of incentives:

- Auctions with specific products (hydro, wind, solar, biomass)
- Designed auction to prioritize renewables.
- Long-term supply contracts.
- Variable Cost cap for thermoelectric participation

The Sellers in the auctions are the Generators technically approved by EPE or ANEEL. The Contracts signed after the auctions are for 30 years for hydro and 20 or 25 years for Thermal, Wind, PV and Biomass.

The energy supply contracts in ACR may vary only between two modalities:

- Quantity: It is a standard financial forward contract, where generators bid an energy price of R$/MWh for their FECs. In this case, the risk of physical delivery led by ONS's central dispatch is assumed by generator. The Contracts for delivering energy, all **risks** are taken by generators to supply the energy contracted.
- Availability: It is a typical call option. Generators receive an option premium in R$/year (fixed cost paid in 12 monthly instalments, like capacity payment) to remain available to the dispatch and receive an operational cost every time it is dispatched. The Contracts for availability, all **risks** of production deviations relative to assured energy are assigned to the pool and passed through to captive consumers.

The contracts consider an Equivalent Forced Outage Rate FOR in%; a Programmed outage rate (downtime Scheduled) in%; and a Firm Energy (EFm) commitment for delivery, each month m in MWh. The Physical Guarantee in Average MWavg is the average of the E_{Fm} values as follows:

$$PhysicalGuarantee = \frac{\sum_{m=1}^{12} E_{Fm}}{8760}$$

The auctions for future energy are carried out according to the planning of EPE in order to maintain the adequacy and security of the system.

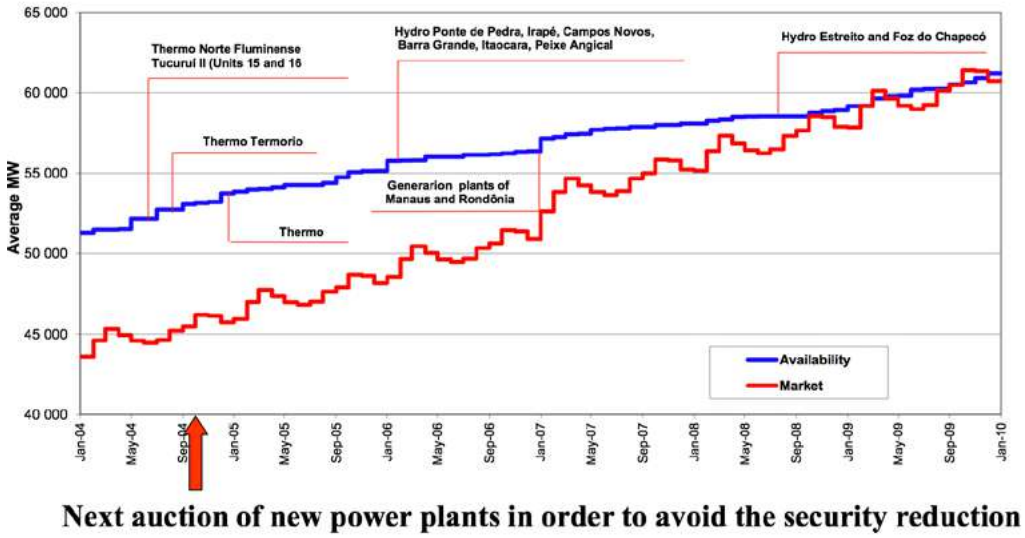
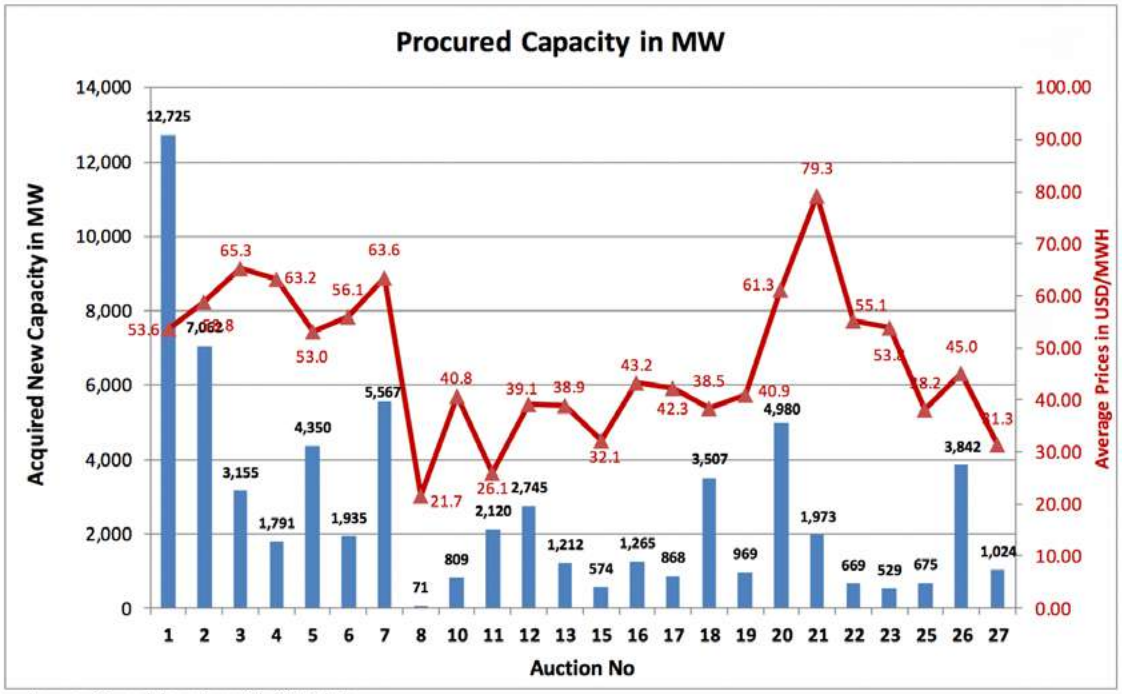


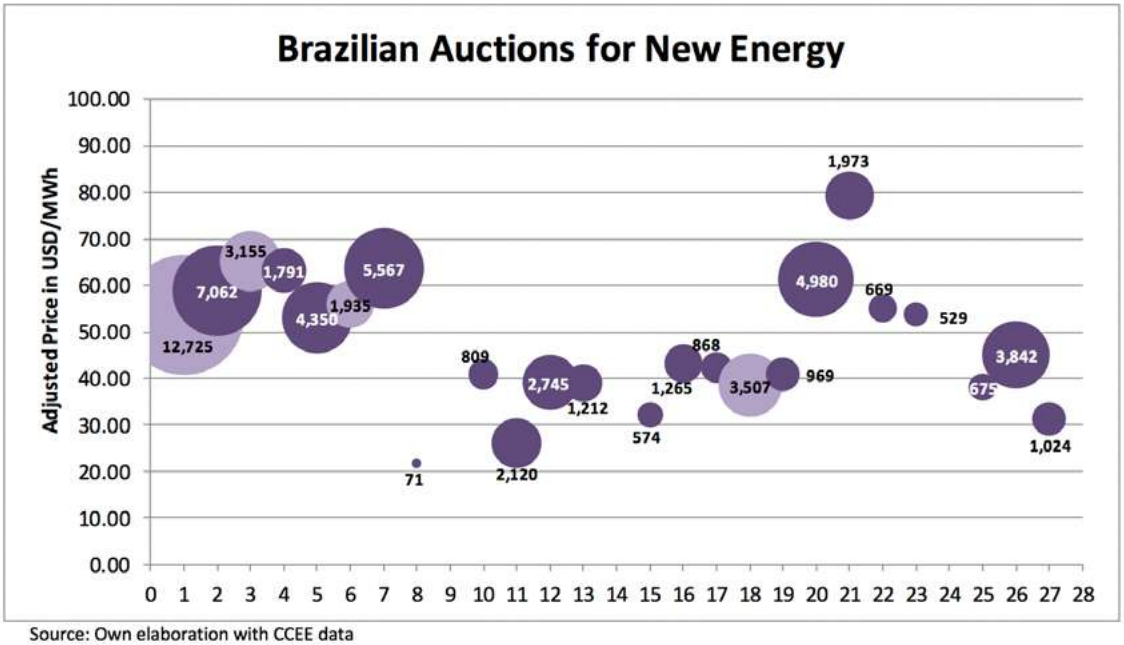
Figure 103: Adequacy and Auctions programming

The Results of new capacity auctions by technology, Dec-2005 to Sep-2014 are following presented:



Source: Own elaboration with CCEE data

Figure 104: New Capacity Auctions 2005-2014



Source: Own elaboration with CCEE data

Figure 105: Average selling price of the New energy Auctions

The following also present the results of the First solar projects contracted during the 6th Reserve Auction performed in Brazil:

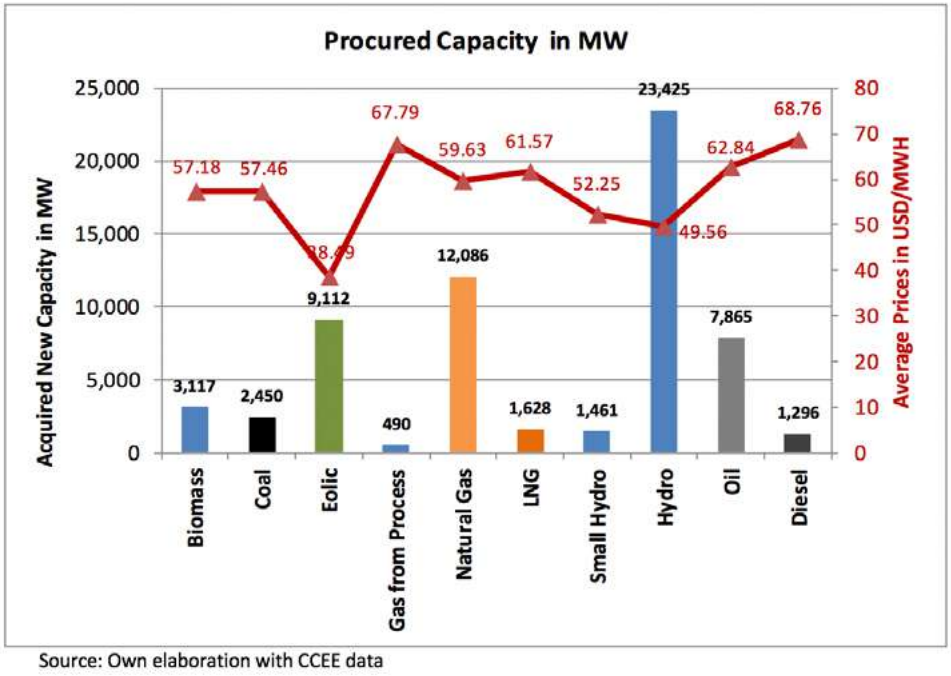


Figure 106: Prices of the Reserve Auction

A3.4.1 Competition in Energy Auctions

In order to evaluate the success of the market reform and the implemented mechanism, it is important to analyse the competition in the auctions regarding the new energy, i.e., new power plants for the Brazilian system.

In order to have an overview, the two recent energy auctions are briefly presented (Figure 107):

- Energy auction 2018 A-4 for new energy to fully supply the regulated market in 2022.
- Energy auction 2018 A-6 for new energy to fully supply the regulated market in 2024.

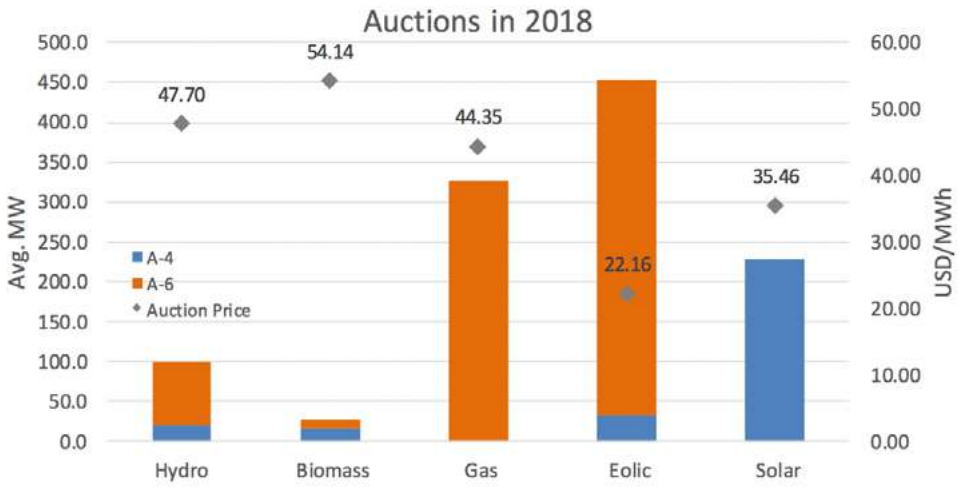


Figure 107: Installed capacity and price from auctions 2018 (Source: Own elaboration with EPE data)

As can be verified in Table 15, the candidate projects for 2018 A-4 were 1,672 with an installed capacity of 48 GW. The qualification of the candidates is based in the legal, studies, environmental license and water use grant; certified capacity by the System Operator for transmission lines in the area and authorization for the use of land. The strict qualification process reduced the offer to 1,059 Projects and 30.5 GW. The results of the auction show 39 projects and 1 GW granted. The amount assigned and the process in USD/MWh are presented in Figure 108.

	OFFER		QUALIFIED		WINNER		
Source	No Projects	Offer (MW)	No Projects	Offer (MW)	No Projects	Offer (MW)	Avg. Discount
Wind	931	26,198	553	15,760	4	114	73.50%
Solar PV	620	20,021	422	13,380	29	807	62.20%
Hydro	3	114	3	114			
Small Hydro	67	896	46	622	2	35	31.90%
Very Small Hydro	23	63	17	44	2	7	31.90%
Biomass	28	1,422	18	625	2	62	39.50%
	1,672	**48,714**	**1,059**	**30,545**	**39**	**1,025**	

Table 15: Candidate projects for energy auction 2018 A-4



Figure 108: Offer, qualification and winner of the auction 2018 A-4 (Source: Own elaboration with EPE data)

Similar to the previous auction, Table 16 and Figure 109 show the results 2018 A-6. It can be verified that the competition is high and the discounts from the reference price of the auction are very high. The prices are competitive for each type of technology and most important, the supply for the captive customers (regulated market) is guarantee until 2024.

As a result of the auctions, each Distribution Company, who required capacity to supply their customers (mandatory), sign contracts with every winner of the auction for the amount that were previously approved by the regulator.

This mechanism eliminated the adequacy problems that were very common in Latin American markets as a result of the privatization or capitalization process.

	OFFER		QUALIFIED		WINNER		
Source	No Projects	Offer (MW)	No Projects	Offer (MW)	No Projects	Offer (MW)	Avg. Discount
Wind	751	23,110	525	16,360	3	95	62.00%
Solar PV	751	26,253	580	20,469	6	204	76.00%
Hydro	4	164	4	163			
Small Hydro	44	606	31	466	5	81	31.00%
Very Small Hydro	12	32	7	18			
Biomass	19	1,039	13	532	1	21	42.00%
	1,581	**51,204**	**1,160**	**38,008**	**15**	**402**	

Table 16: Candidate projects for energy auction 2018 A-6

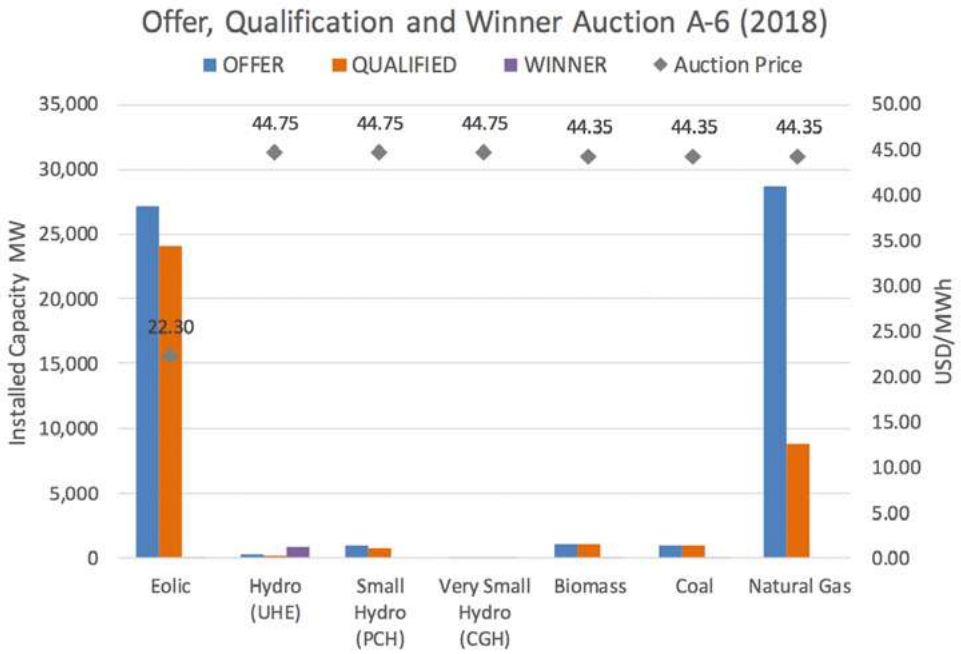


Figure 109: Offer, qualification and winner of the auction 2018 A-4 (Source: Own elaboration with EPE data)

A3.5 Transmission Activity

A3.5.1 Overview

According to the legislation, the Regulatory Authority is empowered to define if the transmission lines and facilities belong to:

- Transmission of the Interconnected System;
- Distribution;
- Generation for exclusive use;
- International Interconnections.

The transmission facilities and electrical components of the National Interconnected System will be under concession by bidding in competitive auction and work integrated into the electrical system, with operating rules approved by Regulator to ensure the optimization of existing or future resources.

The transmission facilities for distribution will be considered by the grantor's integral part of the distribution concession.

A3.5.2 The Transmission Expansion Mechanism

The methodology for tariff remuneration is Revenue Cap and applied for each transmission line or transmission facility which is auctioned every year. The transmission company is then guaranteed the receipt of regulatory revenue regardless of the variation of the paying market.

The auctioned transmission facilities are components of the main Interconnected System called "Basic Network". There are several additional transmission facilities, but they are part of the Concession of Distribution Companies (for sub-transmission purposes) and from generation facilities, to connect the power plant to the Basic Network.

The Transmission expansion is performed through auctions, according to the initial and last reform performed in 2004.

The installations of transmission components that belong to the "Basic Network" of the National Interconnected System is granted by Concession through bidding competitive auctions and with operating rules approved by the Regulatory Authority in order to ensure the optimization of the existing and future resources (amended by Law No. 11. 943, 2009).

The governance of the auctions and the involved institutions are presented in Figure 110. The governance of the auction system is governed by the Ministry of Mines and Energy (MME), which establishes the guidelines for each auction, based on studies prepared by the Energy Research Company (EPE) and the System Operator (ONS). Based on the guidelines published in MME edicts, the Regulatory Authority (ANEEL) prepares the notice of each auction and the model of the contracts to be signed in the auction.

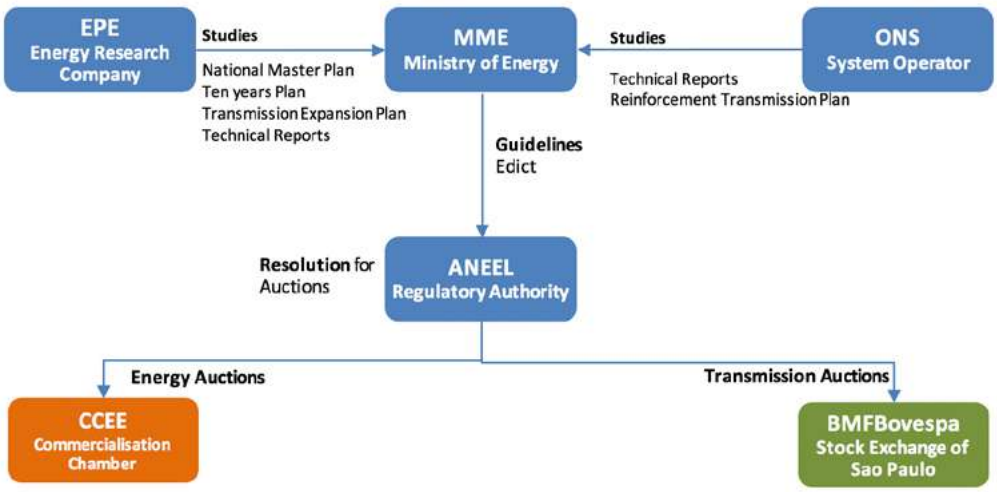


Figure 110: Governance of the auctions and involved institutions in Brazil

As presented in Transmission Tariff, the mechanism to remunerate the transmission companies is the Revenue Cap, which is a maximum amount to be remunerated by the users -during 30 years- for the cost of the capital and the operational expenses. In order to determine the reference price for the *Annual Revenue Required*, to be bid in the transmission auction, a discounted cash-flow is performed during the 30-years and it is determined an equivalent annual value that should be remunerated to the transmission company for each facility. This is the starting point of the auction, which is a descendant Dutch auction type.

In Transmission Auctions, companies submit a financial proposal for Annual Revenue Required for the construction, assembly, operation and maintenance of the transmission facilities of the respective lot for the duration of the concession contract.

The financial proposal contained in the bid of each bidder must take into account all costs with acquisitions, indemnities, services, works and taxes related to the construction, assembly, operation and maintenance of the transmission facilities, including the investment remuneration, the reimbursement of the technical studies included in the Public Notice, meeting all the requirements of the environmental agency, preparing the Basic Environmental Project and implementing compensatory measures.

The transmission auctions have two stages: i) Closed Envelope stage; and, ii) Call out stage.

Closed Envelope stage

The transmission facilities are grouped into Lots that are auctioned sequentially, under the coordination of the Auction Director, appointed by Stock Exchange of Sao Paulo (Brazil).

First, the Annual Revenue Required bids are received from each developer in the Closed Envelope submitted with a financial proposal in writing, without any other auction competitors knowing the value of its bid.

Once all bids have been received (or, alternatively, the bid submission deadline has elapsed), the envelopes are opened when the proposals presented are disclosed.

If the difference between the lowest Annual Revenue Required bid and any other bids is less than five percent, the auction will continue in the call out stage with the companies who submitted bids equal to or less than 105% of the lowest bid.

Call out stage

The call out stage consists of successive bids announced by the representatives of the qualified companies to participate in this stage. The value of each new bid must be less than the last submitted.

If there is no new bid, the Auction Director declares winner of the Lot the company who submitted the last bid. If there is a tie during the Closed Envelope Stage and no company submits a new bid in the call out stage, a raffle will determine the winner.

Next Steps

After the formalities to be a concessionaire of transmission facilities, from the date of availability for commercial operation of the transmission facilities, the concessionaire will receive Annual Revenue Required in twelve monthly instalments, subject to discounts due to unavailability or reduction in the capacity of the transmission facilities.

A3.5.3 Competition in Transmission Auctions

The competition in the expansion of the transmission network was successful and well-seen by the national and foreign investors. The transparency and the stability in the sector are the pillars of the auctions success.

A total of 47 auctions took place from 1999 to 2019 with 422 lots in total and an average of 4,863 km of lines auctioned per year, with peaks in 2008, 2013, 2015 and 2018.

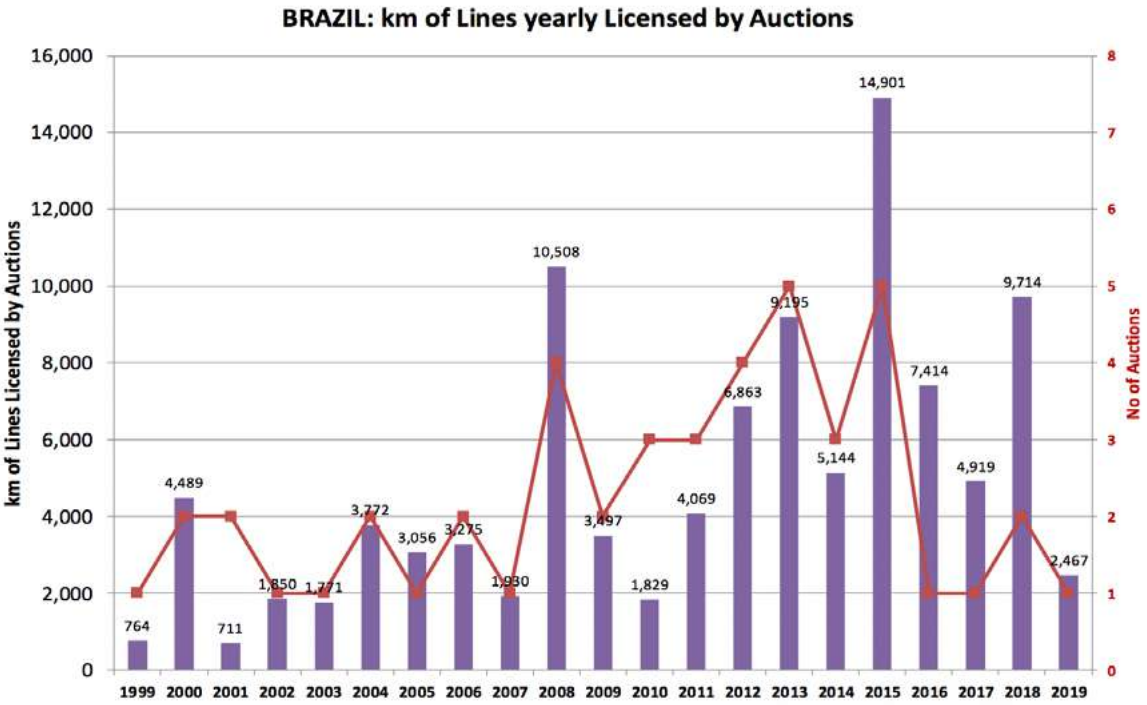


Figure 111: km of Lines Auctioned for Transmission Expansion (Source: Own elaboration with ANEEL data)

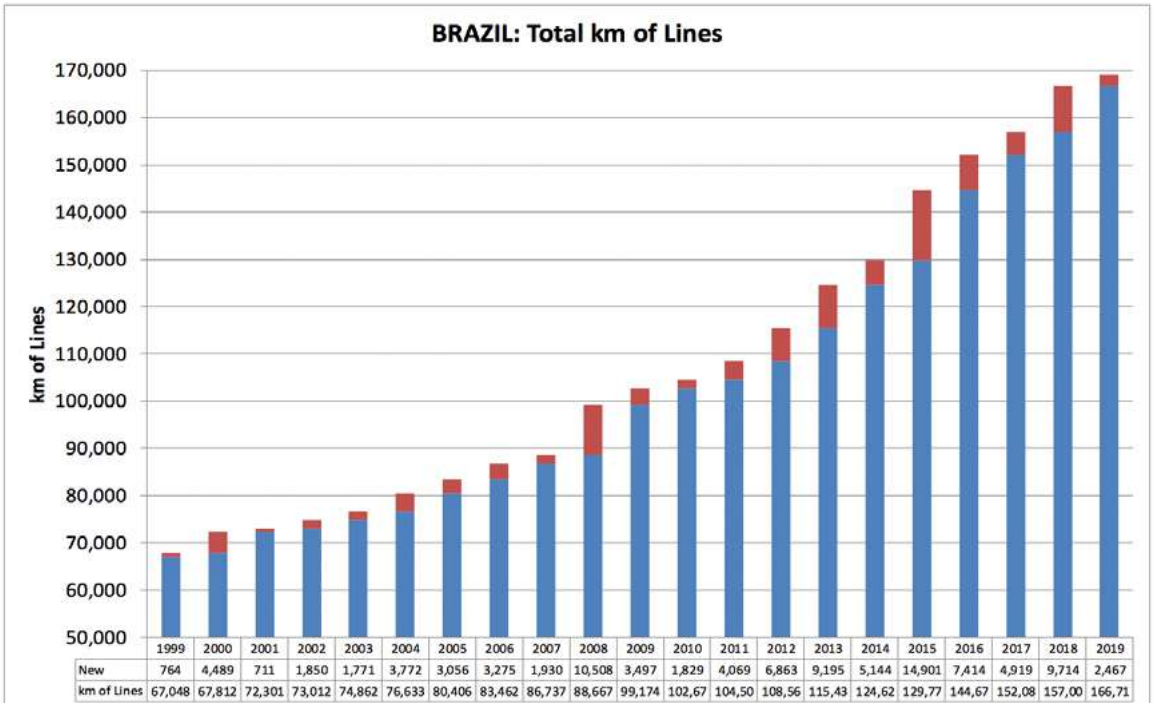


Figure 112: Total km of lines in the Brazilian System

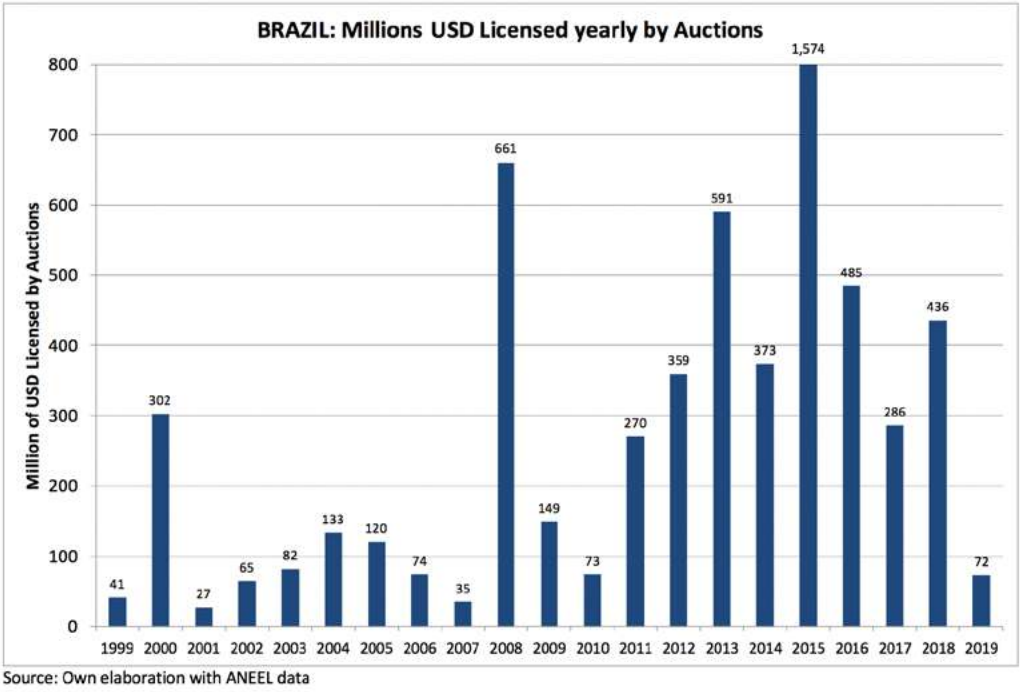


Figure 113: Amount in Annual Revenues Auctioned in Transmission Expansion

Since the Brazilian Law does not require the existence of a single transmission company, there is a great number of transmission companies (156 different in 2019) owners of transmission lines along Brazil and under the operational commands of the (single) System Operator: ONS.

Transmission Auction 02/2019

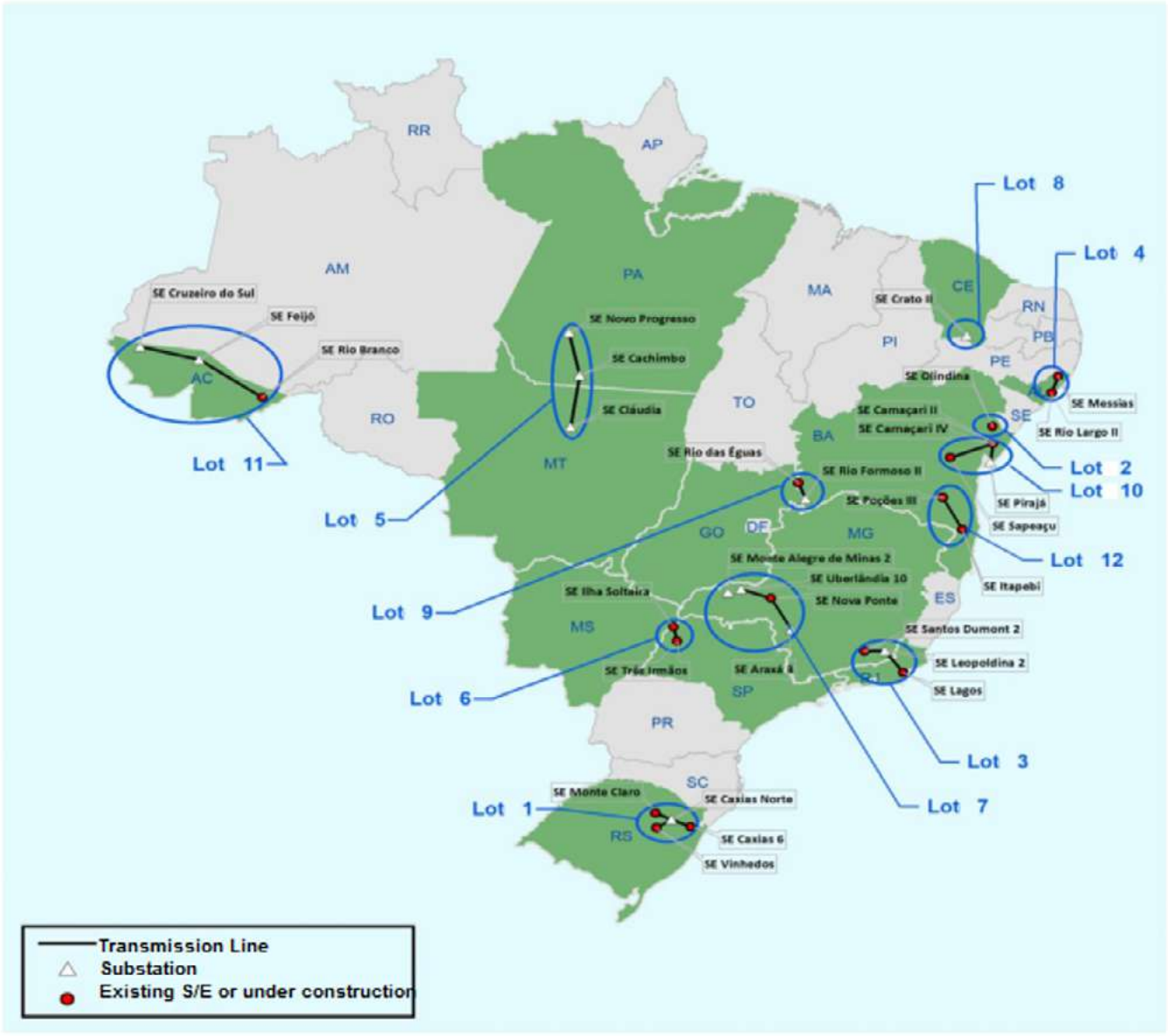
The competition in transmission auction can be verified by the number of participants and the discount rates obtained in the auctions from the reference price.

For this purpose, the last transmission auction 2/2019 is presented. The auction required 12 lots and the expansion of 2467 km of lines at 230 kV, 345 kV and 525 kV; and a capacity of 7791 MVA. The Figure 114 presents the lots and their geographical distribution in the country.

Some of the characteristics of this auction are following summarized:

- *Annual Revenue Required* from the notice: 719,736,790 R$ (around[5] 179 million USD);
- *Annual Revenue Required* contracted: 285,737,219 R$ (around 71 million USD);
- Total discount: 433,999,570 R$ (around 108 million USD);
- Average discount: 60.30%;
- Maximum concession revenue: 18,119,176,210 R$ (around 4.5 billion USD);
- Revenue auctioned: 7,192,434,951 R$ (around 1.8 billion USD);
- Consumer savings: 10,926,741,258 R$ (around 2.7 billion USD).

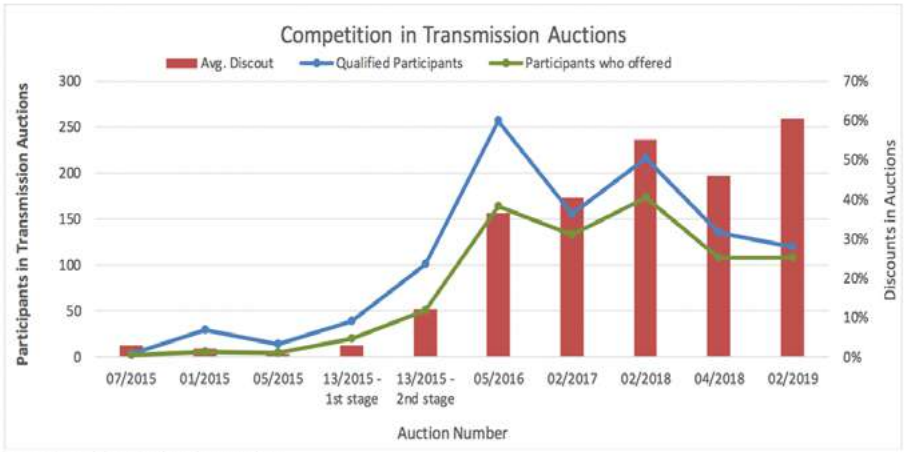
[5] Since the Brazilian Law does not require the existence of a single transmission company, there is a great number of transmission companies (156 different in 2019) owners of transmission lines along Brazil and under the operational commands of the (single) System Operator: ONS.



Source: EPE

Figure 114: Lots in Transmission Auction 02/209

In general, the competition in the transmission auctions has increased and the discounts have been remarkable in the last auctions.



Source: Own elaboration based on EPE data

Figure 115: Competition in Transmission Auctions

This is supported by the high level of transparency, field-level playing and the strong rule of law for investors.

A3.5.4 Transmission Expansion Plan

The Transmission Expansion Plan is a document elaborated, updated and published by EPE every six months.

The last expansion plans show the investments expected in the short-term (6-years) and in the long-term (10-years). The main goal of this section is to give an overview of the last expansion plan issued by EPE (2019) that presents the short-term Transmission Expansion Program (PET) until 2025 and Long-Term Expansion Plan (PELP).

The expansion plan only considers the Basic Network and Basic Border Network that have not been granted yet (auctioned or authorized).

Considering the previous assumptions, the total investment costs associated with the assets described in the document PET/PELP approximately totals R$ 30 billion, of which R$ 24 billion refer to new installations (transmission lines and substations) and R$ 6 billion are related to expansions or reinforcements.

As an investment signal, the following Figures present the general statistics for the transmission planning expansion, as well as the ones specifically related to the greenfield projects, which are suitable for the transmission auction process.



Figure 116: Expected Investments in Transmission Lines in the short and long-term

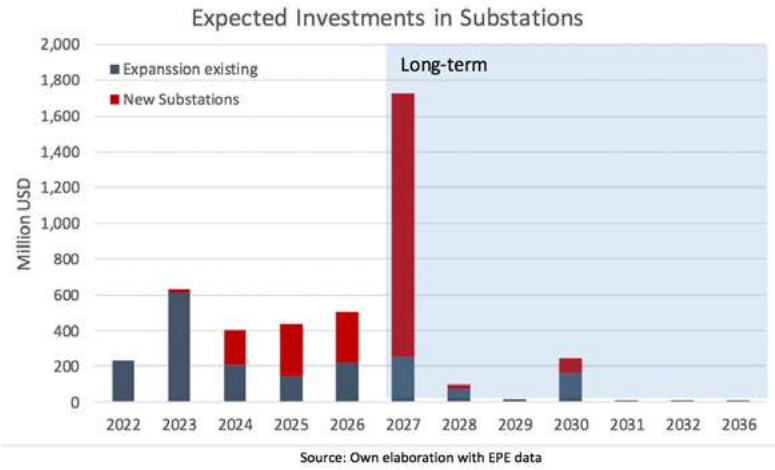


Figure 117: Expected Investments in Substations in the short and long-term

A3.6 Key Topics in a Market Structure and Organization

A3.6.1 Concessions

According to the Brazilian legislation, the Concessions can be granted via auctions:

1. For Public Service: Hydroelectric potential water resources over 3 MW. Thermoelectric plants over 5 MW.
2. For Independent Production: Hydroelectric potential water resources over 3 MW.
3. For exclusive self-production: Hydroelectric potential water resources over 10 MW.

The generation Concessions before 2003 are granted with 35-year concessions and the remaining life span of the plant. For hydroelectric studies, it cannot be deployed hydraulic exploitations that are located in river sections in which another holds Active Record for development of Basic Project or Feasibility Study, or where there is already granted to use [6].

The Independent Producers (IPP) that has Concession or Authorization may sell the energy to:

- Public concessionaire of electrical energy;
- Big customers in the free market;
- Industrial and commercial users to which the producer sells steam because of cogeneration;
- Group of consumers, independent of load and voltage level and which conditions have been agreed with Distribution Company;
- Any consumer that demonstrates that its supply is not assured by the Distribution Company.

According to the new legislation of the market, modified in 2004, the concessionaires for Distribution of Energy **cannot** develop the following activities:

1. Generation.
2. Transmission.
3. Sell Energy to free customers, except those who are captive in his concession area.
4. Participate in other associations, directly or indirectly.
5. Different to Concession object.

The Distribution Co. under a common control that proves rational and operational-economic criteria may unify the Concession areas.

The Distributor shall ensure the service of 100% of its energy and power through contracts registered at the CCEE and approved or registered with the regulator.

The obligations are monitored monthly by CCEE and in the case of non-compliance, the agents shall be liable to penalties.

A3.6.2 Free and Special Consumers

The Free and Special Customers are defined in the legal framework. The Free Customers are those who comply the following conditions:

1. Those consumers ≥10 MW, in voltages ≥ 69 kV to IPP (2004).
2. After 3 years, they can buy energy from anyone.
3. After 5 years: consumers ≥3 MW, in voltages ≥ 69 kV.
4. After 8 years: regulator can reduce the limits.

[6] Provided by Law No. 13,097 of 2015

The Distribution Companies that have captive consumers because of the previous market development may lose their clients which can migrate to the Free Contracting Environment. Losing a consumer does not mean an increase in the tariff of the Distribution Company. Nevertheless, a free consumer can return to be a captive consumer with 5 years previous notice.

Nowadays, consumers older than 1995 (the Law) required the above-mentioned conditions. New consumers starting from 07/07/95 just need to have a peak power ≥3 MW.

A Special Consumer is defined as a consumer responsible for consumer unit or set of consumer units of the integral group(s) of the same submarket in the National Interconnected System, gathered by common interests, whose load is greater than or equal to 500 kW.

Consumer	Minimum Demand	Minimum Supply Voltage	Connexion Date of Consumer
Free Customer	3 MW	69 kV	until 07/07/95
		-	from 07/07/95
Special Consumer	0.5 MW	2.3 kV	-

Table 17: Conditions for Free and Special customers

A previous condition to be a Free or Special Customer, is to be an Agent of the Commercialisation Chamber of Energy (CCEE).

The Figure 118 presents the evolution of the Agents in the CCEE, i.e., shows the growing of the Free Contracting Environment in Brazil.

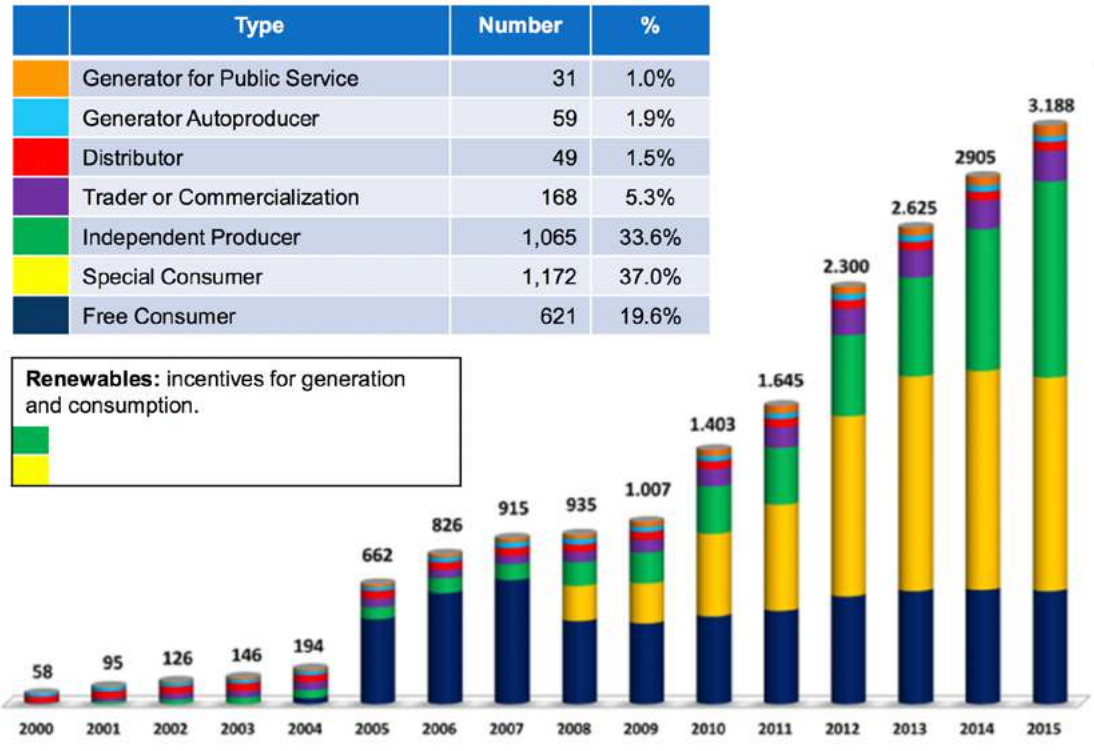


Figure 118: Agents of the Commercialisation Chamber of Energy

A3.6.3 Maximum Market Quotas and Competition

According to the new reforms, the generation companies may not be associated or parent companies to those which develop electric energy distribution activities in the Interconnected System.

On the other hand, there is no provision in the law regarding the limited size of the participants. Nevertheless, there are strong provisions towards competition and the regulatory body has the obligations to perform the monitoring of the concentration of market power.

A3.6.4 Ancillary Service Market

The Reserves are also subject to auctions. In August 2008 it was implemented the first auction for reserve energy with the aim of increasing the national power energy supplying. This auction sold 1,100 MW, specifically for biomass power plants. The cost of this mandatory energy purchase has to be paid through the Reserve Energy Charges, shared among ACR and ACL consumers.

To participate in the auctions, the hydroelectric projects, the renewable energy projects and small hydro projects have to be technically approved by the Energy Research Company (EPE).

The second auction for reserve energy specifically for wind plants took place in 2009 and the results were outstanding, with 753 average MW negotiated and an average price of 58.16 €/MWh. The third auction for reserve energy occurred in 2010 for biomass, wind and small hydraulic plants, with 445 averages MW contracted.

Nowadays, the regulator approved the bidding documents[7] for the first Reserve Energy Auction of 2016. This is for new power plants to be operational on 1st of march of 2020. The Energy Research Company (EPE) registered 133 projects for the Auction, spread over 15 states of Brazil, which add up to an available output exceeding 39,917 MW. The initial price of the auction by quantity for hydroelectric source is set to R$ 248.00 / MWh.

A3.6.5 Pass-through charges

The mechanism of passing through certain charges to the final users is called "Bandeiras tarifarias" or *Tariff Flags*.

The tariff flags reflect the variable costs of generating electricity. Depending on the plants used to generate energy, these costs may be higher or lower. Before the flags, these cost variations were only passed on the next tariff adjustment, a year later. With the flags, the energy bill becomes more transparent and the consumer has the information at the time when these costs occur. The flags reflect the change in the cost of power generation when it happens. When the flag is green, the *hydrological conditions* for power generation are favourable and there is no increase in accounts.

From 2015, the energy bills began to bring something new: The Tariff Flags system. The system has three flags: green, yellow and red, indicating the cost of energy depending on the conditions on the electricity generation market:

- **Green flag:** favourable conditions for power generation. The rate does not suffer any increase;
- **Yellow flag:** less favourable generation conditions. The rate suffers an increase of c$ 0.46 for each kilowatt-hour (kWh) consumed;
- **Red flag - Threshold 1**: costly conditions of generation. The rate suffers an increase of c$ 0.92 for each kilowatt-hour kWh consumed.
- **Red flag - Threshold 2**: even more costly conditions of generation. The rate suffers an increase of c$ 1.38 for each kilowatt-hour kWh consumed.

The flag system is applied by all utilities connected to the National Interconnected System.

[7] http://www.aneel.gov.br/sala-de-imprensa-exibicao/-/asset_publisher/XGPXSqdMFHrE/content/aneel-aprova-edital-do-1-leilao-de-energia-de-reserva-de-2016/656877?inheritRedirect=false

A3.7 ANNEX 1 – Revenue Cap Parameters for Transmission Auctions

The procedure issued by the Regulatory Authority defines the calculation of the Weighted Average Cost of Capital (WACC) for the transmission tariffs and to obtain the Maximum Allowed Revenue Cap for the transmission facilities in the transmission auctions. The procedure is approved in Sub-module 9.8 and defines the WACC as follows:

$$WACC(i)=\%CP(i)*Kp(i)+\%CT*Kd*(1-IR)$$

Where:

Kp(i)	Cost of equity in nominal terms in year i;
Kd	Third-party capital cost in nominal terms;
%CT	Percentage of the capital structure referring to the third-party capital;
%CP(i)	Percentage of the capital structure referring to equity in year i;
IR	Effective corporate income tax and social contribution rate on net income, equivalent to 34% in Brazil.

Cost of Equity (Kp) is estimated using the Capital Asset Pricing Model (CAPM) formula, specifically the Cost of Equity is defined as:

$$Kp= Risk\ Free\ Rate+ \beta_a*7.56\%$$

The Risk Free Rate is obtained as the 3rd quartile (75th percentile) of the values corresponding to the averages, for each day of a 12-month window, weighted by the amount issued, of the interest rates of all series of rates with a maturity of more than 5 years of the Public Bond Brazilian indexed to the Consumer Price Index of Brazil (IPCA). This value is near 5%.

The Cost of Third-Party Capital (Kd) is the cost estimation of borrowing for the project. This parameter is equivalent to the return of the average rates of the series of debentures until maturity, quoted in terms of real interest.

For the beta, the following approach is used:

$$\beta_a = \beta_d * \left[1 + \frac{\%CT(i)}{\%CP(i)} * (1 - IR)\right]$$

Where:

β_a	Levered beta for the project's capital structure for year i;
β_d	Unlevered beta of the electricity sector;
%CT(i)	Percentage of the capital structure referring to third-party capital for year i;
%CP(i)	Percentage of the capital structure referring to Equity for year i;
IR	Effective corporate income tax rate plus social contribution on net profit, equivalent to 34% in Brazil.

The procedure also defines the unlevered beta for the sector as 0,4316 and the Market Risk Premium (MRP) as 7,56% and establish the percentage of third-party capital cannot be less than 30% or more than 45%.

$$\beta_a = 0.4316 * \left[1 + \frac{\%CT(i)}{\%CP(i)} * (1 - 0.34)\right]$$

The Business Risk Premium (BRP) is defined as:

$$BRP = \beta_a * MRP$$

$$BRP = \beta_a * 7.56\%$$

As an example, the values used in an auction in 2009 (regulatory defined on that time)[8] are shown in Table 18.

Capital Cost	
Proportion of Equity	35.00%
Proportion of Third-Party Capital	65.00%
Risk-free rate	5.09%
Market Risk Premium	5.45%
Average levered beta	0.682
Business and Financial Risk Premium	3.66%
Country risk premium	6.07%
Actual cost of equity	11.80%
Nominal Brazil's Long-Term Interest Rate (TJLP)	8.63%
Nominal spread	2.80%
Brazilian Inflation (IPCA)	5.40%
Cost of real debt	5.73%
US average inflation rate	2.71%
WEIGHTED AVERAGE COST OF CAPITAL	
Actual WACC after tax	6.59%

Table 18: Example of WACC used in an auction in 2009

[8] Normative Resolution from the Regulatory Authority ANEEL No. 357/2009

A3.8 ANNEX 2 – Schematic Diagram of Brazilian Hydroelectric Generation Fleet

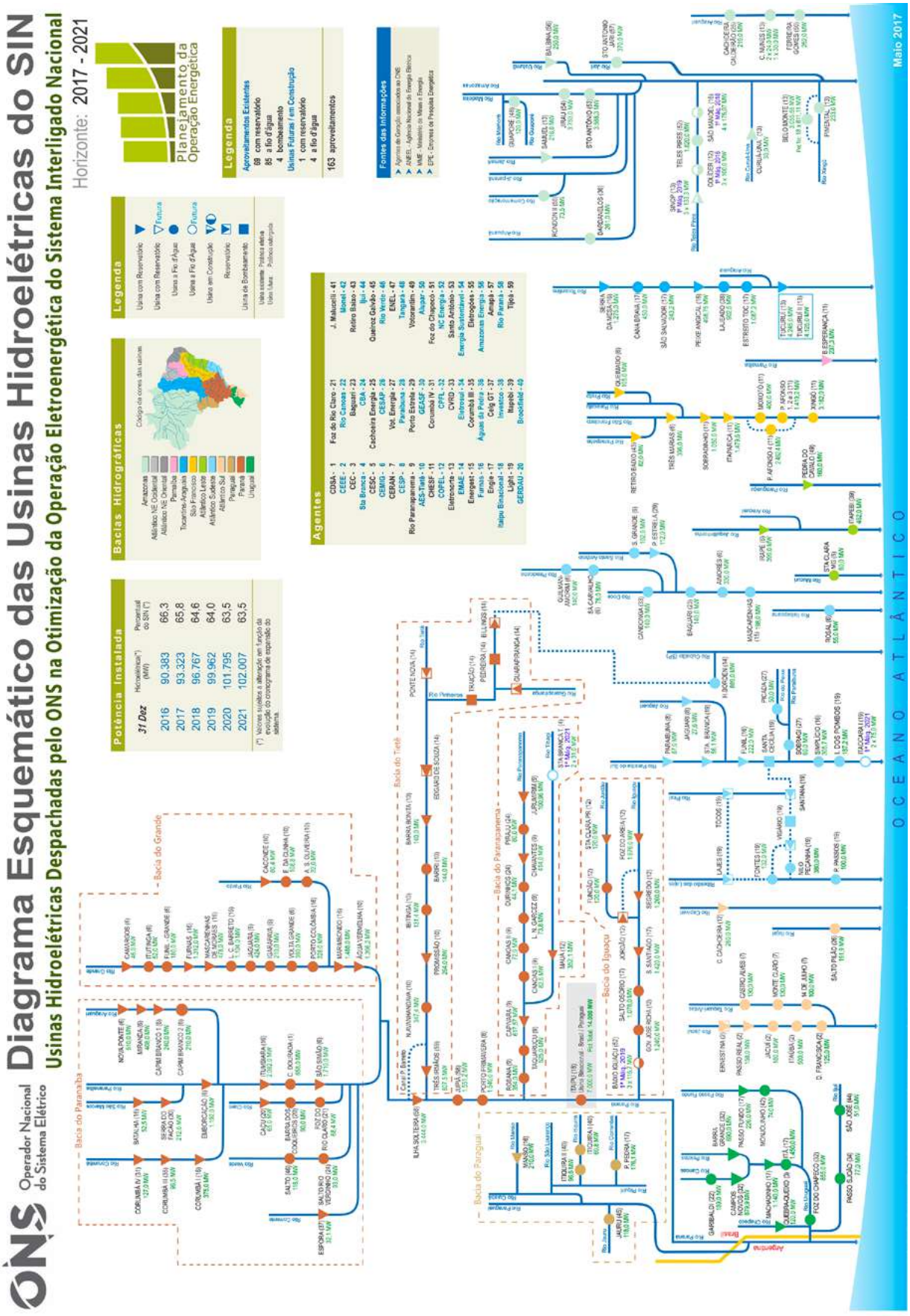


Figure 119: Schematic diagram of Brazilian hydroelectric generation fleet

ANNEX 4 ARGENTINIAN CASE

A4.1 Introduction

There are two interesting reasons to analyse the Argentinian electricity market: it was the second oldest in the world to be unbundled and represented a successful case of competition and well-developed electricity market until the government intervention in 2001.

A brief overview of the key figures of the market is presented as well as the main measures taken under government intervention. The current status of the system is described with focus on how the expansion of the transmission network is being carried out.

A4.2 Overview of Argentinian Market Structure

A4.2.1 Introduction – Key Figures

Argentinian territorial extension is 2,736,690 km² (9th largest in the world) with a population of more than 45 million people. The GDP in 2019 amounted USD 445 billion and the GDP per capita was USD 8,959.

Argentina has 34,919 km of transmission lines in the Interconnected System (SADI) and an installed transformation capacity of 43.2 GVA (Table 19). A simplified diagram of the 500 kV Argentinian system is presented in Figure 120.

The Argentinian installed generation capacity in 2019 was 39.7 GW (Table 20), with a net generation of 131.2 TWh and a peak demand of 26.1 GW.

Voltage (kV)	km	%
132	17,940	51.3%
220	1,668	4.8%
330	1,116	3.2%
500	14,195	40.7%
Total	**126,764**	100.0%

Table 19: Transmission lines in the Interconnected System of Argentina



Figure 120: 500 kV Network of Argentina

Main Sources	Installed Capacity (MW)	%
Hydro	10,812	27.2%
Thermal	24,547	61.8%
Nuclear	1,755	4.4%
Renewables	2,590	6.5%
Total	**39,704**	**100%**

Table 20: Installed capacity of the Argentinian generation system in 2019

The main characteristics of the system are:

- Long distances;
- Concentrated demand in Buenos Aires Province;
- Different regional characteristics;
- Electric restrictions (Technical and stability limits) due to long-distance transmission lines from the generation to the concentrated load.

The evolution of the installed capacity is shown in Figure 121. Few investments were made from 1985 until the privatization and launch of the electricity market in 1993. A high level of private investments was carried out from 1993 until the crisis and government intervention in 2001. The installed capacity remained practically the same from 2001 to 2008. Government intervention was required in order to keep a reasonable generation adequacy in the market from 2008 until now.

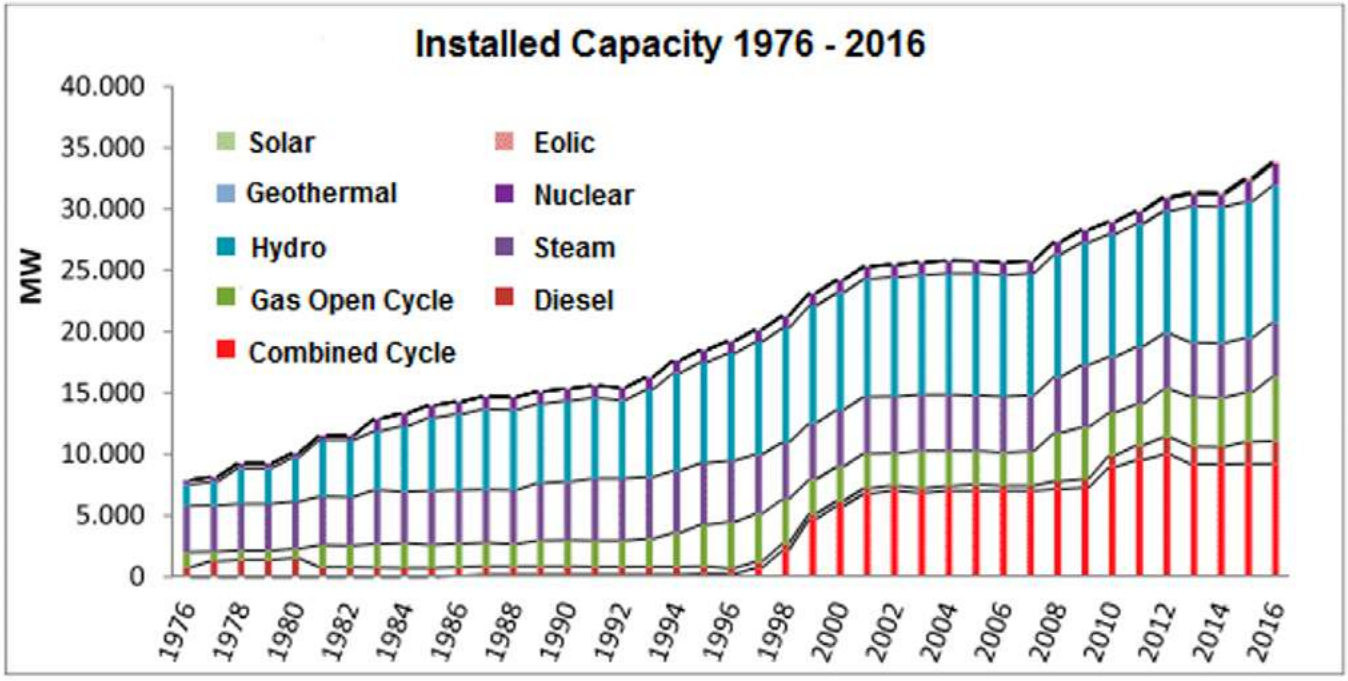


Figure 121: Evolution of the Installed Capacity in Argentinian Electricity System

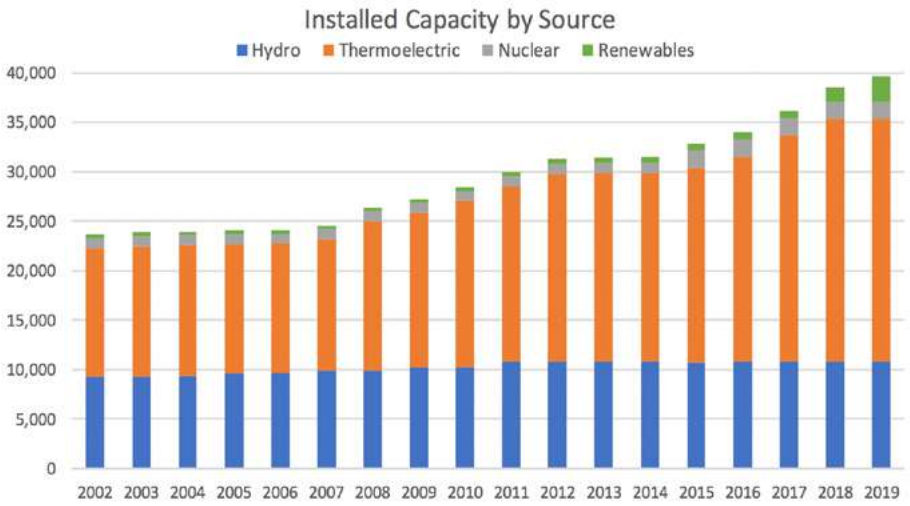


Figure 122: Evolution of the Installed Capacity in Argentinian Electricity System (Source: Own elaboration with CAMMESA)

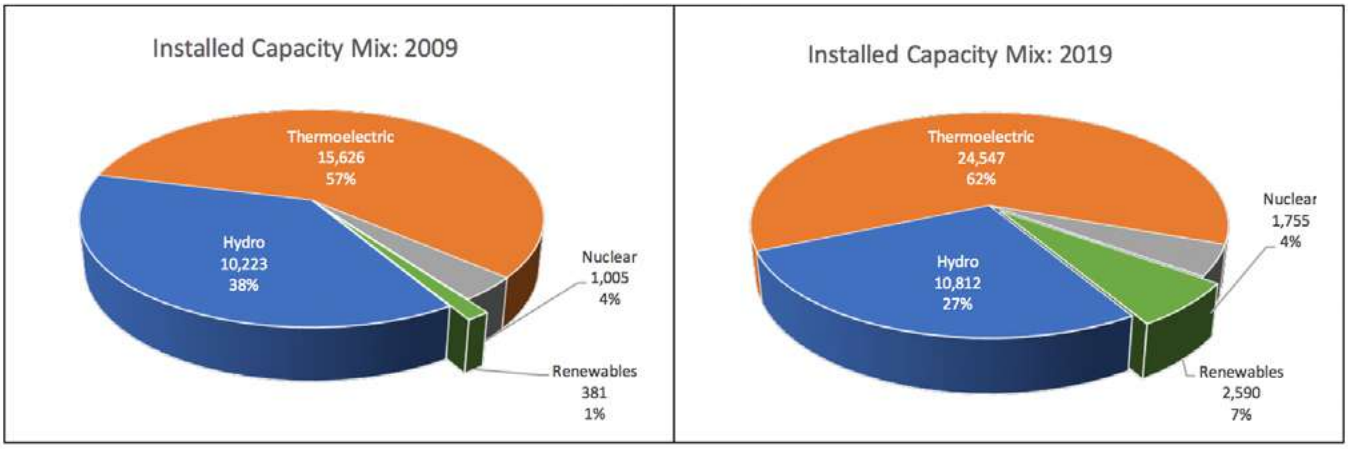


Figure 123: Evolution of the Generation Mix of the Argentinian System

Considering that Argentina has plenty of hydro and natural gas resources, the installed capacity mix has been expanded following these two main resources, by pushing also on the VRE exploitation, especially for wind energy whose potential is great.

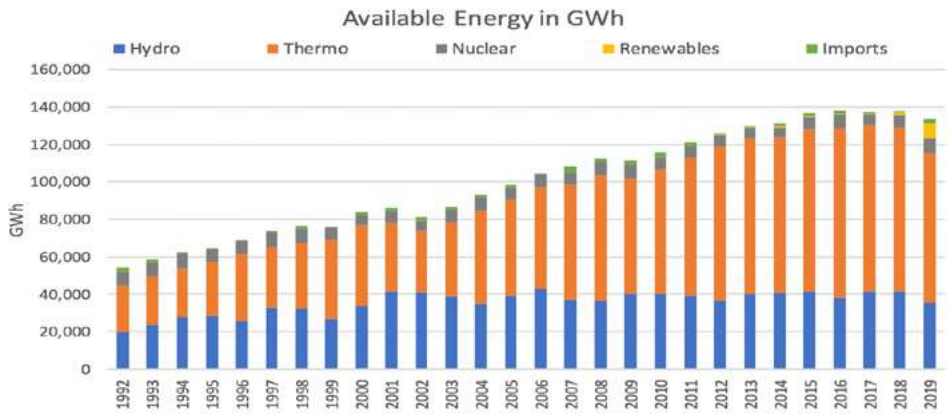


Figure 124: Evolution of the Generated Energy in Argentina

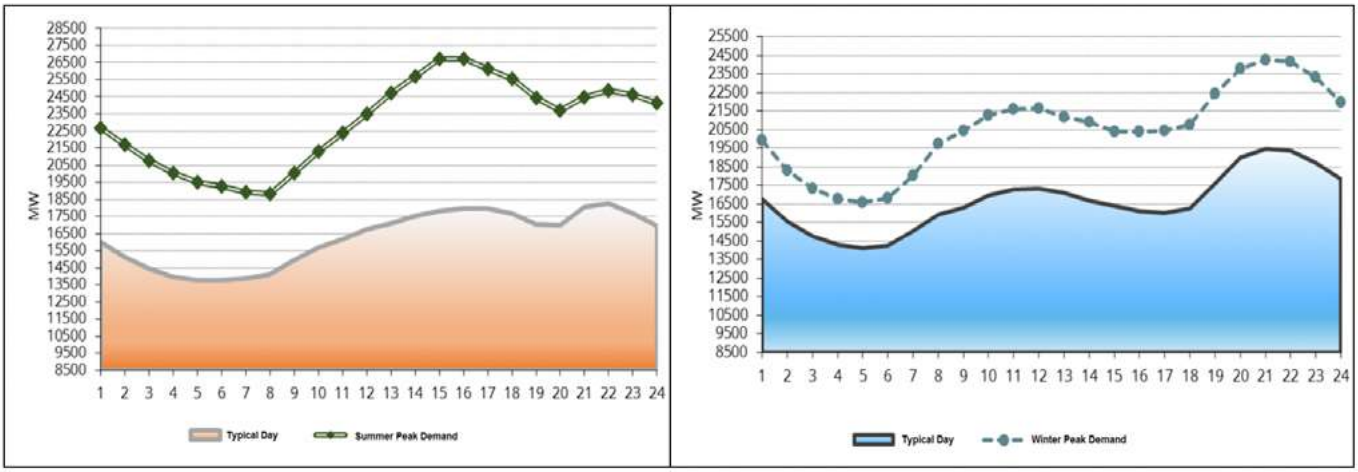


Figure 125: Typical Load Curves in Winter and Summer seasons

The evolution of the peak demand of the Argentinian system is presented in Figure 126.

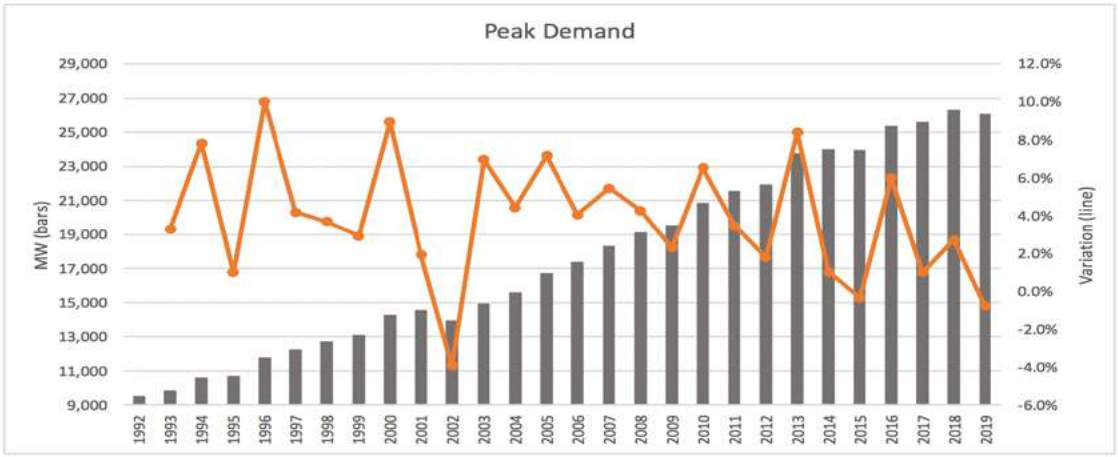


Figure 126: Peak Demand Evolution

The demand of Buenos Aires Province (BSAS in the Figure 127) represents 50% of the total demand of Argentina: its population is 40% of the country and the geographical area is 11% of the entire country. Demand is highly concentrated. The demand of the city of Buenos Aires (GBA in in the Figure 127) is 38% of the total demand of the country, while the metropolitan area represents only 0.5% of the territory.



Figure 127: Regions of the Argentinian System: GBA is Buenos Aires city and BSAS is the Buenos Aires Province

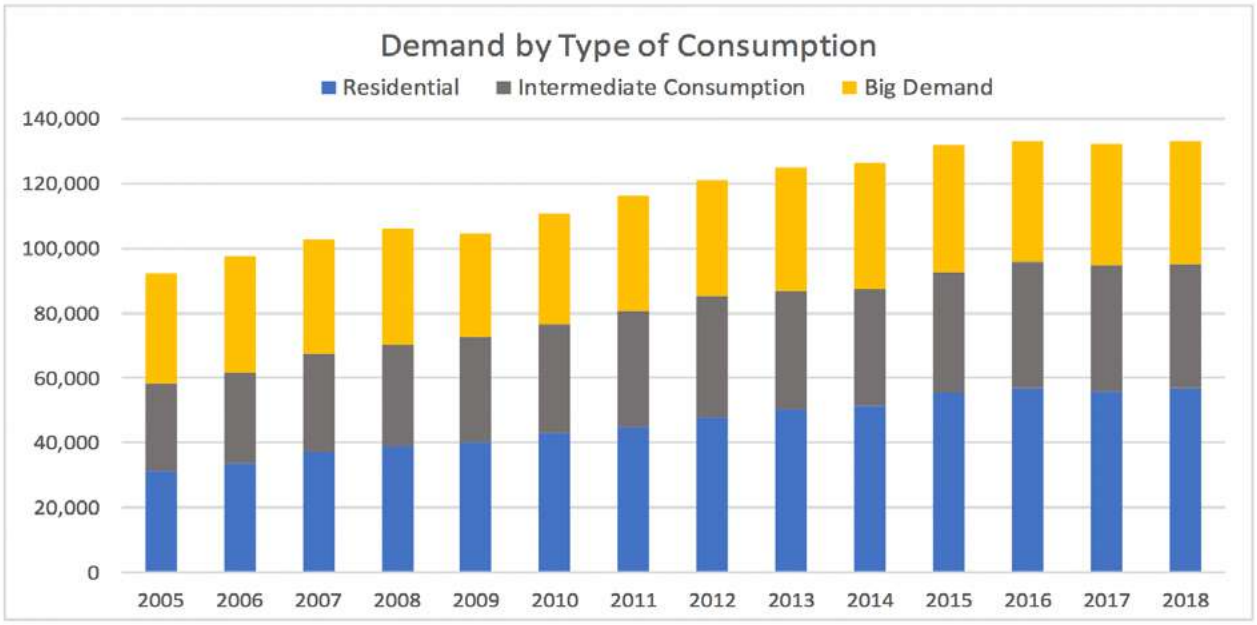


Figure 128: Evolution of the Demand

In December 2019 contracted energy in the market represented 3% of total demand and uncontracted one the remaining 97%. Users and distribution companies purchase energy directly from the spot market, thus minimizing their counterpart risks.

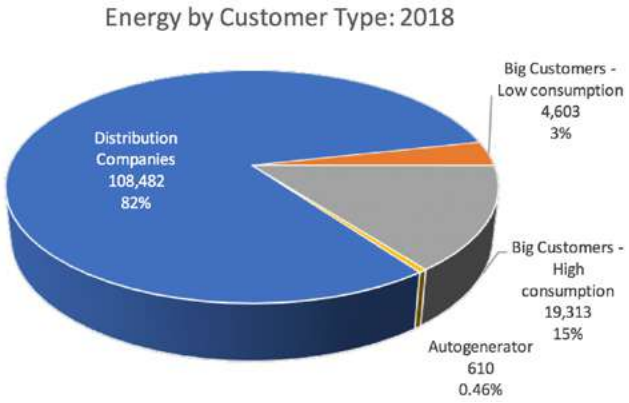


Figure 129: Energy by Type of Customer

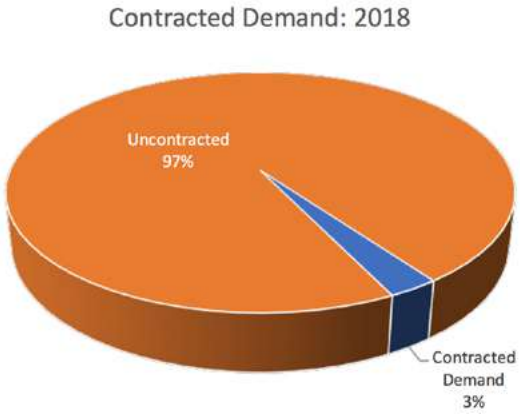


Figure 130: Contracted demand in the Market

Finally, it is worth noting that Argentina shares interconnections with Brazil, Uruguay and Paraguay. A summary of the imports / exports of the country in GWh is presented in Figure 131. The total import in 2019 was 2,746 GWh, which is 2.0% of the total energy offered on the Argentinian market.

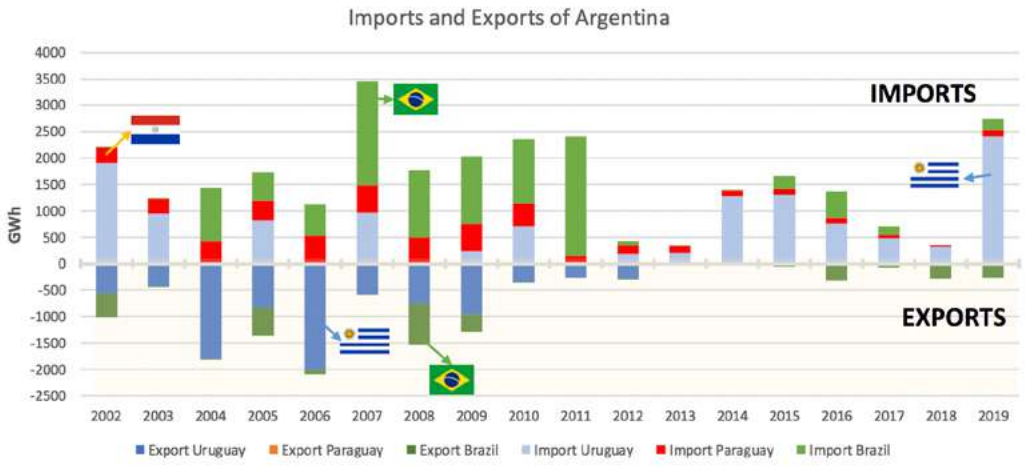


Figure 131: Imports and Exports of Argentina

It is important to highlight that in Argentina the evolution of the energy consumption is correlated with the GDP growth. In several other countries, consumption is not correlated anymore with the GDP, like in USA and Australia, due to the implementation of energy efficiency, renewables and demand management programs.

The big crisis of Argentina in 2001 and 2009 showed a clear correlation between energy consumption and GDP (Figure 132).

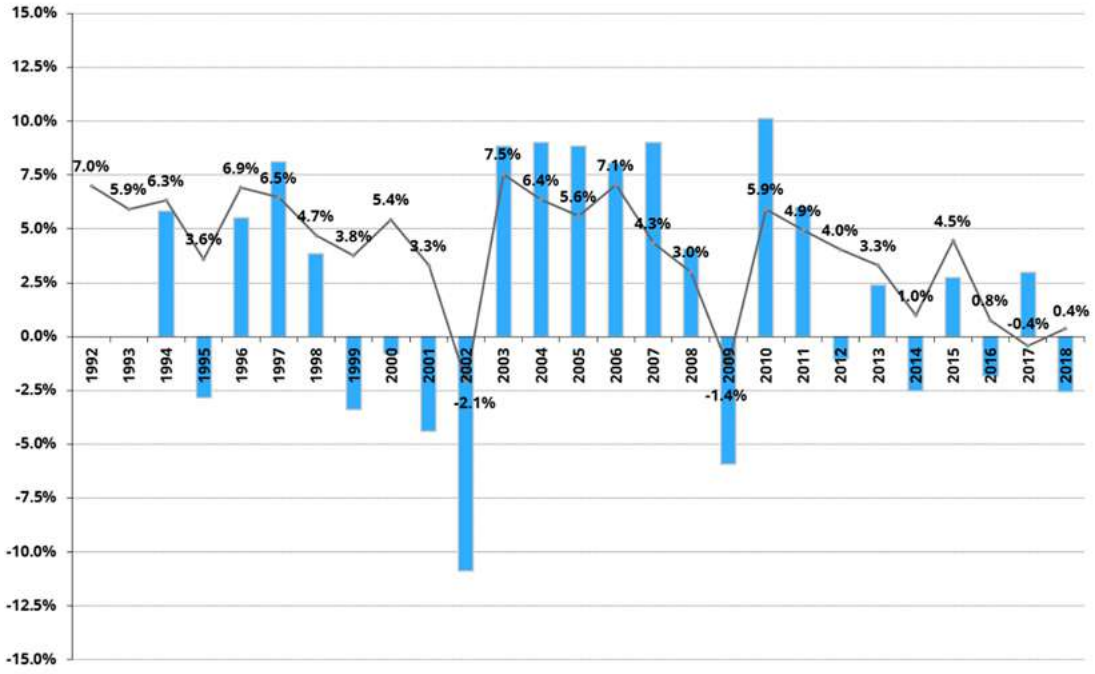


Figure 132: Coupling between Variation of GDP (bar) and Variation of Energy (line)

A4.2.2 Structure

A4.2.2.1 Organization and Actors

In Argentina, the electric sector, originally vertically integrated, was separated into its three stages: generation, transmission and distribution, with well-differentiated structures.

Due to its intrinsic and natural characteristics, the generation sector was conceived as a competing market, while transmission and distribution, being natural monopolies, were given in concession and subjected to regulation by incentives and results.

Electricity and, consequently, the industry in charge of its generation, transmission and distribution (the three basic stages for the provision of electrical energy), have certain characteristics that distinguish them from other goods and, therefore, present particular problems to be solved for optimal market shaping.

The high costs of the energy not supplied, the randomness of the demand, the impossibility of storing electricity and, especially, the restrictions imposed on the transmission network (externalities), require the structuring of institutional mechanisms of coordination of the activities of generation, transmission, and distribution.

The general structure of the current Argentinian market is the following:

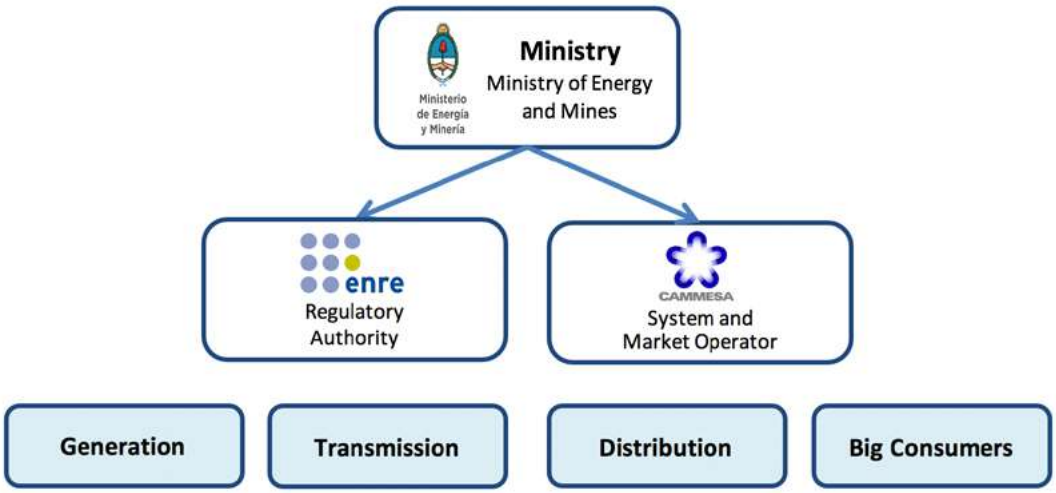


Figure 133: Organization of the Argentinian Sector

Ministry of Energy (Ministerio de Minas y Energia)

The MME is responsible for policy setting and development of the energy sector legislation. The Ministry of Energy performs the supervision of policies for energy development.

National Regulatory Authority (ENRE: Ente Nacional Regulador de la Electricidad)

It is the independent entity within the Energy Secretariat responsible for applying the regulatory framework established by the law issued in 1991. ENRE is in charge of regulation and overall supervision of the sector under federal control. Provincial regulators regulate the rest of the utilities. ENRE and the provincial regulators set tariffs and supervise compliance of regulated transmission and distribution companies with safety, quality, technical and environmental standards.

System and Market Operator (CAMMESA: Compañía Administradora del Mercado Mayorista Eléctrico)

CAMMESA is the System and Market Operator of the SADI, centrally optimizing the resources and performing the centralized mandatory dispatch for the generator companies, independently from any contracts they may have on the Contracting Market.

Transmission Operators

The Transmission Operators (TOs) are responsible for the bulk transmission of electric power on the main high voltage electricity networks. TOs provide open access to the electricity market players (i.e. generating companies, distributors and directly-connected customers) according to non-discriminatory and transparent rules. In order to ensure the security of supply, they also guarantee the safe operation and maintenance of the system. There are 8 transmission companies and only one for the level of 500 kV (TRANSENER).

Generation Companies

The generation companies generate electricity for sale to the distribution companies and big consumers. Producers can include investor-owned, publicly owned, cooperative, and nationalized entities; maybe engaged in all or only in some aspects of the industry, and are regulated by local and national authorities. The producers sell electricity on the contract or spot markets. There are 410 generation companies registered as in 2019.

Distribution Companies

Distribution companies supply electricity to the captive customers. They also provide electricity to the big Customers via the Open Access. There are 28 distribution companies and 46 cooperatives connected to the interconnected system.

Big Customers

The big customers are classified in the following categories:

- GUMA: Large major users, with power demand for own consumption greater than 1 MW and a minimum energy consumption greater than 4,380 MWh per year. They contract about 50% of the expected peak demand;
- GUME: Large minor users, with power demand for own consumption greater than or equal to 30 kW and less than 2,000 kW. There are no minimum consumption requirements, the contracted demand should be 100% of actual demand and requires remote metering and devices;
- GUPA: Large Individual users. They must have a power demand for own consumption greater than or equal to 30 kW and less than 100 kW. There are no minimum consumption requirements and contracted demand should be 100% of actual demand; and
- GUDI: Large users of the distribution grid with power demand greater than or equal to 300 kW.

A4.2.2.2 The Argentinian Markets

The legal and regulatory framework considers the Open Access to transmission and distribution networks in order to preserve the competition in the Argentinian markets.

The following markets are considered in the Argentinian structure:

a. Contracting market or "Mercado a Termino" (MAT) it is a free market environment to search for the supplier by means of contracts between a licensed generator and a licensed distributor or between a licensed generator and an authorized big consumer; and
b. Spot market: It is the market of hourly prices of energy where energy is traded not subject to supply contracts. The price of electricity is defined based on the marginal cost.

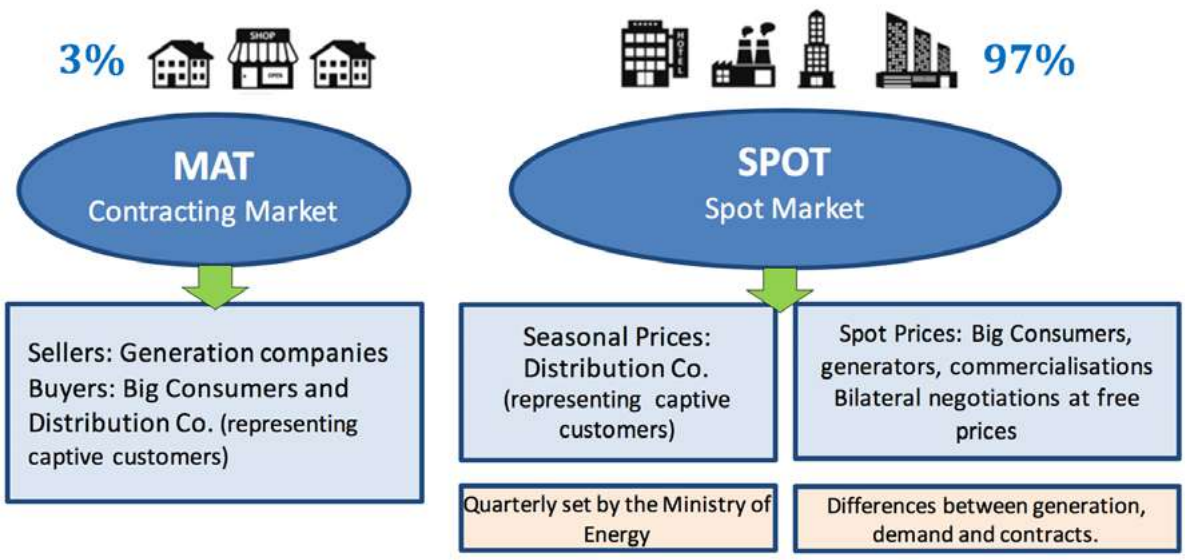


Figure 134: Markets of the Argentinian Sector

The prices in the spot market are divided into:

1. Spot prices: hourly calculated for big consumers and distribution companies and used to clear any differences in contracts; and
2. Seasonal prices: set quarterly by the Ministry of Energy Only distribution companies representing captive customers can participate in the price formation. The rates of the market are calculated by taking into account the average values of future spot prices, based on seasonal prices.

The seasonal price is a stabilized price that is set by the Ministry via resolutions and that currently represents a significant subsidy for end users. The average price in the market in 2019 was 71 USD/MWh as presented following:

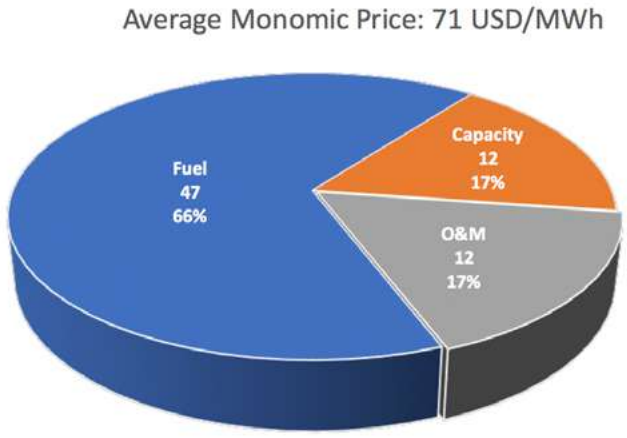


Figure 135: Average Monomic Price

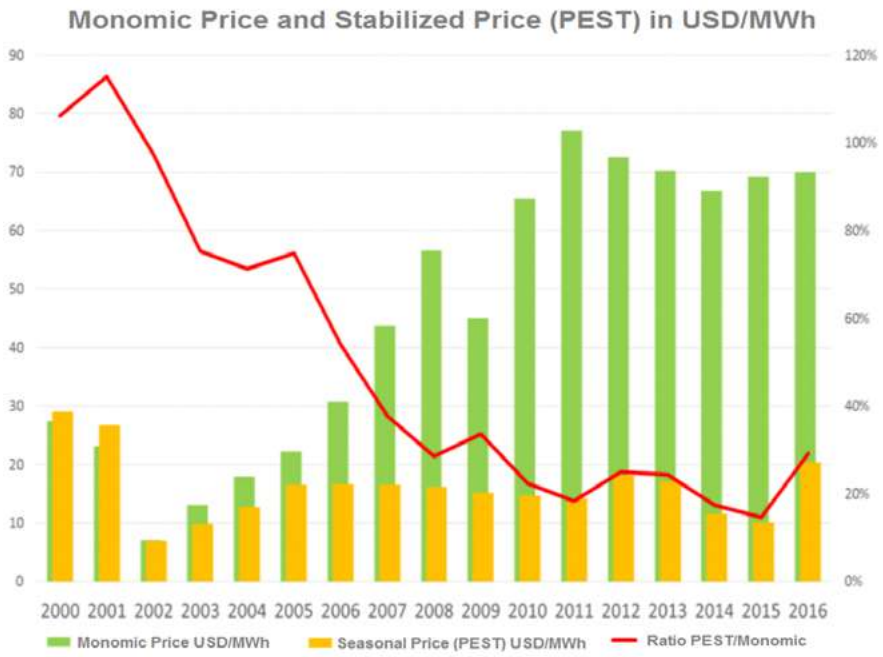


Figure 136: Monomic Prices vs Seasonal Price (PEST)

Initially, the seasonal price was around the average monomic price, covering 100% of it. Since 2003, the average monomic price began to increase more than the seasonal, thus widening the gap between the two until reaching 15% of difference in year 2015. The new seasonal prices entered into force in 2016 increased the difference to approximately 30%.

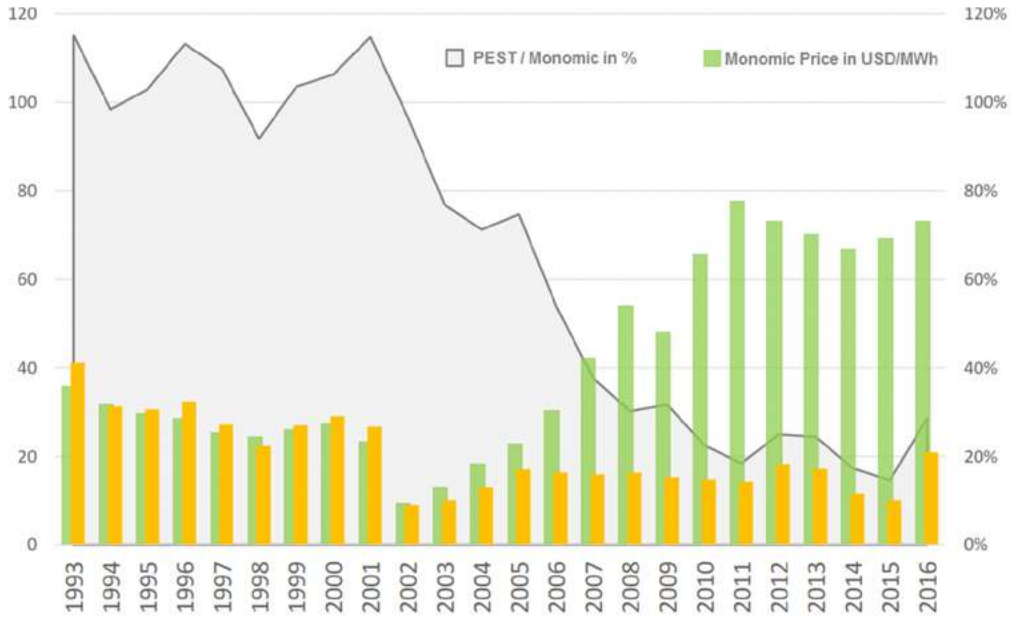


Figure 137: Monomic Prices and Seasonal Price (PEST) Coverage

The minimization of the variable costs is carried out according to the dispatch procedures established by the Sector Authority and the System and Market Operator CAMMESA by Decree in 1992. The cost minimization is performed in different programming periods (Seasonal, Weekly, Daily) until the Operation in Real Time.

The objective is to minimize in each programming period the costs of supplying the demand and the use of water, considering the available resources (machines, fuels, reservoir capacity) and the limitations of the transmission network. The minimization of costs is carried out through capacity allocation processes based on the availability of power and the new offers required to limit failure risks or by increasing the efficiency of the generation through open public tenders.

The Argentine power sector was one of the most competitive and deregulated in South America until 2001. The expansion mechanism at the beginning was purely based on market rules. If the market foresaw high prices (high marginal costs), then companies decided to invest in the sector autonomously. The expansion was carried out by market forces until 2001, when the big crisis occurred in the country and the end-user tariffs were frozen and the spot price capped by the Ministry.

In order to mitigate the losses of the generation companies, who bought the fuel at international market prices, the difference between the spot price and the regulatory cap, were accrued in a special Fund to pay the generation companies in the future.

Due to government intervention, the investments in the energy sector were frozen and this initially successful market took advantage of the overcapacity installed by competitive forces to avoid rationing. The government intervention was again required in order to create parallel market environments to foster investments, but with poor success.

In 2004, the Kirchner government created a national company named Energía Argentina Sociedad Anónima (ENARSA), a company managed by the national state of Argentina for the exploitation and commercialization of oil and natural gas, as well as for the generation, transmission and commercialization of electricity. This was a consequence of poor or null investments of the private sector and the several government interventions in the economy and the electricity sector.

In August 2006, the Argentine government officially announced the decision to reactivate nuclear activity, which included the establishment of a nuclear program for the short and medium term. Because of lack of investments, the government decided in 2006 to launch the Energy Plus Program, to stimulate private investors to build and expand medium and high-power thermal power plants, guaranteeing the purchase of electricity to be supplied at a price above the spot price cap, and passed the Law N ° 26,190/06 implementing the renewable (GENREN) Program.

Accelerated economic growth imposed the need to quickly expand the offer again. As of 2007, the Argentine electricity market recovered the path of growth interrupted by the 2001 crisis, supplying the needs of a growing economy. A strong investment program was implemented public articulated with the private sector for the new economic model.

Nevertheless, the Energy Plus program did not give the expected results from the public and private sectors. The lack of investments forced the government to push the private sector for investment. The government decided to invest the accrued amount in the special Fund in new generation capacity on behalf of the companies. In 2008, Siemens began the construction of two thermal power plants that provided a capacity of 1,660 MW, approximately 10% of the energy available at that time. These plants required an investment of USD 1,097 million accrued in the Fund to pay the difference between the spot price and the regulated cap. This represented an unprecedent intervention of the government in both the market and private funds.

Nowadays, the government is performing the expansion via open public tenders. Tenders delivering renewable generation capacity are also competitive and are aimed at complying with the diversification of the energy matrix through the contribution of renewable energy that replaces the thermal generation and consequently modifies the variable costs incurred by generators.

A4.2.3 Subsidies

In the current scheme, the wholesale price to distributors has different levels of subsidies for different types of users, including the concept of users with social rate.

The scheme of users and purchase prices without social rate in the wholesale electricity is the following:



Figure 138: Subsidies in the Argentinian Electricity Sector

The Social Tariff

Users with social tariffs enjoy a wholesale energy purchase scheme in which a monthly block is zero cost and the surplus over that monthly block is valued.

The scheme of users and purchase prices with social rate in the wholesale electricity is the following:

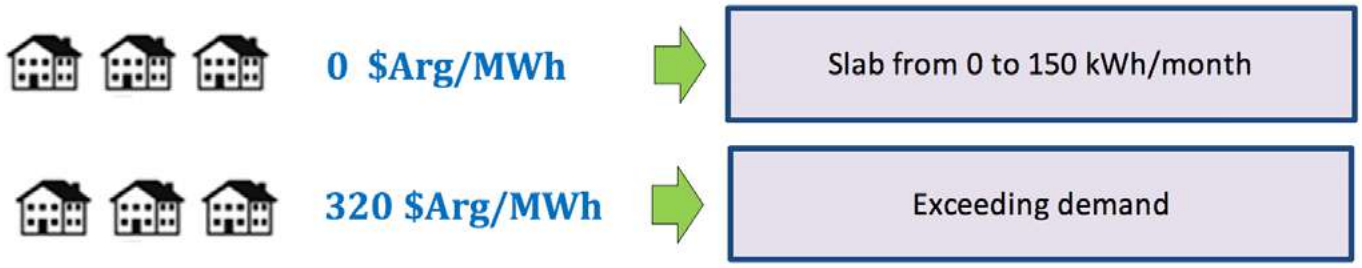


Figure 139: Subsidies in the Argentinian Electricity Sector

The exchange rate at the time of publication of the resolution was 32.7 $Arg/USD, which means approximately 9.8 USD/MWh for the exceeding demand tariff.

The subsidy reduction in 2017 was near 130 $Arg (approximately 29 USD) and impacted 70% of the Argentinian customers. The transmission costs in the electricity invoice of the typical residential customer is practically negligible, representing 1.5% of total bill.

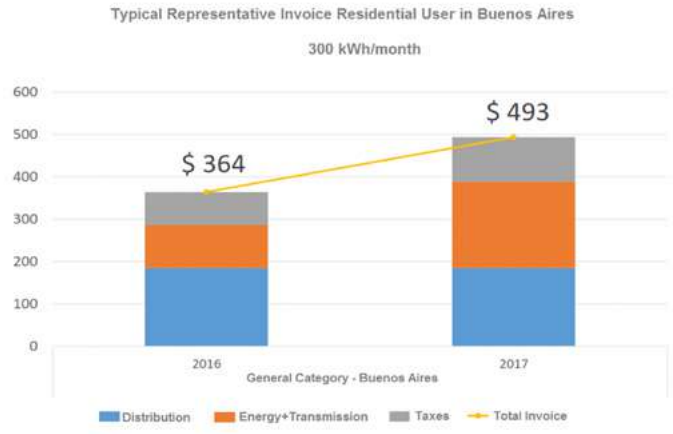


Figure 140: Typical Representative Invoice for a Residential user

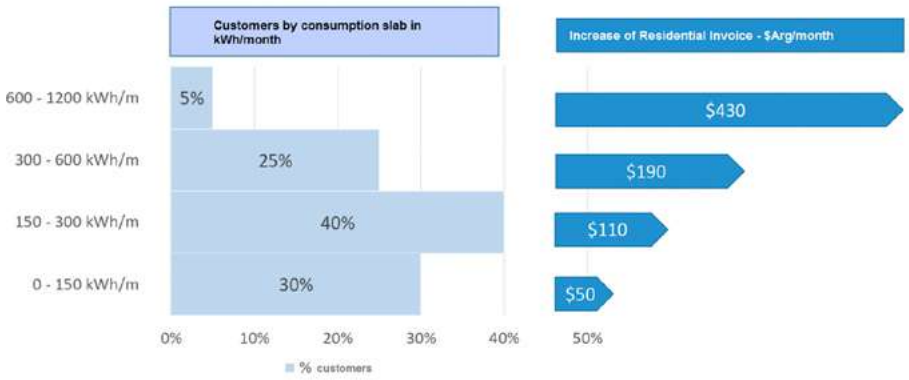


Figure 141: Residential Customers by Consumption Slab

The previous figure shows the residential customers by consumption slab. The representative customers are those in the slab of 150-300 kWh and the reduction of the subsidy impacts the lower slabs of customers (30% + 40%).

The following graph presents the expected reduction of the subsidy programmed until 2019.

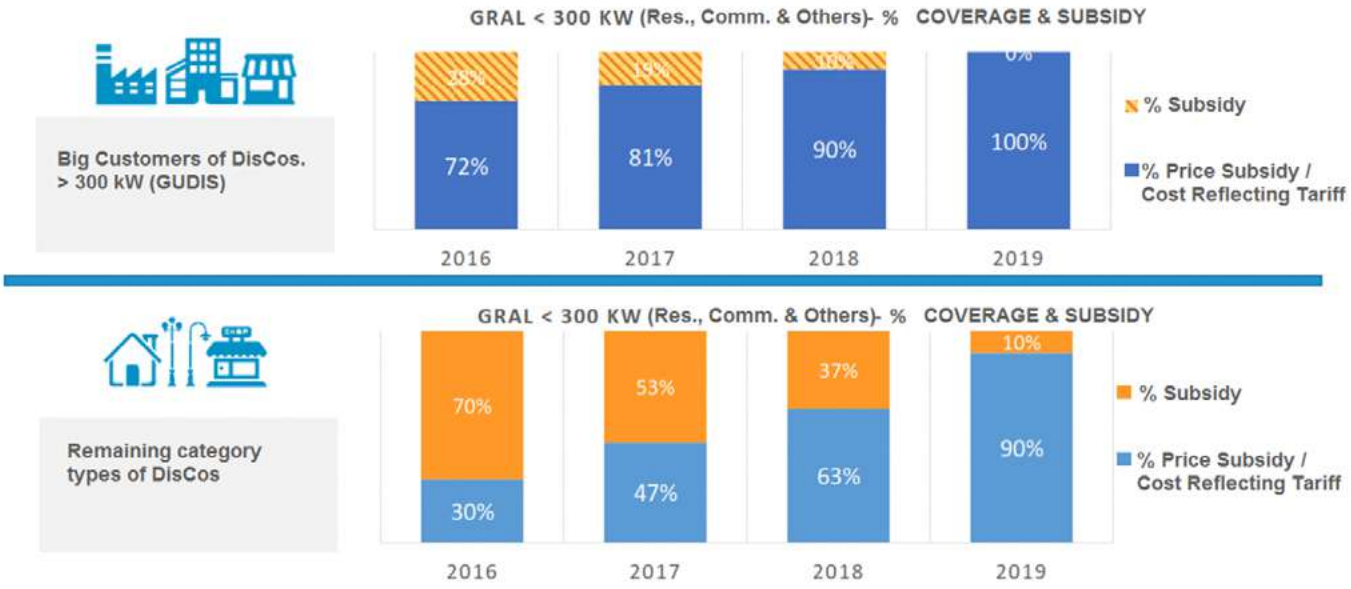


Figure 142: Subsidies by Customer Category

Government intervention and subsidies were also proved to be a high burden for the Argentinian economy, and this is the reason why they have been reduced.

A4.3 Transmission Activity

A4.3.1 Overview

The electricity sector, like in most of the Latin American countries foresees the following activities:

- Generation, a competitive activity opens to the market and based on the price signals.
- Transmission of the Argentinian Interconnected System (Sistema Argentino de Interconxion -SADI). This is a monopolistic activity remunerated via tariffs regulatory approved. The transmission companies are not allowed to generate or distribute electricity and are not allowed to have any share in any generation and/or distribution company. The Open Access is mandatory in order to guarantee the free access to the market by the Generators, Distribution Companies and Big Customers, subject to a wheel charge.
- Distribution activity is a monopolist activity regulated and tariffs are approved by the Regulatory authority of Argentina: Ente Nacional Regulador de la Electricidad (ENRE).
- Big customers are the important clients that are free to choose their supplier in the wholesale market.

The map of the Interconnected Argentinian System is presented below:

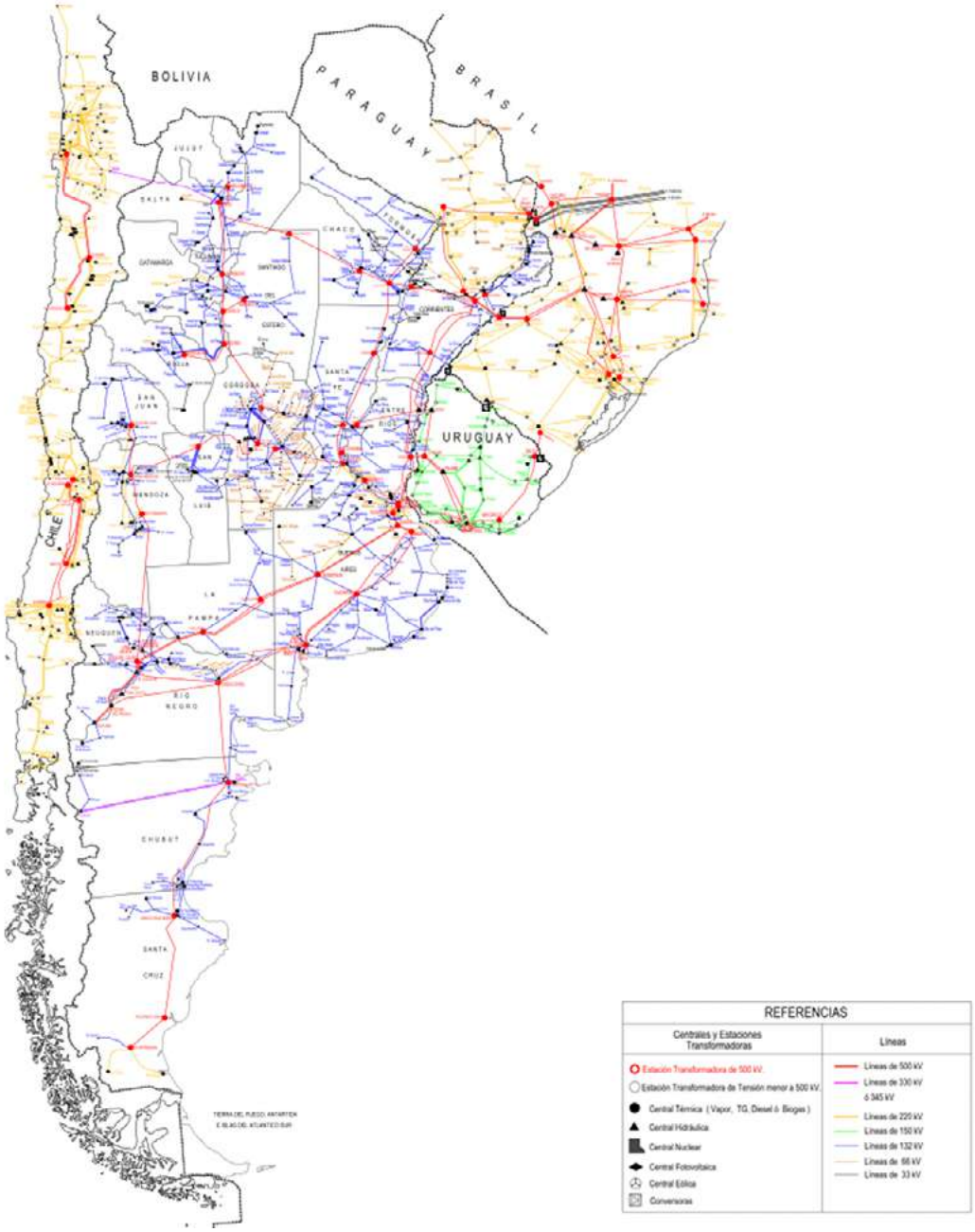


Figure 143: Argentinian Interconnected System (SADI)

The evolution of the kilometres of lines in 500 kV (High voltage) and in 132kV, 220 kV and 330 kV (the "transmission backbone") and the installed transformation capacity is presented in the following chart:

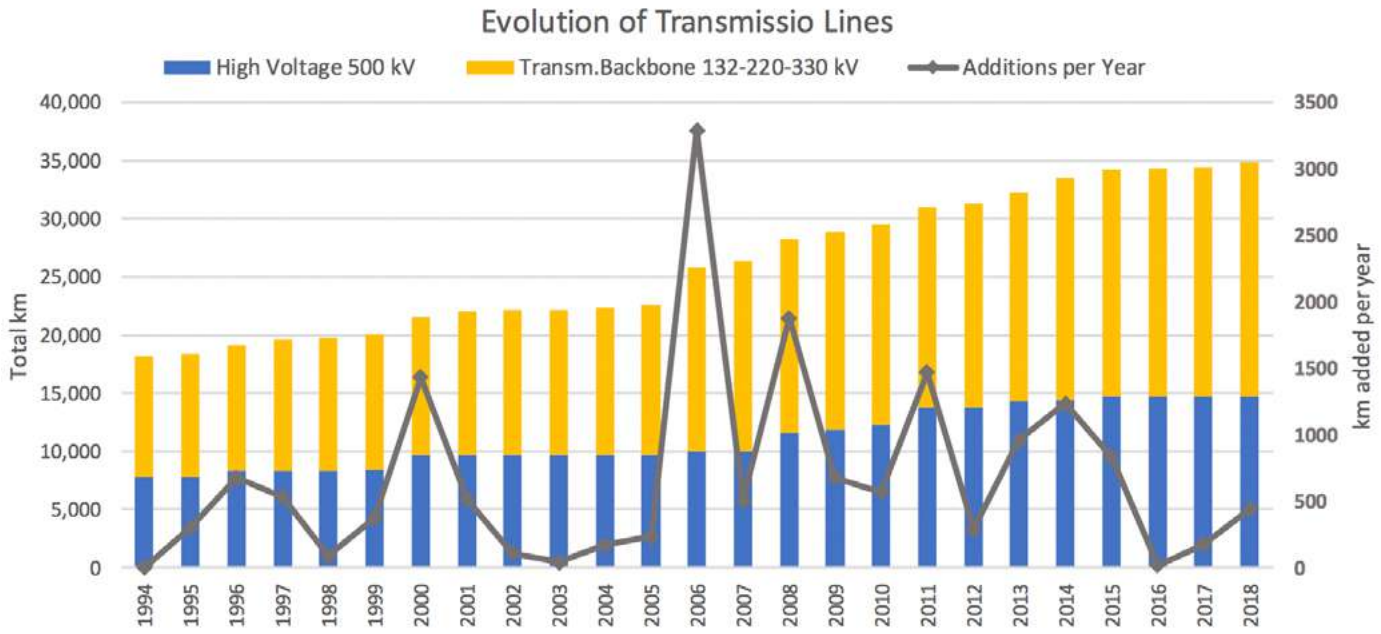


Figure 144: Transmission Lines Total (bars) and increment per year (line)

The transmission lines have been increasing by an average of 700 km per year, near 300 km in 500 kV and 400 km in the remaining voltages levels.

There is evidence that government intervention in the economy and in the energy sector reduced the investments. During the strong government intervention period (2001-2005), the investments in transmission were practically zero. By this reason, the government created additional plans and project to expand the transmission system. The government expanded the network between 2007 and 2013, with near 4,657 km of new lines, expanding the supply in large areas. The most important works were:

- Northwest and Northeast (NOA-NEA) interconnections, which allowed the electrical integration of those regions and their connection with the SADI;
- Third line of hydro power plant Yacyretá, evacuating to the metropolitan area of Buenos Aires the greatest energy produced by the elevation of the Yacyretá level;
- Interconnection of Patagonia, which linked from 2016 Southern Patagonia (Chubut, Santa Cruz) with the SADI;
- Other intra-regional connections were made effective during the period.

The increment of the transformation capacity follows the increment of the transmission lines extension. The evolution of the transformation capacity in MVA is presented in the following chart.

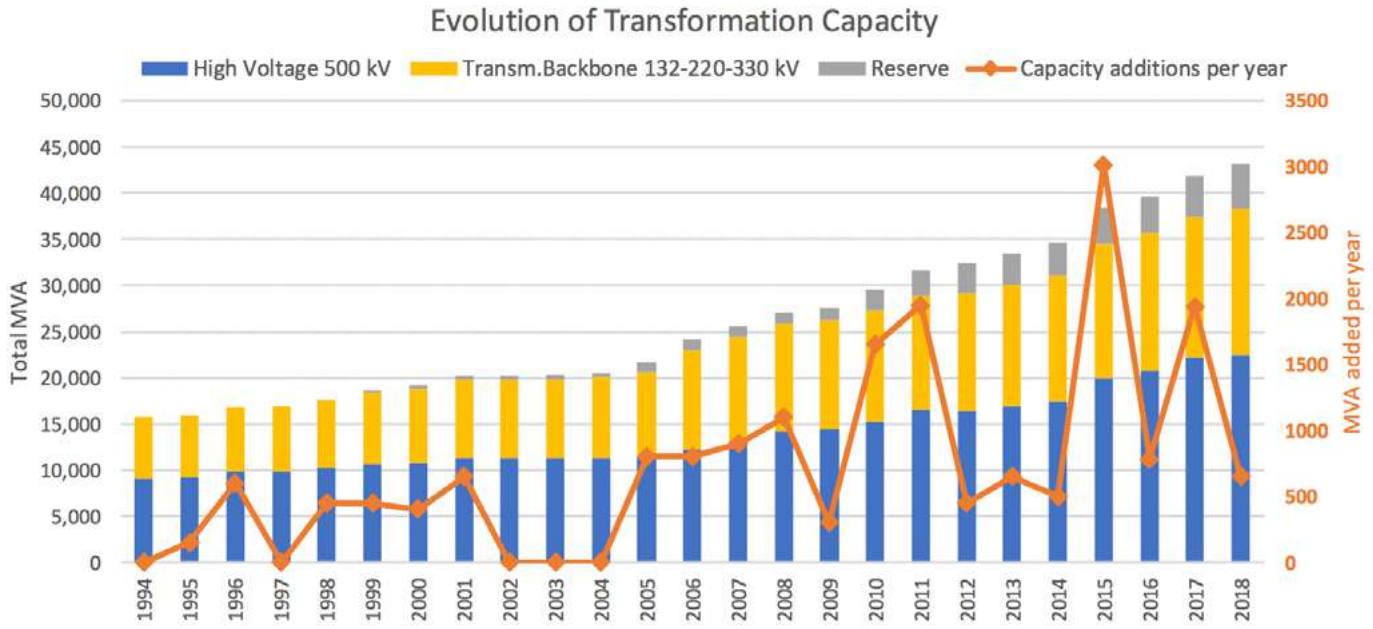


Figure 145: Transformation Capacity Total (bars) and additions per year (line)

Note that the increment of the transmission lines is lower compared to Brazilian system which is more competitive in transmission expansion with remarkable results.

A4.3.2 Transmission Tariffs

The transmission activity, as a monopolistic activity, is remunerated via two regulated charges:

I. Connection charge (fix charge);
II. Capacity use charge (variable charge).

They connection charge remunerates the costs of high voltage equipment required to connect the facility to the transmission network of the SADI. The capacity charge remunerates the annual use of system cost and is paid in twelve (12) monthly instalments.

According to the Argentinian law, the approved CAPEX of the transmission assets are remunerated with a rate of return regulatory determined. For the purposes of the calculation of the remuneration of regulated transmission companies, it must be allowed a reasonable rate of return to those companies that operate efficiently. It is also provided that the rate must: a) be related to the degree of efficiency and operational effectiveness of the company; b) be similar, as an industry average, to other risk activities similar or nationally and internationally comparable.

The Regulatory Authority set the rate of return, via Resolution ENRE 0553/2016, to 7.70% in real terms. The rate was regulatory determined via a study requested to a third-party independent consultant.

The study determines -among others- the value of the variable Beta, a variable that measures the relative risk that the market assigns to the activity under analysis, in this case the transmission of electricity. Beta represents the risk involved in the transmission activity in Argentina, only related to operation and maintenance of assets, with no obligation to expand them, or to sell or buy energy.

To determine this Beta variable, the regulator uses the following formula:

$$\beta_{Arg} = \beta_{USA} * \left[1 + \left(\frac{D}{E}\right) * \left(1 - t_G^{Arg}\right)\right]$$

Where:

β *Arg*	Levered beta for Argentina;
β *USA*	Unlevered beta of the companies in USA listed as "Electric Utilities". Given the lack of a developed stock market in Argentina, the market data of the United States of America is used instead and the Beta of the assets of the public utility companies of USA sector is obtained from the companies listed as "Electrical Utilities" that comprise both distribution and transmission companies;
(D/E)	Optimal debt / equity ratio determined as the average of the Argentinian transmission companies in the past 5 years;
t_G^{Arg}	income tax of Argentina, equivalent to 35%.

The Results of the study shows that:

- The β_{USA} was 0.49;
- The optimal debt relation was 0.57 for the transmission companies in the past 5 years;
- the average debt / equity ratio of the transmission sector amounts to 0.57;
- the Beta equity of the Argentine electric energy transport companies (β_{Arg}) was calculated as 0.67.

In order to determine the cost of equity, the regulator uses the Capital Asset Pricing Model (CAPM):

$$Ke = Risk\ Free\ Rate + Country\ Risk + \beta_{Arg} * Equity\ Risk\ Premium$$

The regulator determined the values of the parameters as follows:

- risk-free rate: 2.13%;
- average market return: 11.36%;
- equity risk premium: 9.23%;
- country risk: 5.27%;
- then, the Ke shareholder return according t the CAPM calculated is 13.59%.

Finally, the Weighted Average Cost of Capital (WACC) determined by regulator in real terms uses the formula:

$$WACC(i) = \frac{E}{D+E} * Ke + \frac{D}{D+E} * Kd * \left(1 - t_G^{Arg}\right)$$

Where:

- the cost of the debt (Kd) was considered as the average bond yields of Argentinian companies in the electricity sector like EDENOR S.A. (Edenor 2022) and TRANSENER S.A. (Transener 2021), which amounts to 9.28%;
- *Ke* was previously determined as 13.59%; and
- t_G^{Arg} income tax of Argentina, equivalent to 35%.

The result is a WACC of 10.07% in nominal terms after taxes. This value is adjusted by the expected CPI in order to obtain the WACC in real terms. The WACC in real terms was approved as 7.70% with an expected inflation rate of 2.2%.

Finally, the transmission charges impact the monomic price in the wholesale market by a value that ranges from 1 $Arg/MWh (0.025 USD/MWh) to 4 $Arg/MWh (0.1 USD/MWh), with the lowest value for TRANSBA and the highest for TRANSNOA. The impact on the invoice of the average residential customer is near 0.42 cents of USD.

A4.3.3 The Transmission Expansion

The transmission expansion in Argentina since 1992 followed market forces and demand. There was no mandatory, but only an indicative expansion plan, not only in generation but also in transmission. Two options were considered to expand the transmission facilities:

1. By contract among the Market Participants
2. By Public Tender

The general scheme is presented below:

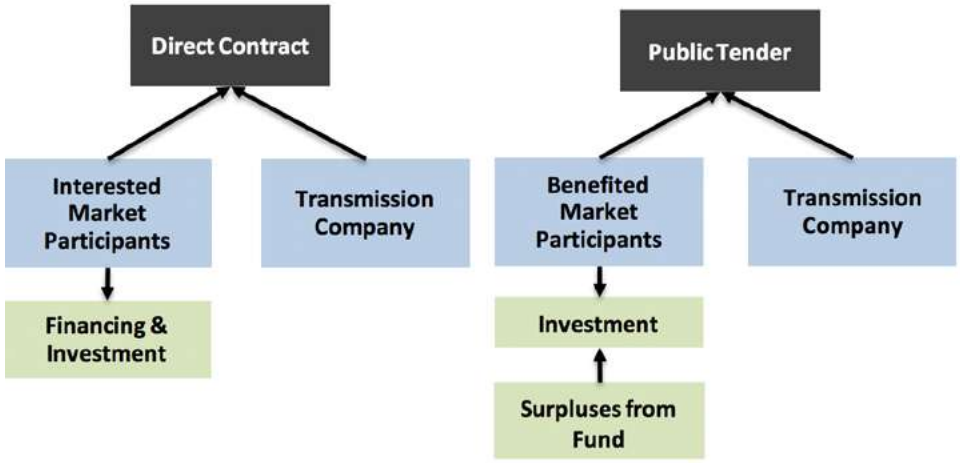


Figure 146: Transmission Expansion Mechanisms 1992-2006

The funds for the transmission expansion (Surpluses in the Figure 146) were coming from the National Electrical Energy Fund created in 1991 as part of the restructuring of the Electricity Sector (Law No. 24065). The Law foresaw a fixed amount paid by distribution companies and big customers who bought energy directly on the wholesale electricity market. The fee was set at 3 $Arg/MWh, which could be increased or reduced by up to 20% by the Ministry of Energy.

This implemented mechanism for transmission expansion based on market requirements presented the following drawbacks:

- Market-related problems like price volatility;
- Weak economic signals in quality and safety for transmission companies;
- Uncertainty about the expansion of the system;
- Absence of rights over the use of extensions.

Additionally, there were problems related to beneficiaries market participants who should pay the transmission expansion:

- Identification of payments by Area of Influence methodology: it did not reflect the economic benefit of the agents and it was dependent on the location of the slack node (arbitrary);
- beneficiaries entitled to veto, so they could stop any expansion;
- beneficiaries paid for idle capacity.

These problems of the expansion mechanism implemented and the crisis in the country in 2001 dramatically reduced the investments in the electricity market by decisions due to government interventions.

As can be noted, the transmission lines and transformation capacity did not increase from 2001 until the government intervention. The government created a Federal Plan of Electricity to expand the transmission network and a Fiduciary Fund for Federal Transmission of Electricity. Therefore, the resources accrued in the Fiduciary Fund for Federal Transmission of Electricity are aimed to collaborate in the financing of the works that the Ministry of energy identifies as an expansion of the transmission system in high voltage, intended for the supply of the demand or the interconnection of electrical regions or for the quality and / or security of the demand. The fund is just to complement the decisions that the market must freely assume.

Consequently and to date, the fee that was initially set as a cap of 3 $Arg/MWh was increased to 5.4687 $Arg/MWh, according to Res. SE No. 1872/2005. From this amount, 1.0861 $Arg/MWh is reserved for the expansion of the federal transmission system (in the Fiduciary Fund for Federal Transmission of Electricity) and the remaining for other electricity funds and to pay the incentives for wind generation.

In 2010 the economy rebounded but slowed again in late 2011 even as the government continued to rely on expansionary fiscal and monetary policies, which kept inflation in the double digits. The government interventions continued and expanded state intervention in the economy: it nationalized the oil company YPF from Spain's Repsol, expanded measures to restrict imports, and further tightened currency controls in an effort to bolster foreign reserves and stem capital flight. Therefore, the investments just relied on the government.

In the first ten years of the privatization (1994-2003), the Transmission System expanded by 2,226 km of high voltage lines. In the next ten years (2004-2013), due to the lack of investments in the market, the government determined to finance the expansion and invest in 4,657 km.

The new government (2015-2019) aimed to liberalize again the economy and then the electricity sector. The government issued in November 2016, the Law 27.328 allowing the public-private participation contracts between the bodies and entities that make up the national public sector with the private sector in order to develop projects in the fields of infrastructure, housing, activities and services, productive investment, applied research and/or technological innovation.

Additionally, in May 2019, the Ministry of Energy created a Special Unit of Electric Power Transmission System (UESTEE) empowered to act as Institutional Initiator and / or Contracting Entity of the National Public Sector, within the framework of the expansion processes of the transmission system (high voltage and trunk distribution).

Following this new regulation, in November 2019, the Secretariat of Renewable Resources and Electricity Market issued the Resolution No. 41/2019 approving the projects included in Stage I of the "Expansion Plan" 2019-2023 for the 500 kV Transmission System.

In accordance with the provisions of the aforementioned Resolution, in order to carry out the Plan, the Special Unit of Electric Power Transmission System (UESTEE), in its capacity as Contracting Entity, may choose to:

I. carry out a Public Tender for these works, in accordance with the provisions of Title III of the Regulation of Access to Existing Capacity and Expansion of the Electric Power Transportation System, approved by Decree 2743 of December 29, 1992; or
II. process the works within the framework of the new Law 27,328 (of Public-Private Participation Contracts).

The Expansion plan approved the following list of transmission facilities to be expanded:

- New substation "Plomer" 500/220/132 kV and complementary works;
- Transmission Line 500 kV "Plomer – Vivoratá" and expansion of the substation in Vivoratá;
- Double Transmission Line 500 kV "Plomer – Ezeiza";
- Transmission Line 500 kV "Plomer - Manuel Belgrano";
- Transmission Line 220 kV "Plomer – Zappalorto";
- Transmission Line 500 kV "Rodeo - La Rioja Sur" and expansion in substations Rodeo, and La Rioja Sur;

- Transmission Line 500 kV “Choele Choel - Puerto Madryn” and expansion of the substations;
- Capacitor Bank series in substation Monte Quemado;
- Transmission Line 500 kV “Río Diamante – Charlone” and a new substation in Charlone.

New substation in Comodoro Oeste 500/132 kV and associated works.


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