Inception Report

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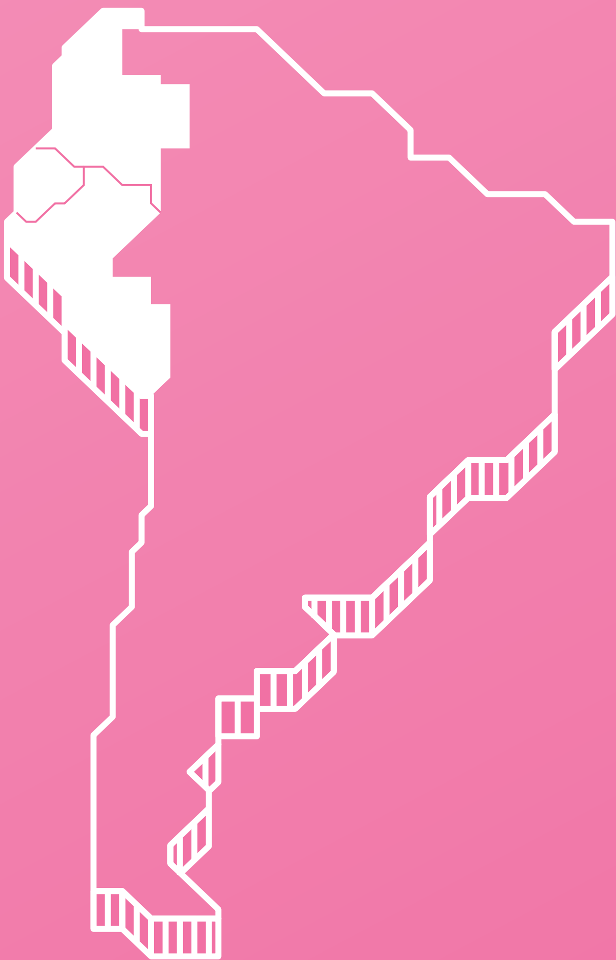

Variable Renewable Energy Sources (VRES) deployment and role of interconnection lines for their optimal exploitation: the **Colombia-Ecuador-Peru** case study

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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LIST OF ACRONYMS

AGR	Average Growth Rate
BOS	Balance of System
CCGT	Combined Cycle Gas Turbine
DANE	Departamento Administrativo Nacional de Estadística (Colombia)
DG	Distributed Generation
EHV	Extra High Voltage
EV	Electric Vehicles
GDP	Gross Domestic Product
GHG	Green House Gas
GR	Growth Rate
GT	Gas Turbine
HVDC	High Voltage Direct Current
IDEAM	Instituto de Hidrología, Meteorología y Estudios Ambientales (Colombia)
IRENA	International Renewable Energy Agency
LATAM	Latin America
LCOE	Levelized Cost of Energy
NTC	Net Transfer Capacity
OECD	Organization for Economic Cooperation and Development
PV	PhotoVoltaic
RES	Renewable Energy Source
SIN	Sistema Interconectado Nacional (Colombia)
ST	Steam Turbine
T&D	Transmission & Distribution
UPME	Unidad de Planeación Minero Energética (Colombia)
VRES	Variable Renewable Energy Source
WACC	Weighted Average Cost of Capital
XM	Compañía Expertos en Mercados (Colombia)

1 FOREWORD

1.1 General objective of the study

Latin America is endowed with outstanding renewable energy resources, namely wind and solar energy, but some areas offer also a good potential for hydro, biomass and geothermal power production. The current decrease of upfront investment costs in RES power plants make power production from green resources more and more competitive with conventional generation from fossil fuels, especially considering that the ongoing trend in investment cost reduction is expected to continue in the coming years. In addition, the achievement of the COP21 targets, widely shared by the Latin American countries[1], further enhances the superiority of RES power plants against conventional generation, when accounting the externality costs associated to the power generation (see costs associated to the various GHG emissions and particulate).

The two above driving factors (lower investment costs and progressive decarbonisation of the power sector) are prompting an accelerated deployment of RES power plants in Latin America.

Unfortunately, the location of new power plants exploiting RES is strictly constrained to the geographical availability of the resources (wind, sun, geothermal, biomasses, hydro). Hence, the connection of a large quantity of RES generation shall be carefully examined in advance to avoid operating conditions calling for RES generation curtailment for security reasons (e.g.: overloads due to insufficient power transfer capability; impossibility to balance the system due to the inflexibility of the conventional generation, poor voltage profiles, risk of cascading effects following an outage on a grid component / generating unit, etc.).

The limitation in the development of RES generation, particularly the variable generation such as wind and PV, can be overcome exploiting the existing interregional or cross-border interconnections, reinforcing the existing ones and building new cross-border corridors.

As a matter of fact, Latin America is still fragmented in national or regional power pools: SIEPAC (interconnected pool from Guatemala to Panama), the Andean interconnected system (from Colombia to Peru) and the Brazilian system (SIN) interconnected basically with Uruguay and Argentina. Other countries are still fully isolated, like Guyana, Suriname, French Guyana and Bolivia or very weakly interconnected, like Chile where just one cross-border line is in operation between SING (Chile) and SADI (Argentina): the Salta-Andes line with a power transfer capacity of about 200 MW owing to network constraints, despite this line is designed for a capacity of about 600 MW.

Thus, dedicated studies shall be carried out specifically to identify the feasible penetration limits of Variable RES (VRES) generation accounting also for the possible power interchange across interconnection lines so to cope with conditions of power surplus or shortfall. Considering the wide geographical extension of Latin America, the analyses shall be applied at a regional level.

[1] Almost all Latin American countries signed the Paris Agreement and a large majority of them already ratified the Agreement. See the updated status of Paris Agreement ratification and entry into force on: http://unfccc.int/paris_agreement/items/9444.php

Within the context recalled above, this study "*RES generation deployment and role of interconnection lines for their efficient exploitation*" aims namely at examining the optimal economic penetration of Variable RES generation (wind and solar) in some Latin American (LATAM) countries and regions within the countries accounting for the possible cross border power exchanges.
The analysis is performed for the target year 2030 and starts from a given set of thermal/hydro generation, defined based on the already existing plants, the ones under construction and the planned ones which will be built before the target year.

The third cluster of countries examined in the study includes Colombia, Ecuador and Peru.

1.2 Contents of the report

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 Colombia, Ecuador and Peru.
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[2]. 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 Colombia, Ecuador and Peru, 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

[2] 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.

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 highlighting to what extent the solutions are stable and hence gives a first general idea on the related investment risk.
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:

- 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[3];
- the evaluations of variables which have an impact on the generation costs, and in particular investment costs for VRES and primary energy costs for fossil 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.

[3] 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.

2 DEFINITION OF REFERENCE SCENARIO

The reference scenario will be modelled looking at the target year 2030 and centred on the countries Colombia, Ecuador and Peru. 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 Colombia, Ecuador and Peru 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:*
  - ***Colombia**: the long term demand forecast is available up to 2031 and it is provided by UPME. Hourly profile of the demand will be estimated by means of the historical time generation available in the XM information system (using at least 6 years of history) http://informacioninteligente10.xm.com.co/oferta/Paginas/HistoricoOferta.aspx?RootFolder=%2Foferta%2FHistorico%20Oferta%2FGeneraci%C3%B3n&FolderCTID=0x01200075F2CCF9F779EE4B93D2D54764CDB78A&View={9F21C71E-AD8F-4E3F-B2EA-0B38F49A9BA8*
  - ***Ecuador**: the long term demand forecast is available only up to 2025 and it is provided by MEER. An extension up to 2030 has been carried out adopting the growth rate considered by MEER. The hourly load profile has not been identified.*
  - ***Peru**: the long term demand forecast is available only up to 2028 and it is provided by MINEM An extension up to 2030 has been carried out adopting the growth rate considered by MINEM. The hourly load profile is available at the public site http://www.coes.org.pe/Portal/portalinformacion/demanda*

Major results

- *The electricity demand and the peak power demand assumed for the Reference Scenario 2030 are summarised in the following table. Also the Compound Average Growth Rate assumed in the period 2016-2030 is highlighted for each country.*

	Electricity Demand			Peak Power Demand		
	% CAGR 2016-2030	2016 [TWh]	2030 [TWh]	%CAGR 2016-2030	2016 [MW]	2030 [MW]
Colombia	3.0%	66.3	100.8	2.4%	9,904	13,810
Ecuador	5.4%	23.5	49.4	5.4%	3,653	7,637
Peru	4.1%	48.5	85.0	3.9%	6,596	11,333

%CAGR: % Compound Average Growth Rate

2.1.1 Colombia

2.1.1.1 Electricity demand

The main actors and sources of information of the Colombia Electricity system are the following companies:

- XM (Compañía Expertos en Mercados), a subsidiary of Colombian state transmission company ISA which provides administration and management services of transactional systems and technology platforms on real time. XM offers services in three areas: energy, finance and transport. In the electric sector, the firm operates Colombia's national SIN (Sistema Interconectado National) grid and administers the local wholesale energy market.
- UPME (Unidad de Planeación Minero Energética), the special administrative/technical unit responsible for the sustainable development of the country's mining and energy sectors, including hydrocarbons. Dependent on the Ministry of Mines and Energy,

In the available documents released by these companies, electricity demand data are computed in two different ways:

- Commercial demand: it considers the own demand of each marketer plus the participation in the losses of the STN (National Transmission System) and the own consumption of the generators. Commercial Demand is equal to Real Demand plus Energy Losses.
- Energy demand of the SIN: it is calculated based on the net generation of the plants and includes: hydraulic, thermal, minor plants, cogeneration units, unmet demand, supply limitation and imports. It considers the plants registered with the MEM. Energy Demand SIN is equal to Generation plus Unattended Demand plus Imports minus Exports

Table 1 shows, for the last years, the Commercial Demand, the Real Demand, the Losses and the Energy Demand of the SIN, while Figure 1 shows the historical data about energy demand of the SIN for a longer period of time.

Table 1 – Historical demand and losses (TWh) – Source UPME [1]

Year	Commercial Demand	Real Demand	Losses	Energy Demand SIN
2013	64.4	63.4	0.956	60.9
2014	66.9	65.9	0.941	63.6
2015	66.5	65.6	0.978	66.2
2016	66.9	65.9	0.951	66.3

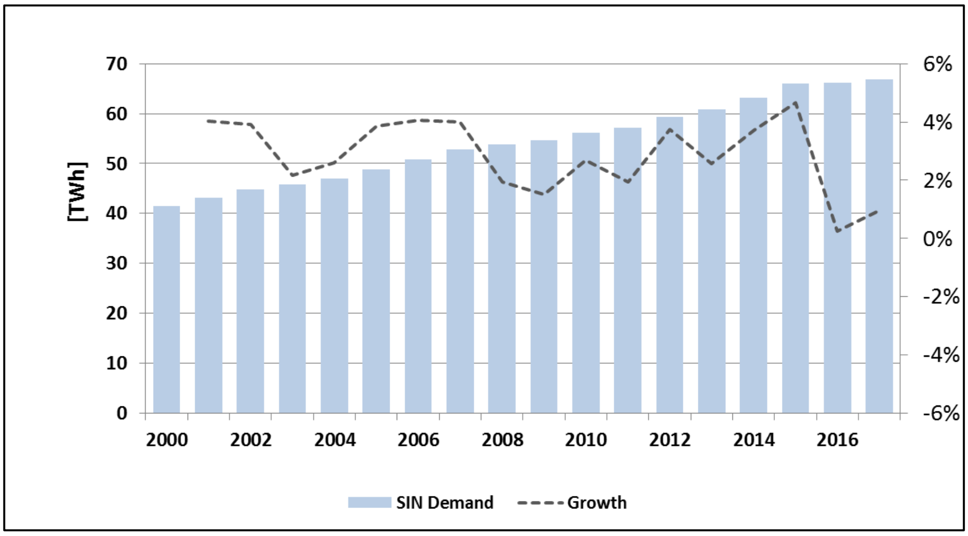


Figure 1 – SIN Demand - Source UPME

As shown by the table above, the electricity demand was about 66.3 TWh in 2016.

In order to achieve an adequate supply of electricity demand, the UPME annually performs a revision of the Plan for the expansion of generation resources and transmission networks. The planning analyses carried out have a long-term horizon and are based on information on the current electrical infrastructure, projects under construction and national and regional projections of energy and power demand. The last and preliminary version of the Plan (Reference Expansion Plan for Generation – Transmission for the period 2017 – 2031) was developed during the course of 2017.

In term of generation, the analysis contained in the Report, is focused on the country's energy resources, such as coal, natural gas, liquid fuels, hydroelectricity and non-conventional renewable sources of energy.

The document presents, among other analyses, the expansion considered for each scenario, its assumptions, the projection of fossil fuel prices, the expected growth of the installed capacity of lower generation plants, the balance between Energy in Firm and the projection of demand for electric power, the contrast between the evolution of installed capacity and peak power.

Regarding transmission, the National Transmission System - STN and the Regional Transmission Systems - STR are analysed, identifying the effects of the growth of demand and the incorporation of generation plants.

The results of the preliminary Plan, that is an upgrade of the results of the previous one, are based on econometric multivariate models such as the VAR (Model of Autoregressive Vectors) and the VEC (Error Correction Vector) model.

The data introduced in the model is the historical series of the Electric Power Demand of Colombia obtained from the System Operator (XM), the economic data (Total GDP) of the National Administrative Department of Statistics (DANE), the data Demographic (Population) of the United Nations Organization

(UN) and the climatic data (Temperature) obtained from the Institute of Hydrology, Meteorology and Environmental studies.

The high and low scenarios are calculated from the middle scenario with a bandwidth of 95% which will allow incorporating the uncertainty caused by the Large Special Consumers (GCE). The assumptions for the middle scenario are described in Table 2.

Table 2 – Main assumptions for the forecast – Source UPME [1]

Year	GDP	T ave	Population	Annual growth		
	[Pesos 2005]	[°C]	[thousands]	GDP	T ave	Population
2011	452.578	23,29	46.407	6,59%	-1,84%	1,06%
2012	470.880	23,31	46.881	4,04%	0,10%	1,02%
2013	493.831	23,38	47.343	4,87%	0,29%	0,98%
2014	515.528	23,55	47.792	4,39%	0,74%	0,95%
2015	531.262	23,98	48.229	3,05%	1,80%	0,91%
2016	541.675	24,21	48.653	1,96%	0,96%	0,88%
2017	549.963	24,09	49.066	1,53%	-0,48%	0,85%
2018	564.861	24,00	49.465	2,71%	-0,35%	0,81%
2019	581.659	24,01	49.850	2,97%	0,01%	0,78%
2020	602.214	24,10	50.220	3,53%	0,40%	0,74%
2021	620.990	24,22	50.576	3,12%	0,47%	0,71%
2022	641.724	24,26	50.917	3,34%	0,17%	0,67%
2023	660.722	24,19	51.244	2,96%	-0,29%	0,64%
2024	680.429	24,22	51.556	2,98%	0,14%	0,61%
2025	699.659	24,26	51.854	2,83%	0,16%	0,58%
2026	721.744	24,27	52.139	3,16%	0,02%	0,55%
2027	743.740	24,33	52.409	3,05%	0,26%	0,52%
2028	766.963	24,36	52.665	3,12%	0,13%	0,49%
2029	791.003	24,32	52.907	3,13%	-0,14%	0,46%
2030	815.424	24,30	53.134	3,09%	-0,09%	0,43%
2031	840.697	24,39	53.347	3,10%	0,36%	0,40%
Source	DANE (UPME elaboration)	IDEAM	ONU			
Revision	June 2017	2015	June 2017			

As said, there are some companies such as Cerromatoso, Cerrejón, Ecopetrol (La Cira-infantas) and OXY, which due to their magnitude of their consumption, are called "Existing Large Consumers" (Existing CG) and other companies, as Rubiales and Drummond, that can be defined as "Great New Special Consumers". All these companies are forecasted to have a significant increase in the participation in the total demand of the SIN, as reported in Table 3.

Table 3 – Projections of electricity demand of great consumers (GWh) – Source UPME [1]

Year	Rubiales	Ecopetrol	Portuary Societies	Drummond	Electrical Vehicles	Bogota Underground
2014	759					
2015	882			36		
2016	1,015			62		
2017	915	158		130	99	
2018	821	467	82	238	110	
2019	666	788	165	438	121	
2020	496	1,173	247	647	134	
2021	433	1,496	247	856	148	
2022	359	1,401	247	982	161	95
2023	292	1,281	247	919	241	97
2024	237	1,161	247	841	380	99
2025	197	1,053	247	762	552	101
2026	162	965	247	691	683	103
2027	133	879	247	633	754	105
2028	109	800	247	577	801	107
2029	90	728	247	525	899	109
2030	74	664	247	478	971	112
2031	74	605	247	436	1,005	114

For these reasons, two different forecasts have been developed for the national energy demand, one with, and the other without the great consumers (GCE), in three different scenarios. The results are reported in Table 4.

Table 4 – Forecast results- [TWh] – Source UPME [1]

Year	Without GCE			With GCE		
	Low	Medium	High	Low	Medium	High
2017	65.6	66.5	67.3	66.9	67.8	68.6
2018	67.3	69.0	70.7	69.0	70.7	72.4
2019	69.1	70.8	72.5	71.2	73.0	74.7
2020	70.9	72.6	74.4	73.6	75.3	77.1
2021	72.8	74.6	76.4	75.9	77.8	79.6
2022	74.7	76.6	78.5	78.0	79.8	81.7
2023	76.7	78.6	80.6	79.8	81.7	83.6
2024	78.8	80.7	82.7	81.7	83.7	85.7
2025	81.0	83.0	85.0	83.9	85.9	88.0
2026	83.2	85.3	87.4	86.1	88.2	90.3
2027	85.6	87.8	89.9	88.4	90.5	92.7
2028	88.1	90.3	92.5	90.7	92.9	95.2
2029	90.6	92.9	95.2	93.2	95.5	97.8
2030	93.3	95.6	98.0	95.9	98.2	100.5
2031	96.2	98.6	101.0	98.6	101.0	103.5

As shown by the table above, according the evaluations performed in 2017 [1], the forecasted national demand at 2030 in the middle scenarios is estimated equal to 98.2 TWh.

It is worth mentioning that the projection of the energy demand and the max peaks are upgraded by UPME regularly. The public available version dated April 2018 contains forecasts up to 2032 [3]. Table 5 shows the results of demand (in the average scenario) for the SIN, for the SIN with Great Consumers (GCE), and in other two configurations considering exchanges with Panama and Distributed Generation(DG).

Table 5 – Forecast results- [TWh] – Source UPME Upgraded forecast [3]

Year	SIN Low	SIN + GCE Medium	SIN + GCE + Panama High	SIN + GCE + Panama+DG Low
2018	67.8	69.1	69.1	69.0
2019	69.7	71.6	71.6	71.5
2020	71.6	74.0	74.0	73.8
2021	73.7	76.6	76.6	76.4
2022	75.8	79.1	79.1	78.9
2023	77.9	81.0	82.3	82.0
2024	80.1	83.1	84.4	84.1
2025	82.5	85.4	86.7	86.3
2026	84.9	87.7	89.1	88.5
2027	87.5	90.4	91.7	91.1
2028	90.1	93.3	94.6	93.9
2029	92.7	96.5	97.8	97.0
2030	95.5	100.8	102.1	101.2
2031	98.5	104.5	105.8	104.8
2032	101.5	108.4	109.7	108.5

As shown by the table above, at the horizon scenario 2030, the upgraded and more recent electricity demand forecast is equal to 100.8 TWh, a bit higher than the previous one. However, it is decided to use the data defined in 2017, because the forecasts from 2017 and 2018 show similar trends up to 2027, but then the most recent ones apply a very strong increase of the demand growth in the last three years (from 2028 to 2030), very different from the behaviour in the previous years, which causes the differences between the values estimated at 2030.

Looking at the regional distribution of the National demand, in the quoted Master Plant there is information at the level of the Unidades de Control de Pronóstico (UCP), since they are the reference used in the dispatch of the electric generators and have primary information of them.
The map of disaggregation of national electricity demand is reported on Figure 2 while Table 6 shows the historical data of disaggregated participation of each region to the national electricity demand.

Figure 2 – Disaggregated Map of SIN - Source [1]

Table 6 – Average participation of regional demand to the National – Source UPME [1]

	2000-2006	2007-2011	2012-2016	2017-2021	2022-2026	2027-2031
Centro	24,0%	25,3%	24,8%	25,3%	25,8%	26,0%
Costa - Caribe	19,8%	20,2%	22,8%	24,6%	25,9%	27,4%
Noroeste	15,7%	14,8%	14,1%	13,2%	12,6%	11,9%
Valle	12,6%	11,5%	10,9%	10,3%	9,6%	8,8%
Oriente	9,7%	10,2%	10,7%	10,7%	11,3%	11,9%
CQR	5,0%	4,5%	4,1%	3,9%	3,5%	3,2%
Tolima Grande	4,5%	4,4%	4,4%	4,6%	4,6%	4,6%
Sur	3,1%	3,0%	2,8%	2,9%	2,8%	2,8%
CG Existentes *	4,1%	4,5%	4,0%	3,0%	2,6%	2,3%
Perdidas	1,6%	1,6%	1,5%	1,6%	1,3%	1,2%

*GC Existentes: Cerrejón, Cerromatoso, OXY and La Cira Infantas

This information will be taken into account for the calculation of the load at 2030 in the different regions.

As a last paragraph, it is interesting to analyse the variation of the composition of electricity consumption. As in many other Countries, Colombia's electricity consumption is a direct function of economic growth which is linked mainly to the level of industrialization and development of the economy.
During the period 2006 - 2016, per capita consumption has grown by nearly 20% (see Figure 3)

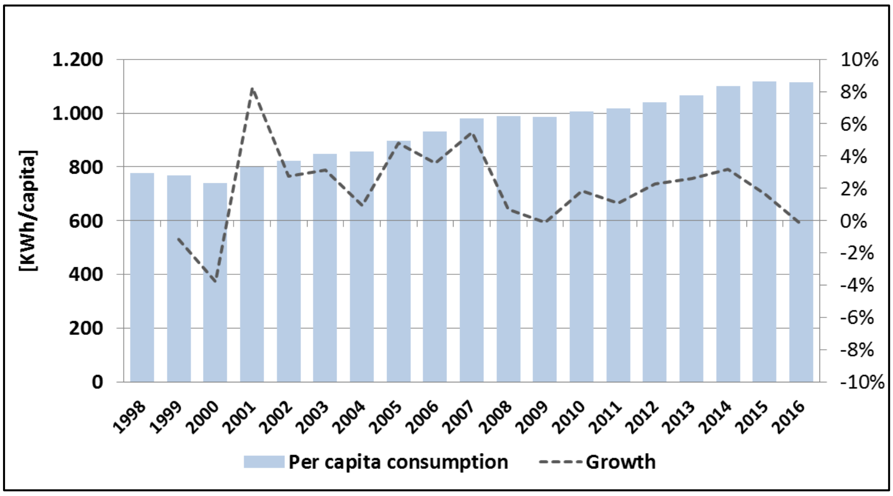


Figure 3 – Per capita consumption - Source [1]

This observation is confirmed by the evolution of the composition of electricity consumption: since 2011, the per capita consumption of the industrial sector has been losing share, due to a large extent by efficient use of energy and technological change, being one of the engines for the dynamic and competitive development of the sector.
On the other hand, the sector classified as "Other sectors" (Provisional, Public Lighting, Special Assistance, Special Education, Common Areas, Industrial Pumping and Irrigation District) has gained participation passing from 4.12% (2006 - 2010) to a 6.14% (2011- 2016), explained by the great participation of Public Lighting (61.67% on average) within it.

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). Historical data of Peak Demand in Colombia are reported in Figure 4.

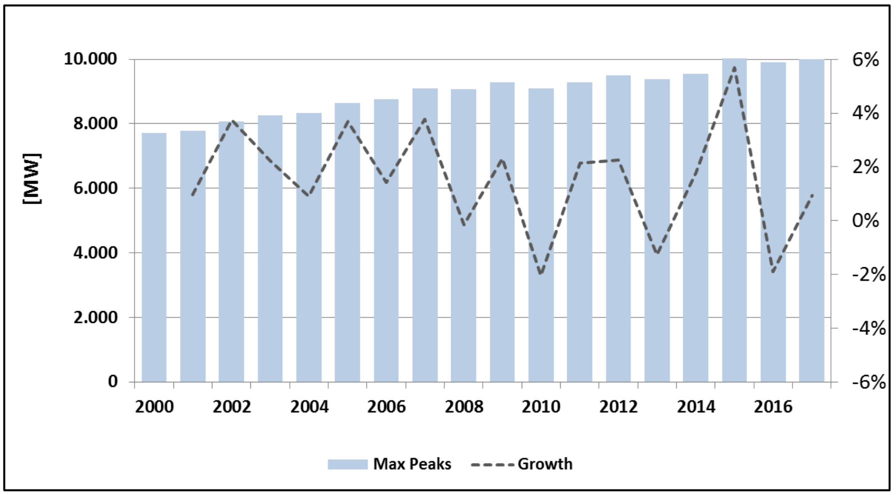


Figure 4 – Max Peaks - Source UPME

As for the electricity demand, Table 7 shows the forecast data for the Great Consumers, while Table 8 shows the maximum peaks in the different forecast scenarios according to the Masterplan and to the more recent forecast.

Table 7 – Projections of maximum peaks of Great Consumers (MW) – Source UPME [1]

Year	Rubiales	Ecopetrol	Portuary Societies	Drummond	Electrical Vehicles	Bogota Underground
2014	130					
2015	144			10		
2016	169			14		
2017	174	60		35	12	
2018	156	89	47	74	13	
2019	127	150	47	83	14	
2020	94	223	47	123	16	
2021	82	285	47	163	17	
2022	68	267	47	187	19	19
2023	56	244	47	175	28	19
2024	45	221	47	160	44	20
2025	38	200	47	145	65	20
2026	31	184	47	132	80	21
2027	25	167	47	120	88	21
2028	21	152	47	110	93	21
2029	17	139	47	100	106	22
2030	14	126	47	91	114	22
2031	14	115	47	83	118	23

Table 8 – Forecast results- [MW] – Source UPME Upgraded forecast [3]

Year	SIN Low	SIN + GCE Medium	SIN + GCE + Panama High	SIN + GCE + Panama+DG Low
2018	10,170	10,481	10,481	10,458
2019	10,374	10,743	10,743	10,717
2020	10,582	11,016	11,016	10,984
2021	10,789	11,321	11,321	11,285
2022	11,012	11,615	11,615	11,572
2023	11,232	11,797	12,064	12,014
2024	11,461	12,005	12,273	12,216
2025	11,707	12,221	12,489	12,422
2026	11,955	12,451	12,719	12,642
2027	12,203	12,702	12,970	12,876
2028	12,475	13,004	13,272	13,169
2029	12,739	13,338	13,605	13,490
2030	13,014	13,810	14,078	13,945
2031	13,312	14,189	14,456	14,302
2032	13,607	14,591	14,854	14,674

The value adopted in the creation of the 2030 scenario is therefore 13,810 MW, as the system will be considered not connected to other countries.

2.1.1.3 Hourly curve

Last important information required to run the probabilistic simulations foreseen in the present activity is the definition of the hourly load profile curve is essential.
Unfortunately, no load hourly time-series has been identified among public available information. At the website http://informacioninteligente10.xm.com.co/demanda/Paginas/HistoricoDemanda.aspx only average daily values are available.

However, from some average behaviour reported in [1] and shown in Figure 5, it is possible to see the flattening of the energy demand load curve during the years, which reflects the effect of the policies of energy efficiency and different distribution of the load during the day. This information is not sufficient to create the scenario for the simulation, but will be taken into account during the process.
The definition of the hourly load profile must be carried out requiring non-public data to system or market operators.

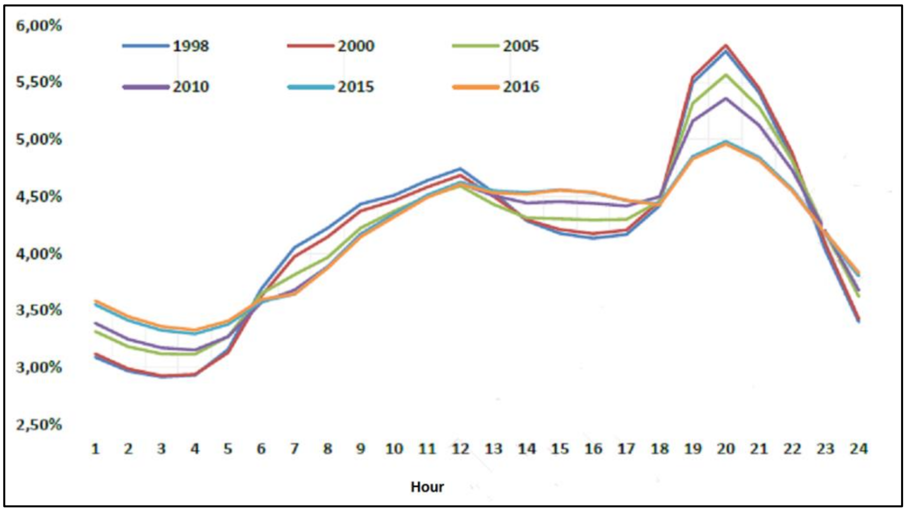


Figure 5 - Hourly demand energy curve - Source [1]

2.1.2 Ecuador

2.1.2.1 Electricity demand

The main actors and sources of information of the Ecuador Electricity system are:

- Corporación Eléctrica del Ecuador (CELEC E.P.): it is a state-owned holding company engaged in the generation, transmission, distribution, commercialization, import and export of electric power. As part of its strategic plan, CELEC aims to guarantee Ecuador's energy sovereignty and change the energy matrix by incorporating renewable energies. CELEC has a portfolio of hydroelectric, thermal and renewable energy projects including the 1500 MW Coca Codo Sinclair hydroelectric plant project in Napo and Sucumbios provinces, the country's largest energy project. (The first four of the project's eight turbines began operations in 2016).
- Ministerio de Electricidad y Energía Renovable de la República del Ecuador (MEER Ecuador**)**:it is the government agency responsible for the country's power sector. Formed in 2007, its functions include developing programs and policies to promote the efficient use of energy resources.
- Agencia de Regulación y Control de Electricidad (ARCONEL): it is the regulatory and monitoring body for the operation and development of the electricity sector in Ecuador. Working under the Ministry of Electricity and Renewable Energy, ARCONEL issues regulations for electric companies, conducts studies and technical analyses, promotes environmental protection initiatives in the sector, and imposes suspension sanctions. ARCONEL was created in 2015 as successor of the former National Council of Electricity (CONELEC), which had been operating since 1996. Its headquarters are in Quito.

The main sources of data are the Energy Balance 2016 [5], the Electricity Statistics for 2016 and the Masterplan 2016 -2025 [6]. This last document provides the demand forecast up to 2025 for different demand growth scenarios. No official data has been published yet on expected demand 2030; for this reason, in order to assess the energy demand expected in 2030, CESI extended the Masterplan forecast.

The electricity sector in Ecuador has changed in the last ten years; in 2007 it was characterized by a low level of the quality of the service, a high level of losses and high production costs, but in the last years some public initiatives have posed the base for a change. These initiatives are:

- the Energetic Sovereignty (Soberanía Energética) and the change of the electric matrix;
- the consolidation and sustainability of the sector;
- the change of the culture for the efficient use of energy;
- the national energetic integration.

In particular:

- the **Energetic Sovereignty and the change of the electric matrix** had the target of increasing the energetic independence of the Country, prioritizing renewable source of energy complementing with thermal efficient energy of last technology, that consumes fuel of national production, ensuring the electric stability of the system and maintaining adequate reserve margins. In this contest, was constituted and placed in service the water reservoir of Mazar, the hydroelectric plants of San Francisco, Mazar, Ocana and Baba (for a total of 480 MW) and the substitution of 600 MW of thermal inefficient generation. Other wind and PV projects have been developed for the Galapagos Islands.
  With these operations, the installed capacity increased from 4,070 MW in 2006 to 8,226 MW in the year 2016.
  About distribution losses they have decreased to 12.2%, ten percentage points less with respect to 2006.
- The **consolidation and sustainability of the sector** have been obtained with the creation of new institutions, a new Electric Law, the recuperation of the planning role and the modernization and improvement of the managing. In particular, with the Executive Decree 475 (July 9th 2007) the Ministry of Energy and Minas was split off and the Ministry of Electricity and Renewable Energy (MEER) was created.
- Another public initiative was focused on the **change of the culture for the efficient use of energy**. This objective, that means that it is not sufficient to produce energy but also to consume it in a clever way, was obtained through the application of proper tariff and the execution of programs of energetic efficiency. These actions permitted a reduction of the electric demand at a national level.
  One of the results was a reduction of about 360 MW at the hour of the maximum demand, with a consistent money saving, avoiding the construction of new generation to supply this demand (see Figure 6).

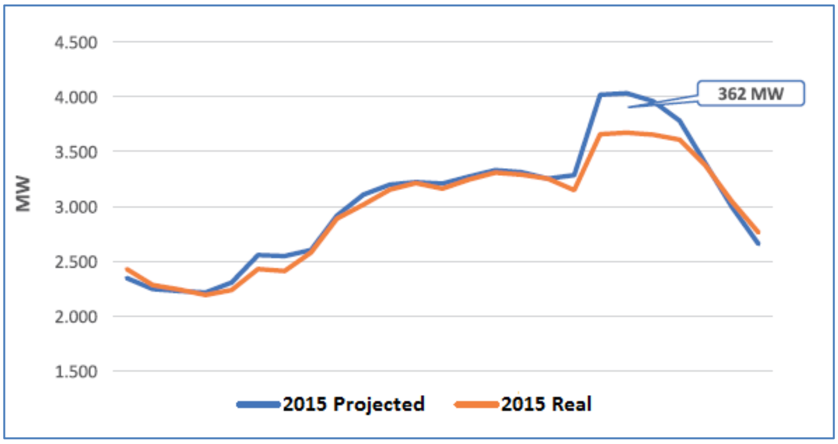


Figure 6 – Demand 2015 real vs projected

The main energy efficiency programs are:

- PEC (Program of Efficient Cooking): a contribution on the change of electric matrix, through the reduction of the demand of liquid gas (GPL) an import fuel;
- RENOVA: a program for the renewal of energy inefficient consumption equipment (substitution of 320.000 refrigerators);

- The **regional energetic integration** has been obtained under the umbrella of the CAN (Comunidad Andina), through which Ecuador could establish commercial relations of electricity with neighboring Countries.

In 2016 the electricity demand was 27.15 TWh of which 23.52 TWh were those in charge of the SNI (Sistema National Interconnectado). The maximum demand of SIN (Yearly Peak) was of 3,653 MW (March, 23rd).

As reported in the Masterplan, the electricity demand for the next years is computed according to the scheme reported in Figure 7.

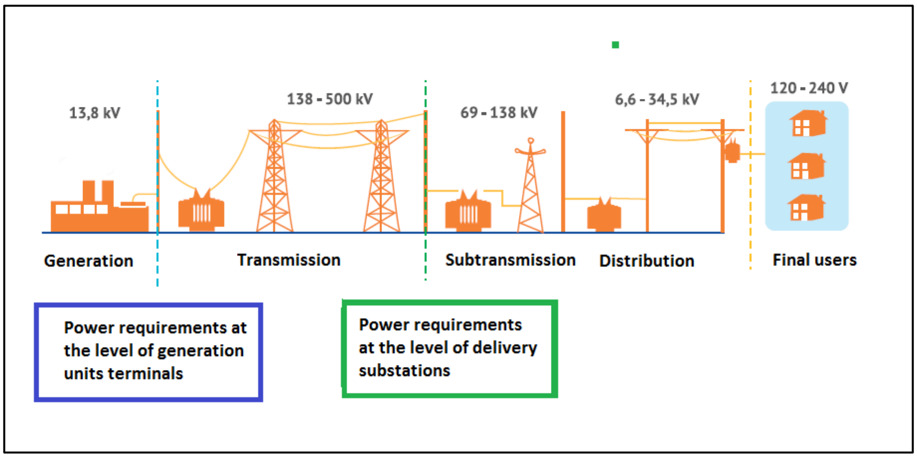


Figure 7 – Scheme of electricity forecast - Source [6]

As showed by the figure above, the first step of the load forecast in the Masterplan is the definition of final users' demand (or consumption).

The final users' demand is obtained by the aggregation of econometric models of consumption of each final users' sector (residential, commercial, industrial and street lighting), based on the analysis of historical data of final users' consumption and of some socio economic independent variables, as GDP and population.

In particular, three different scenarios of GDP growth for the period 2016-2025 are considered: a medium scenario with an average growth of 3%, a low one with a growth of 2% and a high one with a growth of 4%.

Figure 8 shows historical and forecast data of Ecuador GDP annual growth (GDP 2007=1).

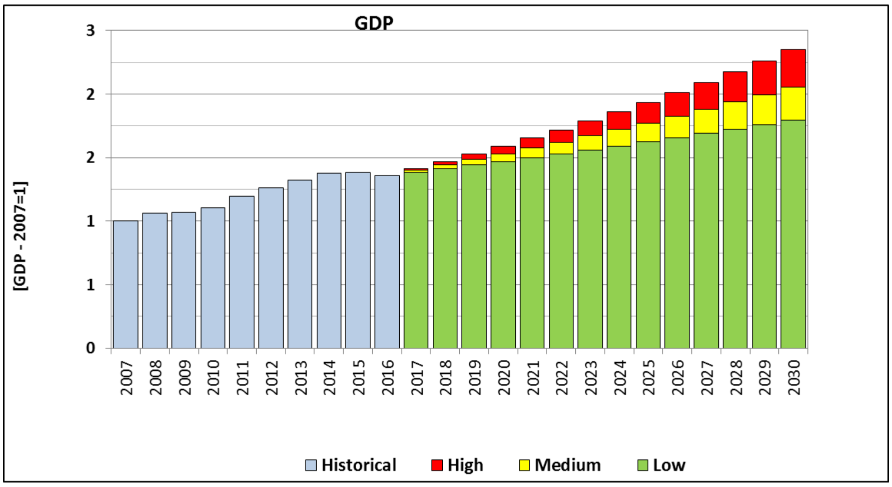


Figure 8 – GDP data - Source [6]

Figure 9 shows the historical and the forecasted evolution of residential demand according to the Masterplan (up to 2025) and CESI assumptions (up to 2030) in the medium scenario.

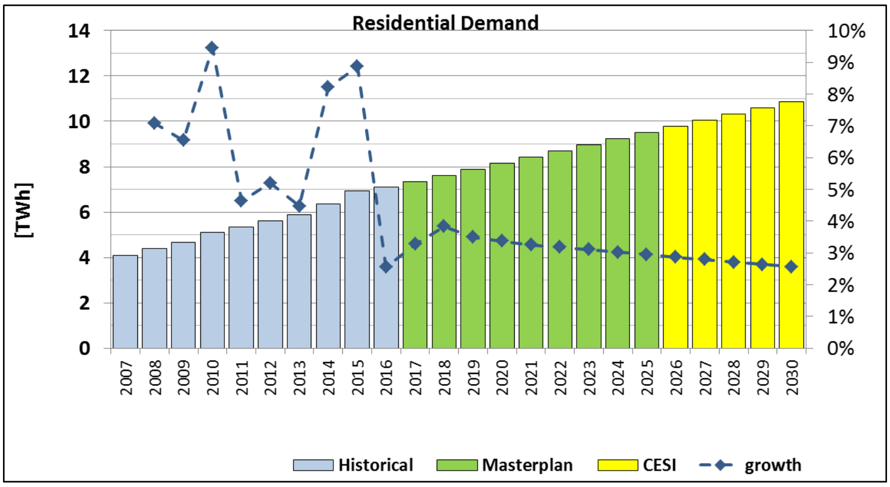


Figure 9 – Historical evolution and forecast of residential electricity demand - Source [6]

As shown by the figure above, the residential demand is forecasted to grow from about 7.1 TWh in 2016 to 9.5 TWh in 2025 and to 10.9 TWh in 2030.

Figure 10 shows the historical and the forecast evolution of commercial demand according to the Masterplan and CESI assumptions in the medium scenario.

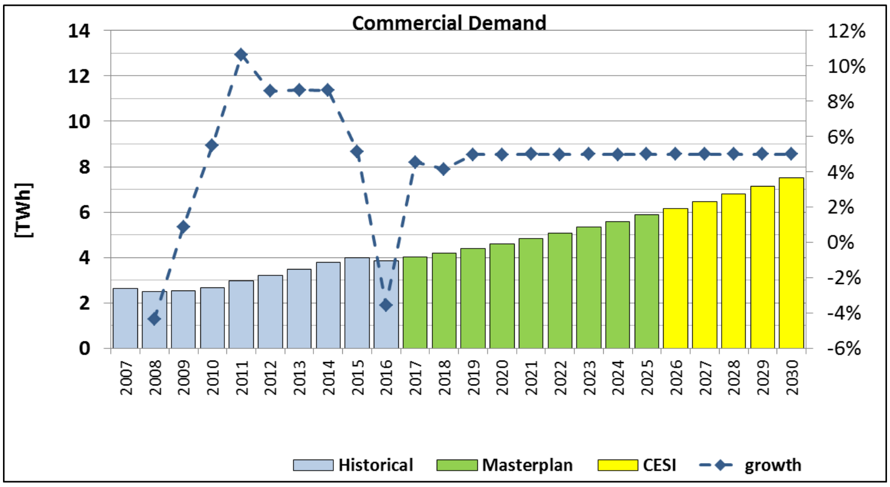


Figure 10 – Historical evolution and forecast of commercial electricity demand - Source [6]

As shown by the figure above the commercial demand is forecasted to grow from 3.8 TWh in 2016 to 5.9 TWh in 2025 and to 7.5 TWh in 2030.

Figure 11 and Figure 12 show the historical and the forecast evolution respectively of industrial and other sector and to the public light sector according to the Masterplan and CESI assumptions in the medium scenario.

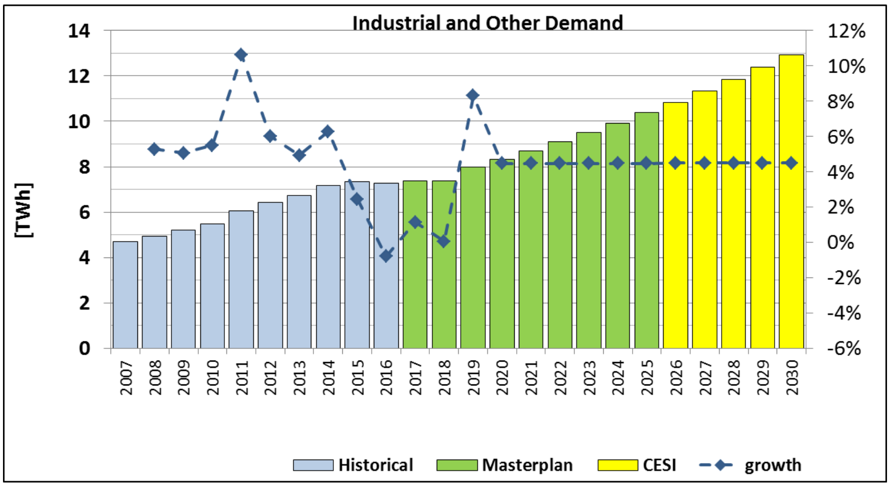


Figure 11 - Historical evolution and forecast of industrial and other demand - Source [6]

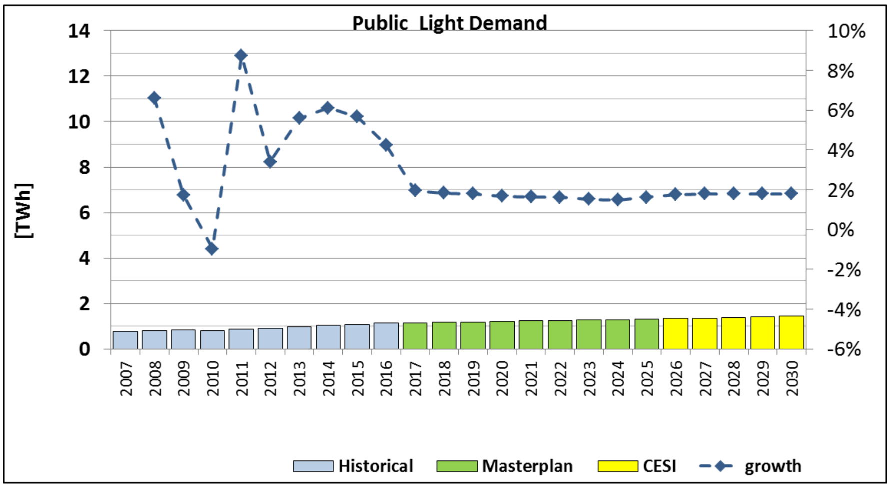


Figure 12 – Historical evolution and forecast of public light demand - Source [6]

As shown by the figures above, the industrial sector is forecasted to grow from 7.3 TWh in 2016 to 10.4 TWh in 2025 and to 12.9 TWh in 2030, while the public light sector is forecasted to grow from 1.1 TWh in 2016 to 1.3 TWh in 2025 and to 1.4 TWh in 2030.

The total composition of demand is reported in Figure 13 and in Table 9.

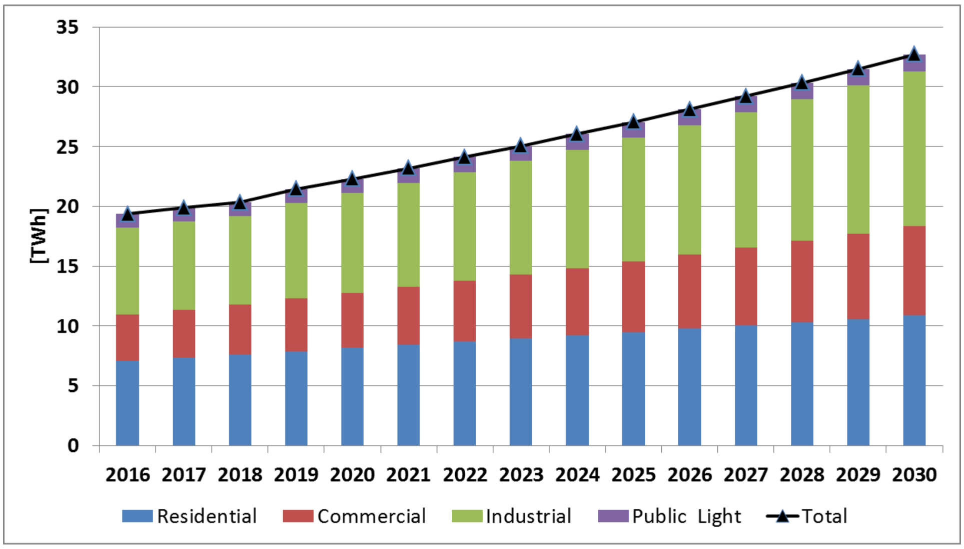


Figure 13 – Historical evolution and forecast of total demand - Source [6]

Table 9 –Forecast of total demand (TWh) - Source [6] and CESI elaborations

Year		Residential	Commercial	Industrial	Public Light	TOTAL
Masterplan	2016	7.1	3.8	7.3	1.1	19.4
	2017	7.3	4.0	7.4	1.1	19.9
	2018	7.6	4.2	7.4	1.2	20.3
	2019	7.9	4.4	8.0	1.2	21.4
	2020	8.2	4.6	8.3	1.2	22.3
	2021	8.4	4.8	8.7	1.2	23.2
	2022	8.7	5.1	9.1	1.3	24.1
	2023	9.0	5.3	9.5	1.3	25.1
	2024	9.2	5.6	9.9	1.3	26.0
	2025	9.5	5.9	10.4	1.3	27.1
CESI	2026	9.8	6.2	10.8	1.3	28.1
	2027	10.0	6.5	11.3	1.4	29.2
	2028	10.3	6.8	11.8	1.4	30.3
	2029	10.6	7.1	12.4	1.4	31.5
	2030	10.9	7.5	12.9	1.4	32.7

The percentage composition of demand in the year 2016, 2025 and 2030 is reported in Figure 14.

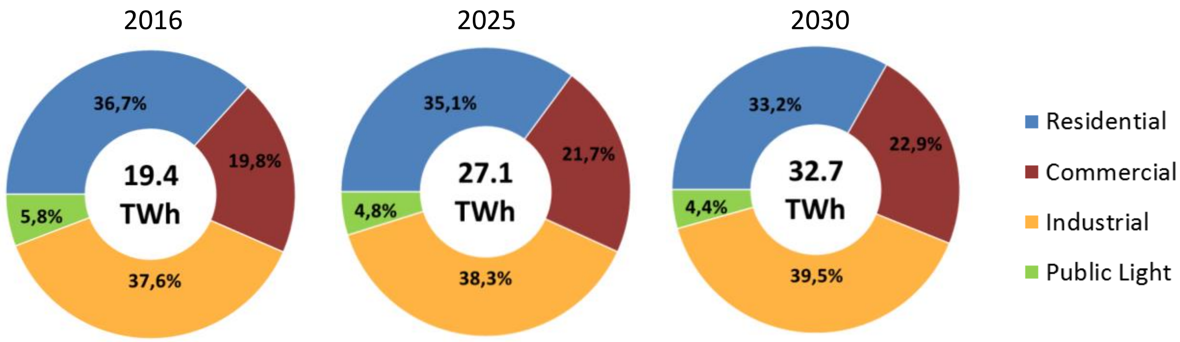


Figure 14 – Consumers Demand - 2016, 2025 and 2030

The Gross demand of the SIN is obtained adding to the demand of Consumers, the losses of the distribution system. The historical and forecast evolution of distribution losses is reported in Figure 15.

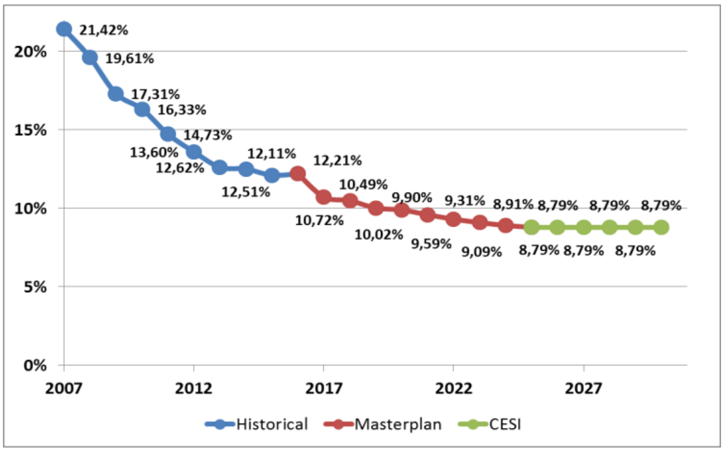


Figure 15 – Historical evolution and forecast of distribution losses - Source [6]

On the base of this data, different hypothesis or cases are developed and described in [6]. They can be summarised as it follows:

- **Hypothesis 1**: it corresponds to the data described above, in which the growth of the electrical demand is computed on the base of the described econometric models;
- **Hypothesis 2:** it corresponds to add to the previous hypothesis, singular industrial loads;
- **Hypothesis 3:** it corresponds to add, to the previous hypothesis, the effects of the Energy Efficiency plan. The Base Case of this Hypothesis is used as a reference for the planning of distribution, transmission and generation contained in the Masterplan;
- **Hypothesis 4:** it corresponds to the previous hypothesis with the addition of the RDP – Refinería del Pacifico Eloy Alfaro;
- **Hypothesis 5:** it includes all the possible loads.

Table 10 shows the results of Hypothesis 3 that, as said, it is used for the Masterplan. An extension up to 2030 has been carried out by CESI adopting the growth rate considered in the Masterplan.

Table 10 –Forecast of total demand (TWh) - Source [6] and CESI elaboration

	Year	Low	Base	High
Masterplan	2016	23.5	23.5	23.5
	2017	23.8	24.0	24.6
	2018	25.4	25.9	26.3
	2019	26.9	27.7	28.4
	2020	28.4	29.3	30.5
	2021	29.9	31.3	32.7
	2022	31.4	33.1	34.8
	2023	32.7	34.9	36.9
	2024	33.7	36.3	38.8
	2025	34.9	37.9	40.9
CESI	2026	36.5	40.0	43.4
	2027	38.1	42.2	46.2
	2028	39.8	44.5	49.1
	2029	41.6	46.9	52.2
	2030	43.5	49.4	55.5

The Base forecast equal to 49.4 TWh will be assumed as reference value to be adopted in the creation of the 2030 scenario to be analysed.

2.1.2.2 Peak Power demand

In the year 2016 the peak power demand in the SIN was equal to 3,653 MW, -0.46% respect to the year 2015 (3,670 MW). In the period 2007 – 2016, as shown by Figure 20, the average growth was about 3.3%.

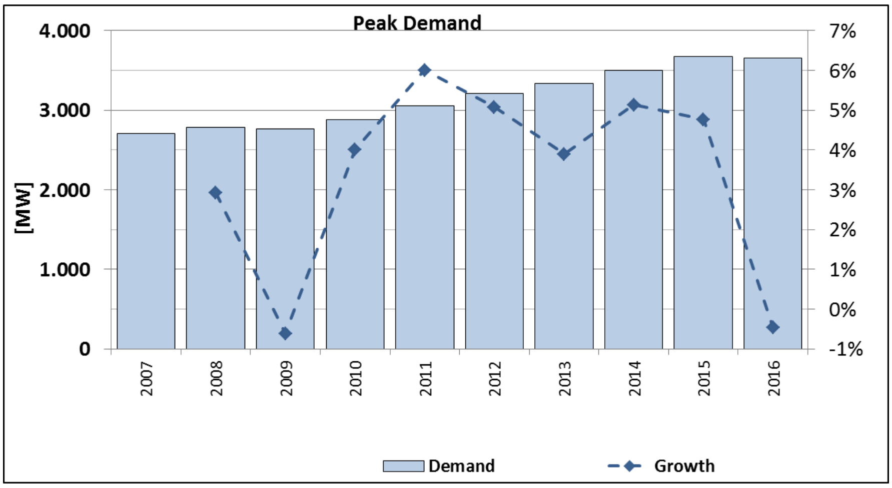


Figure 16 – Historical evolution of peak demand - Source [6]

Table 11 shows the results of Hypothesis 3 forecast that, as said, it is used for the Masterplan. An extension up to 2030 has been carried out by CESI adopting the growth rate considered in the Masterplan.

Table 11 –Forecast of total demand (MW) - Source [6] and CESI elaboration

	Year	Low	Base	High
Masterplan	2016		3,653	
	2017	3,947	3,987	4,020
	2018	4,205	4,205	4,359
	2019	4,456	4,585	4,693
	2020	4,663	4,839	4,989
	2021	4,865	5,091	5,286
	2022	5,074	5,355	5,601
	2023	5,240	5,579	5,878
	2024	5,372	5,773	6,130
	2025	5,409	5,868	6,285
CESI	2026	5,650	6,185	6,676
	2027	5,902	6,520	7,091
	2028	6,165	6,873	7,532
	2029	6,440	7,245	8,001
	2030	6,728	7,637	8,498

The value considered for the creation of the scenario to be analysed is therefore 7,637 MW.

No information about hourly price profiles has been identified, but it is necessary to find more details in order to set up the scenario for the probabilistic simulations.

2.1.2.3 Hourly curve

No detailed load hourly time-series has been identified among the public available information. Proper data must be requested to market or system operators.

2.1.3 Peru

2.1.3.1 Electricity demand

The main actors and sources of information of the Peru electricity system are:

- Comité de Operación Económica del Sistema Interconectado Nacional (COES): it is a private Peruvian non-profit organization made up of generators, distributors, and free users. Its main purpose is to coordinate the interconnected system short, medium and long-term operations in order to achieve the lowest possible operating costs while guaranteeing the security of the system and promoting the efficient use of energy resources. The committee is also responsible for the interconnected system's transmission planning and managing of the short-term market. The organization has about 120 members. COES was founded in 1994 and is headquartered in Lima.
- Ministerio de Energía y Minas del Peru (MINEM): it is the entity responsible for promoting the sustainable development of mining and energy activities in the country, which includes creating competitive conditions for private investment and environmental regulation. It also supports technical and scientific investigation related to mineral and energy resources, and grants

concessions, awards contracts and promotes projects with a view to contributing to the country's potential for energy and mineral development.

- Regulador peruano de inversiones en energía y minería (Osinergmin): it is a public institution tasked with supervising and overseeing national compliance with legal and technical dispositions related to activities in the electric power, hydrocarbon and mining sectors, as well as compliance with legal and technical standards concerning environmental conservation and protection during development of these activities. The entity is also responsible for arranging tender processes for electric power generation from renewable sources and supervising the conditions for power generation licenses. Founded in 1966 the entity is headquartered in Lima and has offices in every region.

The main information about the Peru electricity sector for 2016 and for the past are given by MINEM ([7]), that gives also information on the Plan for the transmission 2017 – 2026 ([7]).

In 2016 the electricity sold (the final consumption of electricity) was about 43.4 TWh[4], of which 48% on the regulated market and 52% on the free one.
About 95% of the electricity sold was transmitted by SEIN (Sistema Eléctrico Interconectado Nacional) while the remaining 5% is due to insulated systems
Regarding the composition, 58.8% of the total is attributable to the Industrial sector, 21.6% to the residential sector, 17.4% to the commercial sector and 2.2% to the street lighting (see Table 12). The historical data about the composition of final demand is reported in Figure 17

Table 12 – Final consumption 2016 - Source [7]

Month	Industrial	Commercial	Residential	Street Lighting	TOTAL
January	2.04	0.64	0.81	0.08	3.56
February	2.02	0.66	0.77	0.07	3.53
March	2.13	0.67	0.81	0.08	3.69
April	2.09	0.66	0.81	0.08	3.63
May	2.15	0.63	0.78	0.08	3.64
June	2.09	0.60	0.76	0.08	3.53
July	2.15	0.59	0.75	0.08	3.57
August	2.15	0.59	0.77	0.09	3.60
September	2.11	0.61	0.78	0.08	3.58
October	2.19	0.62	0.76	0.08	3.65
November	2.16	0.63	0.77	0.08	3.64
December	2.23	0.66	0.78	0.08	3.75
Total	25.48	7.56	9.36	0.96	43.37
%	58.8%	17.4%	21.6%	2.2%	100.0%

[4] 2.15 TWh of auto consumption have to be added to this total in 2016

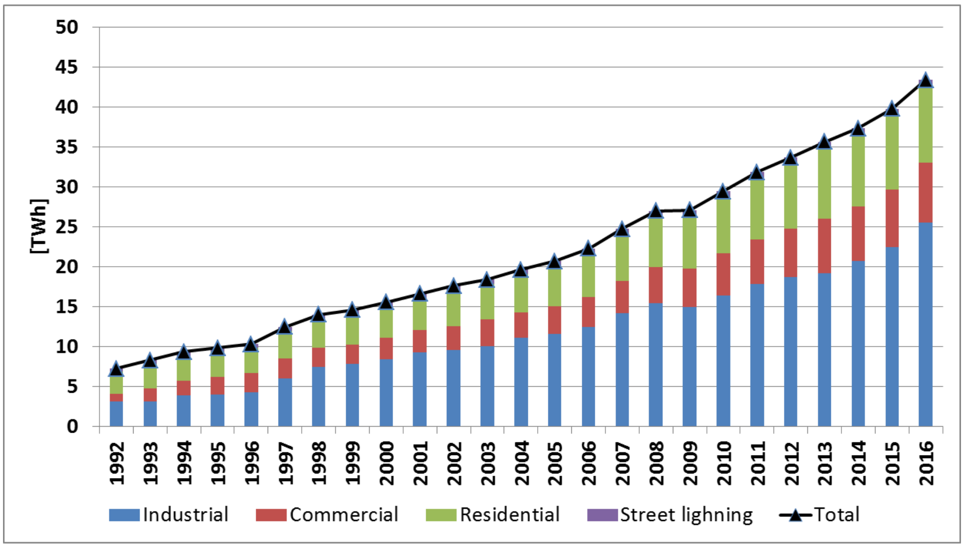


Figure 17 – Historical evolution of consumers demand

The load demand forecast in the existing Plan for the Transmission of the SEIN (2017 - 2026) is based on the projection of two large components, the econometric demand and the large loads (Special loads, Embedded Loads, Projects, etc.).

In particular, the first component, the econometric demand, bases its forecasts on long-term GDP estimates in 5 scenarios: Base, Pessimistic, Optimistic, Very Optimistic and Very Pessimistic.

On the other hand, the second component, the large loads, is elaborated based on the statement and updated information of the sector of each of the large loads (for the period 2015 – 2026 with year 2014 as base year).

Table 13 shows the GDP estimates made by the company Macroconsult, commissioned by COES.

Table 13 – GDP estimates

Year	Very pessimistic	Pessimistic	Base	Optimistic	Very optimistic
2017	0.47%	1.66%	2.17%	3.17%	4.20%
2018	0.95%	2.05%	3.34%	5.02%	6.13%
2019	0.88%	2.03%	3.30%	4.56%	5.57%
2020	1.06%	2.30%	3.60%	4.88%	5.92%
2021	1.07%	2.34%	3.65%	4.96%	5.96%
2022	1.15%	2.31%	3.64%	4.89%	6.02%
2023	1.15%	2.29%	3.57%	4.95%	6.06%
2024	1.15%	2.23%	3.62%	4.97%	6.07%
2025	1.11%	2.23%	3.62%	4.97%	6.13%
2026	1.10%	2.19%	3.57%	4.97%	6.05%
2027	1.12%	2.11%	3.49%	4.87%	6.02%
2028	1.11%	2.12%	3.49%	4.91%	6.25%
2015-2028	1.03%	2.16%	3.42%	4.76%	5.86%

The extreme projections of GDP (Very Optimistic and Very pessimistic) try to cover the entire range of variation of the uncertainty of the demand and serve for the elaboration of the future extremes of it; these futures in turn are a data indispensable in the present process of transmission planning.

The projects and their location by zones[5] (Centro, Norte and Sur) were obtained from the surveys carried out on the owners and promoters of the new projects in mining and / or industrial.
The results for the five different scenarios ([7]) are reported in Table 14, extended by CESI until the horizon year 2030.

Table 14 – Demand forecast (GWh)

	Year	Very pessimistic	Pessimistic	Base	Optimistic	Very optimistic
Masterplan	2016	48,452	48,452	48,452	48,452	48,452
	2017	49,244	49,489	49,934	50,589	50,759
	2018	51,127	51,632	52,531	53,673	54,081
	2019	53,073	53,843	55,450	57,508	58,180
	2020	55,325	56,401	59,111	61,959	62,927
	2021	56,943	58,343	63,083	66,894	68,191
	2022	59,437	61,155	67,353	71,797	73,458
	2023	61,835	63,879	70,843	75,489	77,553
	2024	63,785	66,159	73,535	78,345	80,853
	2025	65,722	68,434	76,153	81,050	84,044
	2026	66,841	69,909	77,922	83,324	86,851
	2027	67,681	71,096	79,627	85,729	89,837
	2028	68,483	72,259	81,383	88,115	92,859
CESI	2029	69,295	73,442	83,177	90,569	95,983
	2030	70,117	74,644	85,011	93,090	99,213

The value assumed as expected demand at 2030 is therefore 85 TWh, corresponding to the forecasted Base case.

2.1.3.2 Peak Power demand

In the year 2016 the peak power demand summed up to 6,492 MW, 3.47% more than in 2015. The historical evolution of peak power demand is highlighted in Figure 20.

[5] Given the geographic characteristics of the SEIN, for the planning, three different are identified

- Norte (bounded by the Chimbote and Kiman Ayllu substations up to the far north),
- Centro (bounded by the Nueva Paramonga, Conococha substations, Campo Armiño and Marcona),
- Sur (bounded from the Cotaruse and Ocoña substations to the extreme south).

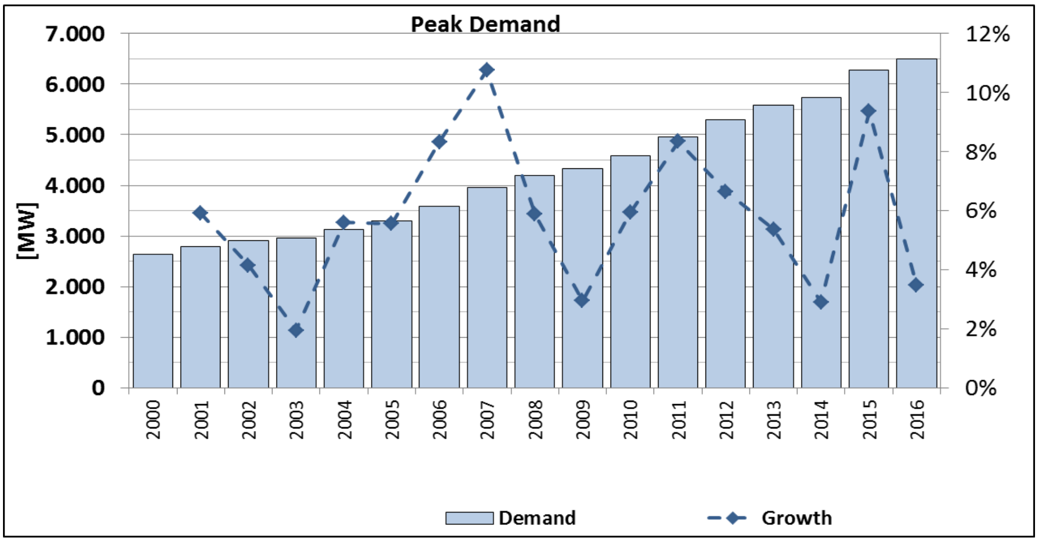


Figure 18 – Historical evolution of peak demand

The results of the load demand forecast for the different cases are reported in Table 15 [7].

Table 15 – Peak forecast (MW)

	Year	Very pessimistic		Pessimistic		Base		Optimistic		Very optimistic	
Masterplan	2016	6,596		6,596		6,596		6,596		6,596	
	2017	6,642	0.7%	6,677	1.2%	6,744	2.2%	6,827	3.5%	6,851	3.9%
	2018	6,876	3.5%	6,948	4.1%	7,062	4.7%	7,214	5.7%	7,273	6.2%
	2019	7,109	3.4%	7,219	3.9%	7,418	5.0%	7,687	6.6%	7,783	7.0%
	2020	7,410	4.2%	7,564	4.8%	7,894	6.4%	8,224	7.0%	8,362	7.4%
	2021	7,596	2.5%	7,796	3.1%	8,379	6.1%	8,858	7.7%	9,043	8.1%
	2022	7,922	4.3%	8,167	4.8%	8,920	6.5%	9,464	6.8%	9,701	7.3%
	2023	8,204	3.6%	8,495	4.0%	9,353	4.8%	9,923	4.8%	10,218	5.3%
	2024	8,435	2.8%	8,773	3.3%	9,684	3.5%	10,303	3.8%	10,660	4.3%
	2025	8,678	2.9%	9,065	3.3%	10,037	3.6%	10,671	3.6%	11,098	4.1%
	2026	8,837	1.8%	9,274	2.3%	10,292	2.5%	11,000	3.1%	11,503	3.6%
	2027	8,961	1.4%	9,448	1.9%	10,540	2.4%	11,345	3.1%	11,931	3.7%
	2028	9,088	1.4%	9,627	1.9%	10,798	2.5%	11,694	3.1%	12,371	3.7%
CESI	2029	9,217	1.4%	9,809	1.9%	11,062	2.5%	12,054	3.1%	12,827	3.7%
	2030	9,347	1.4%	9,995	1.9%	11,333	2.5%	12,425	3.1%	13,300	3.7%

The value used for the creation of the 2030 scenario is then 11,33 MW, corresponding to the Base Case.

2.1.3.3 Hourly curve

At the public site http://www.coes.org.pe/Portal/portalinformacion/demanda the historical hourly load values are available and can be used for the definition of profile to be applied during the study.

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 Colombia, Ecuador and Peru. 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 NP RES development, which is the focus of the study.*

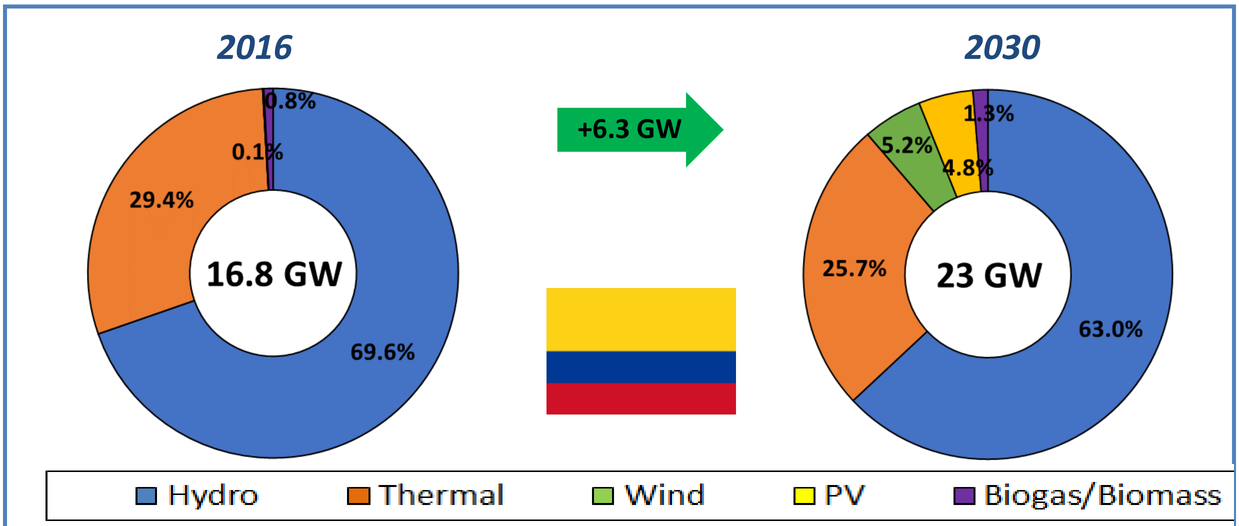
Major results

- *For each country, the additional generation capacity to be considered in the Reference Scenario has been defined. A database of the generation fleet is to be 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 NP RES will be the starting point for the analysed; they will be checked in term of optimal economic penetration and increased if economic.*

  - ***Colombia generation fleet***

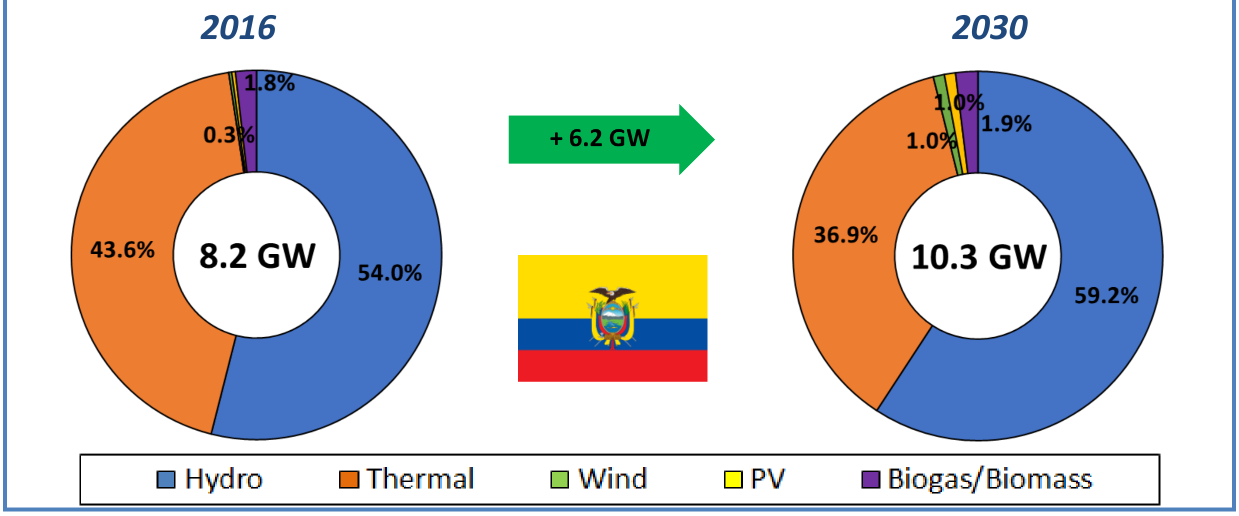
    The "Plan de Expansión de Referencia Generación – Transmisión 2017 – 2031, by UPME gives the main information about the fleet consistency in 2016 and in the next years The following table shows the additional baseline capacity considered in the Reference Scenario of the project

	2016	**Additional Capacity**	**2030**
Hydro	11.7	**2.8**	14.5
Thermal	4.9	**0.9**	5.9
Wind	0.0	**1.2**	1.2
PV	0.0	**1.1**	1.1
Biogas/Biomass	0.1	**0.3**	0.3
TOTAL COLOMBIA	**16.7**	**6.3 GW**	**23.0**



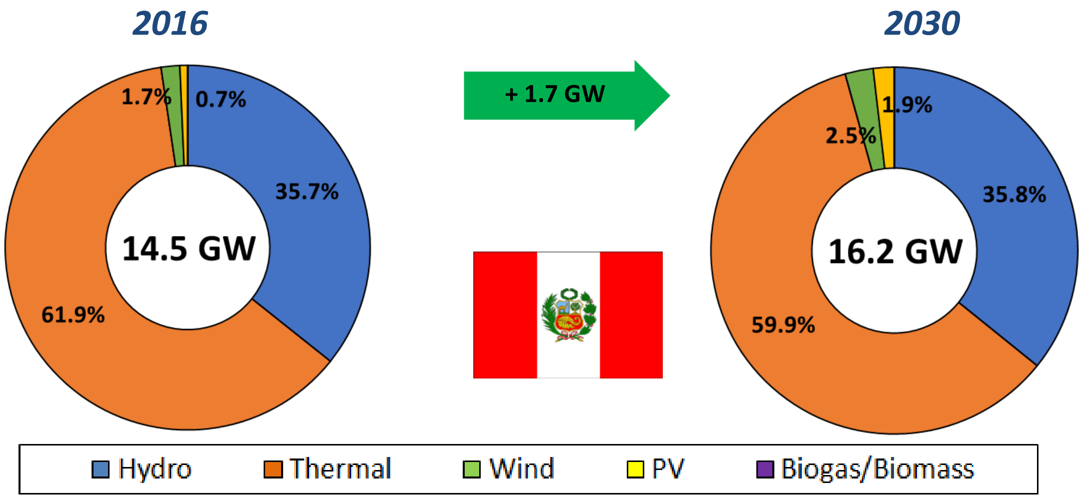
- ***Ecuador generation fleet***
  The following table shows the additional baseline capacity considered in the project, according with National targets. In the total amount are considered also the projects not belonging to the interconnected national system.

	2016	Additional Capacity	2030
Hydro	4.4	**2.3**	6.7
Thermal	3.6	**0.2**	3.8
Wind	0.0	**0.1**	0.1
PV	0.0	**0.1**	0.1
Biogas/Biomass	0.2	**0.0**	0.2
TOTAL ECUADOR	**8.2**	**2.1 GW**	**10.3**



- ***Peru generation fleet***

	2016	Additional Capacity	2030
Hydro	5.2	0.6	5.8
Thermal	9.0	0.7	9.7
Wind	0.2	0.2	0.4
PV	0.1	0.2	0.3
TOTAL PERU	**14.5**	**1.7 GW**	**16.2**



2.2.1 Colombia

2.2.1.1 Existing generation

The generation of electric power in Colombia during the last 5 years has generally presented a growing evolution. Specifically for the year 2017, the generation stood at 66,667 GWh, 1.1% higher than the value recorded in 2016. It is highlighted that for 2016 there was a decrease in the generation growth.
Electricity generation is conditioned by El Niño - Oscillation of the South (ENSO); this is one of the factors that have greater influence in the climatic variability on the Colombian territory.
In fact, El Niño and its counterpart La Niña, modulate to a large extent the behaviour of precipitation and its temporal space variation, which translates into a strong impact on the country's water resources, hand have a great impact on electricity generation, taking into account that currently in the country's energy matrix the hydraulic component represents the largest percentage.

2017 in Colombia was a year marked by a normal hydro climatic situation, making the generation largely based on water resources, which is the most abundant resource in Colombia. Table 16 and Figure 19 show the electricity generation in 2017 compared to that of 2016, in which the effect of El Niño were relevant.

Table 16 – Generated energy to cover demand

Source	2016		2017	
	GWh	%	GWh	%
Fossil fuel	18494.6	28.0%	8682.9	13.0%
Biomass	598.1	0.9%	632.8	0.9%
Hydro	46798.6	71.0%	57342.9	86.0%
Solar	0.0	0.0%	5.4	0.0%
Wind	50.9	0.1%	3.1	0.9%
TOTAL	65942.2		66667.0	

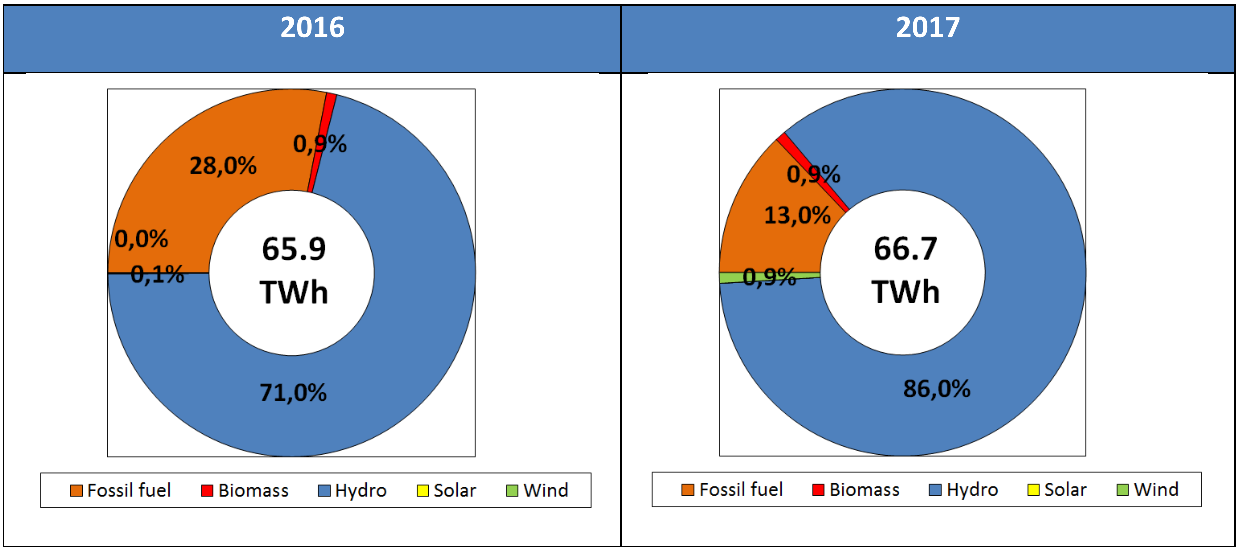


Figure 19 – Generated energy to cover demand

As shown by the table and the figure above, electricity generation is mainly hydro (more than 70% in 2016 and 86% in 2017) while solar and wind cover about 1% of the total.

The generation sector during the past years was driven by a large amount of hydro generation. As highlighted in Figure 20 and Figure 21, hydro generation has been in the past always more than 70%.

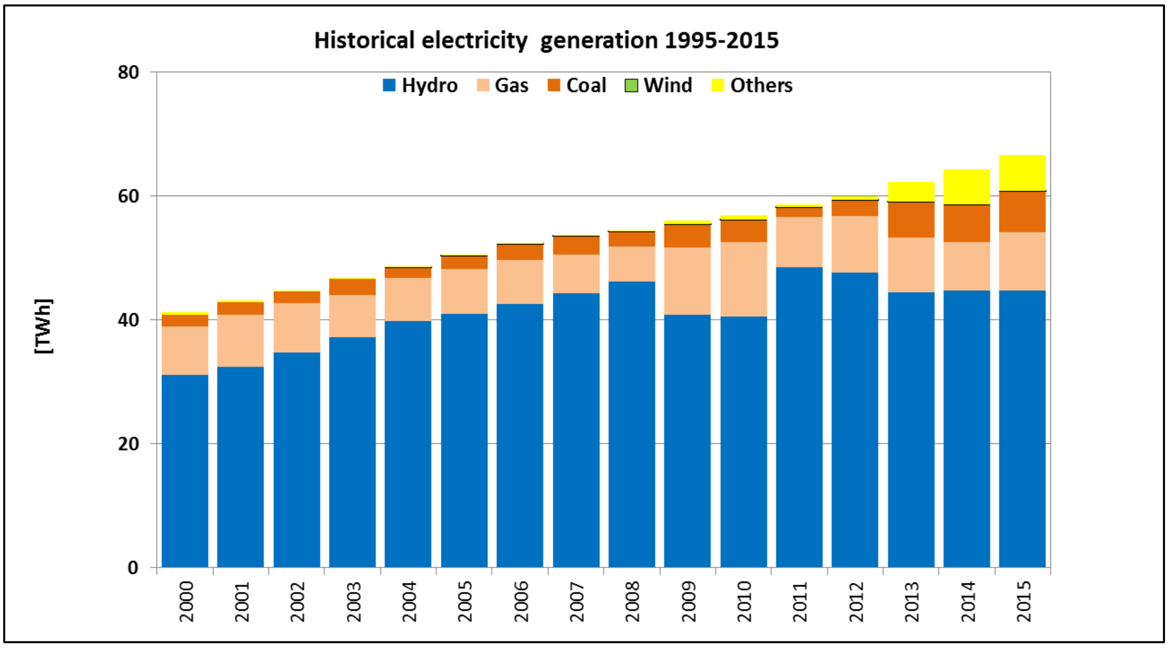


Figure 20 – Historical electricity generation in the period 1995-2015

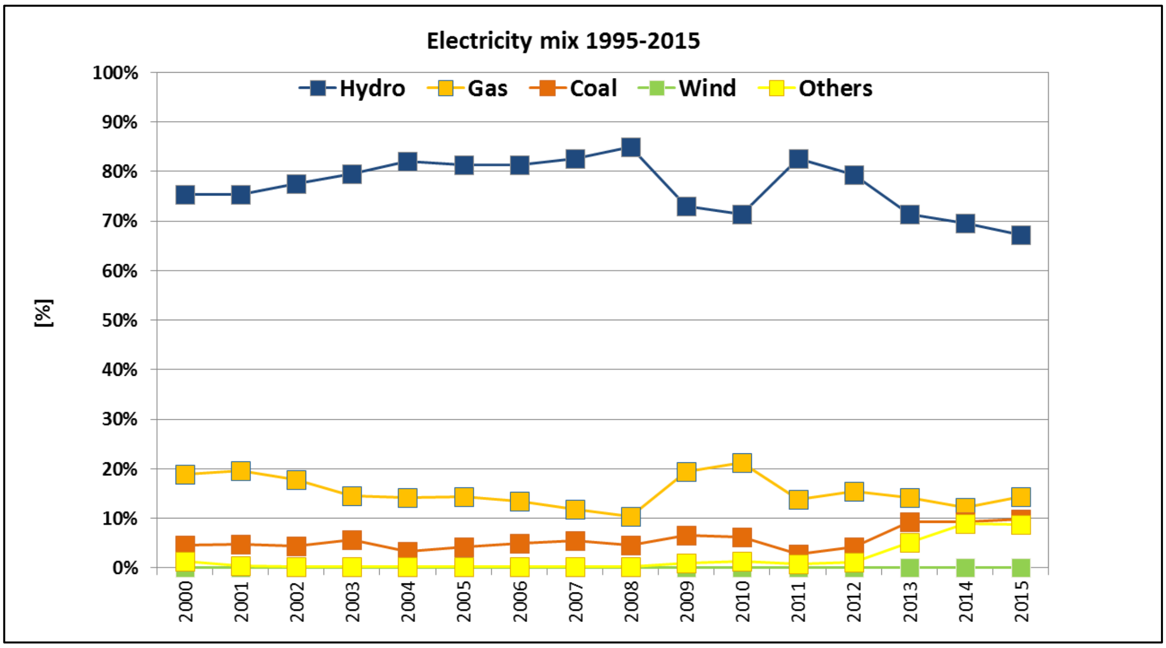


Figure 21 – Historical electricity mix generation in the period 1995-2015

Table 17 shows the available mix capacity at December 2017.

Table 17 – Installed capacity mix

Source	Net Capacity	
	MW	%
ACPM	766	4.5%
Hydro	11725.6	69.7%
Bagasse	130.7	0.8%
Biogas	4	0.0%
Coal	1370	8.1%
Fuel Oil	187	1.1%
Gas	2300	13.7%
JET – A1	44	0.3%
Mix Gas – JET A1	264	1.6%
Solar	9.8	0.1%
Wind	18.4	0.1%
TOTAL	16820	100.00%

As shown in the table, some particular fuels are used, as for example:

- ACPM: It is acronym of Aceite Combustible Para Motores and it is a term used in Colombia for diesel oil extracted by oil. An equivalent term is Petrodiesel and it differs from biodiesel, which is diesel oil extracted from vegetable oil. In Latin America it is more common to use diesel for both except, as said, in Colombia
- Bagasse is the fibrous matter that remains after sugarcane or sorghum stalks are crushed to extract their juice. It is dry pulpy residue left after the extraction of juice from sugar cane.
- JET fuel or aviation turbine fuel (ATF) or avtur, is a type of aviation fuel designed for use in aircraft powered by gas turbine. The most commonly used fuels for commercial aviation are Jet A and Jet A-1, which are produced to a standardized international specification.

The historical values of generation capacity in Colombia are highlighted in Figure 22. Again, it is possible to see that the hydro capacity is dominant.

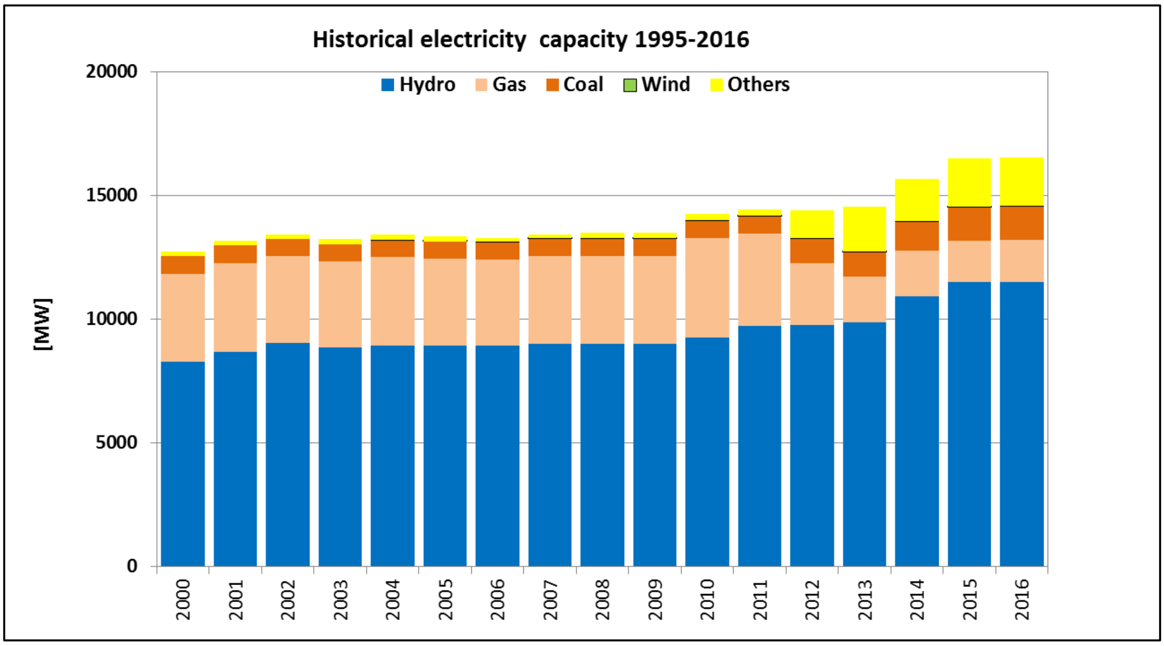


Figure 22 – Historical values of generation installed capacity

2.2.1.2 Power generation developments

In the already quoted preliminary "Plan de Expansión de Referencia Generación – Transmisión 2017 – 2031 by UPME [1], there is a progress with respect to the previous versions of the generation expansion plan, moving from a simulation of "mono nodal" generation sources to "multi-nodal" considering the fifteen electric areas reported in the figure below.

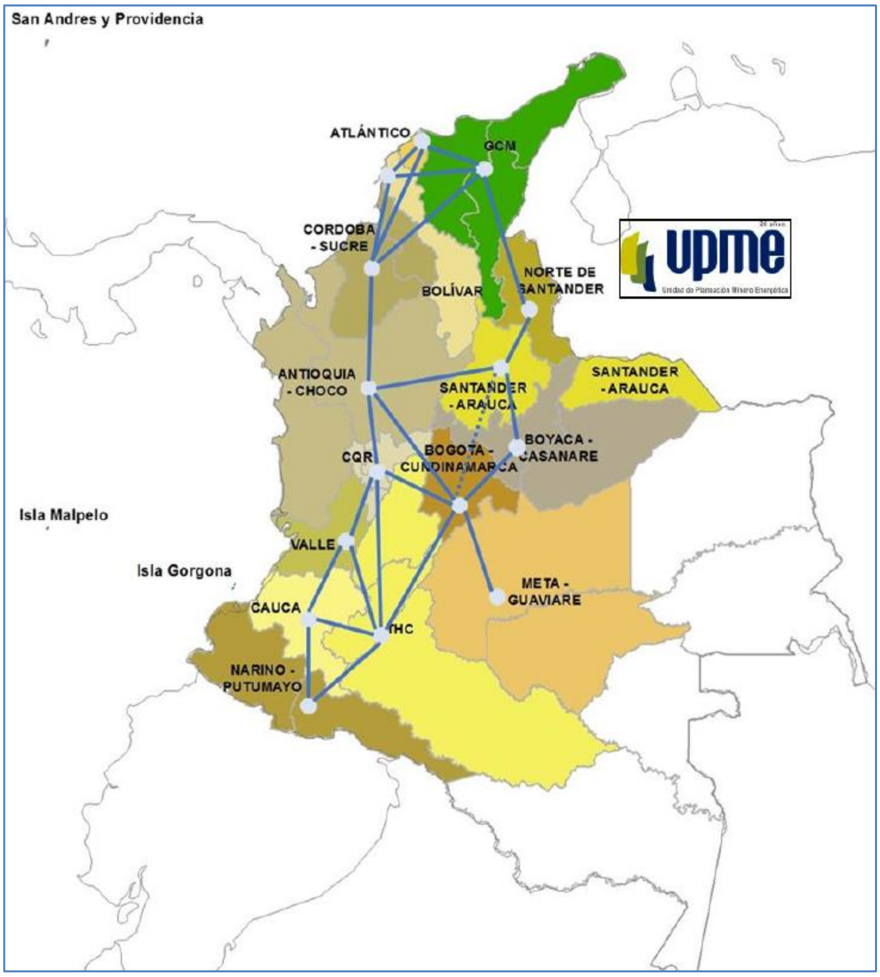


Figure 23– Operative area: source UPME

The innovation consists in considering the transmission restrictions between the fifteen electric areas in the planning of the generation. This activity in the first version has required a greater effort, learning and resources. Long-term scenarios differentiated by area and nationally unified are formulated, where the minimum investment and operating costs are evaluated.
The planning methodology of the generation expansion is adapted to the new technologies of simulation and to the conditions of the country. The fundamental inputs for the expansion plan are the projections of electricity demand, the availability of energy resources by operating area, the projection of fuel prices, etc.
As an initial input, the reliability of the system is verified in the short term (5 years), an initial scenario is modelled considering the existing generation infrastructure and the planned projects. The following are the methodological points followed to determine the expansion of the system in the medium term (10 years) and long term (15 years) for each of the cases analysed:

- the base infrastructure of Generation (G) and Transmission (T) in all scenarios, that is, the current capacity plus the defined expansion.
- the National Interconnected System (SIN) modelled considering its topology through the 15 operational areas of Figure 23, considering its demands, resources and exchanges of electricity,

projections of fuel prices, possibilities of new technologies, options for traditional expansion, as well as investment costs among others, and an integrated minimum cost dispatch;
- the new (undefined) expansion;
- the connection or use costs associated to the new generation projects;
- the minimization of the costs of the operation and investment of the system, looking for a generation matrix and optimal transmission.

Table 30 shows the capacities considered for the expansion of the generation park, divided for each zone analysed. The capacity value represents the sum for each area of:
- In the case of large scale projects, the capacity of potential candidate projects of various values greater than 1 MW
- in the case of self-generation and distributed solar generation projects, the capacity of potential candidate projects of different values less than 1 MW

Table 18 – Total capacity (MW) of identified projects per area

Zone	Hydro	Gas	Coal	Less 1MW	Cog & Biomass	Wind	Solar	Solar Distributed	Geothermal
Ant-Cho	1504		350	279			2	90	
Atlántico			350		7		597	60	
Bog-Cund					10		120	170	
Bolivar		155					92	35	
Boy-Cas		147	240					40	
Cauca				54				12	
Cor-Suc			250				313	35	
CQR				59				30	50
GCM			660		8	4127	4430	60	
THC	45						116	35	
Met-Guav					55		103	20	
Nar-Put								15	
NSant			160				6	25	
Sant-Ara	150				20		101	35	
Valle				83	61		10	70	
TOTAL	**1699**	**302**	**2010**	**475**	**161**	**4127**	**5888**	**732**	**50**

These values represent the potential candidates for the generation expansion increase per technology in the different areas.
The total increase in the generation capacity would be then 15.4 GW, among which Variable Renewable Sources such as PV and wind play a significant role (about 11 GW).

It is important to consider that the very high values of wind and solar expansion indicated can hardly be materialized due to connection and distribution restrictions and lack of definition in the regulation.
The reference scenario that must be considered for the present activity has to identify the amount of feasible projects taking into account also the limitation of the transmission system within each region

and among them. The results of this selection are presented by UPME in the scenario 2 of the updated version of the transmission expansion plan, reported in Table 19, which derive for the optimisation considering the limitations of transmission capacity of the network.

Table 19 – Total capacity (MW) added in the Colombian system in scenario 2

Zone	Hydro	Gas	Coal	Less 1MW	Cog & Biomass	Wind	Solar	Solar Distributed	Geothermal
Ant-Cho	2571			279				90	
Atlántico							302	60	
Bog-Cund					10		120	170	
Bolivar		154					92	35	
Boy-Cas		107	240					20	
Cauca				54				1	
Cor-Suc			250				173	20	
CQR				59				25	
GCM						1231	70	45	89
HTC	45						116	21	
Met-Guav					55		103	10	
Nar-Put								0	
NSant			160					8	
Sant-Ara	150				20		101	20	
Valle				83	61		10	70	
TOTAL	**2766**	**261**	**650**	**475**	**146**	**1231**	**1066**	**595**	**89**

2.2.2 Ecuador

The split of electricity production in Ecuador according the different sources relevant to the year 2016 is reported in Table 20. More than 57% (15.6 TWh) of the production is hydro, while about 40% is thermal (mainly Internal Combustion Motors). Wind and PV summed up only to little more than 0.1 TWh. Interconnections with other countries do no play a significant role in the coverage of the demand.

Table 20 – Electricity generation balance in 2016

Electricity generation		GWh	%
Renewable Energy	Hydro	15590	57.6%
	Wind	84	0.3%
	Solar	39	0.1%
	Biomass	477	1.8%
	Biogas	13	0.0%
No Renewable Energy	Thermal	10870	40.2%
TOTAL		27073	100%

Interconnections	Colombia	44
	Peru	38
	Total Import	82

The following table and graph summarize the above values for better visualization.

Source	2016 [TWh]
Thermal	10.9
Hydro	15.6
Wind	0.1
Solar	0.0
Biomass	0.5
Biogas	0.0
Import	0.1
TOTAL	27.2

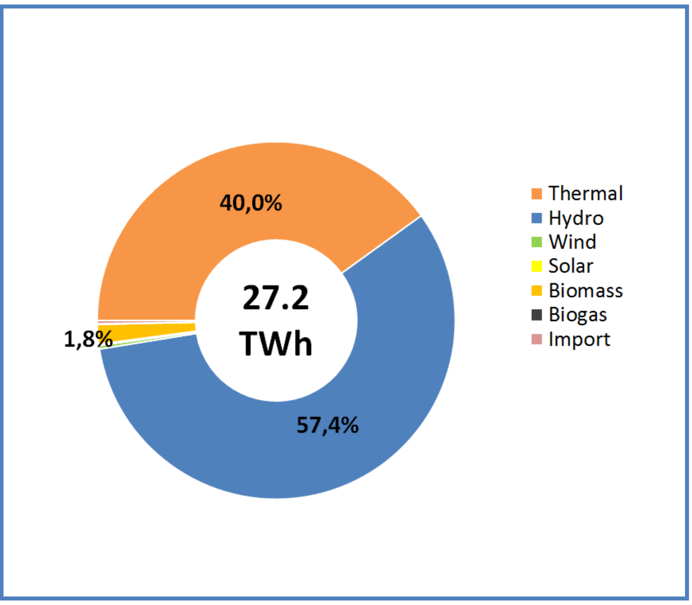


Figure 24 – Generated energy to cover demand 2016

About 86.6 % (23.4 TWh) the electricity generated was dispatched by the Sistema Nacional Interconectado (SNI), while 13.4% (3.6 TWh) was produced by the not interconnected systems.
Taking into account transmission losses (which in 2016 accounted for 585 GWh), the total electricity at the distribution delivery point summed up to 22.44 TWh. The billed electricity summed up to 19.35 TWh. The distribution losses summed up to 2.69 TWh (12.21% at national level).

Historical data about electricity generation are reported in Figure 25.

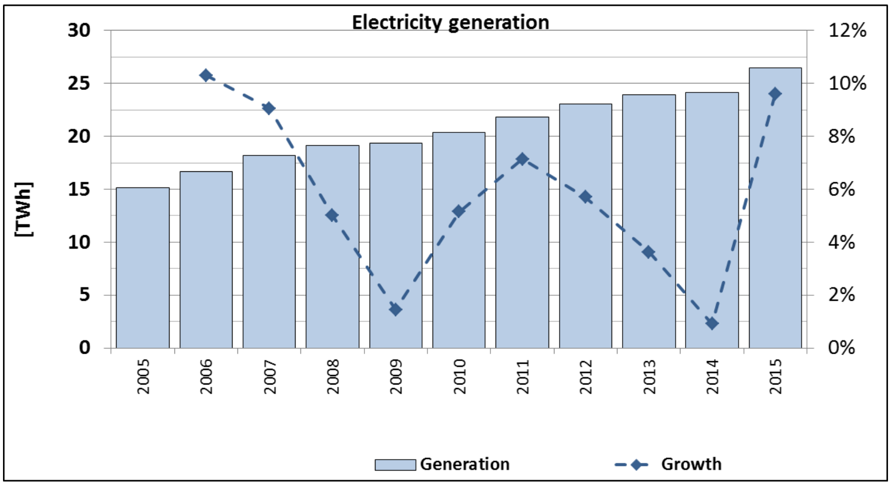


Figure 25 – Historical electricity generation in the period 2005-2015

The generation nominal capacity in 2016 is reported in Table 21, mainly belonging to SNI.

Table 21 – Electricity nominal capacity in 2016

Electricity generation		MW	%
S.N.I	Hydro	4441	54%
	Wind	16.5	0.2%
	Thermal	2450	29.8%
	Biomass	144	1.8%
	Solar	24	0.3%
	Biogas	2	0 %
TOTAL S.N.I		7077.5	86%
Not incorporated	Hydro	6	0.1%
	Wind	5	0.1%
	Thermal	1136	13.8%
	Solar	2	0%
TOTAL not incorporated		1149	14%
TOTAL		8226.5	100%

Table 22 shows the capacity for source of generation. Renewables (hydro) cover more than half of the available capacity.

Table 22 – Electricity nominal capacity in 2016

Electricity generation		MW	%
Renewable	Hydro	4447	54.0%
	Wind	21.5	0.3%
	Solar	26	0.3%
	MCI	2	0%
	Steam	144	1.8 %
TOTAL Renewable		4640.29	56.41%
Not renewable	MCI	2005	24.4%
	Turbogas	1119	13.6%
	Steam	462	5.6%
TOTAL not renewable		3586	43.6%
TOTAL		8226.5	100.00%

The historical values of generation capacity of the SNI are highlighted in Figure 26. The increasing of generation capacity in 2016 was due to the entrance of new plants and the total incorporation of Coca Codo Sinclair plant with a nominal capacity of 1500 MW.

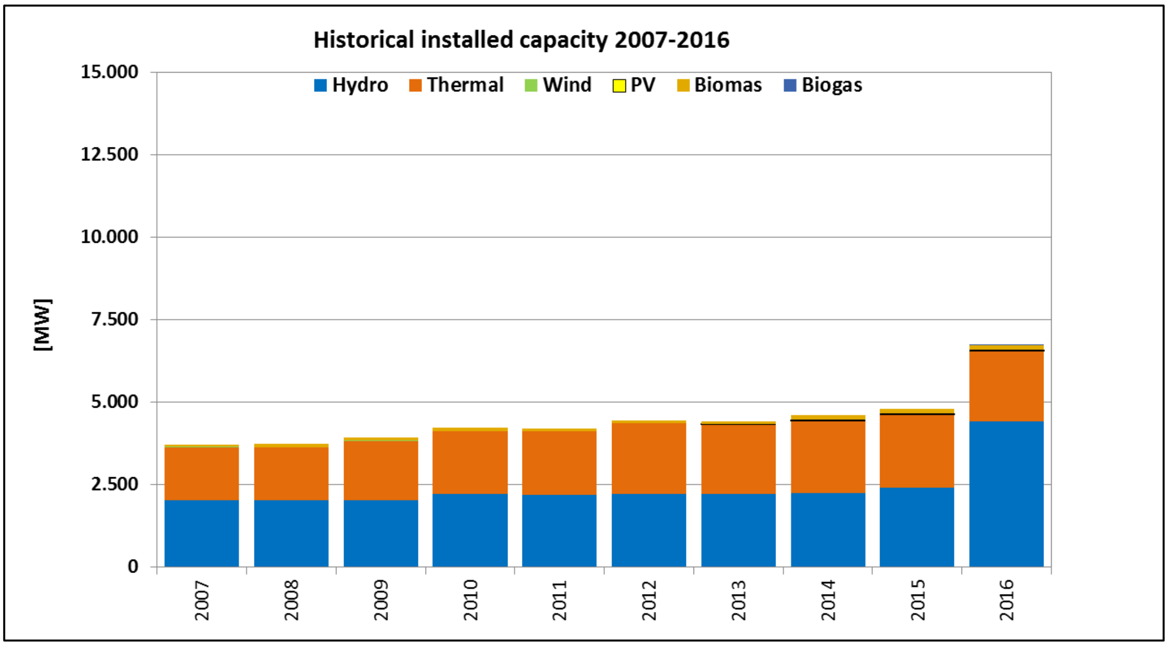


Figure 26 – Historical evolution of electricity capacity - SNI – Source [6]

2.2.2.1 Power generation developments

As said, change the electricity matrix, through the exploitation of existent renewable resources, is one of the objectives of Ecuadorian energy policy. The main strategy is to sustain the construction of hydro, wind, PV and efficient thermoelectric generation plants.

The availability of resources considered in the Generation expansion plan 2016 – 2025 is based on the identification of the technical potential for renewable source and in particular:

- **Hydro resource**. The values of hydro potential of Ecuador identified are:
  - Theoretical Average Hydro potential, estimated with average monthly flow: 91.000 MW;
  - Technically Feasible Hydro potential: 31.000 MW (in 11 hydro basins);
  - Economically Feasible Hydro potential: 22.000 MW (in 11 hydro basins);

  Figure 27 shows the main area of interest

  Taking into account the already installed capacity equal to 4447 MW (4.418 MW of effective capacity), the remaining economically feasible Hydro potential would allow an increase of five times.

  There are some projects under construction, and when they will be incorporated, the effective hydro capacity will sum up to 5.401 MW (24.5% of the economically feasible Hydro potential).

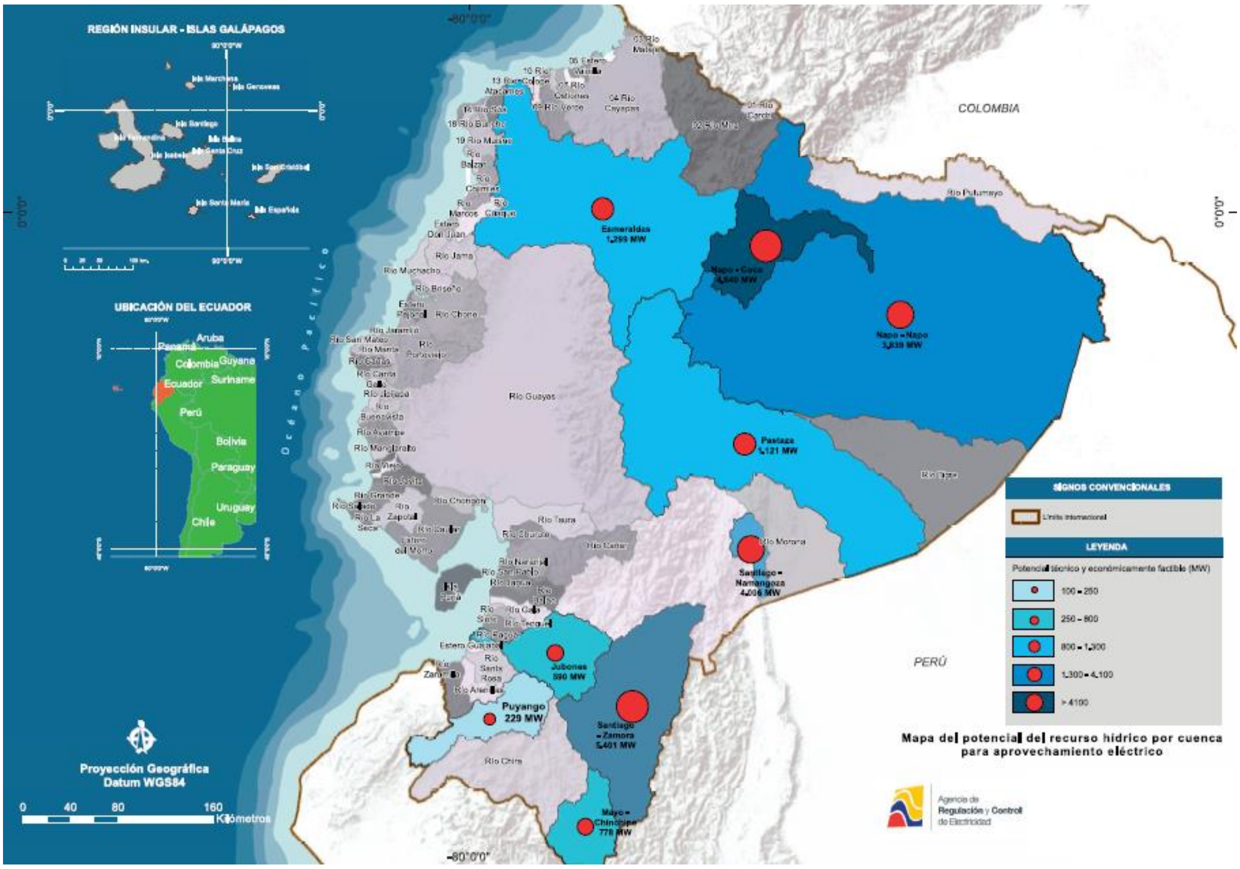


Figure 27 – Map of Hydro potential in Ecuador - [6]

- **Other renewable resources (wind, PV, biomass)**

  According to the "Atlas Eolico del Ecuador con fines de generacion electrica" developed Ministerio de Electricidad y Energia Renovable, the raw wind potential is about 1,700 MW, with an average wind speed of 7 m/s, for an average generation of 2,869 GWh. Figure 28 shows the potential in the different areas. The exploitation of wind is affected by the very low air density present in the areas with highest wind speed.

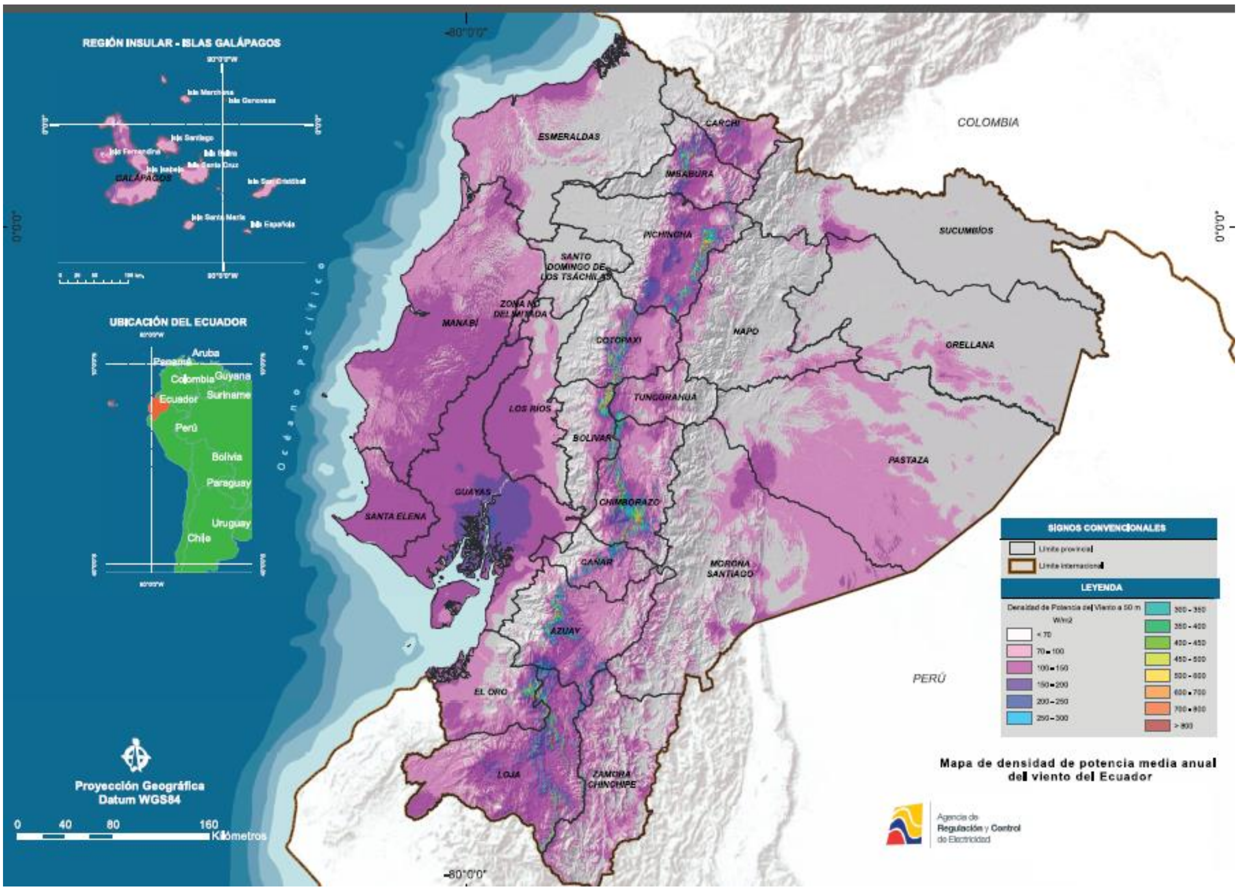


Figure 28 – Map of Wind potential in Ecuador - [6]

According to the “Atlas Solar del Ecuador con fines de generacion electrica”, the average global irradiation is 4,575 Wh/m^2/day (see also Figure 29, which also shows geothermal potential). According to the Masterplan, the sites with the maximum potential are five, with a total potential of about 900 MW.

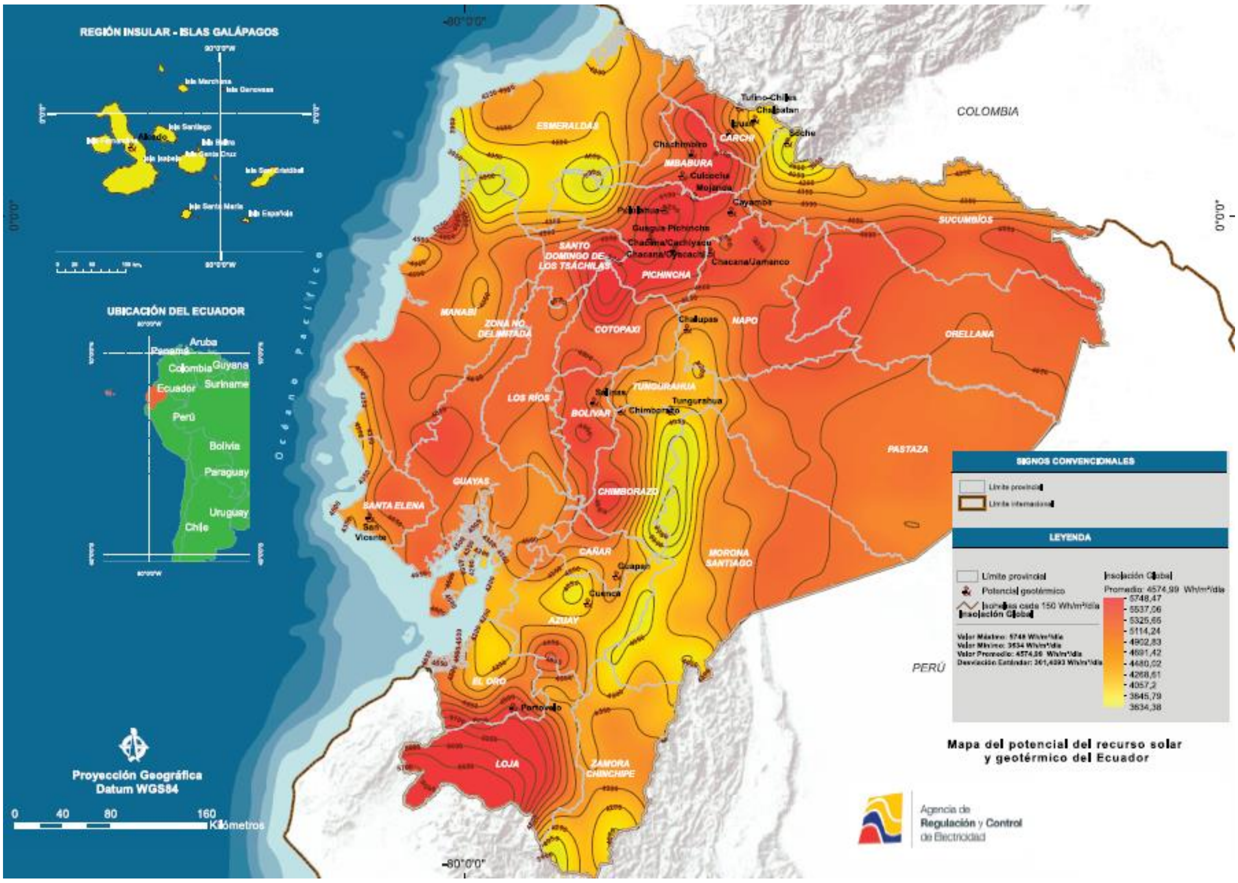


Figure 29 – Map of solar and geothermal potential in Ecuador - [6]

According to the “Atlas Bioenegetico del Ecuador”, the expected resource of biomass is 18.4 million tons year including agricultural, livestock and forestall residuals, with which the expected energetic potential is 230.959 TJ/year, or 12.7 TWh/year. Considering the 50% of major residues as oil palm, bananas and rice, the theoretical potential is 500 MW for the whole year.

Figure 30 shows the potential in the different regions.

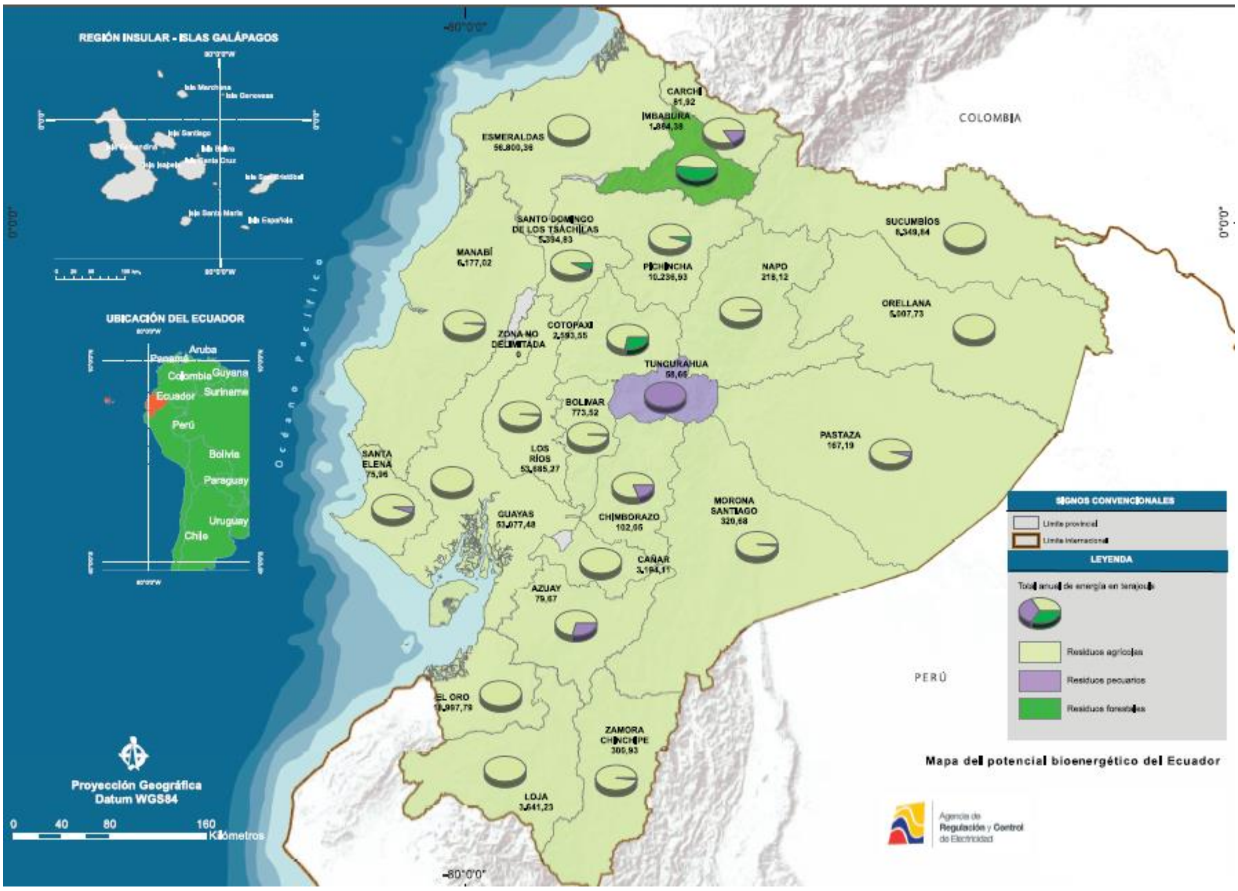


Figure 30 – Map of Bioenergetics potential in Ecuador - [6]

For the definition of the Generation Masterplan, the simulations obtained with the software OPTGEN and SDDP, in the base case (i.e. with the forecast demand growth of Hypothesis 3) give the results described from Table 23 to Table 27. As shown by the tables, the total capacity to be installed sums up, at the year 2023, to about 4,150 MW, mainly hydro with 3,760 MW. It is necessary to reduce these value by the nominal power of the Coca Codo Sinclair, which is already included in the base case.

Table 23 – Electricity projects 2016 – 2025 – Masterplan Base Case – Year 2016

Project/Plant	State	Type	MW	GWH/year	Province	Canton
Mazar Dudas Alazan	Operation	Hydro	6.23	39.1	Cañar	Azogues
San José del Tambo	Operation	Hydro	8.00	45.0	Bolivar	Chillanes
El Inga I	Operation	Biogas	2.00	15.6	Pichincha	Quito
Coca Codo Sinclair	Operation	Hydro	1500.00	8743.0	Napo and Sucumbíos	Chaco and Lumbaqui
Paute Sopladora	Operation	Hydro	487.00	2800.0	Azuay and Morona Santiago	Sevilla de Oro and Santiago de Mendez
Topo	Operation	Hydro	29.20	222.0	Tungurahua	Baños

Table 24 – Electricity projects 2016 – 2025 – Masterplan Base Case – Year 2017

Project/Plant	State	Type	MW	GWH/year	Province	Canton
Victoria	Operation	Hydro	10.00	64.0	-	Quijos
El Inga II	Construction	Biogas	3.00	23.4	Pichincha	Quito
Machala gas 3rd unit	Construction	Thermal	77.00	510.0	El Oro	Machala
Monas – San Francisco	Construction	Hydro	275.00	1290.8	Azuay/El Oro/Loja	Pucarà/Saraguro/Pasaje
Mazar Dudas Alazan	Construction	Hydro	7.19	44-9	Cañar	Azogues
Chorrillos	Construction	Hydro	4.00	23.0	Zamora Chincipe	Zamora
Delsìitanisagua	Construction	Hydro	180.00	1411.0	Zamora Chincipe	Zamora
Palmira Nanegal	Construction	Hydro	10.00	77.0	Pichincha	Quito
Toachi/Pilaton*	Construction	Hydro	254.40	1120.0	Pichincha. Tsachila. Cotopaxi	Mejia. Sto. Domingo de los Tsachilas. Sigchos.
San José de Minas	Construction	Hydro	5.95	37.0	Pichincha	Quito
Machala Gas Combined Cycle	Construction	Thermal	110.00	720.0	El Oro	Machala
Due	Construction	Hydro	49.71	420.9	Sucumbius	Gonzalo Pizarro
Rio Verde Chico	Construction	Hydro	10.20	82.9	Tungurahua	Baños de Agua Santa

*2017/2018

Table 25 – Electricity projects 2016 – 2025 – Masterplan Base Case – Year 2018

Project/Plant	State	Type	MW	GWH/year	Province	Canton
Sigchos	Construction	Hydro	18.57	126.4	Cotopaxi	Sigchos
Pusuno	Construction	Hydro	39.50	216.9	Napo	Tena
Sabanilla	Construction	Hydro	30.00	194.0	Zamora Chincipe	Zamora
Quijos	Construction	Hydro	50.00	355.0	Napo	Quijos
Normandia	Construction	Hydro	48.15	350.7	Morona Santiago	Morona

Table 26 – Electricity projects 2016 – 2025 – Masterplan Base Case – Year 2022

Project/Plant	State	Type	MW	GWH/year	Province	Canton
Block of projects with renewable energy	Waiting for authorization	Renewables	200.00	876.0	Various	Various

Table 27 – Electricity projects 2016 – 2025 – Masterplan Base Case – Year 2023

Project/Plant	State	Type	MW	GWH/year	Province	Canton
Santa Cruz	Selfgeneration Mine – In process	Hydro	138	964	Zamora Chincipe	El Pangui
Paute - Cardenillo	Alta Prioridad	Hydro	595.6	3409.0	Morona Santiago	Santiago de Mendez

The listed plants will be considered in the scenario to be prepared for 2030 simulations.

Another very big hydro power plant, called Santiago G8, is under development. It is composed by 4 different phases, 600MW each. This plant is not considered by CELEC in the Base Case, but added as possible plant in the sensitivity case which involves a higher demand growth and more investments for a change of the generation matrix. Due to the enormous dimension of the investment and to the already high amount of installed power in the country, it is assumed that also in the Base scenario at 2030 considered in the present study the Santiago G8 power plant is not present.

2.2.3 Peru

In Peru, the unbundling of the electricity sector in generation, transmission and distribution sectors started in March 1991, when the Government of Alberto Fujimori implemented an aggressive structural reform process oriented to reduce state intervention and eliminate the distortions in the economy that derived of the previous Government.

Under this general context, a series of laws were promulgated, as, for example, the Legislative Decree No. 662 (Law of Promotion of Foreign Investments), and the Legislative Decree No. 674 (Promotion Law of Private Investment of the Companies of the State).

The latter, in particular, declared the national interest private investment in the field of companies that formed the business activity of the State, for which organs were created in charge of private investment.

In this new context, on November 19, 1992, the Law No. 25844, Electricity Concessions Law (LCE) was released replacing the LGE, previous normative framework of the sector.

The LCE determined the division of activities of the electric sector in generation, transmission, distribution and commercialization, concessions and authorizations were granted for these activities, acting the State as a regulating entity. LCE also established a price freedom regime for the supplies that can be made in conditions of competition (generation and marketing), and a pricing system regulated in those supplies that by their nature require it, recognizing costs efficient (transmission and distribution).

As a complement to this framework, the Technical Standard of Quality of Electrical Services was approved (Supreme Decree No. 020-97-EM).

This established the minimum values that the concessionaire companies in the electric sector should comply regarding the product delivered and the service rendered; and was used for the supervision of companies electricity concessionaires, both private and public.

In November 1997 the Law N ° 26876 (Antitrust and Anti-oligopoly of the Sector Electric - LAASE) was enacted; the scope of this Law is to regulate the possibility of concentration horizontally and vertically in the market electric power; and it was granted to the Institute National Defense of Competition and of the Protection of Intellectual Property (Indecopi), the power to authorize said concentrations when they did not affect free competition in the sector.

2.2.3.1 Existing generation

During 2016, the total electric power generated in Peru summed up to 51700 GWh; of this total, 49534 GWh (96%) corresponds to the electricity market and 2166 GW.h (4%) was for own use.
In relation to the total energy available in the electricity market, 87.9% was destined to national final consumption; 10.6% was recorded as losses and 1.4% of energy was used for own consumption in generation. In 2016, 38 GWh was exported to Ecuador, that is, 0.1% of the total generated.
Finally, of the final consumption that comes from the electricity market, 52% was commercialized to free customers and 48% to regulated ones.

In 2016 the energy was produced about equally by thermal (50.7%) and hydro (46.8%) power plants. RES (mostly wind) covered only 2.5% of the production (Figure 31).

Source	2016 [TWh]
Thermal	26.2
Hydro	24.2
Wind	1.1
Solar	0.2
TOTAL	**51.7**

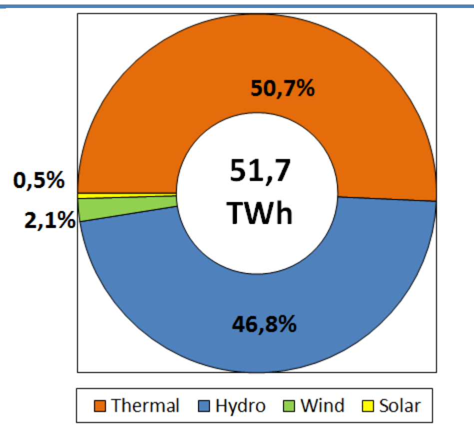


Figure 31 – Generated energy to cover demand 2016

In the last fifteen years, the growth of the generation sector was driven by a large development of thermal generation, reducing the role of hydro power generation to cover the annual demand. As highlighted in Figure 32, Table 28 and Figure 33, thermal production increased its weight in the energy balance from 15.3% in 2001 to 50.7% in 2016, while hydro generation lost the leadership from 84.7% in 2001 to 45.8% in 2016.

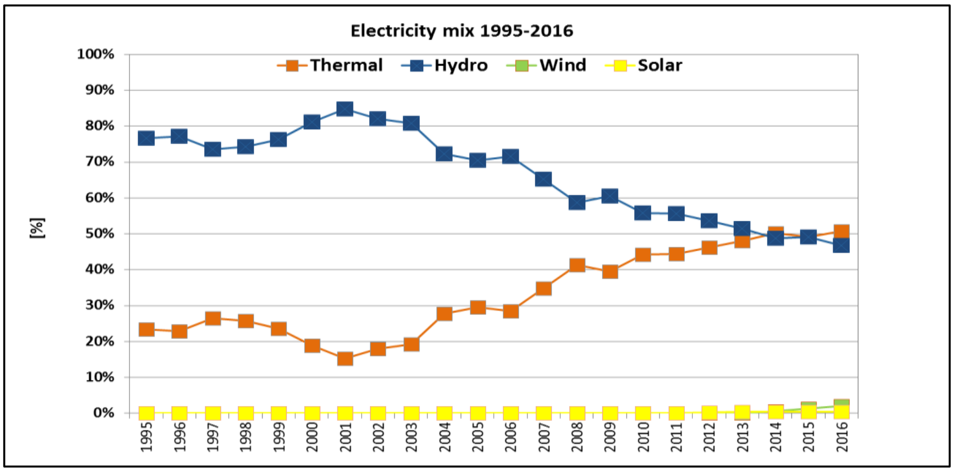


Figure 32 – Electricity mix in the period 1995-2016

Table 28 – Electricity generation in the period 1995-2016

Year	Thermal		Hydro		Wind		Solar	
	[TWh]	[%]	[TWh]	[%]	[TWh]	[%]	[TWh]	[%]
1995	3.9	23.4%	12.9	76.6%	0.0	0.0%	0.0	0.0%
1996	4.0	22.9%	13.3	77.1%	0.0	0.0%	0.0	0.0%
1997	4.7	26.4%	13.2	73.6%	0.0	0.0%	0.0	0.0%
1998	4.8	25.7%	13.8	74.3%	0.0	0.0%	0.0	0.0%
1999	4.5	23.7%	14.5	76.3%	0.0	0.0%	0.0	0.0%
2000	3.7	18.8%	16.2	81.2%	0.0	0.0%	0.0	0.0%
2001	3.2	15.3%	17.6	84.7%	0.0	0.0%	0.0	0.0%
2002	3.9	17.9%	18.0	82.1%	0.0	0.0%	0.0	0.0%
2003	4.4	19.1%	18.5	80.9%	0.0	0.0%	0.0	0.0%
2004	6.7	27.8%	17.5	72.2%	0.0	0.0%	0.0	0.0%
2005	7.5	29.5%	18.0	70.5%	0.0	0.0%	0.0	0.0%
2006	7.8	28.4%	19.6	71.6%	0.0	0.0%	0.0	0.0%
2007	10.4	34.7%	19.5	65.3%	0.0	0.0%	0.0	0.0%
2008	13.4	41.3%	19.1	58.7%	0.0	0.0%	0.0	0.0%
2009	13.0	39.6%	19.9	60.4%	0.0	0.0%	0.0	0.0%
2010	15.9	44.2%	20.1	55.8%	0.0	0.0%	0.0	0.0%
2011	17.2	44.4%	21.6	55.6%	0.0	0.0%	0.0	0.0%
2012	18.9	46.2%	22.0	53.7%	0.0	0.0%	0.1	0.1%
2013	20.8	48.0%	22.3	51.5%	0.0	0.0%	0.2	0.5%
2014	22.9	50.2%	22.2	48.8%	0.3	0.6%	0.2	0.4%
2015	23.7	49.1%	23.7	49.1%	0.6	1.2%	0.2	0.5%
2016	26.2	50.7%	24.2	46.8%	1.1	2.1%	0.2	0.5%

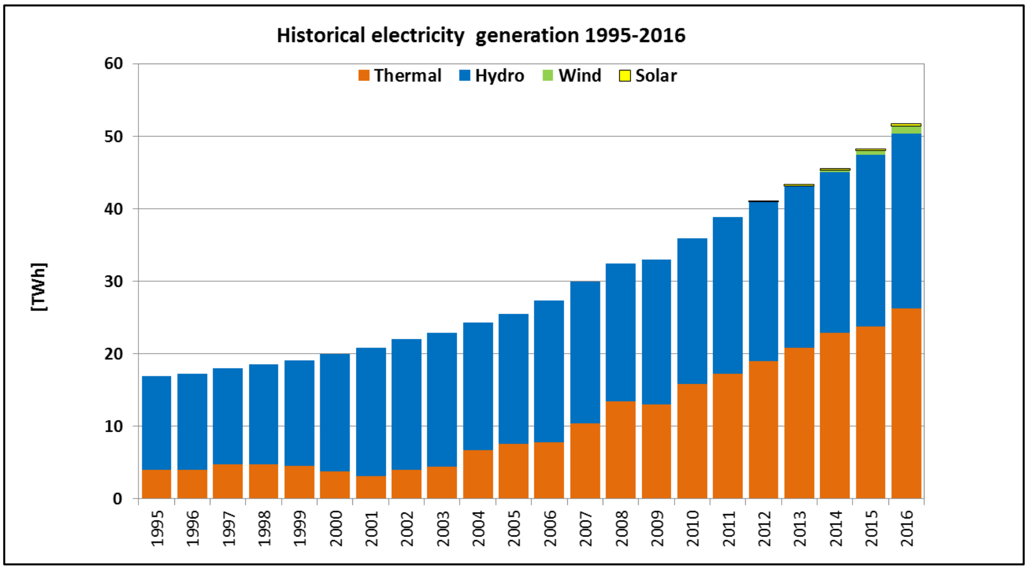


Figure 33 – Historical electricity generation in the period 1995-2016

The electricity generation mix is different analysing the electricity market and the electricity for own use, as report in Table 29. As shown by the table, the own use generation is mainly thermal, with the absence of RES.

Table 29 – Electricity generation (TWh) in the period 1995 - 2016

Year	Electricity Market					Own use		
	Hydro	Thermal	Wind	Solar	TOTAL	Hydro	Thermal	TOTAL
1995	11.5	1.6	0.0	0.0	13.1	1.4	2.4	3.8
1996	11.8	1.5	0.0	0.0	13.3	1.5	2.5	4.0
1997	12.3	3.1	0.0	0.0	15.3	0.9	1.7	2.6
1998	13.4	3.4	0.0	0.0	16.8	0.4	1.3	1.8
1999	14.1	3.3	0.0	0.0	17.4	0.4	1.3	1.7
2000	15.7	2.6	0.0	0.0	18.3	0.4	1.2	1.6
2001	17.2	2.0	0.0	0.0	19.2	0.4	1.1	1.6
2002	17.6	2.8	0.0	0.0	20.4	0.4	1.2	1.6
2003	18.1	3.2	0.0	0.0	21.4	0.4	1.1	1.6
2004	17.1	5.5	0.0	0.0	22.6	0.4	1.2	1.6
2005	17.6	6.2	0.0	0.0	23.8	0.4	1.3	1.7
2006	19.2	6.5	0.0	0.0	25.6	0.4	1.3	1.8
2007	19.1	9.1	0.0	0.0	28.2	0.4	1.3	1.7
2008	18.6	12.0	0.0	0.0	30.6	0.5	1.4	1.9
2009	19.4	11.5	0.0	0.0	30.9	0.5	1.5	2.0
2010	19.6	14.0	0.0	0.0	33.5	0.5	1.9	2.4
2011	21.0	15.2	0.0	0.0	36.2	0.5	2.0	2.6
2012	21.5	16.8	0.1	0.0	38.4	0.5	2.1	2.7
2013	21.7	18.8	0.2	0.0	40.7	0.6	2.1	2.7
2014	21.6	20.8	0.2	0.3	42.8	0.6	2.1	2.7
2015	23.1	21.8	0.2	0.6	45.7	0.6	2.0	2.6
2016	23.7	24.6	0.2	1.1	49.5	0.5	1.6	2.2

Figure 34 shows the map of the electricity generation and capacity in Peru in the year 2016.

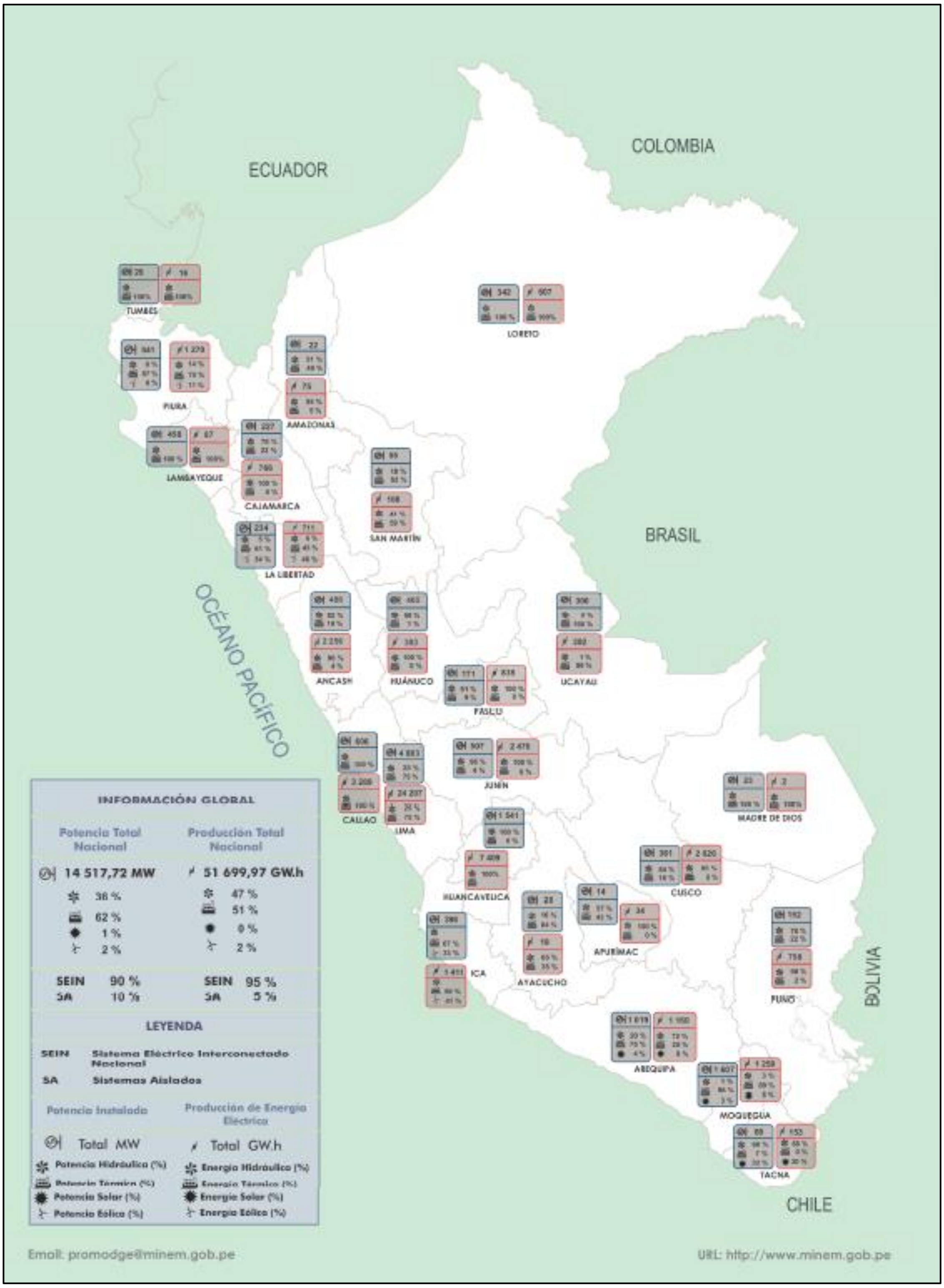


Figure 34 – Map of electricity capacity and generation 2016 - source MINEM

In 2016, total installed capacity of the generation fleet was equal to 14,518 MW. Only the 2.5% of total capacity was available from RES power plants (about 340 MW); 62% was from thermal plants while the 35.7% from hydro power plants. Figure 35 shows the installed capacity in 2016 and the relevant capacity factor[6] for each technology.

Source/ Technology	Installed Capacity [MW]	Capacity Factor [%]
Thermal	8.989	33.2%
Hydro	5.189	53.0%
Wind	240	50.5%
PV solar	100	27.4%
TOTAL	14.518	

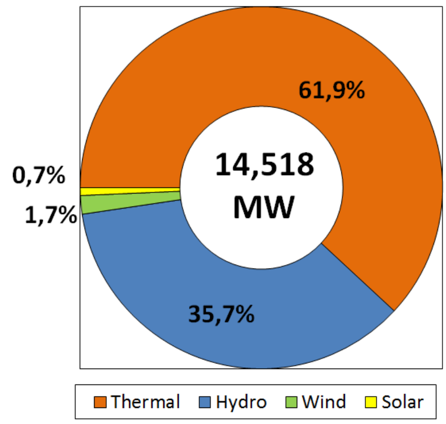


Figure 35 – Generation installed capacity in the year 2016

The historical values of generation capacity in Peru are highlighted in Figure 36 and Table 30, as showed by the figure and the table, the thermal capacity has presented a rapid increase in the last fifteen years.

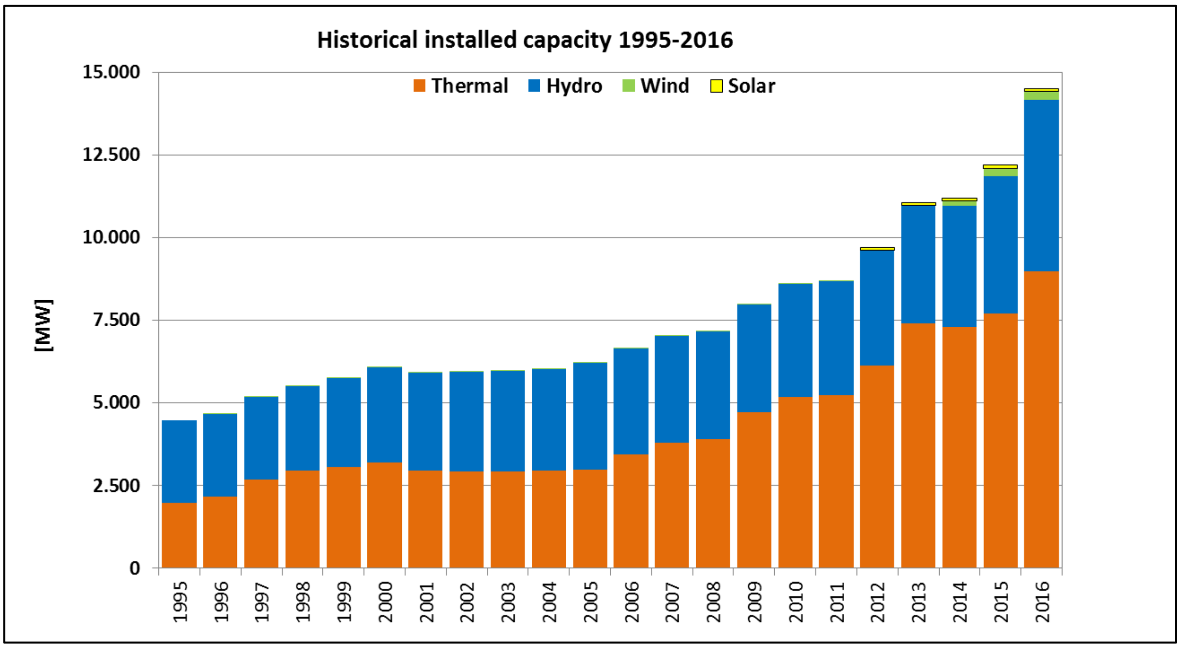


Figure 36 – Historical values of generation installed capacity

[6] 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 30 – Historical values of generation installed capacity

[MW]	Thermal	Hydro	Wind	Solar	TOTAL
1995	2.479	1.982	0	0	4.462
1996	2.493	2.170	0	0	4.663
1997	2.513	2.679	0	0	5.192
1998	2.572	2.943	0	0	5.515
1999	2.673	3.068	0	1	5.742
2000	2.857	3.209	0	1	6.066
2001	2.966	2.940	0	1	5.907
2002	2.996	2.938	0	1	5.936
2003	3.032	2.937	0	1	5.970
2004	3.056	2.960	0	1	6.016
2005	3.207	2.993	0	1	6.201
2006	3.216	3.441	0	1	6.658
2007	3.234	3.793	0	1	7.028
2008	3.242	3.915	0	1	7.158
2009	3.277	4.708	0	1	7.986
2010	3.438	5.174	0	1	8.613
2011	3.451	5.240	0	1	8.691
2012	3.484	6.134	80	1	9.699
2013	3.556	7.414	80	1	11.051
2014	3.662	7.302	96	143	11.203
2015	4.152	7.701	96	240	12.189
2016	5.189	8.989	100	240	14.518

The distribution of generation installed capacity (in the regulated market and for own use) in 2016 is shown in Table 31 and from Figure 37 to Figure 39; as shown by the table the department with the highest installed capacity is Lima followed by Moquegua and Huancavelica

Table 31 – Installed capacity for region and source (MW) - 2016

Region	Electricity Market					Own Use			TOTAL	
	Thermal	Hydro	Wind	Solar	Total	Thermal	Hydro	Total	MW	%
AMAZONAS	8.52	11.41			19.93	2.30		2.30	22,23	0,15%
ANCASH	1.05	393.17			394.22	87.78	3.66	91.44	485,66	3,35%
APURIMAC		8.02			8.02	6.00		6.00	14,02	0,10%
AREQUIPA	703.74	196.03		44	943.77	71.55	3.96	75.51	1,019,27	7,02%
AYACUCHO	11.77	3.26			15.03	5.20		5.20	20,23	0,14%
CAJAMARCA	3.08	174.33			177.41	47.47	1.82	49.29	226,70	1,56%
CALLAO	562.94				562.94	42.78		42.78	605,72	4,17%
CUSCO		301.90			301.90	58.19	0.71	58.90	360,80	2,49%
HUANCAVELICA	0.10	1,533.64			1,533.74	2.13	5.49	7.62	1,541,36	10,62%
HUÁNUCO	0.10	456.73			456.83	4.10	4.30	8.40	465,23	3,20%
ICA	185.53		129.70		315.23	80.94		80.94	396,17	2,73%
JUNÍN	2.45	449.46			451.91	18.91	36.20	55.11	507,02	3,49%
LA LIBERTAD	0.25	9.33	80.25		89.83	142.73	1.72	144.45	234,28	1,61%
LAMBAYEQUE	409.53				409.53	48.35		48.35	457,88	3,15%
LIMA	3,308.98	1,188.88			4,497.86	352.03	32.86	384.89	4,882,76	33,63%
LORETO	122.77				122.77	218.94		218.94	341,70	2,35%
MADRE DE DIOS	23.34				23.34				23,34	0,16%
MOQUEGUA	1,530.77	0.47		36	1,567.24	30.94	9.00	39.94	1,607,18	11,07%
PASCO	0.75	138.44			139.19	15.01	17.06	32.07	171,26	1,18%
PIURA	393.31	42.11	30.00		465.42	75.64		75.64	541,06	3,73%
PUNO	8.39	119.00			127.39	24.89		24.89	152,28	1,05%
SAN MARTÍN	43.61	9.73			53.34	2.00		2.00	55,34	0,38%
TACNA		35.70		20	55.70	4.21		4.21	59,91	0,41%
TUMBES	18.88				18.88	7.34		7.34	26,22	0,18%
UCAYALI	292.22	0.87			293.09	7.05		7.05	300,14	2,07%
TOTAL	**7,632.06**	**5,072.47**	**239.95**	**100**	**13,044.5**	**1,356.47**	**116.78**	**1,473.24**	**14,517,72**	100%

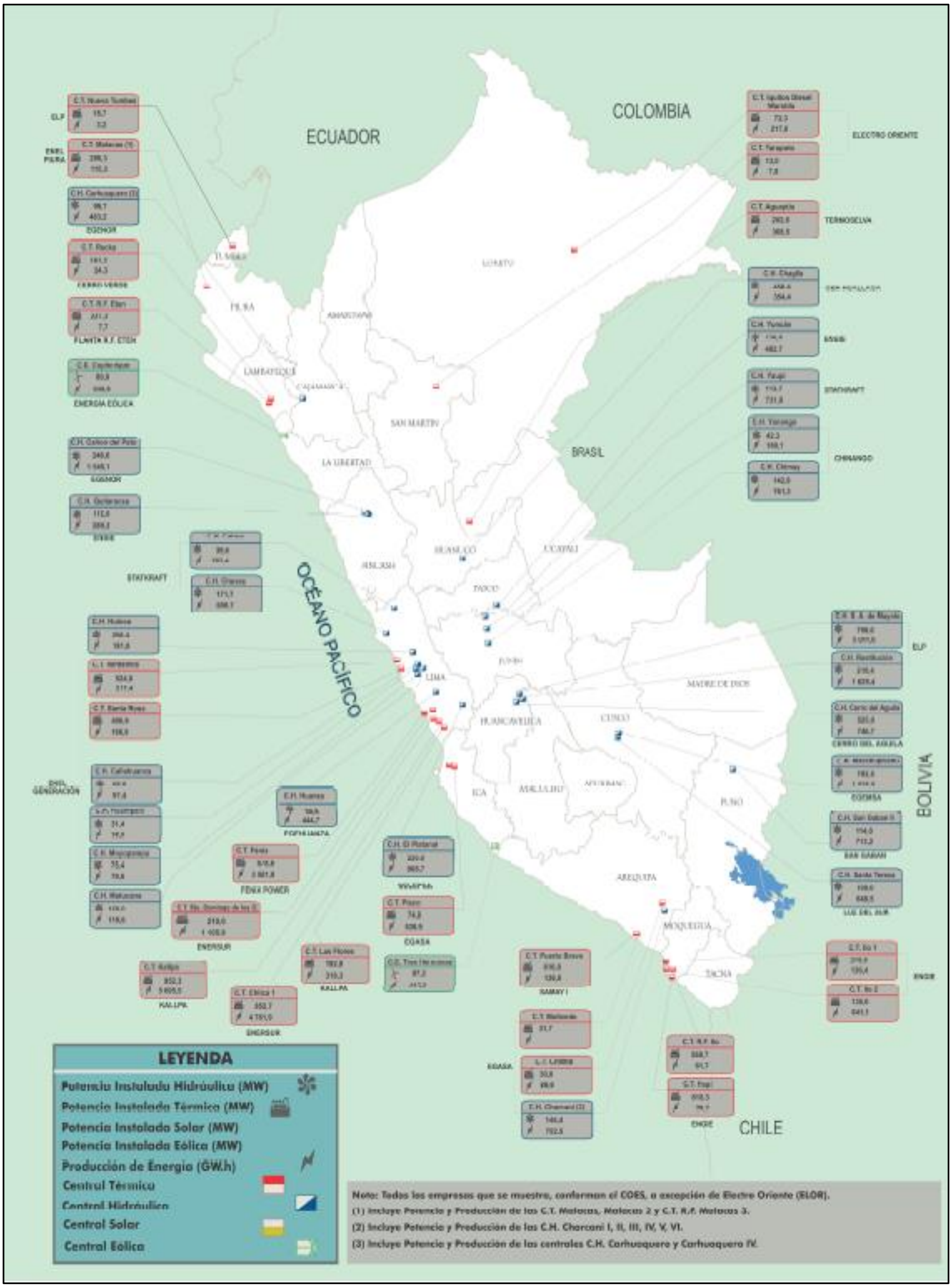


Figure 37 – Map of the main electrical plants (2016) – source MINEM

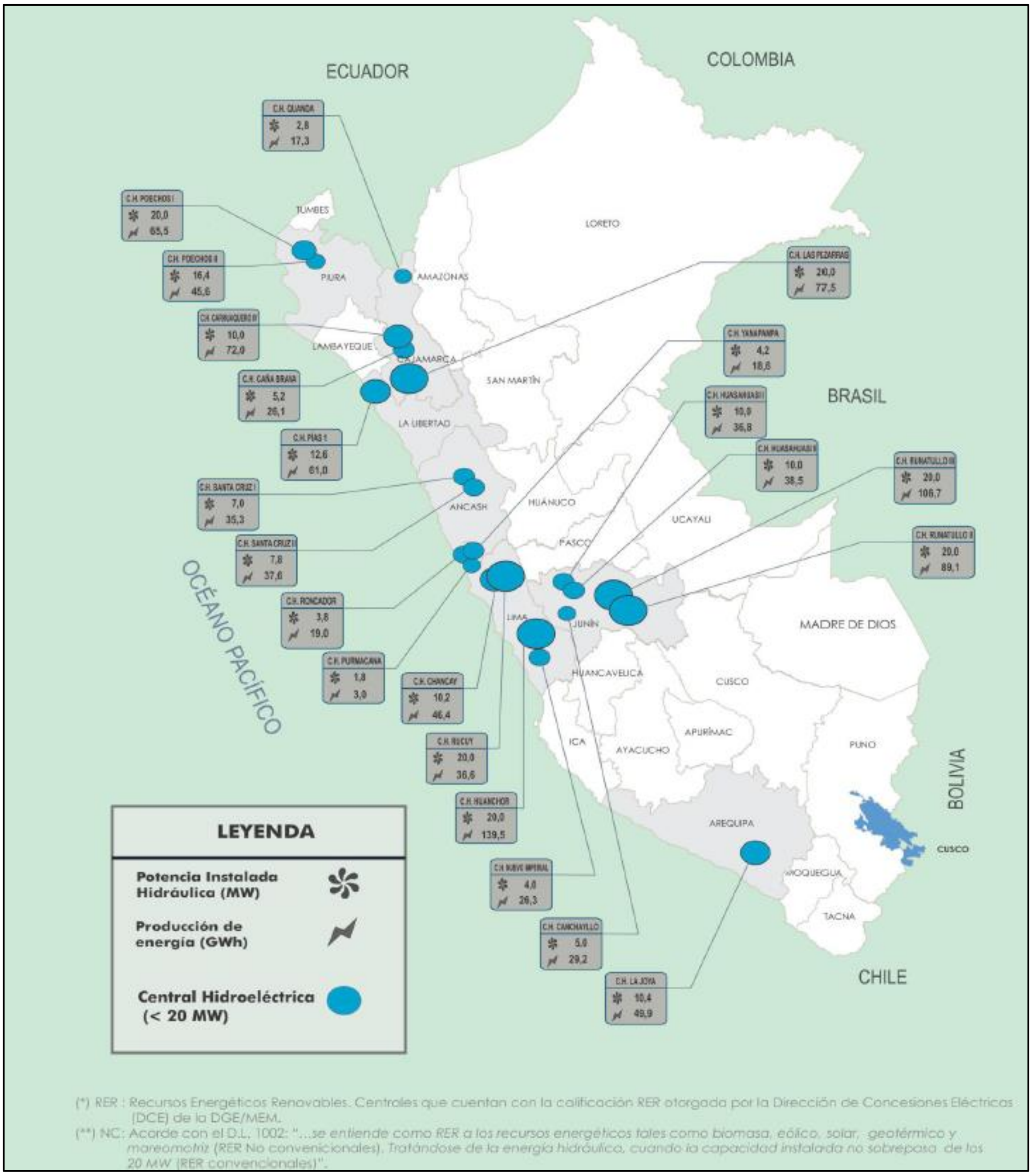


Figure 38 – Map of the main conventional (hydro, wind and solar plants) plants (2016) – source MINEM

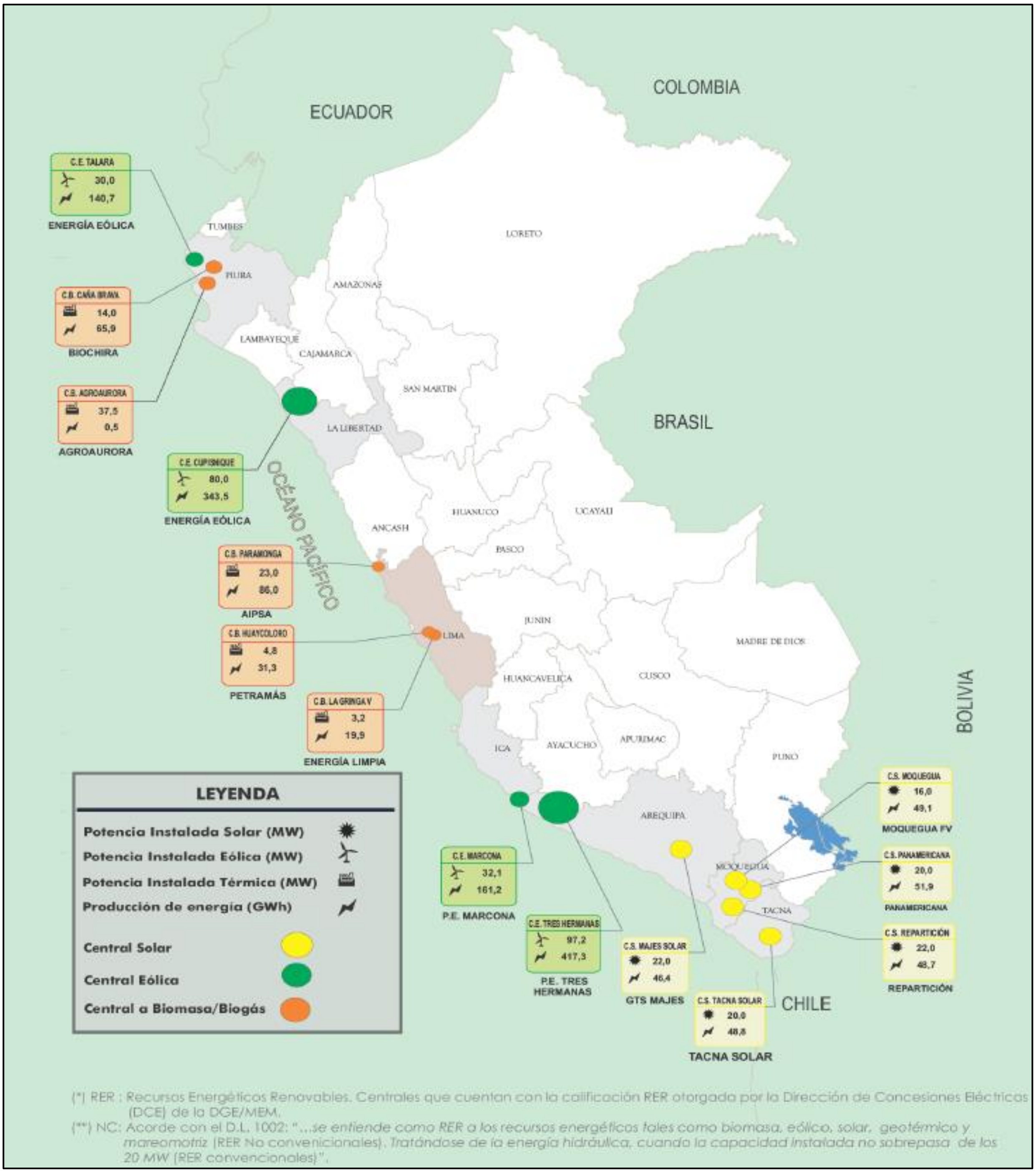


Figure 39 – Map of no conventional RES plants (2016) – source MINEM

2.2.3.2 *Power generation developments*

In a way similar for the demand, the already quoted document “Actualización Plan de Transmisión 2019 – 2028” [7], presents a forecast of the offer (i.e the generation expansion); it is to underline that the transmission plan using the methodology adopted is not associated with any deterministic projection of supply / demand, but rather is focused to evaluate oneself in a wide range of possibilities.
For this purpose, the document analyses the portfolio of existing projects, which are of the following types:

- hydroelectric plants with definitive, temporary and without concession or authorization;
- large hydroelectric power plants in the eastern and northern zone;
- plants with renewable energy and cold reserve;
- thermal power stations in the south and north for the development of natural gas pipelines;
- smaller plants in the long term.

The plants were classified into 7 important groups ordered of greater to less certainty regarding their execution. They are

- Group 1: Projects committed up to 2022, which are programmed;
- Group 2: Projects of long-term hydroelectric power plants. This group of projects was built based on the prioritized list of projects of hydroelectric plants, excluding large projects, which will be studied in a particular way;
- Group 3: Projects of hydroelectric power stations of the North (the projects of the Marañón basin is part of this group);
- Group 4: Projects of hydroelectric power plants in the East. In this group, there are projects associated with a possible agreement with Brazil. Because of the great installed capacity of these plants, their implementation is mainly due to a political decision and, for this reason, the effects of these power plants are analysed in a separated way;
- Group 5: Projects of thermal power plants. This group is made up of projects of thermal power plants of which it is known that they have possibilities of being built, future combined cycle power plants in the South due to the implementation of a gas pipeline to the South, and combined cycle plants in the north due to a possible gas pipeline to the north in the future.
- Group 6: Projects with renewable energy (Article 2 of the Law 1002). This group is made up of projects estimated in location and magnitude on the basis of temporary renewable energy concessions with the objective to comply with art. 2 of decree law 1002, which indicates that 5% of the energy demand of the SEIN must be covered by renewable energy.
- Group 7: Projects of thermal power plants for cold reserve. Is formed by open-cycle power plants that operate with diesel, located in the Centre, North and South to cover the long term cold reserve.

Table 32 resumes the generation capacities of each group considered.

Table 32 – Classification of electric offer

Group	Definition	MW
Group 1	Projects committed up to 2022	1,451
Group 2	Projects of long-term hydroelectric power plants	7,601
Group 3	Projects of hydroelectric power stations of the North	2,013
Group 4	Projects of hydroelectric power plants in the East	6,673
Group 5	Projects of thermal power plants	5,945
Group 6	Projects with renewable energy	224
Group 7	Projects of thermal power plants for cold reserve	2,000

A total amount of 25.9 GW results from the project considered in the groups of the Plan de Transmisión. As shown by the table above the renewable project considered (mainly wind) is a very small part of the generation expansion plan.

This amount of power it too high to be fully included in the scenario at 2030 and some groups are also related to other external factors, such as the power plants belonging to group 4 which are supposed to be operative if an agreement with Brazil is in place, and part of Group 5 projects, which currently have no concession and might be replaced by VRES plants.

In any case, it is to underline that the total amount of new capacity is high respect to the forecasted growth of the demand and is also related to the forecasted results of the plan of interconnection (see below).

For the definition of the 2030 scenario, proper reference will be done to the public network model made available by COES. In particular the mid-term scenario, in which only the committed projects are considered, is taken as starting point.

In addition, the following list of renewable plants, a part of those reported in Table 33, are in the construction phase and must be considered as acquired.

Table 33 – Classification of new plants

Plant	Year	Type	(MW)
C.H. La Virgen	2019	Hydro	84.00
C.H. San Gaban III	2023	Mini Hydro	205.8
C.H. El Carmen	2020	Mini Hydro	8.4
C.H. 8 De Agosto	2020	Mini Hydro	19
C.H. Manta	2020	Mini Hydro	19.8
C.H. Santa Lorenza I	2021	Mini Hydro	18.7
C.H. Carhuac	2018	Mini Hydro	20
C.H. Zaña 1	2019	Mini Hydro	13.2
C.H. Ayanunga	2021	Mini Hydro	20
CE Duna	2021	Wind	18.4
CE Huambos	2021	Wind	18.4

The total installed power in the COES scenario taken as starting point for the definition f the reference scenario for the present analysis is reported in Table 34.

Table 34 – Installed power in the considered mid-term scenario by COES

Source/ Technology	Installed Capacity [MW]
Thermal	9,700
Hydro	5,750
Wind	410
PV solar	270
Other	50
TOTAL	**16,180**

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. The network databases that will be made available 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

- ***<u>Colombian transmission network</u>***
  The National Transmission System of Colombia includes 220 kV and 500 kV transmission lines. The main owner of this system is the Company Empresa Interconexión Eléctrica – ISA. The system includes many different and small areas which have limited exchange capacity.
  Developments are planned to improve these interconnection capacities at 2022 and to build new lines up to 2030.
  An official public network model at 2030 is not available, and for this reason the Colombian transmission network will be built based on the best available knowledge.

- ***<u>Ecuadorean transmission network</u>***
  The National Transmission System (SNT) of Ecuador is composed by different transmission lines operating at 500, 230 and 138 kV. Planned expansion are presented in the Plan Maestro de Electricidad.
  An official public network model at 2030 is not available, and for this reason the Ecuadorean transmission network will be built based on the best available knowledge.

- ***<u>Peruvian transmission network</u>***
  The Peruvian Interconnected National Electric System (SEIN) includes lines up to 500 kV. At the end of 2016 there were about 4,500 km of 138 kV lines, more than 9500 km at 220 kV and nearly 2,000 km at 500kV.
  COES analysed different expansion option up to 2028 reported in the Plan de Transmisión 2019 and its amendments.
  A detailed network model in DIgSILENT is available on the COES website, and will be used to represent the power system for the execution of the simulations starting from the 2021 network.

- ***International interconnections***

  International Interconnection between the Countries of the present cluster are already present and in operation. In particular:
  - *Ecuador-Peru: there is a 220 kV line, which in the past years has been used seldom and below its potential;*
  - *Colombia-Ecuador: there are two links (one 230 kV, the other 138 kV). In the past, energy exchange has been mainly from Colombia to Ecuador, while in 2016 there has been a change in the direction;*

  Moreover, there are also 220 kV lines interconnecting Colombia to Venezuela, with a total exchange capacity in the range about 200 MW and 350 MW depending on the direction.

  Many future projects are under analysis considering:
  - *Improvement of the interconnection between Ecuador and Peru with a 500 kV line for a transmission capacity up to 500 MVA*
  - *Interconnection between Peru and Chile, with a HVDC 500 kV line (up tot 1,000 MVA) and a shorter and lower voltage line for additional 50-200 MVA depending on the solutions;*
  - *Interconnection between Peru and Brazil with a 500 kV line*
  - *Interconnection Peru – Bolivia with a 220 kV line up to 140 MVA with a back-to-back solution due to the different system frequencies in the countries;*
  - *Interconnection between Colombia and Panama*

  At this stage, the interconnection lines with Countries outside the cluster (Bolivia, Brazil, Chile and Venezuela) will be considered in the model but no energy exchange will be set.

2.3.1 Colombia

The National Transmission System (STN - for its Spanish acronym) is the electric energy interconnected transmission system comprising a set of lines with their corresponding connection modules that operate voltages equal to or greater than 220 kV.

Empresa Interconexión Eléctrica S.A. E.S.P. (called “ISA”) is the main STN transporter, and it is the owner of around 75% of the network assets.

The remaining transporters, in importance according to percentages of assets they own, are: Transelca, Empresa de Energía de Bogotá (EEB), Empresas Públicas de Medellín (EEPPM), Empresa de Energía del Pacífico (EPSA), Electrificadora de Santander (ESSA), Distasa, Corelca, Central Hidroeléctrica de Betania (CHB), Centrales Eléctricas de Norte de Santander (CENS) and Electrificadora de Boyacá (EBSA).

The main characteristics of the transmission system in the year 2016 are represented in the transmission network map (500 KV and 230 kV lines), reported in Figure 40.

Figure 40 – Colombia - Map of transmission network – 2016

A map of the transmission network with the difference operative areas of the power system is reported Figure 41.

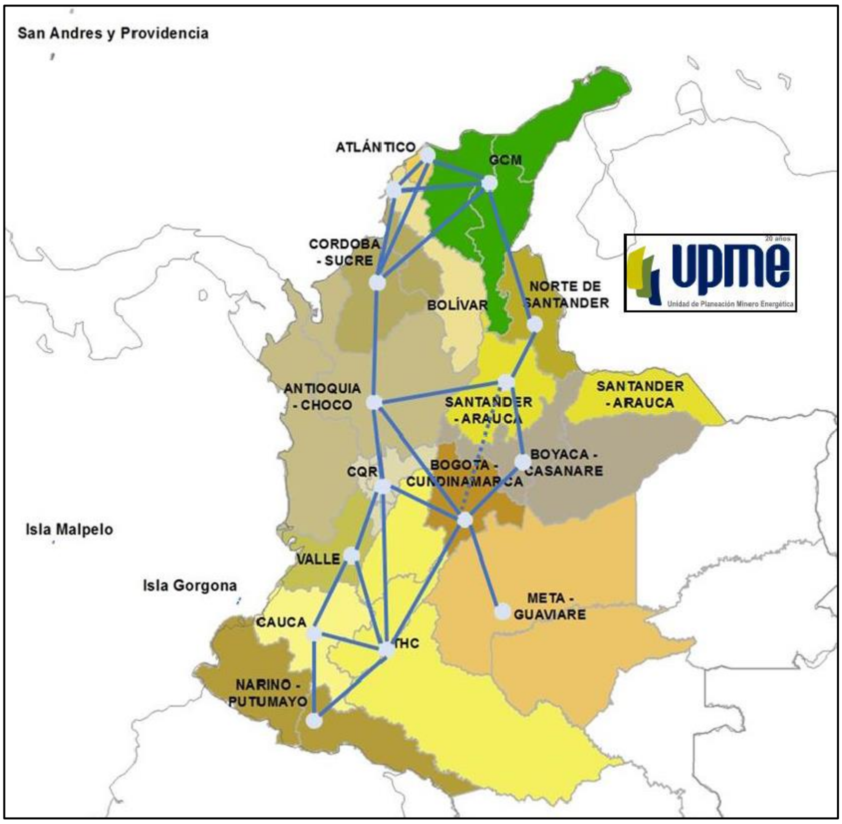


Figure 41 – Colombia - Map of different areas of transmission network

Table 35 shows the existing interconnection capacities between the operational areas and the improvements foreseen in the next years up to 2022.

Table 35 – Existing and defined interconnections capacities (MW) – source UPME

Area to ↓	from → Year	Ant-Cho	Atlantico	Bog-Cund	Bolivar	Cauca	Cor-Suc	CQR	THC	NSant	Sant Ara	Valle
Bog-Cund	2017	617										
Bolivar	2017		335									
	2022		639									
Boy-Cas	2017			407							361	
	2022										375	
Cauca	2017								221			407
Cor-Suc	2017	1126	652		68							
	2018	1649										
	2022	1663	755		204							
CQR	2017	1126		543					68			
	2018	1649		749								
	2022	1663		1048								
GCM	2017		407		335					1051		
	2018						652					
	2022				639		755					
THC	2017			407								543
	2018											749
	2022											1048
Met-Guav	2017			475								
	2018			499								
	2022			629								
Nar-Put	2017					318			221			
NSant	2017										788	
	2018										900	
	2022										907	
Sant-Ara	2017	1126										
	2018	1649		617								
	2022	1663										
Valle	2017							543				
	2018							749				
	2022							1048				

Due to the very fragmented situation, the network model will not consider all the different small areas, but will take into account the limited transmission capacity of specific lines to consider the constraints on the power transmission.

Figure 42 shows the Colombian transmission system resulting from the already quoted Masterplan for the year 2030, that will be assumed as reference network for the present study. In blue, it is possible to identify the lines already defined and in construction, while in orange and black there are lines still under analysis, respectively for 220 kV and for 500 kV.

In order to ensure the proper execution of the simulations, it is necessary to obtain the network model as defined by the Masterplan at the horizon year.

Figure 42 – Colombia - Map of transmission network – 2030

2.3.2 Ecuador

The National Transmission System (SNT) of Ecuador is composed by different transmission lines operating at 500, 230 and 138 kV.

500 kV lines only represent a minor part of the system, totalling about 250 km. The length of 230 kV lines sums up to 1593 Km (double circuit) and 975 Km (single circuit), while at 138 kV level there are 791 Km on double circuit and 1342 km on simple circuit, that fundamentally serve to connect the transmission system with generation plants and distribution centres.

A map of SNT is reported in Figure 43. It is possible to note that there are interconnections towards Colombia and Peru.

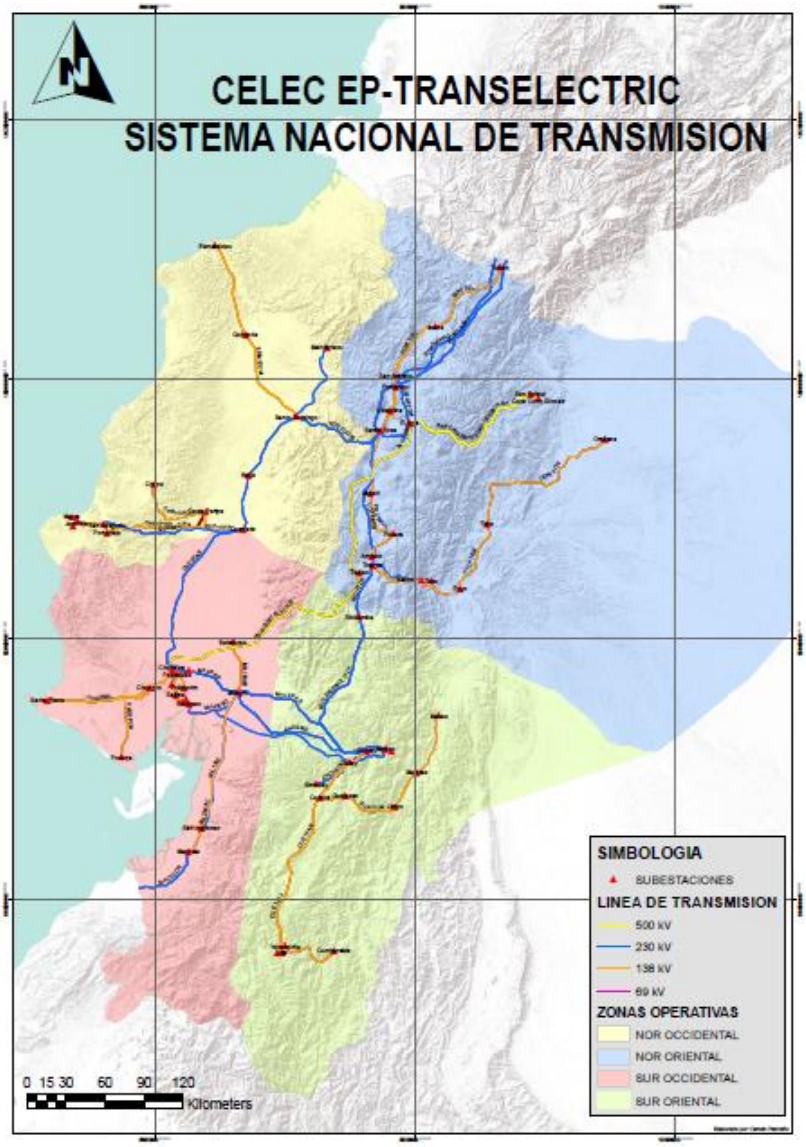


Figure 43 – Ecuador - Map of transmission network

In the Plan Maestro de Electricidad [6] released by the Ministerio de Electricidad y Energia Renovable, the expansions reported in Table 36 are identified for the Base Case of the demand growth.

Table 36 – Expected expansions of transmission system in Ecuador till 2025

Equipment	Quantity
500 kV lines	284 km
230 kV lines	860 km
138 kV lines	534 km
Additional transformer capacity	> 8 GVA

Figure 44 shows the map of the expected system.

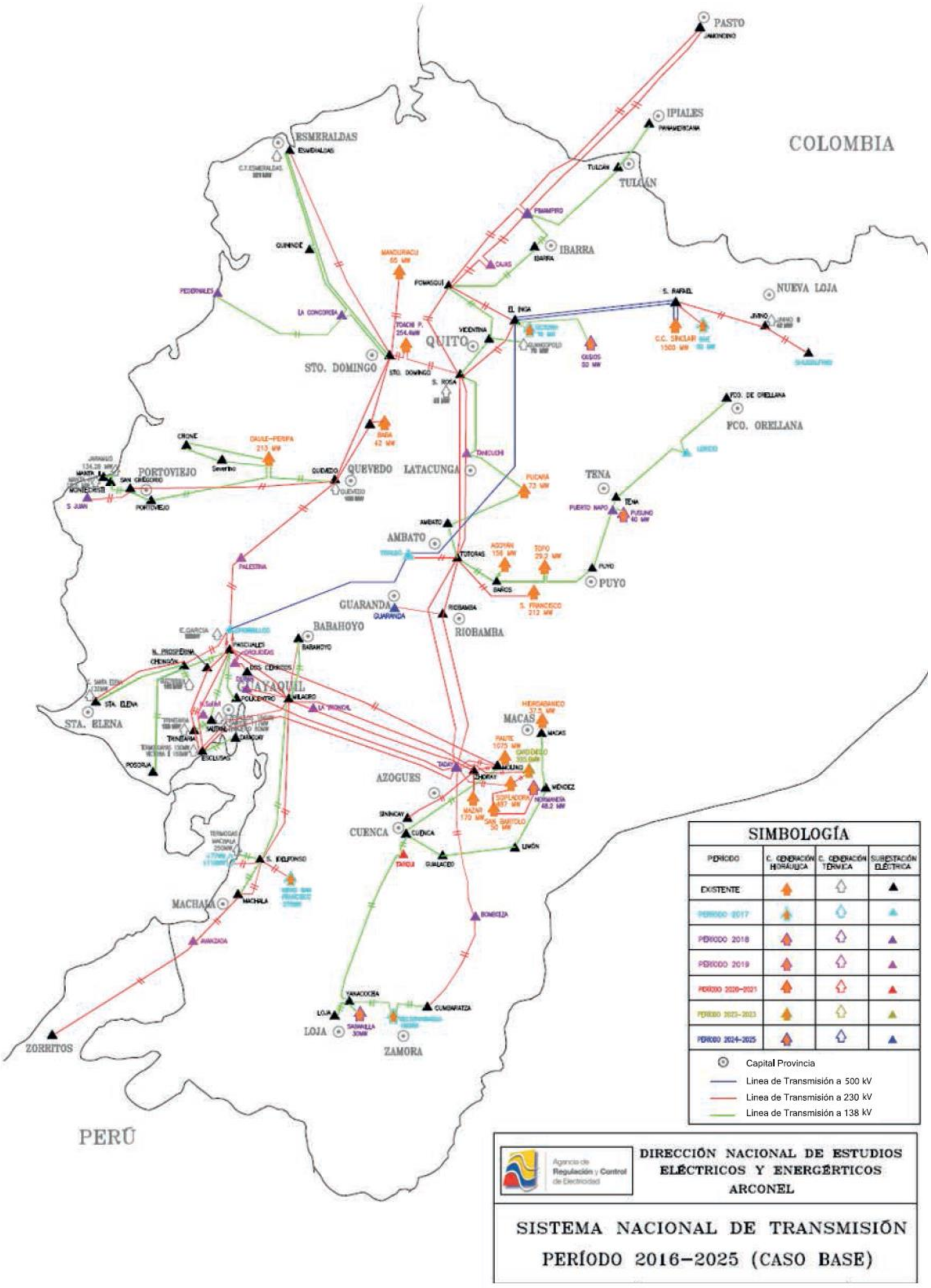


Figure 44 – Ecuador - Map of transmission network at 2025 [6]

The future network model has not been found among the public information available. In order to ensure the highest consistency with the assumptions on the development of demand, generation and transmission system, it is important to have the proper network model available, preferably in the format of DIgSILENT or PSSE software.

2.3.3 Peru

The transmission of electrical energy in Peru is carried out through the Interconnected National Electric System (SEIN) and through Isolated Systems (SS. AA.). Both systems gather a total of nearly 23,500 km of transmission lines, with voltage levels higher than 30 kV.

The SEIN Transmission System is integrated by guaranteed and complementary transmission lines[7], as well as lines of the main and secondary system of transmission[8].

At the end of 2016, the SEIN registered 23,210 km of transmission, of which 19% belong to the guaranteed system[9], 19% to the complementary[10], 12% to the principal and 51% to the secondary transmission system; these lines transport electric power to the north, centre and south of the country. On the other hand, the SS. AA. have 278 km of transmission lines, but won't be considered during the study.

A resume of the characteristics of the Peruvian transmission system is reported in Table 37 and Table 38, while a map of the transmission system is reported in Figure 45.

Table 37 – Length of transmission lines system (km)

Line	Guaranteed system	Complementary system	Principal system	Secondary system	TOTAL
SEIN	4,297	4,445	2,685	11,783	23,210
SS AA		253		25	278
TOTAL	4,297	4,699	2,685	11,807	23,488

[7] The guaranteed and complementary transmission system is made up of those facilities whose commercial operation starts after the date of the enactment of Law 28832 (23/07/2006).
[8] The main and secondary transmission system covers those facilities, whose commercial start-up occurred before the promulgation of Law 28832.
[9] The guaranteed transmission system is made up of facilities of the transmission plan, which are built as a result of a tender process.
[10] The complementary system of transmission, is composed by facilities included in the transmission plan that are built by own initiative of the agents, those built on the initiative of the distributors not included in the transmission plan and all those that are built without being included in the transmission plan.

Table 38 – Line Types (km)

Line	Guaranteed system	Complementary system	Principal system	Secondary system	TOTAL
500 kV	1,827	143			1,970
220 kV	2,164	1,507	2,287	3,610	9,568
138 kV	84	580	398	3,370	4,432
60 – 75 kV	120	1,374		3,735	5,230
30 – 50 kV	101	1,095		1,093	2,288
Total	**4,297**	**4,699**	**2,685**	**11,807**	**23,488**

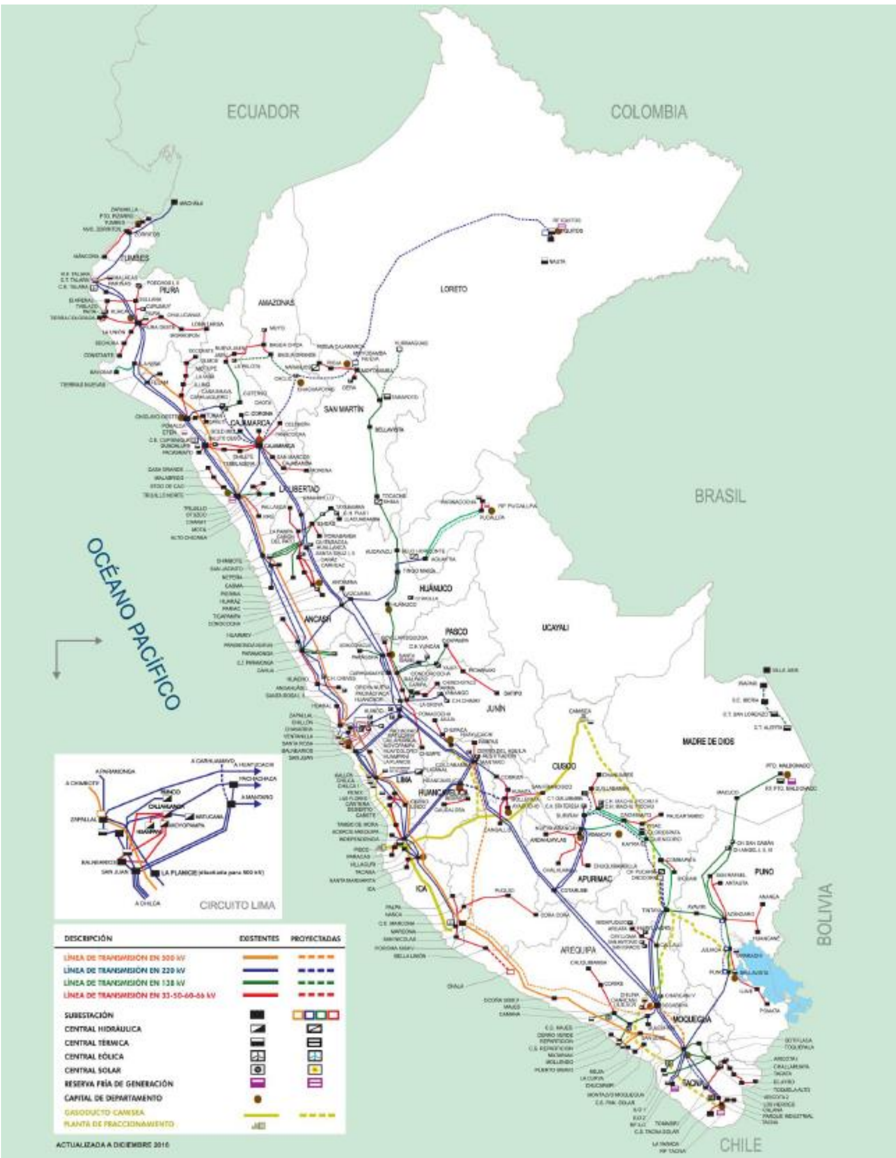


Figure 45 – Peru - Map of transmission network – 2016

In the “Propuesta Definitiva de Actualización del Plan de Transmisión 2019 – 2028” released by COES [7], different possible expansions are analysed and, in addition to reinforcements on 220kV system committed for 2024, the best identified solution at 2028, with a new 500 kV loop and further 220 kV lines, corresponds to the transmission system shown in Figure 46.

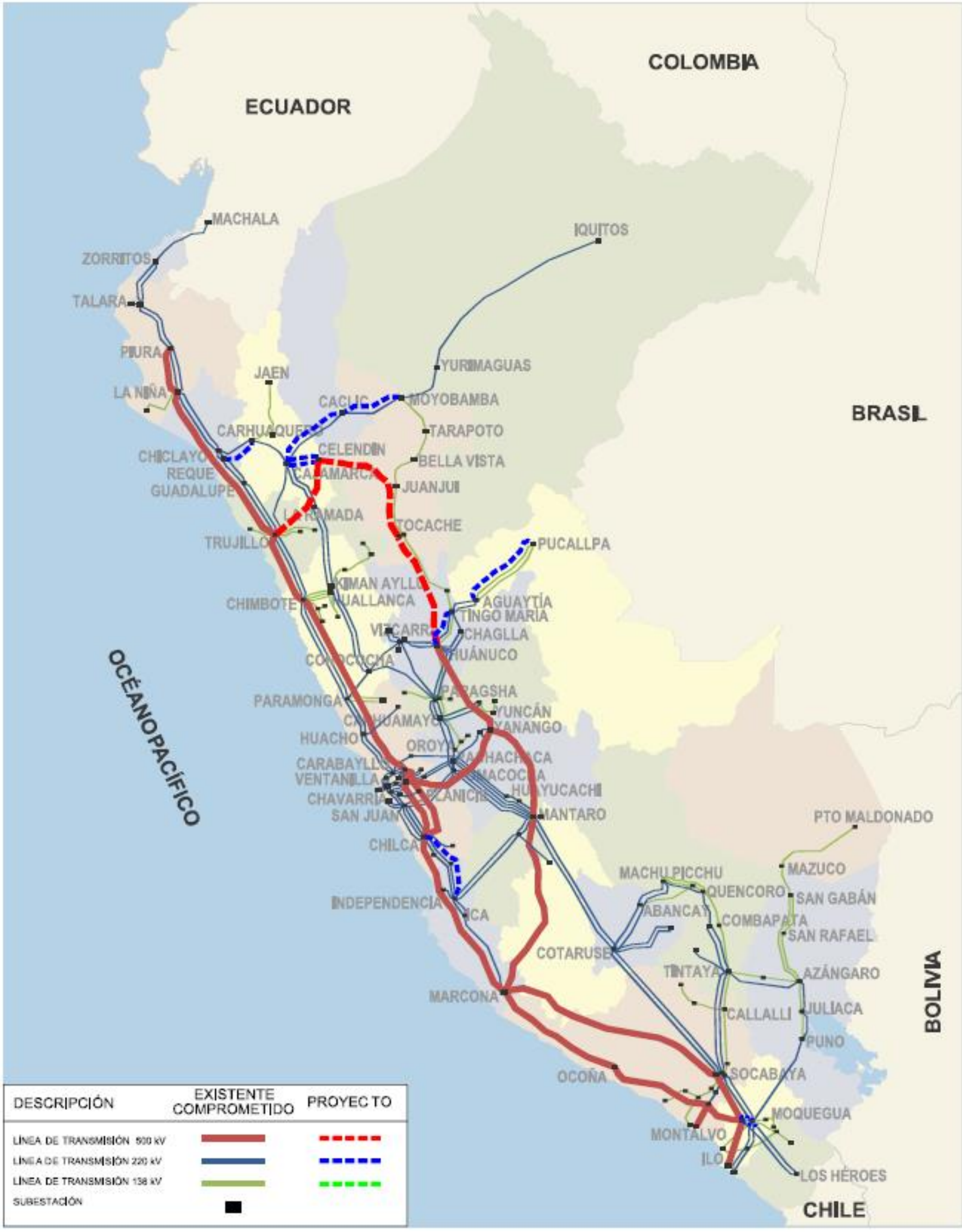


Figure 46 – Peru - Map of transmission network – 2028

For the execution of the study, reference will be done to the network model made available by COES, which represents the most reliable source of information concerning the development of the Peruvian power system. The starting point will be the network committed for 2024, and other reinforcements will be included if necessary to reliably supply the load increased at the 2030 level. The choice to use the 2024 network is due to the highest confidence that the reinforcements foreseen at that year will be done, while the 500 kV lines considered at 2028 are more uncertain and subject to the development also of the generation. As during the present study, a different development of the generation might be defined, more shifted towards VRES with respect to the one found in the study by COES, it is possible that different reinforcements have to be analysed, having more impact on the VRES deployment.

2.3.4 International interconnections

In this paragraph a description of the existing or planned international interconnection lines between Colombia, Ecuador and Peru and with neighbouring countries is presented, according to the already quoted main sources of data.

- Colombia - Venezuela

  Colombia is connected to Venezuela through the 220 kV lines listed in Table 39. These interconnections will not be considered during the analysis of the three countries belonging to the identified cluster, because no energy exchanges with other countries will be taken into account.

Table 39 – Colombia – Venezuela interconnection capacities (MW)

Lines	To Colombia	From Colombia
Corozo 1	55	150
Cadafe	0	36
Cuatricentenario 1	150	150
Total	**205**	**336**

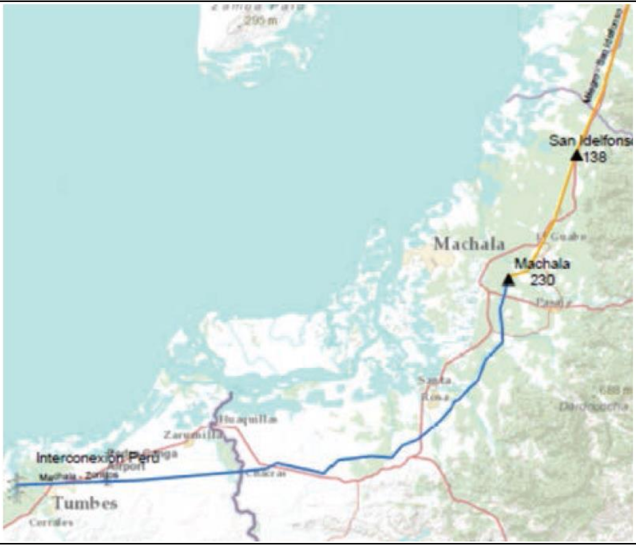
- Ecuador – Peru

  A 103 km long interconnection line from the substations Machala in Ecuador to Zorritos in the Peruvian side is in operation. It is a 220 kV line with a capacity of 160 MW.

  It is a line that has been exploited seldom and below its potential, as it can be seen from the energy exchanged between the countries reported in the Table 40 below.

Table 40 – Interconnections Ecuador - Peru

Electricity exchanges (GWh)		
Year	**From Equador**	**From Peru**
2003		-
2004		-
2005		7.4
2006		-
2007		-
2008		-
2009		62.5
2010	0.2	78.4
2011	6.2	-
2012	5.4	2.2
2013	0.	-
2014	0.4	12.4
2015	0.5	54.6
2016	21.3	37.7



- Colombia - Ecuador

  The interconnection between Colombia and Ecuador is realized through 230 kV and 138 kV lines 436 km long from the substation of Pomasqui on the Ecuadorian side to Jamondino in the Colombian side. The interconnection capacity is reported in Table 41, while the path and the energy exchanged between the countries are shown in Table 42.

Table 41 – Interconnection capacity Ecuador - Colombia

Interconnection capacities (MW)		
Lines	**From Ecuador to Colombia**	**From Colombia to Ecuador**
230 kV	500	360
138 kV	35	35
Total	535	395

Table 42 – Interconnections Ecuador Colombia

Electricity exchanges (GWh)		
Year	From Equador	From Colombia
2003	67.2	1119.6
2004	35.0	1641,6
2005	16.0	1716.1
2006	1.1	1570.5
2007	38.4	860.9
2008	37.5	500.2
2009	20.8	1058.2
2010	9.7	794.5
2011	8.2	1294.6
2012	6.5	236.0
2013	42.5	657.0
2014	56.3	812.1
2015	45.2	457.2
2016	378.3	43.4

2.3.4.1 Future projects

The analysis reported here below is mainly based on the Chapter 9 of the Definite Proposal of the Actuation of the Peruvian Masterplan [7], that is devoted to a description of the situation of Peru international interconnections, and its effect on the formulation of the 2017-2026 Transmission Plan Update.

This information are then integrated with the Masterplans of the two other Countries and to the international media.

As reported in the quoted Chapter 9, all the interconnection projects described here below are a part of the Andean electrical interconnection system (SINEA), a project that arises from the desire to achieve a regional connection between the countries which comprise the Andean Community, namely: Colombia, Ecuador, Peru and Bolivia, as well as Chile as a partner.

For what regards Peru, the possible future interconnections of Peru analysed are reported in Figure 47 [7]

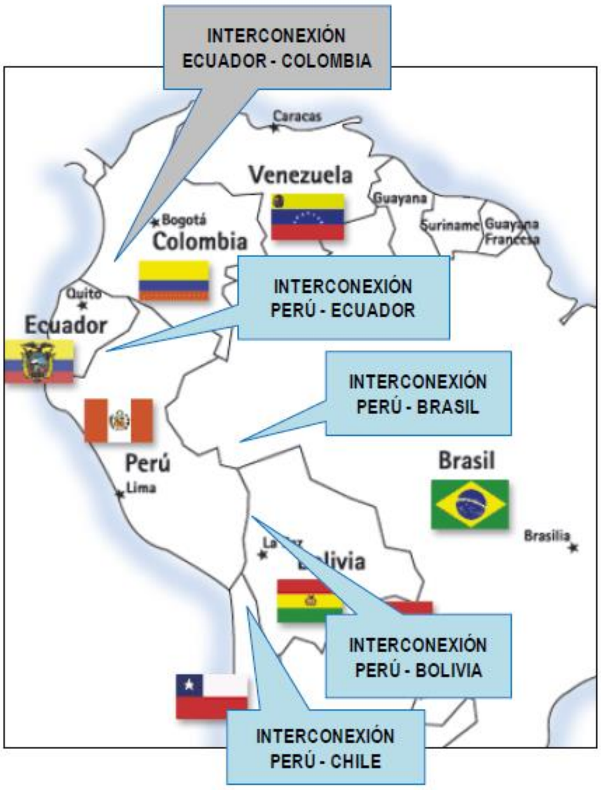


Figure 47 – Peru – Possible electrical interconnections

The conclusion of a feasibility study of the interconnections described in the figure above, made in the framework of SINEA, found the economic feasibility of the interconnections reported in Table 43

Table 43 – Peru Interconnection Lines economically doable

Interconnection	Description
Ecuador - Peru	Line 500 kV La Niña-Daule (540 km, 500 MVA)
Peru - Chile	Back-to-back + line 220 kV Los Héroes – Arica (70 km, 130 MVA)
	Line HVDC 500 kV Montalvo – Crucero (650 km, 1000 MVA)
Peru - Bolivia	Line 220 kV Laguna Colorada – Chuquicamata (140 km, 140 MVA)

In the following paragraphs, some more details of the interconnection lines described in the table above and for other ongoing projects are provided.

<u>Ecuador – Peru.</u>

The scheme of interconnection is reported in Figure 48 and Figure 49.

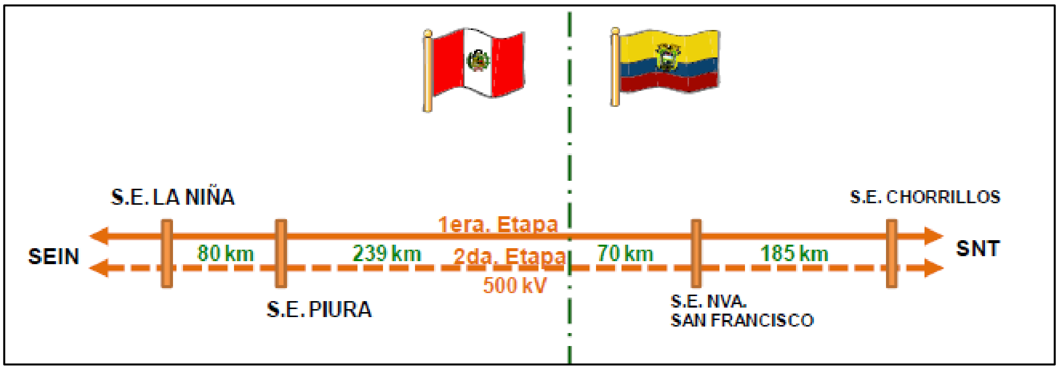


Figure 48 – Peru – Ecuador 500 kV interconnection project

Figure 49 – Peru – Ecuador 500 kV interconnection project

As it is possible to see in the figures above, the interconnection with Ecuador includes the line of Chorrillos - Pasaje - Piura - La Niña transmission, with a length of 587 km and a single circuit (first stage). Regarding the development of the transmission systems in 500 kV inside both countries, in the case of Peru, there is a transmission system in 500 kV up to SE La Niña, and in the Transmission Masterplan the construction of a 500 kV LT to Piura is proposed. In the case of Ecuador, it is planned that this has expanded to SE Pasaje in 2017.

The interexchange potential is:

- from Ecuador to Peru, 750 MW - 1000 MW;
- from Peru to Ecuador, 500 MW – 1000 MW

<u>Interconnection Peru – Chile</u>

Currently there is no a binational electric interconnection agreement between Peru and Chile; however, there have been progresses at the sectorial level with the installation of a Peru Chile Working Group on

Energy Issues, and the formation of two binational committees: one for regulatory harmonization and the other for planning infrastructure.
A scheme of the possible interconnection is reported in Figure 50.

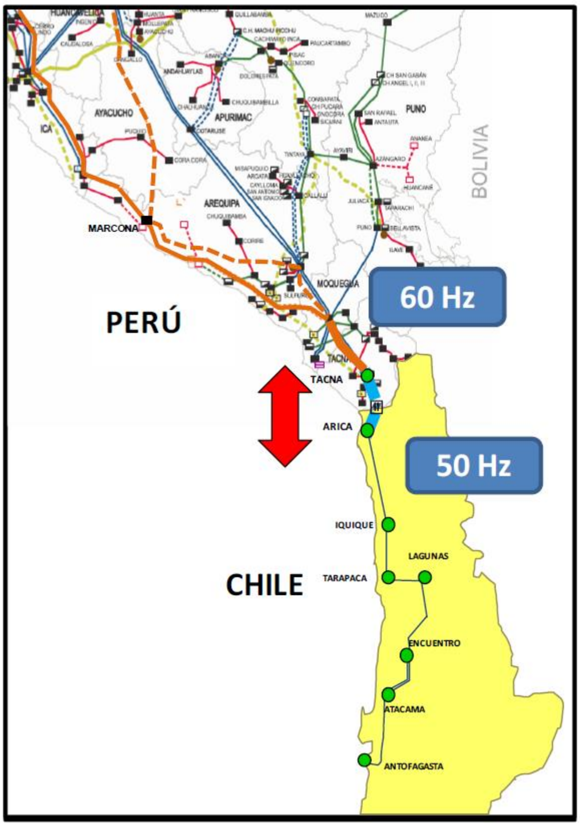


Figure 50 – Peru – Chile interconnection project

As already mentioned, in the study in the framework of the Andean Electrical Interconnection System (SINEA), two possible connections where considered, one of 150 MW - 220 kV between Peru and the North of Chile and another with 500 kV. Both connections would be of the asynchronous type, given the difference in frequencies between the countries (60 Hz in Peru and 50 Hz in Chile).
Based on the alternatives proposed in SINEA, COES (Peru) and the Coordinador Electrico Nacional of Chile carried out a study that aimed at developing the analyses, at the level of feasibility and developing the engineering at the concession tender level, of the 220 kV link - Los Heroes (Tacna) - Parinacota (Arica). This interconnection would have a length of 55 km and a transfer capacity between 100 and 200 MW, and would be in service as of year 2020 (see Figure 51)

Figure 51 – Peru – Chile interconnection

As a result of the study, two conceptual arrangements for the interconnection have been identified. The first one considers a 220 kV line with a station Back-to-Back converter on the border between Peru and Chile, with a capacity between 100 and 200 MW and an investment between US $ 82 and 131 Million, depending on the transmission capacity. The second arrangement considers a line in DC with converter stations in the Los Heroes substations (Peru) and Parinacota (Chile), the capacities would also be between 100 and 200 MW and the amounts of investment would be between US $ 92 and 146 million, depending on the capacity of transmission. These schemes are shown in Figure 52 and Figure 53

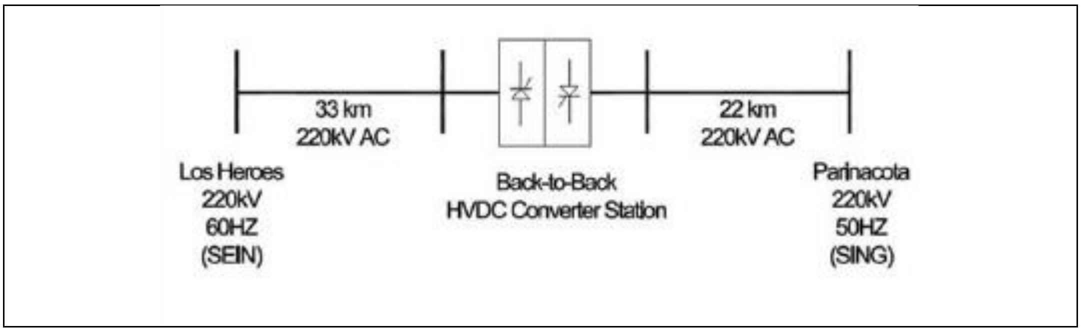


Figure 52 – Peru – Chile interconnection – Back to back line

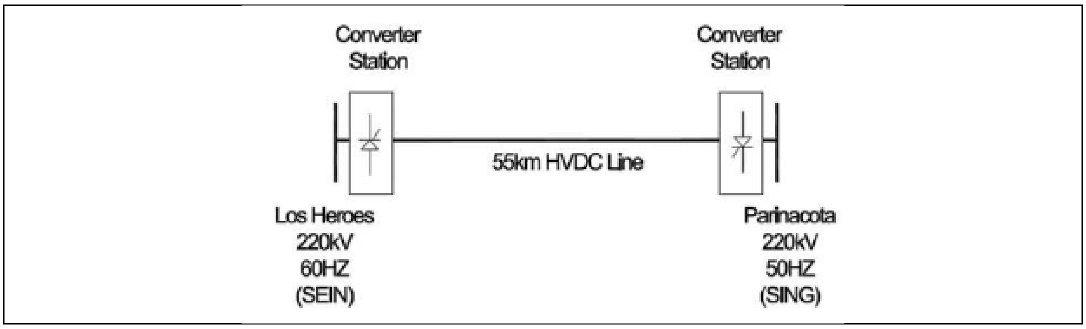


Figure 53 – Peru – Chile interconnection – HVDC line

<u>Interconnection Peru - Brazil</u>

The project of a 500 kV interconnection line between Peru and Brazil is contained in the previous Transmision Plan. The more recent Transmission plan maintains the scheme of the interconnection Colectora Sur - Marcona, adding a new substation Independencia 500/220 kV (see figure below).

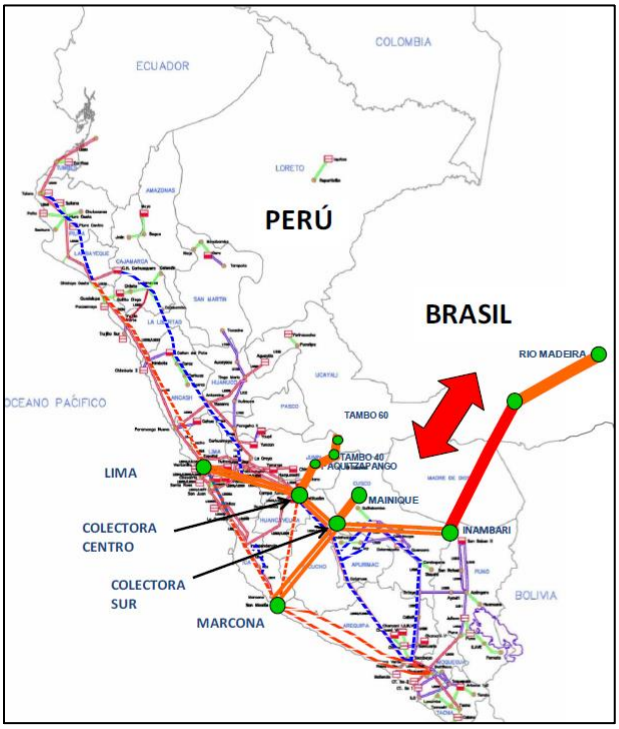


Figure 54 – Peru – Brazil 500 kV interconnection project

However, this interconnection will not be considered in the present study, as the possibility to exchange energy with neighbouring countries is not taken into account.

<u>Interconnection Peru – Bolivia</u>

Another possible but not yet defined project is the interconnection Peru – Bolivia. A possible layout is reported in Figure 55.

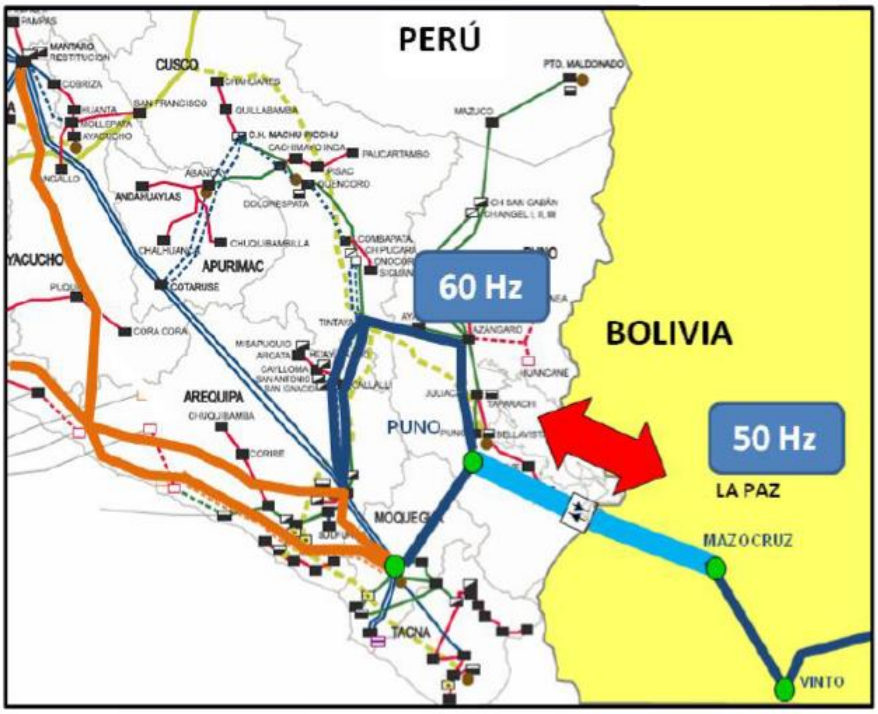


Figure 55 – Peru – Bolivia interconnection scheme

Also in this case this interconnection will not be considered in the present study, as Bolivia does not belong to the cluster of countries under analysis.

<u>Colombia – Panama</u>

A feasibility analysis of a Colombia-Panama interconnection project, which includes 340 km of lines in Colombia and 260km in Panama, was successfully carried out some years ago. The initiative seeks to promote the integration of regional power markets as part of the Mesoamerica project, which was designed to boost sustainable development in the region and which includes the Central American power interconnection system SIEPAC.

The direct current interconnection will boast up to 400MW capacity.

Being Panama not part of the cluster, this interconnection will not be considered.

2.4 Variables for the assessment of energy costs

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.*
  - *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.*
- *Projection to year 2030 – PV total costs –USD/kW*
- *Projection to year 2030 – Wind total costs –USD/kW*

Table 44 – PV Costs in the year 2030

Solar PV - Costs in USD/kW - Projection to year 2030			
	Colombia	Ecuador	Peru
Total	670	860	600
O&M (per year)	9.4	9.4	9.4

Table 45 – Wind Costs in the year 2030 according to all the sources

Wind Onshore - Costs in USD/kW - Projection to year 2030			
	Colombia	Ecuador	Peru
Total	1145	1180	1140
O&M (per year)	23.8	23.8	23.8

2.4.1 Investment and operating costs of RES generation split by technology

As for the previous Inception Reports related to other LATAM Countries [11][12], this section is mainly based on “Power to change 2016 [14], the report from IRENA that analyses the market of the renewable energies and provides future trends for the solar and wind technologies.

Referring to these documents for a full detailed description, here below the main conclusions are summarised.

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

The main conclusions of analysis carried out for previous clusters are:

- 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 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.
- Considering utility scale PV plants, a current inverter price of 0.15 USD/Wp shall be considered in the present study. Again, this is an international price and it should not be affected at regional or national level.
- Based on the IRENA data, we can use the available estimate of 1,250 USD/kW (year 2015) as the BOS costs that regard the construction of solar PV in countries with advanced development, while for countries with limited experience in such technologies a more complex analysis suggests a price of about 1,350 USD/kW.
- IRENA identified that the global average total installed cost of utility-scale PV systems could fall from around USD 1,800/kW in 2015 to USD 800/kW in 2025.

On the base of these evaluations, the PV total cost for the analysed Countries, according to the IRENA evaluation, reported in the past Reports for the year 2030 were those resumed in Table 46.

Table 46 – PV Costs in the year 2030 according to IRENA assumptions

Solar PV - Costs in USD/kW - Projection to year 2030			
	Chile	**Argentina**	**Brazil**
Total	788	828	828
O&M (per year)	11.5	11.5	11.5

These results were integrated by the analysis of the sources of data and in particular:

- IHS ENERGY Renewable Power Price Outlook in Emerging Markets, 2015–30 [15]
- Bloomberg H2 2016 LCOE AMER Outlook [16] and H2 2016 LCOE PV Update [17]

The main results of the analysis of these documents is that in general stronger reduction of the costs can be assumed, based on historical data (comparison between 2016 costs by Bloomberg and 2015 costs by IRENA show a significant decrease that can push IRENA estimations further down).

On the base of the analysis of all the sources, a final evaluation regarding the future costs of the PV projects was made: the results are reported in Table 47.

Table 47 – PV Costs in the year 2030 according to all the sources

Solar PV - Costs in USD/kW - Projection to year 2030			
	Chile	**Argentina**	**Brazil**
Total	670	860	860
O&M (per year)	11.5	11.5	11.5

IRENA Reports doesn't report data for the three Countries object of these Reports. Instead, the Bloomberg documents already quoted, gives for Ecuador and Peru for the year 2016 the values of PV CAPEX reported in Table 48, compared with those of Argentina, Brazil, and Chile, obtained by the same source in the past.

Table 48 – Cost of Solar PV projects – Source Bloomberg (October 2016) [17]

Cost of Solar PV projects ($/kW)	Reference Date	Argentina	Brazil	Chile	Ecuador	Peru
Bloomberg (October 2016)	October 2016	1.980	1.660	1.350	2.230	1.370

As shown by the table above, according to Bloomberg (October 2016) Peru PV costs are aligned with those of Chile while Ecuador PV costs are the highest one. For the year 2030 it is possible to make the assumptions that Peru PV CAPEX will be aligned with those of Chile, while Ecuador CAPEX costs will be higher than these.

Finally, based on actual installation costs of recent projects in Peru and on other recent cost reduction forecasts by BNEF, which show that in 2030 PV will cost approximately 66% of today price, a further decrease of the PV cost with respect to the already low values considered for Chile is possible, and the final assumed value for Peru is USD 600/kW. Also O&M costs can be slightly reduced based on actual values down to USD 9.4/kW, and assumed the same for all the countries. With these last considerations, the proposed costs for PV power plants in Peru and Ecuador is reported in the following Table 49.

Table 49 – Proposed PV Costs in the year 2030

Solar PV - Costs in USD/kW - Projection to year 2030		
	Ecuador	**Peru**
Total	860	600
O&M (per year)	9.4	9.4

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

As described in the already quoted previous documents, 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.

The main conclusions about these categories are:

- Globally, the installed costs of onshore wind have seen a significant decline since the early 1980s. Global weighted average installed costs declined from USD 4,766/kW in 1983 to USD 1,623/kW in 2014. Data for 2015 suggests that the global weighted average installed cost of onshore wind may have fallen to around USD 1,560/kW.
- Total installed cost ranges by country are quite wide and not uniformly distributed.
- 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.
- 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 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.
- For what regards O&M costs, 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

Table 54 shows the cost of wind projects from the already quoted Bloomberg document, in which costs of the three Countries object of this Report are compared with those analysed in the past.

Table 50 – Cost of Wind projects – Source Bloomberg (October 2016) [17]

Cost of Wind projects ($/kW)	Reference Date	Argentina	Brazil	Chile	Ecuador	Peru
Bloomberg (October 2016)	October 2016	1.980	1.930	1.780	N.A	1.880

As shown in the table above, Peru wind costs are between Chile and Brazil costs, while there is not information neither for Ecuador nor for Colombia.

For Peru, based on actual costs of recent projects and assuming the cost decrease foreseen by BNEF, the value of USD 1,140/kW can be assumed at 2030, well aligned with the costs considered for other countries. Concerning O&M costs, projections by BNEF focused on US market show a value of USD 23.8/kW. This value can b assumed also for the countries of the present cluster, taking into account that in such countries there is less expertise and less availability of proper means for an optimal maintenance, but also the personnel cost is lower than in US.

2.4.1.3 Information from local sources for Colombia

With regards to the three Countries considered in the present Report, for Colombia, the already quoted Masterplan [2] contains an economic analysis of the investment costs in the new generation. These data, resumed in Table 51, have been used for the economic evaluation of the generation expansion in three different cost scenarios.

Table 51 – Costs of investment in the generation (USD/kW) - Source UPME

Type	Average	Max	Min
Hydro	2,102	2,341	1,515
Thermal Coal	1,870	2,472	1,425
Thermal Gas	1,151	1,213	1,090
PV	1,107	1,417	838
Wind	1,663	1,750	1,112
Geothermal	3,587	3,587	3,587
PV Distributed	1,687	2,438	1,000
Biomass	1,381	1,714	1,125

The width of the cost range for PV and wind is quite large. In general, costs assumed by UPME would be higher than the ones defined for the other countries. This might be also due to the fact that UPME considers investments in new plants (and in particular VRES ones) along the different years up to 2030, while in the present activity only the 2030 value is taken into account.

In this sense, costs for Colombia can be assumed close to the minimum values reported in Table 51, considering also the evaluations done for Peru and Ecuador, where more information is available.

2.4.1.4 Cost evaluation

On the base of the all the data and the assumptions described, the estimated values of PV total costs for the year 2030 are those reported in Table 52.

These data are assumed taking into considerations that the estimated PV CAPEX in 2016 for Peru and Colombia were low (and similar to the ones assumed for Chile), while they were the highest for Ecuador.

Table 52 – PV Costs in the year 2030 according to all the sources

Solar PV - Costs in USD/kW - Projection to year 2030			
	Colombia	**Ecuador**	**Peru**
Total	670	860	600
O&M (per year)	9.4	9.4	9.4

Data about the estimated values of wind plants in 2030 are reported in Table 53. They are assumed lower for Colombia and Peru and slightly higher for Ecuador.

Table 53 – Wind Costs in the year 2030 according to all the sources

Wind Onshore - Costs in USD/kW - Projection to year 2030			
	Colombia	**Ecuador**	**Peru**
Total	1145	1180	114’
O&M (per year)	23.8	23.8	23.8

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 international publications as a source for projections to 2030.*
  - *Crosscheck the estimates from the international organization with available estimates issued from recognised organizations in the countries of the study.*

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 54 – Primary energy costs

Primary energy costs - Target year 2030 - Prices in USD			
	Colombia	**Ecuador**	**Peru**
Crude oil	128.5 USD/barrel	128.5 USD/barrel	128.5 USD/barrel
Natural gas	8.2 USD/MBTU	7.8 USD/MBTU	4.35 USD/MBTU (regulated)*
Coal	1.8 USD/MBTU	3 USD/MBTU	3 USD/MBTU

* The gas price in Peru without regulation is considered 6.8 USD/MBTU

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 Colombia, Ecuador and Peru.
Most of the information provided in the present section comes from the OECD/IEA "World Energy Outlook 2016" [18] that describes the present energy costs and the future trends, whereas additional data related to the countries of interest 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 that 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 regard 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 the 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 might 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 55.

Table 55 – Evolution of GDP in the region analysed in WEO-2016 [18]

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 regard 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 56).

Table 56 – 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 the 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 56 summarises the trend of crude oil price that regard the three relevant scenarios.

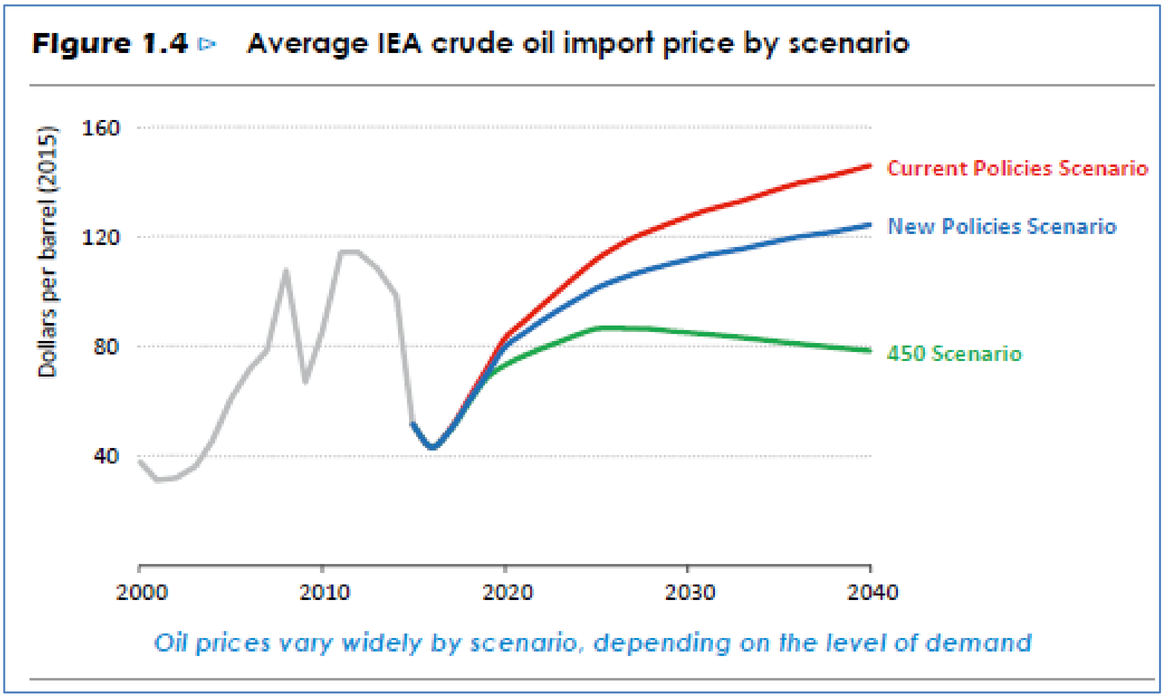


Figure 56 – Average crude oil price by scenario (Source: WEO 2016)

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 57 summarises the trend of natural gas price that regard the New Policy Scenario.

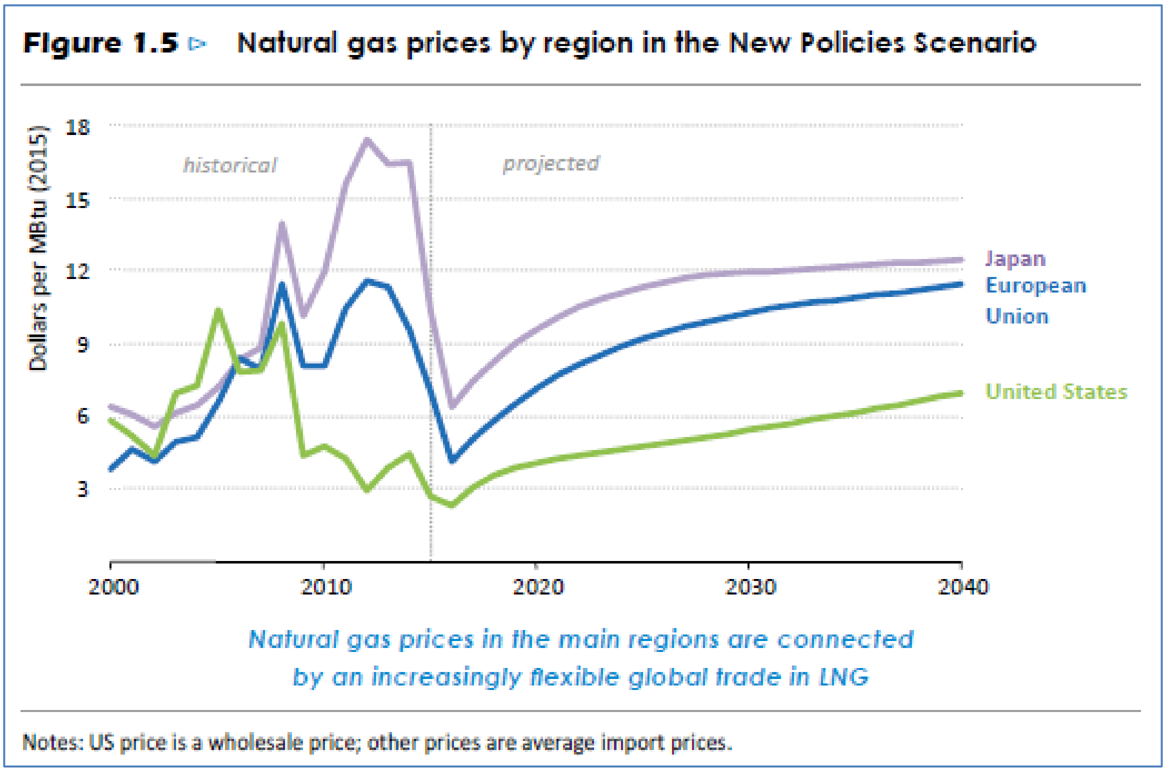


Figure 57 – Average natural gas price in the New Policies Scenario (Source: WEO 2016)

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 58) 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.

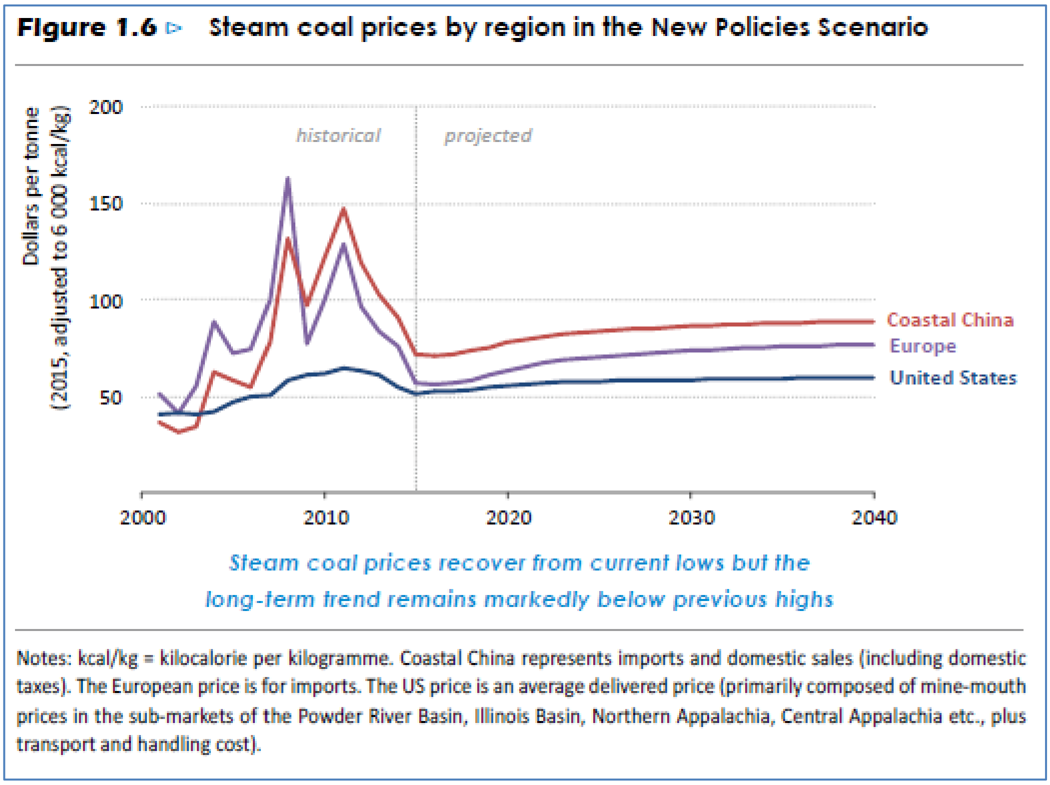


Figure 58 - Average coal price in the New Policies Scenario (Source: WEO 2016)

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 59) is the US EIA Annual Energy Outlook 2017 [19]; the data were uploaded from the collection "Energy Prices by Sector and Source, Reference case, United States"[11].

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

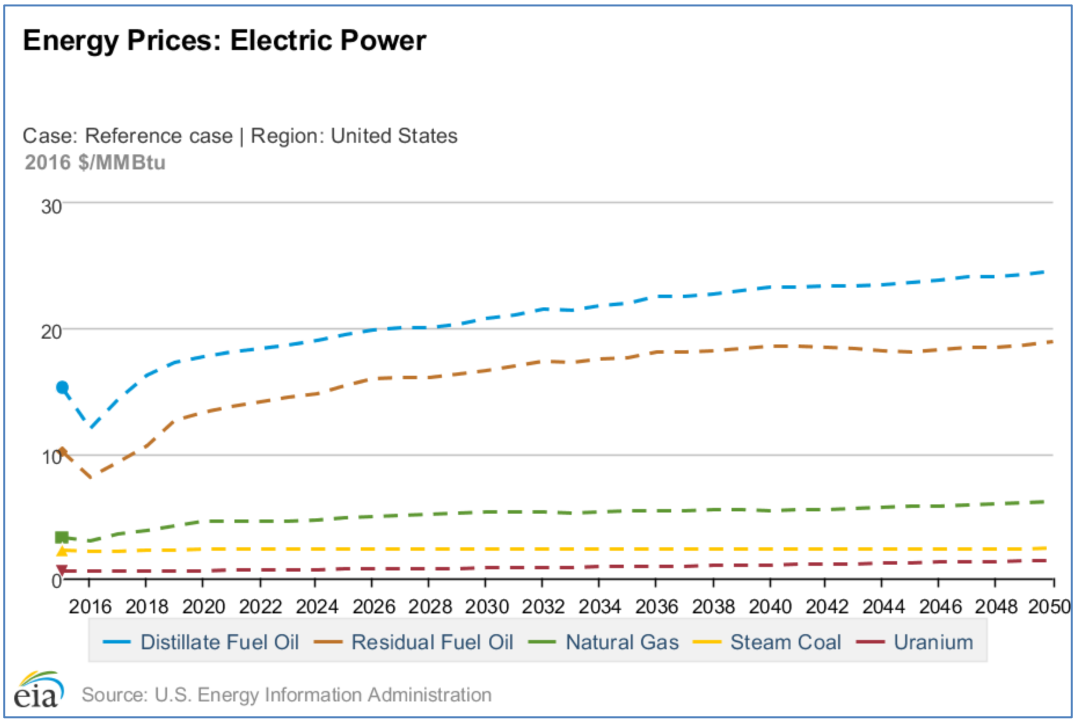


Figure 59 – Energy Prices: Electric Power – Projections of energy prices for electric power generation until 2050

The data shown in the Figure 59 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 shown for 2030 in Figure 56 is aligned with the price in Figure 59 (considering that 1 barrel oil equals 5.7 MMBTU)
- Natural gas. The USA price 5 $/MBTU in Figure 57 is equal to the price 5 $/ MMBTU in Figure 59 (knowing the units shown in the two graphs can be equivalent)
- Coal. The price 75 $/tonne in Figure 58 compares to the price 3 $/MMBTU in Figure 59 (for 1 tonne of coal equals 21.7 MMBTU)

From this comparison, it can be assumed that the international references provide comparable values for the different energy sources.

2.4.2.3 Information about the primary energies by sources from Colombia, Ecuador and Peru

Primary energy costs for Colombia are reported in [2].

Figure 60 to Figure 62, from [2], show the projection of costs of coal, gas and liquid fuel for Colombia in the next years. For coal, a quite wide spread is present among the different natural sources where coal is taken from. Also liquid fuel shows different values, depending on the considered type. Assumptions have then to be made on proper average prices, which should reflect the variability with respect to other countries.

For the coal, for Colombia it is possible to consider the cost of 1.8 USD/MBTU, which is lower than the international forecasts.

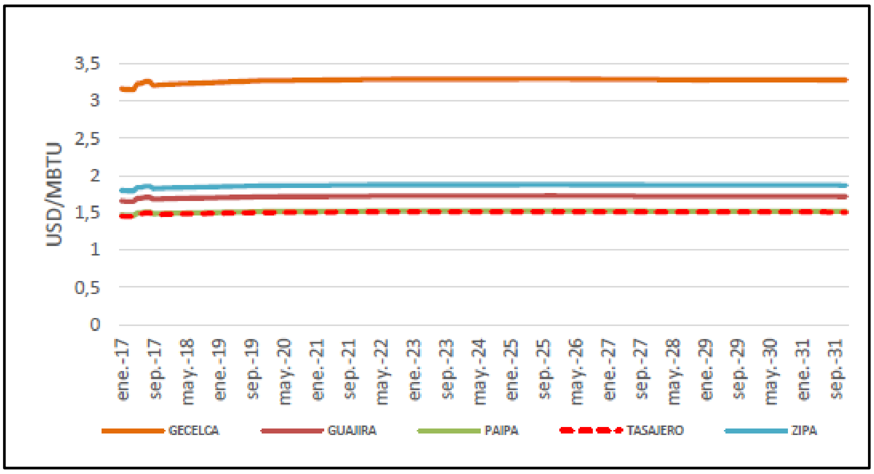


Figure 60 – Colombia - Coal prices projections – Source UPME

For Natural Gas, the value 8.2 USD/MBTU is assumed which is slightly higher than the international price, as in Colombia the gas infrastructure presents some weaknesses and the distribution of the gas in some areas is not cost-effective. This cost is aligned with the forecasts for many areas in the country reported in Figure 61.

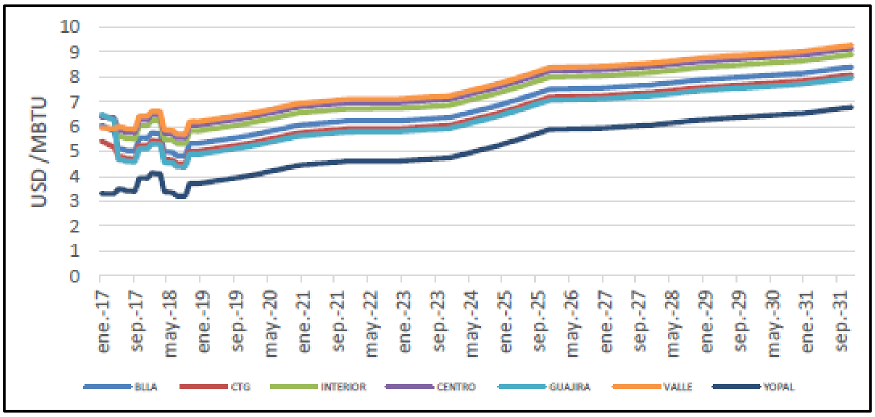


Figure 61 – Colombia - Gas prices projections – Source UPME

For liquid fuel, the cost of 22 USD/MBTU is aligned with the forecast based on international references (Figure 56), which can be assumed also for Colombia.

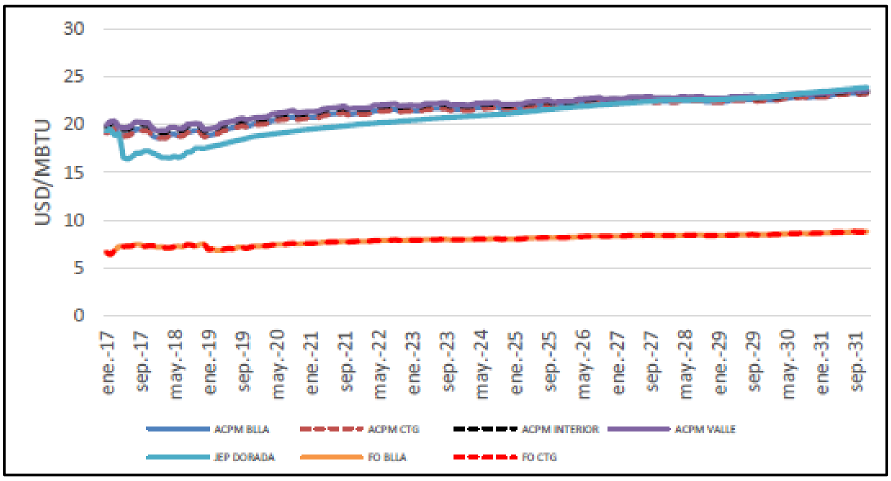


Figure 62 – Colombia - Liquid fuel prices projections – Source UPME

For Peru the projections of costs are described in the Annex E of the already described Masterplan. Values of costs, based on EIA projections, are reported for oil in Table 57 and Figure 63 and for gas in Table 58 and Figure 64 (tables are limited to target year 2030, while graphs reach 2040).

Table 57 – Peru - Average costs of oil without sulphur – USD/barrel

Year	High	Reference	Low
2010	81.1	81.1	81.1
2011	94.9	94.9	94.9
2012	92.5	92.5	92.5
2013	87.8	87.8	87.8
2014	114	88.3	76
2015	126	88.2	71
2016	137	91.3	68
2017	142.7	96.1	66
2018	146.3	98.7	66.3
2019	149.9	101.3	66.6
2020	153.3	103.6	66.9
2021	156.6	105.8	67.2
2022	160	108.1	67.5
2023	163.5	110.5	67.8
2024	167	112.9	68.1
2025	170.6	115.4	68.4
2026	174.3	117.9	68.7
2027	178.1	120.4	69
2028	181.9	123.1	69.3
2029	185.9	125.7	69.6
2030	189.9	128.5	69.9

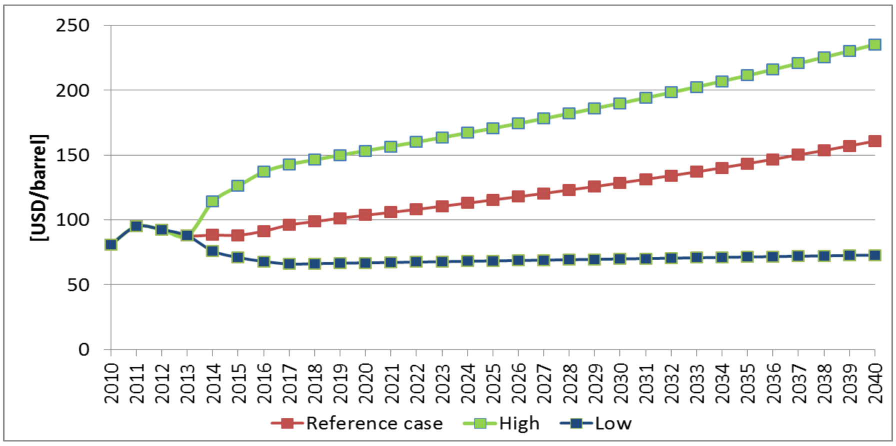


Figure 63 – Peru - Average costs of oil without sulphur – USD/barrel

NG price in Peru is regulated and kept below standard international prices. Two assumptions will be made during the study, considering a value 4.35 USD/MBTU (valid in case of active regulation), and also the value 6.8 USD/MBTU, more aligned with the actual cost of the gas production in Peru.

Table 58 – Peru - Average costs of natural gas – USD/MBTU

Year	High	Reference	Low
2012	2.8	2.8	2.8
2013	3.7	3.7	3.7
2014	4.4	4.4	4.3
2015	3.7	3.6	3.4
2016	3.8	3.7	3.3
2017	4.1	3.8	3.6
2018	4.2	4.2	3.9
2019	4.6	4.3	4.2
2020	4.9	4.6	4.3
2021	5	5	4.3
2022	5.4	5.1	4.4
2023	6	5.2	4.7
2024	6.4	5.3	4.8
2025	6.7	5.5	5
2026	7.1	5.7	5.2
2027	7.2	5.7	5.5
2028	7.3	5.7	5.6
2029	7.6	5.7	5.4
2030	7.9	5.7	5.5

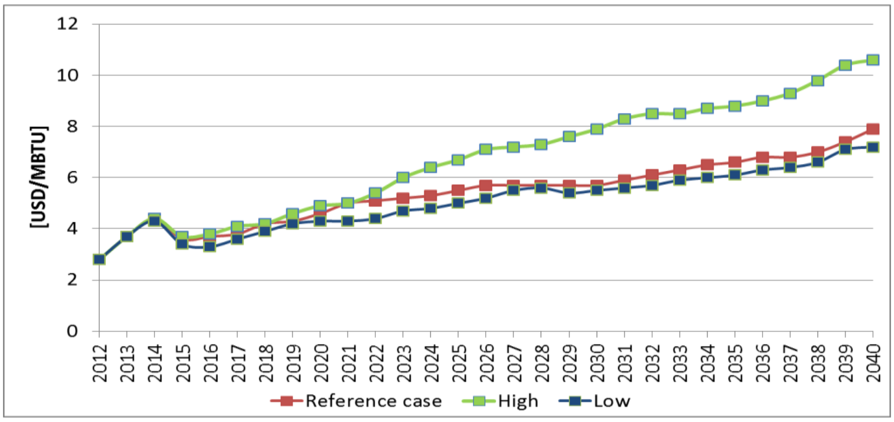


Figure 64 – Peru - Average costs of natural gas – USD/MBTU

2.4.2.4 Information about primary energy production and reserve

The data about the primary energy production described below comes mainly from the World Energy Council web site [20]. Table 59 reports for each Country primary energy reserve and production.

Table 59 – Primary energy reserve and production - Source [20]

		Colombia	Ecuador	Peru
Oil (million tonnes)	Reserve	333	1170	170
	Production/Year	53.1	29.1	4.7
Coal (Mtoe)	Reserve	4720	-	-
	Production/Year	59.9	-	
Gas (Mtoe)	Reserve	122	9.81	373
	Production/Year	9.9	0.54	11.3
	Amount in place	2050	18	2300

About the primary energy production, the main facts are reported below.

<u>Colombia</u>

- Initially, oil discoveries were made principally in the valley of the Magdalena. Subsequently, other fields were discovered in the north of the country (from the early 1930s), and in 1959 oil was found in the Putamayo area in southern Colombia, near the border with Ecuador. More recently, major discoveries have included the Cano Limon field near the Venezuelan frontier and the Cusiana and Cupiagua fields in the Llanos Basin to the east of the AndesHowever, the remaining proved reserves have been shrinking in recent years and, despite a modest rise in 2008, are still at a very low level in relation to production.
- Colombia's vast coal resources are located in the north and west of the country.
- Colombia overall has seen its proved natural gas reserves increase in recent years, however its total amount of proved reserves is still relatively modest. Due to producing more natural gas than the consume, Colombia has achieved self-sufficiency and a high level of energy security of

supply in regard to natural gas. Currently in Colombia, there is a separation between where the majority of the proved natural gas reserves is located and where the largest production of natural gas is occurring. The largest amount of natural gas reserves in Colombia can be found in the Llanos basin. However, the largest amount of natural gas production occurs in the Guajira basin at the moment.

Ecuador

- Ecuador – OPEC's smallest producer – has cut some low-priority projects in its oil sector. By 2020, production capacity in the Andean nation is forecasted at 590 kb/d, up by 20 kb/d from 2014. Oil is one of the primary sources of export revenue for Ecuador's 15 million people and if prices continue to fall, public spending may be cut.

Peru

- Peru is probably the eldest commercial producer of oil in South America. Much of Peru's proven oil reserves are onshore, and the majority of these onshore reserves are in the Amazon region. Eleven important new hydrocarbon discoveries have occurred in just the past few years.
- Although Peru's proved natural gas reserves are relatively small based on a global scale, they are still one of the largest natural gas reserve holders in South America. The majority of Peru's proved natural gas reserves and natural gas production are a result of their Camisea field.

Other information about primary energy balance are reported in the Reports edited by the public Authorities of each of the Countries analysed.

Colombia

According to the National Statistic Bulletin [4], the production of coal, in terms of thousands of tonnes, is reported in Figure 65, while Figure 66 shows the historical data of oil production.

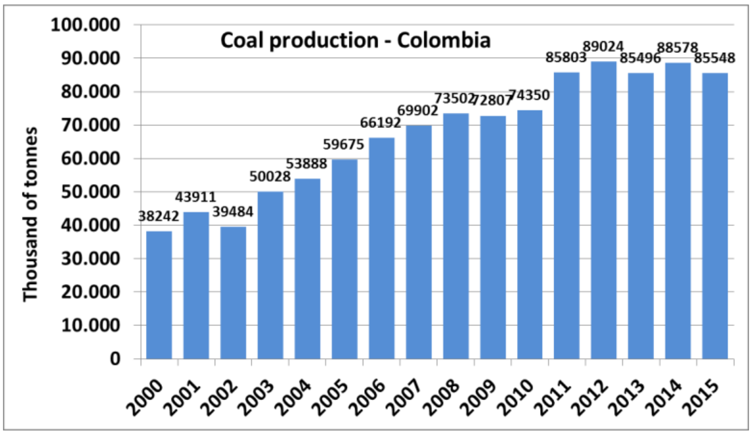


Figure 65 – Colombia – Coal production – Source [4]

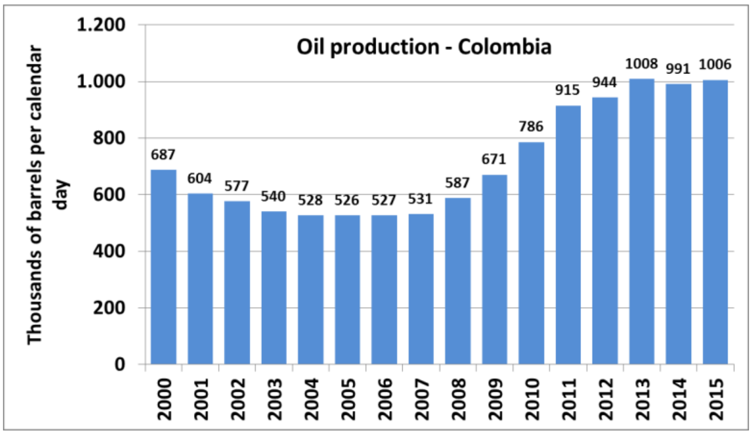


Figure 66 – Colombia – Oil production – Source [4]

Ecuador

According to the National Energy Balance 2016 [5], the production of oil, in terms of thousands of barrels per year, is reported in Figure 67, while the gas production, in terms of million cubic feet, is reported in Figure 68.

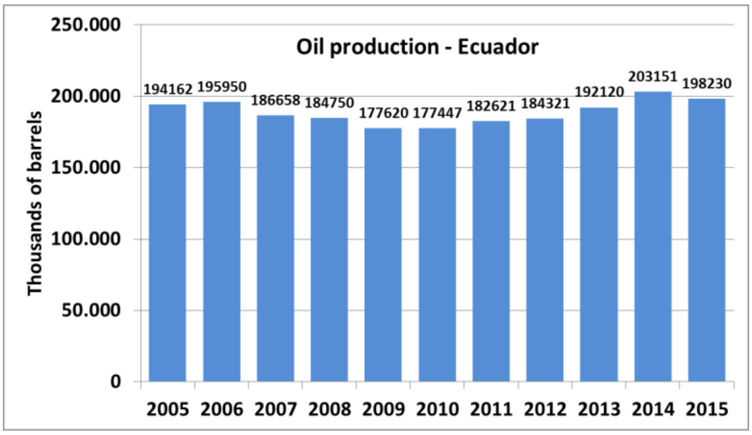


Figure 67 – Ecuador – Oil production – Source [5]

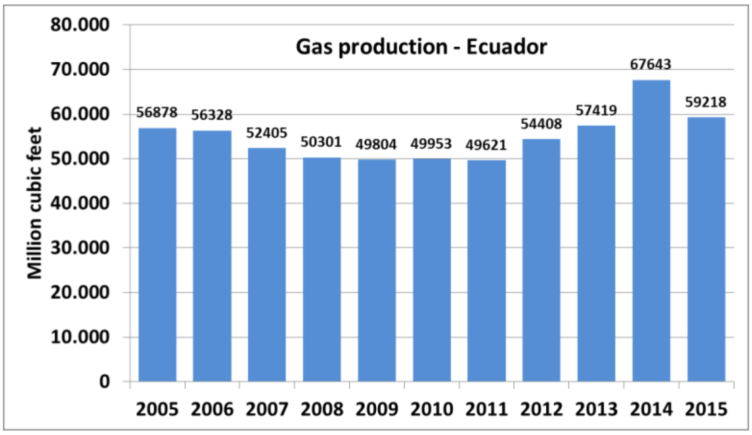


Figure 68 – Ecuador – Gas production – Source [5]

Peru

According to the National Energy Balance 2016 [11], the primary energy production in the years 2015 and 2016 reached the values reported in Table 60.

Table 60 – Primary energy production (TJ)

	2015	2016
Oil	122.604	85.545
Gas + LNG	690.109	735.341
Coal	7.117	7.343

2.4.2.5 Primary Energy Costs in 2030

On the basis of the data reported by the different sources described in the previous paragraphs, primary energy costs for 2030 are assumed to be those reported in Table 61.

Table 61 – Primary energy costs

Primary energy costs - Target year 2030 - Prices in USD			
	Colombia	**Ecuador**	**Peru**
Crude oil	128.5 USD/barrel	128.5 USD/barrel	128.5 USD/barrel
Natural gas	8.2 USD/MBTU	7.8 USD/MBTU	4.35 USD/MBTU (regulated)*
Coal	1.8 USD/MBTU	3 USD/MBTU	3 USD/MBTU

* The gas price in Peru without regulation is considered 6.8 USD/MBTU

Data reported in the table above have been obtained on the base of the following assumptions:

- No detailed data is available for primary energy costs in Ecuador, and only a generic reference to the international values is reported in the already quoted Masterplan. This is due also to the limited reserve available in the country;
- Colombia and Peru costs have been extracted by the information of the two National Masterplans described in the previous paragraphs;
- Where information is not sufficient, the different prices have been aligned to a common and reasonable value equal for the three Countries considered.

2.4.3 Discount rates and lifetime of projects

The report "IRENA Power to Change 2016" [14] 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.

With 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 regard to the present study, the qualification of Colombia, Ecuador and Peru with respect to the OECD membership shall not be taken into account because these Countries are not member of OECD.
Considering the different level of maturity of the VRES technologies in the countries and their attractiveness, a WACC equal to 8% is assumed for Colombia and Peru, while 10% is assumed for Ecuador.

With respect to the lifetime to be considered for the different technologies, the following comparison is provided in the Table 62. Sources: LAZARD - Lazard's Levelized Cost Of Energy Analysis—V.10.0 – Dec 2016 [21].

Table 62 – Life of the facility according to the generation technology (Source: [21])

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

These values are kept aligned with the analysis performed in the previous clusters, in order to maintain same assumptions and the possibility to better compare the results.

As far as the transmission projects are concerned, the assumption gathered from the ENTSO-E Guideline for Cost Benefit Analysis of Grid [22] 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".
Also in this case, the value is maintained aligned with the previous clusters.

3 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 clusters, 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

Based on the available information for each country reported in Chapter 2.1, it is assumed to analyse a Variant with the following demand increase with respect to the Reference Scenario: Colombia +5%, Ecuador +12% and Peru +12%. 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:

- In Colombia UPME set the target of 400,000 Electric Vehicles (EV) at 2030, with a corresponding load increase equal to 971 GWh (see Table 3);
- In Peru 100,000 EV and 40,000 in Ecuador mainly concentrated in the big cities.
- Where no other information on the load increase is available, it has been calculated assuming a usage equal to 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 971 GWh in Colombia (more than 1% of the total load), 300 GWh in Peru (less 0.4% of total load) and 120 GWh in Ecuador (less than 0.3% of the total load).
This demand will be considered in the simulations only concentrated in the area of the main cities, in the night hours.
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 Colombia, Ecuador and Peru, 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, their flexibility will be already considered.

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…)..

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 low grow scenario available for Ecuador and Peru, the demand in this country is set 15% lower than in the Reference Scenario.

In Colombia provides lower reduction percentage (around -2.5%) without considering a boosted energy efficiency scenario. For this reason, it is decided to reduce the Colombian load by a lower ratio, 10% instead of 15%.

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[12] which must be fulfilled

[12] 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.

by thermal and programmable hydro capacity is smaller and can lead to problems with reserve and minimum power constraints.

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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