Inception Report

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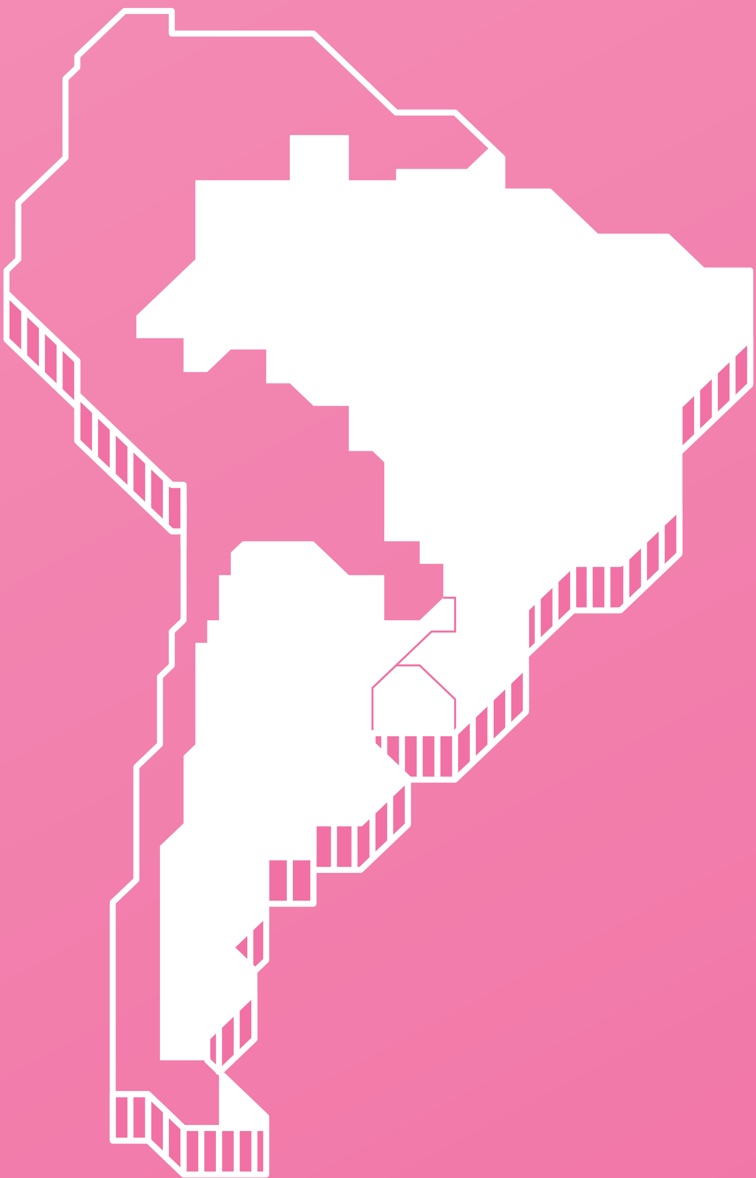

Variable Renewable Energy Sources (VRES) deployment and role of interconnection lines for their optimal exploitation: the **Argentina-Brazil-Uruguay** case study

This research series was conducted by Enel Foundation with the technical support of CESI, a world-leading consulting and engineering company in the field of technology and innovation for the electric power sector.

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Table of contents

LIST OF ACRONYMS

AGR	Average Growth Rate
BOS	Balance of System
CCGT	Combined Cycle Gas Turbine
DG	Distributeg Generation
EHV	Extra High Voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
EPE	Empresa de Pesquisa Energética
EV	Electric Vehicles
GBA	Grand Buenos Aires
GDP	Gross Domestic Product
GHG	Green House Gas
GoA	Government of Argentina
GR	Growth Rate
GT	Gas Turbine
HVDC	High Voltage Direct Current
IRENA	International Renewable Energy Agency
LACE	Levelized Avoided Cost of Energy
LATAM	Latin America
LCOE	Levelized Cost of Energy
LCOT	Levelized Cost of Transmission
MEM	Mercado Eléctrico Mayorista
MINEM	Ministerio de Energía y Mineria (Argentina)
MLCU	Millions of Local Currency Unit
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Cooperation and Development
ONS	Operador Nacional do Sistema Elétrico (Brazilian System Operator)
PV	PhotoVoltaic
RES	Renewable Energy Sources
S/S	Substation
SEN	Sistema Eléctrico Nacional
SIC	Sistema Interconectado Central
SING	Sistema Interconectado del Norte Grande
ST	Steam Turbine
T&D	Transmission & Distribution
VRES	Variable Renewable Energy Sources
WACC	Weighted Average Cost of Capital

1 FOREWORD

This report depicts the results of the extensive data collection and elaboration carried out to have a clear definition of the scenario(s) to be built and investigated. Data were retrieved by examining publicly available documents issued mainly by relevant Ministries, Regulators, System Operators describing the planned evolution of the electrical systems (demand, generation, transmission) and by international Agencies or Companies assessing the expected costs of primary sources and VRES technologies in Argentina, Brazil and Uruguay.

The information gathered during the Data Collection Task is then elaborated in order to define the main parameters needed to set up the Reference Scenario which is the basis for the following analyses. It is worth mentioning that for many key parameters, different sources can provide different data. These discrepancies are mainly due to slightly diverse assumptions or diverse point of view adopted[1]. In this case, an evaluation of the assumptions and a comparison with the scope of the analysis have been carried out, so to select and elaborate the appropriate data to set up the Reference Scenario.

In summary, this report presents:

- an overview of the information gathered about Argentina, Brazil and Uruguay to describe the electric power system at the target year, based on available projections at 2030, if any, or for years close to it;
- the references considered as a basis for the definition and the elaboration of the Reference Scenario;
- the explanation of the main assumptions taken for the creation of the Scenario to be examined;
- the description of the changes applied to some key parameters to define two Variants which will be analysed after the Reference Scenario.

In fact, when examining forward scenarios to give indications on investments either on new generation or new transmission assets, uncertainty shall always be considered. Thus, one usually sets up a Reference Scenario adopting assumptions estimated as having the maximum likelihood to materialise (e.g.: demand growth, fuel prices, etc.). Then, the results obtained in the Reference Scenario are confronted against the outcomes from Variants where one or several key parameters are changed, reflecting deviations from the baseline trends (e.g.: lower demand growth related to a slowdown in the economy growth) and/or technological breakthroughs (e.g.: higher end-use efficiency, switch from gas to power, electric mobility).

The analysis of the various outcomes from Variants with respect to the Reference Scenario allows to highlight to what extent the solutions are stable and hence gives a first general idea on the related investment risk.

[1] For instance, for a company responsible for the development of the transmission system or the generation fleet, the critical index to be evaluated is the risk of lack of production in peak loading conditions, and consequently the analyses are in general based on assumptions of high demand growth. By contrast, a generation company who wants to invest in a new plant will be focused on low demand growth scenarios to assess the economic viability of its investment in a situation of potential overcapacity. For this reason, the demand growth forecasted by the two companies will be probably different.

In summary, the outcome of the study shall provide clear information about the optimal penetration of VRES in the countries based on the assumptions in the Reference Scenario and Variants, highlighting the possible need for reinforcements in the transmission networks and in the interconnection between countries.

The document is structured in sub-chapters each one addressing specific topics, namely:

- a general analysis of the expected growth of the economy in the countries and evaluations on interest rates to be considered for the assessment of the discounted costs of new plants or infrastructures;
- the assessment of the total expected demand in the countries, with a proposal for the subdivisions in areas and definition of load profile along a whole year. If specific data are not available at the target year, some extrapolations are performed taking into account the forecasts on the GDP and the population growth;
- the description of the generation forecasted to cover the demand at the target year. If specific data are not available, hypothesis are formulated based on the targets set by Ministries, towards a green transition of the power sector, essentially based on additional VRES development, which is the focus of the study;
- the description of the transmission network considered and the main reinforcements foreseen, including the list of interconnections between the countries under investigation and between them and other boundary countries not part of the cluster[2];
- some considerations on the Grid Code requirements related to the connection and operation of RES generation and in particular on the assessment of the generation reserve required in the countries to cope with unexpected variation of VRES generation or unscheduled outages. This calls for an enhanced flexibility of the power system, ensured by either the conventional generating units or new devices such as storage systems. A further measure to enhance flexibility consists of strengthening the transmission links within and between countries, all that with the final aim to ensure the system capability of load following in presence of a high share of VRES generation.

The defined Scenario(s) are used in the next tasks of the study where simulations of the whole system are performed to identify the optimal economic penetration of VRES generation (wind and solar) in the countries accounting for the possible cross border power exchanges, based on their economic impact in the power system operation. As a further parallel result, this study also shows the effect of the new VRES generation on the transmission lines, highlighting on the one hand the need for reinforcements, and on the other the best areas for the VRES exploitation.

In particular, in a first step, the simulation of a simplified system represented by a single busbar model, are focused on the analysis of the most critical conditions for electrical systems with massive presence

[2] The study specifically addresses the interregional transmission infrastructures within each country and the cross-border transmission links that can play a role in the assessment of the feasible VRES generation penetration. Local transmission grid reinforcements needed to connect the new power plants or to solve local congestion are disregarded not being within the scope of this wide scale analysis.

of VRES (situations with lowest net demand which may limit the VRES production). This analysis provides the upper boundaries of VRES generation penetration due to system-wide operation constraints.

In a second step, the operation along a typical year is simulated using a probabilistic approach based on Monte Carlo method with the analysis of thousands different situations, weighted for their probability to happen. The impact of the expected renewable generation on the power flows internally to the country under examination and between the countries will be assessed, focusing on possible curtailments due to lack of transmission capacity and leading to the suggestion of possible transmission network improvements to allow higher VRES penetration.

2 DEFINITION OF REFERENCE SCENARIO

The reference scenario will be modelled looking at the target year 2030 and centred on the countries Argentina, Brazil and Uruguay. The main assumptions on load, generation, transmission and investment costs are presented in the following paragraphs.

2.1 Load description

Problem statement

- *Assessment of the demand foreseen in 2030 in Argentina, Brazil and Uruguay to define the variables for the Reference Scenario:*
    - *Electricity demand (TWh)*
    - *Peak power demand (MW): the maximum power demand expected in one hour over a period of one year;*
    - *Hourly time-series for annual basis analyses.*

Methodology

- *Collection of public domain data regarding the most recent demand forecast carried out by the national authorities:*

    - ***Argentina***: *the long term demand forecast is available only up to 2025 and it is provided by MINEM. An extension up to 2030 has been carried out taking into account the scenario "Tendencial" provided by MINEM for energy demand [1] and the growth of GDP and population expected in the country. At the same time, the peak power demand 2030 was assessed taking into account the information provided by CAMMESA at year 2025.*
    The most recent load hourly time-series will be rescaled to define the hourly time series able to reach the targets 2030 in term of peak power demand and energy demand during one year. Where information is available, rescaling will consider how the shares of demand evolve across sectors, e.g. residential vs. industrial.

    - ***Brazil***: *the long term demand forecast is available only up to 2026 and it is provided by EPE* [4]. *An extension up to 2030 has been carried out adopting the growth rate considered by EPE. The 2030 load profile will be obtained starting from the most recent hourly load profile published by ONS, in order to reflect the peak power demand and energy demand forecasts.*

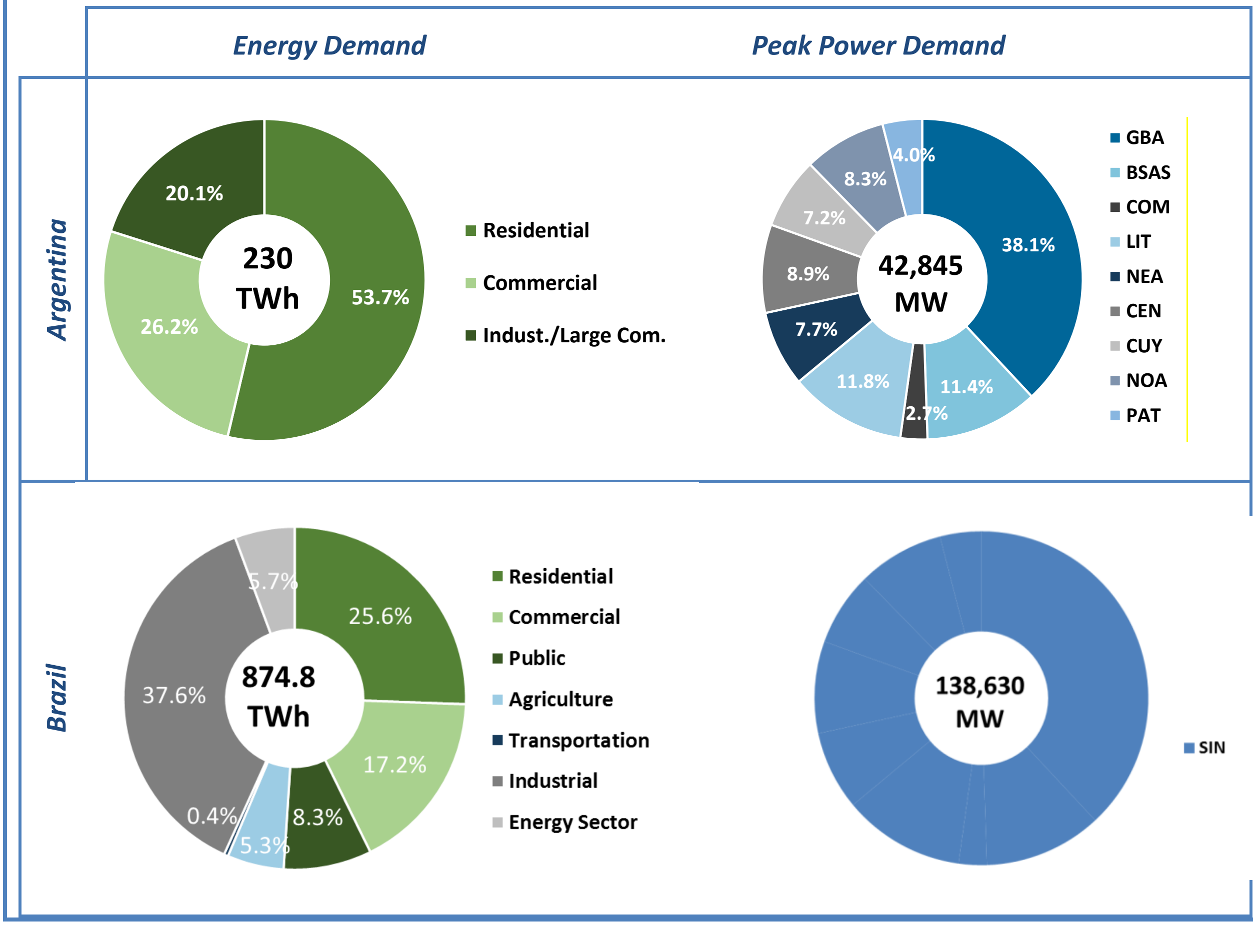
    - ***Uruguay***: *the 2030 energy demand forecast is provided by MIEM DNE [5] while the expected 2030 peak power demand has been calculated considering the average peak demand growth of the last 15 years (2%). The load profile is published by the Uruguayan market operator (ADME)*

Major results

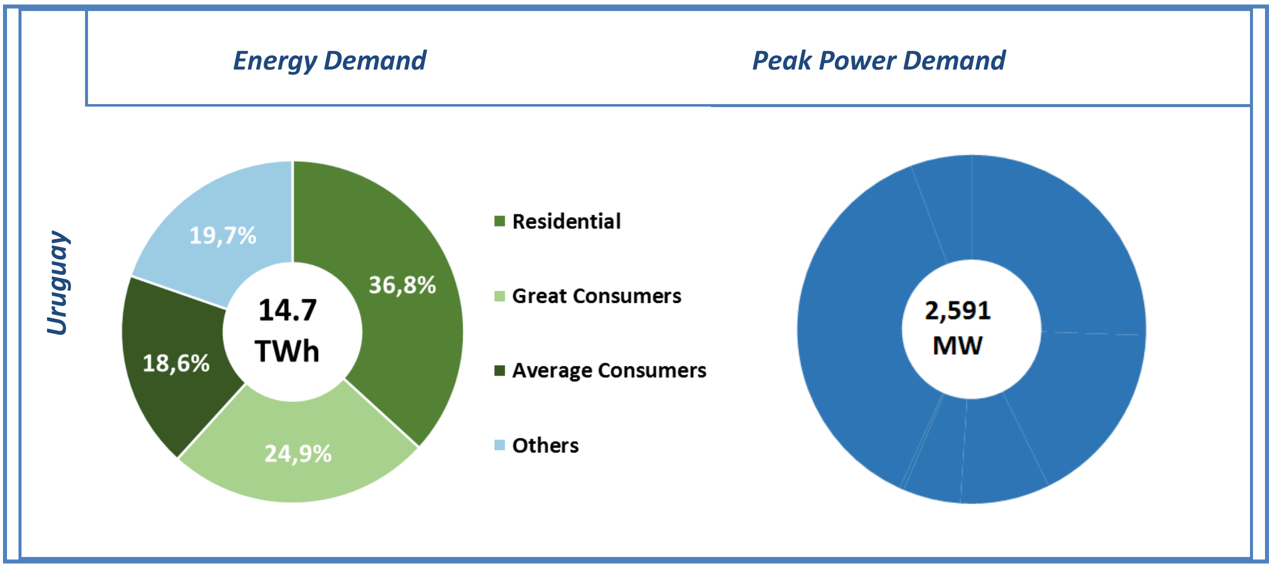
➢ *The electricity demand and the peak power demand assumed for the Reference Scenario 2030 are summarised in the following tables, including the type of customers and the area distribution of demand[3]. Also the Average Growth Rate assumed in the period 2016-2030 is highlighted for each country.*

	Electricity Demand			*Peak Power Demand*		
	% AGR 2016-2030	*2016 [TWh]*	*2030 [TWh]*	*% AGR 2016-2030*	*2016 [MW]*	*2030 [MW]*
Argentina	*4.2%*	*133.0*	*229.9*	*3.8%*	*25,380*	*42,845*
Brazil	*3.8%*	*520.0*	*874.8*	*3.8%*	*81,999*	*138,600*
Uruguay	*2.0%*	*11.1*	*14.7*	*2.0%*	*1,964*	*2,591*

%AGR: % Average Growth Rate



[3] Argentine areas: Gran Buenos Aires (GBA), Buenos Aires (BSAS), Comahue (COM), Litoral (LIT), Noreste (NEA), Centro (CEN), Cuyo (CUY), Noroeste (NOA), PATAGONIA (PAT)



2.1.1 Argentina

2.1.1.1 Electricity demand

In 2016 the electricity demand in Argentina was equal to 132.9 TWh[4]; only +0.6% compared with demand 2015. In the last five years the average growth rate of electricity demand was +2.7%, with floating values of each year included in the range +4.5% (2015) and +0.6% (2016). Figure 1 shows the historical values of electricity demand and growth rates from 1992.

The most recent information published by the Ministerio de Energía y Mineria (MINEM) of Argentine Republic about the electricity demand forecast are included in the document "Escenarios Energéticos 2025" published in December 2016 [1]. MINEM provided the demand forecast up to 2025 for two demand growth scenarios: one scenario "Tendencial" as baseline scenario and one scenario "Eficiente" where efficiency in electricity consumptions was analysed. Scenario "Tendencial" will be considered to define the Reference Scenario of the current study, where the expected demand in 2025 is equal to 192 TWh and the average annual growth rate +3.8% in the period 2015-2025. An elaboration of MINEM data allowed an assessment of the annual growth rate of electricity demand for the period 2017-2025: about +4.2% (Figure 1). No official data has been published yet on expected demand 2030.

[4] Demand of MEM agents (distributors and big users), including the distribution losses and excluding export, consumption of pumping power plants and transmission network losses.

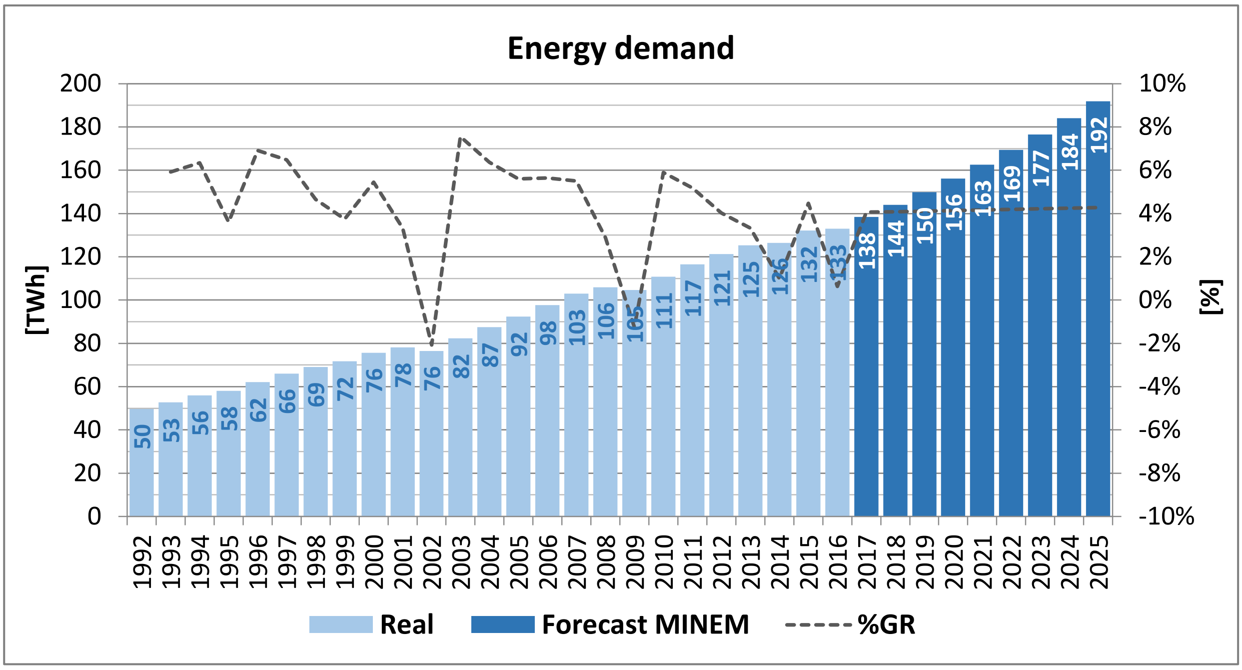


Figure 1 – Electricity demand in the period 1992-2025 [Sources: MINEM and CAMMESA]

In order to assess the electricity demand expectable in 2030, MINEM forecast was compared with a demand forecast carried out with a top-down model based on GDP and population. The results are highlighted in Table 1 and Figure 2. The MINEM curve (green in Figure 2) represent the demand forecasted by MINEM up to 2025 with an extension up to 2030 applying, in the period 2026-2030, the same growth rate assumed by MINEM in the period 2016-2025 (about +4.2%). With this approach the electricity demand expected in 2030 is 235.7 TWh. The red curve in Figure 2 shows the demand forecasted by CESI by means of a top-down model based on GDP and population; +3.7% is the growth rate expected in the period 2017-2030 with an electricity demand of 225.2 TWh in 2030.

The comparison between the MINEM curve and the CESI curve allowed a definition of a final curve (blue in Figure 2) based on MINEM forecast for the period 2016-2025 with +4.2% growth rate and based on CESI forecast for the remaining period 2026-2030 with 3.7% growth rate. The final curve will be adopted as reference to assess the demand to be used for the analyses: 229.9 TWh in 2030.

Table 1 – GDP, Population and Electricity Demand 1992-2030

Year	GPD	Population	MINEM Curve		CESI Curve		FINAL Curve	
			Demand	GR	Demand	GR	Demand	GR
	[MLCU]	[Millions]	[TWh]	[%]	[TWh]	[%]	[TWh]	[%]
1992	388,093.8	33.7	49.7	-	49.7	-	49.7	-
1993	411,018.2	34.1	52.7	5.9%	52.7	5.9%	52.7	5.9%
1994	435,006.1	34.6	56.0	6.3%	56.0	6.3%	56.0	6.3%
1995	422,629.2	35.0	58.0	3.6%	58.0	3.6%	58.0	3.6%
1996	445,986.7	35.4	62.0	6.9%	62.0	6.9%	62.0	6.9%
1997	482,160.8	35.8	66.0	6.5%	66.0	6.5%	66.0	6.5%
1998	500,724.9	36.2	69.1	4.7%	69.1	4.7%	69.1	4.7%
1999	483,773.1	36.6	71.7	3.7%	71.7	3.7%	71.7	3.7%
2000	479,956.1	37.1	75.6	5.4%	75.6	5.4%	75.6	5.4%
2001	458,795.6	37.5	78.1	3.3%	78.1	3.3%	78.1	3.3%
2002	408,812.2	37.9	76.5	-2.1%	76.5	-2.1%	76.5	-2.1%
2003	444,939.1	38.3	82.3	7.5%	82.3	7.5%	82.3	7.5%
2004	485,115.2	38.7	87.5	6.4%	87.5	6.4%	87.5	6.4%
2005	528,238.6	39.1	92.4	5.6%	92.4	5.6%	92.4	5.6%
2006	571,250.6	39.6	97.6	5.6%	97.6	5.6%	97.6	5.6%
2007	622,753.1	40.0	103.0	5.5%	103.0	5.5%	103.0	5.5%
2008	648,247.7	40.4	105.9	2.9%	105.9	2.9%	105.9	2.9%
2009	609,266.3	40.8	104.6	-1.3%	104.6	-1.3%	104.6	-1.3%
2010	672,347.1	41.2	110.8	5.9%	110.8	5.9%	110.8	5.9%
2011	713,679.5	41.7	116.5	5.2%	116.5	5.2%	116.5	5.2%
2012	706,165.4	42.1	121.2	4.0%	121.2	4.0%	121.2	4.0%
2013	722,424.7	42.5	125.2	3.3%	125.2	3.3%	125.2	3.3%
2014	703,941.7	43.0	126.5	1.0%	126.5	1.0%	126.5	1.0%
2015	720,641.2	43.4	132.1	4.5%	132.1	4.5%	132.1	4.5%
2016	710,552.3	43.8	132.9	0.6%	136.1	3.0%	132.9	0.6%
2017	736,132.2	44.2	138.5	4.2%	141.1	3.7%	138.5	4.2%
2018	761,896.8	44.6	144.2	4.2%	146.3	3.7%	144.2	4.2%
2019	788,563.2	45.0	150.3	4.2%	151.7	3.7%	150.3	4.2%
2020	816,162.9	45.4	156.5	4.2%	157.3	3.7%	156.5	4.2%
2021	843,096.2	45.8	163.1	4.2%	163.0	3.6%	163.1	4.2%
2022	870,918.4	46.2	169.9	4.2%	168.9	3.6%	169.9	4.2%
2023	900,529.7	46.6	177.0	4.2%	175.1	3.7%	177.0	4.2%
2024	931,147.7	47.1	184.4	4.2%	181.5	3.7%	184.4	4.2%
2025	962,806.7	47.5	192.1	4.2%	188.2	3.7%	192.1	4.2%
2026	995,542.1	47.9	200.1	4.2%	195.1	3.7%	199.1	3.7%
2027	1,029,390.5	48.3	208.4	4.2%	202.2	3.7%	206.4	3.7%
2028	1,064,389.8	48.8	217.1	4.2%	209.6	3.7%	213.9	3.7%
2029	1,100,579.1	49.2	226.2	4.2%	217.3	3.7%	221.8	3.7%
2030	1,137,998.8	49.7	235.7	4.2%	225.2	3.7%	229.9	3.7%

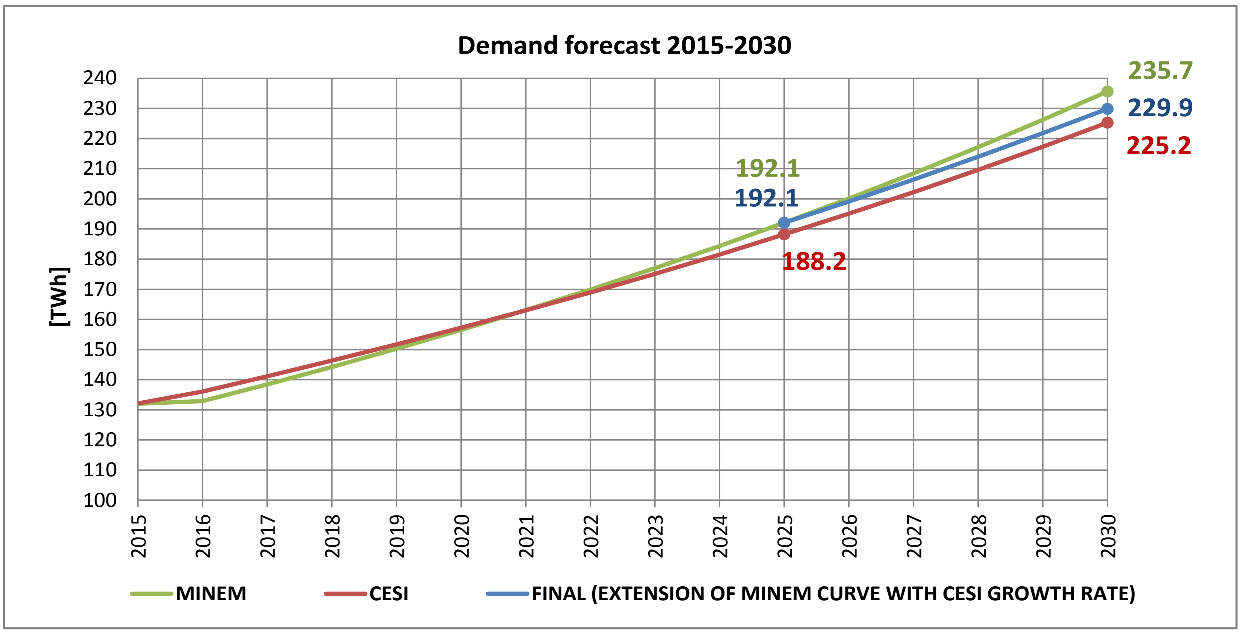


Figure 2 – Demand forecast 2015-2030

The total consumption to be covered by generation power plants includes the demand of customers and also the network losses. As highlighted in Figure 3, T&D network losses decreased from 20.5% of generation output[5] in 1992 to 14.3% in 2014. In 2014 the transmission network losses registered by CAMMESA were 3.2% of generation output, and the distribution network losses were the remaining part.

Distribution losses have been significant in the last years, with values higher than 10% of the produced electricity, while transmission losses reached acceptable values. Without information about the future trend, for the 2030 scenario, it is reasonable assume that investments in the electric system will contribute to the reduction of distribution losses down to 7% of generation output. Assuming 3% for the transmission losses, the overall T&D network losses reach 10% of generation output at year 2030.

[5] Generation output excluding auto-consumptions

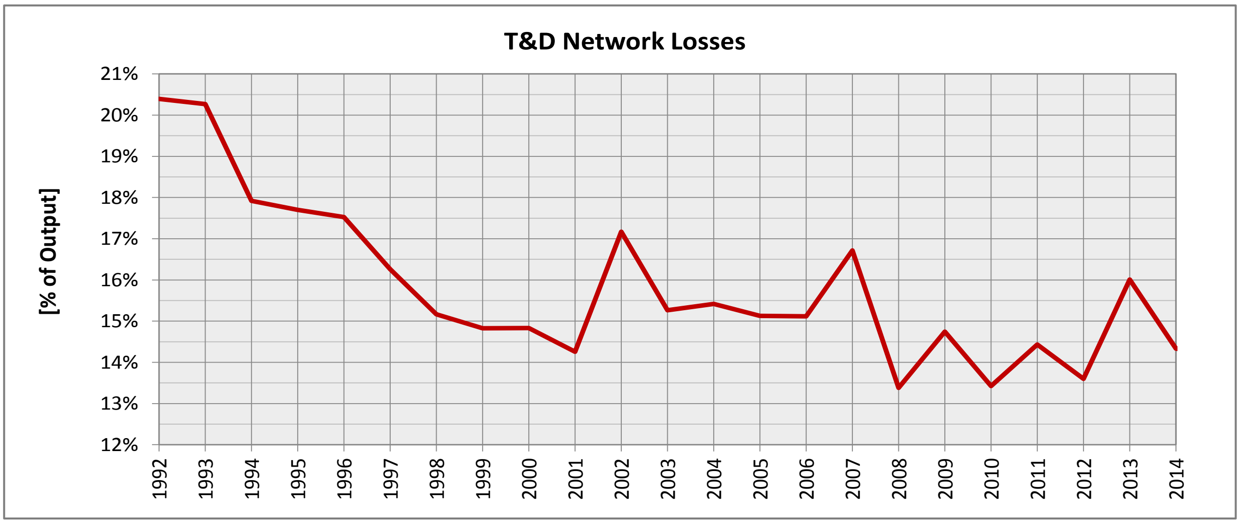


Figure 3 – T&D network losses in Argentine electric power system (Source World Bank)

The electricity demand forecast for type of customer is highlighted in Table 2: residential customers, commercial customers (available power < 300 kW) and industrial/large commercial customers (available power > 300 kW). The table include also the share of transmission network losses based on the above mentioned approach. In 2030, the sum of electricity demand from MEM agents and the transmission network losses will be assumed equal to 237 TWh.

Table 2 – Demand for type of customer + Transmission losses

[TWh]	Residential	Commercial	Industrial/Large Commercial	TOTAL DEMAND	Transmission Losses	DEMAND + LOSSES
2013	50.4	35.9	38.9	**125.2**	4.1	**129.3**
2014	51.4	36.0	39.0	**126.5**	4.2	**130.7**
2015	55.4	37.4	39.3	**132.1**	4.1	**136.2**
2016	57.0	38.5	37.5	**133.0**	4.3	**137.3**
2017	60.3	39.8	38.2	**138.3**	4.3	**142.6**
2018	63.9	41.2	38.9	**144.0**	4.4	**148.4**
2019	67.7	42.6	39.6	**149.9**	4.6	**154.5**
2020	71.7	44.1	40.3	**156.1**	4.8	**160.9**
2021	75.9	45.6	41.0	**162.6**	5.0	**167.6**
2022	80.4	47.2	41.8	**169.4**	5.2	**174.6**
2023	85.2	48.8	42.6	**176.5**	5.4	**182.0**
2024	90.2	50.5	43.3	**184.0**	5.7	**189.7**
2025	95.6	52.2	44.1	**191.9**	5.9	**197.8**
2026	100.7	53.8	44.6	**199.1**	6.2	**205.3**
2027	106.0	55.3	45.1	**206.4**	6.4	**212.7**
2028	111.5	57.0	45.5	**213.9**	6.6	**220.5**
2029	117.3	58.6	45.8	**221.8**	6.9	**228.7**
2030	123.4	60.3	46.2	**229.9**	7.1	**237.0**

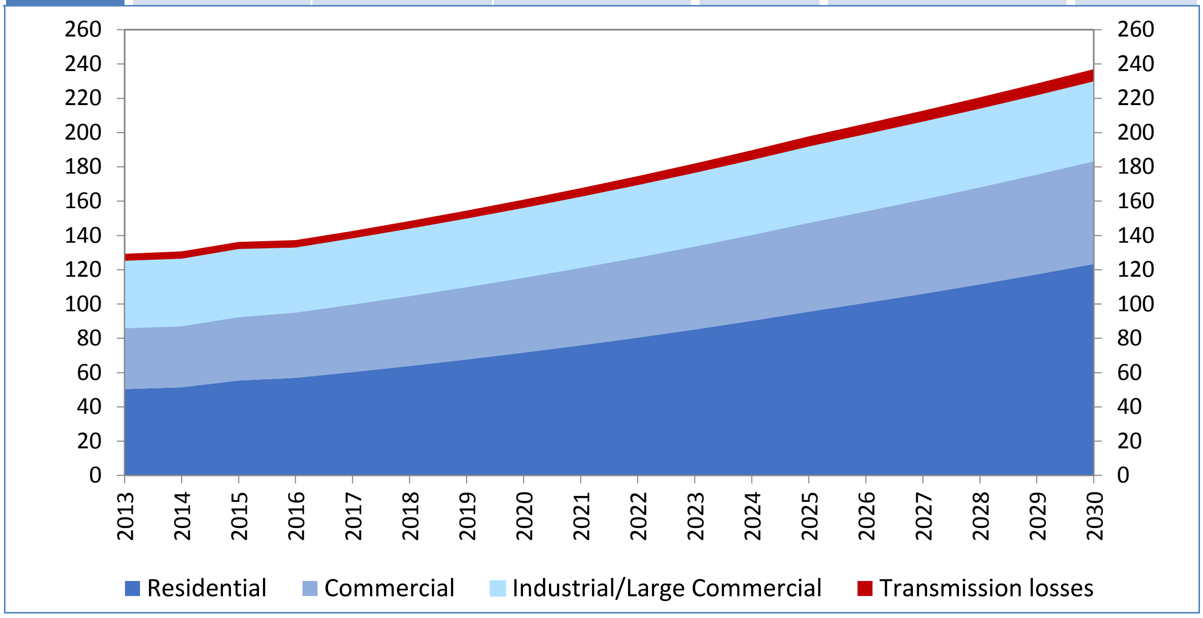


Figure 4 shows the expected trends of consumption mix. In 2016 the residential demand was about 43% of the total demand, while the consumptions of commercial customers and industrial/large commercial customers were very similar 29% and 28% respectively. In 2025, MINEM forecasts an increasing role of residential customers in the electricity mix (about 50% of total demand) and a reduction of the other sectors: 27% for commercial customers and 23% for industrial/large commercial customers. According with MINEM trends 2016-2025, the forecast of electricity demand for type of customers for the period 2026-2030 (Figure 4) was carried out. In 2030 the consumption mix is composed by 54% of residential demand, 26% of commercial demand and 20% of industrial demand.

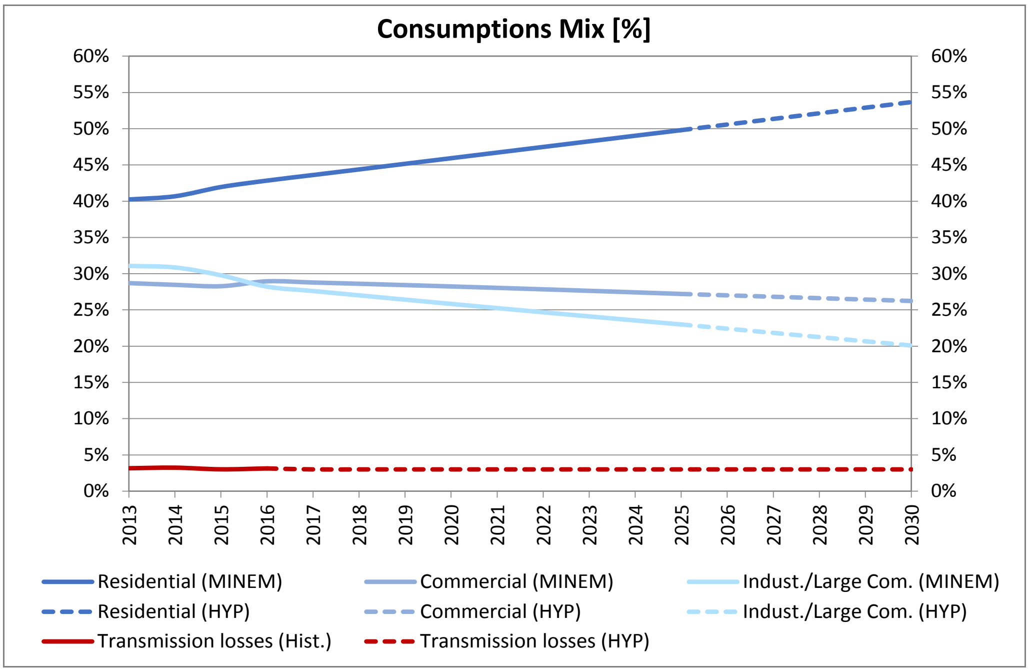
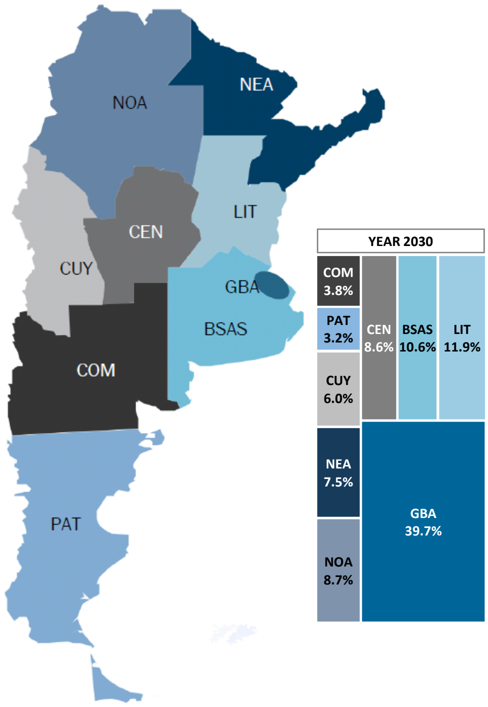


Figure 4 – Consumption mix 2013-2030

According with CAMMESA information, the Argentine electric power system is divided into nine electrical regions formed by groups of provinces:

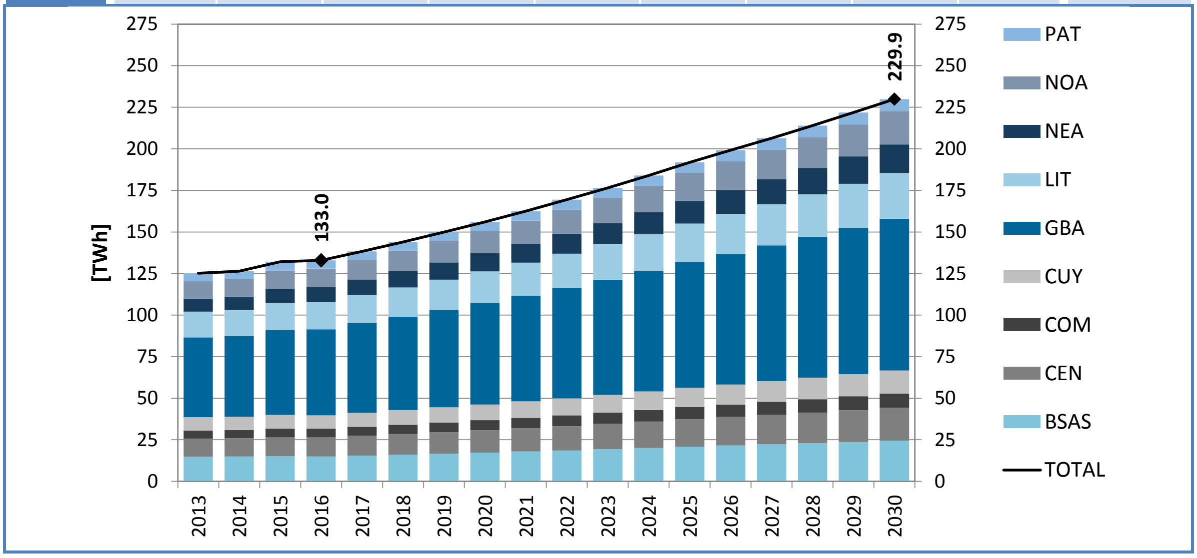
- COMAHUE (COM): provinces of La Pampa, Río Negro and Neuquén;
- BUENOS AIRES (BSAS): province of Buenos Aires;
- GRAN BUENOS AIRES (GBA): Ciudad de Buenos Aires, Ciudad de La Plata and Gran Buenos Aires;
- LITORAL (LIT): provinces of Santa Fé and Entre Ríos;
- NORESTE AREA (NEA): provinces of Formosa, Chaco, Corrientes and Misiones;
- CENTRO (CEN): provinces of Córdoba and San Luis;
- CUYO (CUY): provinces of Mendoza and San Juan;
- NOROESTE AREA (NOA): provinces of La Rioja, Catamarca, Santiago del Estero, Salta, Jujuy and Tucumán;
- PATAGONIA (PAT): provinces of Río Negro, Chubut and Santa Cruz.



In Argentina most of electricity demand is concentrated in a limited set of regions: in 2016 about 39% in Gran Buenos Aires and another 40% in a large area of the country including Litoral, Buenos Aires, Centro and Noroeste. The existing demand and load forecast 2017-2030 for each electrical region of Argentina are showed in Table 3.

Table 3 – Regional distribution of electricity demand in the period 2013-2030

[TWh]	BSAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT	Total ARG
2013	14.9	10.8	4.9	8.0	48.0	15.5	7.9	10.3	4.9	**125.2**
2014	15.0	10.9	4.9	8.1	48.5	15.7	8.0	10.4	5.0	**126.5**
2015	15.2	11.3	5.2	8.3	51.1	16.2	8.5	11.0	5.3	**132.1**
2016	15.0	11.5	5.2	8.1	51.7	16.3	9.0	11.3	5.0	**133.0**
2017	15.5	12.0	5.4	8.4	53.9	16.9	9.4	11.8	5.1	**138.3**
2018	16.1	12.4	5.6	8.8	56.1	17.6	9.9	12.3	5.3	**144.0**
2019	16.7	13.0	5.8	9.1	58.5	18.3	10.4	12.8	5.4	**149.9**
2020	17.3	13.5	6.0	9.5	61.0	19.0	10.9	13.3	5.6	**156.1**
2021	17.9	14.0	6.2	9.9	63.7	19.7	11.4	13.9	5.7	**162.6**
2022	18.6	14.6	6.5	10.3	66.4	20.5	12.0	14.5	5.9	**169.4**
2023	19.3	15.2	6.7	10.7	69.3	21.3	12.6	15.2	6.1	**176.5**
2024	20.1	15.9	7.0	11.1	72.4	22.2	13.2	15.8	6.3	**184.0**
2025	20.8	16.5	7.3	11.6	75.6	23.1	13.9	16.6	6.4	**191.9**
2026	21.5	17.2	7.6	12.0	78.6	23.9	14.5	17.2	6.6	**199.1**
2027	22.2	17.8	7.8	12.5	81.6	24.8	15.1	17.9	6.8	**206.4**
2028	23.0	18.4	8.1	12.9	84.7	25.6	15.8	18.6	6.9	**213.9**
2029	23.7	19.1	8.3	13.3	87.9	26.5	16.5	19.3	7.1	**221.8**
2030	24.5	19.8	8.6	13.8	91.3	27.5	17.2	20.0	7.3	**229.9**



In 2030, the region of Gran Buenos Aires will continue to use the most of the electricity sold, 91 TWh equal to about 40% of total Argentine demand. Litoral and the region of Buenos Aires follow with 27 TWh (12% of National demand) and 24 TWh (11% of National demand). Figure 5 represents the regional distribution of electricity demand expected in 2030 with information on customer types, while Figure 6 shows the mix of consumptions for each Argentine region in 2030.

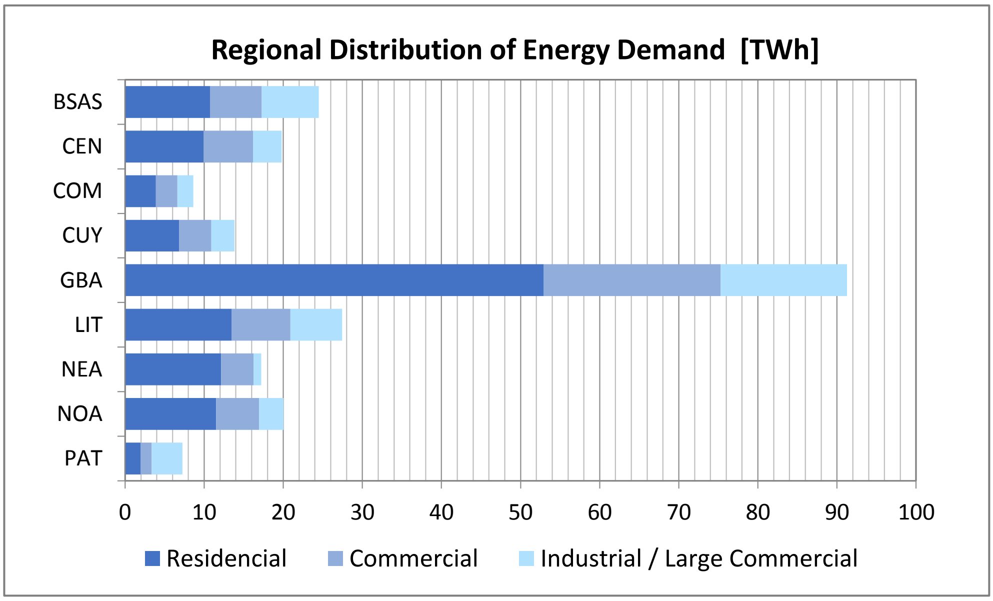


Figure 5 – Electricity demand for type of customer of each electrical regions (year 2030)

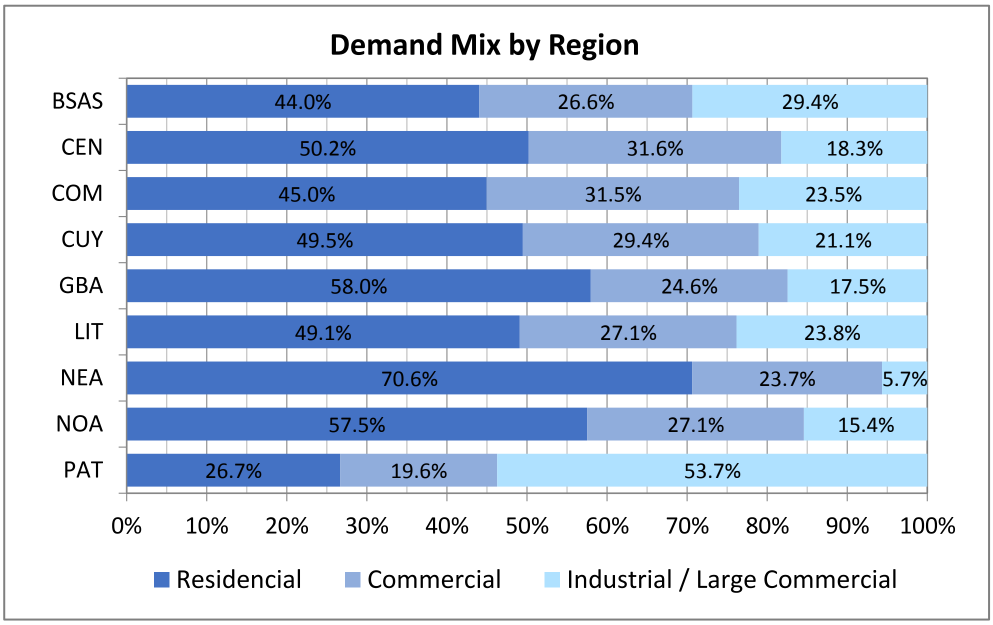


Figure 6 – Demand mix of each electrical region in 2030

2.1.1.2 Peak power demand

Another important parameter for the demand forecast of a Country is the maximum power demand expected in one hour over a period of one year, i.e. the peak power demand (MW). In 2016 the peak power demand registered in Argentina was 25,380 MW, with a growth rate +6% of peak power demand 2015. As highlighted in Figure 7, the annual growth rate had a very floating profile, with values between -4% and +10%.

MINEM didn't provide the forecast of peak power demand in its official document [1], nevertheless CAMMESA provided the peak power demand expected in 2025 (35,537 MW). In the period 2016-2025, the average annual growth rate needed to reach the peak power demand indicated by CAMMESA (35,537 MW) is +3.8%; applying this value also in the period 2026-2030 we assessed a peak power demand in 2030 equal to 42,845 MW (Figure 7 and Table 4). Like electricity demand, also the peak power demand highlighted in this paragraph is the demand of MEM agents, including the distribution losses and excluding the transmission losses, consumption of pumping power plants and export.

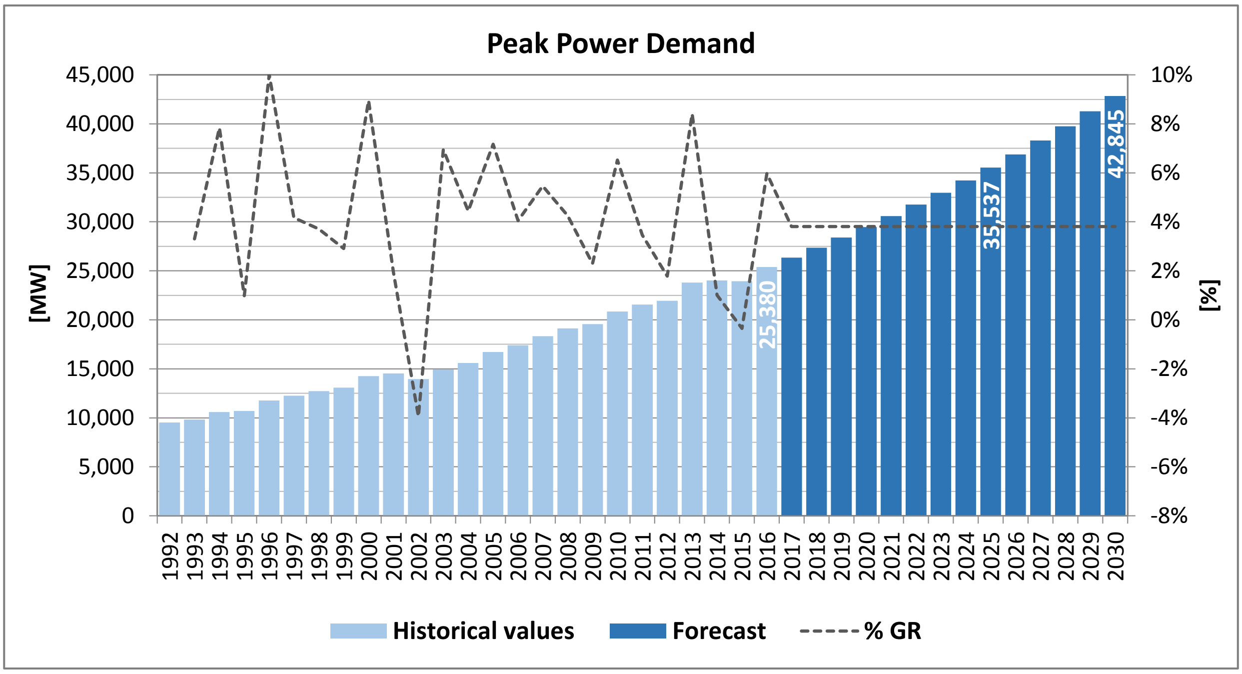


Figure 7 – Peak power demand in the period 1992-2030

Table 4 – Peak power demand 2013-2030

Year	Peak Power Demand [MW]	GR [%]
2013	23,794	8.4%
2014	24,034	1.0%
2015	23,949	-0.4%
2016	25,380	6.0%
2017	26,347	3.8%
2018	27,351	3.8%
2019	28,394	3.8%
2020	29,476	3.8%
2021	30,599	3.8%
2022	31,765	3.8%
2023	32,976	3.8%
2024	34,232	3.8%
2025	35,537	3.8%
2026	36,891	3.8%
2027	38,297	3.8%
2028	39,757	3.8%
2029	41,272	3.8%
2030	42,845	3.8%

Figure 8 shows the peak power demand assumed for 2030, divided by electrical regions. The same percentages provided by CAMMESA for the year 2025 were applied for the target year 2030.

Region	[MW]	[%]
GBA	16,305	38.1%
BSAS	4,891	11.4%
COM	1,165	2.7%
LIT	5,044	11.8%
NEA	3,278	7.7%
CEN	3,811	8.9%
CUY	3,078	7.2%
NOA	3,563	8.3%
PAT	1,710	4.0%
TOTAL ARG	**42,845**	**100.0%**

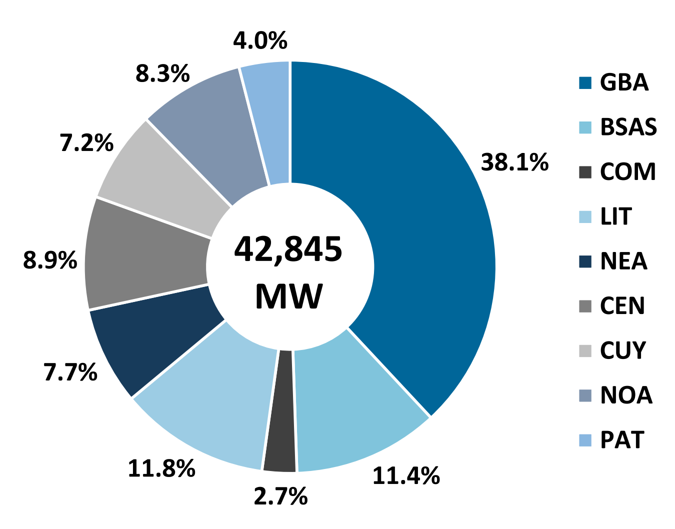


Figure 8 – Peak power demand in the year 2030 divided by regions

2.1.1.3 Hourly time-series

The historical hourly time-series provided by the Client, based on data made available by CAMMESA, will be used to calculate the hourly time series of demand expected in 2030, needed for yearly based probabilistic analyses. An annual profile (8,760 h) will be created considering the expected peak power demand and forecasted electricity demand, rescaling the historical time-series provided by the Client to reach the selected targets. The available time series only report the overall load, not divided by sectors (e.g. residential vs. industrial), and there are no detailed data which allow a rescaling of the profile taking into account the evolution of the shares of demand across sectors and identification of the load present in the network as residential or industrial. For this reason, a single hourly load profile will be defined as described above and applied to all the loads. This simplified approach can have an impact on the load flows at local level, due to the load profile which is applied to every node and might differ from the real one in specific nodes, but has a limited influence on the overall results. In fact, the analysis foreseen in the activity is focused on the EHV network and power flows along corridors between big areas of the countries which are more related to load and generation balances in wide areas, and less dependent on the behaviour of the individual load in a particular node.

2.1.2 Brazil

2.1.2.1 Electricity demand

In 2016 the electricity demand in Brazil was equal to 520 TWh[6]; only -0.9% compared with demand 2015 [3]. Brazil economy has presented consistent growth in the last decade, although it has experienced a strong recession in the last years.

EPE - Empresa de Pesquisa Energetica has developed a long term forecast 2026 ("PDE - Plano Decenal de Expansão de Energia 2016" [4] . This forecast has been completed for the period 2027 – 2030.

The figure below shows the electricity consumption forecasted by EPE and completed until 2030. In 2030 the forecasted Electricity Demand is equal to 875 TWh.

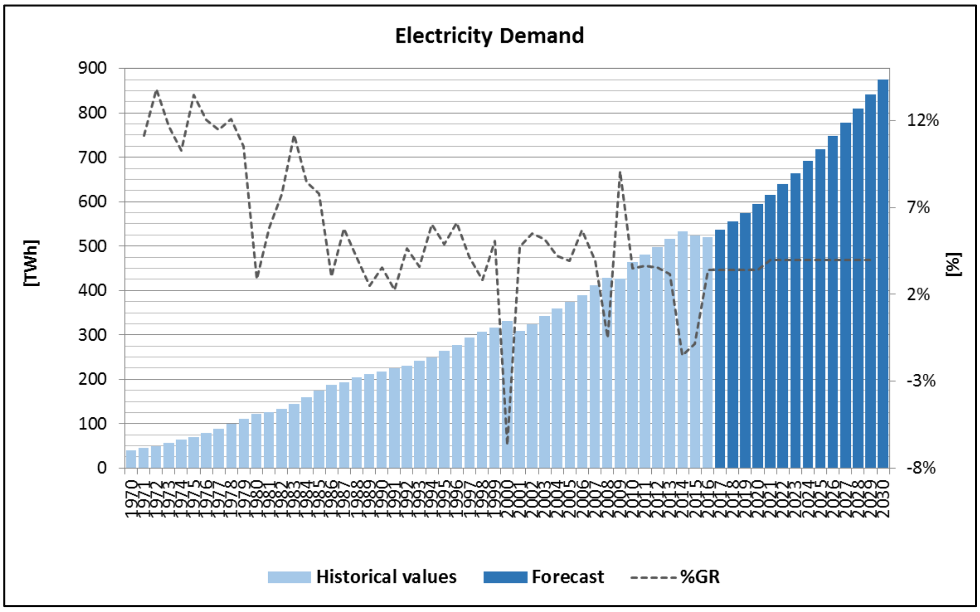


Figure 9 – Electricity demand in the period 1970-2030

Electricity demand, Population and GDP in the period 1970 – 2016 are reported in the table below.

[6] Net consumption, excluding export, consumption of pumping power plants and T&D network losses.

Table 5 – GDP, Population and Energy Demand 1970-2016 – Source EPE and World Bank

Year	GDP	Population	Demand		Year	GDP	Population	Demand	
	[MLCU]	[Millions]	[TWh]	[%GR]		[MLCU]	[Millions]	[TWh]	[%GR]
1970	349.603	95,3	39,7		**1994**	1.035.375	159,7	249,8	3,6%
1971	389.091	97,7	44,8	13,1%	**1995**	1.081.105	162,3	264,8	6,0%
1972	435.988	100,1	49,8	11,1%	**1996**	1.104.971	164,9	277,7	4,9%
1973	496.933	102,6	56,7	13,8%	**1997**	1.142.485	167,5	294,7	6,1%
1974	541.866	105,1	63,3	11,7%	**1998**	1.146.350	170,2	307,0	4,2%
1975	570.092	107,6	69,9	10,3%	**1999**	1.151.727	172,8	315,8	2,8%
1976	625.907	110,2	79,3	13,5%	**2000**	1.199.093	175,3	331,8	5,1%
1977	654.738	112,9	88,8	12,1%	**2001**	1.215.759	177,8	309,7	-6,7%
1978	675.897	115,6	99,0	11,5%	**2002**	1.252.880	180,2	324,4	4,7%
1979	721.630	118,3	111,0	12,1%	**2003**	1.267.175	182,5	342,2	5,5%
1980	787.378	121,2	122,7	10,5%	**2004**	1.340.163	184,7	359,9	5,2%
1981	752.786	124,0	126,2	2,9%	**2005**	1.383.077	186,9	375,2	4,2%
1982	757.154	126,9	133,6	5,8%	**2006**	1.437.873	189,0	390,0	3,9%
1983	731.336	129,9	143,9	7,7%	**2007**	1.525.150	191,0	412,1	5,7%
1984	769.871	132,8	160,0	11,2%	**2008**	1.602.846	193,0	428,2	3,9%
1985	831.044	135,7	173,6	8,5%	**2009**	1.600.829	194,9	426,0	-0,5%
1986	897.431	138,5	187,1	7,8%	**2010**	1.721.343	196,8	464,7	9,1%
1987	929.735	141,3	192,8	3,0%	**2011**	1.789.756	198,7	481,0	3,5%
1988	928.780	144,0	203,9	5,8%	**2012**	1.824.140	200,6	498,4	3,6%
1989	959.239	146,7	212,4	4,2%	**2013**	1.878.953	202,4	516,2	3,6%
1990	929.480	149,4	217,7	2,5%	**2014**	1.888.422	204,2	532,6	3,2%
1991	943.533	152,0	225,4	3,5%	**2015**	1.817.243	206,0	524,6	-1,5%
1992	939.128	154,6	230,5	2,3%	**2016**	1.751.918	207,7	520,0	-0,9%
1993	982.940	157,1	241,2	4,6%					

The total consumption to be covered by generation power plants includes the demand of customers and also the network losses. T&D network losses since 1970 are reported in the figure below (source EPE). As highlighted in the figure below, T&D network losses increased from 14% of generation output (i.e. excluding auto-consumptions) in the period 1970 – 1990 to 19% in 2016.

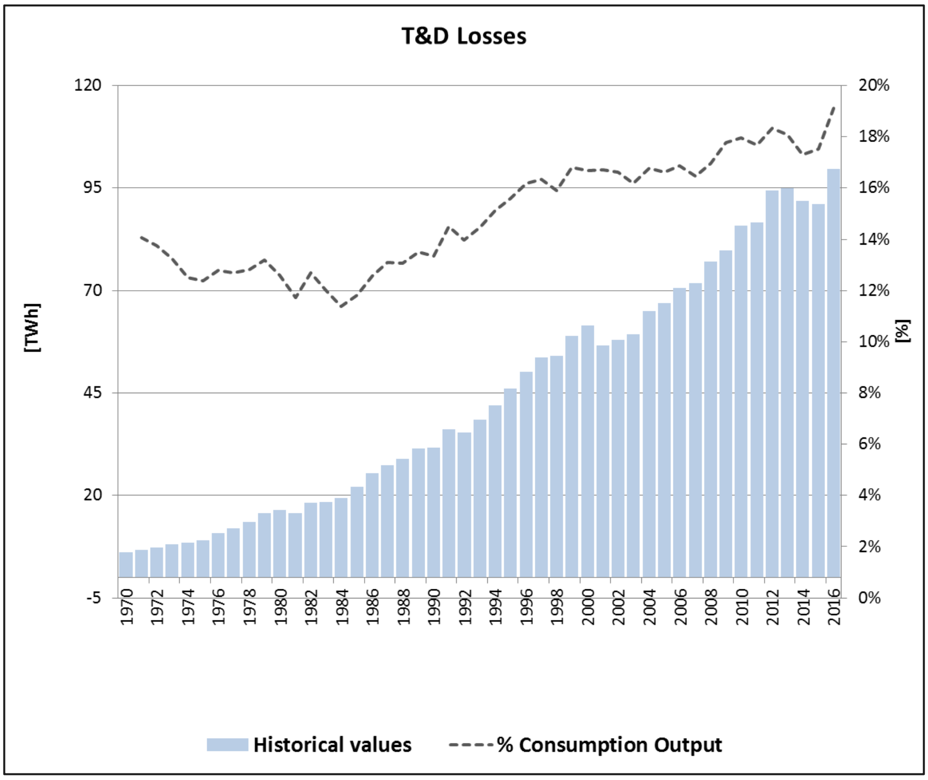


Figure 10 – T&D Losses in the period 1970-2016

Consumption mix, as highlighted in the figure below, has shown in the years a decrease in the industrial sector electricity consumption and an increase in the residential and commercial ones. In 2016 the industrial sector electricity consumption was equal to 37.6%, in the residential and commercial was equal to 25.6 5 and 17.2% respectively.

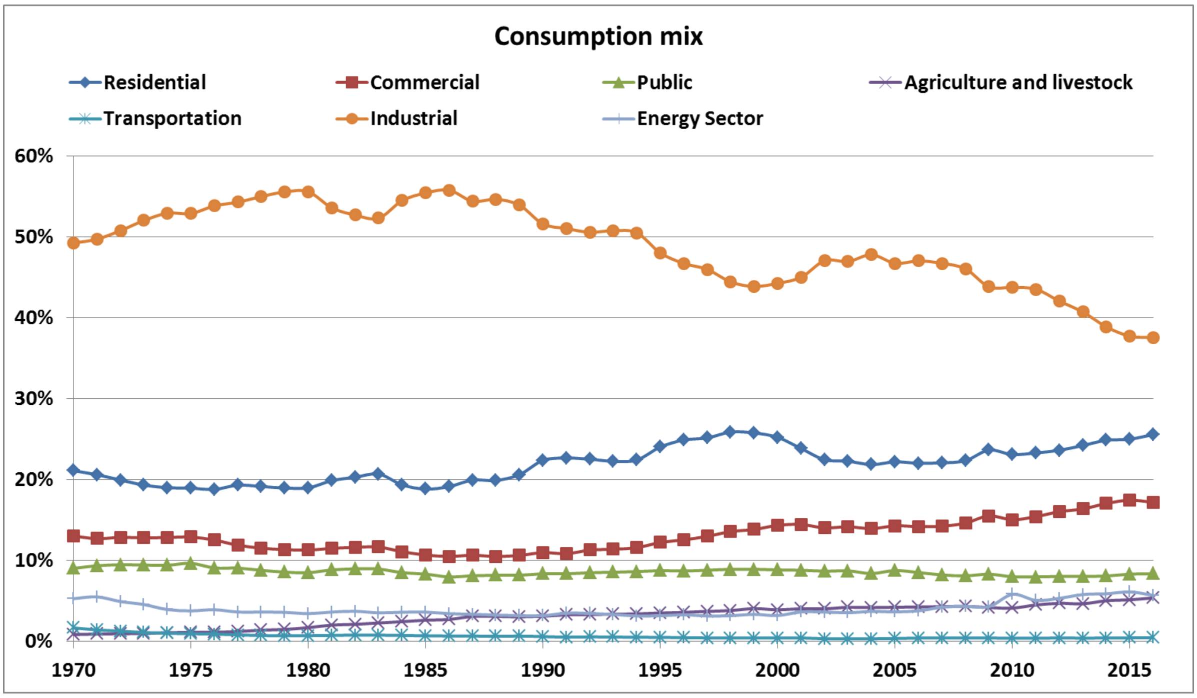


Figure 11 – Consumption mix 1970 - 2016

The total consumption is partially covered by import. As highlighted in the figure below, in the last years Import electricity values were substantially oscillating around the value of 40 TWh.

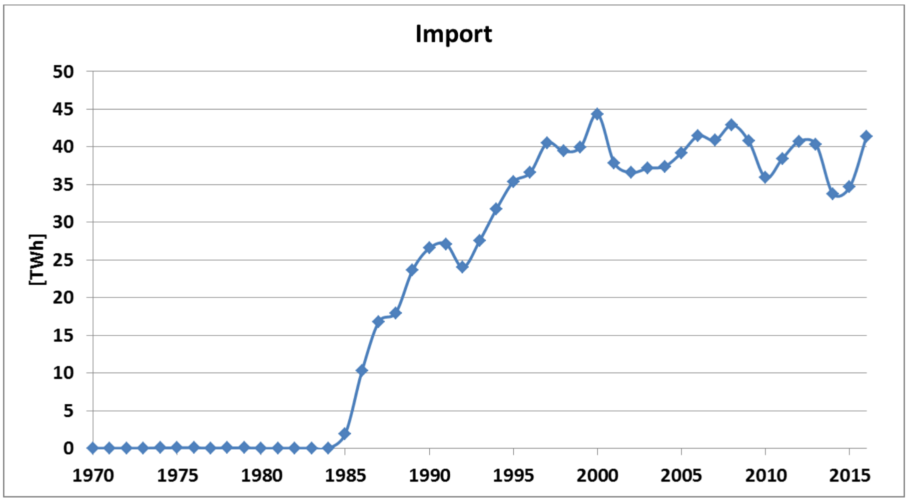


Figure 12 – Import 1970 - 2016

2.1.2.2 Peak power demand

In 2016 the peak power demand registered in Brazil was 81,999 MW, with a growth rate -3.0% of peak power demand 2015. As highlighted in the figure below, the annual growth rate had a profile, with values between -7.4% and +7.5%.

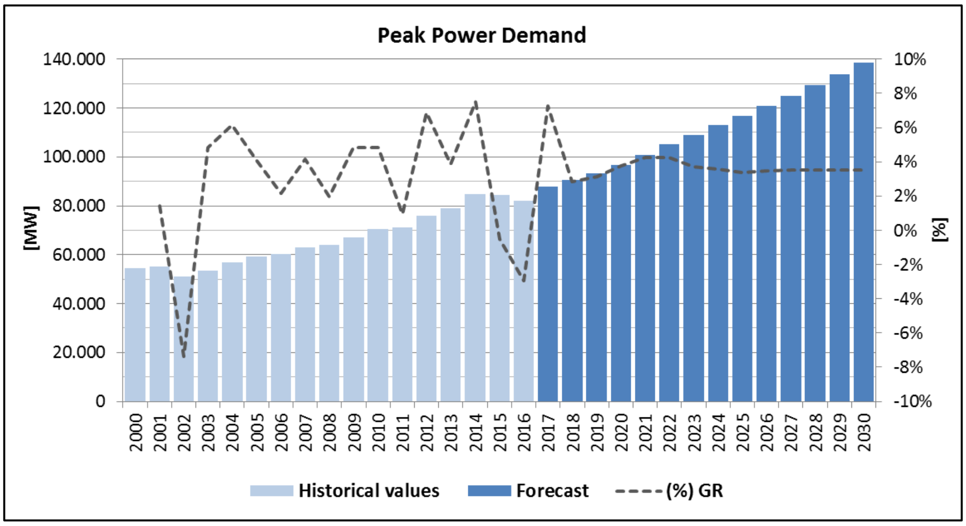


Figure 13 – Peak Power Demand 2000 - 2030

Table 6 – Peak power demand 2000 - 2030

Year	Peak Power Demand [MW]	GR [%]
2000	54,321	
2001	55,095	1.4%
2002	51,023	-7.4%
2003	53,498	4.9%
2004	56,795	6.2%
2005	59,103	4.1%
2006	60,389	2.2%
2007	62,888	4.1%
2008	64,125	2.0%
2009	67,227	4.8%
2010	70,478	4.8%
2011	71,135	0.9%
2012	76,044	6.9%
2013	78,983	3.9%
2014	84,920	7.5%
2015	84,494	-0.5%
2016	81,999	-3.0%
2017	87,955	7.3%
2018	90,437	2.8%
2019	93,266	3.1%
2020	96,759	3.7%
2021	100,851	4.2%
2022	105,118	4.2%
2023	109,006	3.7%
2024	112,916	3.6%
2025	116,749	3.4%
2026	120,808	3.5%
2027	125,036	3.5%
2028	129,413	3.5%
2029	133,942	3.5%
2030	138,630	3.5%

2.1.2.3 Hourly time-series

The most recent historical hourly time-series published by the Brazilian Operador Nacional do Sistema Elétrico (ONS) will be used to calculate the hourly time series of demand expected in 2030, needed for yearly based probabilistic analyses. An annual profile (8,760 h) will be created considering the expected peak power demand and forecasted energy demand, rescaling the historical time-series to reach the selected targets.

2.1.3 Uruguay

2.1.3.1 Electricity demand

In 2016 the electricity demand in Uruguay was equal to 11.1 TWh; according to the forecast described in [5], the expected average growth in electricity demand will be in the period 2016 – 2030 equal to 2%.

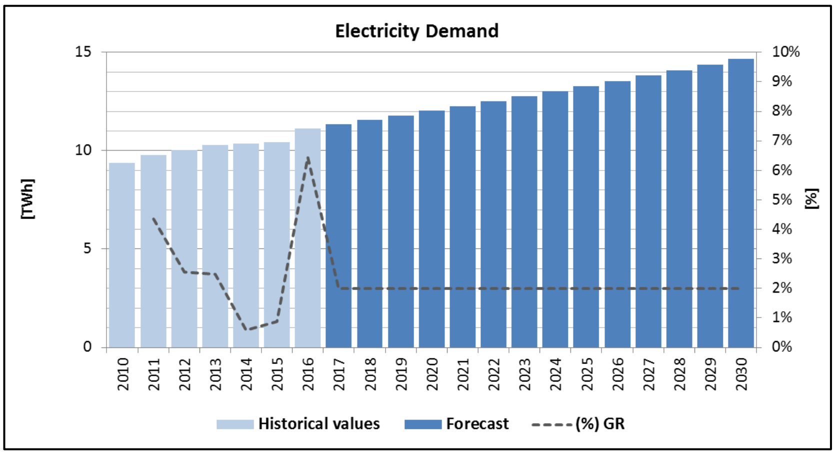


Figure 14 – Electricity Demand 2010 - 2030

The total consumption to be covered by generation power plants includes the demand of customers and also the network losses. T&D network losses since 1970 are reported in the figure below (source World Bank). As highlighted in the figure below, T&D network losses has decreased to 10% of generation in 2014 (Source World Bank).

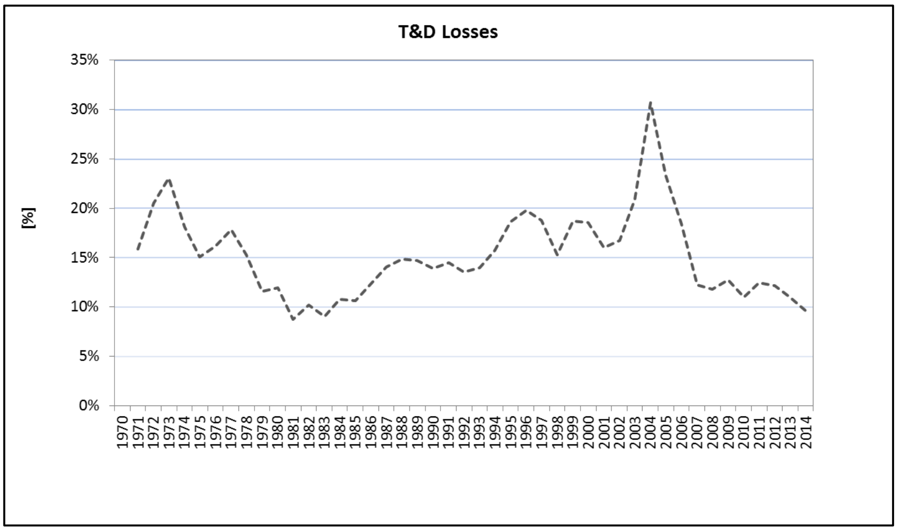


Figure 15 – T&D Losses 1971-2014 – Source World Bank

The transmission losses in 2016 accounted for about 3.5%. This value will be kept as a reference also for future years.

2.1.3.2 Peak power demand

In 2016 the peak power demand registered in Uruguay was 1,964 MW (this value does not consider the losses on the transmission network), with a growth rate +4.3% of peak power demand 2015. As highlighted in the figure below, the annual growth rate had a very floating profile, with values between -10% and +17%.

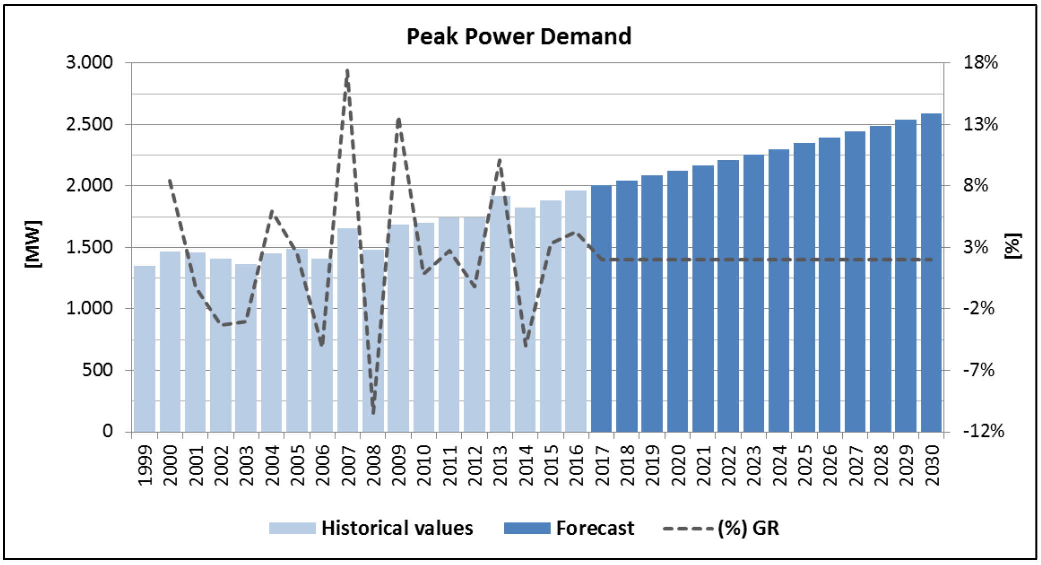


Figure 16 – Peak power demand in the period 1999-2030

Table 7 – Peak power demand 1999-2030

Year	Peak Power Demand [MW]	GR [%]
1999	1,349	
2000	1,463	8.5%
2001	1,459	-0.3%
2002	1,411	-3.3%
2003	1,368	-3.0%
2004	1,449	5.9%
2005	1,485	2.5%
2006	1,409	-5.1%
2007	1,654	17.4%
2008	1,481	-10.5%
2009	1,684	13.7%
2010	1,698	0.8%
2011	1,745	2.8%
2012	1,742	-0.2%
2013	1,918	10.1%
2014	1,822	-5.0%
2015	1,883	3.3%
2016	1,964	4.3%
2017	2,003	2%
2018	2,043	2%
2019	2,084	2%
2020	2,126	2%
2021	2,168	2%
2022	2,212	2%
2023	2,256	2%
2024	2,301	2%
2025	2,347	2%
2026	2,394	2%
2027	2,442	2%
2028	2,491	2%
2029	2,541	2%
2030	2,591	2%

2.1.3.3 Hourly time-series

The historical hourly time-series published by the Uruguayan power market operator (ADME) will be used to calculate the hourly time series of demand expected in 2030, needed for yearly based probabilistic analyses. An annual profile (8,760 h) will be created considering the expected peak power demand and forecasted electricity demand, rescaling the historical time-series to reach the selected targets. The available time series only report the overall load, not divided by sectors (e.g. residential vs. industrial), and there are no detailed data which allow a rescaling of the profile taking into account the evolution of the shares of demand across sectors and identification of the load present in the network as residential or industrial. For this reason, a single hourly load profile will be defined as described above and applied to all the loads. This simplified approach can have an impact on the load flows at local level, due to the load profile which is applied to every node and might differ from the real one in specific nodes, but has a limited influence on the overall results. In fact, the analysis foreseen in the activity is focused on the EHV network and power flows along corridors between big areas of the countries which are more related to load and generation balances in wide areas, and less dependent on the behaviour of the individual load in a particular node.

2.2 Generation description

Problem statement

- *Description of the generation fleet forecasted to cover the demand at the target year 2030 highlighting the existing power plants that will still be in service in 2030 and the additional capacity already foreseen by the national authorities (power plants under construction, committed or with high probability to be built).*

Methodology

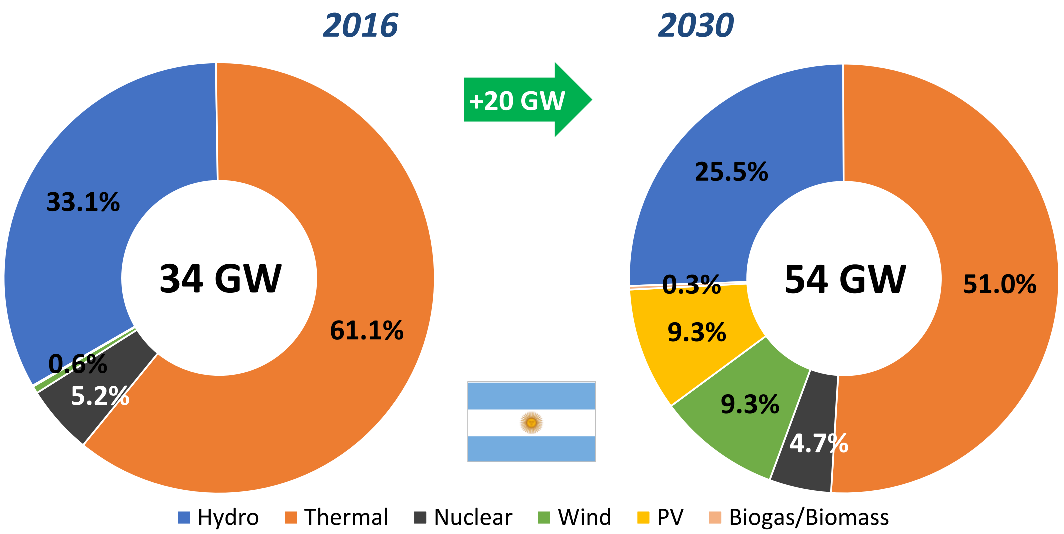
- *Collection of public domain information and data collection from meetings with the stakeholders in Argentina, Brazil and Uruguay. If specific data are not available, hypotheses are formulated based on the targets set by Ministries, towards a green transition of the power sector, essentially based on additional VRES development, which is the focus of the study.*

Major results

- *For each country, the additional generation capacity to be considered in the Reference Scenario has been defined. A database of the generation fleet was built including the list of the existing power plants and those already forecasted by the National authorities; technical characteristics of power plants were collected. National targets for VRES will be the starting point for the analysed; they will be checked in term of optimal economic penetration and increased if economic.*

  - ***Argentine generation fleet***
    CAMMESA database up to 2025 was the reference for the definition of the generation expansion plan at 2030. All power plants expected in 2025 by CAMMESA and MINEM will be considered in the model as baseline generation, both thermal and renewables. The following table shows the additional baseline capacity considered in the Reference Scenario of the project, according with National targets. New VRES capacity will be added to evaluate the optimal economic penetration of wind and PV productions.

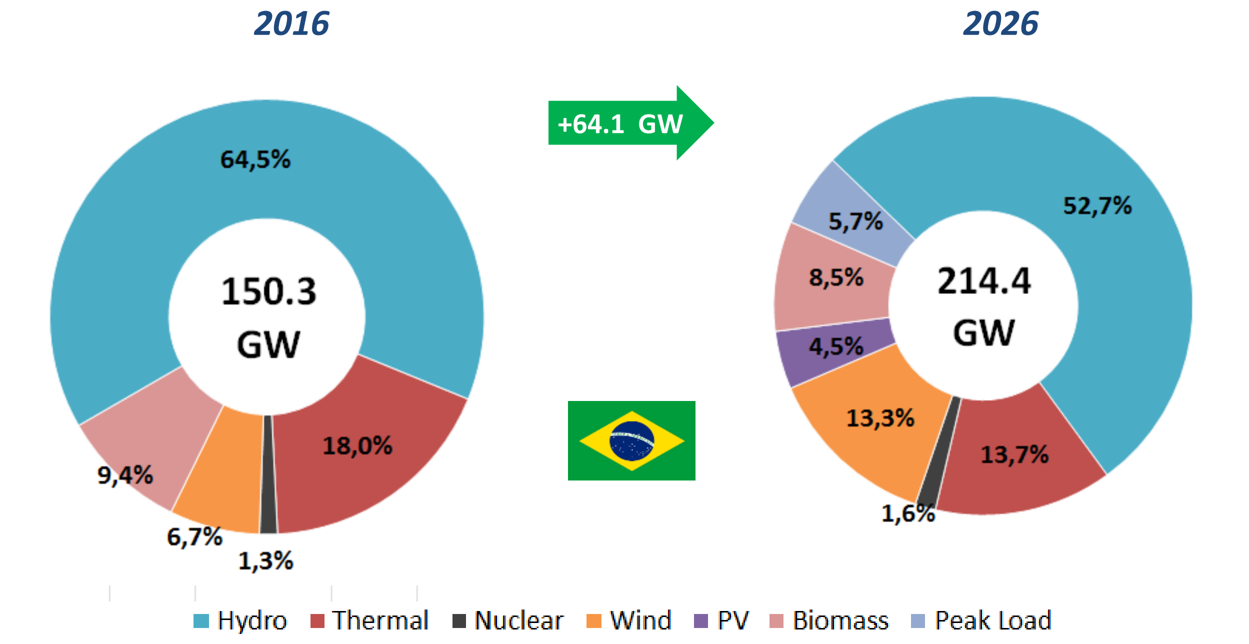
	2016	Additional Capacity	2030
Hydro	11.2	+2.5 GW	13.7
Thermal	20.8	+6.8 GW	27.6
Nuclear	1.8	+0.8 GW	2.6
Wind	0.2	+4.8 GW	5.0
PV	0.01	+5.0 GW	5.0
Biogas/Biomass	0.02	+0.1 GW	0.1
TOTAL ARGENTINA	**34.0**	+20.0 GW	**54.0**



- ***Brazil generation fleet***
  According to the reference scenario of the development plan PDE 2016 (Plano Decenal de Expansão de Energia - 2016), published by EPE Empresa de Pesquisa Energetica [4], the additional capacities of different sources foreseen at 2026 are reported in the table below.

	2016	Additional Capacity	2026
Hydro	96.9	+16.1 GW	113.0
Thermal	27.1	+2.3 GW	29.4
Nuclear	2.0	+1.4 GW	3.4
Wind	10.1	+18.4 GW	28.5
PV	0.0	+9.6 GW	9.6
Biomass	14.1	+4.1 GW	18.2
Peak Load[7]	0.0	+12.2 GW	12.2
TOTAL BRAZIL	**150.3**	**+64.1 GW**	**214.3**

[7] Gas turbine in open cycle, pumped-storage hydro plants, additional hydroelectric power generation, storage systems (batteries), demand side management



The generation fleet described by EPE at 2026 will be assumed as starting point for the calculation of the optimal amount of VRE at 2030, that will be obtained considering increasing share of PV and wind plants, paying attention that the the system adequacy is ensured, eventually including also dispatchable power plants.

- ***Uruguay generation fleet***

  At the end of December 2016, installed generation capacity in Uruguay was equal to 3912 MW, divided in 39% hydro, 31% wind, 17% thermal, 11% biomass and 2% PV. Over the last few years, installation of VRES plants has increased considerably, while thermal generation is reduced.

  No detailed generation development plan is available for the future . The generation fleet defined by UTE at 2021 will be assumed as starting point for the analysis at 2030.

2.2.1 Argentina

In Argentina, the unbundling of the electricity sector in generation, transmission and distribution sectors started at the end of 1991 with the Decree 634/91 and was implemented with the Law 24.065 published on January, 16th 1992. About the generation system, private and state-owned companies carry out generation in a competitive, mostly liberalized electricity market, with about 75% of total installed capacity in private hands. The share in public hands corresponds to nuclear generation and to the two bi- national hydropower plants: Yacyretá (Argentina-Paraguay) and Salto Grande (Argentina-Uruguay). Power generators sell their electricity in the wholesale market operated by the CAMMESA (Compañía Administradora del Mercado Mayorista Eléctrico S.A.). CAMMESA is responsible for the operation and dispatch of generation, the price calculation in the spot market, the real-time operation of the electricity system and the administration of the commercial transactions in the electricity market.

2.2.1.1 Existing generation

In 2016 the energy needed to balance the annual demand, including consumption of pumping power plants, export and network losses, was equal to 138.1 TWh ; +0.9% compared with generation 2015. The most of energy was produced by thermal power plants powered by natural gas and oil fuel; with 90.1 TWh they cover the 65% of total needs. Hydro power plants covered about the 27% of generated energy followed by nuclear (5%), RES and imports from neighbouring countries (Figure 17).

Source	2016 [TWh]
Thermal	90.1
Nuclear	7.7
Hydro	38.0
RES[8]	0.8
Import	1.5
TOTAL	**138.1**

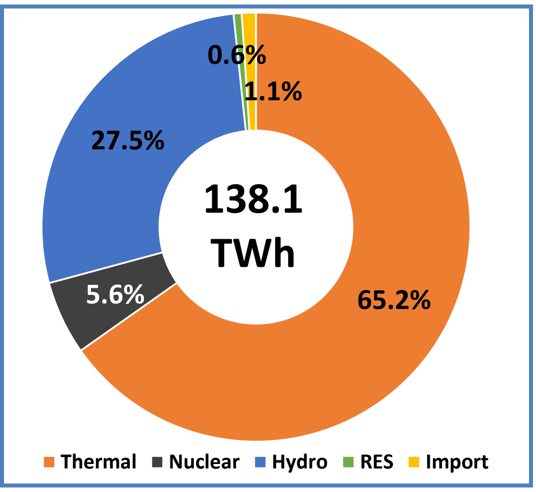


Figure 17 – Generated energy to cover demand 2016

In the last fifteen years, the growth of the generation sector was driven by a large development of thermal generation powered by natural gas, reducing the role of hydro power generation to cover the annual demand. As highlighted in Figure 18 and Table 8, thermal production increased its weight in the energy balance from 40% in 2002 to 65% in 2016, while hydro generation lost the leadership from 50% in 2002 to 26% in 2016. Nuclear generation and the energy imported by the neighbouring countries have been kept quite constant in the last years. In 2011, the first wind farms and photovoltaic power plants were installed in the country laying the foundation for a development of a large RES development plan.

[8] Including small hydro

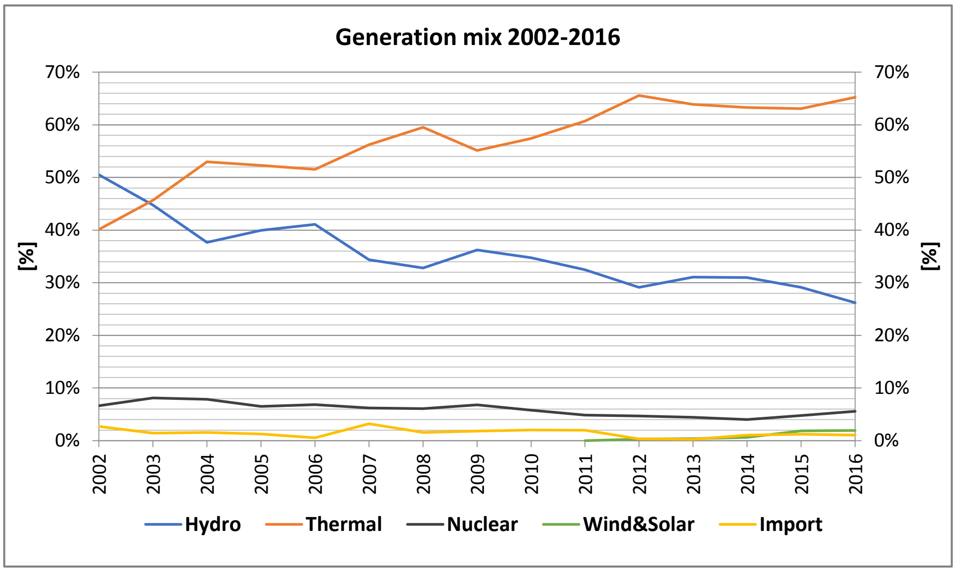
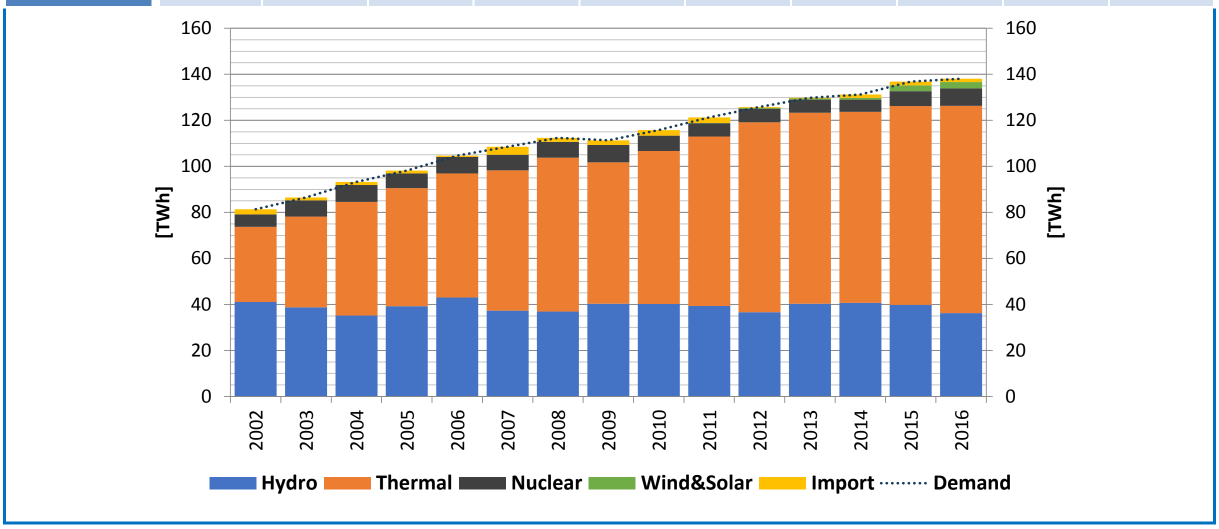


Figure 18 – Energy mix in the period 2002-2016

Table 8 – Generation in the period 2002-2016

Year	Hydro		Thermal		Nuclear		Wind & Solar		Import	
	[TWh]	[%]	[TWh]	[%]	[TWh]	[%]	[TWh]	[%]	[TWh]	[%]
2002	41.09	50.5%	32.64	40.1%	5.39	6.6%	-	-	2.21	2.7%
2003	38.72	44.8%	39.47	45.7%	7.03	8.1%	-	-	1.23	1.4%
2004	35.13	37.7%	49.40	53.0%	7.31	7.8%	-	-	1.44	1.5%
2005	39.21	39.9%	51.35	52.3%	6.37	6.5%	-	-	1.22	1.2%
2006	42.99	41.1%	53.93	51.5%	7.15	6.8%	-	-	0.56	0.5%
2007	37.29	34.4%	61.01	56.2%	6.72	6.2%	-	-	3.46	3.2%
2008	36.88	32.8%	66.88	59.5%	6.85	6.1%	-	-	1.77	1.6%
2009	40.32	36.2%	61.39	55.1%	7.59	6.8%	-	-	2.04	1.8%
2010	40.23	34.8%	66.47	57.4%	6.69	5.8%	-	-	2.35	2.0%
2011	39.34	32.4%	73.57	60.7%	5.89	4.9%	0.02	0.01%	2.41	2.0%
2012	36.63	29.1%	82.49	65.6%	5.90	4.7%	0.36	0.3%	0.42	0.3%
2013	40.33	31.1%	82.95	63.9%	5.73	4.4%	0.46	0.4%	0.34	0.3%
2014	40.66	31.0%	83.05	63.3%	5.26	4.0%	0.85	0.6%	1.39	1.1%
2015	39.84	29.1%	86.32	63.1%	6.52	4.8%	2.53	1.9%	1.65	1.2%
2016	36.19	26.2%	90.07	65.2%	7.68	5.6%	2.66	1.9%	1.47	1.1%



In 2016, total installed capacity of the generation fleet is equal to 33,970 MW. Only the 1% of total capacity is available from RES power plants (about 200 MW); 66% is from thermal and nuclear power plants while the 33% from hydro power plants. Figure 19 shows the installed capacity in 2016 and the capacity factor[9] for each technology.

Source/ Technology	Installed Capacity [MW]	Capacity Factor [%]
Thermal	**20,763**	**50%**
Steam Turbine	*4,451*	*41%*
Gas Turbine	*5,251*	*38%*
CCGT	*9,227*	*67%*
Diesel Engine	*1,834*	*15%*
Nuclear	**1,755**	**50%**
Hydro	**11,240**	**39%**
RES	**212**	**45%**
Wind	*187*	*33%*
PV solar	*8*	*20%*
Biogas	*17*	*100%*
TOTAL	**33,970**	

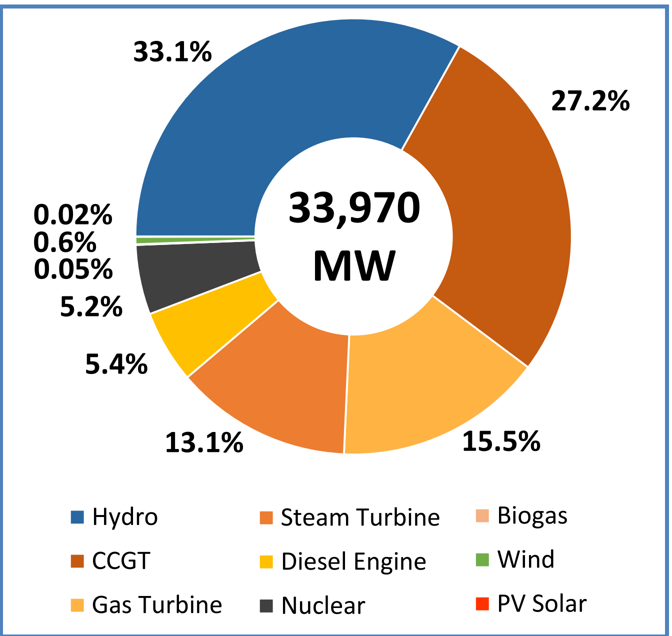


Figure 19 – Generation installed capacity in the year 2016

The historical values of generation capacity in Argentina are highlighted in Figure 20 and Table 9. As above mentioned, the last fifteen years recorded the increase of gas power plants (CCGT and OCGT) as main source to follow the growth of national demand.

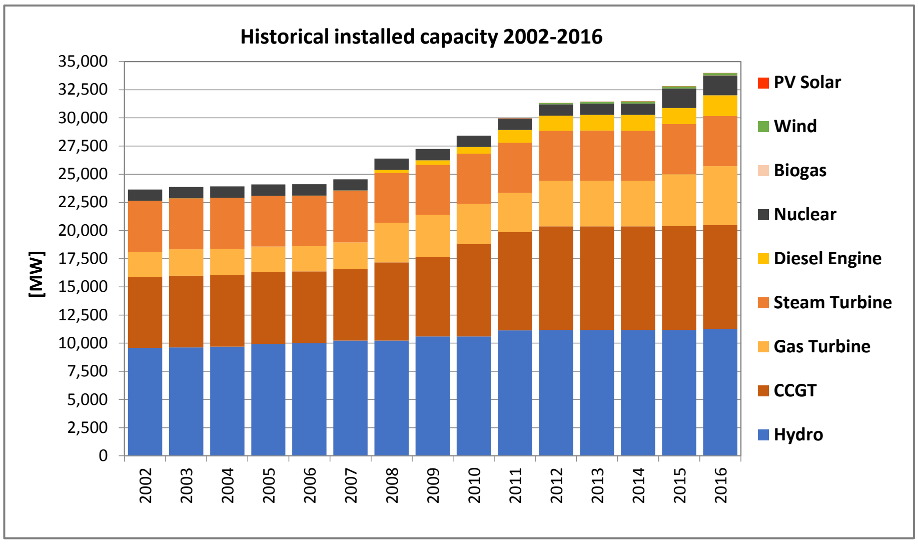


Figure 20 – Historical values of generation installed capacity

[9] The capacity factor of a power plant, or group of power plants, is the ratio between the actual output over a period of time (typically one year) and the potential output if the operation at full nameplate capacity could be possible continuously over the same period of time

Table 9 – Historical values of generation installed capacity

[MW]	Hydro	CCGT	GT	ST	Nuclear	Diesel	Biogas	Wind	PV	TOTAL
2002	9,586	6,307	2,223	4,521	1,005	4	0	0	0	23,646
2003	9,628	6,363	2,339	4,521	1,005	4	0	0	0	23,860
2004	9,699	6,363	2,317	4,526	1,005	4	0	0	0	23,914
2005	9,939	6,363	2,277	4,496	1,005	4	0	0	0	24,084
2006	10,009	6,363	2,264	4,463	1,005	4	0	0	0	24,108
2007	10,226	6,363	2,359	4,573	1,005	26	0	0	0	24,552
2008	10,233	6,935	3,512	4,438	1,005	267	0	0	0	26,390
2009	10,604	7,046	3,744	4,438	1,005	398	0	0	0	27,235
2010	10,604	8,185	3,588	4,438	1,005	607	0	0	0	28,427
2011	11,135	8,725	3,493	4,445	1,005	1,131	0	7	1	29,942
2012	11,175	9,191	4,036	4,451	1,005	1,347	0	109	6	31,320
2013	11,176	9,191	4,061	4,451	1,010	1,388	0	162	8	31,447
2014	11,178	9,191	4,035	4,451	1,010	1,415	0	187	8	31,475
2015	11,178	9,227	4,595	4,451	1,755	1,415	0	187	8	32,816
2016	11,240	9,227	5,251	4,451	1,755	1,834	17	187	8	33,970

The distribution of generation installed capacity 2016 in the Country (33,970 MW) is shown in Figure 21. For each electrical region, the share of installed capacity is highlighted, together with the source types. 46% of total generation capacity is located in the central area of the Country (Gran Buenos Aires, Buenos Aires and Comahue) near the biggest load centers (Gran Buenos Aires, Buenos Aires and Litoral).

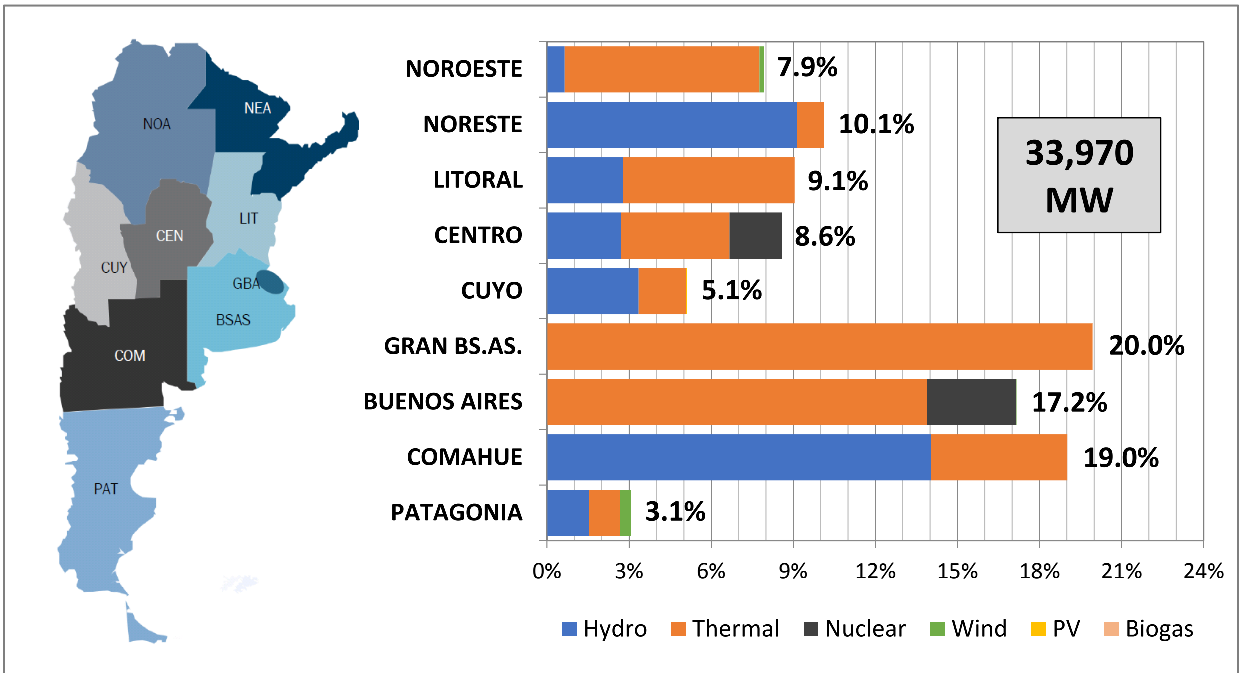


Figure 21 – Regional distribution of generation installed capacity in 2016

2.2.1.2 *Power generation developments*

In order to reduce the dependence of Argentina from conventional thermal sources, such as natural gas and diesel, the Government of Argentina (GoA) with MINEM defined a development plan of renewable energy in the Country. In 2015, the GoA approved the Renewable Energy Act 27,191 setting the basis for a new legal framework to foster the renewable energy development. Act 27,191 had set up ambitious targets for the share of renewable energy in the short, mid and long terms. Figure 22 shows the targets set by the Act up to 2025, in terms of renewable energy penetration. Long term target is for 2025 with 20% of RES penetration; in order to reach the 20 % target for 2025, at least 10,000 MW of additional installed renewable generation capacity is expected.

As a first step to comply with the Renewable Energy Act 27,191, the GoA launched in May 2016 the RenovAr program as a public tendering program to attract private investors in renewable energy sector. Two rounds were still launched (Rounds 1 and Round 1.5) and 2.4 GW of new-build renewable generation projects were awarded during 2016.

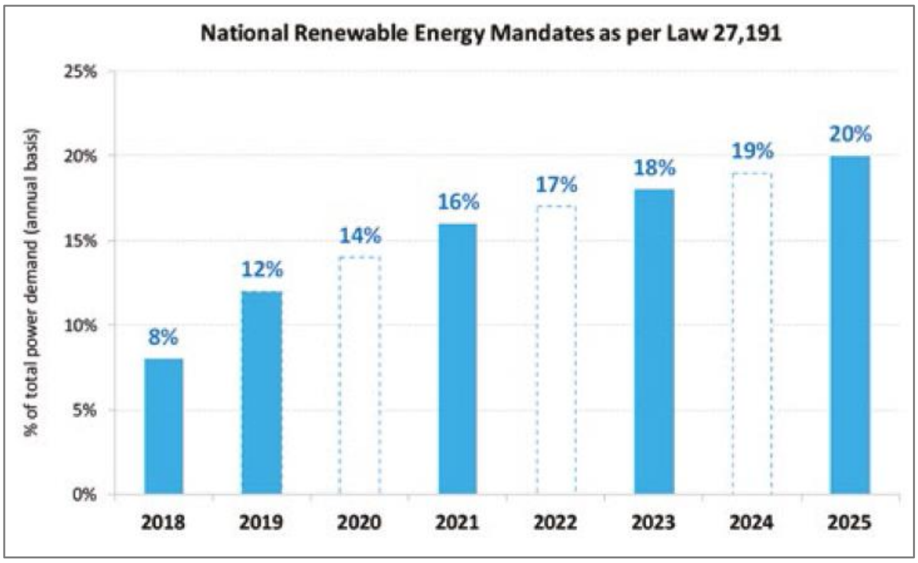


Figure 22 – National RES production targets (Source [8])

Due to the difficulty to cover the peak power demand in the short term (2017-2018), at the beginning of 2016 MINEM launched a request for proposal (Resolución 21/2016 or RES 21/2016) for the fast commissioning of new thermal generation capacity. Two bidding rounds were carried out and specific projects were selected by CAMMESA for its short-term seasonal planning. Thermal power plants of RES 21/2016 selected by CAMMESA will be considered in our Reference Scenario 2030.

At the end of 2016, MINEM made public the national vision for the growth in energy sector up to 2025 ("Escenarios Energéticos 2025" [1]) taking into account the RES 21/2016 and the Renewable Energy Act 27,191. The document includes a baseline scenario, named "Tendencial", with the expected demand and generation 2025 (Figure 23) based on the following objectives:

- cover the increasing electric demand with hydroelectric, nuclear and renewable generation;
- decrease thermal participation;
- reduce the use of liquid fuels for generation, on behalf of natural gas;
- 20% of electricity generation is achieved from renewable energy.

This scenario was taken into account to define the Reference Scenario of the project. Due to the lack of official information on the expected generation in 2030, all generation sources expected in 2025 by MINEM and CAMMESA will be considered in the model, both thermal and renewables, while from 2025 to 2030 only wind and PV generation development will be included, according with the scope of the project. Furthermore, relevant generation projects indicated by CAMMESA, and included in the network model will be considered.

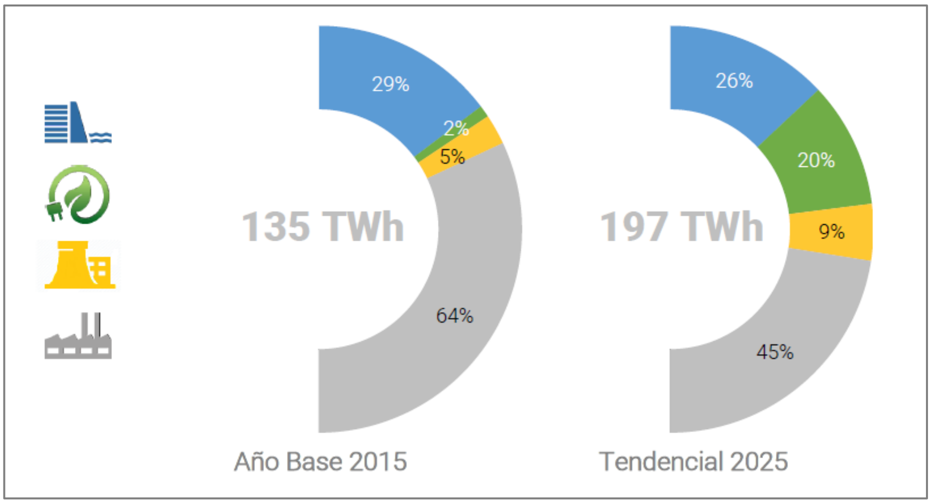


Figure 23 – Generation mix proposed by MINEM for 2025 [1]

Figure 24 shows the additional capacity expected by CAMMESA for the year 2025 that will be considered in our reference generation fleet 2030. About 20 GW of new capacity is expected in the period 2017-2025 to reach total 54 GW of installed capacity that will be simulated:

- 10 GW of wind and PV power plants. 5 GW of wind farms mainly located in the Atlantic coast (Patagonia, Comahue and Buenos Aires) and 5 GW of PV power plants located in the north west areas of the Country (Noroeste and Cuyo);
- Additional 2.5 GW hydro power plants, developing large-scale hydroelectric projects in Patagonia, Comahue and Cuyo;
- Third nuclear power plant in Atucha;
- Addition of about 7 GW of thermal capacity in the short and medium term, completing combined cycles and other current projects.

The list of the main hydro, thermal and nuclear projects to be considered in the Reference Scenario 2030 is showed in Table 10. The most of new thermal installed capacity is located in the electrical regions of Litoral (42%), Gran Buenos Aires (17%) and Buenos Aires (10% of conventional installed capacity + 745 MW nuclear power plant Atucha III). Patagonia will house the third biggest hydro complex of the country, after Yaciretá and Salto Grande: “La Barrancosa-Cóndor Cliff” project will include Néstor Kirchner and Jorge Cepernic hydro power plants (total 1310 MW).
The regional distribution of the additional capacity considered in the Reference Scenario 2030 is highlighted in Figure 25. According with wind and solar radiation potentials, wind farms already forecasted by CAMMESA are located in south east regions while PV power plants in North West regions.

Source	Additional capacity 2017-2025 [GW]
Hydro	2.5
Thermal	6.8
Nuclear	0.8
Wind	4.8
PV	5.0
Biogas/Biomass	0.1
TOTAL	**20**

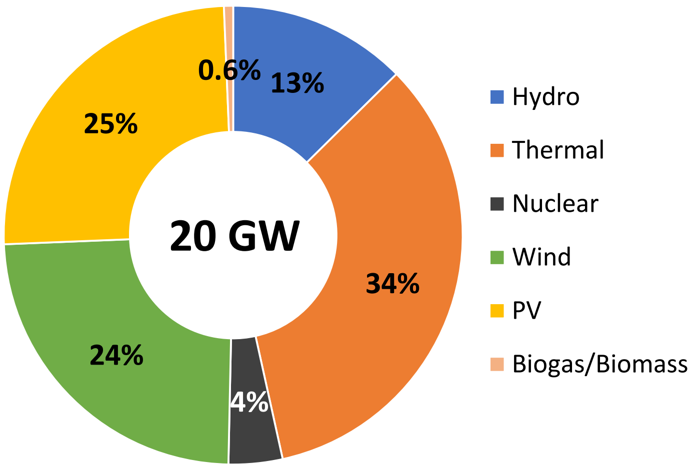


Figure 24 – Additional capacity to reach CAMMESA targets 2025

Table 10 – Main hydro and thermal projects in the period 2017-2030

Power Station Name	Type/ Technology	Province	Region	Pinst. [MW]
NÉSTOR KIRCHNER	Hydro	Santa Cruz	Patagonia	950
CHIHUIDOS I	Hydro	Neuquén	Comahue	640
JORGE CEPERNIC	Hydro	Santa Cruz	Patagonia	360
LOS BLANCOS I-II	Hydro	Mendoza	Cuyo	440
GUILLERMO BROWN	CCGT	Buenos Aires	Buenos Aires	900
BELGRANO II	CCGT	Buenos Aires	Buenos Aires	840
ATUCHA III	Nuclear	Buenos Aires	Buenos Aires	745
BRIGADIER LOPEZ	CCGT	Santa Fe	Litoral	420
VUELTA DE OBLIGADO	CCGT	Santa Fe	Litoral	280
EL BRACHO	OCGT	Tucuman	Noroeste	270
MATHEU ARAUCARIA ENERGY	OCGT	Buenos Aires	Gran Buenos Aires	260
RIO TURBIO	ST	Santa Cruz	Patagonia	240
MATHEU APR ENERGY S.R.L.	OCGT	Buenos Aires	Gran Buenos Aires	215
ZARATE ARAUCARIA ENERGY	OCGT	Buenos Aires	Buenos Aires	210
A.G. RENOVA TIMBÚES	CCGT	Santa Fe	Litoral	205
LOMA CAMPANA 1-2	OCGT	Neuquén	Comahue	205
GRAL ROJO RÍO ENERGY	OCGT	Buenos Aires	Buenos Aires	150
EZEIZA ALBANESI	OCGT	Buenos Aires	Gran Buenos Aires	150
LUJÁN ARAUCARIA ENERGY	OCGT	Buenos Aires	Buenos Aires	130

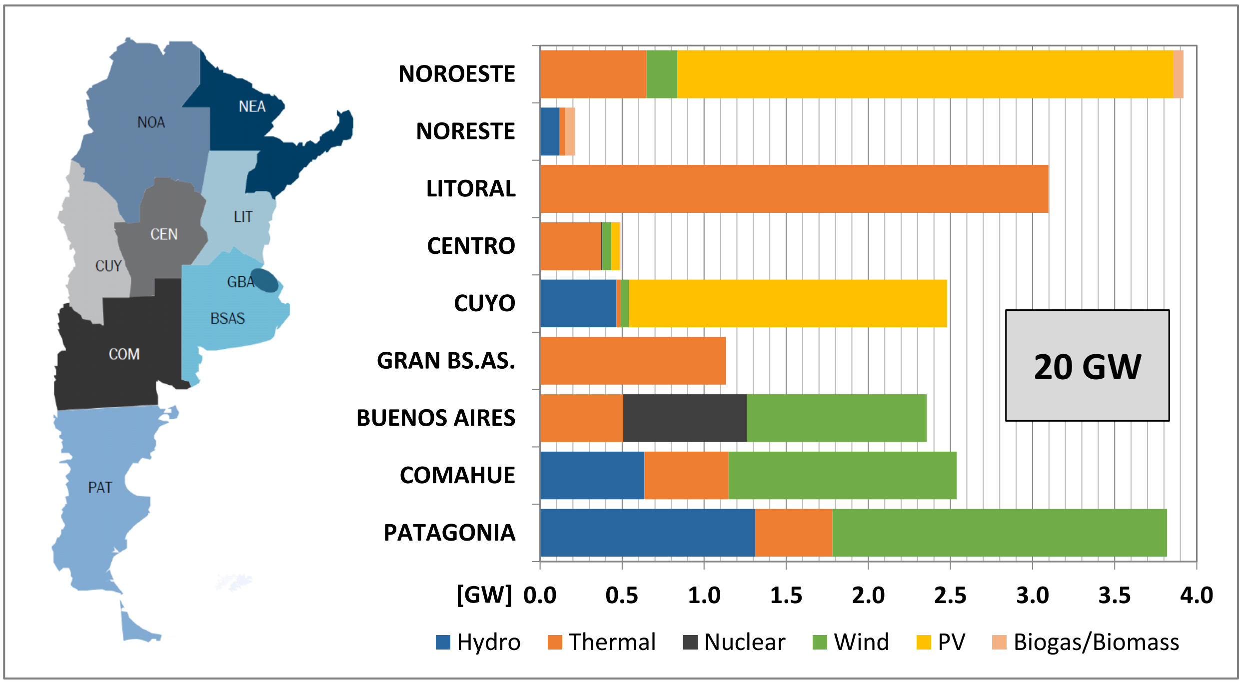


Figure 25 – Regional distribution of additional capacity 2017-2025

2.2.2 Brazil

The electric system of Brazil as a whole is organized as illustrated in the below scheme (Figure 26).

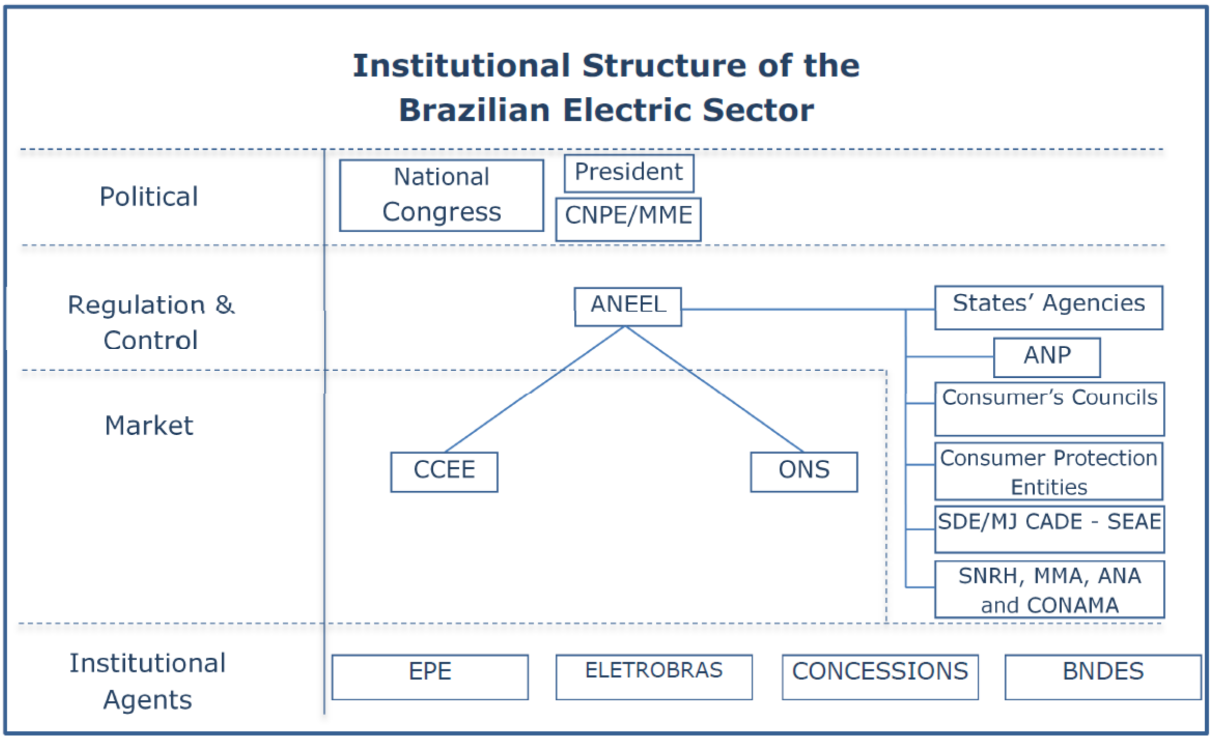


Figure 26 - Institutional Structure of the Brazilian Electric Sector (source [2])

The government's influence in the energy sector is exclusive to the Ministério de Minas e Energia (MME) in combination with the Conselho Nacional de Politica Energética (CNPE), with support from the National Congress and the President.

The policies developed by those bodies are regulated and controlled by the Agência Nacional de Energia Elétrica (ANEEL), regarding financials with the Câmara de Comercialização de Energia Elétrica (CCEE) and in operations with the Operador Nacional do Sistema Elétrico (ONS). ANEEL is under the oversight of representatives of the people, the federation's states, the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP), and diverse public institutions. The authorized and regulated activities are then carried out by the Empresa de Pesquisa Energética (EPE), ELETROBRAS, utility companies that hold concessions for their operations, and the Banco Nacional de Desenvolvimento Econômico e Social (BNDES) – all of which are either public private partnerships with open capital, or non-profit organizations. Utility companies dealing with electric energy usually do not participate in other markets, and the activity of multi-utility companies is low in Brazil.
The electric power system, SIN (Sistema Interligado Nacional) regulated by ONS, is composed by four subsystems (Sul, Sudeste/Centro-Oeste, Nordeste and most of the North region).
Currently, there are 246 isolated locations in Brazil, where about 760 thousand consumers live. Most are in the North, in the states of Rondônia, Acre, Amazonas, Roraima, Amapá and Pará. The island of Fernando de Noronha, in Pernambuco, and some localities of Mato Grosso complete the list. Among the capitals, Boa Vista (RR) is the only one that is still served by an isolated system.
Consumption in these locations is low and represents less than 1% of the country's total load. The demand for energy from these regions is mainly supplied by diesel fuel.

2.2.2.1 Existing generation

In 2016 the energy need to balance the annual demand, including network losses and import, was equal to 620,2 TWh; +0.7% compared with the energy required in 2015. The most of energy was produced by hydro power plants that cover about 61.4%% of total need.

Source	TWh
Hydro	380.9
Natural gas	56.5
Biomass	49.2
Oil	12.1
Nuclear	15.9
Steam Coal	17.0
Wind	33.5
Solar	0.1
Other	13.7
Import	41.3
TOTAL	**620.2**

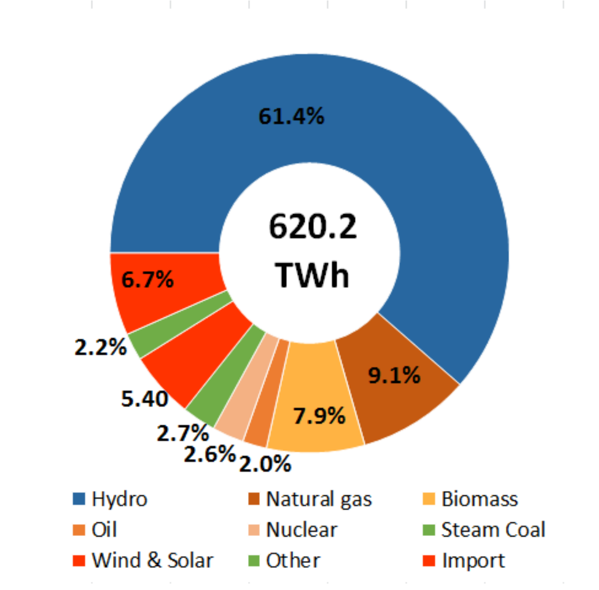


Figure 27 – Generated energy to cover demand 2016

As reported in the figure below, installed capacity in SIN amounted to 150,338 MW at end-December 2016. Hydro plants accounted for 64.5% of total installed capacity and thermal for 27.5%.Wind capacity amounted to 6.7% while solar (PV) installed capacity is a very little fraction of the total (only 24 MW).

Source	MW
Hydro	96,925
Thermal	41,275
Nuclear	1,990
Wind	10,124
Solar	24
TOTAL	**150,338**

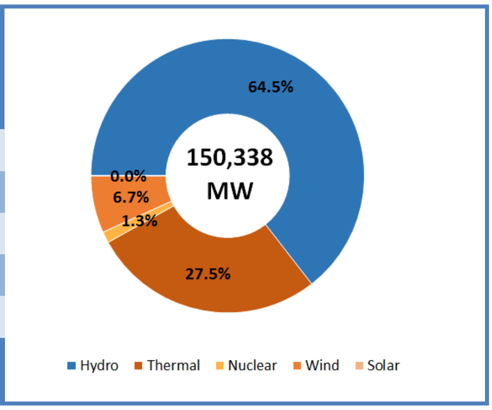


Figure 28 – Generation installed capacity in the year 2016

The figure below shows the evolution of installed generation capacity in the last sixteen years. Since 2001 an almost constant thermal and hydro capacity was installed. It is to underline the great increase of wind capacity in the last three years.

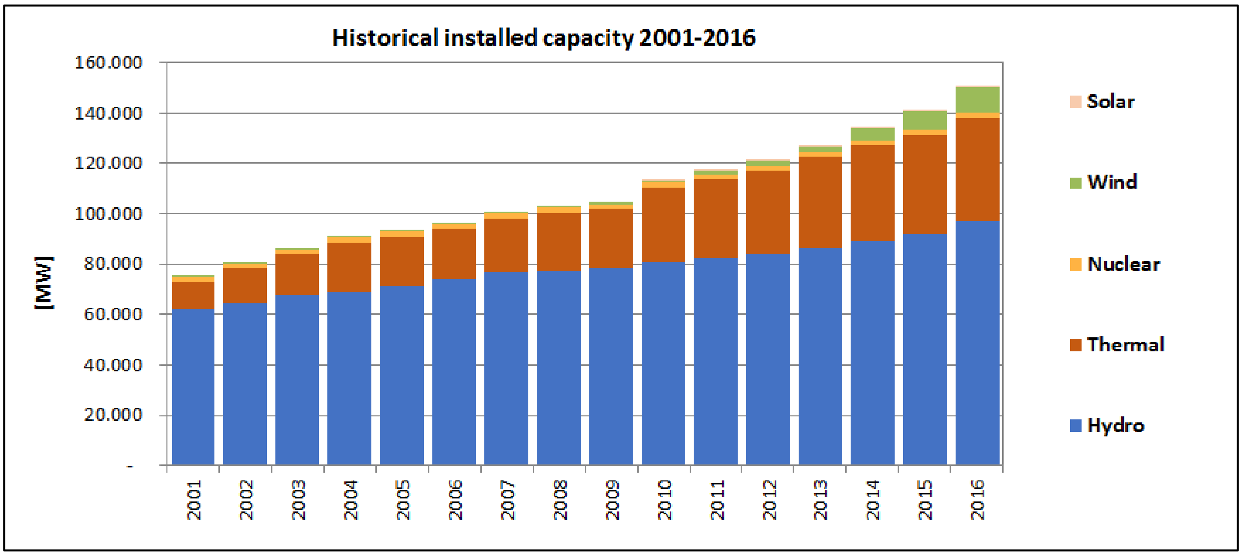


Figure 29 – Historical values of generation installed capacity

Table 11 – Historical values of generation installed capacity

[MW]	Hydro	Wind	Solar	Thermal	Nuclear	TOTAL
2001	62,409	21	0	10,481	1,966	74,877
2002	64,474	22	0	13,813	2,007	80,315
2003	67,698	22	0	16,130	2,007	85,857
2004	69,088	29	0	19,556	2,007	90,679
2005	71,059	29	0	19,770	2,007	92,865
2006	73,678	237	0	20,372	2,007	96,294
2007	76,869	247	0	21,229	2,007	100,352
2008	77,545	398	0	22,999	2,007	102,949
2009	78,610	602	0	23,350	2,007	104,569
2010	80,703	927	1	29,689	2,007	113,327
2011	82,459	1.426	1	31,243	2,007	117,135
2012	84,294	1.894	2	32,778	2,007	120,975
2013	86,018	2.202	5	36,528	1,990	126,743
2014	89,193	4.888	15	37,827	1,990	133,913
2015	91,650	7.633	21	39,564	1,990	140,858
2016	96,925	10.124	24	41,275	1,990	150,338

2.2.2.2 Power generation developments

As reference for the generation expansion plan of Brazil up to the target year, it was used the EPE's development plan [4] (the Plano Decenal de Expansão de Energia – 2016, called "PDE"), which defines the optimal generation fleet at 2026.

The PDE approach is based on a computational model of investment decision (MDI) developed by PDE which obtains the optimum expansion of the electric capacity through the minimization of investment costs. The results of the model are then adjusted by the NEWAVE model, a stochastic dual dynamic programming based approach for the long term hydropower scheduling of the interconnected Brazilian power system.

The input to the computational models are economical[10] and technical; but the results have to take into account the annual average growth of 2700 MW in the load peak (with an average rate of 3.5%) on a ten years horizon in the electrical national grid (SIN) (see paragraph 2.1.2.2).

The model has to take into account the available resources and in particular:

- the projects for future hydro plants for the next ten years, for a total amount of 3066 MW.
- the thermal plants candidate to a modernization
- peak load thermoelectric plants;
- the repowering or installation of additional generating units in existing hydroelectric plants;
- pumped storage hydroelectric plants;
- demand side management;
- chemical storage of energy (batteries).

[10] Discount rate = 8%; WACC: Debt = 60% , rate of interest of debt = 7%, Equity =40% rate of interest of Equity = 7%,; Taxation = 34%

Another element considered in the model is the energy integration with the neighbour countries. The figure below shows the existing studies on this subject.

Figure 30 – Projects for the energy integration with the neighbour countries

The model takes also in consideration, according to the contract until 2016, the capacities that will enter in commercial operation in the next 10 years; a resume of these capacities are reported in the table and figure below.

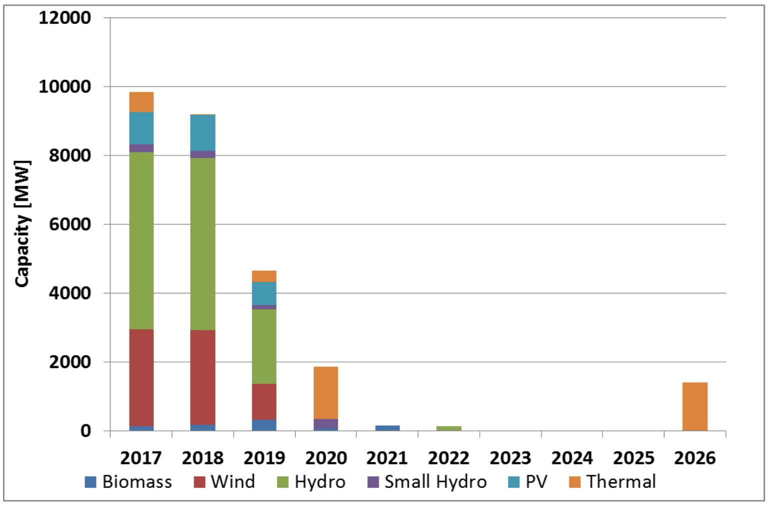


Figure 31 – Expansion capacity contracted until 2016- Annual capacity increase

Table 12 – Expansion capacity contracted until 2016- Annual capacity increase

Source	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Biomass	129	172	324	71	155	0	0	0	0	0	**851**
Wind	2.818	2.755	1.048	0	0	0	0	0	0	0	**6.620**
Hydro	5.148	5.000	2.162	0	0	142	0	0	0	0	**12.452**
Small Hydro	232	218	123	264	0	0	0	0	0	0	**838**
Solar	940	1.029	670	0	0	0	0	0	0	0	**2.639**
Thermal	591	28	340	1.521	0	0	0	0	0	1.405	**2.480**

About renewable sources, the assumptions in the model are:

- wind : 1000 MW in 2020 (80 % Northeast, 20% South) then growth according to the model,
- PV : 1000 MW in 2020 then growth according to the model

On the base of these premises and assumptions, the study considers eight scenarios of probable future generation expansion. These scenarios are

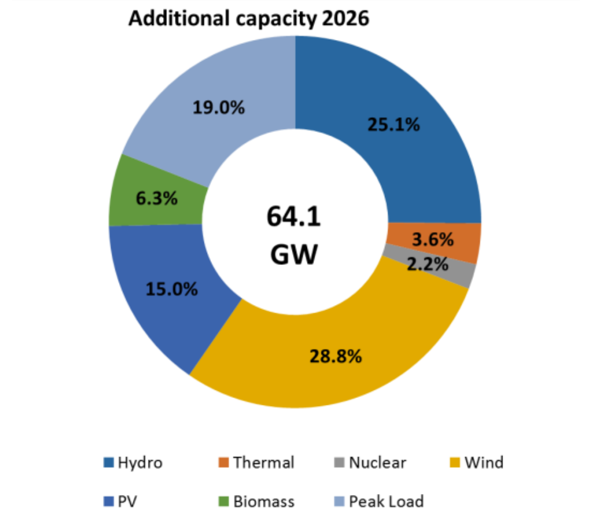
1. Reference Expansion : is the base scenario, that considers the assumptions described above;
2. Alternative Expansion : based on an alternative demand scenario with the same assumptions of the Reference Expansion, but using an alternative load projection
3. Expansion with uncertainty in demand : this scenario takes into account the uncertainty in the market projection
4. Expansion considering reduction of the cost of investment for PV: based on the main assumption of a 40% reduction of CAPEX in the next ten years;
5. Expansion with total restriction for HPP: in this scenario all HPPs are considered candidates for the next 10 years considering the market projection as reference;
6. Assessment of the impacts of a change in water with flow restrictions in the Northeast region: based on the analysis of critical hydrological situation in the Northeast;
7. Effect of energy policies on cost of the expansion of the system
8. Effect of the May 2017 situation on the evolution of the operating marginal cost

The main results of reference expansion scenario are reported in Table 13 below.

The generation fleet described by EPE in this scenario will be assumed as starting point for the calculation of the optimal amount of VRES to be installed at 2030. It will be obtained evaluating the system adequacy and the resulting benefits through simulations carried out increasing the share of VRES power plants and keeping the same installed capacity of the other technologies. In case the VRES will not be able to cover effectively and economically the load increase from 2026 to 2030, other dispatchable technologies will be considered, up to the amount needed to ensure the minimum acceptable system adequacy, evaluated applying the threshold on the Expected Energy not supplied equal to 10^{-5} p.u. of the net load, or up to the economic convenience.

Table 13 – Additional capacity considered at 2026 with respect to 2016

Source	Additional capacity [GW] 2017 - 2026		
	Contracted until 2016	Reference scenario	Total
Hydro[11]	13.3	2.8	**16.1**
Thermal	2.5	-0,2	**2.3**
Nuclear	-	1.4	**1.4**
Wind	6.6	11.8	**18.4**
Solar	2.6	7,0	**9.6**
Biomass	0.9	3.2	**4.1**
Peak Load[12]		12.2	**12.2**
Total	**25.9**	**38.2**	**64.1**



The location of wind farms and PV plants contracted in energy auctions finalized so far is reported respectively in Figure 32 and Figure 33 below. In the calculation of the optimal economic amount of VRES PV and wind power plants will be considered installed in the same areas in an amount proportional to the reported values, as these regions represent the areas with highest renewable resource and also where it is possible to obtain the authorizations for VRES power plants.

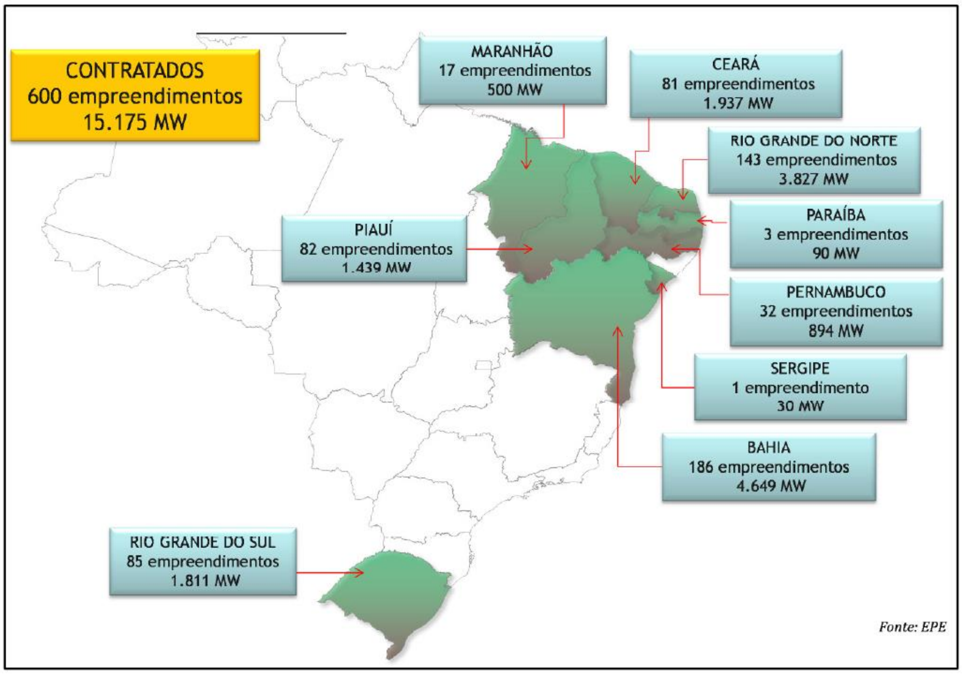


Figure 32 – Location of wind farms contracted in energy auctions

[11] With small Hydro

[12] Gas turbine in open cycle, pumped-storage hydro plants, additional hydroelectric power generation, storage systems (batteries), demand side management.

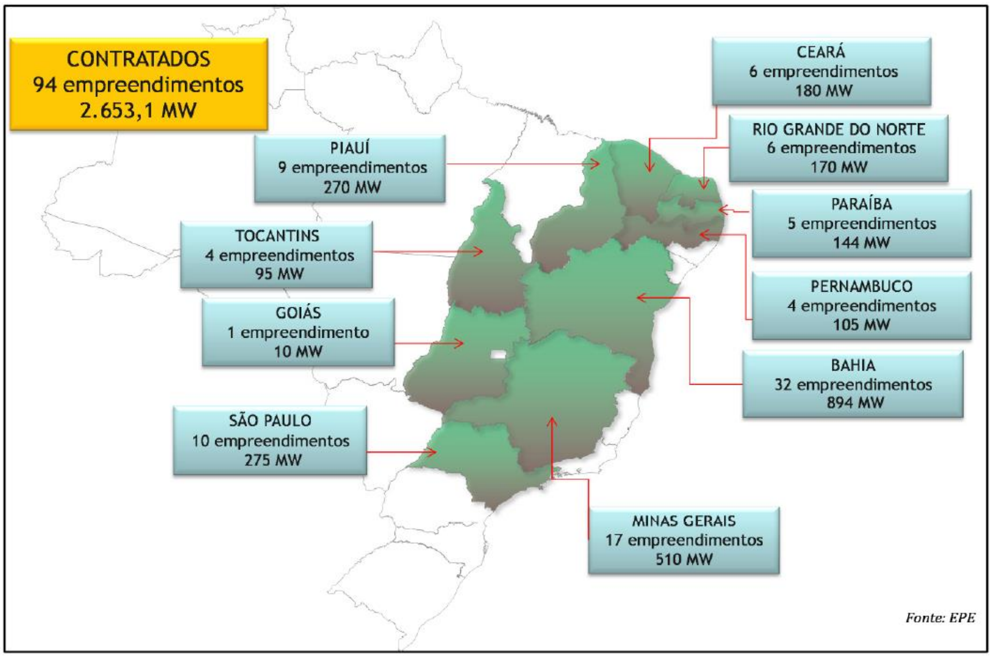


Figure 33 – Location of PV plants contracted in energy auctions

2.2.3 Uruguay

Three are the main subjects in the electricity generation in Uruguay:

- UTE (Administración Nacional de Usinas y Trasmisiones Eléctricas, a vertically integrated State company, proprietary of hydro, thermal and wind power plants, focused on the generation, transmission, distribution and commercialization of the energy industry, the provision of services and the consultancy;
- ADME (Administración del Mercado Eléctrico), a governmental entity responsible for the operation and administration of the national dispatching of demand, and, on the other hand, for the administration of the electricity market;
- MIEM (Ministerio de Industria, Energía y Minería)

2.2.3.1 Existing generation

In 2016 the energy need to balance the annual demand, including network losses and import, was equal to 12 TWh; +2.6% compared with the energy required in 2015. The most of energy was produced by hydro power plants that covered about 63.2% of total need. It is to underline that a great amount of the Uruguay electric production is given by the energy coming from the Central Hydroelectric Power Plant of Salto Grande.

Source	TWh
Hydro	7.6
Thermal	1.3
Wind	3.0
Solar	0.1
TOTAL	**12.0**

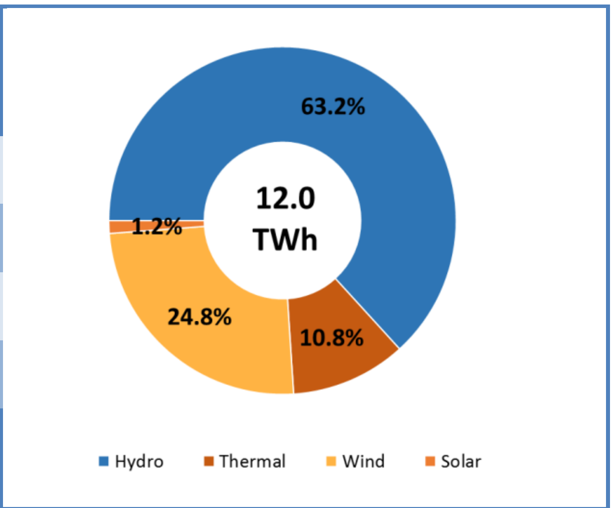


Figure 34 – Generated energy to cover demand 2016

As reported in the figure below, installed capacity amounted to 3912 MW at end-December 2016. Hydro plants accounted for 39.3% of total installed capacity, wind for 31.0%, biomass for 10.9% and other thermal units for 16.6%.

Source	MW
Hydro	1,538
Thermal	650
Wind	1,211
Solar	88
Biomass	425
TOTAL	**3,912**

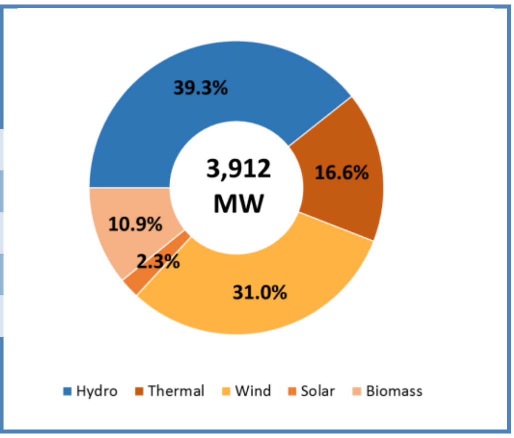


Figure 35 – Generation installed capacity in the year 2016

The figure below shows the evolution of installed generation capacity in the last twenty six years. It is to underline the great increase of wind capacity in the last years.

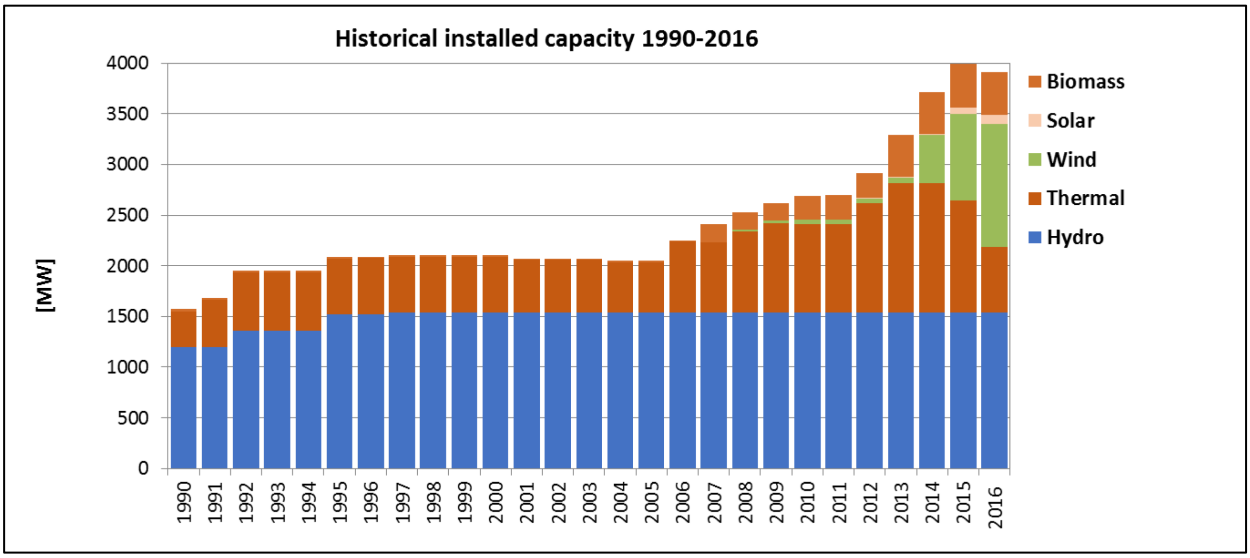


Figure 36 – Historical values of generation installed capacity

Table 14 – Historical values of generation installed capacity

[MW]	Hydro	Thermal	Wind	Solar	Biomass	TOTAL
1990	1,199	351			22	1,571
1991	1,199	465			22	1,685
1992	1,356	578			20	1,954
1993	1,356	578			15	1,949
1994	1,356	578			16	1,950
1995	1,519	551			15	2,085
1996	1,524	552			14	2,089
1997	1,538	552			14	2,104
1998	1,538	551			14	2,103
1999	1,538	553			14	2,105
2000	1,538	553			14	2,105
2001	1,538	520			14	2,072
2002	1,538	519			14	2,070
2003	1,538	518			13	2,069
2004	1,538	498			13	2,050
2005	1,538	497			14	2,049
2006	1,538	697			14	2,250
2007	1,538	695		0	173	2,406
2008	1,538	801	15	0	173	2,526
2009	1,538	878	31	0	173	2,620
2010	1,538	876	41	0	236	2,690
2011	1,538	876	44	0	243	2,701
2012	1,538	1,076	53	1	244	2,911
2013	1,538	1,275	59	2	414	3,288
2014	1,538	1,275	481	4	415	3,712
2015	1,538	1,105	857	64	425	3,989
2016	1,538	650	1.211	88	425	3;912

2.2.3.2 Power generation developments

As reference for the generation expansion plan of Uruguay up to the target year, MIEM does not provide information about the expected type of capacity needed to cover the yearly 2% demand growth up to 2030 [5].

With respect to the generation fleet of 2016, reported in Figure 35, some developments have been introduced in the last months, with the installation of new wind and PV power plants and the start of the works for the connection of a 550 MW CCGT (Punta del Tigre B), which is currently operating with the first installed equipment.

The most reliable dataset of the generation capacity foreseen in the Uruguayan power system in the next years is represented by the network model available on the UTE website [6], which provides the expected configuration of the system at 2021. Figure 37 shows the installed power per technology present in the considered network.

Source	MW
Hydro	1538
Thermal	1185
Wind	1554
Solar	228
Biomass	312
TOTAL	4,767

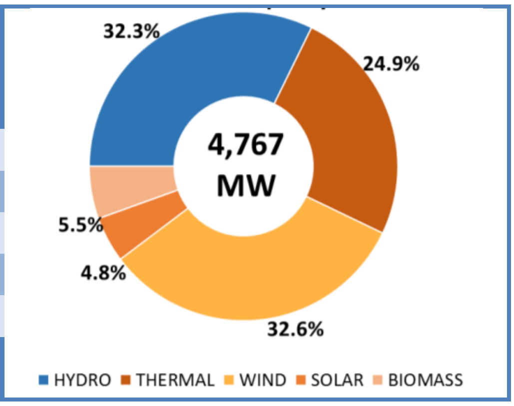


Figure 37 – Generation installed capacity in the 2021 network and considered as starting point at 2030

Based on other information available on the UTE website showing the map of the system at 2023[13], it was possible to identify candidate sites for new additional biomass, PV and wind power plants. These plants have been selected as preferred solutions for future development when new sites and power plants will have to be considered during the activity.
In particular, the following options have been identified:

- for biomass, two plants with a total power equal to 50 MW
- for PV, 7 plants with a total power equal to 45 MW
- for wind, 12 plants with a total power equal to 745 MW

They will be introduced during the analysis when the economic assessment will show the convenience to increase the installed power of these technologies.

[13] The map is available at https://portal.ute.com.uy/sites/default/files/documents/files/mapa%202023.pdf

2.3 Transmission system description

Problem statement

- *The description of the transmission network considered in the project, including the list of interconnections between the countries under investigation and between them and other boundary countries not part of the cluster.*

Methodology

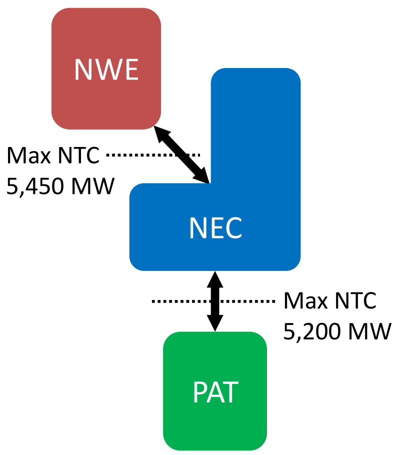
- *Collection of public domain information and data collection from meetings with the stakeholders in Argentina and Brazil. The network databases collected will be converted in GRARE format to build the electric power system model 2030 for the annual base simulations.*
  GRARE, Grid Reliability and Adequacy Risk Evaluator, is a powerful computer-based tool which evaluates the reliability and the economic operation of large electric power systems. GRARE supports medium and long-term planning studies using probabilistic Monte Carlo approach and modelling in detail the transmission networks (see Appendix 1).

Major results

- ***Argentine transmission network***
  The network database (PSS/E format) provided by CAMMESA during the kick-off meeting will be used as reference for the project. The network of the Argentine electric power system expected by CAMMESA in 2025 is represented in the database, where also a new 3,500 MW HVDC link will be considered between Patagonia and Gran Buenos Aires (the main option presented by CAMMESA to exploit wind potential in Patagonia).
  No network developments are already planned from 2025 to 2030, so, the topology 2025 provided by CAMMESA will be the reference also for 2030 and possible reinforcements (on the main corridors) will be an output of GRARE simulations.

  The electric system will be modelled considering three macro areas and two limited sections:

  - *NWE area (North West): NOA, North Cuyo and Centro*
  - *NEC area (North East and Center): NEA, Litoral, Buenos Aires, Gran Buenos Aires, Comahue and South Cuyo*
  - *PAT area: Patagonia*



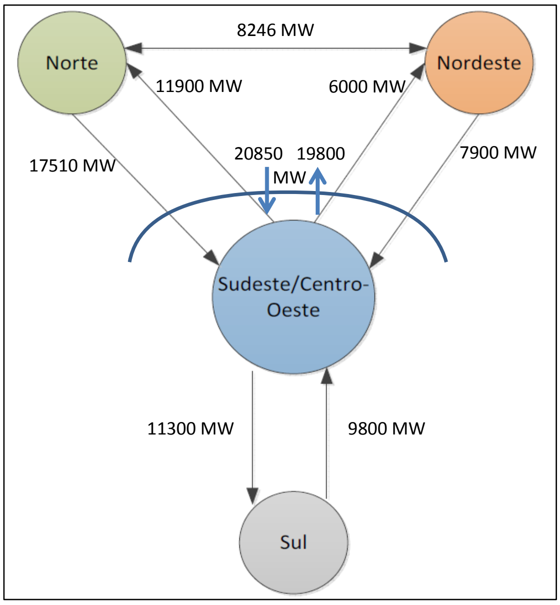
- ***Brazilian transmission network***
  The networks used by EPE (Empresa de Pesquisa Energética) for the analysis of the last Plano

Decenal de Expansão de Energia (PDE 2026) will be the reference for the current project. The network model is available on EPE website.

The Brazilian transmission system will be divided in four macro areas:

- *N: Norte*
- *NE: Nordeste*
- *SE/CO: Sudeste – Centro-Oeste*
- *S: Sul*

The NTC expected defined by EPE at 2025 are reported in the scheme, and will be considered also for 2030.



- ***Uruguay***
  Transmission system of Uruguay is much smaller than the Argentinian and Brazilian ones. Only one area will be considered, based on the network model made available by UTE. Some further network improvements will be considered or proposed during the study if 500 kV network reinforcement turns out to be necessary.

- ***International interconnections***
  In order to analyse the impact of countries integration on VRES optimal penetration, the following interconnections will be considered between Argentina, Brazil and Uruguay:
  - *Argentina-Brazil: existing lines Rincón de Santa María (AR) - Nodo Frontera Garabí (BR) with back-to-back solution allowing up to 2000 MW power exchange and additional 1000 MW interconnection (San Isidro (AR) - Foz de Iguacu (BR))*
  - *Argentina-Uruguay: two existing lines in Salto Grande and C.Elia (AR)-San Javier (UY) with maximum power exchange up to 2000 MW*
  - *Brazil-Uruguay: one 500 kV line and a 150 kV line for a maximum power exchange equal to 500 MW + 70 MW*

At this stage, the interconnection lines with the other Countries outside the cluster will be considered in the model but no energy exchange will be set.

2.3.1 *Argentina*

The transmission network of Argentine includes four voltage levels: 500 kV, 330 kV, 220 kV and 132 kV. CAMMESA is responsible for transmission network planning with an integrated approach able to identify the network needs. The new network reinforcements are not carried out by CAMMESA but from private companies by means of public tenders. Eight companies operate on the high voltage transmission network.

CAMMESA provided the network database (PSS/E format) of the Argentine electric power system for peak load scenario 2025, including 10,000 MW of RES power plants. This network model includes the strengthening lines needed for the secure management of the system at 2025 with high RES penetration.

During the kick-off meeting CAMMESA presented four network reinforcement options to allow high integration of new RES power plants (especially wind) in Patagonia within 2025. The different options are able to increase the maximum power that it is possible to transfer from south area of the Country to Gran Buenos Aires area from the current 1,500 MW to 3,000 MW with 500 kV reinforcements or up to 4,000 MW with new 750 kV lines or up to 5,000 MW if a new 3,500 MW HVDC line will be built. The option with a new HVDC link will be considered in the reference model as it is expected that at 2030 the highest power transfer capacity is needed.

This database will be converted in GRARE format and the load and generation models will be updated according with the assumptions of the project. No network developments are already planned from 2025 to 2030, so, the topology 2025 provided by CAMMESA will be the reference also for 2030 and possible reinforcements (on the main corridors) will be an output of GRARE simulations. The study specifically addresses the interregional transmission infrastructures within each country and the cross-border transmission links that can play a role in the assessment of the feasible VRES generation penetration. Therefore, local transmission grid reinforcements needed to connect the new power plants or to solve local congestions are disregarded by the scope in this wide scale analysis and mainly the EHV network will be analysed. In case local congestions are often present in the analysed scenario, they will be removed considering an improved transmission capacity of the limiting lines, to avoid that local constraints which can be solved with relatively small effort and investments can affect inter-area power flows. This approach simulates the solution of local network problems by means of specific local improvements of the network performed by the Grid Operator before the target year. The list of the main areas where such need for local improvements is expected will be reported among the results of the analysis.

Argentine electric power system is divided into nine electrical regions (groups of provinces):

- COMAHUE (La Pampa, Río Negro, Neuquén)
- BUENOS AIRES (Buenos Aires)
- GRAN BUENOS AIRES (Ciudad de Buenos Aires, Ciudad de La Plata, Gran Buenos Aires)
- LITORAL (Santa Fé, Entre Ríos)
- NEA (Formosa, Chaco, Corrientes, Misiones)
- CENTRO (Córdoba, San Luis)
- CUYO (Mendoza, San Juan)
- NOA (La Rioja, Catamarca, Santiago del Estero, Salta, Jujuy, Tucumán)
- PATAGONIA (Río Negro, Chubut, Santa Cruz)

Maybe, not all sections between the existing regions will be critic in 2030. Therefore, a subset of the main areas will be modelled analysing the network model 2025 and assessing the critical electric sections inside the Country. Three macro areas were defined and two sections with limited net transfer capacity (NTC) were highlighted (Figure 38):

- **NWE area**: North West area of the Country including the electrical regions NOA, North Cuyo and Centro;
- **NEC area**: North East and Central area of the Country including the electrical regions NEA, Litoral, Buenos Aires, Gran Buenos Aires, Comahue and South Cuyo (load and generation connected under Rio Diamante S/S);
- **PAT area**: Patagonia area including only the electrical region Patagonia.

One limited section was highlighted between PAT and NEC areas due to the limited number of lines available to exploit RES potential in Patagonia (mainly from wind) to cover national demand mostly located in Gran Buenos Aires, Buenos Aires and Litoral. As stated above, one new HVDC link 3,500 MW, indicated by CAMMESA, will be considered in the model to increase the NTC from Patagonia to the rest of the Country (the main project to maximize the RES integration in the Country).

The second section was defined between NWE and NEC areas. NWE area has a high potential for solar radiation exploitation and the power produced by PV power plants in this area could be exported towards the big demand centres in NEC area. The maximum export from NWE area is according with the four 500 kV lines that limit the section NWE-NEC.

Table 15 shows the lines that form the sections with the summer and winter limits in normal (N) and contingency (N-1) conditions, these last were rounded down. N-1 contingency condition considers the worst outage of one line and the power limit calculated in this condition represent the maximum NTCs of the sections[14]. Two poles are expected for the new HVDC link “Puerto Madryn – Plomer”, therefore the worst N-1 condition in NEC-PAT section is the loss of one pole (1,750 MW).

[14] The NTC value can be further reduced by operational constraints, such as an uneven loading of the lines belonging to the section.

Table 15 – Section limits in normal and contingency conditions

Line Name	Reg.From–Reg.To	Vn [kV]	Length [km]	Summer Limit [MW]	Winter Limit [MW]
SECTION NWE–NEC					
Monte Quemado – Chaco	*NOA-NEA*	*500 AC*	*263*	*1,732*	*1,970*
San Francisco – Santo Tomé	*CEN-LIT*	*500 AC*	*120*	*1,732*	*2,158*
Arroyo Cabral – Rosario Oeste	*CEN-LIT*	*500 AC*	*250*	*866*	*1,732*
Rio Diamante – Los Blancos – Gran Mendoza	*CUY-CUY*	*500 AC*	*103*	*1,732*	*1,750*
	Limit in normal condition (N)			**6,050**	**7,600**
	Limit in contingency condition (N-1)			**4,300**	**5,450**
SECTION NEC–PAT					
Puerto Madryn – Choele Choel (1st)	*PAT-COM*	*500 AC*	*354*	*1,263*	*1,732*
Puerto Madryn – Choele Choel (2nd)	*PAT-COM*	*500 AC*	*354*	*1,263*	*1,732*
Puerto Madryn – Plomer (HVDC)	*PAT-GBA*	*600 DC*	*1,800*	*3,500*	*3,500*
	Limit in normal condition (N)			**6,000**	**6,950**
	Limit in contingency condition (N-1)			**4,250**	**5,200**

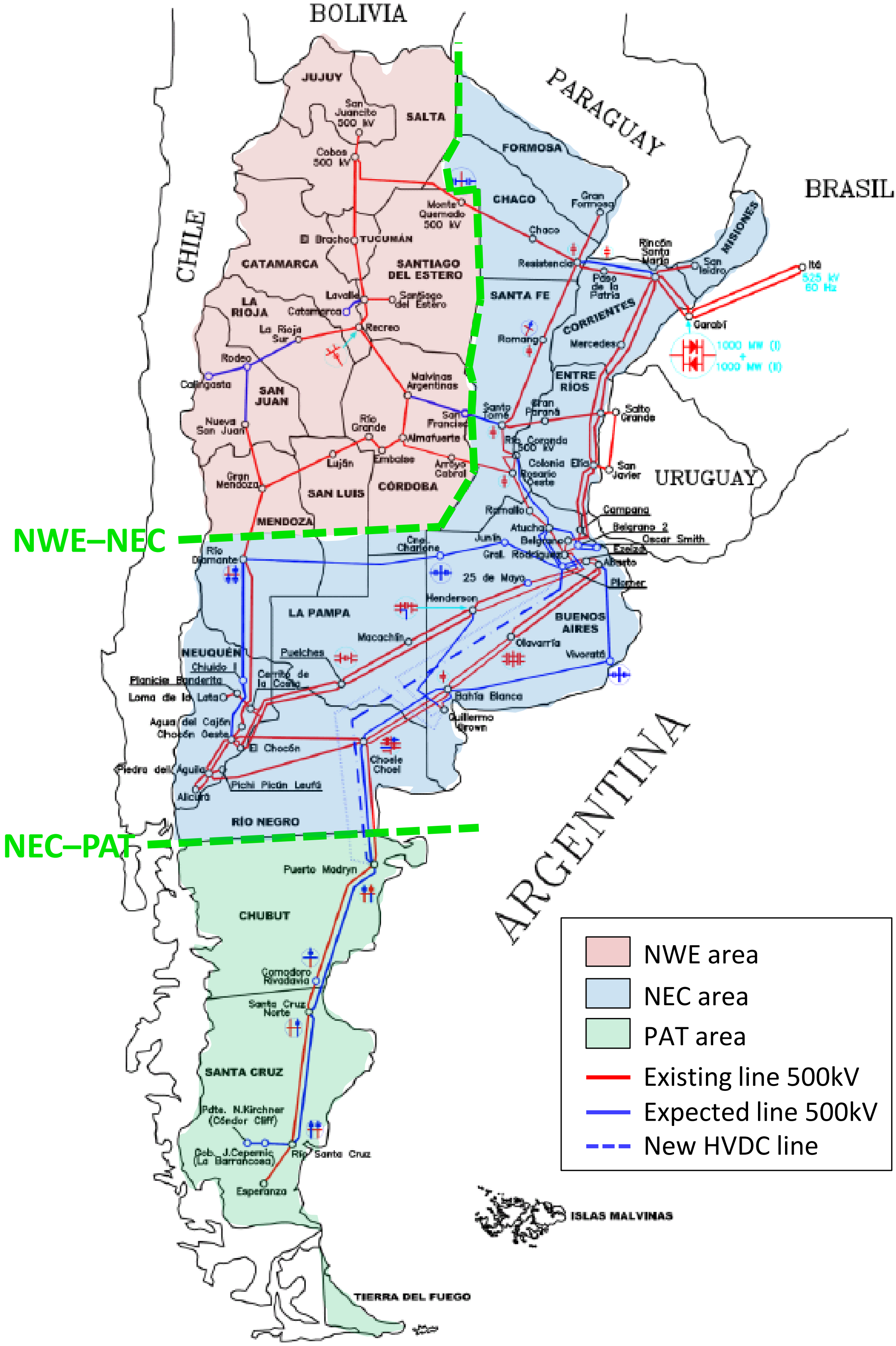


Figure 38 – Macro areas of Argentine electric system 2030

2.3.2 *Brazil*

The transmission network of Brazil includes integrated systems at 765 kV, 500 kV, 440 kV, 345 kV, 230 kV and 138 kV. The complex transmission line system is necessary to cover the high distances due to the great geographical extension of Brazil and optimize the hydroelectric energy production (that represents the greatest part of the installed power), taking into account the differences in hydrological regimes.

The Ministry of Energy and Mines (MME) has the overall responsibility for policy setting in the electricity sector. The National Interconnected System (Sistema Interligado Nacional or SIN), is a large-scale electricity generation and transmission system operated by private, publicly held and state owned companies, managed by the National System Operator (ONS). The transmission assets that form this grid are operated under the regulation of the Brazilian National Electric Energy Agency (ANEEL).

The Empresa de Pesquisa Energética – EPE provides services with research and studies aimed at subsidizing the planning of the energy sector, such as electric power, renewable energy sources and energy efficiency, among others. The ten year development plan (Plano Decenal de Expansão de Energia) has been recently released considering the horizon year 2026. Within this document, EPE made available also the network model for the software ANAREDE[15], which is taken as reference for the future configuration of the transmission system.

Brazil electric power system is divided into four electrical regions (groups of provinces):

- SUL (S): includes the provinces of Rio Grande do Sul, Santa Caterina, Paranà;
- SUDESTE – CENTRO-OESTE (SE/CO): includes the provinces of Espírito Santo, Rio de Janeiro, Minas Gerais, São Paulo, Goiás, Distrito Federal, Mato Grosso, Mato Grosso do Sul, Acre, Rondônia;
- NORTE (N): includes the provinces of Pará, Tocantis e Maranhão, Amazonas, Amapá, Roraima;
- NORDESTE (NE): includes the provinces of Piauí, Ceará, Rio Grande do Norte, Paraíba, Pernambuco, Alagoas, Sergipe, Bahia.

From an electrical point of view, the three states of Amazonas, Amapá, Roraima (named MAN/AP/BV) in the Norte region and the two states of Acre, Rondônia (named as AC/RO) in SE/CO region, are generally considered separately as two isolated areas and will be considered as described in the network model made available by EPE

Then, since hydroelectric energy production is very relevant in Brazil, some additional "electrical areas" are usually defined in order to better represent and integrate the most important hydro power plants in the system; these regions are:

- ITAIPU (IT), located in Paraná (S);
- IVAIPORÃ (IV), located in Paraná (S);
- XINGU (XIN), located in Pará (N);
- BELO MONTE (BM), located in Pará (N);

[15] http://www.epe.gov.br/Transmissao/Paginas/Dadosparaestudosdeplanejamentodatransmissão-PDE2026.aspx

- TAPAJÓS/TELES PIRES (TP) respectively located in Pará (N) and on the border between Pará and Mato Grosso (N-SE/CO).

Finally, a further area is generally considered, called IMPERATRIZ (IMP). This area is located in Maranhão (belonging to Norte region), and it is defined in order to obtain in the model a better distribution of the power flows coming from XIN, N, NE and SE/CO.

The following map, taken from PDE 2024 by EPE, represents the geographical position of the detailed areas defined for the Brazilian system up to the that version of PDE.

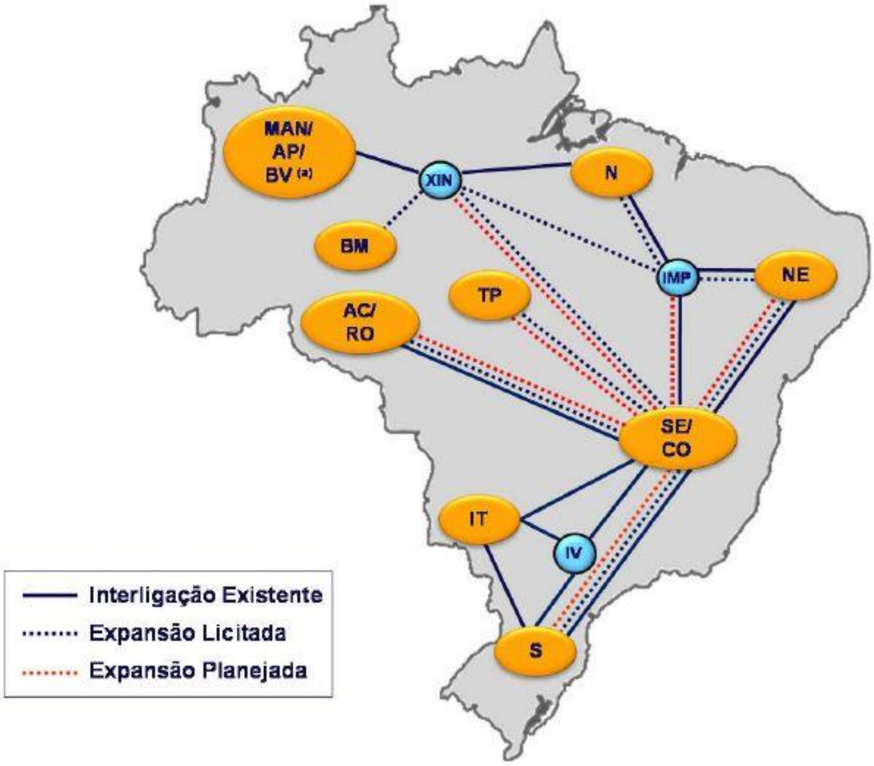


Figure 39 – Detailed electrical areas in Brazil

In the last PDE (PDE 2026), EPE reduced the number of areas in which the Brazilian system is divided, keeping only the four market zones corresponding to regions: SUL (S), SUDESTE – CENTRO-OESTE (SE/CO), NORTE (N) and NORDESTE (NE).

As PDE 2026 is taken as reference also for the network model, in this study the same approach is followed. The following scheme represents the areas and the interconnections considered in the model.

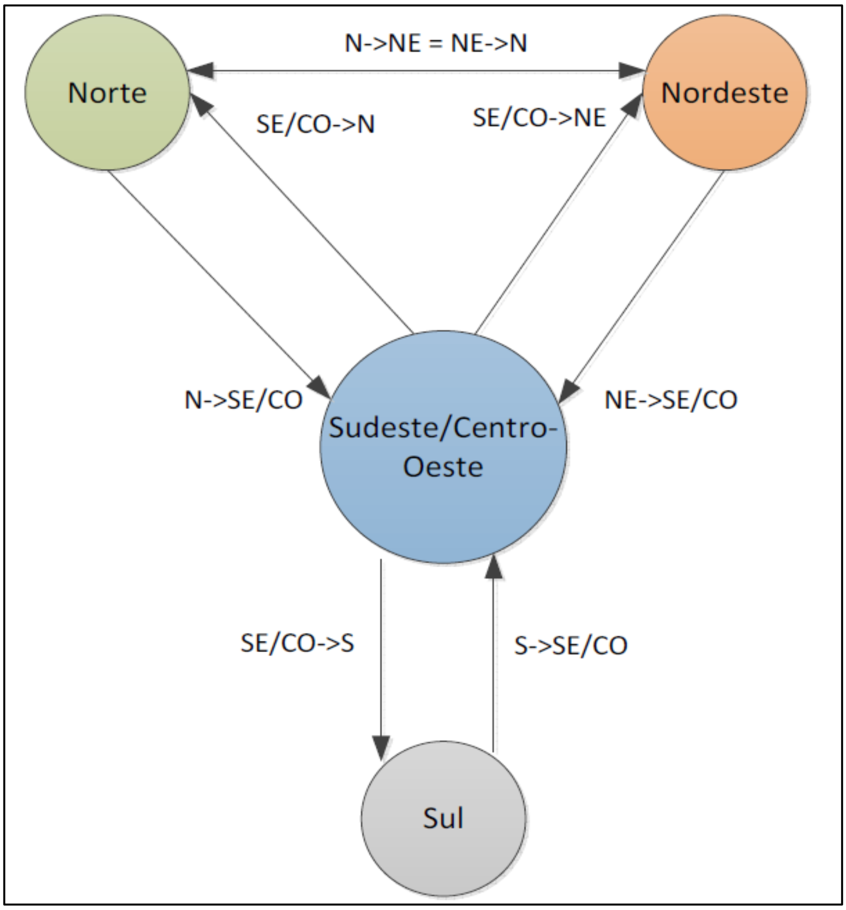


Figure 40 – Brazilian areas considered in the study according PDE 2026

Huge investments are expected in the development of the Transmission System in Brasil, to increase the interconnection capacity between the different areas and to ensure that the big hydro power plants will be able to transfer the power towards the main load centres. The following table reports the current of the transmission lines, divided depending on the voltage level, and the expected development for the next years up to 2021 and to 2026.

Table 16 - expected development of Brazilian transmission system [source: EPE]

Voltage level	±800kV	750kV	±600kV	500kV	440kV	345kV	230kV	TOTAL
	Extension [km]							
existing 2016		2683	12816	46569	6748	10320	55820	134956
development 2017-2021	9158	0	0	14778	316	802	7222	32276
development 2022-2026	2920	0	0	15959	123	535	10071	29608
development 2017-2026	12078	0	0	30737	439	1337	17293	61884
total 2026	12078	2683	12816	77306	7187	11657	73113	196840

The Net Transfer Value among the regions is also defined by EPE, and is reported in the following table. Thanks to the expected development of the transmission system, some limited NTCs between areas will be improved.

Table 17 – current and expected NTC between Brazilian regions

FROM --> TO	NTC [MW]		FROM --> TO	NTC [MW]	
	2016	**2025**		**2016**	**2025**
N - NE	2600-3900	8246	NE - N	2600-3900	8246
N - SE/CO	3319	17510-17850	SE/CO - N	4000	11900-14840
NE - SE/CO	600	7900-8100	SE/CO - NE	1000	6000
NE->SE/CO + N->SE/CO	*3900-4000*	*20850-22370*	*SE/CO->NE + SE/CO->N*	*4100-4300*	*19800*
SE/CO - S	11000	11300	S - SE/CO	8200	9800

The values which will be considered are then reported in the following scheme.

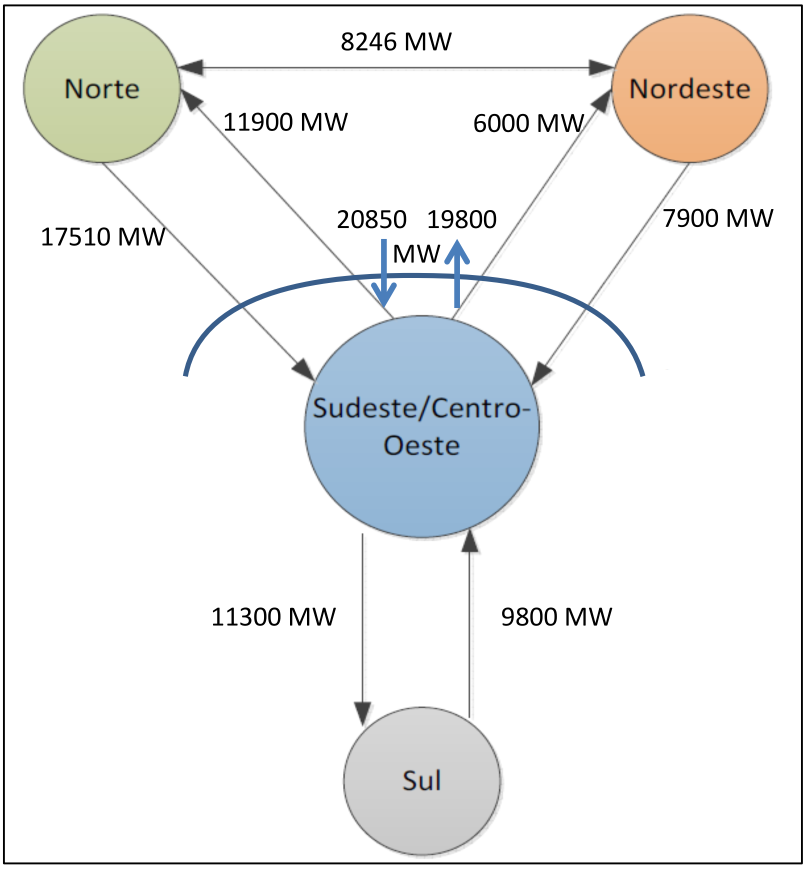


Figure 41 – NTC between Brazilian areas considered in the study

For sake of completeness, a map showing the current configuration of the Brazilian transmission system taken from the PDE 2026 by EPE (but based on information by ONS) is reported below.

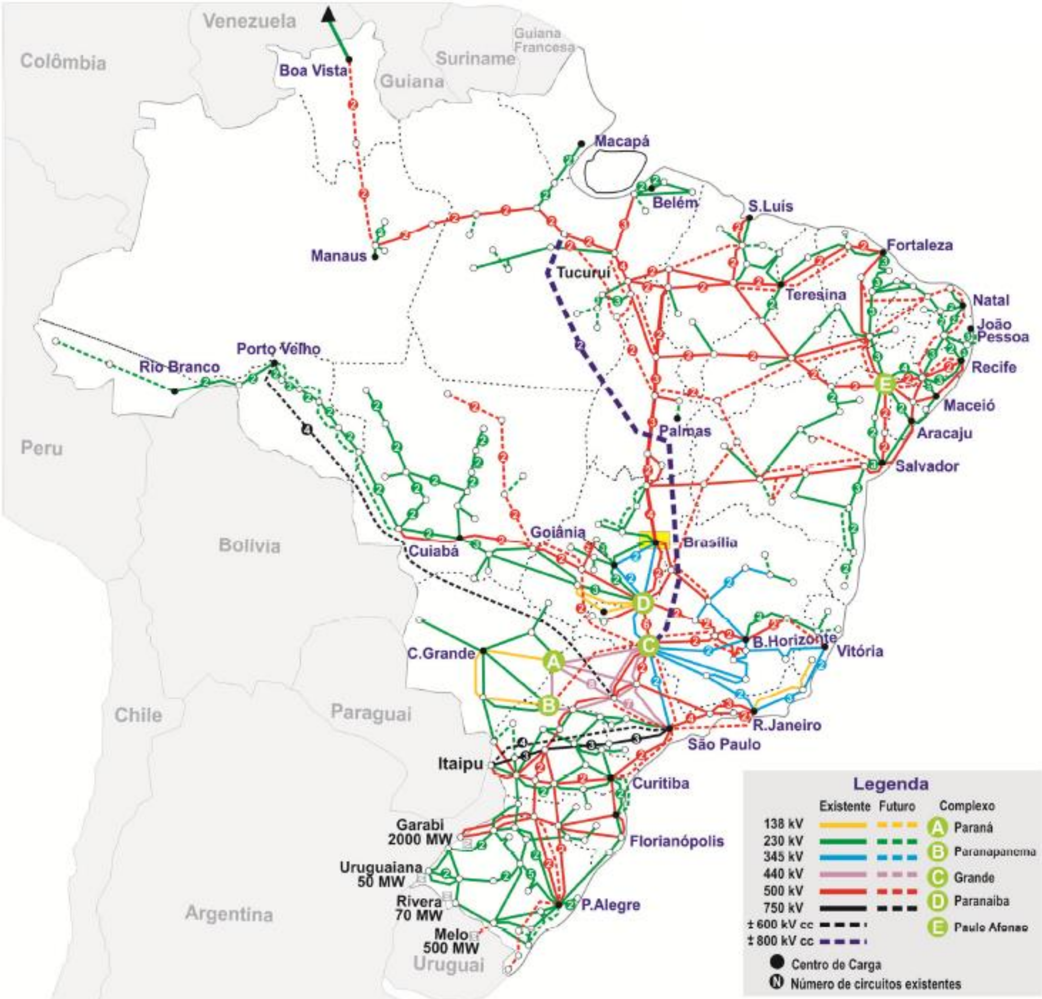


Figure 42 - Current configuration of the Brazilian transmission system

2.3.3 Uruguay

Compared to the Transmission system of Argentina and Brazil, Uruguay is characterized by a small extension of the network, which in 2016 was constituted by about 5000 km of lines mainly at 150 kV. The table below show the detailed information about the extension of the transmission system in 2016, taken from the periodical report by UTE[16].

Table 18 – Extension of transmission system in Uruguay in 2016 [source: UTE]

Voltage level	Total length [km]
150 kV	3923
230 kV	11
500 kV	1078

Uruguay will be then modelled as a single area system.

The map showing the configuration of the electrical system in 2016, as available on UTE website is reported in the following figure.

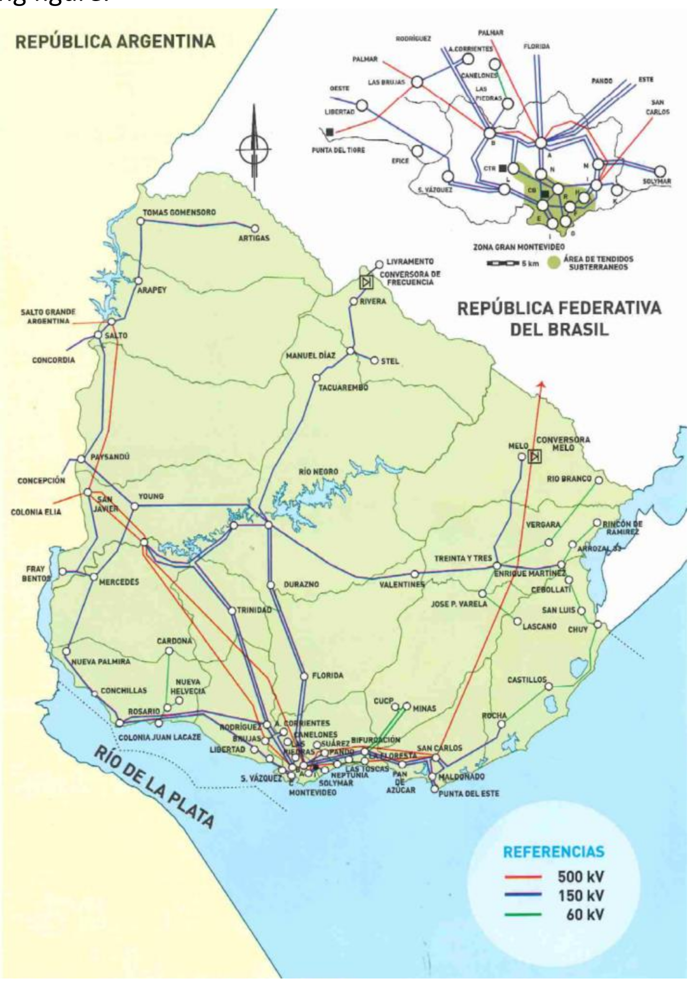


Figure 43 – Current transmission network in Uruguay [source: UTE [9]]

[16] http://portal.ute.com.uy/sites/default/files/documents/files/UTE%20en%20Cifras%202016_0.pdf

UTE makes available on its website the network models in PSS/E of the current network and the one for the future system at 2021. This will be taken as reference for the study.
Furthemore, in the Memoria annual 2016, UTE describes some planned improvement of the network, which will be considered if not already included in the 2021 network model due to the long timing required for the execution of the activities.
The main network reinforcement to be considered are:

- Construction of the 500 kV line Tacuarembó-Melo in the northern part of the country, 210 km long, and related 500/150 kV transformers in Tacuarembo
- Construction of the 150 kV line Artigas-Rivera close to the Brazilian border, about 150 km long
- Improvement of the transformation capacity in Montevideo from 500 kV to 150 kV
- Second circuit for the Bonete-Young-Paysandú line in the west area
- Improvement of the connection of Melo substation (last substation before the Brazilian border) to the 150 kV network.

Two important mining loads have been also added to the system in the area of Valentines and Rocha. For some years there have been several activities also followed by legal discussions about the permissions to exploit the natural resources in these areas, and no solution in the short term are foreseen. However, due to the big potential in the area and the steps performed so far, it is reasonable to assume that by 2030 a feasible solution will be found, and load will be increased in these areas due to mining activities.

2.3.4 International interconnections

In this paragraph, the list of the international interconnection lines which are considered in the Reference Scenario is given. The lines have been selected among the already existing and operating ones (in some cases changing their capability or the way how they are currently used, foreseeing a greater utilization in the future) and among the possible future projects discussed during the meetings held with the operators of the systems.
The study will assess the impact of the interconnection lines between Argentina and Brazil on the optimal penetration of VRES, highlighting if the transfer capacity between the countries considered in the Reference Scenario constitutes a limitation factor for installation of new PV or wind power plants. In case some limitations are found, a further investigation on the impact of new interconnection lines on the system will be carried out, and the list of future projects will be considered in the definition of the new transfer capacity.
The interconnection lines with the other Countries are also listed but the simulations will be performed keeping to zero the power exchanges with countries not belonging to the cluster under analysis. This decision is taken to highlight during the analysis the adequacy of the Argentinean and Brazilian system to supply their load independently from possible exchanges with other countries. The generation fleet and the VRES power plants considered in the analysis are dimensioned to ensure that the two interconnected countries under analysis are able to fulfil the demand.
It is worth underlining that in the regional analysis foreseen at the end of the study, where the three clusters will be analysed together, a more detailed simulation of the interactions among the countries will be performed. The power exchanges calculated by means of the economical optimization of the overall generation, exploiting the interconnections between the countries, will be part of the results, providing additional information about the value that the interconnection lines can have on the development of the VRES in the whole region under analysis.

The lines included in the Reference Scenario are the following:
Interconnections Argentina-Brazil:

- Existing lines Rincón de Santa María - Nodo Frontera Garabí with back-to-back solution allowing up to 2000 MW power exchange
- Additional 1000 MW interconnection (San Isidro - Puerto Iguazù - Foz de Iguacu)

Interconnections Argentina-Uruguay:

- two existing 500 kV lines in Salto Grande and between C.Elia (AR) and San Javier (UY) with maximum power exchange up to 2000 MW.

Interconnections Brazil-Uruguay:

- Existing line Santana do Livramento (BR) – Rivera (UY) with back-to-back solution allowing 70 MW power exchange.
- Interconnection between the conversion substation in Melo (UY) and P. Medici/Candiota (BR), with back-to-back solution allowing up to 500 MW power exchange.

Interconnections with countries not belonging to the cluster, whose power flow are kept to zero:

Argentina-Chile	Existing line Salta-Andes, with power flow exchange increased to 600 MW[17].
Brazil-Venezuela	Existing 780 km AC interconnection 230 kV between Boa Vista and Macagua allowing 200 MW power exchange (due to lack of reactive power compensation in Venezuela, it is not possible to import more than 150 MW to Brazil).

[17] Currently the limit is set around 200-250 MW due to problems in the SING area, which cannot export more to Argentina without causing overloads and dynamic instability. It is assumed that at 2030 these issues will be definitively solved, also thanks to the SIC-SING interconnection, and that the power exchange limit will be determined by the capacity of the line.

2.4 Variables for the assessment of energy costs

2.4.1 Investment and operating costs of RES generation split by technology

Problem statement

- ➢ *Assessment of RES costs in the last decades and of the projections for the years to come.*
  - *Solar photovoltaic generation.*
  - *On-shore wind generation.*

Methodology

- ➢ *Collection of data regarding the state-of-the-art and the expected improvements for the RES*
  - *Description of the cost decline of PV plants, particularly PV modules, and of future reductions envisaged for the PV modules and the costs of BOS.*
  - *Description of the cost decrease of Wind farms, particularly and of the future advantages envisaged thanks to the further increase of rotor size.*

Major results

- ➢ *Definition of the evolution of the RES prices, solar PV and wind technologies, until the year 2030. The costs envisaged for each technology are summarised in the tables below.*

Solar PV - Target year 2030 - Costs in USD/kW			
	Brazil	**Argentina**	**Uruguay**
PV modules	240	240	240
Inverter	70	70	70
BOS	430	550	550
Total	740	860	860
O&M (per year)	11.5	11.5	11.5

Onshore Wind - Target year 2030 - Costs in USD/kW			
	Brazil	**Argentina**	**Uruguay**
Wind turbines	802	802	802
BOS	378	378	378
Total	1180	1180	1180
O&M (per year)	48	48	48

This section is mainly based on “Power to change 2016” [15], the report from IRENA that analyses the market of the renewable energies and provides future trends for the solar and wind technologies.
IRENA has developed a Renewable Cost Database. This contains information on the installed costs, capacity factors and LCOE of 15000 utility-scale renewable power generation projects around the world. It is also supplemented by secondary sources, where data gaps exist.

The important points for interpreting these IRENA data and analysis are listed below.

- The analysis is for utility-scale projects only (Solar PV>1 MW, Onshore wind>5 MW). Projects below these size levels may have higher costs. Information is added (paragraph 2.4.1.4) in regards to the cost of residential solar PV projects.
- All cost data refer to the year in which the project is commissioned.
- All data are in real 2015 USD, that is to say corrected for inflation
- When average data are presented, they are weighted averages based on capacity.
- Data for costs and performance for 2015 are preliminary for solar PV and onshore wind. Some revisions are likely as additional data are reported.
- Cost data exclude any financial support by governments (national or subnational) to support the deployment of renewables or to correct the non-priced externalities of fossil fuels.
- The impact of grid constraints and curtailment is not accounted for in this analysis. This is a market issue beyond the scope of the cost analysis that IRENA performed.
- The weighted average cost of capital (WACC) is fixed over the period 2015-25 for the more mature solar PV and onshore wind technologies.
- The LCOE of solar and wind power technologies is strongly influenced by resource quality; higher LCOEs don't necessarily mean inefficient capital cost structures.
- Different cost metrics yield different insights, but in isolation don't necessarily provide sufficient information to assess whether or not costs in different markets are at "efficient" cost levels.
- Publicly available data for power purchase agreements (PPAs), feed-in tariffs (FITs), tenders and auctions are not necessarily directly comparable between each other or with LCOEs calculated in this report. Care must be taken in interpreting these values. Further comments by IRENA are reported in the following paragraph 2.4.1.1.9.
- Learning curve analysis utilises renewable power technology capacity projections from previous IRENA's analysis.

IRENA's analysis focused the impacts of technology and market developments on the LCOE. To understand the drivers of these changes requires an analysis of the equipment costs, total installed costs, performance (capacity factors), operation and maintenance (O&M) costs and WACC. The LCOE is an indicator of the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate. An electricity price above this would yield a greater return on capital, while a price below it would yield a lower return on capital, or even a loss.

2.4.1.1 Photovoltaic: price of modules, inverters, BoS, total system costs, LCOE

The analysis regard PV plants commissioned until 2015.

2.4.1.1.1 PV modules

The price of the PV modules has been decreasing in the past decades, thanks to the improvement of the design and technology, and to the optimization of the manufacturing process. The "learning curve" in Figure 44 ([8]) shows the decline of the prices of the PV modules since 1980.

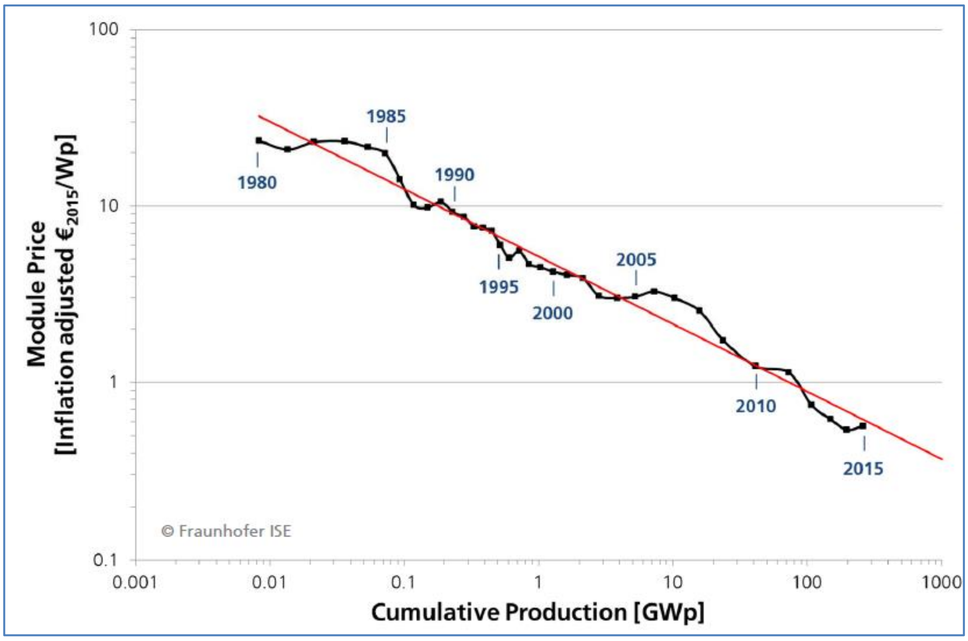


Figure 44 - Price Learning Curve (all commercially available PV technologies). Learning Rate: each time the cumulative production doubled, the price went down by 23 % for the last 35 years (Source: Fraunhofer ISE [8])

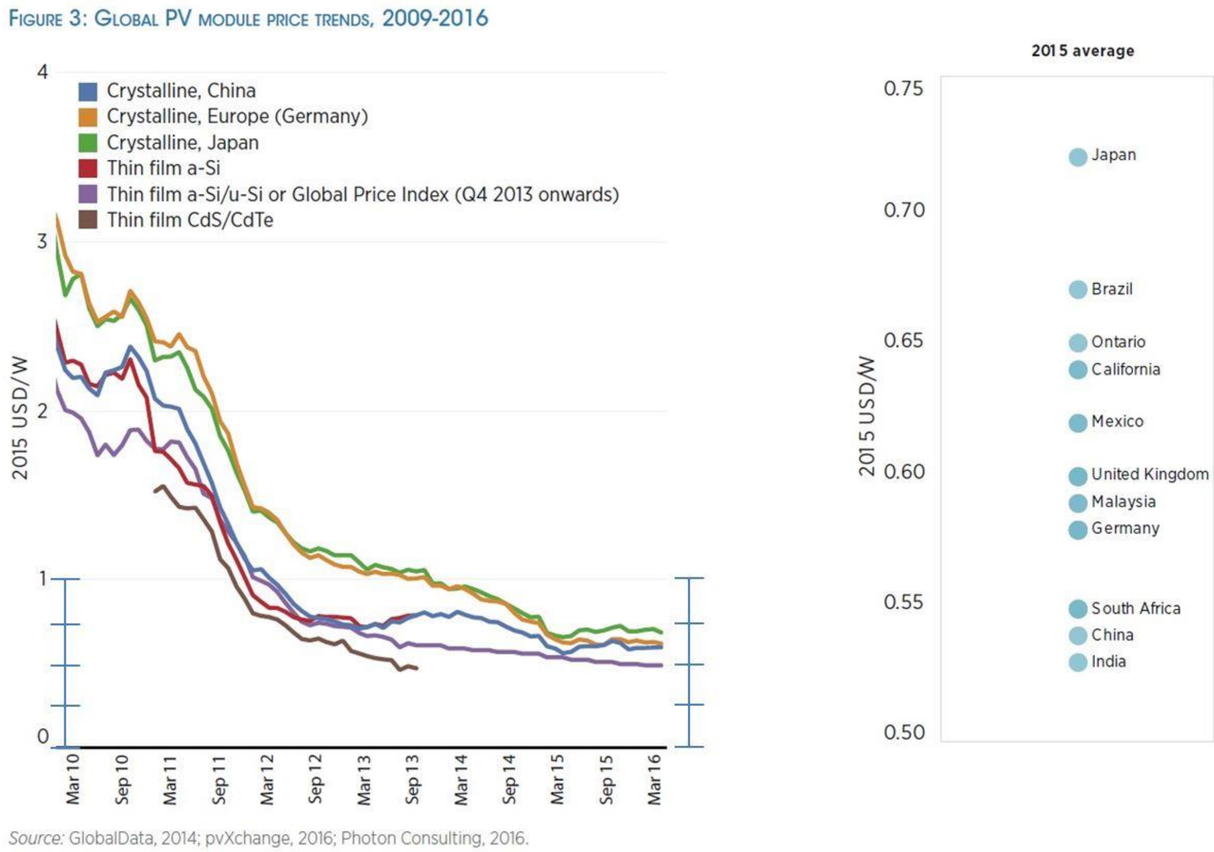


Figure 45 – Decrease of price of the PV modules since 2009-2016 (Source: IRENA [15])

The actual cost of the modules depends on technology, efficiency level, and overall product quality. Additionally it is worth to note that more than 90% of the modules are based on silicon cell technology.

The Figure 45 shows the decline of module prices - with reference to cell technology - in the latter 5 years, and country level module prices recorded in 2015. The trend shows that all technologies have reached price floors and suggests that the price decline may at least slow down for some time.
Based on these data we shall consider 0.6 USD/Wp as the current price of the PV modules. This is an international price and it should not be affected at regional or national level. This value is confirmed, for Brazil, on what is reported in the EPE Forecast Plan [4], in which a cost of 0.64 USD/Wp is considered.

2.4.1.1.2 Inverters

The Figure 46 reports on the cost of the inverters. Considering utility scale PV plants, a current inverter price of 0.15 USD/Wp shall be considered in the present study. This is an international price and it should not be affected at regional or national level.

TABLE 2: CURRENT SOLAR PV INVERTER TECHNOLOGY CHARACTERISTICS AND COSTS

Characteristic/Component	Central Inverters	String Inverters	Micro-Inverters
Power	> 100 kWp	< 100 kWp	Module power range
Efficiency	Up to 98.5%	Up to 98.0%	90.0-95.0%
Global 2015 prices (2015 USD/W)	~0.14	~0.18	~0.38
Power electronics	0.015	0.017	0.069
Control card	0.001	0.002	0.010
Filters	0.006	0.006	0.010
Distribution board and others	0.020	0.026	0.110
Indirect costs	0.075	0.100	0.117
Margin	0.023	0.030	0.063
Chinese manufacturers 2015 prices (2015 USD/W)	0.03-0.05	0.06-0.08	n.a.

Source: CREARA, 2016.

Figure 46 – Cost of inverters, 2016 data (Source: IRENA [15])

2.4.1.1.3 BOS – Balance of System

BOS costs are a significant portion of the price of PV plants. The contributions to BOS are listed below.

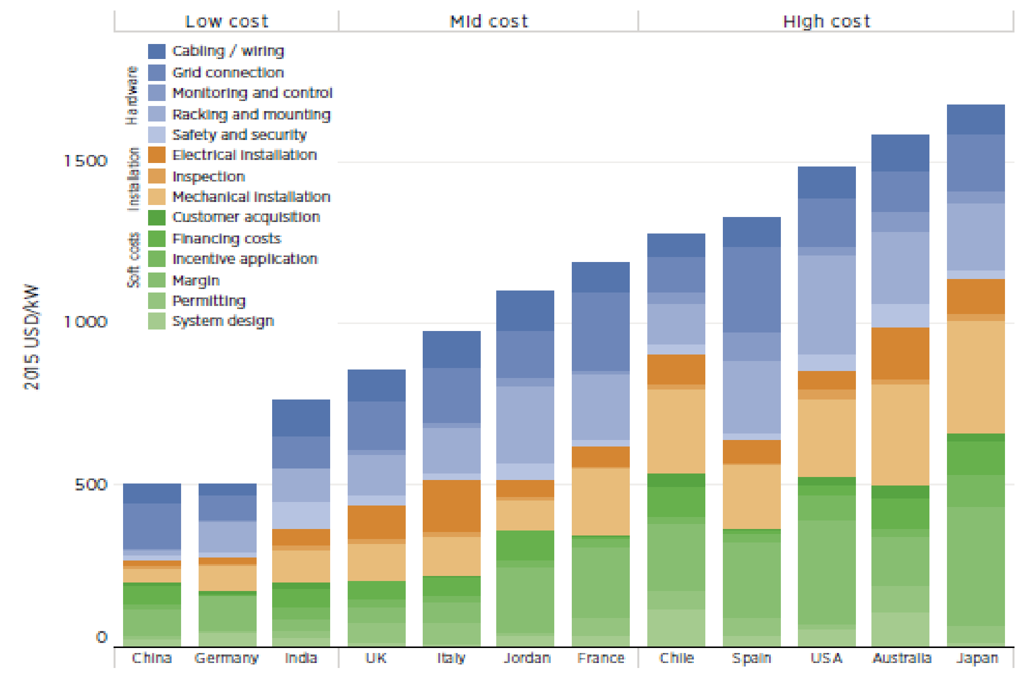
- Hardware (except PV modules and inverters). Cables and wiring, string boxes and panels to connect PV field and inverter, inverter and grid connection cabins and equipment (MV/LV transformer, controlgears/switchgears, monitoring system, etc.).
- Installation. Civil works, mechanical installation particularly of PV modules, testing and inspection to assure the PV plant is workmanlike constructed and commissioned.
- Soft costs. Project preparation until technical and financial close is achieved. Design of PV plant and of grid connection. Permits and any certificates required before the construction starts.

As shown in Figure 47, BOS costs range from 500 USD/kW (China, Germany) to 1700 USD/kW (Japan) and depend heavily on the country.

- China, Germany and India have lowest BOS costs. Germany accumulated a solid know-how in solar PV, both utility scale and distributed generation plants. China has become a leader in the mass manufacture of PV modules, China and India are also implementing huge capacity PV plants, thanks to low labour costs from engineering to commissioning.

- UK, Italy, France and Jordan occupy the intermediate cost level. Lower installation costs are recorded in Jordan, most probably for a lower cost of manpower.
- Countries like Japan, Australia, USA, Spain and Chile occupy the higher cost level.
    - Chile and Japan show a higher contribution from the "soft cost" category, which includes permitting and financing, most probably due to the recent start of the PV initiatives.
    - Spain shows a higher contribution from "hardware", most probably due to taxation and cost of import of equipment from abroad (similar to Jordan).
    - Instead Australia and Japan show very high installation costs.

FIGURE 2: DETAILED BREAKDOWN OF SOLAR PV BOS COSTS BY COUNTRY, 2015



Source: IRENA Renewable Cost Database.

Figure 47 – Breakdown of solar PV system BoS, 2015 (Source: IRENA [15])

Based on the IRENA data, no estimate is available for Argentina and Brazil, because the implementation of PV is a new topic in these countries. We can rely on general concepts and try to figure out how much the BOS could be. Furthermore a conservative approach should be adopted due to the scarce political stability of these countries, and the chance that government decisions and unexpected economic conditions may heavily affect the BOS costs in the future.

- Hardware. The hardware for PV is not available in Argentina and Brazil and it should be imported from overseas/abroad. For this component we could consider the highest cost level shown in Figure 47. This is represented by Spain, where this cost is about 600 USD/kW.
- Installation. This part of BOS costs depends largely on the cost of labour. The Table 19 shows the gross annual income by country and by two kinds of industry employees, construction worker and electrical engineer, that can be relevant for the implementation of renewable power plants like the solar PV and the wind generators in the countries of the LatAm region, as

well as in some European countries. It should be noted that the next information is general and not specific to the PV field.

Table 19 - Gross annual incomes (in USD/year) in the industrial sector ([16])

Town	Construction worker	Electrical Engineer
Buenos Aires	9921	16929
Lima	7220	18663
Santiago de Chile	10062	33944
Rio de Janeiro	7658	36006
Bogota'	4364	15556
Lisbon	11539	20684
Athens	10073	17222
Madrid	21992	31631

According to Table 19 labour costs for the system design could be lower in Argentina than in Brazil, whereas labour costs for installation works will be lower in Brazil than in Argentina. Regarding Argentina and Brazil, Spain could represent a suitable reference for the estimate of this cost component, which should be about 150 USD/kW.

- Soft costs. Argentina and Brazil have started the implementation of PV plants very recently, thus a prudent approach would suggest considering an amount slightly higher than in other LatAm countries as Chile. In the end, the soft component could cost about 600 USD/kW.

Based on the above analysis, the estimate of total BOS cost for Argentina and Brazil could be 1350 USD/kW.

2.4.1.1.4 Total PV system costs

IRENA analysed the total system costs recorded in the last decade (Figure 48). The weighted average for the year 2015 corresponds to 1.8 USD/W. Yet it is worth to notice that bottom prices as low as 1.0 USD/W and even lower were recorded with reference to year 2015.

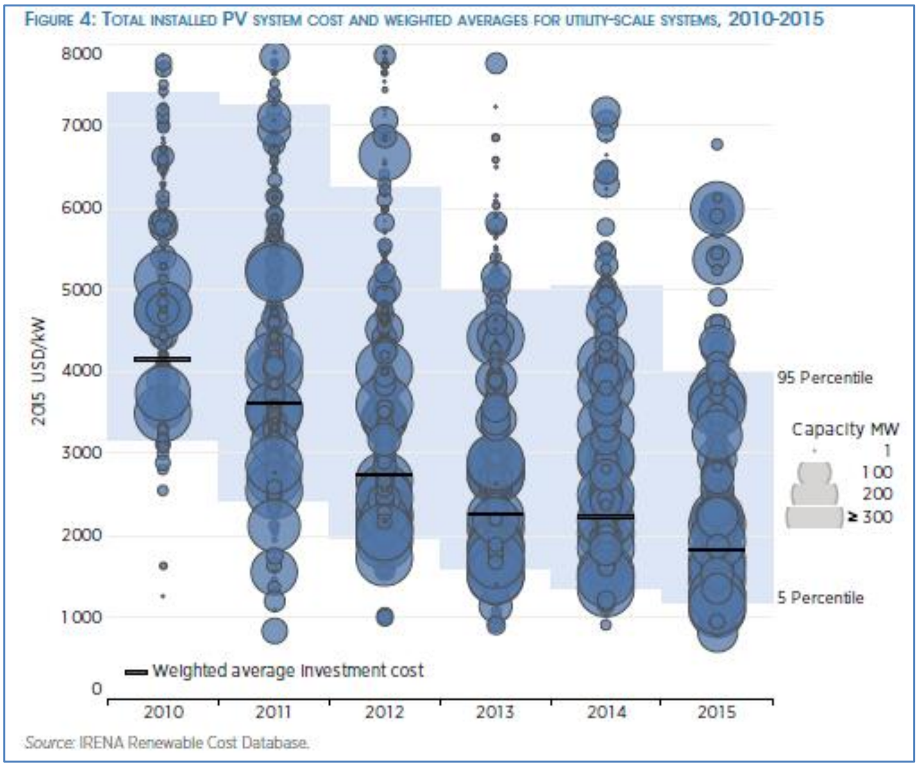


Figure 48 – Total cost of utility scale solar PV systems 2010-2015 (Source IRENA [15])

2.4.1.1.5 Operation and maintenance costs

Solar PV O&M costs have not historically been considered a major challenge to their economics. Yet, with the rapid fall in solar PV module and installed costs in the last five years, the share of O&M costs in the LCOE of solar PV in some markets has climbed significantly. O&M costs in some OECD markets, such as Germany and the United Kingdom, now account for 20‑25% of the LCOE (18-22 USD/kW per year if producibility were 1500 kWh/kWp). Data for the United Kingdom in 2014 suggested maintenance costs accounted for 45% of total O&M costs, land lease for 18%, local rates/taxes for 15%, insurance for 7%, site security and administration costs for 4% each, and utilities (including purchased electricity) for 2% (STA, 2014). Land lease costs are very site and market specific and can be essentially negligible or quite significant where land constraints are an important challenge, such as in densely populated locations. O&M costs for utility-scale plants in the United States have been reported to be between USD 10 and USD 18/kW per year (Lawrence Berkeley National Laboratory, 2015; Fu, et al., 2015).

Based on the above information included in the IRENA report, a conservative value such as USD 20/kW per year could be used as a reference cost for the O&M component, year 2015.

2.4.1.1.6 Cell technology and cost reduction

The information in the present paragraph are sourced from NREL ([17]) and IRENA report "Rethinking Energy" [18].

The market of the PV modules is dominated by the crystalline silicon (cSi) cell technology (93% market share). Monocrystalline cells are made from silicon manufactured in a continuous single crystal without grain boundaries; this cell type is more efficient and expensive than most other types of cells.

Multicrystalline cells are made from silicon manufactured in numerous small crystals forming grains; this is the most common type of cells, with a 69% share; these cells are less expensive but also less efficient than those made from monocrystalline silicon. The other consolidated types of cells rely on the thin film technology. Thin film cells are manufactured using three types of cell technology (market share): amorphous silicon (0,5%), copper indium gallium (di)selenide or CIGS solar cells (2,5%) and cadmium telluride or CdTe (4%). The CdTe is the only thin film material to rival crystalline silicon thus far in cost per watt. These thin film modules are used in some of the world's largest PV power stations.
The chart in Figure 49 is regularly updated by the National Renewable Energy Laboratory (NREL) to provide a concise view of the progress made by all types of PV cell. Multicrystalline silicon cells have reached 21.9% efficiency (about 15-17% efficiency of PV modules). Instead single crystal cells have reached 25.3% efficiency (about 20% efficiency of PV modules).

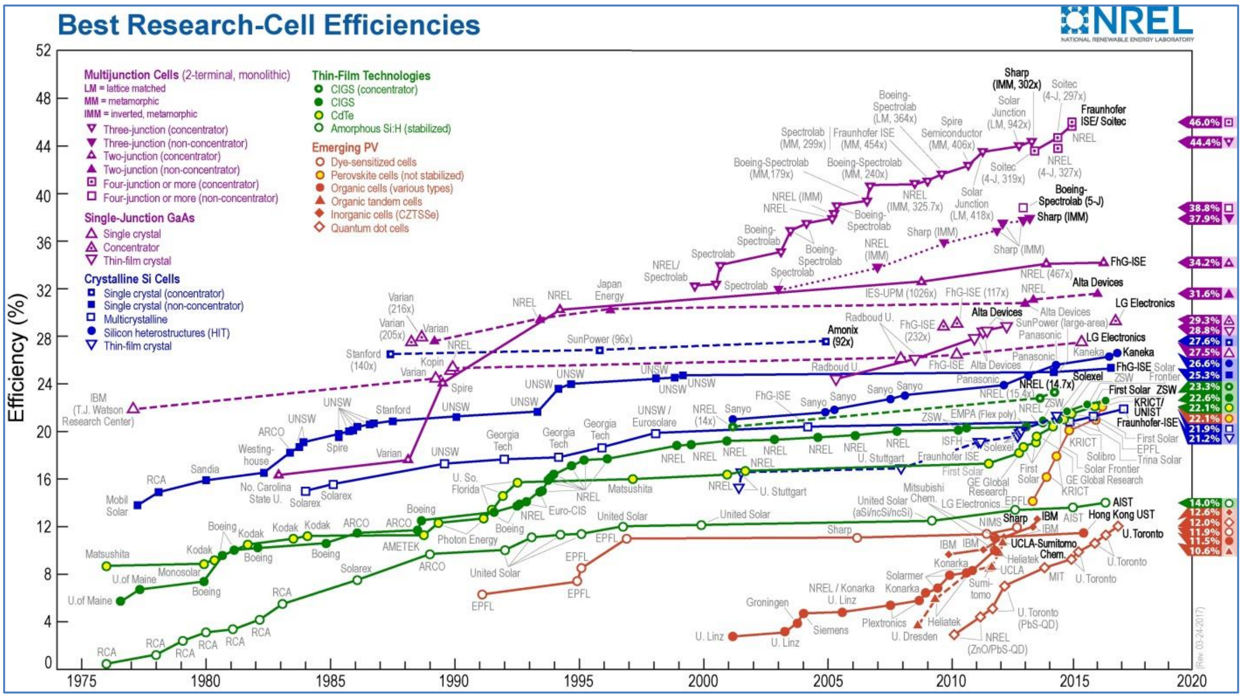


Figure 49 – Progress of PV cell efficiency since 1975

(Source: NREL https://www.nrel.gov/pv/assets/images/efficiency-chart.png)

The silicon technology has almost reached the theoretical performance limit (29%) and improvements capable to significantly change the present performance levels are not expected. Many non-silicon technologies are under development including the more advanced thin films such as CdTe but it is still unclear if this type of cell (as well as other types of cells based on the new technologies) could become more efficient than the silicon cells.
Based on the above information, the price of the PV modules could still decline in the future although at a lower rate, thanks to marginal improvement of the cell efficiency and/or further optimization of the manufacturing process and costs.

2.4.1.1.7 Inverters estimate of PV module cost reduction

The cost reduction potential for solar PV inverter technologies out to 2025 will be driven by two types of opportunities: technological progress and economies of scale. The latter will be driven by the increased presence of Asian players in international markets.
IRENA reported that analysts have estimated a maximum decrease of inverter costs of around 40% towards 2025 (Figure 50), with annual price reductions in the order of 8-9% per annum to 2020.

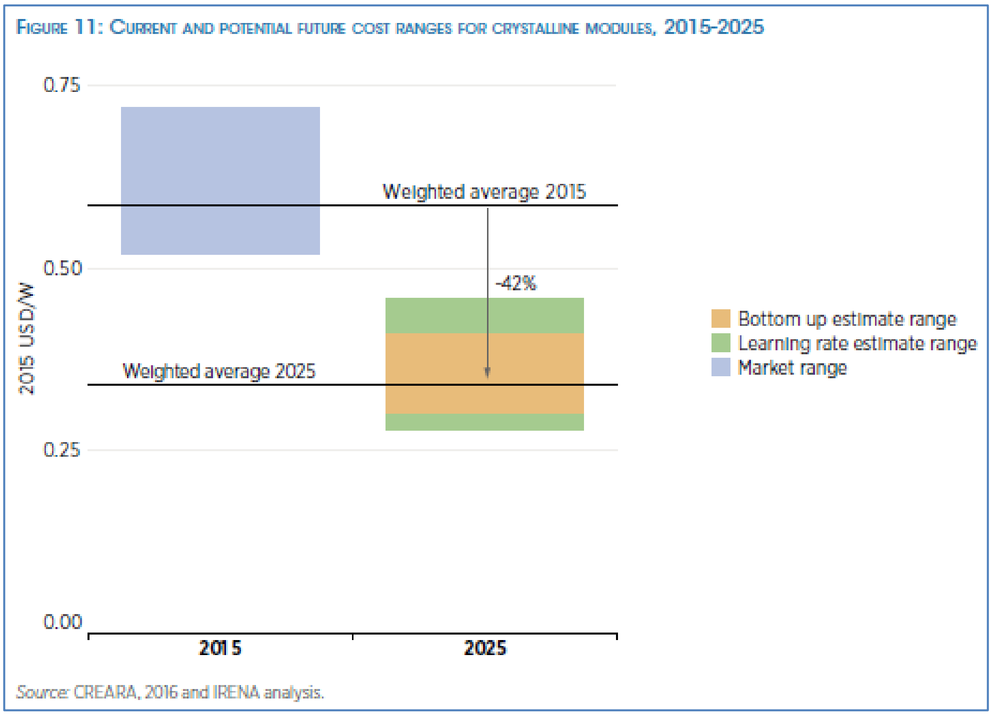


Figure 50 – Cost of the PV modules, projections to 2025 (Source: IRENA [15])

2.4.1.1.8 Estimate the reduction of PV costs

IRENA identified that the global average total installed cost of utility-scale PV systems could fall from around USD 1.8/W in 2015 to USD 0.8/W in 2025 (Figure 51). Taking into account the uncertainty of the different cost drivers, the actual range of this 57% reduction could be between 43% and 65%.
IRENA studied the contribution of the different components to the possible reduction of the costs, particularly the two most important components, the PV module and the BOS costs.
Until now the cost reductions have been driven by PV module and, to a lesser extent, by BOS. With the current module prices between 0.5 and 0.7 USD/W, more opportunities are foreseen from the continuous reduction of the BOS costs.
For this reason IRENA expects that the major cost reduction (about 70%) will come from lower BOS costs, as shown in Figure 51. This average estimate of reduction has to be adapted to the country conditions. For example a PV plant installed in Germany can have a current total cost (0,6+0,15+0,5)=1,25 USD/W. When estimating the price this system may cost in 2025 we must take into account that BOS costs cannot be reduced much further compared to the present value (500 USD/kW), and thus a lower reduction shall be considered.

Regarding the expected cost reductions, IRENA envisaged the average percentages listed below.

- PV module costs could fall by 42% (Si crystalline modules, the predominant cell technology).
- BOS costs for utility scale PV plants could fall by 31% in more efficient markets and by up to 69% in less efficient markets, assuming policies are in place to accelerate convergence in costs.

These cost reductions could cause the global average PV price in 2025 to be in the range of USD 0.63 – 1.04 per Watt, that are the two level 20% lower and 32% higher than the average estimate 0.8 USD/W.

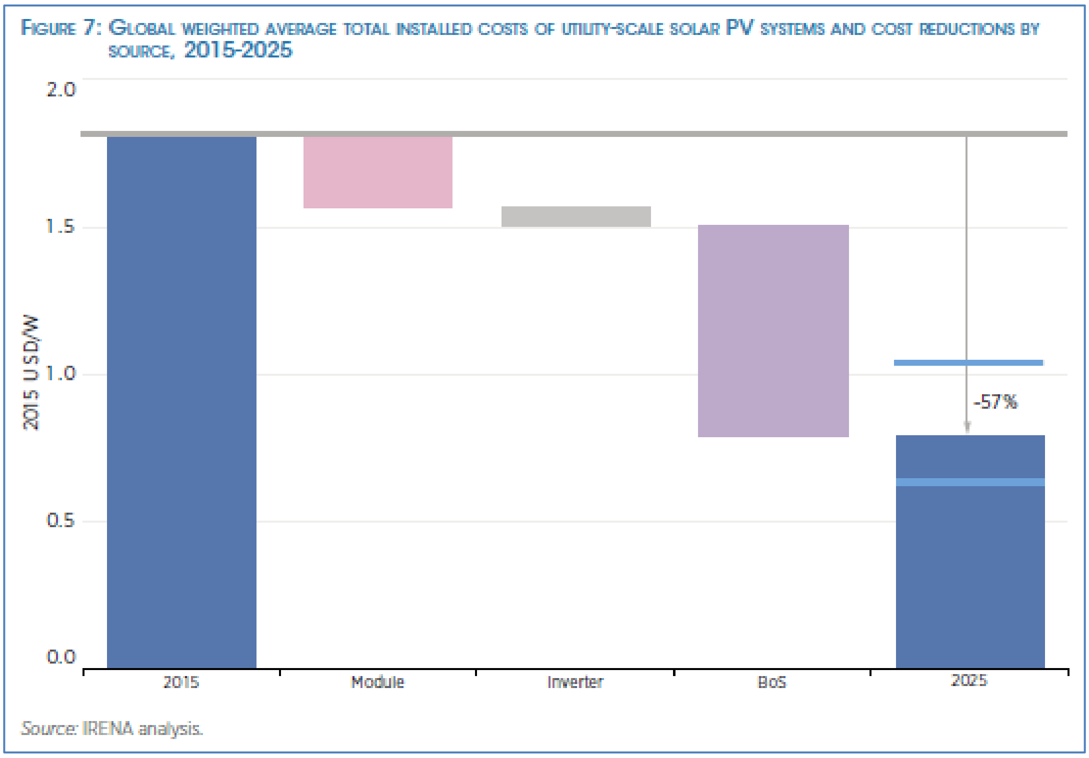


Figure 51 – Estimate of cost reduction between 2015 and 2025 (Source: IRENA [15])

2.4.1.1.9 LCOE

For the completion of the information reported, this paragraph describes the LCOE advertised in the latter years, regarding the prices that system developers offered in the frame of international tenders. The Figure 52 shows the LCOE of utility scale solar PV plants in the two years between 2014 and 2015.

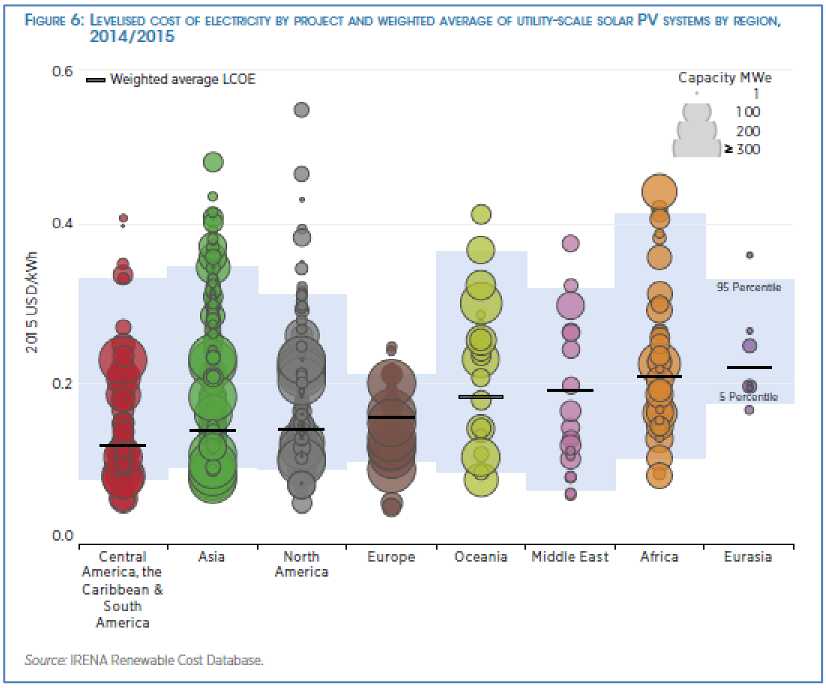


Figure 52 – LCOE of utility scale solar PV plants 2014-2015 (Source: IRENA [15])

Significant reductions of LCOE have been recorded based on the information that regards the contracts awarded since 2015. However, care should be paid for the advertised figures are representative of the electricity price that developers specified in the tendering process, with respect to the stipulation of PPA or similar agreements with the owner or the off-taker.

The IRENA report analyses the difference between the cost of the PV plant and the LCOE.

As highlighted in the IRENA report, the LCOE represents an indicator of the price of electricity required for a project in which revenues would equal costs. This includes making a return on the capital invested equal to the discount rate, while excluding the impact of existing government incentives or financial support mechanisms. For solar and wind technologies in particular, various PPA prices have been announced recently in different locations. With such developments, it can become harder to distinguish between these "record" prices and the LCOE concept as discussed in this report.

These very low PPA prices often cannot be compared to the LCOE, for the end PPA prices may depend on a set of obligations and contract-defined terms that are very dependent on the specific market situation of the project setting. Assumptions made to calculate them usually differ from the more standardised ones used for the LCOE indicator calculations. There is also the chance that if these conditions are not fulfilled, the PPA price may not materialize – if, for example, the independent power producer (IPP) does not fulfil the output requirements or electricity quality. In extreme cases, the deficiencies in the initial winning bid may see a developer walk away from the project as the financial penalties incurred are lower than the expected loss if the project is completed.

As an example of the potential differences between PPA prices and LCOEs, in 2015 a United States solar PV developer agreed to sell power at a record low headline price of USD 0.0387/kWh from a 100 MW solar plant to utility NV Energy. However, it was not widely quoted that this price included a 3% escalation clause and that according to a filing with the Public Utilities Commission of Nevada the LCOE of the project was estimated at about USD 0.047/kWh after the Investment Tax Credit (Public Utilities Commission of Nevada, 2015). Allowing for the impact of the 30% Investment Tax Credit raises the electricity price to around USD 0.066/kWh (70% higher than the headline value).

2.4.1.1.10 Estimate the costs of PV in Argentina and Brazil and projections to 2030

Based on the above data and analysis, a breakdown of the cost of a utility scale PV system can be provided for years 2015, 2025 and 2030.

The analysis of the average cost of a PV plant (USD 1.8/W, year 2025) considered the different cost components: PV modules, inverter, and BOS. Standard international estimates were considered for PV modules and inverter costs; in regards to the BOS costs possible differences were considered between the countries, Brazil and Argentina.

An average 57% decrease can be expected for the projection to year 2025, according to Figure 51. Percentages of decline specific to PV modules, inverters, and BOS costs (these ones different by country) were considered. The BOS component has been further analysed in order to get an estimate of this cost with respect to Brazil and Argentina, and an estimate of the cost of a PV plant in this countries.

Finally the forecast to 2025 was extended to get an estimate for the year 2030. Based on the decline expected between 2015 and 2025, and adopting a conservative estimate for the year to follow, a further 20% reduction of the total PV costs was assumed, for both Brazil and Argentina.

Finally USD 20/kW per year is used as a reference O&M cost for the year 2015, and about half the decline of the BOS costs between 2015 and 2030.

The detailed values for year 2015 and the projections to 2025 and 2030 are summarised in the Table 20.

Table 20 – Evaluation of PV costs in 2015 and projections to the year 2025 and 2030 – Estimation based on IRENA figures

Prices in USD/W	**Brazil**			**Argentina**
Averaged historical data referred to year 2015				
PV modules	0.60			0.60
Inverter	0.15			0.15
BOS	1.35			1.35
Total	2.10			2.10
O&M (per year)	0.02			0.02
Projection from year 2015 to year 2025				
		Fall expected		
PV modules	0.27	55%		0.27
Inverter	0.09	40%		0.09
BOS	0.675	50%	50%	0.675
Total	1.035	51%	51%	1.035
O&M (per year)	0.015	25%	25%	0.015
Projection from year 2025 to year 2030				
		Fall expected		
PV modules	0.216	20%		0.216
Inverter	0.072	20%		0.072
BOS	0.54	20%	20%	0.54
Total	0.828	20%	20%	0.828
O&M (per year)	0.0115	10%	10%	0.0115

2.4.1.1.11 Projection of LCOE for the solar PV plants

According to IRENA, the LCOE of utility-scale PV systems is expected to continue its downward trend towards 2025, driven by lower BOS costs and further reductions in PV module costs.

The Figure 53 shows the LCOE range for utility-scale PV projects from 2010‑2015 and a projection towards 2025. From 2010‑2015, the capacity weighted average LCOE decreased 58%. The LCOE of utility-scale PV systems is expected to continue its decline. The global weighted average LCOE could decline from USD 0.13/kWh in 2015 to USD 0.055/kWh by 2025 (-59%). This trend is in line with recent PPA and tender results for solar PV around the world, bearing in mind that they are not necessarily directly comparable with an LCOE calculation. In 2015 and 2016, record low prices were set for projects to come on line in 2017 and 2018 in the United Arab Emirates (USD 0.058/kWh), in Peru (USD 0.048/kWh), and Mexico (a median price of USD 0.045/kWh). In May 2016, an auction of 800 MW of solar PV in Dubai attracted a bid as low as USD 0.03/kWh. This LCOE projected range also accounts for differences such as irradiation levels in different countries and the expected costs of the PV systems. The lower boundary of the projected LCOE range in Figure 53 is not inconsistent with estimates from other relevant studies (SEMI "ITRPV 2015", ed. 2016) in which LCOE by 2026 were estimated in the range of USD 0.03-0.06/kWh (for 2000-1000 kWh/kWp), and for a system cost of USD 763/kWp.

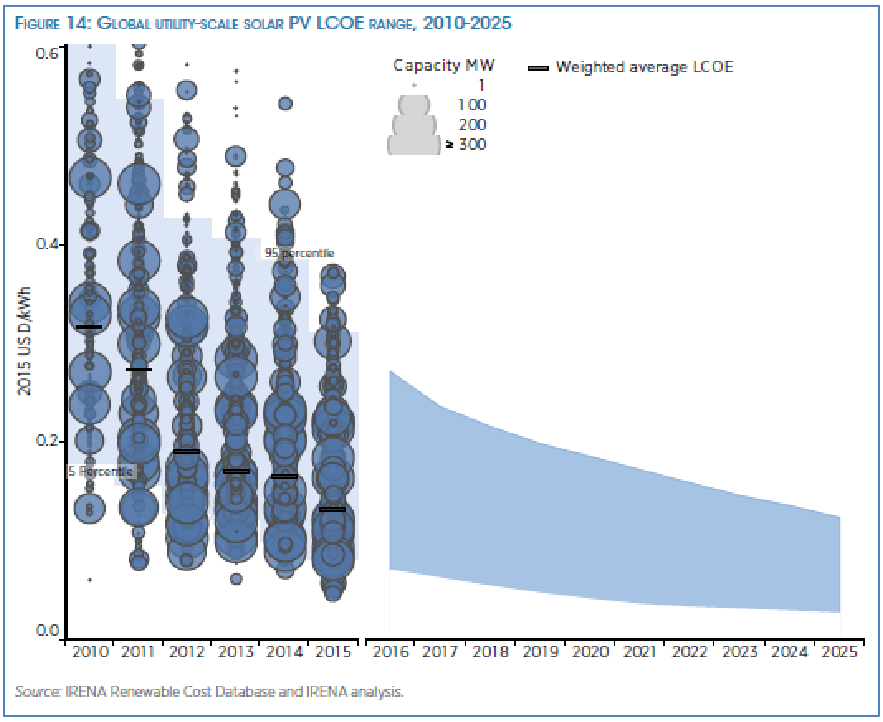


Figure 53 – LCOE of the PV systems, projections to 2025 (Source: IRENA [15])

The trend shown in Figure 53 could be used as a reference for analysing future LCOE of utility scale solar PV plants: for example a possible projection to 2030 may be achieved by the interpolation of the available weighted average LCOE data.

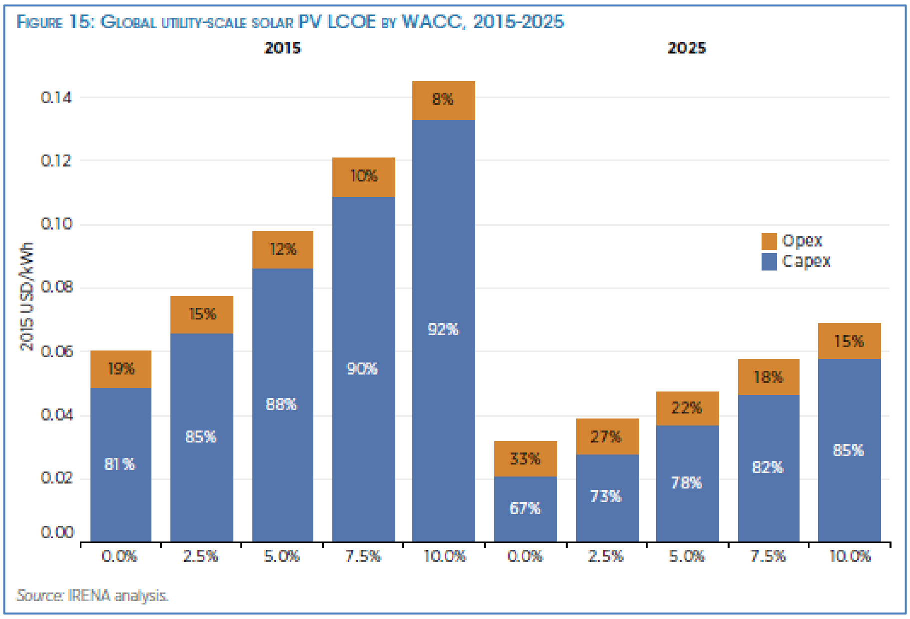


Figure 54 – LCOE of PV systems by WACC, comparison 2015 and 2025 (Source: IRENA [15])

Figure 54 shows a sensitivity analysis for the LCOE to different WACC levels. The share of capital expenditures in 2015 ranges from 81% (0%WACC) to 92% (10% WACC). In the 2025 scenario, the capital expenditures are expected to range from 67% (0%WACC) to 85% (10%WACC).

Further comments can be added to the above data analysis from IRENA. Particularly record low prices for very large solar PV project in 2016 might be difficult to justify according to the standard evaluation of LCOE presented in the IRENA study. IRENA remarked that these LCOE calculations can sometimes differ with respect to the figures communicated, based on international auctions and tenders. Regarding the evaluation of these record low prices, further comments are provided below.

- A very large PV field can be commissioned according to a schedule that could last some years. In this case a project developer, when defining the price offered in 2016, can consider that the PV equipment will be cheaper in the following years.
- The record low prices recently communicated regard agreements negotiated in 2016, in the date when the project was awarded. However these PPAs will come in force after the PV plants will be commissioned. As IRENA mentioned, further possible agreements like price escalation or tax reductions can significantly affect the costs of the projects, and provide justifications for assumptions that can reduce the net price offered by the project developers.
- Electricity and Water authorities in the Middle East, DEWA (Dubai) and ADEWA (Abu Dhabi) tendered large utility scale PV projects. DEWA is taking part to the company that is developing the 200 MW solar PV plant and Phase II of the Al Maktoum Solar Park, the site that will host 5GW of solar power according to the energy strategy of the Emirate of Dubai.

2.4.1.2 *Wind: price of wind turbines, BOS, total system costs, LCOE*

The capital costs of a wind power plant can be assigned to four major categories:

- turbine cost: rotor blades, gearbox, generator, power converter, nacelle, tower and transformer;
- civil works: construction works for site preparation and foundations for towers;
- grid connection costs: transformers, substations and connection to the local distribution or transmission network;
- planning and project costs: development cost and fees, licenses, financial closing costs, feasibility and development studies, legal fees, owners' insurance, debt service reserve and construction management.

2.4.1.2.1 Price of wind turbines and wind projects

Charts in Figure 55 and Figure 56 show respectively the prices of the wind turbines and the prices of the wind projects. The figures highlight a significant variability of the advertised prices, which recommend a careful assessment of these data.

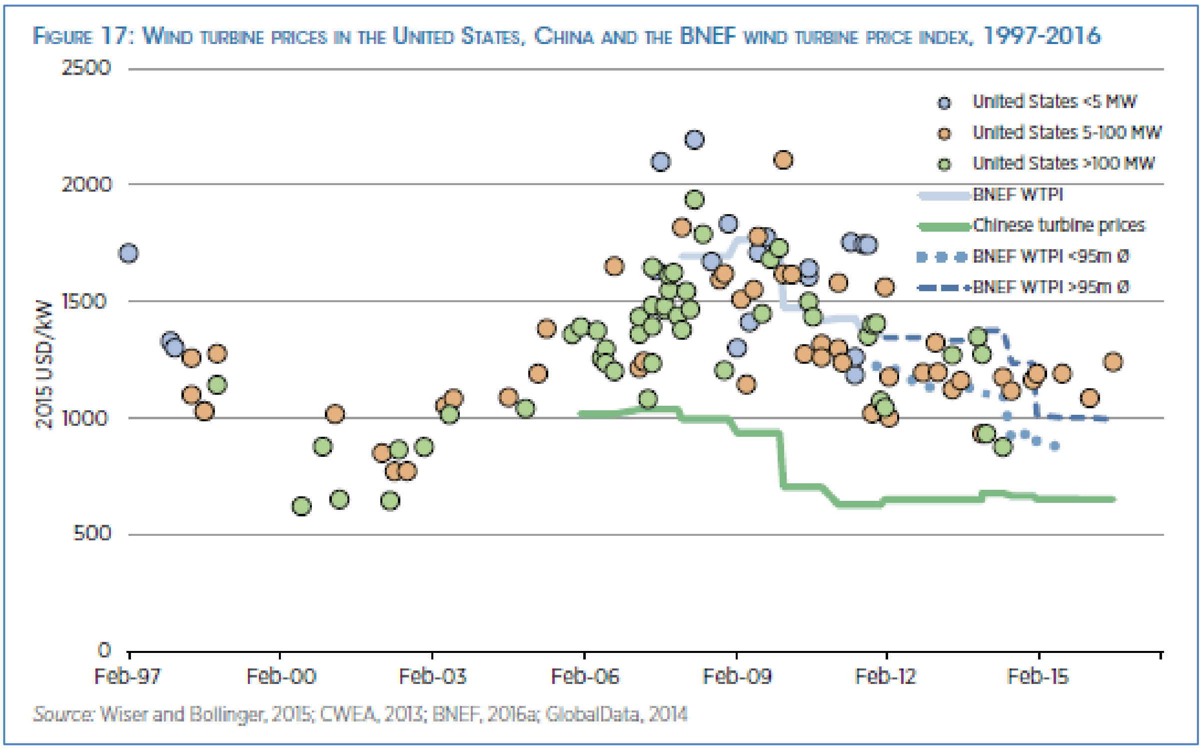


Figure 55 – Prices of wind turbines, 1997-2016 (Source: IRENA [15])

Figure 56 shows the total installed costs of wind projects (annual weighted averages or individual project data) from 12 different countries. On average, a doubling of the cumulative installed capacity of onshore wind between 1983 and 2014 resulted in a 7% reduction in weighted average installed costs. Globally, the installed costs of onshore wind have seen a significant decline since the early 1980s. Global weighted average installed costs declined from USD 4766/kW in 1983 to USD 1623/kW in 2014. Data for 2015 suggest that the global weighted average installed cost of onshore wind may have fallen to around USD 1560/kW. The increase in turbine prices between 2002 and 2008/2009 was balanced by China and India emerging as markets with lower cost structures than other regions. Total installed cost ranges by country are quite wide and not uniformly distributed. Average costs in China were the lowest in the world in 2014 and 2015, at around USD 1270/kW. India rivalled China in low installed costs, which averaged around USD 1325/kW. Outside these two countries, average installed costs are higher and their ranges wider. This is because other countries and regions do not benefit from the low local commodity prices, low-cost labour and manufacturing bases available in China and India and projects are more diverse in nature. A key driver of cost reduction has been the growth in economies of scale that have been experienced as the market has grown from 6.6 GW of new installations globally in 2001 to 59.5 GW in 2015. Other drivers include greater competition among suppliers and technological innovation. The latter has driven costs down and through higher rated turbines, hub heights and rotor diameters that have increased yields from the same or lower wind resource. Additionally, improved logistical chains and streamlined administrative procedures contributed to the observed cost declines.

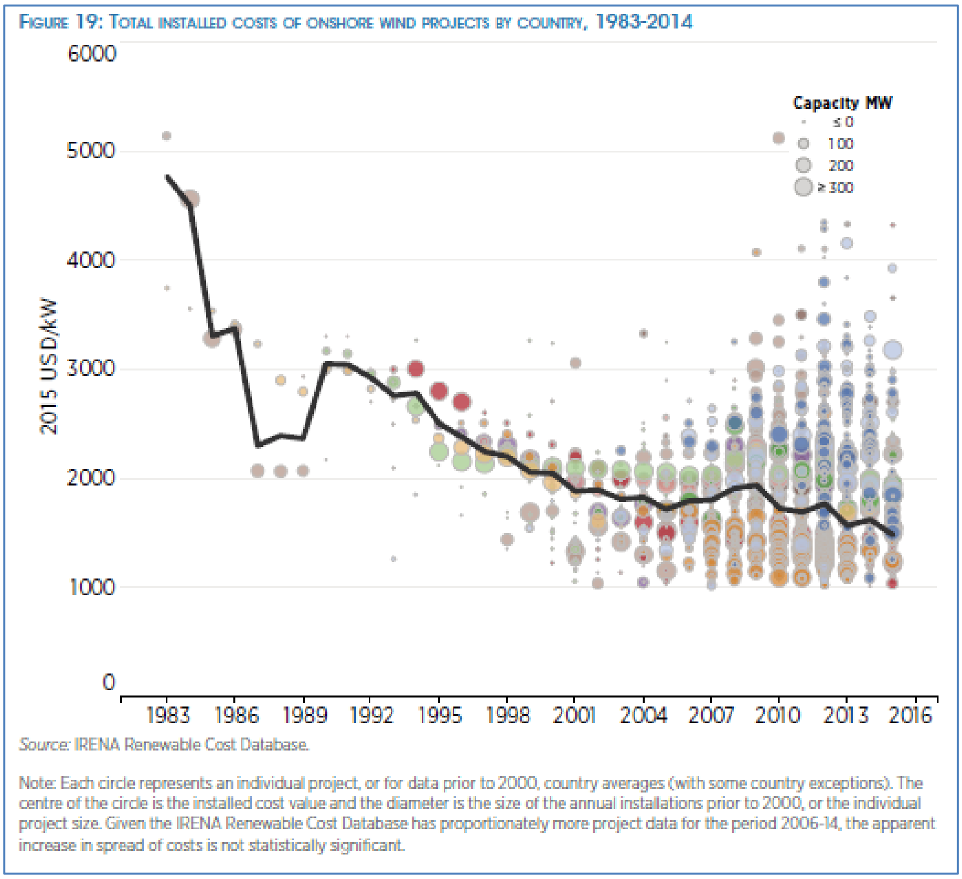


Figure 56 – Total cost a wind projects, 1982-2014 (Source: IRENA [15])

According to the data IRENA reported, the average price of the wind projects (year 2015) was about USD 1560/kW.

Wind turbines, including towers and installation, are the main cost components in developing wind projects. According to the literature, the turbines can account for between 64% and as much as 84% of an onshore wind project's total installed costs, the more predominant range being 64‑74% of installed costs; the actual percentage can depend on several factors including the country. In this regards we can assume that the turbines account 65-75% of the project costs, whereas the other cost components that can be qualified as the BOS, account the remaining 25-35% of the project costs.

2.4.1.2.2 Comments regarding the BOS costs

The BOS component includes costs further than the turbine costs, which can be associated with the stage of pre-development of the wind project, the construction on-site, and the additional works required for the connection of the wind farm to the grid.

The drivers and the country dependence of these BOS costs are rather complex and difficult to analyse. For example, in regards to the grid connection, costs can vary significantly, especially when the project site is far from the available transmission infrastructure. Construction costs depend on local labour and material costs, additionally the topography of the project site can affects these costs very much. Project sites that are distant from demand centres or close to mountains may require extensive civil works, and result in higher construction and transportation costs. The costs for getting the required permits can represent a significant challenge for wind projects, for dedicated environmental impact studies are usually required. The time required for getting the grid connection is another important issue especially if the connection is provided much time after to the completion of the wind project.

As mentioned in the previous paragraph, based on the IRENA report, the BOS costs are about 25-35% of the overall project costs (for PV the range can be 40-65%).

Additionally, based on the comments reported with reference to the cost of labour in the section devoted to PV, the BOS costs will be assumed the same for Brazilandr Argentina

2.4.1.2.3 Capacity factors

Higher hub heights and larger rotor diameters have played a key role in increasing the average capacity factors of wind farms. Larger rotor diameters increase the swept area of wind turbines, which has a linear positive relationship with energy capture. Thus, the energy capture of the respective wind turbine increases for the same wind resource, driving upwards the capacity factors. This is despite the fact that in some markets there is an increased share of lower quality wind sites being developed than previously. The Figure 57 highlights the 35% increase of the global average capacity factors between 1983 and 2014, raised from 20% in 1983 to 27% in 2014. Capacity factors vary significantly by region, driven predominantly by resource quality. Higher hub heights and rotor diameters account for the vast increase in capacity factors observed over the 32 years. Improvements in wind farm development (e.g., better micro-siting of turbines based on more detailed wind resource analysis) and improved wind turbine reliability helped to increase the capacity factors of onshore wind. Additionally, thanks to the increase in capacity factors due to better technology, the turbines optimised for low wind speed have allowed developers to exploit lower resource wind sites that were previously uneconomical.

An additional advantage is that wind turbines with larger swept areas tend to have more constant wind output, helping to smooth output variability to a certain extent.

Both the price and the LCOE of the wind projects can benefit of the increase of these capacity factors.

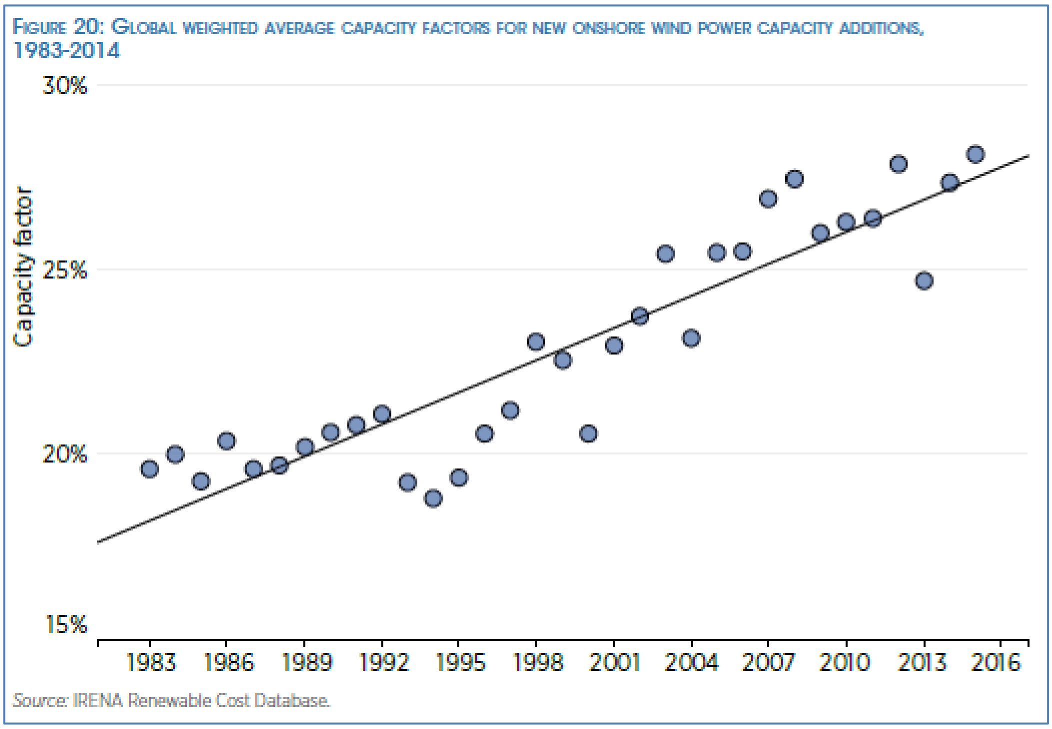


Figure 57 – Increase of capacity factor for new wind power capacity, 1983-2014 (Source: IRENA [15])

2.4.1.2.4 Operation and maintenance

According to Wind Europe, O&M costs can account for 20‐25% of the total LCOE of wind power systems in Europe. Unfortunately data for actual O&M costs from commissioned projects are not widely available. Indeed, even where some data are available, care must be taken in extrapolating from historical O&M costs, for two main reasons. One issue is the changes occurred in wind turbine technology over the last two decades. Another issue is that cost data for operations (management costs, fees, insurance, land lease payments and local taxes) are not systematically collected. However it is clear that the annual average O&M costs of wind power systems have declined substantially since 1983. BNEF data show that between 2008 and 2015 full-service maintenance contract prices fell by 27%. Total O&M costs reported by publicly traded developers in the United States were around USD 0.024/kWh in 2013. A survey of more than 5000 wind turbines installed since 2006 in Denmark (Manwell et al., 2009) has shown that with higher rated turbines, O&M costs have declined from 3% of CAPEX per year to 1.5-2% of CAPEX.

The Figure 58 presents data for the O&M costs reported for selected countries. An average value of around USD 0.02 to 0.03/kWh would appear to be the norm, but the data are far from comprehensive or conclusive. In non-OECD countries O&M costs are lower and assumed to be USD 0.01/kWh (IRENA, 2015). Most developers prefer their first O&M contracts, typically from the turbine manufacturer, to last three to five years so that they benefit from future cost reductions in O&M prices or create the in house O&M capabilities in order to better control O&M costs (MAKE Consulting, 2015).

Table 5: Reported O&M costs in selected OECD countries	Variable (2015 USD/kWh)	Fixed (2015 USD/kW)
Austria	0.040	
Denmark	0.0161-0.018	
Finland		37-40
Germany		75
Italy		50
Ireland		74
Japan		76
The Netherlands	0.0138-0.0180	
Norway	0.022	
Spain	0.029	
Sweden	0.0106-0.0351	
Switzerland	0.046	

Source: IEA Wind, 2011.

Figure 58 – O&M costs in selected countries (Source: IRENA [15] - IEA Wind 2011)

Based on the above information included in the IRENA report, the level of USD 0.02/kWh could be used as a reference cost for the O&M component for both Brazil and Argentina. This value represents the average between the maximum cost for OECD countries and cost level for non-OECD countries.

2.4.1.2.5 LCOE of wind projects

The LCOE of a wind power project is determined by:

- total capital costs,
- wind resource quality,
- the technical characteristics of the wind turbines,
- O&M costs,
- the economic life of the project and the cost of capital.

As with today's range of installed costs, the LCOE also varies by country and region.
Figure 59 presents the LCOE of wind power by region and country in 2014-2015. The weighted average LCOE by country or region ranged from USD 0.053/kWh in China to USD 0.12/kWh in Other Asia. North America had the second lowest LCOE after China, with USD 0.06/kWh. Eurasia (USD 0.08/kWh), Europe (USD 0.07/kWh) and India (USD 0.08/kWh) had slightly higher average LCOEs than China and North America, but exhibited a range of very competitive projects. Lastly, but not far behind, are Central and South America, Oceania and Africa with weighted average LCOEs of between USD 0.08 and 0.10/kWh. In 2014 and 2015, the best wind projects delivered electricity at between USD 0.04-0.05/kWh. Some regions will see significant declines in the weighted average LCOE of newly installed projects in coming years as regional markets gain scale; notably South America where lower-cost Brazilian wind farms will come on line in 2016.

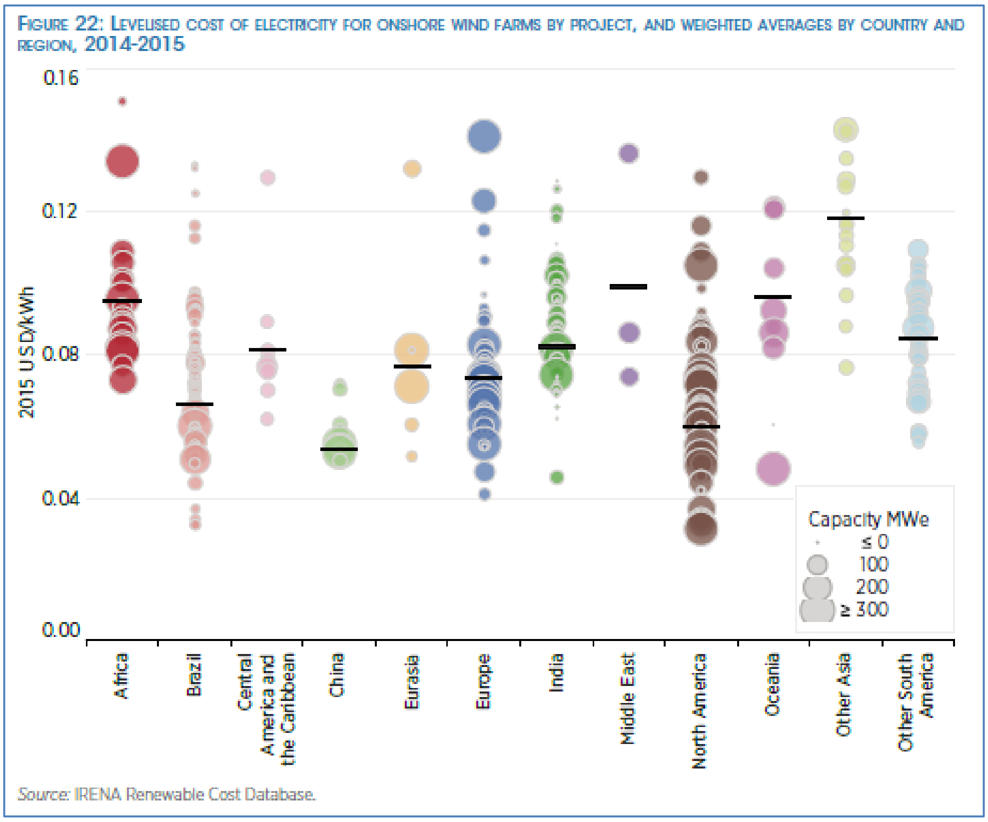


Figure 59 – LCOE of wind projects by region, 2014-2015 (Source: IRENA [15])

2.4.1.2.6 Cost reduction potential

Onshore wind still holds significant cost reduction potential for the period out to 2025. IRENA assessed the cost reduction potential based on the analysis of learning curves (top-down analysis), and looking at the future developments (bottom-up analysis) that regards both higher performance turbines and technology innovations. Furthermore the contribution of increased market scale and maturity were estimated based on trends in turbine pricing and analysis.

IRENA reports that the reduction of the LCOE of onshore wind out to 2025 will be based on the key factors described here below.

1. Improvements in the turbine design and materials. Larger turbines will lower installed costs through economies of scale. Advanced blades can raise electricity output. Advanced towers can reduce installed costs, relative to conventional steel towers, in order to access higher average wind speeds or "smoother" winds at greater heights.
2. Improved O&M. Best practices can reduce turbine downtime and raise electricity yields, while reducing maintenance costs from unscheduled malfunctions.
3. Development of manufacturer organization. Lean supply chains and increased competition will reduce installed costs. Best practices can also reduce development and installation costs.

In the next paragraph the potential of cost reduction will be further described.

2.4.1.2.6.1 Wind turbines

Cost reduction potentials are related to turbine and nacelle components, towers and blades. Increased supply chain optimisation and competition could drive down costs further. Average blade lengths are growing as the trend to larger turbines and greater swept area drives increased electricity yields. Reducing the transportation and installation costs of blades 70 m in length is becoming a priority. Weight is also becoming an issue for these blades and manufacturers are investigating novel manufacturing techniques e.g. reducing fibre misalignment, using advanced materials, redesigning the blade roots and looking at more slender air-foils and structural load management strategies to reduce weights while maintaining structural integrity (MAKE Consulting, 2015).
The trend towards higher-rated turbines (Figure 60), particularly the 3 MW, presents the opportunity to introduce further innovations. These include hybrid drivetrains, unique structural architecture and different yaw and pitch system arrangements on a range of semi-standardised platforms optimised for different wind environments. Standardised turbine platforms offer economies of scale, spreading the development costs over a wider product line. General Electric, Siemens and Vestas have all roughly doubled the number of offerings in their portfolio since 2010. Utilising the same structural components across a given platform can mean up to 50% of the turbine components are identical, significantly reducing development costs and unlocking supply chain efficiencies.

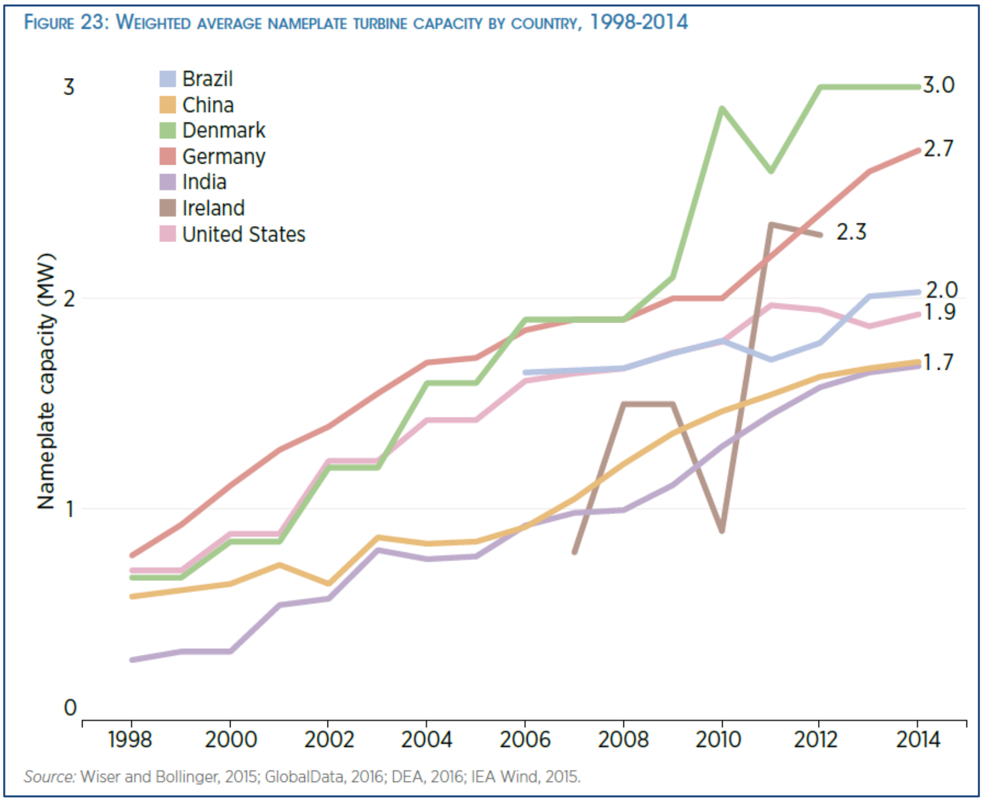


Figure 60 – Increase of average turbine capacity by country, 1998-2014 (Source: IRENA [15])

Advanced, taller towers are an important part of future electricity cost reduction potential by unlocking greater wind resources at higher heights and areas with good wind resources, but otherwise unsuitable for shorter, conventional towers (e.g., forested areas needing higher height clearance). Although taller towers typically cost more, due to the necessity of supporting increased loads, efforts to reduce the materials used for towers while maintaining the same structural limits can help reduce installed costs. General Electric's space frame tower, Siemens' bolted shell tower and Vestas' large diameter steel towers are designed to reduce logistics costs and the challenges of tall towers, while avoiding the need to use expensive concrete towers. By increasing the base diameter, these innovations allow reduced thickness for the same load and reduced material costs relative to conventional steel towers. Overall cost reductions for the global weighted average installed cost could average around 12% between 2015 and 2025, taking into account the trend towards larger turbines, with higher hub heights and larger swept areas. This bottom-up estimate is within the range of the learning rate of 7% for total installed costs identified by updated onshore wind learning curve and the IRENA Remap projections to 2030 (IRENA, 2016).

Turbines and towers account for the largest share of the installed cost reduction potential to 2025 (Figure 61). These account for 27% and 29%, respectively of the total reduction in the global weighted average installed cost of onshore wind farms (IRENA and MAKE Consulting, 2015). Yet, the increased application of best practices in wind farm development by project developers and regulators could yield around one quarter of the total cost reduction. Best practices include streamlined project approval procedures and nationally agreed evaluation criteria for local consultation. Supply chain and manufacturing economies of scale account for around 13% of the total cost reductions and advanced blades for the balance.

According to the IRENA report, the global weighted average total installed cost for onshore wind could fall from around USD 1560/kW in 2015 to USD 1370/kW in 2025.

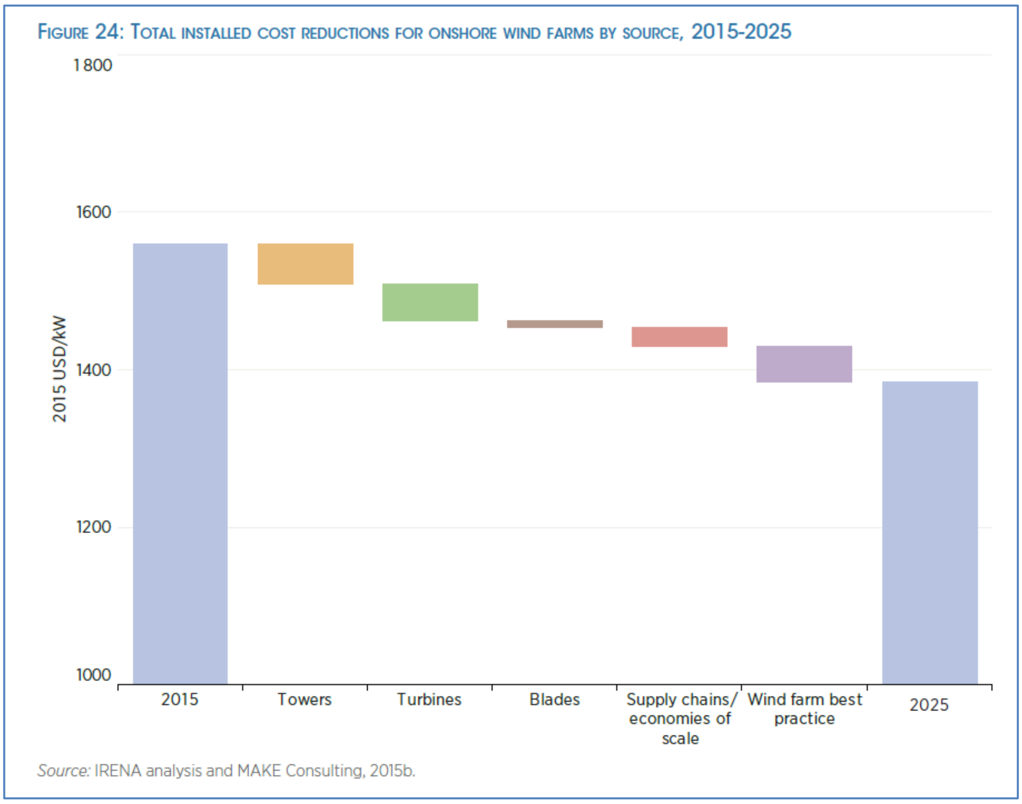


Figure 61 – Total installed cost reduction potential, projections to 2025 (Source: IRENA [15])

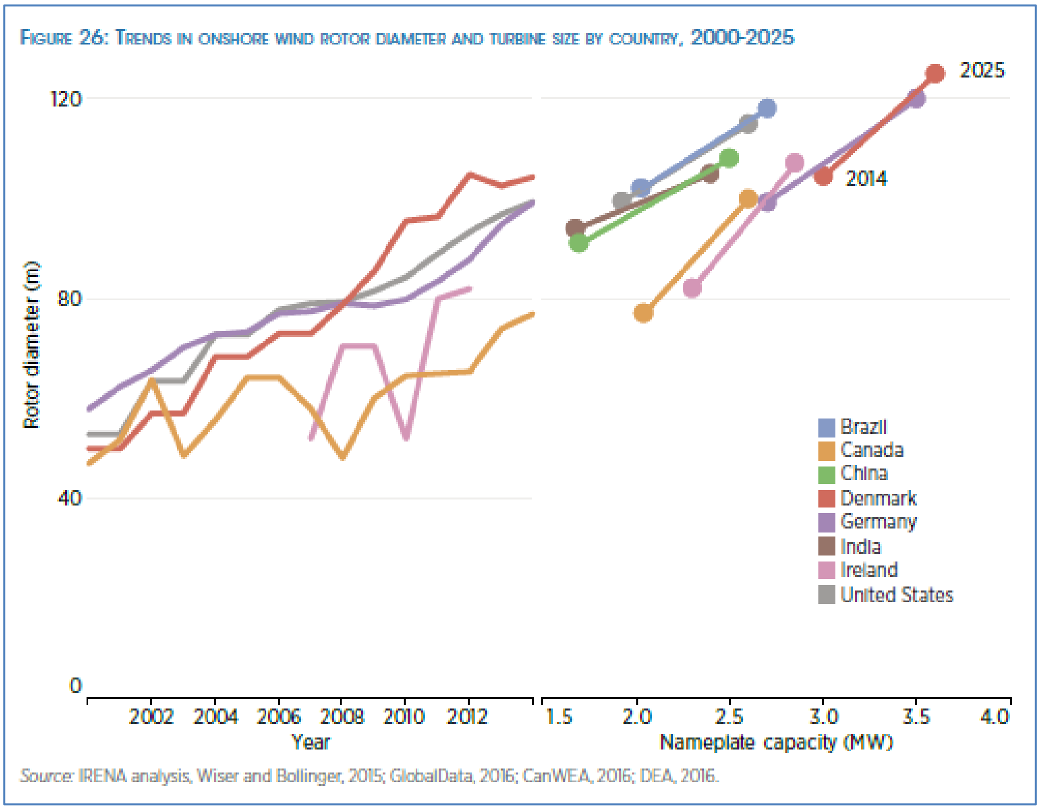


Figure 62 – Trend in rotor diameter and turbine size, 2000-2012, and projections to 2025 (Source: IRENA [15])

2.4.1.2.6.2 Capacity factors

By 2025, weighted average nameplate capacity is expected to reach 2.2 MW in Asia-Pacific, 2.7 MW in the Americas and 3 MW in Europe, Middle-East and Africa (IRENA and MAKE Consulting, 2015). By country in 2025, the weighted average nameplate capacity for newly installed capacity is forecast to be 3.6 MW in Denmark, 3.5 MW in Germany, 2.6 MW in the United States, 2.4 MW in India and 2.5 MW in China. The forecasts contain a degree of uncertainty, however, since they are made for a period of more than ten years and depend, amongst other factors, on the geographic distribution of deployment within these countries.

Rotor diameters are estimated to reach 125 m in Denmark, 119 m in the United States and 120 m in Germany by 2025 (Figure 62). Depending on technological innovation and developers' choices, the final numbers might be lower or slightly higher. Wind turbine hub heights have also increased in recent decades and this trend is projected to continue. Higher hub heights allows developers to access better wind resources and exploit rougher terrains in countries where land constraints are an issue, such as in densely populated Europe. This allows developers to exploit sites previously uneconomical due to location or low wind conditions.

Also helping will be innovative solutions for yaw and pitch systems that optimise the turbine orientation and blade angles to the constantly changing wind characteristics facing each turbine. Innovative data management techniques and forecasting software for preventative O&M, combined with weather forecasting software, will allow developers to increase the reliability and operation of wind turbines and to optimise O&M operations. This will help further increase capacity factors by reducing downtime from unplanned maintenance. It will also help to reduce O&M costs by reducing expensive, unplanned maintenance interventions.

When combining the trends in the increasing use of today's latest technology, availability increases from improved reliability, as well as new innovations in turbine controls, advanced and more efficient blades, and the improvements in micro-siting and wind farm development, IRENA reports that the global weighted average capacity factor could increase from 27% in 2015 to 32% in 2025. At a global level, the average contribution of increased capacity factors would be to reduce the global weighted average LCOE by around USD 0.01/kWh.

2.4.1.2.6.3 Operation and maintenance

O&M costs typically account for 20-25% of the total LCOE of wind power systems in Europe, with a clear declining trend, despite the difficulties in identifying solid data on O&M costs. All projects will see a rise in O&M costs over their lifetime, as equipment ages. But, in many cases, O&M costs over the life of the wind farm are not known today: the turbine technology has changed rapidly over the last 15 years, and personnel must be suitably trained with respect to the specific turbine. Furthermore purchase agreements and responsibility issues may require that O&M contract services are awarded to the turbine manufacturer. Thus not surprisingly IRENA states that actual O&M costs data are extremely difficult to obtain, thus projections are more speculative. Yet these costs appear to be trending down, partly due to the increased overall share of emerging markets with lower cost structures.

From an operational and technological perspective, there are two tendencies in terms of O&M strategies that will have an impact on LCOE declines. One is the use of advanced meteorological and fatigue modelling software to forecast wind turbine output and fatigue lifetimes for turbine components, to better manage the servicing of wind turbines. The other is the improved reliability of turbines that is being driven by a focus on minimising O&M costs with more reliable system configurations and components.

These innovations will reduce the downtime of wind turbines and increase electricity output, as well as reduce costly unscheduled maintenance. Combined with more widespread application of best practices in O&M, these trends are set to diminish the overall O&M costs. Globally, IRENA reports that improved drivetrain and turbine reliability are expected to yield cost reductions of USD 0.002/kWh, while the wider adoption of best practice O&M strategies could reduce the LCOE by a further USD 0.001/kWh.

Based on the above information included in the IRENA report, a reduction of 10% of the O&M costs in year 2025 could be considered with reference to year 2015.

2.4.1.2.6.4 Estimate the costs of wind in Brazil, Argentina and Uruguay and projections to 2030

Based on the above data and analysis, a breakdown of the cost of onshore wind farm was attempted for the year 2015, in order to provide separate estimates for Brazil, Argentina and Uruguay. It is worth to note that references to projects carried out in the countries of interest are not included in the IRENA report [15].

The average cost that IRENA reported for the wind projects was assumed as a reference for both countries. The BOS costs (average 30% of project costs) were deducted to derive a reference price for wind turbines only. A decline of wind turbine price was considered based on the international trend expected by the IRENA report. Slightly different BOS costs were considered for Brazil and Uruguay, 30%, and Argentina, 33% (for the implementation of wind is still to be started), with same percentage of decline in the years that follow.

In regards to the O&M costs, based on the values shown in Figure 58, the same estimates can be considered for all the countries, equal to USD 55/kW.
Based on the IRENA report [15] a 12% price reduction of wind projects (turbines and BOS costs) and 10% reduction of O&M costs are also expected by the year 2025.
In regards to the projections to year 2030 a further 5% price reduction can be considered for the wind projects (turbines and BOS costs), and 4% reduction for O&M costs. These estimates can be applied to the countries.
The detailed values for year 2015 and the projections to 2025 and 2030 are summarised in the Table 21.

Table 21 – Evaluation of the costs of onshore wind projects in 2015 and projections to year 2025 and 2030

Prices in USD/kW	**Brazil - Uruguay**		**Argentina**	
Averaged historical data referred to year 2015				
Wind turbines (§)	1092	70%	70%	1092
BOS (#)	515	30%	33%	515
Total	1560			1607
O&M (per year)	55			55
Projection out to year 2025				
		Fall expected		
Wind turbines	961	12%		961
BOS	453	12%		453
Total	1373			1414
O&M (per year)	50	10%	10%	50
Projection out to year 2030				
		Fall expected		
Wind turbines	913	5%		913
BOS	430	5%		430
Total	1304			1343
O&M (per year)	48	4%	4%	48
§ wind turbine cost = 70% of international average price of wind projects USD 1560/kW **# BOS cost = percentage of international average price of wind projects USD 1560/kW. 30% for Brazil, 33% for Argentina**				

2.4.1.2.6.5 Projection of LCOE at the target year 2030

Onshore wind is now a highly competitive source of new power generation capacity, with medium and even low-wind speed sites now economically viable with recent wind turbine improvements. Manufacturers are continuing to push the envelope in terms of turbine efficiency and design, and cost competitiveness. At the same time, they are also trying to broaden their portfolio of products to better match individual markets. The result is that the global weighted average LCOE of onshore wind could fall by 26% by 2025. This bottom-up analysis is very close to the suggested long-run learning rate for onshore wind (12% cost reduction for every doubling of cumulative installed capacity) and deployment projections from previous IRENA's analysis.

Future cost reductions in the cost of electricity from onshore wind are increasingly likely to come from technological improvements that yield higher capacity factors for a given wind resource. The potential improvement in capacity factors by 2025 could result in reducing the global weighted average LCOE of onshore wind by around USD 0.01/kWh, or 49% of the total projected reduction in onshore wind LCOE of USD 0.018/kWh as the global weighted average LCOE falls to USD 0.053/kWh by 2025.
Reductions in total installed costs, driven mostly by cost reductions for towers, turbines and wind farm development, contribute around USD 0.006/ kWh (34%) of the total reduction in the LCOE.
Improvements in turbine reliability, improved predictive maintenance schedules and the more widespread application of best practice O&M strategies reduce the LCOE by around USD 0.003/ kWh by 2025, or 17% of the total reduction.

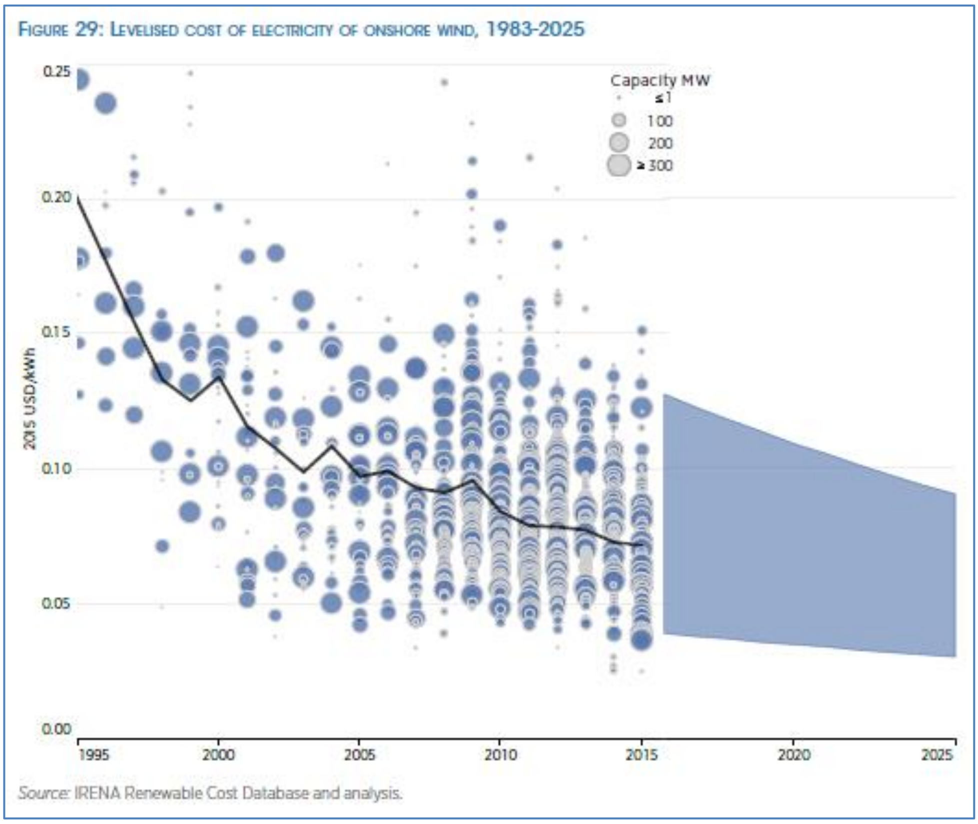


Figure 63 – LCOE of wind projects, projections to 2025 (Source: IRENA [15])

Looking at the evolution of the LCOE cost for individual projects, at the lower end LCOEs are unlikely to fall below USD 0.03/kWh (5th percentile); projects where excellent wind resources, very low installed cost structures and highly competitive O&M costs exist will challenge this lower bound. For the upper bound (95th percentile), the LCOE could fall to USD 0.9/kWh (from USD 0.11/kWh in 2015).

Similar to the potential trend for solar PV, wind LCOE is likely to converge in a range of more competitive costs, driven by the rapid growth of new markets, notably Africa and Latin America.

The above data shall provide a price representative for the future wind projects. Like in the case of solar PV, the set of historical data and the learning curve suggests that the decrease of prices shall continue in the future, although at a reduced rate. This rate of decrease shall be deducted from previous charts, particularly from Figure 63, showing a 30% decrease in the latter 10 years. The trend shown could be used as a reference for analysing future LCOE of wind projects: for example a possible projection to 2030 may be achieved by the extrapolation of the available weighted average LCOE data.

The O&M costs are a significant part of the overall project costs, although their influence is lesser as the WACC gets higher (Figure 64). Wind projects are very sensitive to cost of capital variations and the LCOE of onshore wind is 78% higher at a WACC of 10% than at 2.5% in 2015, and this difference is expected to get to 81% in 2025.

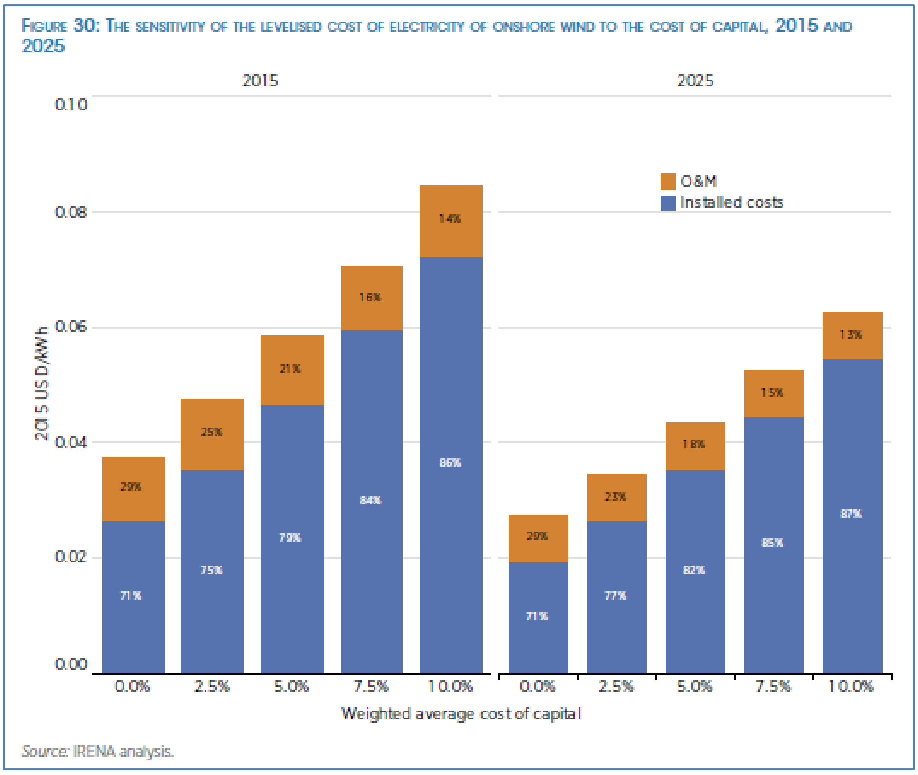


Figure 64 – Sensitivity of LCOE to the cost of capital, 2015 and projections to 2025 (Source: IRENA [15])

2.4.1.3 Further analysis regarding the costs of Solar PV and Wind projects

2.4.1.3.1 Costs of wind projects according to the German Industry Association VDMA

We further investigated the costs of wind projects through a communication issued by VDMA [23], the Mechanical Engineering Industry Association that represents more than 3200 medium-sized German companies. This communications shows data that regard the cost of wind projects operational in 2016-2017.

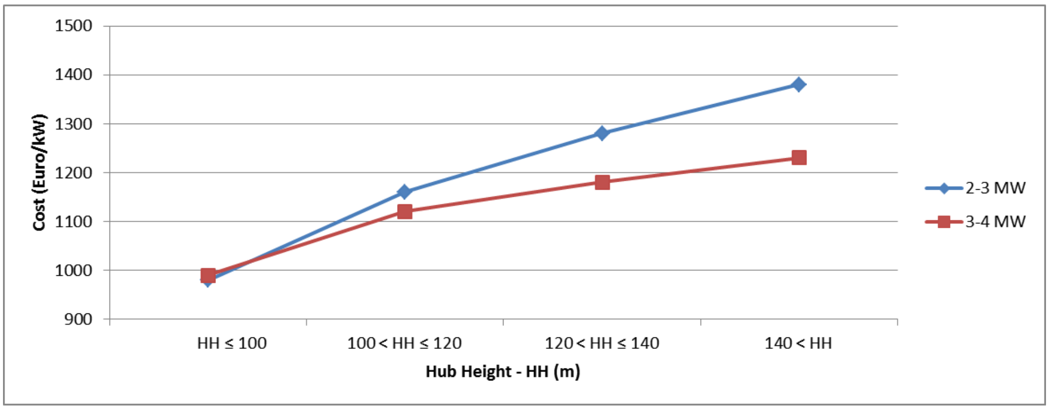


Figure 65 - Costs (turbine, transportation, installation) of German wind projects operational in 2016-2017 (Source [23])

According to the data in Figure 65, the cost (turbine, transportation, installation) per kW increases with the hub height: the higher the height, the more the material needed, the greater the costs for transportation and for installing the rotor at a higher height. The higher costs are required to catch favourable wind conditions: in case the suitable wind conditions are met for a hub height lesser than 100 meters, the wind project will probably cost less. The same German study estimates the average ancillary (BOS) costs (foundation, grid connection, road connections, planning, etc.) to be 387 €/kW. The total cost estimate of wind turbine projects operational in 2016-2017 is 1387 Euro/kW (about 1525 UD$/kW). This estimate can be still in agreement with the estimate 1560 US$/kW by the IRENA report.

The hub height is a feature that can affect the cost of the project. The IRENA report doesn't investigate in detail the issue of the hub height, and costs are weighted by the capacity only. In Germany, the hub height has increased since 1990: the Figure 66 shows that the average hub height was below 100 meters until 2014. This is comparable to the average hub height of the wind projects in the analysed countries and thus the hub height cannot justify significant differences in the costs of the wind projects.

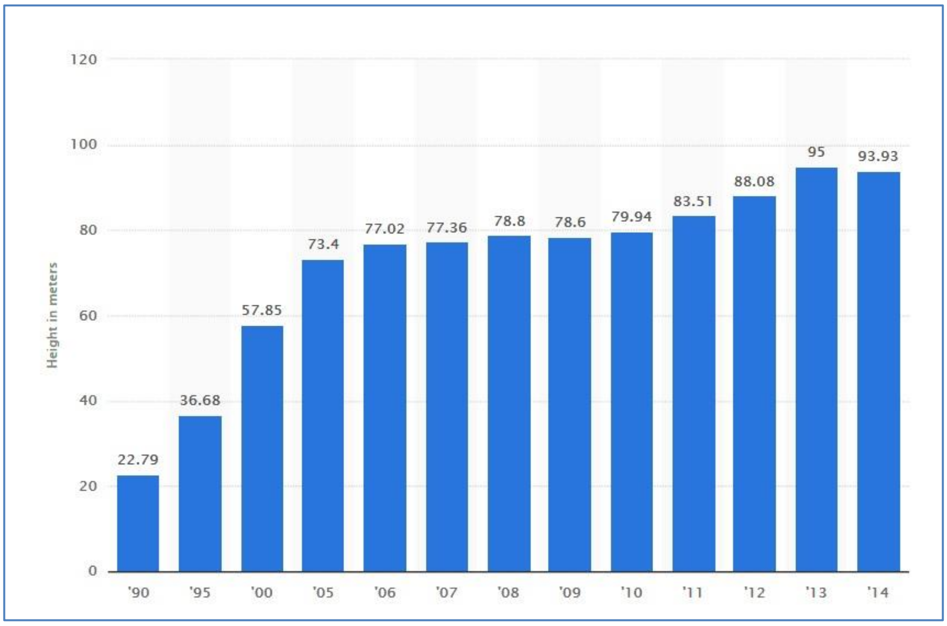


Figure 66 - Average rotor hub height of German onshore wind turbines - 1990 to 2014 (Source www.statista.com)

2.4.1.3.2 Costs of Solar PV and Wind projects according to market analyses

The costs of solar PV and wind projects have experienced significant changes between 2015 and 2016. Additional data were analysed to improve the estimates of renewable project costs based on the IRENA report, for this report analysed the cost information available until the year 2015.

<u>Cost of the PV Modules according to</u>:

- Bloomberg (PV Market Outlook Q1 2016) [24]

The Figure 68 shows the cost of multicrystalline PV modules between 2010 and early 2016, average and regional markets (EMEA, AMER, ASOC). The change of the cost of PV modules between 2015 and 2016 in represented in Table 22 that describes the decrease of international average costs (about 7.8% in one year) from 0,77 $/W (first half 2015) to 0,71 $/W (first quarter 2016).

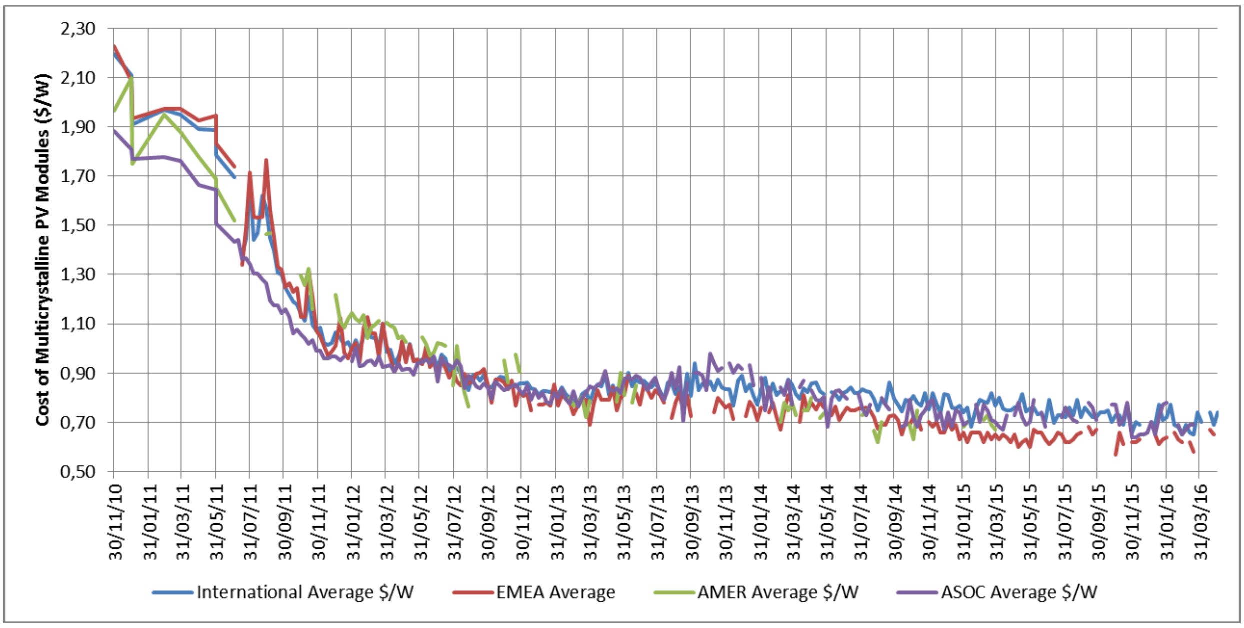


Figure 67 - Cost of multicrystalline PV modules between late 2010 and early 2016 (Source: Bloomberg [24])

Table 22 – Average cost of multicrystalline PV modules 2015 and 2016 (Own elaboration, Source: Bloomberg [24])

Multicrystalline PV modules		Jan-Jul 2015	Aug-Dec 2015	Jan-Apr 2016
International Average	$/W	0,77	0,73	0,71
EMEA Average	$/W	0,65	0,64	0,63
AMER Average	$/W	0,69	0,69	N.A.
ASOC Average	$/W	0,72	0,72	0,70

These data are similar to the data shown in IRENA report (Figure 45) and the assumption presented in Table 20 in regards to the cost of the PV modules with reference to year 2015.
Therefore the decrease in the costs of the PV projects shall depend on other sources. Further analyses were performed based on the data from market reports.

<u>**Cost of Solar PV projects in Brazil and Argentina according to**</u>:

- IHS ENERGY Renewable Power Price Outlook in Emerging Markets, 2015–30 [25]
- Bloomberg H2 2016 LCOE AMER Outlook [26] and H2 2016 LCOE PV Update [27]

The IHS ENERGY data are included in a report issued in March 2016, whereas Bloomberg data in two reports issued in October 2016. These sources contain only few information specifically referred to Uruguay, so for this specific case, being the PV market still in the starting phase in this country, it will be assumed equal to Argentina, which shows higher costs. This is also consistent with the fact that lower prices are expected in Brazil which is a much greater country with a widely bigger potential for PV installations, which contributes also to the cost reduction.

Table 23 – Cost of Solar PV projects (Source: IHS ENERGY [25] and Bloomberg [26] and [27])

Cost of Solar PV projects ($/kW)	Reference Date	Brazil	Argentina
IHS ENERGY	2015	2.100	N.A.
IHS ENERGY	March 2016	1.776	N.A.
Bloomberg (October 2016)	October 2016	1.660	1.980

The Table 23 shows information from different sources and period of the year 2016, and allows the following comments:

- According to IHS ENERGY the cost of Solar PV projects in Brazil was 2.100 $/kW in 2015 and 1.776 $/kW in 2016. According to Bloomberg the cost of Solar PV projects in 2016 in Brazil was 1.980 $/kW (the same of Argentina).

  With regard to Brazil:
  Based on the above figures the value 1718 $/kW (mean between HIS and Bloomberg data) could be used as the representative cost of PV projects for the year 2016. This costs represents a 18.2% decrease compared to the estimate (year 2015) from the IRENA report.
  With regard to Argentina:
  IHS ENERGY does not provide any data, whereas Bloomberg provides an estimate of 1.980 $/W for the second half of 2016 (report October 2016). We can consider this value representative for the year 2016. This costs represents a 5.8% decrease compared to the estimate year 2015 we gathered from the IRENA report.

- IHS ENERGY provided an outlook for PV project costs in Brazil, till to 2030:
  - 1.776 $/kW in 2016 (-15.4% compared to 2015),
  - 1.142 $/kW in 2025 (-45.6% compared to 2015, and -35.7% compared to 2016),
  - 1.006 $/kW in 2030 (-52.1% compared to 2015, and -43.4% compared to 2016).

  These changes, 36,9% between 2015 and 2016 or 44,4% between 2015 and 2030, are lesser than the percentages we envisaged according to forecasts form IRENA report.

- Based on Bloomberg and HIS updated costs of PV projects in year 2016, the above mentioned percentages of reductions could be modified as it is described below:
  - Updated cost of PV projects in 2016 are as follow:
    - 1,72 $/W for Brazil. This is 18% less than the 2,1 $/W based on the IRENA report with regard to year 2015 (confirmed by HIS ENERGY report).

        ▪ 1,98 $/W for Argentina. This is 5,5% less than the 2,1 $/W gathered according to the IRENA report with regard to year 2015.
- Same yearly rate of decrease is assumed regarding the 9 years period between 2016 and 2025, according to IRENA assumption for the period 2015-2025.
- A further decrease for the period 2025-2030, percentage of decrease 20%.

Based on the above figures and percentages, the evaluation regarding the present and future costs of the PV projects shall be updated as it is specified in the following Table 24:

Table 24 – Updated evaluation of the costs of PV in 2015, 2016 and projections to the year 2025 and 2030

Costs in USD/W	Brazil	Decrease of costs (%)		Argentina - Uruguay
Averaged historical data referred to year 2015 (ref. IRENA, IHS ENERGY)				
PV modules	0.60			0.60
Inverter	0.15			0.15
BOS	1.35			1.35
Total	2.10			2.10
O&M (per year)	0.02			0.02
Cost of projects, year 2016 (ref. Bloomberg, IHS ENERGY)				
		Reduction 2015-2016		
PV modules	0.60	0%	0%	0.60
Inverter	0.14	5%	5%	0.14
BOS	0,98	22%	8%	1.24
Total	1.72	18%	5,5%	1.98
O&M (per year)	0.02			0.02
Projection from year 2016 to year 2025				
		Fall expected		
PV modules	0.30	50%		0.30
Inverter	0.09	36%		0.09
BOS	0.54	45%	45%	0.68
Total	0. 93	46%	46%	1.08
O&M (per year)	0.015	25%	25%	0.015
Projection from year 2025 to year 2030				
		Fall expected		
PV modules	0.24	20%		0.24
Inverter	0.07	20%		0.07
BOS	0.43	20%	20%	0.55
Total	0.74	20%	20%	0.86
O&M (per year)	0.0115	10%	10%	0.0115

Cost of Wind projects in Brazil and Argentina according to:

- IHS ENERGY Renewable Power Price Outlook in Emerging Markets, 2015–30 [25]
- Bloomberg H2 2016 LCOE AMER Outlook [26]

Cost of wind projects for Brazil and Argentina were gathered from market analysis that provide the estimates reported below. These sources do not contain specific data referred to Uruguay.

Table 25 – Cost of Wind projects (Source: IHS ENERGY [25] and Bloomberg [26])

Cost of Wind projects ($/kW)	Reference Date	Brazil	Argentina
IHS ENERGY	March 2016	1.840	N.A.
Bloomberg (October 2016)	October 2016	1.930	1.980

The costs reported by the above market analyses are higher than the estimate we gathered from the IRENA report (1.560 $/kW).

Therefore the cost estimates that regard Wind projects (Table 21) can be updated, as it is shown below, by considering a reduction of 12% to the total project costs (1370 USD/kW instead of 1560 USD/kW). This cost reduction regards particularly Chile, but can be extended to Brazil and Argentina by using the approach shown in the Table 21.
The other assumptions regarding the falling of the costs in the future years remain unchanged. In regards to Argentina, cost estimates for wind projects are changed; in fact Argentina has just started the development of renewable projects but no information is available about the actual costs of wind (or solar PV) projects could be found during our searches.

The Table 26 shows the costs of the wind projects updated as mentioned above.

Table 26 – Updated evaluation of the costs of onshore wind projects in 2015 and projections to year 2025 and 2030

Costs in USD/kW	Brazil	Decrease of costs (%)		Argentina
Averaged historical data referred to year 2015 (ref: IRENA)				
Wind turbines	959			959
BOS	452			452
Total	1411			1411
O&M (per year)	55			55
Projection out to year 2025				
		Fall expected		
Wind turbines	844	12%		844
BOS	398	12%		398
Total	1242			1242
O&M (per year)	50	10%	10%	50
Projection out to year 2030				
		Fall expected		
Wind turbines	802	5%		802
BOS	378	5%		378
Total	1180			1180
O&M (per year)	48	4%	4%	48

It turns out that in Argentina and Brazil it is possible to assume the same cost for wind projects. Consequently, also for Uruguay the same value will be applied.

2.4.1.4 Addition information regarding the costs of residential Solar PV

The potential of the rooftop PV market has been described in a presentation that the GIZ (German Federal Organization for the sustainable development through international cooperation) delivered to the CIREC-Week in October 2015 [30]

The presentation described the legal framework for self-consumption and delivery of the excess power to the network, the market potential and economic feasibility of rooftop PV, the barriers that still exist, and the initiatives underway to remove these barriers.

At the time the presentation was delivered (October 2015), the price of the modules was one of the barriers preventing the quick development of the market. The price recorded at that time in Chile and Germany are compared in the slide shown in the Figure 68.

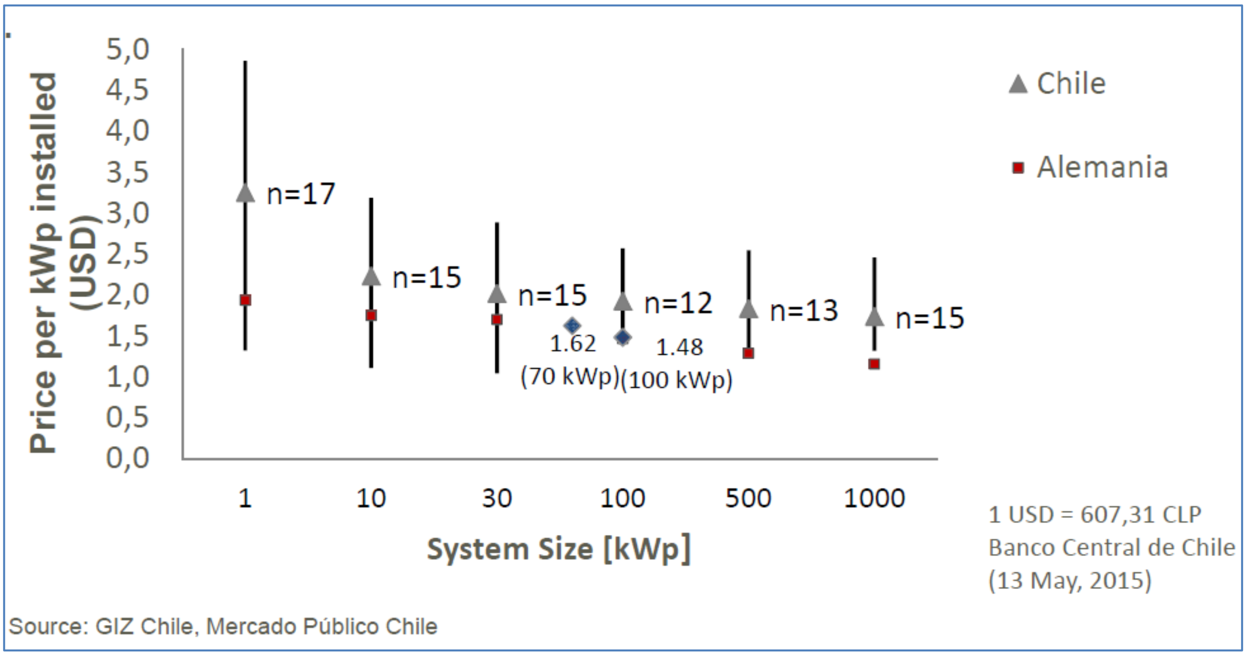


Figure 68 – Comparison of net cost of PV systems - May 2015 [30]

The figure shows that, in the range 1-10 kWp, the cost of the PV system was between 3,25 and 2,25 USD/kWp. This estimates can be considered as an evaluation of the PV system costs in 2015, whereas reductions of the same percentage applied to the cost of the utility scale PV systems could be adopted to get a corresponding cost projection out to 2030 for rooftop PV.

2.4.2 *Primary energy costs*

Problem statement

- *Assessment of the current primary energy costs and the projections for the years to come.*
  - *All the products used in the generation of electrical power.*
  - *Report on the present costs and the costs expected in the future with respect to:*
    - *The international scenario*
    - *The countries that are the subject of the present study – Brazil, Argentina and Uruguay*

Methodology

- *Collection of the data regarding the present costs and the trends expected in the future.*
  - *Description of the trend of the costs for oil, carbon, and natural gas, and scenarios analysed.*
  - *Select primary energy costs by World Energy Outlook 2016 as a source for projections to 2030.*
  - *New Policies Scenario is the reference for the study for the adoption of policy measures such as the removal of subsidies in net-importing countries.*
  - *Crosscheck the estimates from the international organization with available estimates issued from recognised organizations in the countries of the study.*
    - *Argentina: Metodología para la elaboración y evaluación de escenarios energéticos 2015 - Plataforma escenarios energeticos Argentina 2035*
    - *Brazil : Plano Decenal de Expansão de Energia*
    - *For Uruguay, no specific offical sources have been identified. Reference is then done to international forecasts and to [5]*

Major results

- *Definition of the evolution of the primary energy costs until the year 2030. The costs envisaged for each primary energy are summarised in the table below.*

Table 27

Primary energy costs - Target year 2030 - Prices in USD			
	Brazil	**Argentina**	**Uruguay**
Crude oil	85 $/barrel	98.90 $/barrel	98.90 $/barrel
Natural gas	10 $/MBTU	9 $/MBTU as average of: 6 $/MBTU (indigenous) 12 $/MBTU (from Bolivia)	10$/MBTU as weighted average of: 9$/MBTU import from Arg 15$/MBTU LNG
Coal	78 $/tonne	78 $/tonne	-

The present section regards the costs of the primary energies according to the international scenario and based on the information specifically released with reference to Brazil and Argentina.

Most of the information provided in the present section comes from the OECD/IEA "World Energy Outlook 2016" [19] that describes the present energy costs and the future trends, whereas additional data related to Brazil and Argentina were collected from the references quoted in the text.

The World Energy Model (WEM) generates the energy projections described in the OECD/IEA World Energy Outlook 2016. WEM is a large-scale simulation tool that IEA has developed in-house; the model is updated and enhanced each year in order to reflect ever more closely how energy markets operate

and how they might evolve. It covers the whole energy system in detail, to focus on global or regional aggregates, to zoom in on the roles of distinct technologies and end-uses, the evolution of power sector and end-user prices, and the implications of different pathways for investment, trade and greenhouse-gas emissions.
The current version models global energy demand in 25 regions, 12 of which are individual countries. Global oil and gas supply is modelled in 120 distinct countries and regions, while global coal supply is modelled in 31 countries and regions. The main modules cover energy demand, fossil fuel and bioenergy supply, and energy transformation.
The input data to the modelling in the WEO-2016 report are listed here below.

a) Energy policies

The policies are assumed to be pursued by governments around the world vary by scenario: indeed, different policy assumptions are instrumental in producing the different scenarios (Current Policies, New Policies and Decarbonization).
The guidance that countries provided on future energy policies in their Nationally Determined Contributions (NDCs) submitted in the run-up to the Paris COP21 is an important input to WEO-2016. They include programmes to support renewable energy and improve energy efficiency, to promote alternative fuels and vehicles, and to change the way that energy is priced, for example, by reforming subsidized consumer prices for oil, gas and electricity.
In regards to fossil-fuel subsidies, their removal is not assumed in the Current Policies Scenario unless a formal programme is already in place. In the New Policies Scenario, all net-importing countries and regions phase out fossil-fuel subsidies completely within ten years. In the 450 Scenario, while all subsidies are similarly removed within ten years in net-importing regions, they are also removed in all net-exporting regions, except the Middle East, within 20 years. Another influential policy variation between the scenarios is the scope and level of carbon pricing, which has a major impact on the relative costs of using different fuels. As of mid-2016, 63 carbon pricing instruments were in place or scheduled for implementation, either cap-and-trade schemes or carbon taxes, with wide variations in coverage and price. In addition to schemes already in place, which are assumed to remain throughout our Outlook period, the New Policies Scenario includes the introduction of new carbon pricing instruments where these have been announced but not yet introduced.
The New Policies Scenario could be considered as a reference for the study for it considers the adoption of policy measures such as the removal of subsidies in net-importing countries.

b) Economic outlook

Economic prospects are important in determining the outlook for energy consumption, not only the headline rate of growth in gross domestic product (GDP), but also the way in which growth rates might vary across different sectors of the economy. For the world as a whole, GDP growth is pushing energy consumption higher. However, this relationship has diverged substantially across countries over recent years. Among the OECD group of economies, growth in GDP (expressed in real purchasing power parity [PPP] terms) was even associated with a slight decline in primary energy demand for the period 2000-2014. This is a noteworthy turn of events, but not necessarily a surprising one given that structural economic shifts, saturation effects and efficiency gains produced a peak in primary energy demand in Japan (in 2004) and the European Union (in 2006), since when demand in both has fallen by more than 10%; and demand in the United States is already 5% below the high point reached in 2007. Elsewhere, however, the links between economic growth and energy consumption remain strong. Overall, for every one percentage point rise in non-OECD economic growth over the period 2000-2014, energy demand increased by around 0.7%. In each of the scenarios included in this Outlook, the world economy is assumed to grow at a compound average annual rate of 3.4% over the period 2014 to 2040.

The way that future growth in economic activity translates into demand for energy is heavily dependent on policies (notably energy efficiency policies, the intensity of which varies by scenario) and structural changes in the economies. Future GDP growth based on an expansion of industrial output, especially in energy-intensive sectors, such as iron and steel, cement or petrochemicals, has much stronger implications for energy demand than a similar expansion based on the services sector.

For the global economy as a whole, services account for the largest share of current GDP, at 62%, and this share rises steadily to reach 64% by 2040. The rising role of the services sector in GDP is particularly striking in the case of China, whose economy is already rebalancing away from a reliance on manufacturing and exports towards a more domestic- and service-oriented economy, with a much less energy-intensive pattern of growth than in the past. The share of industry in China’s GDP is projected to fall from 42% today to 34% in 2040. Evolution of GDP in the regions analysed in WEO-2016 is summarised in the next Table 28.

Table 28 – Evolution of GDP in the region analysed in WEO-2016 [19]

Table 1.2 ▷ Real GDP growth assumptions by region

	Compound average annual growth rate				
	2000-14	2014-20	2020-30	2030-40	2014-40
OECD	1.6%	2.0%	1.9%	1.7%	1.9%
Americas	1.8%	2.3%	2.2%	2.1%	2.2%
United States	1.7%	2.3%	2.0%	2.0%	2.0%
Europe	1.4%	2.0%	1.7%	1.5%	1.7%
Asia Oceania	1.7%	1.4%	1.6%	1.3%	1.4%
Japan	0.7%	0.4%	0.8%	0.7%	0.7%
Non-OECD	6.0%	4.6%	4.9%	3.8%	4.4%
E. Europe/Eurasia	4.4%	1.1%	3.0%	2.7%	2.4%
Russia	4.1%	0.0%	2.6%	2.5%	2.0%
Asia	7.6%	6.1%	5.5%	3.9%	5.0%
China	9.6%	6.2%	5.2%	3.2%	4.6%
India	7.2%	7.5%	7.0%	5.3%	6.5%
Southeast Asia	5.3%	5.0%	4.9%	3.7%	4.5%
Middle East	4.6%	3.0%	3.8%	3.4%	3.4%
Africa	4.7%	4.0%	4.8%	4.3%	4.4%
South Africa	3.1%	1.7%	2.8%	2.9%	2.6%
Latin America	3.5%	0.8%	3.1%	3.1%	2.6%
Brazil	3.3%	-0.5%	2.9%	3.1%	2.2%
World	3.7%	3.5%	3.7%	3.1%	3.4%
European Union	1.3%	1.9%	1.6%	1.4%	1.6%

Note: Calculated based on GDP expressed in year-2015 dollars in PPP terms.

Sources: IMF (2016); World Bank databases; IEA databases and analysis.

c) Demographic trends

In regards to population and demographics, the WEO-2016 adopts the medium variant of the latest United Nations' projections as the basis for population growth in all scenarios (UNDP, 2015). According to these projections, the world population is expected to grow by 0.9% per year on average, from 7.3 billion in 2014 to 9.2 billion in 2040.

2.4.2.1 International prices and technology costs

The World Energy Model generates price trajectories for each of the fossil fuels and the evolution of costs for different energy technologies.

In the case of fossil-fuel prices, the need is to reach a level which brings the long-term projections for supply and demand into balance, and price trajectories are adjusted in iterative model runs until they satisfy this criterion. The price trajectories are smooth trend lines, and do not attempt to anticipate the cycles and short-term fluctuations that characterize all commodity markets in practice (Table 29).

Table 29 – Fossil fuel import prices by scenario (Source: WEO-2016)

Table 1.4 ▷ Fossil-fuel import prices by scenario

		New Policies Scenario			Current Policies Scenario			450 Scenario		
Real terms ($2015)	**2015**	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**
IEA crude oil ($/barrel)	51	79	111	124	82	127	146	73	85	78
Natural gas ($/MBtu)										
United States	2.6	4.1	5.4	6.9	4.3	5.9	7.9	3.9	4.8	5.4
European Union	7.0	7.1	10.3	11.5	7.3	11.1	13.0	6.9	9.4	9.9
China	9.7	9.2	11.6	12.1	9.5	12.5	13.9	8.6	10.4	10.5
Japan	10.3	9.6	11.9	12.4	9.9	13.0	14.4	9.0	10.8	10.9
Steam coal ($/tonne)										
OECD average	64	72	83	87	74	91	100	66	64	57
United States	51	55	58	60	56	61	64	53	52	49
European Union	57	63	74	77	65	80	88	58	57	51
Coastal China	72	78	86	89	79	92	98	73	72	67
Japan	59	66	77	80	68	84	92	61	59	53

Notes: MBtu = million British thermal units. Gas prices are weighted averages expressed on a gross calorific-value basis. All prices are for bulk supplies exclusive of tax. The US price reflects the wholesale price prevailing on the domestic market. The China and European Union gas import prices reflect a balance of LNG and pipeline imports, while the Japan import price is solely LNG.

Considerations regarding the oil price

With the oil price only rarely breaking above $50/barrel in the first three-quarters of 2016, the idea that oil prices could stay “lower for longer” has gained a firm foothold in discussions on the oil market outlook. But how much longer could a period of lower prices plausibly last?

In WEO-2015 the long-term durability of low oil prices was tested in a Low Oil Price Scenario, where a set of conditions would allow lower oil prices to persist all the way through to 2040. The main assumptions (compared to the New Policies Scenario) were:

- lower near-term economic growth and a more rapid phase out of fossil-fuel consumption subsidies (both restraining growth in oil consumption);
- greater resilience among some non-OPEC sources of supply to a lower price environment, notably tight oil in the United States;
- a lasting commitment by OPEC countries to give priority to market share and to a price that limits substitution away from oil; and
- favourable assumptions about the ability of the main oil-producing regions to weather the storm of lower hydrocarbon revenues.

One year on, some of these assumptions are holding. Economic prospects have indeed dimmed and many countries – oil importers but also oil exporters – have announced their intention to reform energy prices, dampening prospects for strong demand growth. Production in some key non-OPEC countries, notably USA and Russia, has held up well under testing conditions, although the shift towards greater reliance on lower cost producers in the Middle East, another feature of the Low Oil Price Scenario, is already visible, with the share of the Middle East in global output rising to 35%, a level not seen since the late 1970s.

However, other assumptions are looking unstable. OPEC countries announced a plan to return to active market management at a meeting in Algiers in September 2016. This announcement was indicative of the testing conditions that lower oil prices have created for many OPEC producers, especially those that faced the downturn with limited accumulated financial reserves. The budgetary cuts necessary to adjust to the reduced levels of revenue have been deeply destabilizing in countries like Venezuela, Iraq, Nigeria and Libya, especially when considered alongside existing political and security challenges. The Low Oil Price Scenario offers the potential for lower cost producers to expand their output (because of the stimulus to demand and because higher cost producers are squeezed out of the supply mix); but they also stand to lose more from the lower price than they gain from higher production. The pressure that a lower price trajectory puts on the fiscal balances of these key producers ultimately makes such a scenario look increasingly unlikely, the further it is extended out into the future.

2.4.2.2 Trends of the prices of the fossil products

2.4.2.2.1 Oil

According to the analysis reported in the previous paragraph, oil prices are seen to increase in the next years: after a significant increase, the incremental trend shall become less pronounced, for both the Current Policy and the New Policy scenarios, whereas the 450 Scenario will see the oil price to become stable and possibly start a slight decline. In the New Policies Scenario, the oil price trend continues to edge gradually higher post-2020, with three main considerations underpinning this rise.

1. The amount of new production that is required to keep pace with demand. This might appear modest at first glance, since oil use rises only by 13 mb/d over a 25-year period; but most of the investment required in all scenarios is to replace declining production from existing fields.
2. In almost all cases, oil is more costly to produce in 2040 than today. There have been strong cost reductions in many upstream activities in recent years, but, in our estimation, there is a cyclical component to these reductions that is set to reverse as upstream activity picks up and the supply and services markets tighten. Even though continued improvements in technology and efficiency are considered, their impact on upstream costs is more than counterbalanced, for most resource types, by the effects of depletion.
3. Logistical and other constraints on the rate at which oil can be developed (in both OPEC and non-OPEC countries) can easily keep the oil price trajectory above the marginal cost of the barrel required to meet demand. These include geopolitical risks, that might constrain investment and output of the world's lowest cost oil, and our assumption that the main low-cost resource-holders in OPEC follow through with efforts (following the recent meeting in Algiers) to defend a global price level above that implied by the global supply-cost curve.

The Figure 69 summarises the trend of crude oil price that regard the three relevant scenarios.

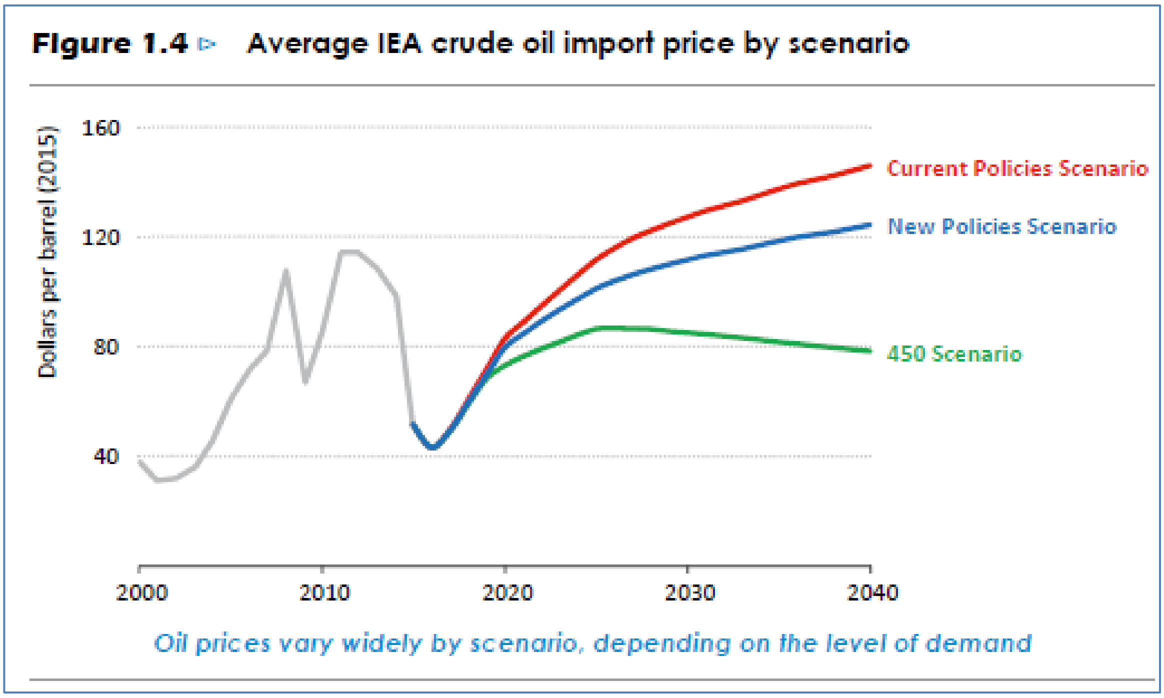


Figure 69 – Average crude oil price by scenario (Source: WEO 2016)

The price 111 $/barrel could be used as a reference for the study, for it considers the adoption of policy measures such as the removal of subsidies in net-importing countries. Nevertheless the historical trend testifies that forecast about the oil price are generally unreliable, so in the model appropriate sensitivity analyses will be considered.

2.4.2.2.2 Natural gas

At present there is no single global price for natural gas. Regionally determined prices, loosely connected, reflect the distinct market dynamics and pricing mechanisms of different regional markets. The WEO 2016 focuses on three regional prices: North America, Asia and Europe.

1. In North America, the reference price is that of Henry Hub, a distribution hub in the US pipeline system in Louisiana where the price is set entirely by gas-to-gas competition, i.e. it is a price that balances regional supply and demand (including demand for gas for export). The price paid by consumers includes the costs of transmission and distribution, fees and charges. The price of gas exported from North America as liquefied natural gas (LNG) reflects the additional costs of liquefaction, shipping in LNG tankers and regasification at the importing terminal.

The other regional gas prices are the average prices paid in each case by importers: they reflect the different pricing arrangements prevailing in the various markets.

2. In Europe, this currently means an increasing share of imported gas priced off trading hubs, particularly in north-western Europe, but with a sizeable residual volume with prices indexed in full or in part to oil product prices (concentrated in southern and south-eastern Europe).
3. In Asia, oil-indexation remains the norm for most imported gas, but new contracts in many parts of the region are weakening this linkage by including references to other indices (such as the US Henry Hub).

Throughout the world, the trend is towards greater flexibility of contract terms, shorter contract duration and a greater share of gas available on a spot basis. However, there are still multiple contractual, regulatory and infrastructure barriers that prevent the gas market from operating like a standard commodity market.

The Figure 70 summarises the trend of natural gas price that regard the New Policy Scenario.

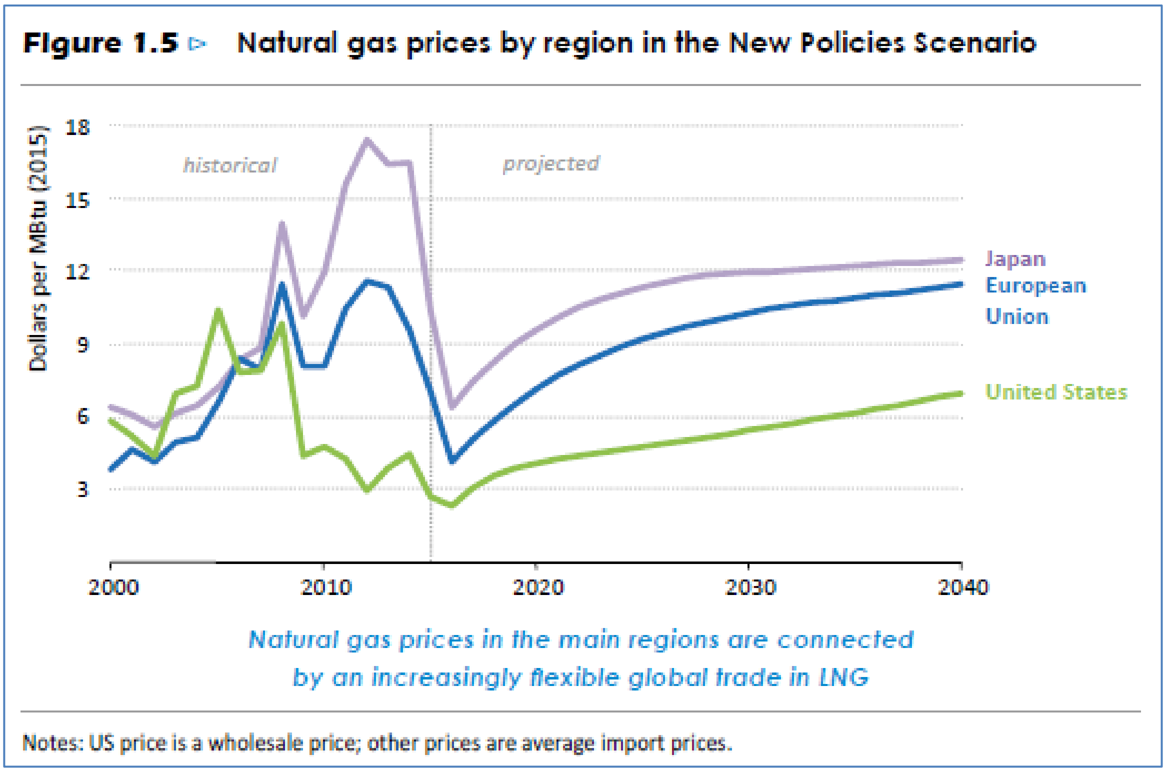


Figure 70 – Average natural gas price in the New Policies Scenario (Source: WEO 2016)

With respect to the estimates that could be used in the study, the price of Natural Gas can be assumed equal to:

- 5 $/MBTU in case gas is a home product (as in Argentina)
- 11.5 $/MBTU when overseas transportation is involved.

2.4.2.2.3 Coal

The global coal market consists of various regional sub-markets that interact with each other through imports, exports and arbitrage opportunities. The international coal market plays a pivotal role in connecting the different sub-markets and in determining overall price trends. Although prices vary significantly between the regional markets (due to transportation cost, infrastructure constraints and coal quality), they typically move in lockstep with international coal prices.
All major coal prices had been in steep decline for four consecutive years before bottoming out in early 2016. The average price of imported steam coal in Europe fell to $57/tonne in Europe and $59/tonne in Japan in 2015. Such price levels were last seen in the early 2000s, just before the big price hike started in the mid-2000s. While much of the price increase between 2007 and 2011 had to do with

strong global coal demand growth, China's emergence as a major importer, supply capacity shortages, overheated supply chains and the relative weakness of the US dollar; much of the price decline over the last four years has to do with a reversal of these fundamentals.
Global coal demand growth has stalled, Chinese imports are declining, supply capacity is amply available, the US dollar has appreciated against all major currencies and supply chains (shipping and infrastructure but also machinery and consumables supply) have slackened.

It is not unusual for coal markets to follow business cycles, but the key question is whether the coal market will find a way out of the current downturn and achieve an economically viable price trajectory. Coal price trajectories in the WEO 2016 rest on four pillars:

1. Policies and market forces underpin the closure of mines that are unable to recoup their costs, which leads to a reduction of excess capacity and supports a balancing of supply and demand by the early 2020s, with the profitability of the industry by-and-large restored.
2. Global coal demand growth of 0.2% per year, in combination with gradual depletion of existing mines, partially absorbs overcapacity and requires investments in coal supply of $45 billion per year over the Outlook period in the New Policies Scenario.
3. Geological conditions are worsening, new mines are deeper or further away from markets and coal quality is deteriorating; all of these factors put modest upward pressure on costs that cannot be fully offset by productivity gains.
4. Current exchange rates remain unchanged, while cyclically low input prices for steel, tyres and fuel trend upwards in the long term.

Spurred by the implementation of a first set of capacity cuts in China, coal prices started rising in the second-quarter of 2016. According to that, for example, the New Policies Scenario (Figure 71) sees this process continuing slowly, with European and Japanese import prices reaching $70/tonne and $73/tonne respectively in 2025 and thereafter increasing gradually to $77/tonne and $80/tonne in 2040.

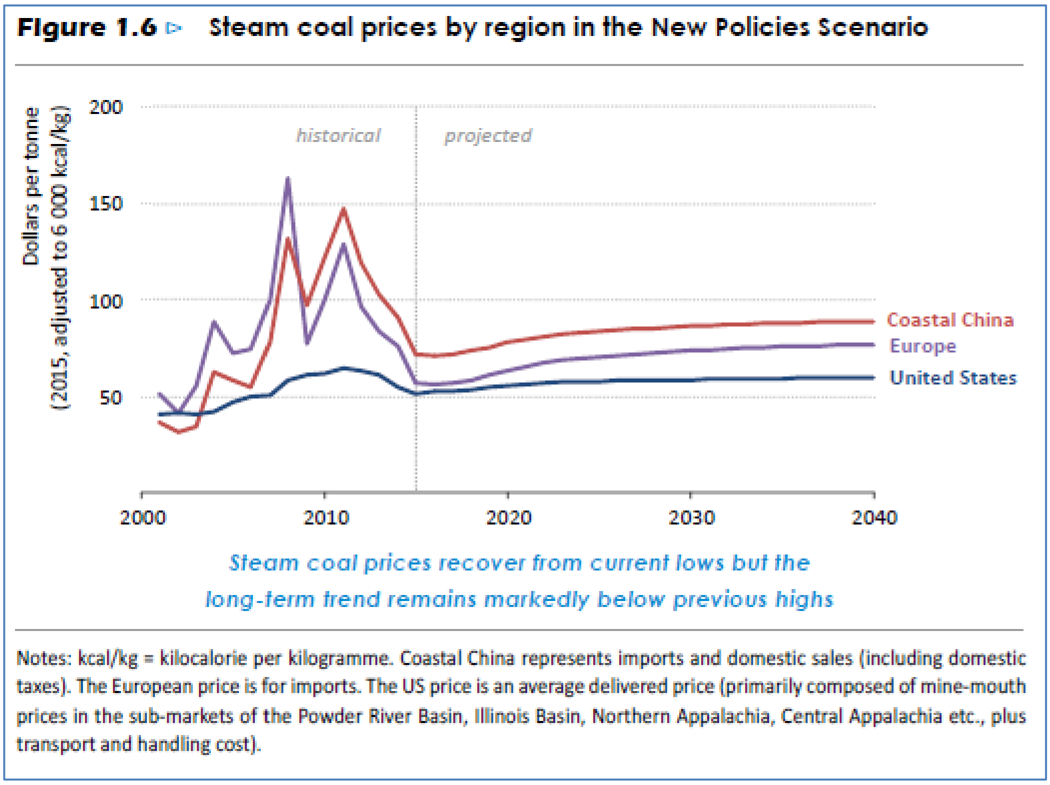


Figure 71 – Average coal price in the New Policies Scenario (Source: WEO 2016)

The price 75 $/tonne could be considered for the study, for the USA price is a local price, and Europe is comparable to LatAm with respect to the additional costs, namely transportation.

2.4.2.2.4 Primary energy costs from another notable source

Additional information has been collected for another notable source in order to crosscheck the evaluations from the WEO-2016 report. The source of the next graph (Figure 72) is the US EIA Annual Energy Outlook 2017 [20]; the data were uploaded from the collection "Energy Prices by Sector and Source, Reference case, United States"[18].

[18] EIA website https://www.eia.gov/outlooks/aeo/data/browser

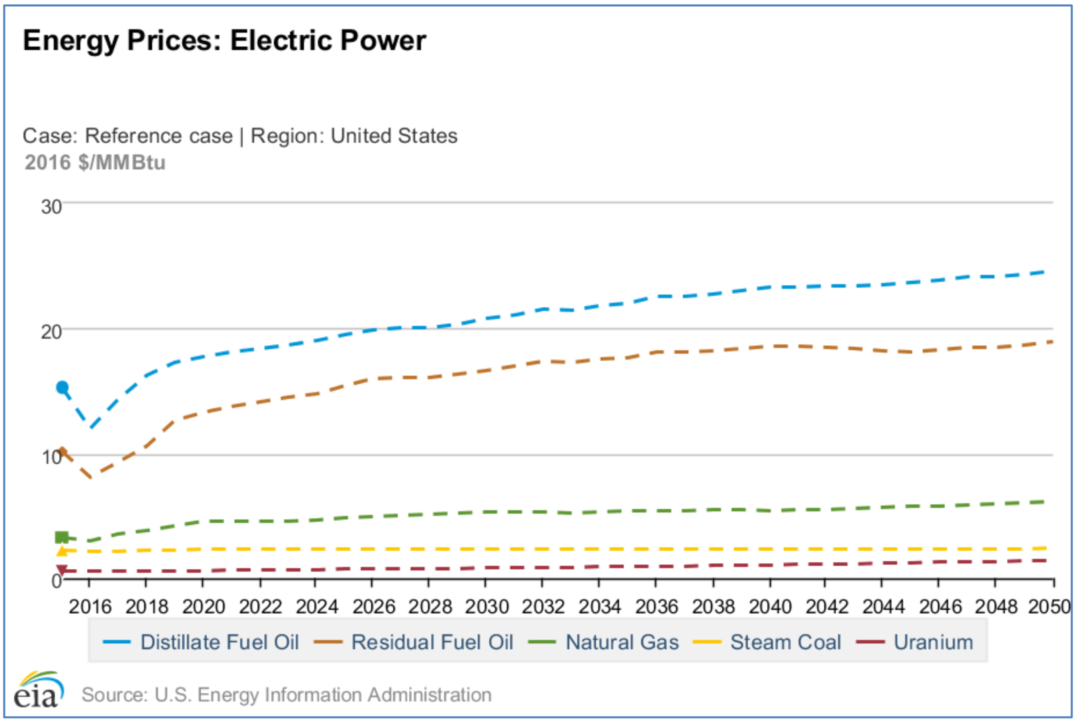


Figure 72 – Energy Prices: Electric Power – Projections of energy prices for electric power generation until 2050

The data shown in the Figure 72 compares well to the data shown in the preceding plots by the WEO-2016 that regard crude oil, natural gas and coal. Care must be taken when converting different units, for example a million BTU is usually MBTU, but MBTU is occasionally expressed as MMBTU and is intended to represent a thousand thousand BTUs, in which case MBTU stands for a thousand BTU. Conversion factors can be found from the website www.eia.gov.

- Crude oil. The price 110 $/barrel in Figure 69 compares to the price 20 $/MMBTU in Figure 72 (for 1 barrel oil equals 5.7 MMBTU)
- Natural gas. The USA price 5 $/MBTU in Figure 70 compares to the price 5 $/ MMBTU in Figure 72 (knowing the units shown in the two graphs can be equivalent)
- Coal. The price 75 $/tonne in Figure 71 compares to the price 3 $/MMBTU in Figure 72 (for 1 tonne of coal equals 21.7 MMBTU)

2.4.2.3 Information about the primary energies by sources from Brazil, Argentina and Uruguay

Information could be found, issued by organizations from Brazil and Argentina, that provide prices projections for the primary energies, as it is described in the following paragraphs. No specific publications have been found for prices in Uruguay.
Because these information from Brazil and Argentina are based on the data from international organizations, the trends are similar to those reported from the WEO-2016.
Nevertheless these projections can be considered in the present study, for they are country specific projections and can better represent the future primary energy costs for Brazil and Argentina in the year 2030.

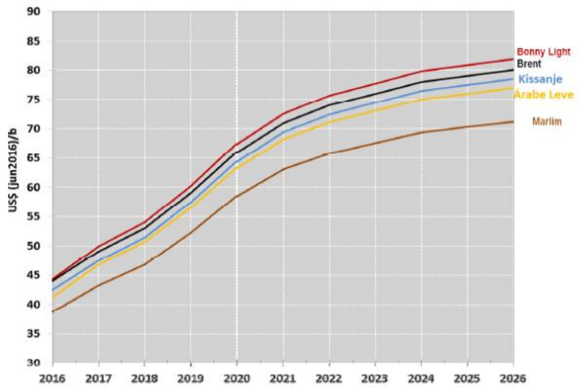
2.4.2.3.1 Brazilian – future trends

In regards to the price projections issued by Brazilian institutions, information has been found from the Plano Decenal de Expansão de Energia [4] and from the Plano Nacional de Energia 2030

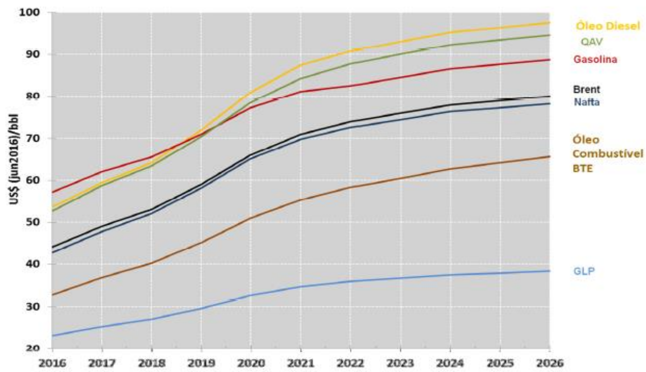
The source analysed relevant information from other notable sources:

- Annual Energy Outlook (AEO) 2016 - Energy Information Administration (EIA) - USA.
- Commodity Market Outlook Q2, 2016 - World Bank.

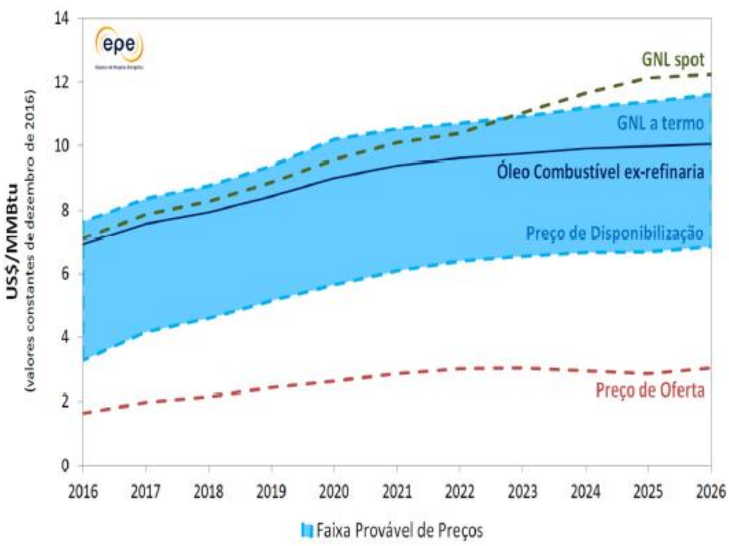
Between these two sources, AEO 2016 was chosen because of the adequate sensitivity scenarios and a cross-sectional view of crude oil, natural gas and coal for the horizon 2016-2031. The main energy sector indicators are shown in the plots of Figure 73.



Oil Brent Type



Oil and oil derivatives



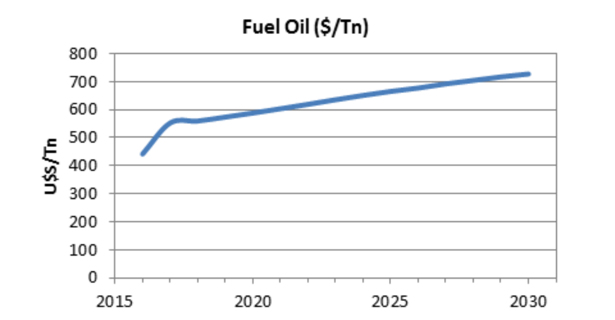
Natural Gas

Figure 73 – Energy prices projections to 2026 in Brazil (source EPE)

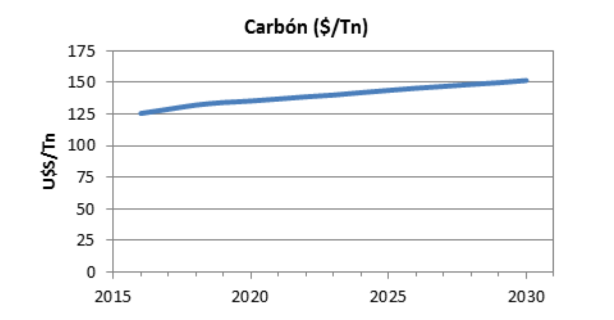
As far as coal is concerned, EPE foresees a stable trend of its cost up to 2026, which remain around 2.27 $(MBTU, equal to around 78 $/ton. This value is assumed also for 2030.

2.4.2.3.2 Argentina – future trends

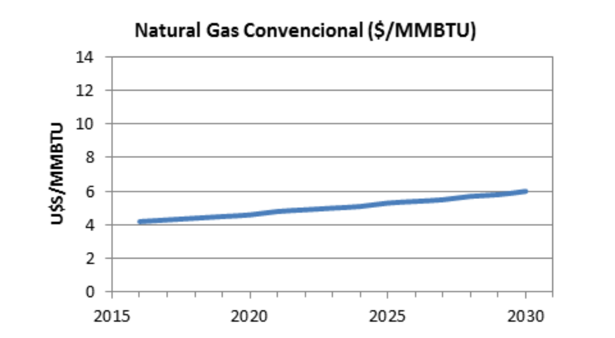
In regards to the price projections issued by Argentinian institutions, information has been found from the following source "Metodología para la elaboración y evaluación de escenarios energéticos 2015 - Plataforma escenarios energeticos Argentina 2035 - http://www.escenariosenergeticos.org" [28].
The document focalised the methodology that shall be used to study future energy scenarios. The methodology is based on LEAP. LEAP is not a model of a particular energy system, but rather a tool to create models of different energy systems. The LEAP data sets compile international data provided by various sources, for example energy resource data from the World Energy Council.
The data shown in the report provide the price projections of the primary energies.
The main energy sector indicators are shown in the plots of Figure 74.



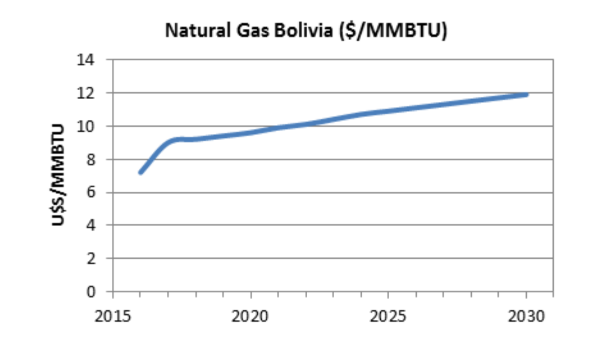
Projected prices for Fuel oil



Projected prices for coal



Projected natural gas prices



Projection of natural gas prices from Bolivia

Figure 74 – Energy prices projections to 2030 in Argentina (Source: Plataforma escenarios energeticos Argentina 2035)

The cost of fuel oil is estimated about 725 $/tonne, or 98.9 $/barrel (1 tonne = 7.33 barrels).
Two different prices are shown for natural gas, for a part of the gas comes from internal sources, and a part is imported. According to a BP report [29], in 2015, Argentina produced 36.5 billion cubic meters of natural gas, and consumed 47.5 billion cubic meters, hence 11 billion cubic meters were imported: 50% from Bolivia through the pipeline, and 50% liquefied gas shipped from suppliers overseas.
The prices shown in the plot of Figure 74 compare well to the prices from the WEO-2016.
Coal price is nearly double the value forecasted at international level. This difference is deemed too high, and the value considered for Brazil (78 $/ton) is assumed also for Argentina. The impact of this reduced cost is not significant for the system due to the fact that the installed power of coal power plants is limited in Argentina, and the operational cost per MWh is lower than the cost of production from Natural Gas with both the values, so the coal plants are running for a very high amount of equivalent hours being one of the cheapest thermal technology.

2.4.2.3.3 Uruguay – future trends

As far as Uruguay is concerned, no specific official documentation has been identified. Reference to International trends and to the situation of Argentina and Brazil was adopted. Also assumptions in [5] can be taken into account as a valid reference.

The cost of fuel oil is assumed equal to 98.9 $/barrel, aligned with Argentinean case, and higher than Brazil.

Natural Gas is assumed coming mainly from Argentina through the existing pipeline and partially supplied by LNG plant (currently under evaluation to improve security of supply). The resulting cost can be obtained as a weighted average between the average cost in Argentina (9 $/MBTU) and the expected cost of LNG (15 $/MBTU). Assuming that five parts of gas are obtained from Argentina and one part from the LNG system, the final average cost is equal to 10 $/MBTU.

Cost of coal is not relevant for Uruguay as there are no coal power plants in the system.

2.5 Discount rates

Discount rates for power generation projects

The sources and the relevant assumptions are summarised below.

1) The study described in IRENA report "Power to change 2016" [15] defines the assumptions that regard the WACC (average weighted cost of capital) in non OECD countries, set equal to 10%..
2) Similar estimates are shown in the paper "Eolic Projects in Emerging Countries (Argentinean case)" [22]; this paper analysed the cost of equity in Argentina (as well as other developing in the Latin America).
3) Input data used in "PDE – Plano Decenal de Expansão de Energia" 2016 is equal to 8%
4) Uruguay can be deemed a country with financial conditions similar to Brazil.

The resulting values are shown in the following table.

Table 30

Discount rates for power generation projects		
Country	WACC (%)	OECD member state
Argentina	10	No
Brazil	8	No
Uruguay	8	No

Discount rates for power transmission projects

The discount rates for power transmission projects are defined by Regulators appointed by specific laws .

1) In Argentina the current value is defined by Ente Nacional Regulador de la Electricidad (ENRE) and is equal to 7.70% after taxes.
2) In Brazil and Uruguay, no specific values for transmission projects have been identified, and the same WACC used for generation facilities will be applied in this case.

Table 31

Discount rates for power transmission projects	
Country	Discount rate (%)
Argentina	7.7
Brazil	8
Uruguay	8

Proper sensitivity analysis will be performed in order to cover a wider range of possible values of discount rates for power transmission systems in the Countries.

The assumptions regarding the discount rates that shall be sued when evaluating the costs of the electricity generation and transmission projects are summarised in the following.

2.5.1 Discount Rate for the Generation Projects

The report "IRENA Power to Change 2016" [15] analysed the costs of solar and wind renewable energies between 2015 and 2015. IRENA's analysis focuses on the impacts of technology and market developments on the LCOE. This analysis regards the total costs of the energy generation projects, including equipment, installation, O&M, and the cost of the capital. The cost of capital is briefly outlined in this paragraph, whereas the equipment installation and O&M costs regarding solar photovoltaic and on-shore wind generation projects are presented in a next paragraph.

The LCOE is an indicator of the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate. The analysis takes into account the weighted average cost of capital or WACC. The WACC is defined according to the following equation:

$$WACC = \frac{Debt * rd + \ Equity * re}{Debt + Equity}$$

where

- the investment is the sum of equity and debt: Debt is financed with money not of the owner of the asset, and Equity is directly financed by the owner.
- rd is the rate of interest of debt
- re is the rate of interest of equity

Because an asset can be financed through debt and equity, WACC is the average of the costs of these types of financing, each of which is weighted by its proportionate use in a given situation.

In regards to WACC, the analysis in the IRENA report assumes a WACC for a project of 7.5% in the Organisation for Economic Cooperation and Development (OECD) countries and China. Borrowing costs are relatively low in these countries, while stable regulatory and economic policies tend to reduce the perceived risk of renewable energy projects. For the rest of the world, a WACC of 10% is assumed. IRENA specifies that these assumptions are average values: the cost of debt and the required return on equity, as well as the ratio of debt to equity, varies between individual projects and countries. This can have a significant impact on the average cost of capital and the LCOE of renewable power projects. It also highlights that ensuring that policy and regulatory settings minimize perceived risks for renewable power generation projects can be a very efficient way to reduce the LCOE by lowering the WACC.

The analysis by IRENA focuses on the technology and market drivers of cost reduction in terms of improved performance and lower installed costs, as well as O&M costs. IRENA assumed a fixed cost of capital in the period analysed by IRENA, between 2015 and 2025, for solar PV and on-shore wind projects.

The above assumptions hold for all mature generation technologies: today solar PV and onshore wind are much more mature and financial institutions are more experienced in their development. An additional comment regards the markets that are new for these technologies: although it may take time for local financial institutions to be able to properly assess the real risks facing solar PV and onshore wind (meaning cost of capital premiums over more mature markets may persist until experience is gained by local developers and financing institutions), the increased presence of international developers is expected to limit or even eliminate the premium sometimes experienced in new markets.

In regards to the present study, the qualification of Argentina, Brazil and Uruguay with respect to the OECD membership shall not be taken into account because these Countries are not member of OECD. The updated list of the OECD member states is available from the OECD website (Source: http://www.oecd.org/about/membersandpartners/list-oecd-member-countries.htm).
According to the information above the following average discount rates (WACC) shall be used with reference to the countries considered in the study:

- Argentina , Brazil and Uruguay not OECD member state 10%

More insight has been gathered about the cost of capital – debt and equity, in order to check the assumptions that will be applied when studying the countries of interest. For example a project information document by the World Bank [21] analyzed the development of the renewable sources in Argentina, and mentioning that "In April 2016, after more than a decade, Argentina successfully returned to global debt markets with a US$16.5 billion bond sale (largely oversubscribed with orders of almost US$70 billion) and a lower than expected 7.5% yield for the 10-year tenor".
In regards to the cost of equity, we reports the results of the analysis described in the paper "Cost of Equity: Eolic Projects in Emerging Countries (Argentinean case)" [22]. This paper describes a calculation method of the cost of equity for wind energy projects in Argentina and in the LatAm emerging countries. The proposed framework is deemed valid for PV projects as well. The methodology to estimate the cost of equity is the Capital Asset Pricing Model (CAPM), and the cost of equity is estimated by adding the following contributions:

- Risk free rate
- U.S. risk premium x β[19]
- Country risk premium

Further details about the calculation method can be found in the paper. Here below we report the result of the calculations that shows the Country Risk premiums and the Cost of equity that were estimated for Argentina, Brazil and Uruguay.

Country	Country Risk Premium (%)	Cost of Equity (%)
Argentina	4.75	14.55
Brazil	2.65	12.44
Uruguay	2.53	12.33

2.5.2 Discount Rate for the Transmission Projects

In Argentina and Brazil, the discount rate to be used for the calculation of the remuneration for the regulated transport companies[20] which build and own transmission lines is defined by the Regulators

[19] Beta is a measure of the volatility, of an individual stock or a portfolio, in comparison to the whole market. In this case the author analysed the volatility of the wind energy companies.
[20] In Argentina, the criteria for the calculation of the discount rate are defined in the Article 41 of the Law N° 24.065.

following processes described in relevant Laws and regulations. This approach is proposed to, on one hand, ensure the investments needed for the construction of the electrical infrastructure, and, on the other, control the tariffs to avoid an excessive increase of the costs and the advantage of some companies.

In Argentina, the discount rate is defined by the Ente Nacional Regulador de la Electricidad (ENRE), and for the current period in the Resolución ENRE 0553/2016 it has been defined equal to 7.70%, after taxes.

The values assumed in the project are then 7.7% for Argentina and 8% for Brazil and Uruguay, where no specific information for Transmission project is available.

However, proper sensitivity analysis will be performed in order to cover a wider range of possible values of discount rates applied to the investments in transmission lines in the Countries.

2.5.3 *Lifetime of power system projects*

2.5.3.1 *Power generation projects*

Comparison of different power generation technologies is provided in the Table 32. Sources: LAZARD - Lazard's Levelized Cost Of Energy Analysis—V.10.0 – Dec 2016 [11]

Table 32 – Life of the facility according to the generation technology (Source: [11])

	Technology				
	PV (Utility scale) Crystalline or TF	Wind	Nuclear	Coal	Gas Combined Cycle
Life of the facility (years)	30	20	40	40	20

Below further crosschecks of life time assumptions for PV and Wind technologies.
In regards to Solar Photovoltaic, the following information was collected from the report by IEA-PVPS, Task 12 Methodology Guidelines on Life Cycle Assessment of Photovoltaic Electricity, 3rd Edition, January 2016 [12]. According to this IEA-PVPS report on LCA, the lifetime of the PV systems can be assumed 30 years. More details of the assumptions that regard the parts of the PV equipment are shown below, from Paragraph 3.1.1. - Life expectancy:
"The recommended life expectancy used in LCAs of PV components and systems differentiates between the components:

- Modules: 30 years for mature module technologies (e.g., glass-glass or glass-Tedlar encapsulation); life expectancy may be lower for foil-only encapsulation. This life expectancy is based on typical PV module warranties (i.e., 20 % or less efficiency degradation after 25 years) and the expectation that modules last beyond their warrantees
- Inverters: 15 years for small plants (residential PV); 30 years with 10% part replacement every 10 years (parts need to be specified) for plants at utility scale (>1 MW) (Mason et al. 2006)
- Transformers: 30 years
- Structure: 30 years for roof-top and façades, and between 30 to 60 years for ground-mount installations on metal supports. Sensitivity analyses should be carried out by varying the service life of the ground-mount supporting structures within the same time span
- Cabling: 30 years

"

In regards to Wind projects, the following information was collected from the IEA WIND 2014 Annual Report [13]: "… average conventional lifetime of (wind) plants is 20–25 years."

2.5.3.2 *Transmission network projects*

In regards to transmission projects, the assumption gathered from the ENTSO-E Guideline for Cost Benefit Analysis of Grid [31] is reported below.
"The assessment period is typically driven by the expected economic asset life of the proposed project without considerable replacement cost. Empirical evidence suggests that a typical transmission project has an asset life of approximately 40 years. Such an assumption can be readily adopted across Europe or further afield".

2.6 Reserve requirements

2.6.1 Existing reserve requirements

2.6.1.1 Argentina

Existing reserve requirements are described in the CAMMESA procedures [33][34]. The value adopted for the period from May 2017 to October 2017 are reported in the MEMNet section of the CAMMESA website [35], which provides information and definitions for each type of reserve adopted for system operation:

- **Primary reserve.** It is a fast regulation, with a response time of less than 30 seconds, dimensioned considering demand forecast error statistics, when the electrical system is in normal operating mode. The requirement for this type of reserve is 3% of the total dispatched generation.
- **Secondary reserve.** It is the manual or automatic action on power generation aimed to frequency restoration. The variations compared to scheduled balance are compensated in the first instance by primary regulation. The secondary regulation allows restoring the level of primary control and its response time is of the order of several minutes. The requirement for this type of reserve is 2.1% of the total dispatched generation.
- **Operational reserve**, or 5 minutes reserve. It is another fast reserve in machines, with a response less than five minutes, which allows the balancing of demand, complementing the frequency regulation service and guaranteeing the operation of the system. In order to guarantee the operation of the electrical system and the ability to respond quickly to a contingency in the transmission system or in the generation fleet, it is considered necessary to maintain an operational reserve equivalent to the secondary frequency reserve, equal to the 2.1% of the total dispatched generation.
- **10 minutes reserve**. It is necessary for restoring the operational reserve in case of contingency; consequently it is necessary to have a reserve of 10 minutes equal to 2.1% of the total dispatched generation.
- **20 minutes reserve.** In order to cover prolonged supply or demand deviations during this period, it is considered necessary to have a cold reserve equivalent to 3% of the total dispatched generation.

2.6.1.2 Brazil

The existing reserve requirements of the Brazilian electric power system are described in the ONS manual for operating procedures [36]. In-depth analyses of power system operation are carried out by ONS with a probabilistic approach in order to assess the total operating reserve required for the safe operation of the system.

The total operating reserve (RT) is the power reserve sufficient to restore the balances between the available generation and the load can happen due to the occurrence of events such as generation loss/reduction and load forecast errors. The probabilistic approach takes into account both the forced outage probability of the generation fleet and the load forecast error probability. The total operating reserve is the sum of the primary, secondary and tertiary reserves defined as follow by ONS:

- **Primary reserve.** It is the reserve margin used to response at frequency deviations due to instantaneous demand/generation variations. This is a reserve for very fast regulation; it able to re-establish the balance between the generation and the load without, however, re-establish the frequency in the original value. The primary reserve is assessed with deterministic method and it corresponds to 1% of the dispatched generation in each area (R1). This must be distributed on all generator units with unlocked speed governor and power generation lower than the maximum output.

- **Secondary reserve.** It is the power generation aimed to restore the programmed frequency of the system; this is in addition to the action of primary regulation. Secondary reserve regulation, when automatic, is performed by the Automatic Generation Control (AGC). The secondary reserve requirements recommended by ONS include a secondary upward reserve equal to 4% of the total dispatched generation (R2e) and a secondary downward reserve equal to 2.5% (R2r). Therefore, the total recommended secondary regulation margin corresponds to 6.5% of the load.
- **Tertiary reserve.** It is the difference between the total operating reserve calculated with probabilistic analyses and the primary and secondary reserves (R3 = RT – R1 – R2e). If the total operating reserve calculated with probabilistic approach is lower than 5% of demand, the tertiary reserve (R3) is considered equal to zero.

2.6.1.3 Uruguay

No detailed information has been found describing the way how reserve is currently ensured in Uruguay. It is important to underline that Uruguay in the past had a system with strong presence of big hydro and thermal power plants, including Open Cycle Gas Turbine, which allow an accurate control of the unbalances with respect to the load forecasts. Moreover, the system is characterized by a high interconnection capacity with neighbouring countries, often not fully exploited, but available in critical conditions to ensure a right balance of the power system.
With the strong introduction of VRES plants, in particular wind farms, the possibility of big errors between the forecasted load and generation increases, requiring a special focus on the reserve.
The approach commonly adopted in presence of high penetration of VRES is described in the following paragraph.

2.6.2 Reserve requirements with Variable RES

Integration of RES generation, such as wind and photovoltaic generation, into the power grid introduces major challenges for power system planning and operation because RES are variable and programmable in a limited share. Therefore, when a high penetration of VRES has to be integrated into the grid, their variability will significantly impact many technical issues, e.g., reserve requirements. In this paragraph, we propose a technique to assess the reserve requirements in presence of a big amount of wind and photovoltaic generation.
Among RES, wind power can be considered one of the most variable resources. Wind power generation is a non-linear function of wind speed and fluctuates on various time-scales from seconds to seasons according to the availability of the primary source. Wind power production has a seasonal pattern due to meteorology but also a diurnal pattern due to daily weather, influenced especially by temperature. Wind speeds are subject to a broad range of uncertainty of both atmospheric and geographic nature; then the predictability of wind speed is rather low and has limited accuracy; consequently, it affects the predictability of wind farms production.

On the other hand, photovoltaic power plants convert sun light into electrical energy, depending on the intensity of solar radiation. While dependence on the position of the power plant is not a big issue, the time-characteristics of solar energy can result in additional requirements for the power system, with different features with respect to wind. Electricity production from PV has both seasonal variation – with the peak in summer and diurnal variation – and it is typically peaking during mid-day. It also fluctuates in inter-hourly scale for example due to clouds and rain fall. However, the output power from PV generation is more predictable than wind power production.
The knowledge of the variable output characteristics of RES is very important to deal with their impacts on reserve requirements. Wind power is much more fluctuating and unpredictable than power production from PV and also than load. Besides, while PV generation occurs in hours of high load, not so happens for wind generation. Therefore, wind and PV generation have completely different features, in terms of requirements for the reserve.
The forecast errors of RES productions introduce additional uncertainty into the operation of power systems due to the natural variability of power production from RES and the inherent uncertainty in its forecasting. Therefore the RES integration into a power system may need an additional amount of reserve.
To assess the additional reserve due to the penetration of RES generation, several methods have been developed. The most popular method is the statistical method, in which the variability/forecast errors of RES generation are combined to those of load to investigate their statistical properties. If load and power generation from RES (wind and solar PV) are not correlated, the standard deviation of the total forecast error (σ_E) can be calculated from standard deviations of load errors (σ_L) and RES generation forecast errors (σ_W for wind production and σ_{PV} for PV production) as follows:

$$\sigma_E = \sqrt{\sigma_L^2 + \sigma_W^2 + \sigma_{PV}^2} \qquad (1)$$

Considering the distribution of the total forecast error ($E_{f\text{-}tot}$) as a normal distribution, the 99.7% of values will be included in the following range:

$$-2.74 \cdot \sigma_E \leq E_{f-tot} \leq +2.74 \cdot \sigma_E \qquad (2)$$

The extreme values of the range define the maximum downward and upward reserve able to cover 99.7% of expected forecast errors. Therefore, the standard deviation of forecast error can be used to evaluate the tertiary reserve requirements in presence of Variable RES power plants.
The maximum total forecast error ($E_{f\text{-}tot\text{-}max}$), downward and upward, can be defined as the combination of forecast errors of load, wind production and PV production as follow:

$$E_{f-tot-max} = \sqrt{E_{f-L-max}^2 + E_{f-W-max}^2 + E_{f-PV-max}^2} \qquad (3)$$

Where the maximum load forecast error ($E_{f\text{-}L\text{-}max}$), greater than the 99.7% of expected forecast errors, is:

$$E_{f-L-max} = 2.74 \cdot \sigma_L \tag{4}$$

While the maximum wind forecast error ($E_{f\text{-}W\text{-}max}$) and the maximum PV forecast error ($E_{f\text{-}PV\text{-}max}$), greater than the 99.7% of expected forecast errors, are the minimum values between 2.74 times the standard deviation of forecast error and the difference between the installed power and the forecast of generated power.

$$E_{f-W-max} = min\begin{cases} 2.74 \cdot \sigma_W \\ P_{W-inst} - P_{W-gen} \end{cases} \tag{5}$$

$$E_{f-PV-max} = min\begin{cases} 2.74 \cdot \sigma_{PV} \\ P_{PV-inst} - P_{PV-gen} \end{cases} \tag{6}$$

2.6.2.1 Secondary reserve

The secondary reserve must be sized to contain and restore any frequency deviation and power exchange at the border (ACE: Area Control Error). The secondary reserve is activated by the secondary control systems.

The secondary reserve (R_{sec}) can be sized with the following methodology:

1) Calculation of $R_{sec\text{-}1}$ using the empirical formula adopted by ENTSO-E and previously by UCTE:

$$R_{sec-1} = \sqrt{10 \cdot L + 150^2} - 150 \tag{7}$$

Where $R_{sec\text{-}1}$: the recommended value for the secondary reserve in MW
L : the load (in MW) according to area and period of time

2) Comparison between the $R_{sec\text{-}1}$ and P_{group_max} for the largest generating unit in service:

$$R_{sec-2} = max\{R_{sec-1}; P_{group\_max}\} \tag{8}$$

3) If necessary, multiplication of $R_{sec\text{-}2}$ by a coefficient (e.g. 1.05) to take into account any additional factors:

$$R_{sec} = R_{sec-2} \cdot coeff \tag{9}$$

Sometimes the formula (8) relative to the larger unit in the system is not considered to not increase excessively the secondary reserve requirement.

2.6.2.2 Tertiary reserve

The tertiary reserve should be sufficient to make up for the largest foreseeable amount of power loss (incident of reference) in the control area under the responsibility of the system operator. There are at least two types of tertiary reserve:

- Tertiary upward reserve
- Tertiary downward reserve

The need for a tertiary reserve R_{ter} also takes into accounts the secondary reserve R_{sec}, so: $R_{ter} > R_{sec}$. To determine the size of the tertiary reserve, it is possible to use either deterministic criteria (a list of events involving unavailability of the production units and/or load rejection) or probabilistic criteria (typically, the uncertainty of predicting demand or the probability of the production unit tripping). Moreover, the tertiary reserve should permit complete re-establishment of the secondary reserve and making up for delayed or anticipated increase/decrease in load.
Taking into account the impact of Variable RES in the electric power system and the statistical method on the forecast errors of RES generation we can define the following tertiary reserve requirements to be used for the evaluation of the additional reserve due to RES integration.

Tertiary upward reserve:
Comparison between the secondary reserve in peak load condition ($R_{sec\text{-}1\text{-}peak}$), the biggest dispatched unit and the maximum error due to the forecast of load, wind generation and PV production:

$$R_{ter-up} = max\begin{cases} R_{sec-1-peak} \\ P_{group\_max} \\ E_{f-up-\mathrm{max}} \end{cases} \tag{10}$$

Where:

$R_{sec\text{-}1\text{-}peak}$	:	the recommended value for the secondary reserve in MW during peak load
P_{group_max}	:	the largest generating unit in service during peak load
$E_{f\text{-}tot\text{-}up\text{-}max}$	:	maximum upward forecast error in MW, calculated as. (3)

Tertiary downward reserve:
Comparison between the secondary reserve in minimum load condition ($R_{sec\text{-}1\text{-}min}$), the minimum power of biggest pumping unit and the maximum error due to the forecast of load, wind generation and PV production:

$$R_{ter-down} = max\begin{cases} R_{sec-1-min} \\ P_{pump} \\ E_{f-tot-max} \end{cases} \tag{11}$$

Where:

$R_{sec\text{-}1\text{-}min}$	:	the recommended value for the secondary reserve in MW during minimum load
P_{pump}	:	minimum power of the largest pumping unit
$E_{f\text{-}tot\text{-}down\text{-}max}$	:	maximum downward forecast error in MW, calculated as (3)

3 DEFINITION OF VARIANTS

This chapter presents the characteristics of two different scenarios, called Variants, to be investigated in order to evaluate the behaviour of the system in case some major changes take place with respect to the assumptions at the basis of the Reference Scenario discussed in the previous chapters.
Like the previous cluster, the aim of the analysis of these Variants is the investigation of the impact that some key parameters can have on the operation of the overall system and on the results obtained in the Reference Scenario.
Examination of Variants allows taking into account the uncertainty in the evolution of key parameters, such as the electrical demand, and / or technological breakthroughs.
By comparing the outcomes of the various Variants with those of the Reference Scenario, it is possible to appraise to what extent they fit against possible different evolutions of the power systems. The more flexible are the solutions, the better is for the potential investors.

The main key parameters that are modified with respect to the Reference Scenario are:

- Electric demand
- Generation evolution
- Possibility to have electrical storage systems

A limited set of changes in the parameters with respect to the Reference Scenario is introduced in each Variant to clearly identify the relationships between the assumptions adopted in the Variants and the relevant outcomes. In fact, if many parameters are modified together, it becomes hard to identify the main reasons of a change in the system operation. In some cases, changes in the assumptions can have opposite effects on the results, so there is the risk to miss some important effects on the operation of the system that may be netted by another change in the parameters having an opposite impact.
Thus, basically two key criteria are used to build Variants:

1) selection of a reduced set of key parameters to be modified;
2) definition of clearly distinct scenarios.

A short description of the Variants, with the rationale behind the proposed changes with respect to the Reference Scenario, is given in the next paragraphs.

3.1 First Variant

The first Variant aims at considering a scenario of higher demand in the countries. In this case, the analysis wants to assess whether the additional load can be supplied by new VRES and whether this requires further improvements of the transmission capacity between the areas. Moreover, the need for possible additional requirements on the thermal and hydro plants due to reserve constraints will be highlighted.
In general, a higher demand requires more generation to meet the adequacy standards. In this Variant the new level of economically feasible VRES will be assessed. In this situation, more reserve is needed in order to compensate possible variations of VRES output due to fast changes of wind or solar irradiation.

With an increased load, the system risks to face situations with lack of generation, but also there might be also situations with problems of overgeneration due to technical constraints of programmable generators in service.

Demand

As stated at the beginning of the paragraph, in this Variant a scenario with higher demand is analysed. The main drivers which can contribute to a demand higher than the one in the Reference Scenario are:

- Stronger economic growth of the countries
- Increase of population
- Higher electricity penetration, with particular reference to transport sector and residential use

It is assumed to analyse a Variant with a demand 8% higher than the Reference Scenario. This is equivalent to consider an annual growth rate of the load about 0.5% higher than the one assumed in the Reference Scenario. The increase of the load is assumed to be mainly due to a stronger economic growth and partially to the impact of the e-mobility, concentrated in the biggest cities.

To assess the load due to e-mobility, the following considerations have been made:

- Expected cars: 335 per 1,000 inhabitants in Argentina based on information by MINEM[21]. The same amount of cars can be expected in Brazil applying the same growth rates of Argentina. Also Uruguay will be simulated with 335 cars per 1,000 inhabitants.
- 5% electric vehicles in Argentina, which is a very high value assumed to stress the impact which e-mobility can have on the electrical system, also in case of a disruptive development of this sector. 15% electric vehicles are expected in Uruguay[22] while only 1% in Brazil according to the national policy about the electric vehicles [23]
- Considering EV mainly in large urban areas, and given the number of inhabitants of Gran Buenos Aires (about 15.18 million people), Sao Paulo (about 21.39 million people), Rio de Janeiro (about 12.38 million people) and Montevideo (about 1.31 million people), it means a rough estimate of about 250,000 electric vehicles circulating in Buenos Aires, 71,000 in Sao Paulo, 41,000 in Rio de Janeiro and 66,000 in Montevideo.
- About 20,000 km and 0.15 kWh/km as average values for the vehicles.

On these assumptions, the additional demand due to e-mobility can be estimated in 750 GWh in Argentina (0.32% of the total load), 336 GWh in Brazil (0.04% of total load) and 198 GWh in Uruguay (1.35% of the total load).

This demand will be considered in the simulations only concentrated in the area of Grand Buenos Aires Sao Paulo, Rio de Janeiro and Montevideo, in the night hours.

[21] Annual growth rates of cars fleet expected by MINEM (Argentina): 2.43% in the period 2015-2025 and 1.82% in the period 2025-2040.

[22] MIEM-DNE in the "Estudio de demand: escenarios" published in 2014 provided a forecast of increasing participation of electric vehicles starting from 2020 and reaching 15% in 2030.

[23] EPE in the "PDE - Plano Decenal de Expansão de Energia 2026" foresees that, over the next eight years, the national vehicles fleet will be essentially consist of vehicles with internal combustion engines (mainly flex fuel biodiesel vehicle due to the importance of biofuels in the country). EPE expects a very low share of electric vehicles in 2026 (less than 1%); therefore, in 2030, we can assume this share equal to 1% of the cars fleet and it will be concentrated in the biggest urban areas (Sao Paulo and Rio de Janeiro).

The rest of the demand increase (the part caused by a general higher economic growth of the countries) will be applied in a flat way in all the regions.

Generation

Due to the load increase, it is expected that the systems will suffer of lack of generation if no additional plants are added. To ensure the compliance with generation adequacy standards, we assume that the additional generation will be based on VRES with the aim of relying exclusively on "carbon free" generation as far as possible. Hence, we assess the optimal penetration of VRES to cover the additional demand. When no traditional generation is considered, and its percentage with respect to the overall installation capacity is reduced, higher reserve is needed, to compensate possible variations of VRES production which become higher in absolute values. For this reason, it is also possible that, with more VRES installed, situations with overgeneration can occur, leading to possible curtailments of VRES. More flexibility is in general required and, if necessary, a simulation reducing the constraint on minimum power of the thermal generation will be performed to assess the benefits for the electrical system coming from it.

In this Variant, the transition towards a "coal-free" generation in Argentina, Brazil and Uruguay, aimed to minimize GHG emissions, will be simulated: all the coal power plants in the systems will be considered switched off. The production of the power plants which are phased-out in this Variant will be replaced by additional installation of VRES in the areas with highest potential and, if necessary for technical reasons such as dispatchability and reserve provision, by equivalent Natural Gas power plants.

Electric storage systems

Also the need of storage systems will be evaluated, to increase the flexibility of the overall system, reducing the constraints on the minimum production and increasing also the ability to cope with the peak load. With reference to the hydro power plants, the higher flexibility will be obtained considering an increased installed power in some specific plants and considering that also run-of-river plants can use their storage capacity, if any, to contribute to production modulation.

If needed, storage systems will be simulated by few big plants connected in the areas with most critical situations in terms of lack of production or curtailments due to overcapacity.

3.2 Second Variant

The second Variant aims at examining a scenario of lower demand in the countries. In this case, the analysis assesses whether in this condition there is the risk of overgeneration and which can be its impact on curtailments of the VRES generation.

The rationale behind a lower demand scenario is related, on the one hand, to the possibility that the economic growth in the countries will not be in line with the forecasts, and on the other hand to the increase of the energy efficiency with respect to what already accounted for in the Reference Scenario, which can reduce the amount of electrical energy needed for specific uses (light, electric motors, industrial processes…). As a reference, it is worth mentioning that the Ministerio de Energia e Mineria in Argentina states that the energy efficiency can lead in 2025 to a load 15% lower than the one considered in the base case (163 TWh against 192 TWh at 2025).

The investigation of such Variant turns out to be important both for the Transmission System Operators and the owners of RES power plants, since a lower demand level can lead to a higher amount of curtailed VRES generation.
The reduction of the minimum power limit of the thermal fleet and, if significant, the increase of interconnection capacity will be investigated to assess their impact on the operation of the systems with the objective to keep the same risk of VRES generation curtailment.

Demand

In line with the possible effect of energy efficiency stated by MINEM for Argentina, the demand in this country is set 15% lower than in the Reference Scenario. This 15% reduction is applied to the load forecasted at 2030[24]. The same share will be assumed in Uruguay
In Brazil the energy efficiency has been already partially included in the load forecasts performed by EPE and considered in the creation of the Reference Scenario, so the impact that can be expected on a further reduction of the demand is lower. For this reason it is decided to reduce the Brazilian load by a lower ratio, 10% instead of 15%.
In Uruguay, the energy efficiency national plan defined by MIEM for the period 2015-2024 [37] provides the actions needed to reach 5% reduction of energy demand expected in 2024, compared to the demand expected without energy efficiency. Taking into account this target and the growing impact of energy efficiency in the long term, 8% energy demand reduction will be applied to the target year 2030 in Uruguay[25].

Generation

To assess the risk of overgeneration, the simulations will be performed considering the same VRES installed power resulting from the optimization process carried out in the Reference Scenario. This amount can become more critical in case of reduced load, because the net load[26] which must be fulfilled by thermal and programmable hydro capacity is smaller and can lead to problems with reserve and minimum power constraints.
In this Variant, also the presence of increased Distributed Generation (DG) in Brasil will be analysed. According to PDE 2026 by EPE, DG is expected to grow in the next years, led maily by small PV plants, which will reach 3,300 MW installed at 2026. Other technologies, such as ones based on biogas, will be also present in much lower amount. The scenario at 2030 will be built assuming 3,300 MW PV plants installed in lower voltage levels than the ones considered in the models.To this aim, load profiles will be modified under the assumption that DG PV plants are distributed in every area in a way proportional to the load, and the power demand will be reduced during the day hours to take into account that part of the load is supplied by generators which are not modelled. The presence of small

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[24] The 15% reduction is applied to the load forecasted at 2030 instead of 2025 (date considered by the MINEM), to assume a softer approach, considering that energy efficiency reduces the demand growth with respect to the Reference Scenario slightly less than what presented by MINEM. In this way, the 15% reduction is reached in 5 years more. This decision is taken to consider possible delays in the implementation of strong actions towards energy efficiency in Argentina.
[25] The 8% reduction was calculated extending up to 2030 the energy demand reduction trend foreseen by MIEM.
[26] Net load is the total load minus the generation which should not be curtailed, i.e. minimum power of thermal plants in service, run of river hydro plants, VRES generation… This value corresponds to the actual load which must be covered with the dispatchable generation.

amount of biogas DG dispatchable plants will not be considered, due to their low contribution to the overall generation fleet and in order not to introduce flexible generation, highlighting problems which might arise due to the imposed generation.

Electrical storage systems

Also the need of storage systems to reduce the constraints on the minimum production will be investigated. As for the first Variant, if needed storage systems will be simulated inserting in the system power plants connected in the areas with most critical situation in terms of lack of production or curtailments due to overcapacity. These plants will be considered as equivalent plants of many smaller storage systems distributed over the territory and connected also to lower voltage levels.

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