Modelling of Decarbonization of the Electricity Sector in Peru. A Regional and Intertemporal Approach

Horizon 2019 – 2050. Masters Thesis

In partial fulfilment of the requirements for the degree
Master of Science Power Engineering
At the TUM Department of Electrical and Computer Engineering of the Technical University of Munich.

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Abstract

Peru has an electricity demand of 180 PJ per year, which is currently met with a generation fleet dominated by fossil fuels and hydropower plants. This demand is expected to almost quadruple within the next thirty years and how the system copes with its expansion is still to be determined.

This project proposes a model of the electric system which divides the country in four different regions, englobing departments with similar resources availability, population density, energy requirements and geographical location. The renewable potential of these areas is accounted for, as well as their associated costs and those of all other technologies participating in the sector, such as fossil fuels, storage or electricity transmission between zones.

This model is then implemented into the software urbs, which provides the cost optimal path to be undertaken to guarantee a reliable electric supply. Additionally, different scenarios are considered, such as adding a CO_2 taxation or limiting the GHG emissions to comply with the climate change sustainable development goals.

Results highlight the importance of hydropower in the system, as well as the increasing need for storage and transmission expansion as the grid decarbonizes. Wind has more importance during the first years of the model but stagnates due to the scarcity of optimal locations on shore. On the other hand, PV gains relevance in the last years of the model. Optimistic results are obtained as it appears feasible to achieve a carbon-neutral system by 2050. Nevertheless, additional incentives such as CO_2 taxation should be implemented.

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Contents

1. Introduction

Peru is a country located in the western region of South America, bordering with Ecuador, Colombia, Brazil, Bolivia and Chile. The country is constituted by 24 departments and one constitutional province, which add up to a population of 34 million people, making it the fourth most habited state of the subcontinent [1].

Figure 1 Peru location in South America, "Map In Seconds" [2]

1.1. Energy sector

Peru has a final energy consumption of 873 PJ per year, of which the electricity accounts for a 21%. Similarly, the emissions of green house gases of the sector are an 18% of the total of 54 million tonnes of CO_2-eq [3]. The slight variance between both percentages is a consequence of the implementation of renewables in the electricity sector, which make it less carbon intense than transport, for instance, which currently depends on direct consumption of oil.

The transport is the economic sector with the most energy consumption with close to 380 PJ in the year 2019 [3].

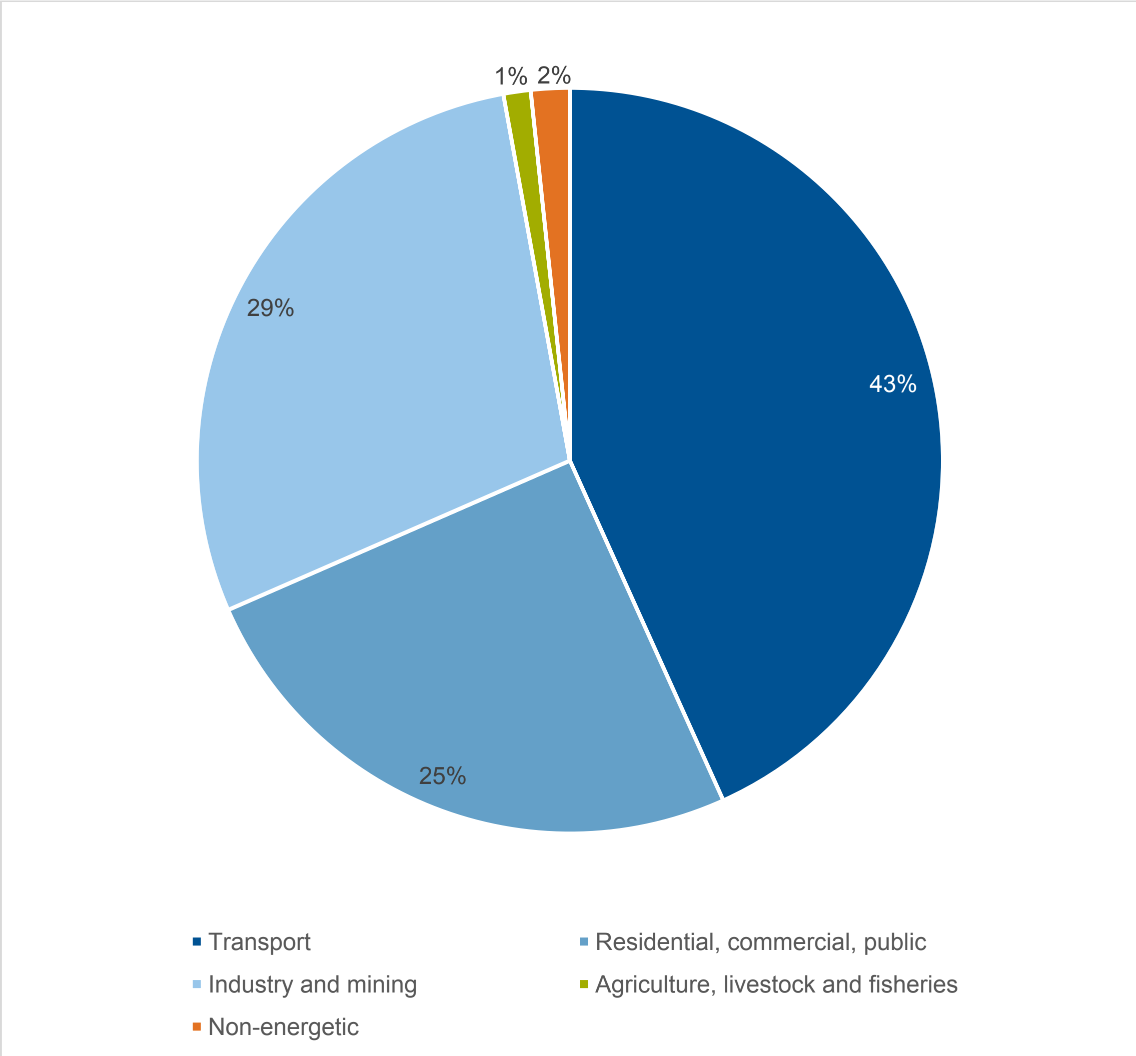

Figure 2 Final energy consumption by economic sectors

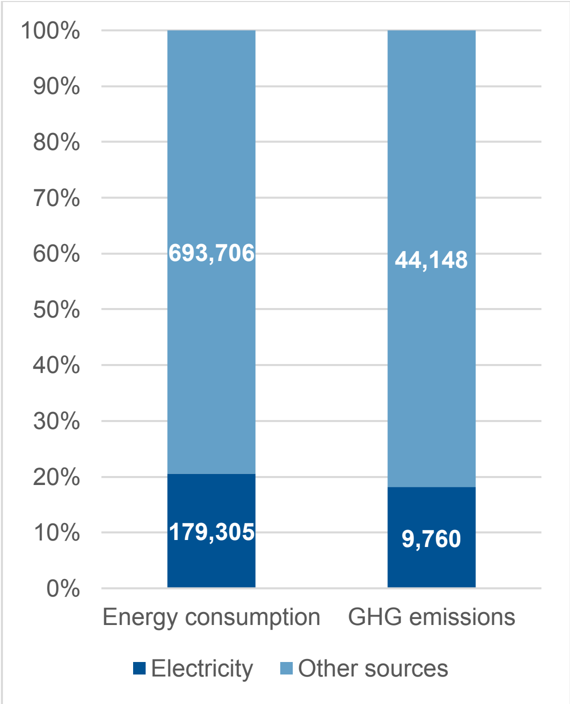

Figure 3 Energy consumption [TJ] and GHG emissions [tonnes of CO_2-eq * 10^3]

As the system evolves, the share of electricity consumed is expected to increment, as it will englobe other sectors for which renewables integration is not as feasible, such as transport [4].

1.2. Context

This study is a continuation of a previous paper developed by Tubella Boada, C. [5], where a single year approach is undertaken to find the optimal path towards the integration of renewables in the Peruvian system. For this, three years are analysed separately, 2019, 2030 and 2050.

The main additions this project entails are an intertemporal analysis, the subdivision of the country in four interconnected regions and a hydro model with storage possibilities. All of these will be explained in detail in the methodology section.

Additionally, different scenarios were implemented, costs were updated, alternative models were developed for the generation estimation of some technologies, such as wind, and specific regional data were collected.

1.3. Objectives and motivation

There is certainty around the change towards decarbonized systems that the global energy sector must experience in the coming years, if environmental threats like climate change are to be dealt with. Nevertheless, the way it must evolve is still unclear [4] [6]. Hence, this report aims to analyse the feasibility of renewables integration into the electric grid, under specific conditions, for the Peruvian case study.

Peru is of great interest due to their great RERs potential, which is expected to be able of meeting the growing regional electric demand. Furthermore, the electric sector of Peru is experiencing expansion, and hence, its reliability compromised to some extent, enhancing the importance of the proposed feasibility analysis.

Additionally, the state possesses natural gas reserves that could be traded for capital with countries with less potential. This would allow Peru to gain independence from this source over time while decarbonizing the country, if earnings were to be invested into renewables implementation [7].

Overall, the main objective is to develop an open model, freely available, that represents the country's system, from which a clear path towards the decarbonization of the country can be deduced.

2. Methodology

The model developed will be implemented into urbs to obtain the most cost-effective path for the integration of renewables in the system within the period 2019 – 2050. To do this, first a single year model for 2019 is developed, then validated, and finally integrated into the intertemporal analysis.

The software urbs is a tool developed by the Chair of Renewable and Sustainable Energy Systems of the Technical University of Munich, based on linear optimisation [8] [9].

The main results from urbs display the yearly energy generation by technology, as well as the capacity to be installed and their associated costs for each modelled year. The inputs for the tool considered are the generation technologies, the transmission capabilities, the storage capacity, the electrical demand and the intermittency of supply for the renewable energy resources.

The generation technologies are classified as either stock or supply intermittent, which applies for variable renewable energies such as wind or photovoltaics. Stock is always available for a given price, and refers to diesel, natural gas or biomass. On the other hand, supply intermittent technologies are free but can only be used at specific time slots, which account for available resource.

For the second input listed, transmission capabilities, the transport of electric power between regions tolerated by the system is required.

In the storage capacity, limitations for storable energy and power are displayed. Additionally, the initial and final energy stored for each modelled year can be implemented. The energy saved for this study will be of two types, electricity, used by lithium-ion batteries and potential energy of saved water, used for conventional plants, whose input comes from a dam.

These three inputs, generation, transmission and storage, have associated processes, in which cost, lifetime, efficiency, currently installed capacity and maximum or minimum installed capacity are specified.

The next input, electrical demand, represents the energy requirements in a time series. This demand must be always met by the generation of the system. If the system were incapable of meeting this, an error from the software would be displayed.

The last input is the intermittency of supply, previously introduced. In the same way as the electrical demand, these data are presented as a time series, but representing available generation in this case. This input is relevant for variable RER, for which the capacity factors are listed.

2.1. Model nodes

Differentiating between nodes allows for a more accurate model. This way, the same demand, depending on the region, will entail different costs, not only economical but also environmental, because of differences in power grid mixes or transmission losses. Additionally, this approach allows for transmission limitations between the regions that would have otherwise been overlooked.

For the model, developed four different nodes will be considered: Center, East, North and South. This region division considers departments with similar resources availability, population density, energy requirements and geographical location, and is associated with the interconnecting transmission lines [10].

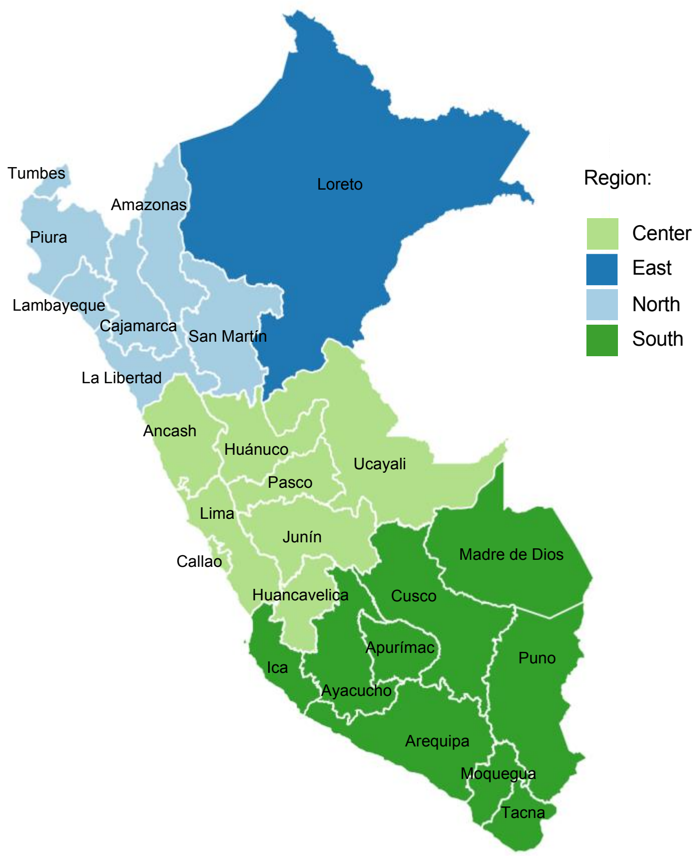

Figure 4 Regions Peru by departments, “Map In Seconds” [2]

Despite regions being similar in size, the center comprises most of the population with close to 50% of the total, while north and south together account for 47% and the east just above 3%. This disparity, together with differences in living conditions, leads to variations in the electricity demand and generation behaviours. These will be analysed in detail in the data collection sections 3.1, 3.2 [10].

Table 1 Nodes population and demand [10]

Region	**Population**	**Energy demand [GWh]**	**Energy demand per capita [GWh/person]**
Center	16.018.971	26.636,6	1662,8
East	1.015.212	834,1	821,6
North	8.288.259	6.508,06	785,2
South	6.808.958	15.961,88	2344,2

2.2. Intertemporal approach

The intertemporal approach goes through the years 2019, 2024, 2030 and 2040, until reaching the end of the timeline, 2050. This type of modelling allows for an analysis of the system development, rather than specific configurations [11].

The initial year is selected to be 2019 for two main reasons. First of all, some of the sources required and referenced in this study, such as MINEM's executive yearbook [10], undergo a time lap in their publications, being data for the mentioned year the most updated available. Secondly, as the experimental results for the year are used to validate the model, it's considered convenient to place the origin before the covid pandemic, to avoid deviations from the normal system behaviour.

The final year chosen is 2050 because this is the deadline, provided by the United Nations, to achieve the Climate Change Sustainable Development Goal (SDG 13) of a net zero carbon emission system [12]. As the horizon advances, the system considers certain cost reductions, demand progressions and increases in transmission capacity, that will be specified in the input data and collection section 3.1, 3.4.2, 3.8.

2.3. Hydrology

For the purpose of this project three different types of hydro technology are differentiated:

- Conventional hydro: the water used to power the turbines is obtained from dams which provide energy storage. Their investment is limited due to the social and environmental these entail in the country [13] [14] [15]. Hence, the utilization of this technology will be only tolerated during their remaining lifetime for all scenarios.
- Large RoR hydro: run off river with a power equal or greater than 20 MW.
- Small RoR hydro: run off river with less than 20 MW of power. This technology will be the only one considered renewable [16].

2.4. Scenarios

Certain factors considered for the report have a significant effect on the results when modified. Due to this, different scenarios are analysed, in which assumptions made deviate.

2.4.1. Scenario 1: base

Business as usual scenario. Here, the cheapest alternatives will be considered, with no CO_2 limitation.

2.4.2. Scenario 2: renewables cheap

Business as usual scenario in which latest RERs evolve into more competitive prices [17] [18].

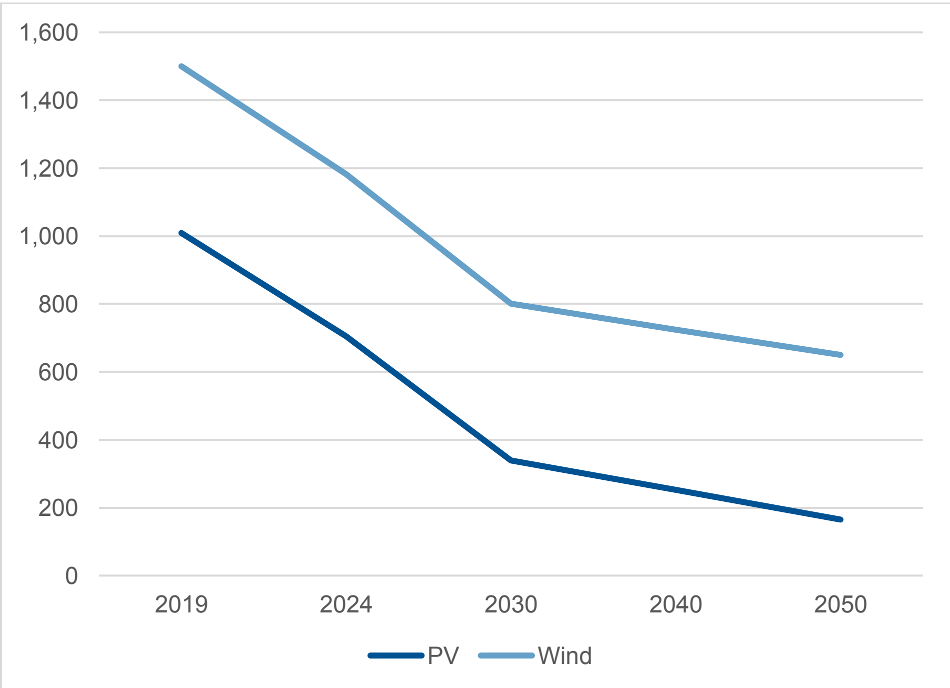

Figure 5 Latest RERs installation cost forecast [USD/kW]. Scenario 2

2.4.3. Scenario 3: CO_2 tax

Business as usual scenario with a CO2 tax of 50 USD per ton emitted [19].

2.4.4. Scenario 4: SDG 13

Here, the CO_2 emissions per year are limited to comply with the Climate Change Sustainable Development Goal. The allowed carbon dioxide emitted follows a linear trend starting from the emissions resulting from the single year model of 2019.

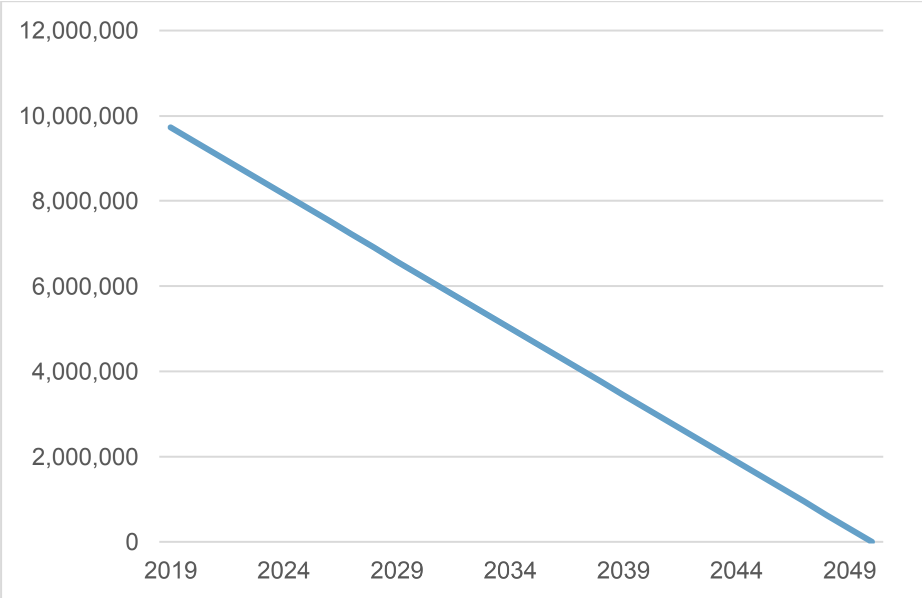

Figure 6 Emissions progression [tonnes of CO_2 / year]. Scenario 4

2.4.5. Scenario 5: RER & SDG 13

Scenario SDG 13 restricting the investment in large RoR plants, as these are not considered renewable [16]. Hence, the system will only allow the operation of this technology during its remaining lifetime.

2.4.6. Scenario 6: Macrogrid & SDG 13

Scenario SDG 13 incorporating international transmission capacity from 2030 onwards [20]. Here, the latest prices for commercial electricity are selected.

Table 2 International transmission. Scenario 6

	Buy price [USD/MWh] [21]	**Sell price [USD/MWh] [21]**	**Capacity [MW] [20]**
North – Ecuador	92	116	1.000
South – Brazil & Chile	118	116	2.300

The GHG emissions from the acquired energy are not considered.

2.4.7. Scenario 7: Conventional hydro & SDG 13

Scenario SDG 13 in which conventional hydro can receive investment if it doesn't surpass its current installed capacity. This implies that only after their lifetime has expired is investment allowed.

3. Input data collection and modelling

3.1. Electricity demand

As mentioned in the methodology, 2.1, the electricity demand in Peru is distributed unevenly between the different nodes, not only due to the population difference but also because of lifestyle variations. The center, the region with the largest population, also dominates in energy consumption, followed by the south. On the other hand, north and east together add up to 15% of the country's demand [16].

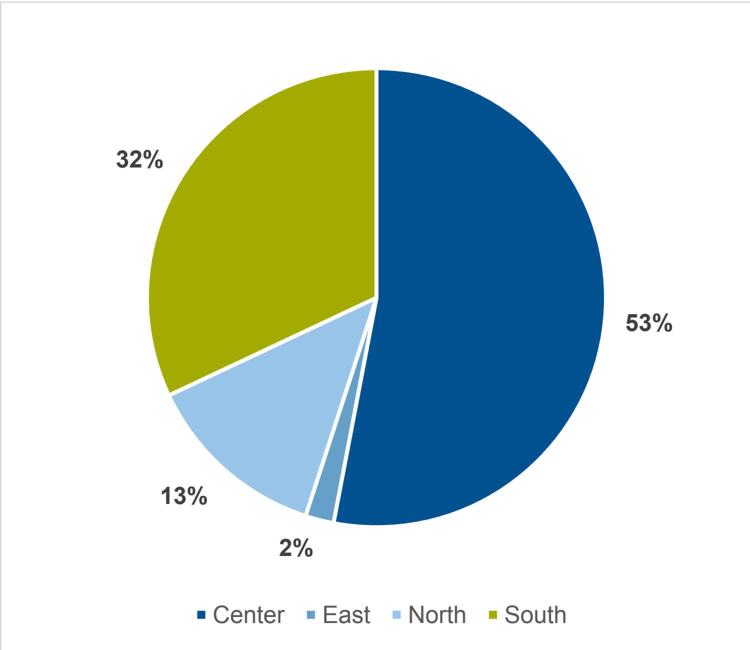

Figure 7 Regional electrical demand distribution

The nodes selected also present different behaviours in terms of demand growth. The southern region saw the steepest growth in recent years, while demand in the north and center showed a similar increase and the east stagnated [10]. These values were used to calculate the repartition of demand growth for the modelled years, along which the total demand is expected to quadruple [22].

Table 3 Regional demand growth

Region	Recent demand growth [%] [10]	Calculated demand growth distribution [%]
Center	4,9	26,1
East	0,1	0,5
North	5,2	27,7
South	8,6	45,7

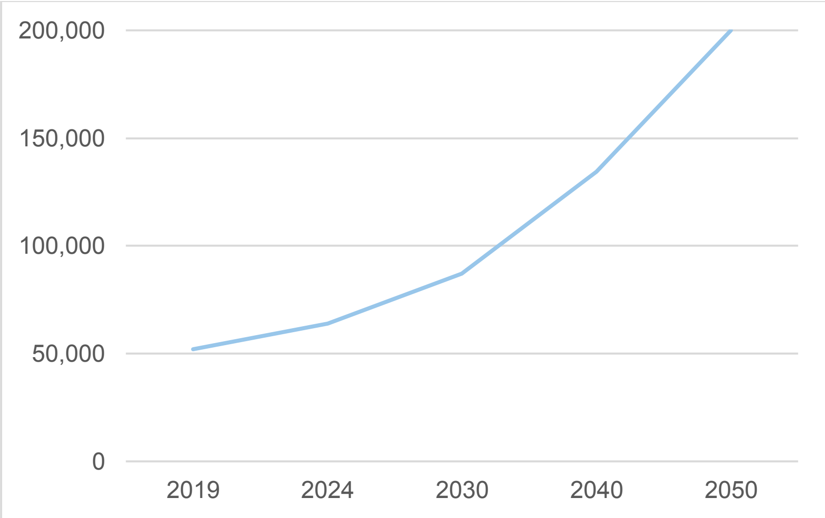

Figure 8 Total demand forecast (2019 – 2050) [MWh] [22]

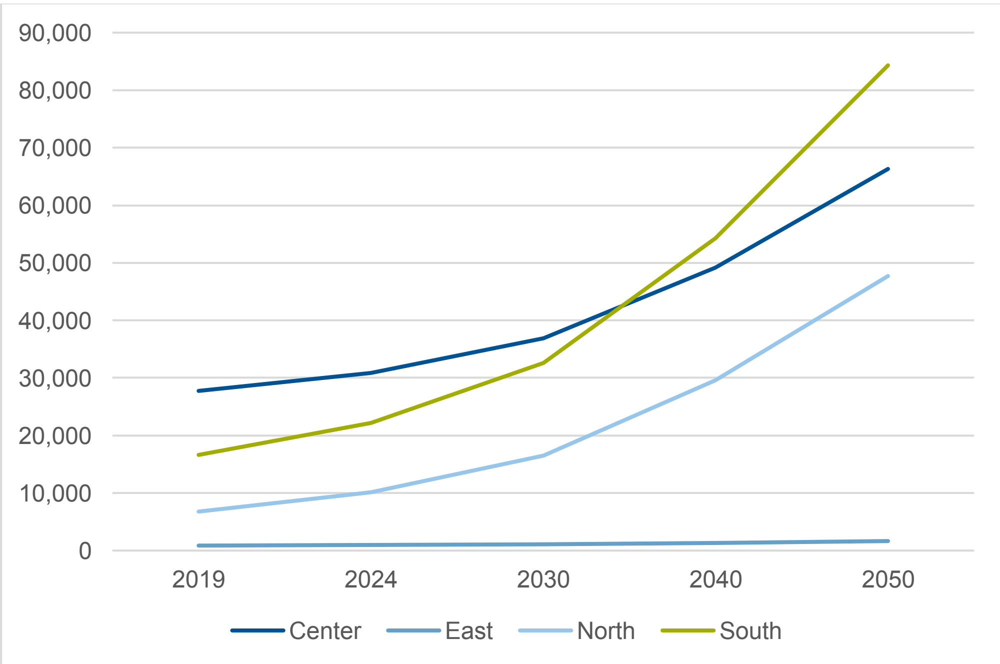

Figure 9 Regional demand forecast (2019 – 2050) [MWh]

Along the day the demand peaks between 10am to 10pm, while the off-peak hours are between midnight and 7am. On the other hand, seasonal variations in demand are mild, due to the proximity of the country to the equator [23].

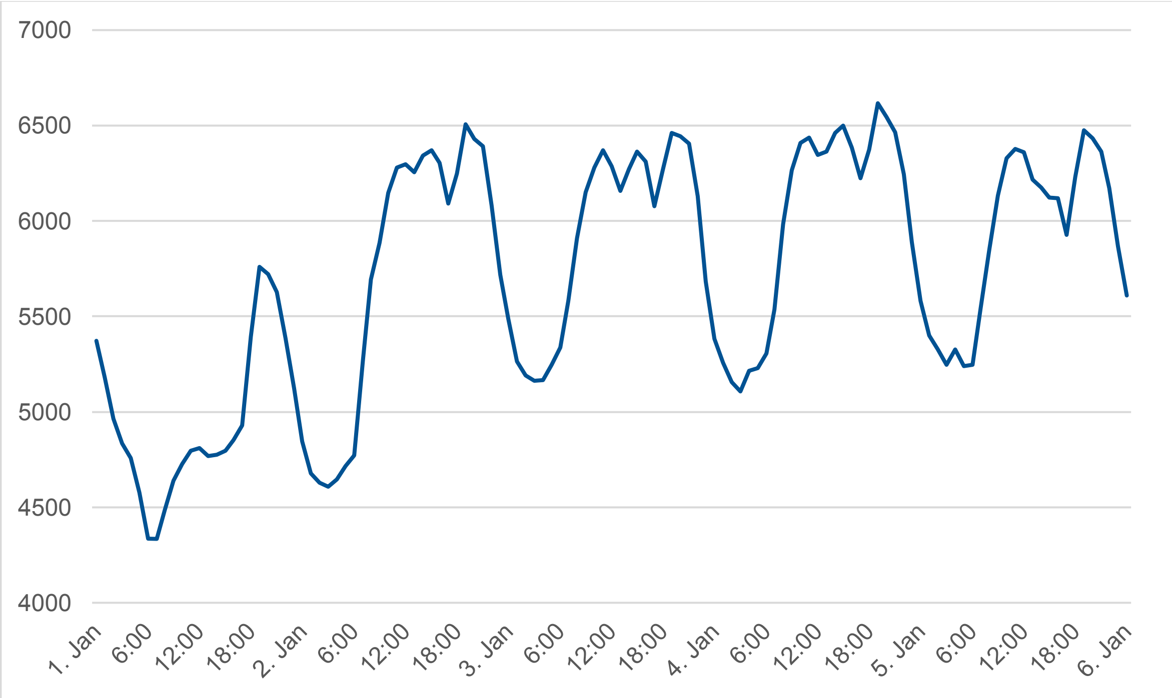

Figure 10 Demand time series extract 2019 [MWh]

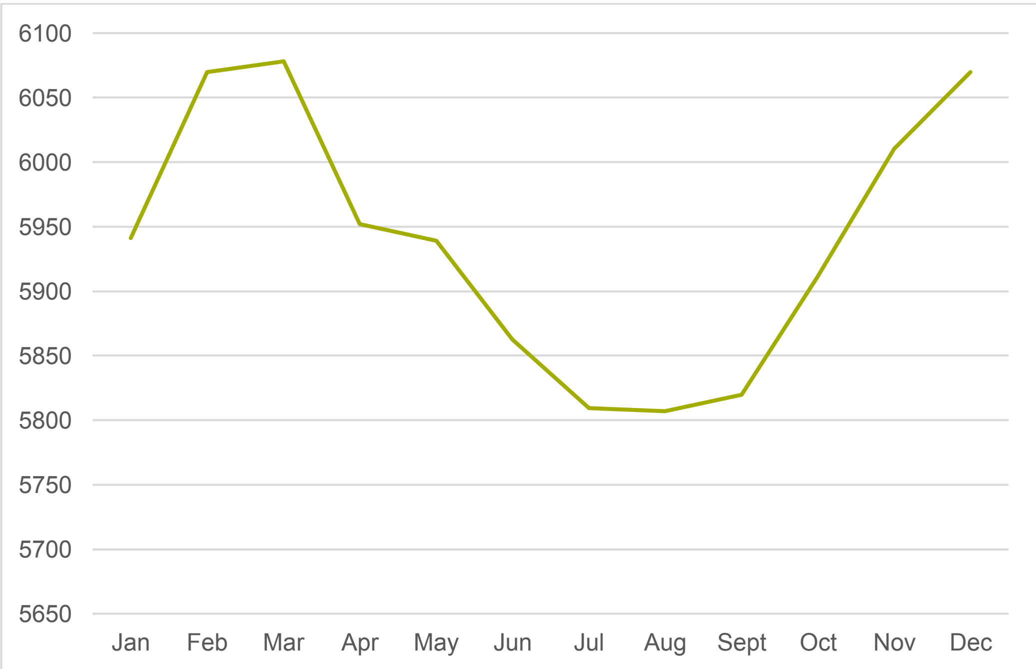

Figure 11 Monthly mean demand variation in 2019 [MWh]

3.2. Installed generation capacities

Just as the demand, the generation capacity differs greatly between regions. The center has the highest, with a large percentage of hydro and fossil fuels. The south, with a share of renewables of over 20%, is the second region with the largest total capacity. Despite this, the south is highly dependent on imports from the center, because of their accelerated demand growth. The north has the highest relative share of renewables, while the east, with the lowest generation, is exclusively powered by fossil fuels. North and east together account for 10% of the total generation [16], [24], [25].

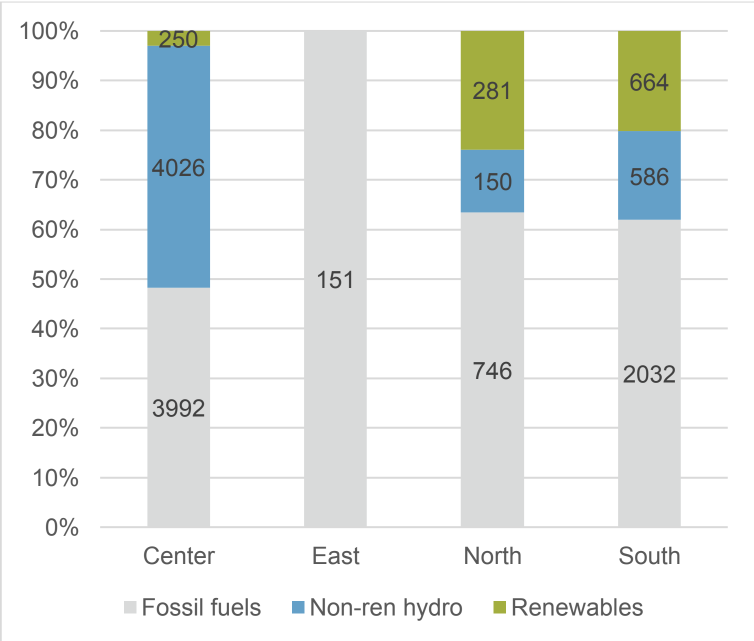

Figure 12 Regional installed generation capacity [MW]

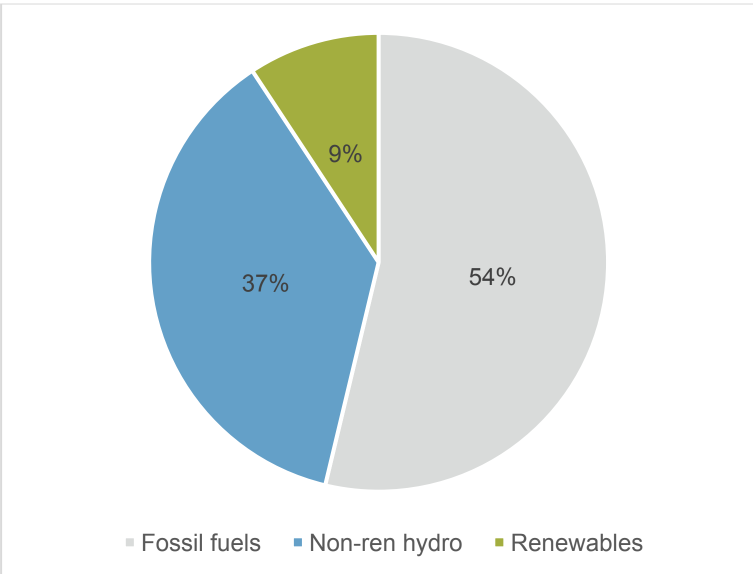

Figure 13 Sources generation contribution

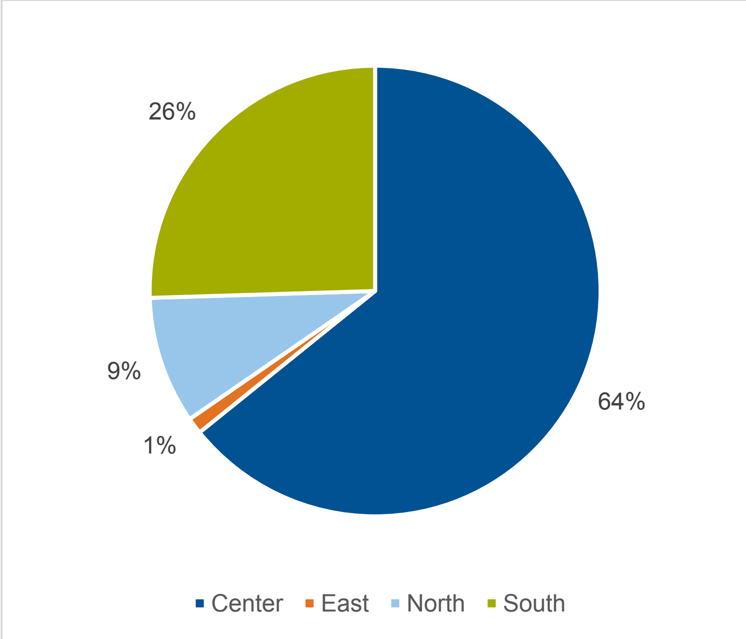

Figure 14 Regional generation contribution

3.2.1. Fossil fuels

The Peruvian system uses mostly natural gas as a fossil fuel source, as there are reservoirs in the region available. Despite this, natural gas plants can't be found in the south, where most of the installed fossil plants are powered by diesel. Coal, the least used fossil fuel, can only be found in the south, where it holds a modest share.

Table 4 Installed capacities fossil fuels [MW]

Region	Coal	Diesel	Natural gas
Center	0	41	3.951
East	0	151	0
North	0	402	344
South	141	1.891	0

3.2.2. Hydrologic resources

Large RoR is the most common hydrologic technology found in Peru, with close to 70% of the total hydrologic capacity. These are located mostly in the center. Conventional plants account for over 20% of the total installed power, with plants in the center and southern regions. The last technology, small RoR is found in all areas but the east, region with no hydro capacity [16], [24].

Table 5 Installed capacity hydropower [MW]

Region	Conventional	Large RoR	Small RoR (RER)
Center	568	3.458	221
East	0	0	0
North	0	150	135
South	586	0	118

3.2.3. Renewable Energies

Besides small RoR, Peru has installations of biomass, wind and photovoltaic energy. The south is the region with the largest renewables capacity, followed by the north. The center has no PV nor wind energy plants, as natural gas is cheap in this region and better locations for renewables are found in northern and southern areas, as will be reasoned when the RER potential is discussed in 3.10.

Table 6 Installed capacities RER [MW]

Region	Biomass	Wind	PV
Center	29	0	0
East	0	0	0
North	32	114	0
South	0	261	285

3.3. Energy storage capacity

Currently, the Peruvian system uses exclusively hydro dams for energy storage. These are in the center and south. As the system integrates more renewables in the future, the energy storage capacity is expected to expand as a consequence of the impossibility of intermittent sources to meet the demand on their own, as their generation depends greatly on external, environmental factors [24].

Table 7 Hydro dam energy storage capacity

	Effective power [MW]	Useful energy [GWh]	Initial capacity [%]
Center	568	274	34%
South	586	1.148,3	48%

3.4. Transmission capacities

3.4.1. Present time

Currently the electric system relies on energy transmissions from the center to north and south, whose current generation cannot cope with their demand. Especially critical is the connection center to south, as it has risks of saturating in the future. The east is currently isolated from the interconnected system, depending exclusively on its generation [16] [26] [27] [28].

Table 8 Representative transmission lines. Effective power and length

Connecting Areas	Code	Effective Power [MW]	Length [km]
Center – North	2272 / 2274	192	104
Center – North	5008	1.040	145
Center – South	5034	688	358
Center – South	5033	421	360
Center – South	2051 / 2052	393	296

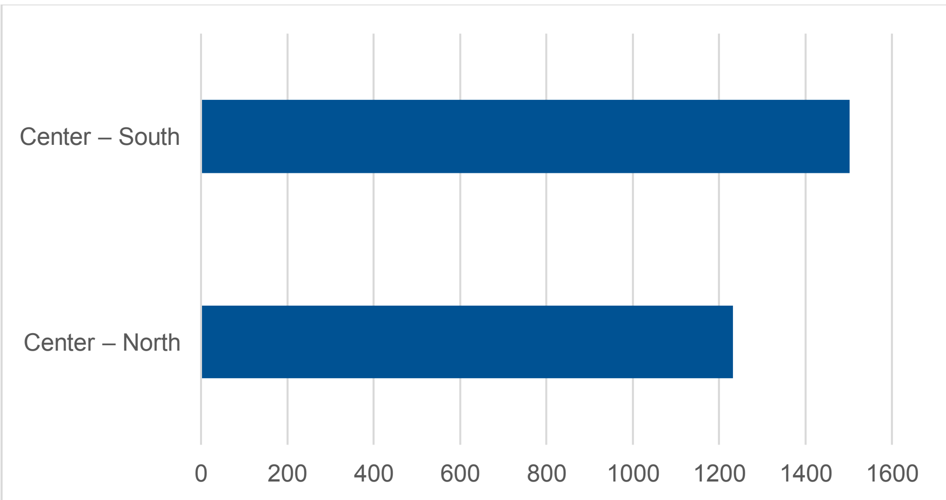

Figure 15 Transmission capacity [MW]

A surpass by as much as 10% from the installed capacity will be allowed by the system as tolerance [26]. The efficiency of transmission is set to 94% for all lines [24].

3.4.2. Expected evolution

Plans to expand transmission between regions include connecting north and east and increasing the capacity from the centre to the north and south by 38% and 30% respectively.

Table 9 Transmission capacity forecast [MW]

	2019	2024	2030	2040	2050
North – East	0	0	120	300	300
Center – North	1232	1232	1700	1700	1700
Center – South	1502	1650	1950	1950	1950

In the model, the increase in capacity will not be forced but allowed, so that urbs can decide whether it's more economical to invest in generation, transmission or storage.

3.5. Technology Investment and Operation Costs

Since the urbs tool aims to calculate the most cost-effective way of integrating renewable energies in the system, special care must be invested into defining the costs accurately. Urbs accounts for three process costs:

- Fixed costs: yearly cost of existing capacity, independent of the actual energy generation. Measured in USD/MW/year.
- Variable costs: generation dependent costs. These include wear and tear of moving parts and operation liquids, but do not account for the actual costs of fuel. Measured in USD/MWh.
- Investment costs: costs of adding new capacity. These are annualized depending on the lifetime of the process and the weighted average cost of capital, assumed to be of 7 % for all technologies. Measured in USD/MW.

The lifetime of the different technologies will also be analysed in this section since it's of great relevance when it comes to calculating the investment costs, as mentioned previously.

The depreciation period represents the total lifetime of the different technologies and is used to calculate the annuity factor for the investment costs. On the other hand, the lifetime accounts for the remaining years during which the plant can operate. To calculate these, information regarding the increment of power capacity was collected to estimate the age of the technologies, which was later subtracted from the total lifetime [16].

3.5.1. Generation of fossil fuels

The investment costs of coal plants when compared with the alternatives, diesel and natural gas plants, is the highest, although it has a longer lifetime on average [29].

Table 10 Fossil fuel technology and operation costs, lifetime

	Investment cost [USD/kW]	Fixed [USD/kW/year]	Variable [USD/MWh]	Lifetime [years]	Depreciation period [years]
Coal	4.563	61	4	28	40
Diesel	975	17	4	8	20
Natural gas	975	17	4	8	20

3.5.2. Generation of renewable technologies and hydro

The investment costs for the different renewable technologies deviate considerably. PV has the lowest cost per installed power while geothermal technology, currently not found in the system, has the highest [29] [30] [31].

Table 11 Renewable and hydro energy technology and operation costs, lifetime

Source	Investment cost [USD/kW]	Fixed [USD/kW/year]	Variable [USD/MWh]	Lifetime [years]	Depreciation period [years]
Biomass	2.173	87	5	18	30
Conventional hydro (non-RER)	1.717	40	–	16,5	27,5
Geothermal	5.275	14	17	–	25
Large hydro (non-RER)	1.717	40	–	16,5	27,5
Photovoltaics	1.009	12	–	25	30
Small hydro	2.268	40	–	16,5	27,5
Wind	1.500	33	–	15	20

3.5.3. Energy storage

Two alternatives for energy storage are considered in this assessment: utility scale lithium ion batteries and hydro dams, whose output feeds the conventional hydro plants [32], [33]. The dams imply lower costs and longer lifetimes, with a deficit in the battery efficiency.

Table 12 Energy storage technology and operation costs, lifetime and efficiency

Technology	Investment capacity cost [USD/kWh]	Fixed power cost [USD/kW/year]	Efficiency [%] [34]	Lifetime [years]	Depreciation period [years] [34]
Lithium ion	350	20	90	– *	15
Hydro dams	165	15,9	80	17	45

The lifetime of the hydro dams is the same as the selected for conventional hydro plants in Table 11. This is to avoid the fixed costs of the dams once the plants are out of operation, as no investment in these is allowed. Otherwise, this would entail a cost with no real impact in the system.

3.5.4. Transmission lines

The costs for transmission greatly depend on the line's length. Accordingly, an average length for interconnecting lines is calculated using the data from Table 8. With this, an average investment cost of 933 USD/MW/km and a 5,5 % fixed cost contribution, the costs as input for urbs can be estimated [35]. As no lines connect east and north currently, the same costs for center to north are considered.

Table 13 Transmission costs, efficiency and lifetime

Regions	Investment cost [USD/MW]	Fixed cost [USD/MW/year]	Efficiency [%] [24]	Lifetime [years] [36]	Depreciation [years] [37]
East – North *	116.196	6.391	94	–	100
Center – North	116.196	6.391	94	90	100
Center – South	315.456	17.350	94	90	100
North – Ecuador [20]	401.000	22.055	94	–	100

The remaining lifetime considers exclusively new investments in high voltage lines of 220 and 500 kV.

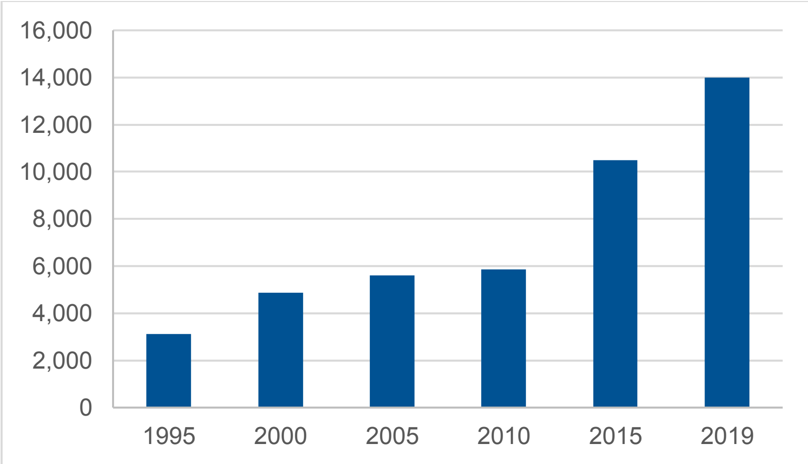

Figure 16 HV transmission lines length progression [km] [16] [36]

3.6. Commodity costs

The commodity costs are the actual cost of fuel. These are strictly variable costs but are analysed by urbs separately because of their importance and fluctuating nature. The commodity costs are significant only for the fossil fuels, since REs consume natural, “free” sources such as waste for biomass or sunlight for PV generation [38].

Natural gas has the lowest volumetric energy density. Due to this, international trading is more expensive, and prices differ on the regional level. Accordingly, data for coal and diesel is taken from a generic dataset, while a regional source is considered for natural gas, which shows a different price within the country regions [38] [39].

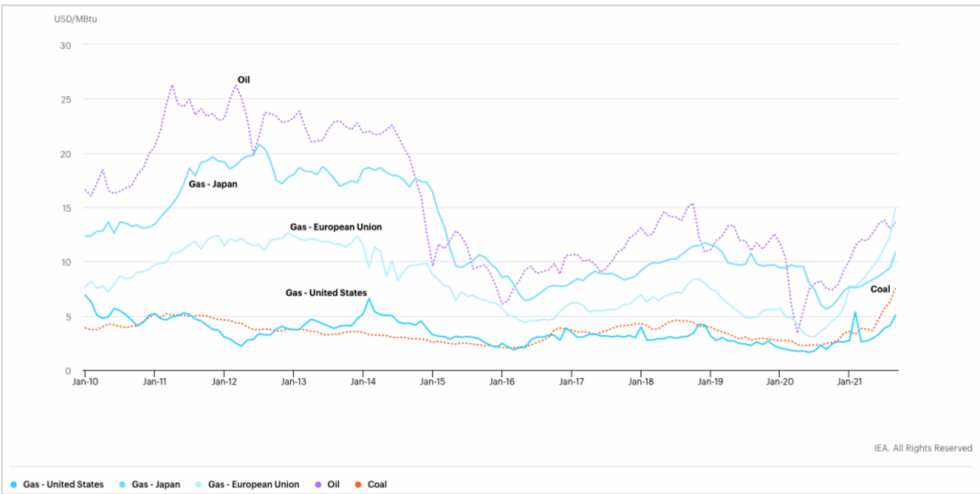

Figure 17 Fossil fuels commodity costs 2010-2022 [USD/MMBtu], IEA [38]

Table 14 Fossil fuels commodity costs [USD/MWh] and efficiency 2019

Fuel	Center	East	North	South	Efficiency [%] [29]	CO_2 tonnes / MWh_{el} [40]
Coal	10,2	10,2	10,2	10,2	40	1,63
Diesel	40,9	40,9	40,9	40,9	55	1,33
Natural gas	14	25,6	25,6	20,6	64	0,47

These costs are assumed constant for the whole modelling period.

3.7. Capacity Factors Renewables

The capacity factor is the unitless ratio of energy output over maximum capacity, taking values between cero and one. This ratio is especially relevant for renewable energies.

The CFs are dependent on the type of RER, classified as intermittent, constant or controllable.

- **Constant RE:** Once the generation starts it maintains a relatively constant production that cannot be altered. Only geothermal belongs to this category. To model this, the geothermal commodity was considered as intermittent supply with a constant 0,9 capacity factor [41].

- **Controllable:** biomass and dammed hydro. The generation of these plants can be tuned to increase production when there is peak demand and decrease it when the electricity demand is lowest. These are both modelled as stock.

  The stock of biomass is considered as always available and the plants will be able to operate at 70% capacity [30]. In the case of dammed hydro, the amount of stock depends on the intermittency of the rivers feeding the dam.

- **Intermittent:** These are hydro, PV and wind. They are characterised by a fluctuating nature. The system must adapt to their generation. Only these will require a detailed study of their variable capacity factors.

3.7.1. Hydro

The capacity factors for hydro were calculated using the data from the volume circulating through the turbines [42].

Table 15 Volumetric flow circulating through turbines [m³/s]

	Conventional		Large RoR		Small RoR		
	Center	South	Center	North	Center	North	South
Jan – 19	138,8	189,7	696,9	48,2	142,8	83,5	18,8
Feb – 19	134,1	190,1	832,9	58,5	133,3	151,4	19,3
Mar – 19	137,2	195,1	751,4	59,6	141,1	153,9	27,4
Apr – 19	146,4	184,3	858,5	70,2	155,1	158,3	28,3
May – 19	127,5	173,5	724,2	59,6	141,8	148,9	26,1
Jun – 19	91,0	156,3	546,7	33,3	114,5	121,3	21,7
Jul – 19	88,1	146,3	526,3	22,6	101,9	77,9	19,0
Aug – 19	87,4	138,9	474,9	15,1	89,7	71,0	17,3
Sept – 19	89,7	136,1	462,6	15,3	87,6	74,6	16,6
Oct – 19	96,7	154,4	533,3	31,7	101,4	88,9	12,5
Nov – 19	122,9	186,4	655,8	56,3	129,7	112,6	22,9
Dec – 19	143,9	185,2	823,5	73,8	153,9	98,7	29,0

With these data and the maximum circulating flow for each location and technology, the monthly capacity factor is calculated as the ratio of flows [24].

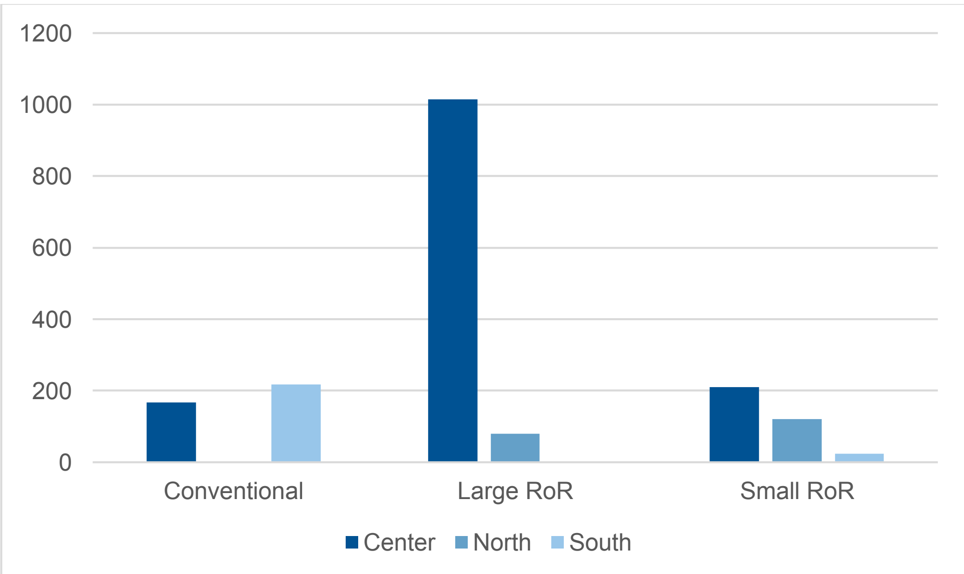

Figure 18 Maximum hydro volumetric flow per region and type of plant [m³/s]

Table 16 Monthly hydro capacity factors

	Conventional		Large RoR		Small RoR		
	Center	**South**	**Center**	**North**	**Center**	**North**	**South**
Jan – 19	0,83	0,87	0,69	0,60	0,68	0,70	0,82
Feb – 19	0,80	0,87	0,82	0,73	0,64	1,00	0,83
Mar – 19	0,82	0,90	0,74	0,74	0,67	1,00	1,00
Apr – 19	0,88	0,85	0,85	0,87	0,74	1,00	1,00
May – 19	0,76	0,80	0,71	0,74	0,68	1,00	1,00
Jun – 19	0,54	0,72	0,54	0,41	0,55	1,00	0,94
Jul – 19	0,53	0,67	0,52	0,28	0,49	0,65	0,82
Aug – 19	0,52	0,64	0,47	0,19	0,43	0,59	0,75
Sept – 19	0,54	0,63	0,46	0,19	0,42	0,62	0,72
Oct – 19	0,58	0,71	0,53	0,39	0,48	0,74	0,54
Nov – 19	0,74	0,86	0,65	0,70	0,62	0,94	0,99
Dec – 19	0,86	0,85	0,81	0,92	0,74	0,82	1,00

The monthly capacity factors of the locations without operating plants of a certain technology are estimated as the mean of the capacity factors of the region. For the East, since there are no hydro plants at the moment, the mean of the plants in the North is considered.

Finally, to obtain the hourly capacity factors, the following model is used for the conversion [43] [44].

Equation 1

$$\boldsymbol{X_{t+1} = \mu_x + \rho\ (X_t - \mu_x) + \sigma_x(1 - \rho^2)^{1/2}\varphi}$$

In which:

X_{t+1}: calculated hourly capacity factor.

μ_x: mean of the monthly capacity factors for each region and technology.

ρ: correlation factor taking the value of 0,45.

X_t: previous hourly capacity factor. For the first hour the monthly mean "μ_x" is considered.

σ_x: standard deviation of the monthly capacity factors.

φ: random noise.

3.7.2. Photovoltaics and wind

The capacity factors for PV and wind are obtained with data from the software pyGRETA, which provides four time series for each region, depending on the quality of the location [45].

- Percentile 90 (Q90): excellent location, 90% of the locations are worse (top 10%).
- Percentile 60 (Q60): good location, 60% of the locations are worse.
- Percentile 50 (Q50): average location, 50% of the locations are worse.
- Percentile 20 (Q20): bad location, 20% of the locations are worse.

In addition to this, an optimal location percentile will be added (Q95) for wind in the north and south, since otherwise the coastal areas with maximum generation potential would be underestimated. Currently all the wind generation plants are in these regions, shown in the Figure 19. This percentile is calculated to englobe the current generation plants located in these areas.

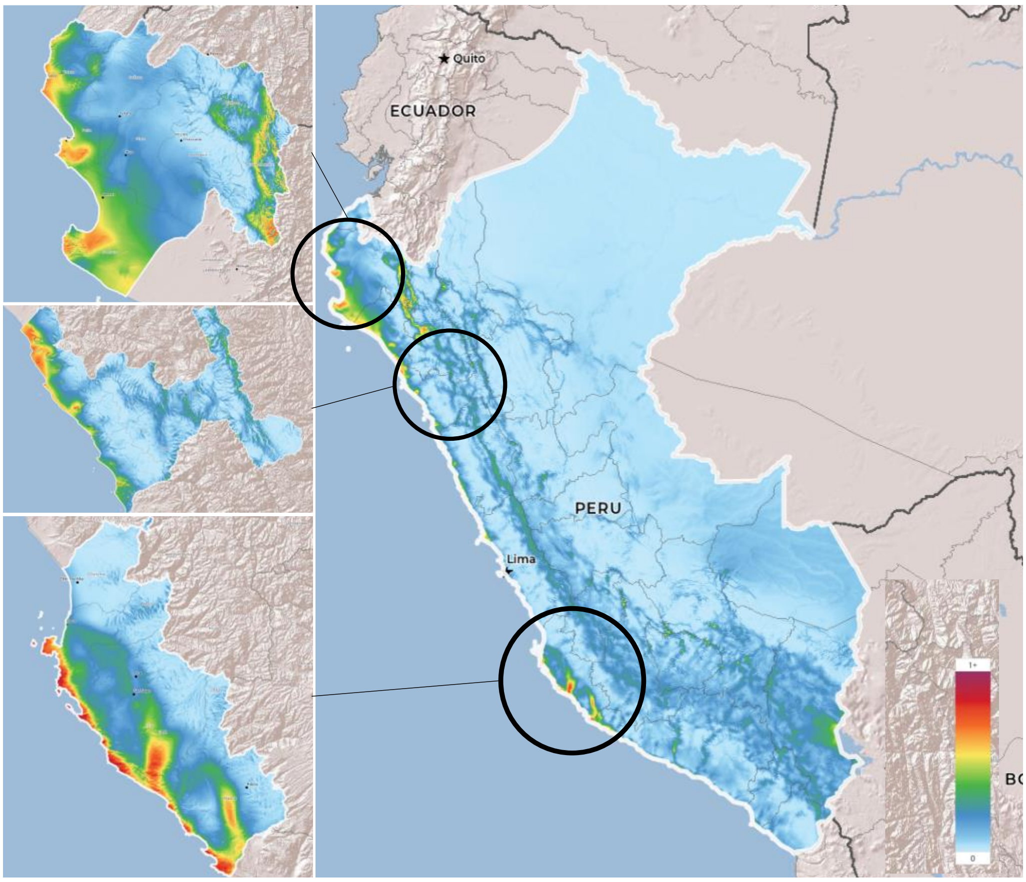

Figure 19 Wind capacity factors distribution, Global wind atlas [46]

For calculating the 95th percentile capacity factors, first, wind speed temporal data for regions hosting wind plants at present time is collected [46].

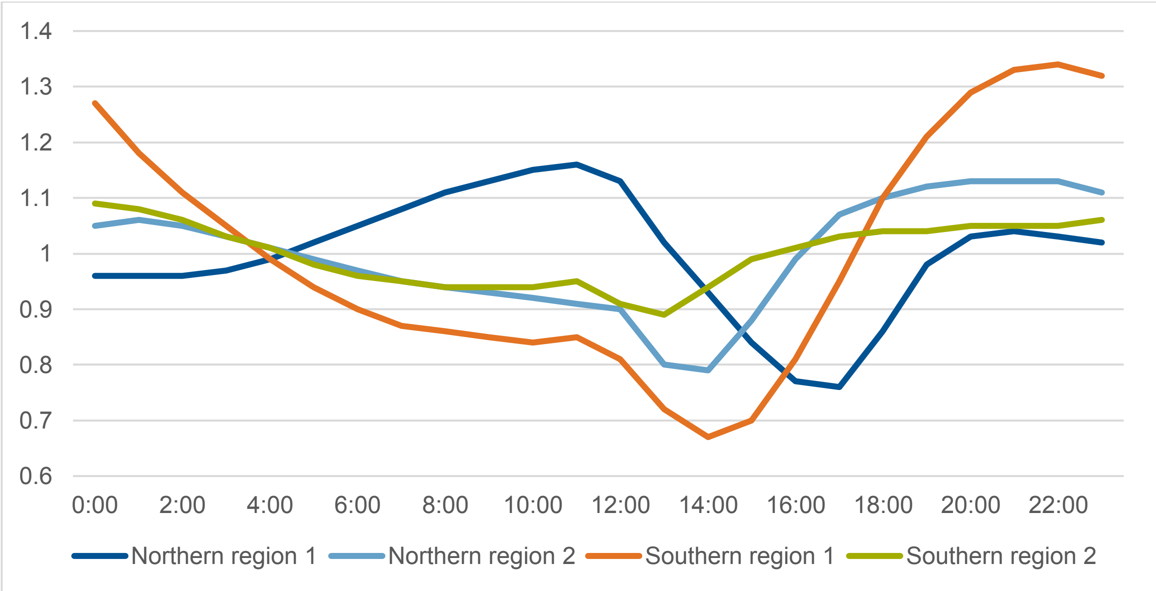

Figure 20 Normalised, hourly average wind speed in a day

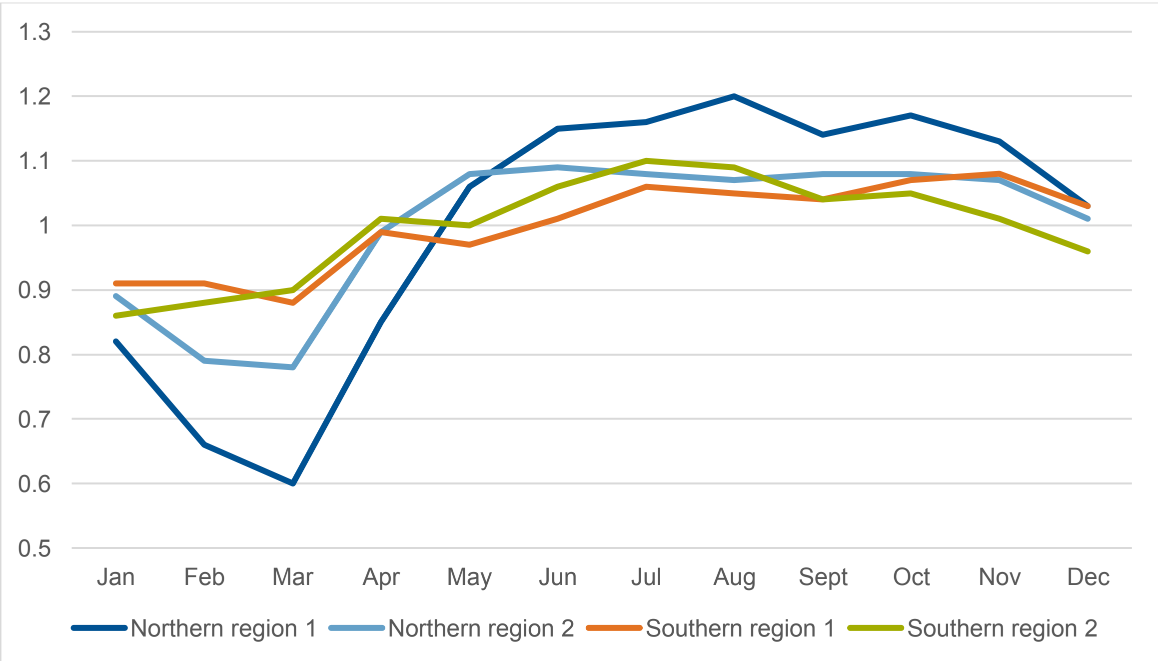

Figure 21 Normalised monthly average wind speed in a year

With these data, the hourly values for an average day for each month is calculated. Next, the complete hourly wind speeds in a year are obtained in a similar way as for 3.7.1.

$$X_t = \mathbf{A_t} + \sigma_x \, (1 - \rho^2)^{1/2} \varphi$$

In which:

X_t: calculated hourly wind speed.

A_t: hourly wind speed for an average day for each month.

ρ: correlation factor, taking the value of 0,45.

σ_x: standard deviation of the maximum wind speeds per day in a year [47].

φ: random noise.

Finally, once the wind speed time series is obtained, the capacity factors are calculated with the simplified wind speed to CFs conversion of wind generators, shown in Figure 22.

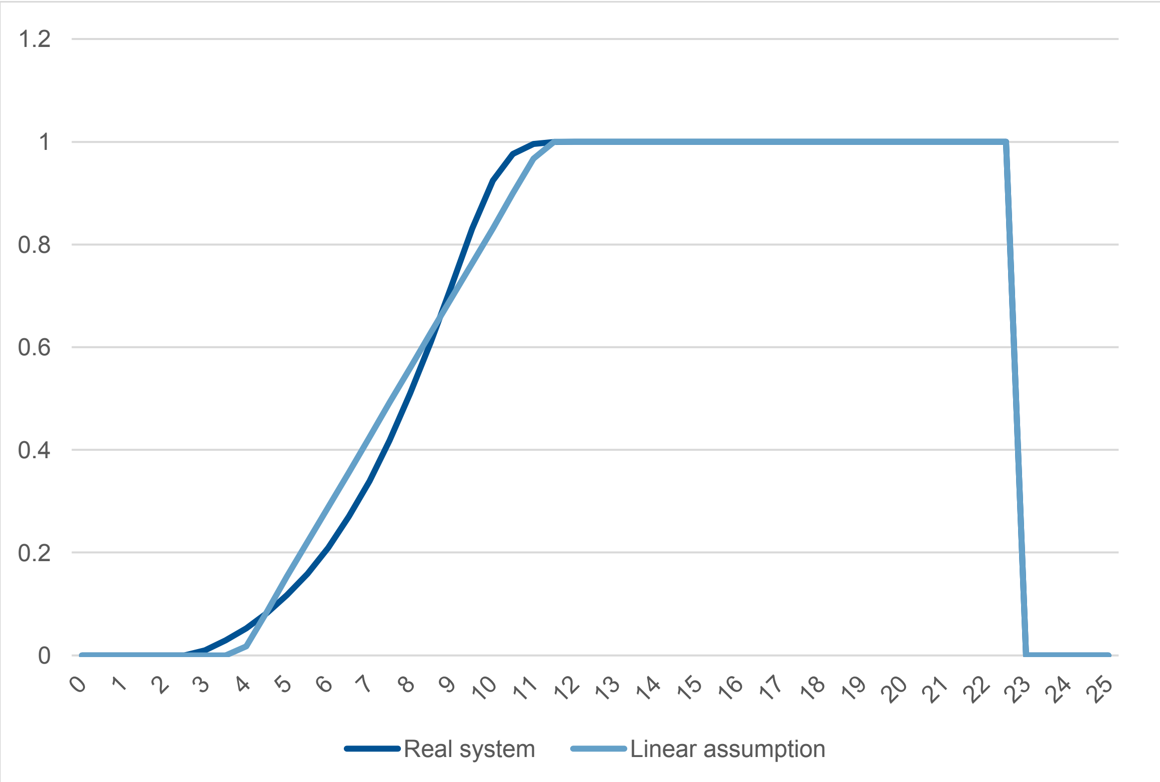

Figure 22 Wind Capacity factors / Velocity [m/s]

For winds stronger than 22,5 m/s a break is activated to avoid damage to the infrastructure. Hence, the capacity factor is null.

The optimal location percentile will not be necessary for PV generation, as the areas with maximum CFs are broader [48].

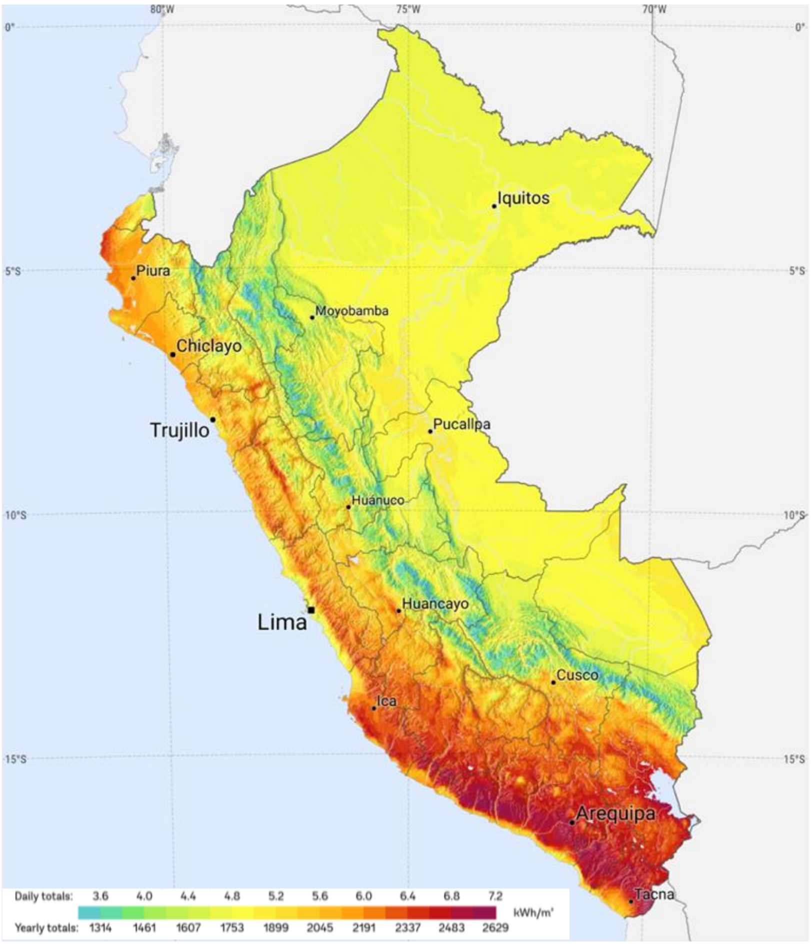

Figure 23 Solar horizontal irradiation, Global solar atlas [48]

3.8. Installation costs forecast

New technologies such as PV, wind or utility scale batteries have the potential of experiencing a significant reduction in their costs in coming years, because of research advancements. Particularly significant is the prospect for PV, expected to reduce their installation costs to a third of their current price by the end of the modelling period [17] [18] [32].

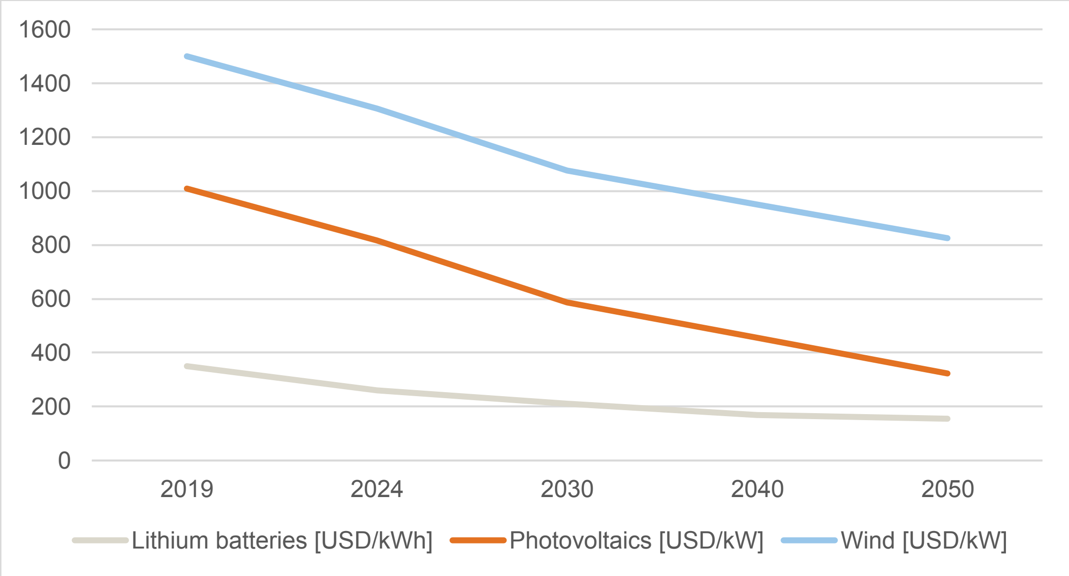

Figure 24 New technologies installation cost forecast

3.9. Natural gas availability

Joules are used when discussing resources availability to differentiate between useful energy, measured in Wh, and embedded energy (J). Depending on the application, different efficiencies for this conversion are expected. For instance, for the electricity generation, the efficiency of 64% displayed in Table 14 is considered.

Peru has close to 12 EJ of proven natural gas reserves, around 0,22 % of the total reserves found in the world [49] [50]. With the current consumption of 0,75 EJ per year from all sectors, these would last for around 16 years.

From the total natural gas consumption experienced in the year 2020, just a 19% is directed into electricity generation. Considering this share as the only available for electricity generation, the reserves for our study are diminished to 2 EJ.

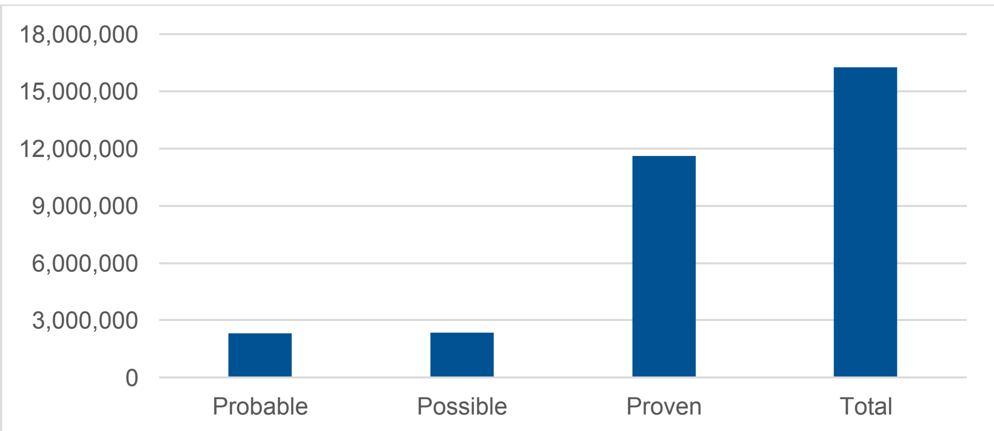

Figure 25 Natural gas reserves of Peru [TJ] [49]

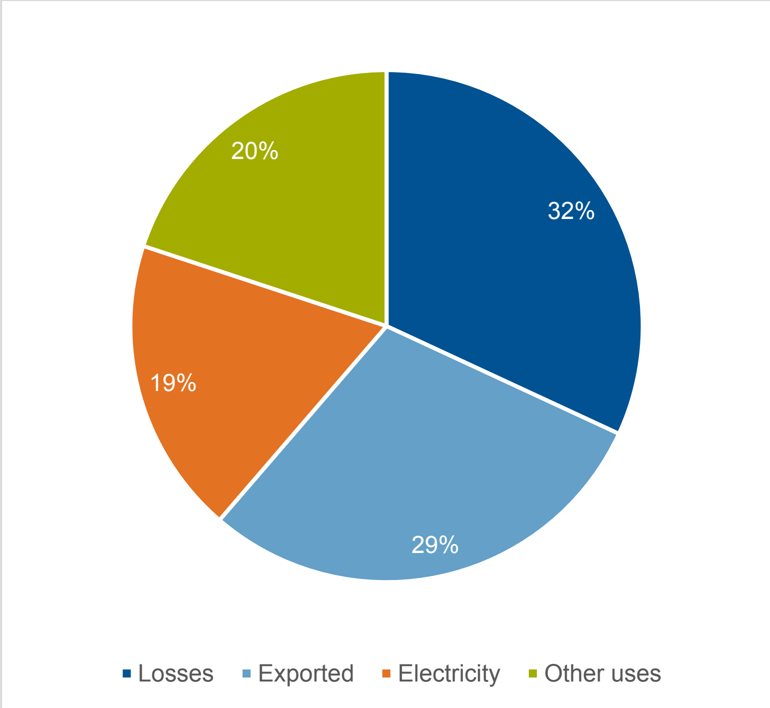

Figure 26 Peruvian natural gas consumption 2020 [49]

3.10. Renewable Energy Potentials

The generation of renewable energy resources is limited due to topographic, land-use, environmental and performance constraints [51]. Hence, the potentials studied in this section are set in urbs as upper bounds for the generation capacity, not to surpass the renewable capabilities of the country.

3.10.1. Biomass

Two types of biomasses are currently in use in Peru for energy generation: biogas and bagasse. Although both originate from organic waste from agricultural activities, biogas involves an additional anaerobic process by which microorganisms transform solid waste into a mixture of methane and carbon dioxide. The thermal plants using this mixture, also known as biogas, show higher efficiencies.

The total potential of biomass, without surpassing its' current land use of 19% [52], is between 450 and 900 MW. The mean, 675 MW, is selected for this study. More than half of the potential is located in the north [40].

This capacity is low compared with the potential of other RER such as wind or PV, but since it's a controllable renewable resource, it can play a regulatory role that would otherwise be taken by storage technologies.

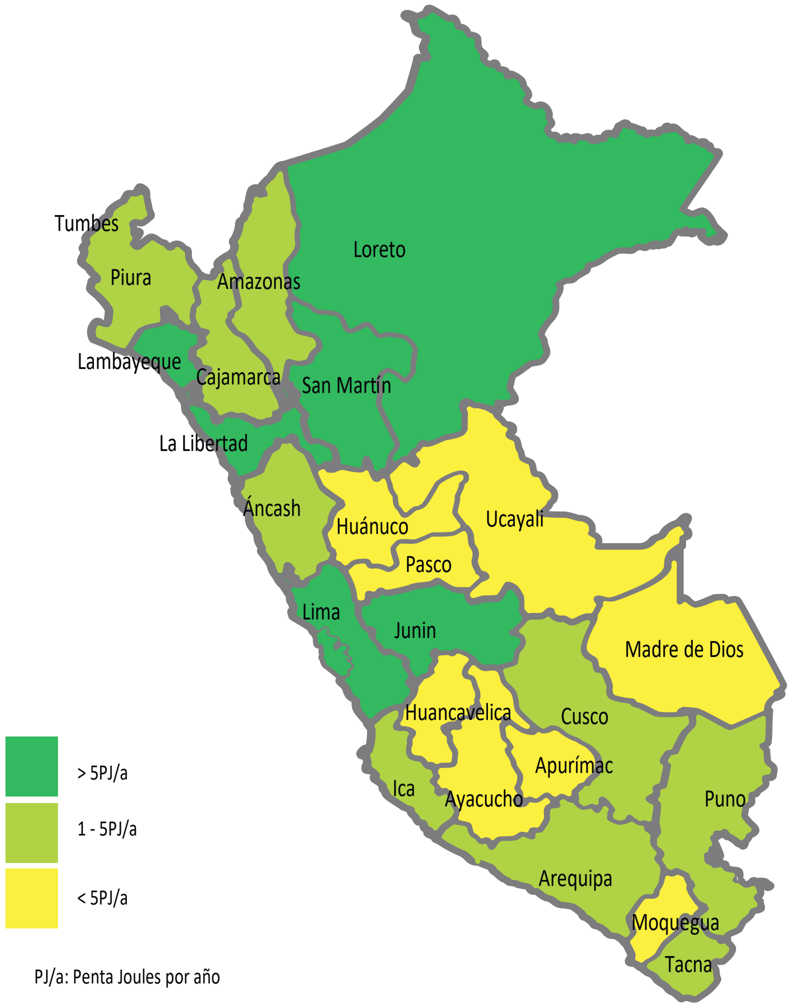

Figure 27 Regional allocation of biomass potential [PJ/year] [40]

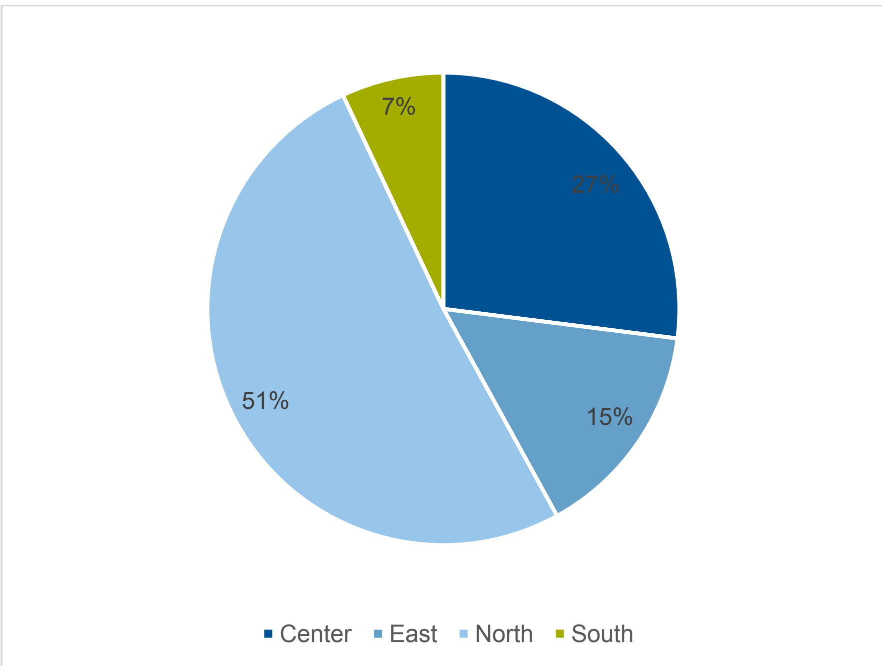

Figure 28 Regional distribution of biomass potential

3.10.2. Photovoltaics

There is significant deviation in the literature regarding the usable PV potential in Peru [40] [45]. In this study, the more conservative approach will be considered, which accounts for a total of of 25.000 MW [40]. To identify the distribution between regions the software pyGRETA is consulted, which ranks the south as the area with more exploitable PV resources [45], in accordance with the solar irradiation map of Peru, displayed in Figure 23.

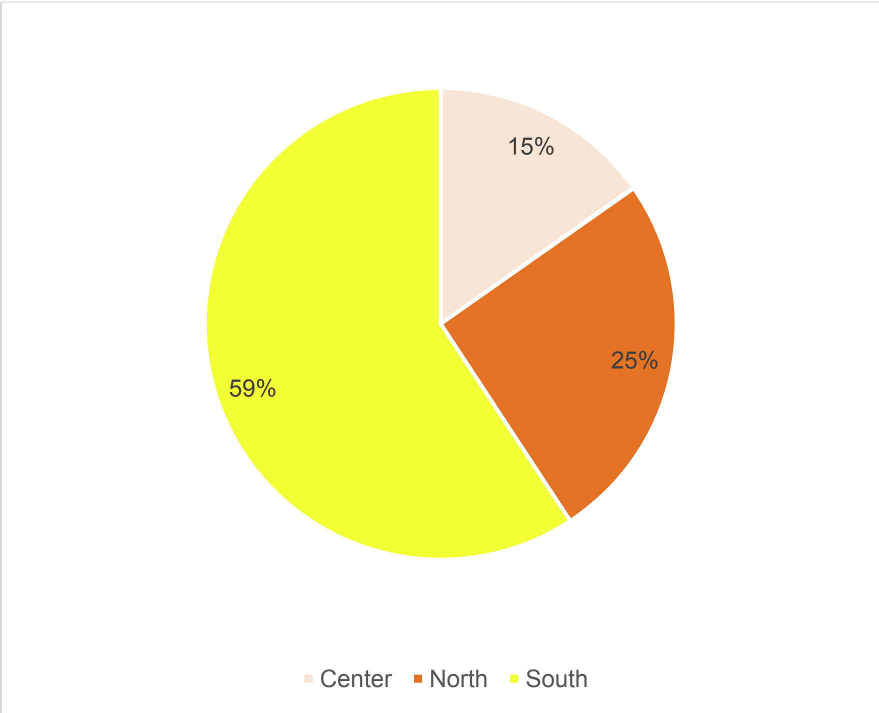

Figure 29 Solar potential regional distribution

The regional solar potential will be classified according to the pyGRETA percentiles specified in 3.7.2. This way, once the installed capacity of PV in the north surpasses the 10% of its total potential, for instance, the capacity factors used for new installations will change from best location (Q90) to good location (Q60). This classification implies that the potential is reduced to an 80% of the total, as locations worse than percentile Q20 are not considered.

3.10.3. Wind

The north is the region with the highest wind potential, with over 70% of the total. By contrast, the east has a null potential [40].

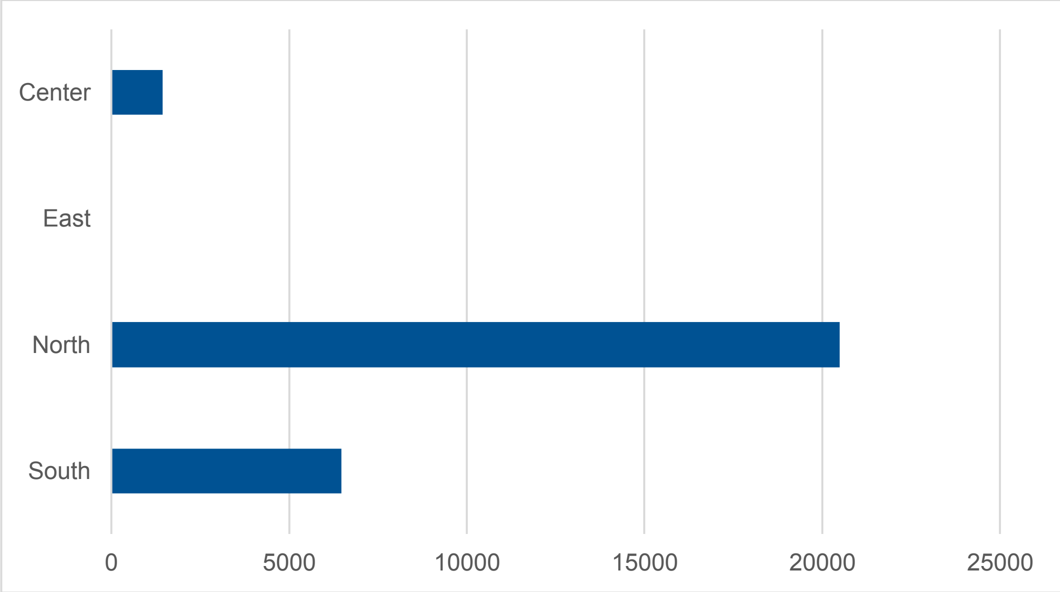

Figure 30 Regional total wind potential [MW]

The total capacity is considered instead of the exploitable one, as 20% of the listed potential is classified as non-exploitable, for their capacity factors are not listed by pyGRETA. Just as for PV, the regional wind potential will be classified according to this software quartiles [40] [45].

3.10.4. Geothermal

The potential of geothermal is rather limited in Peru, with 74% of its potential in the south. Nevertheless, similarly to biomass, the predictability characteristic of this source could provide a base load for the system [40].

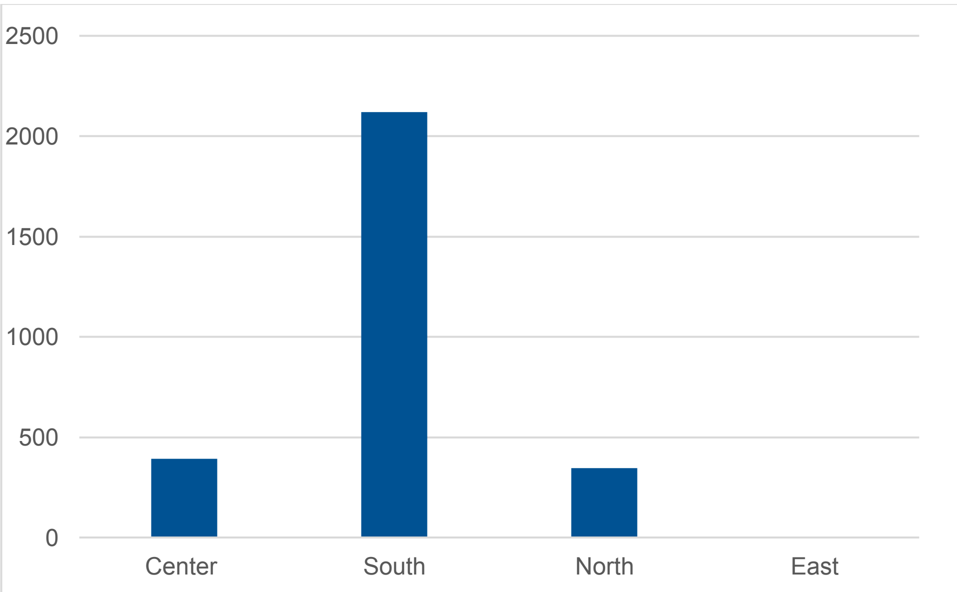

Figure 31 Regional geothermal potential [MW]

3.10.5. Hydro

Hydro plants in Peru have a potential of 70.000 MW, the largest of all technologies here listed. The hydrologic resources in the east account for more than 9.000 MW, of special relevance considering the scarcity of other renewables in the region [53].

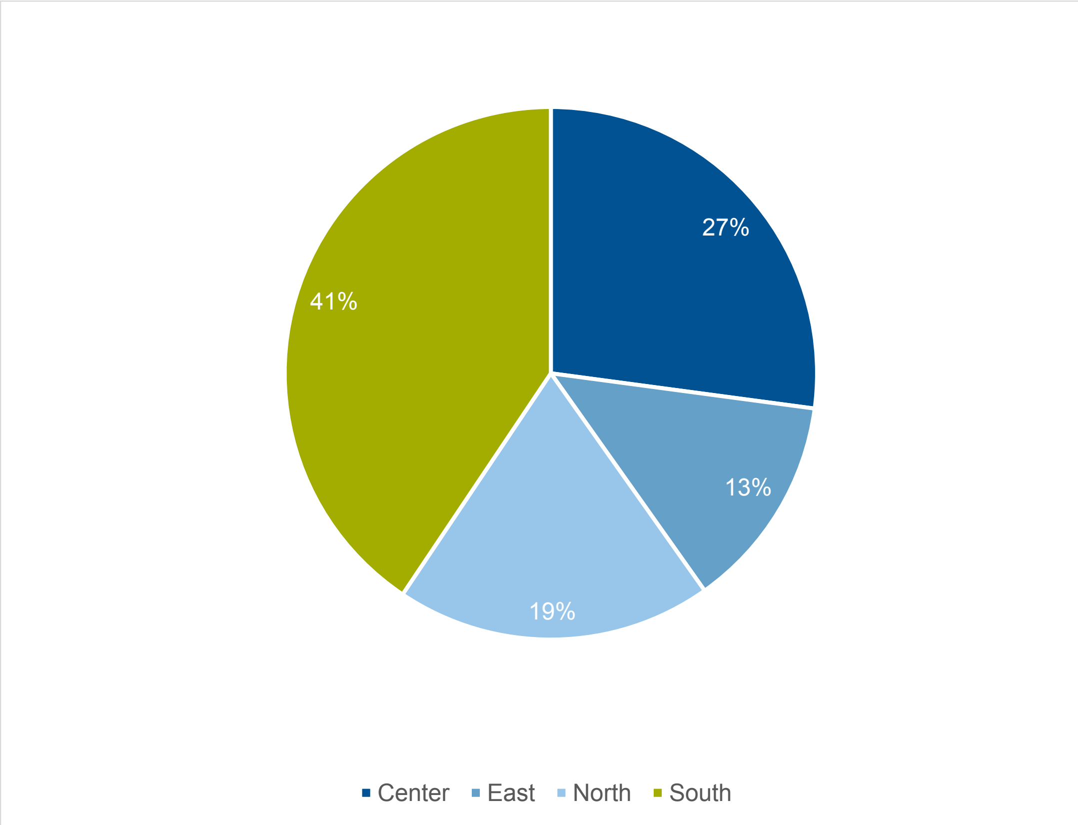

Figure 32 Hydro potential allocation

3.10.6. Potential overview

The total renewables potential accounts for 126 GW. The majority, 55%, comes from hydro installations. Nevertheless, there is a 42% of PV and wind potential, especially significant in the northern and southern regions. Biomass and geothermal account for less than 3% of the total potential.

Table 17 Renewables generation potential [MW]

	Center	East	North	South
Biomass plant	185	101	341	48
Geothermal	393	–	345	2.121
Small RoR plant	18.830	9.085	13.338	28.191
Photovoltaics	3.802	12	6.373	14.813
Wind Park	1.434	–	20.490	6.471

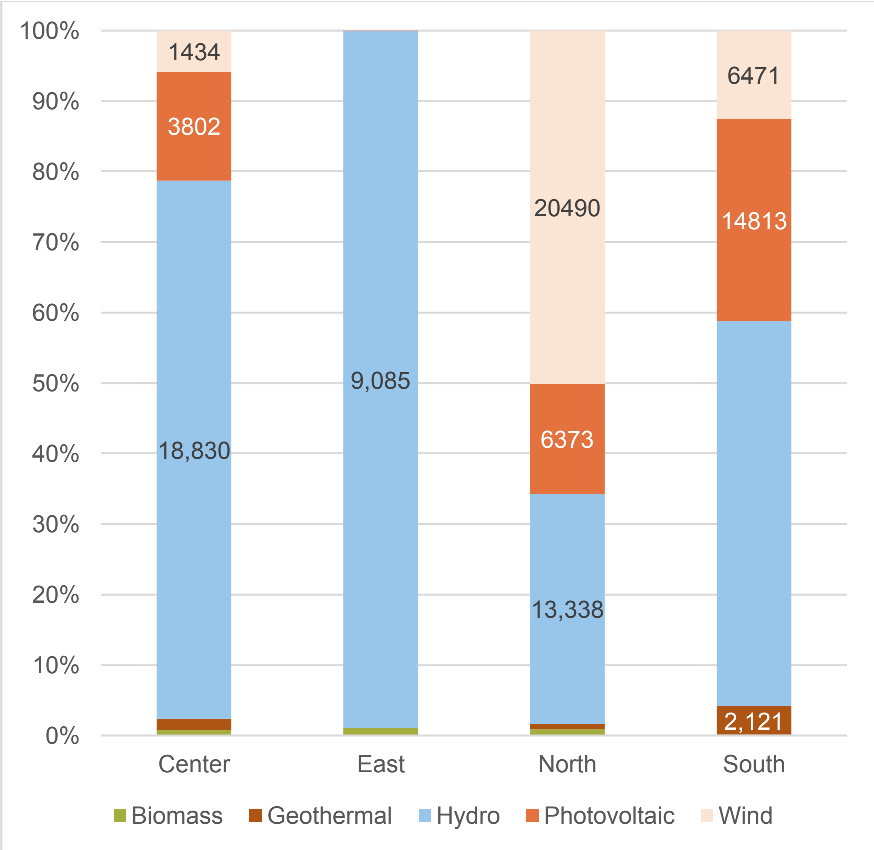

Figure 33 Regional RER potential [MW]

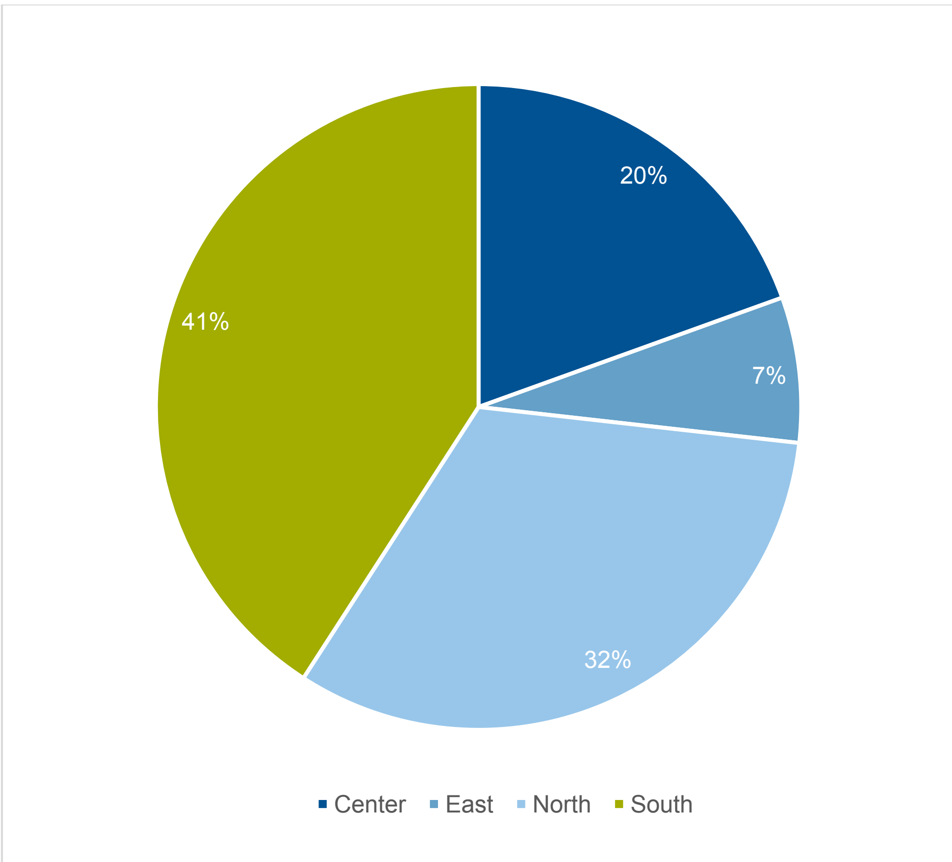

Figure 34 Total RER potential distribution

4. Results and Evaluation

4.1. Single year optimization

Once all the inputs are added into urbs, an optimization of the year 2019 is performed to validate the model. The results obtained are compared with those of the previous Peruvian model by Tubella Boada C. [5] and with experimental data from COES [24].

Table 18 Single year energy generation by source [GWh]

	Own model	Previous model	Real system
Hydro	**30.830**	**30.169**	**30.168**
Renewable	3.026	N/D	1.845
Non-renewable	27.804	N/D	28.323
Other renewables	**2.890**	**2.254**	**2.670**
Biomass plant	375	215	252
Photovoltaics	673	582	762
Wind Park	1.841	1.457	1.646
Fossil fuels	**19.176**	**20.470**	**20.061**
Coal plant	–	135	36
Diesel plant	869	999	74
Gas plant	18.308	19.336	19.951
Total	**52.897**	**52.892**	**52.889**

4.1.1. Observations

The experimental and previous model present almost identical results regarding hydro, since the monthly generation from the experimental results were used as inputs for calculating the capacity factors. On the other hand, in the developed model the water flows circulating through the different plants were used for this purpose, as explained in 3.7.1, explaining the slight discrepancy when comparing the non-renewable production.

Additionally, the renewable production is significantly higher for the own model. This is because some small RoR plants were not listed in the experimental case, as they don't belong to the COES.

The model produces around 9% more than the experimental case. Biomass is generating more in the model because the capacity factor of 70% considered is not obtained from regional but from general values. Solar produces less because of the areas hosting the generation plants being in a better percentile than the 10% considered by pyGRETA. Finally, wind has a greater production due to greater wind variations than considered in the model, in which the average CFs were considered, although noise was added as function of the maximum wind deviation.

Finally, in the own model there is no coal production because of the increment of wind generation from the south. This allows the coal plant, working as peak plant in the system, to remain shut down. The increase in diesel production is a consequence of the experimental case not considering data for the East, greatest diesel consumer, as this region is not a part of the interconnected system.

4.1.2. Key performance indicators

The east and center are self sufficient, meaning that they only depend on their own generation. Meanwhile, northern and southern regions rely heavily on imports from the center to operate. These imports are the cause of the 1% deficit between demand and production, consequence of interregional transmission losses.

Table 19 Regional self sufficiency

	Center	East	North	South
Production [GWh]	42.700	869	2.444	6.885
Demand [GWh]	27.746	869	6.779	16.627
Self sufficiency [%]	100	100	36	41

The grid mixes vary to a large extent depending on the regions. While south and north have no direct fossil fuel consumption, in the center their share is more than 40%. Additionally, as the center is the only electricity exporter, its relevant portion of fossil fuels implies that both north and south rely indirectly on fossil fuels.

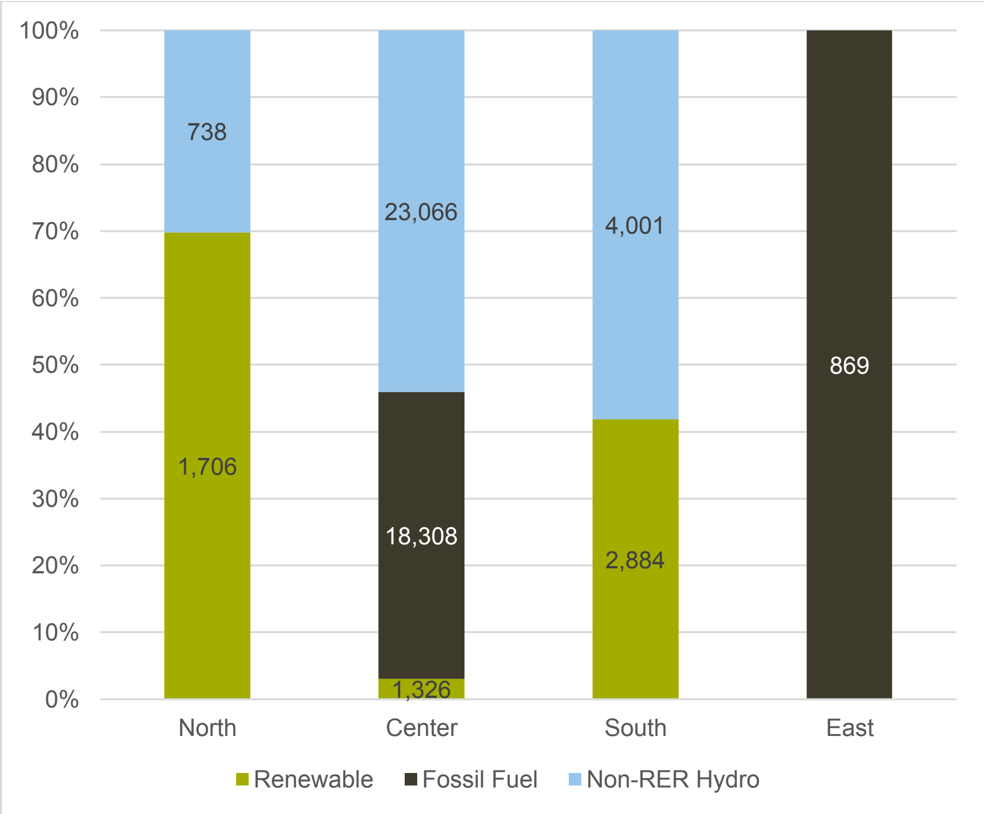

Figure 35 Regional production [GWh]

The technology with the lowest LCOE is the conventional hydro plant, while the highest cost is associated with natural gas electricity production. Nonetheless, this metric does not consider the value of the energy provided, higher for gas or biomass plants due to their flexible production. Additionally, the natural gas plant fleet is operating at 49% of its capacity compared with the 100% CF of biomass. This indicates an over dimension which inflates the fossil fuel costs. In the intertemporal analysis discussed below, with optimal dimensioning, the system has preference for natural gas over the green alternative.

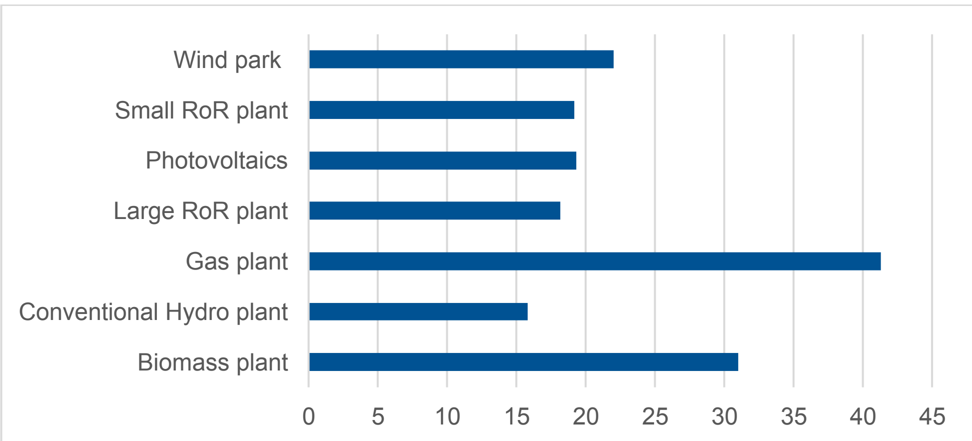

Figure 36 Levelized cost of energy [USD/MWh]

For this analysis, coal and diesel production were excluded due to their roles as peak plants in the system.

4.2. Intertemporal

4.2.1. Base case

The demand increase in the system is met by installing wind, hydro, PV and natural gas plants. During the first three modelled years, the installed power stagnates in the center while it increases significantly in the south and east through hydro, and moderately in the north, through wind energy mainly. From 2040 onwards, PV experiences a steep growth, especially remarkable in southern and central regions. In this same period, hydro capacity increments in north and south, through small and large RoR respectively. The center maintains an important natural gas share throughout the model, while the share in the east is dominated by investment in large RoR plants.

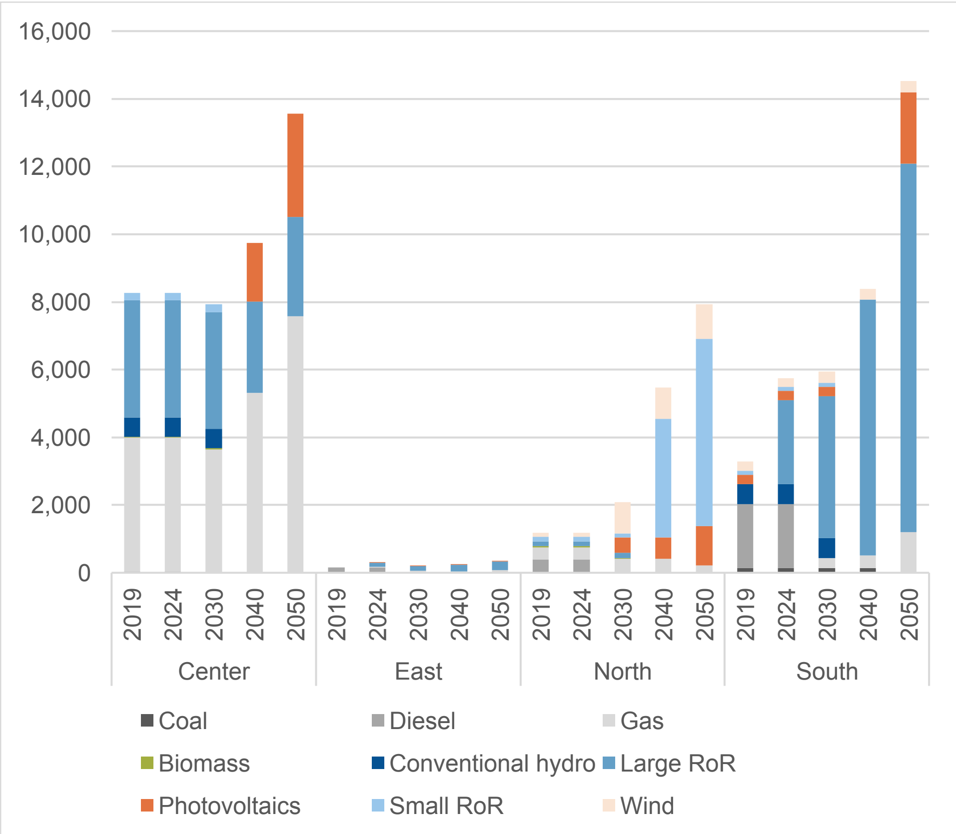

Figure 37 Regional installed capacity [MW]. Base scenario

Natural gas, assuming a linear progression between the modelled years, generates 780 TWh of electricity within the 31-year time frame. That implies a total consumption of 2,8 EJ of the fossil fuel. This quantity could be met with the proven reserves of the country, but the total share invested into electricity would need to increase from the current 19%, displayed in Figure 26, to a 24%, by reducing exports correspondingly.

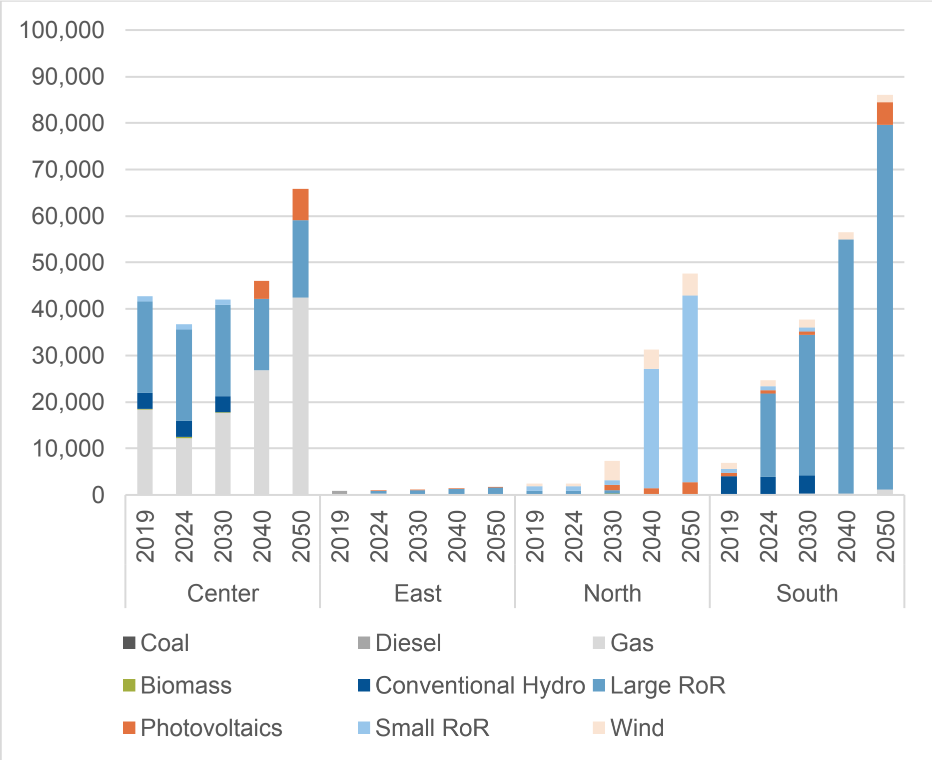

Figure 38 Regional generation [GWh]. Base scenario

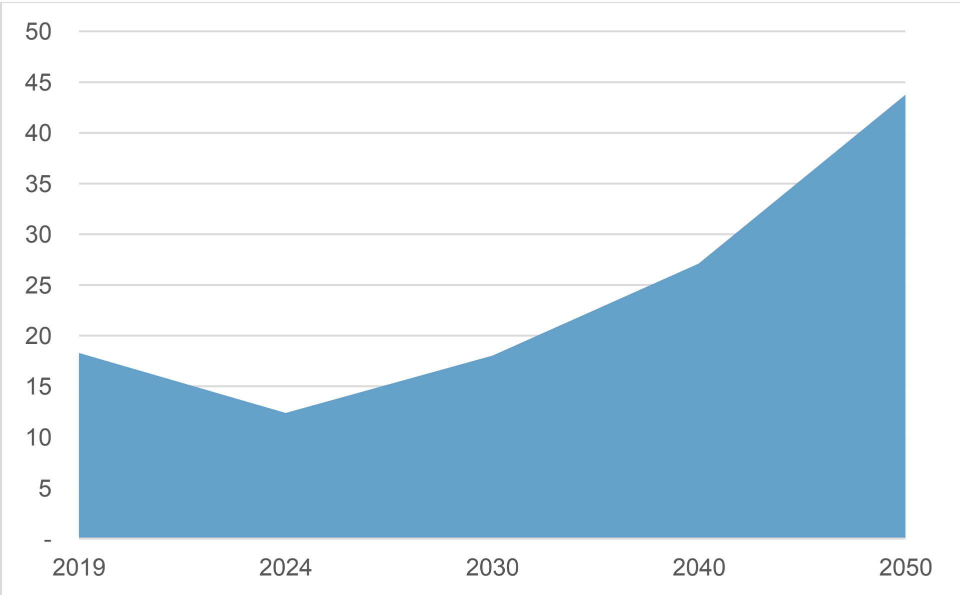

Figure 39 Natural gas generation [TWh]. Base scenario

The energy stored in the reservoirs behaves similarly in center and south, increasing its capacity until April and decreasing during the months when river flows are lower.

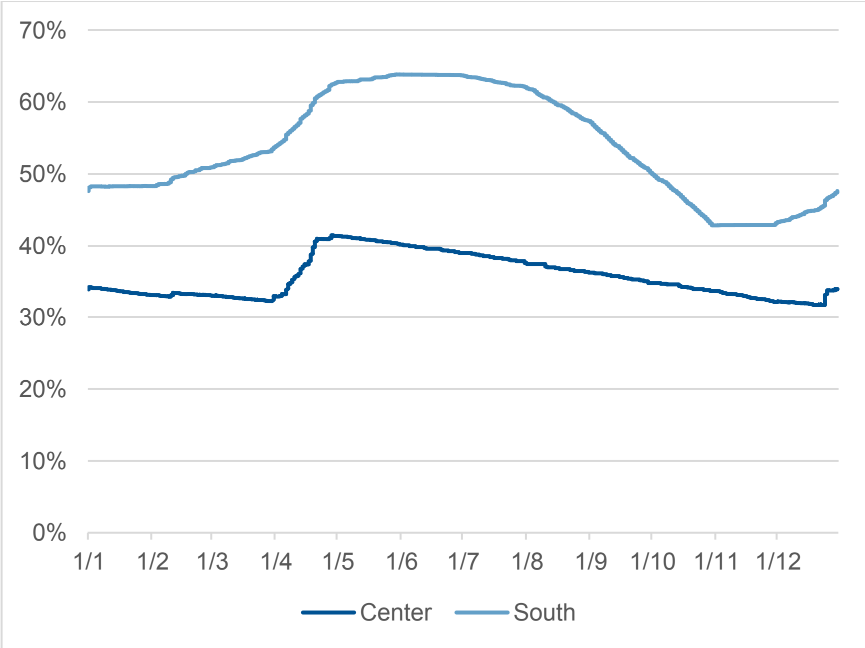

Figure 40 Storage capacity 2024

4.2.2. Electric system. Scenarios 1 – 4

The main difference in scenario 2 with respect to the base case is the preference of photovoltaic technology over hydro. This shift makes it necessary to have a more flexible generation fleet to cover demand during night-time, when solar production is limited. Because of this, the scenario doesn't have a positive effect when it comes to decarbonization, as the installed natural gas is larger than in the reference. Although wind has lower prices in "renewables cheap", its capacity doesn't vary. This is because the optimal locations are fully exploited in both cases.

Scenario 3 requires less installed natural gas plants than scenario 1. These are substituted in the system by hydro technology and biomass. The latter receives relevant investment from 2030 onwards, reaching its maximum potential for the last two modelled years.

The only scenario in which the capacity of natural gas doesn't increase with the growing demand is the scenario 4, in which the CO_2 emitted is limited. To compensate for the decreasing fossil fuel capacity, the system expands towards hydro, through small and large RoR. Additionally, in a similar way to scenario 3, the biomass reaches its maximum potential in the last 20 years. This scenario presents a significantly higher total capacity than all the others, consequence of the reliance on renewables, which cannot function at full capacity on demand.

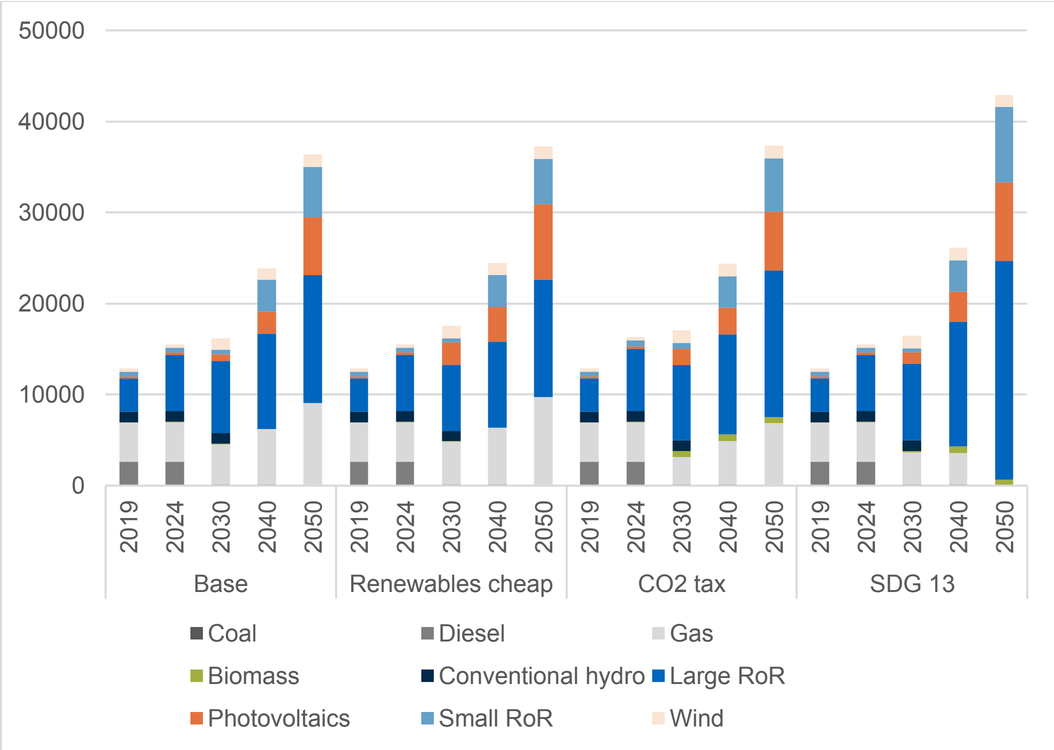

Figure 41 Total installed capacity [MW] Scenarios 1 – 4

The increase of demand experienced in 2024 is met thanks to a relevant hydro expansion in eastern and southern regions for all scenarios. Meanwhile, the capacity of the center stagnates during the first three modelled years, increasing in the last two decades specially through photovoltaic plants. This technology reaches its full potential in the region in 2050 for all scenarios. Additionally, scenario 4 in the central area presents the lowest capacity, despite showing the largest global one. This is because, in all other scenarios, the center regulates the system through fossil fuel generation capacity instead of energy storage, because of low natural gas prices.

The east depends on natural gas reserves for scenarios 1 and 2. This is mainly consequence of the limited renewable potential, as it has no quality wind locations and a scarce PV capacity. These circumstances limit the versatility of the renewable fleet, composed mostly of hydro. In scenarios 3 and 4, nevertheless, most of the gas plants are substituted by biomass generation.

In a similar way to the center, the east displays a decreasing capacity in scenario 4. This is because, to regulate the system, instead of natural gas, the transmission with the north increments, in such a way that hydro generation is completely cut off the last year of the model.

Northern and southern areas are composed mostly of renewable technologies in all scenarios. Especially successful is the renewables integration in the north, where, already in the year 2050 of scenario 3, natural gas can't be found in the region. The reason for this is the diverse renewable fleet available, which has relevant wind and biomass reserves in contrast with the south, area with the highest overall renewable potential, but lead solely by PV and hydro.

Both zones show an increase in the generation capacity for scenario 4, same behaviour as that observed in the general comparison. This increment is particularly relevant in the north, as the expansion in transmission capacity raises the east's dependence on northern generation.

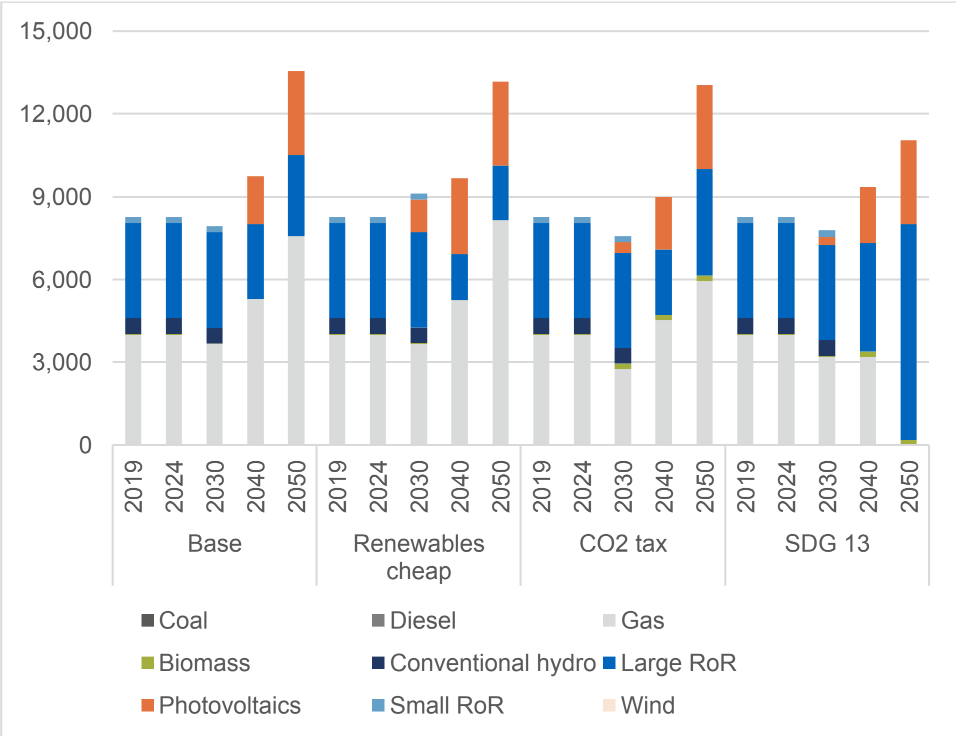

Figure 42 Center installed capacity [MW]. Scenarios 1 – 4

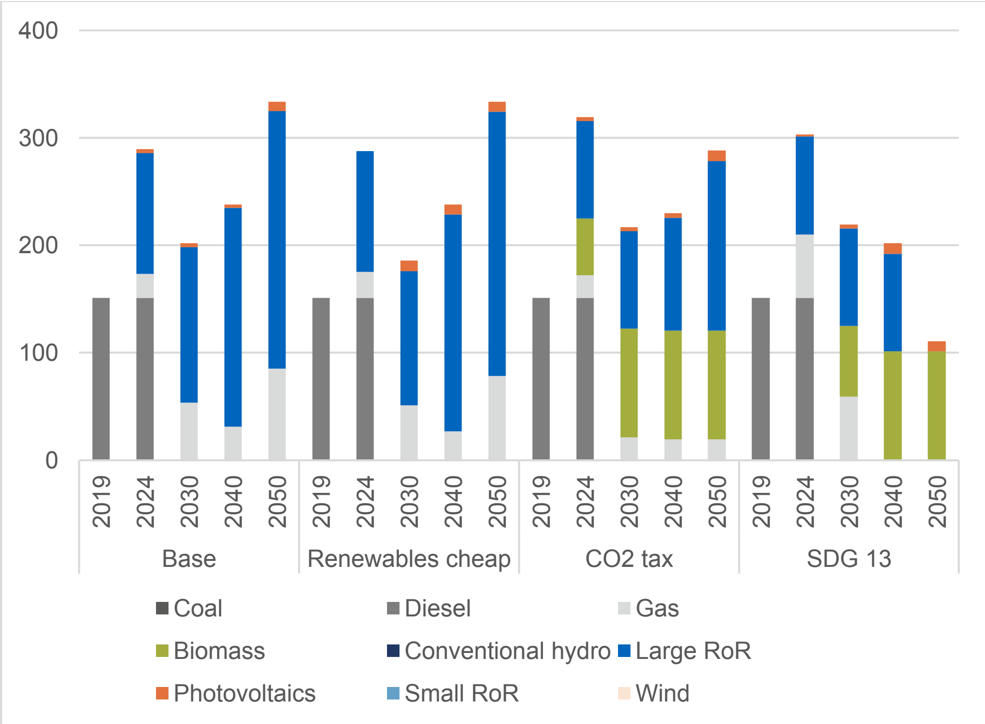

Figure 43 East installed capacity [MW]. Scenarios 1 – 4

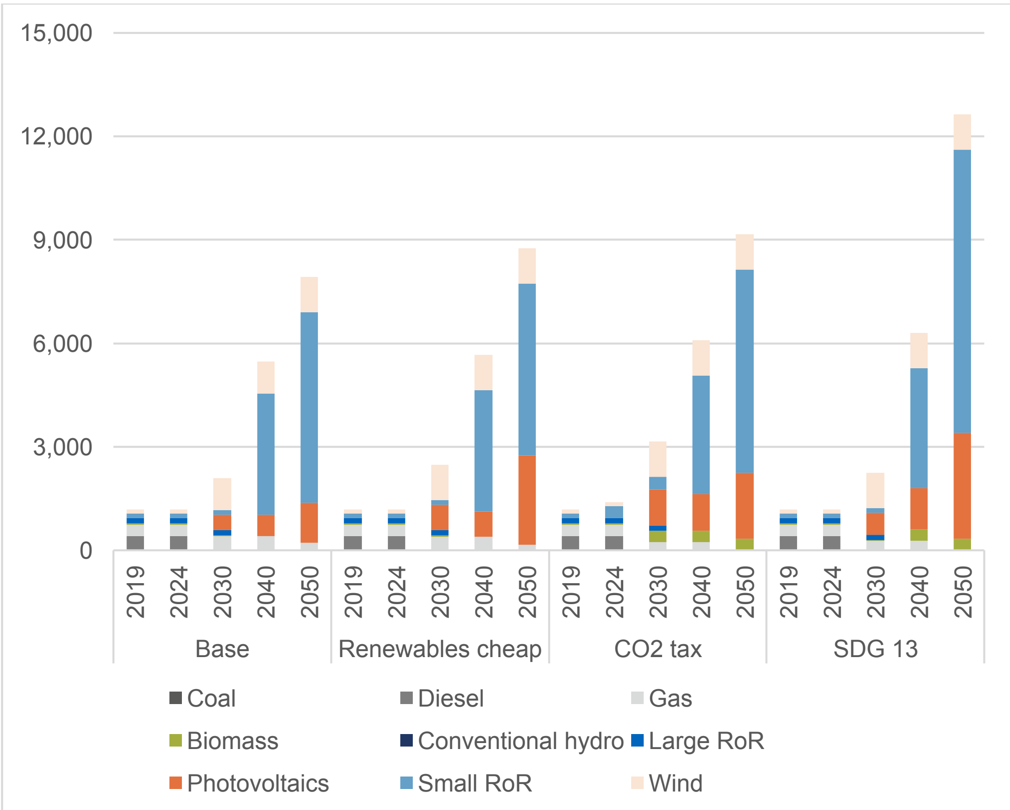

Figure 44 North installed capacity [MW]. Scenarios 1 – 4

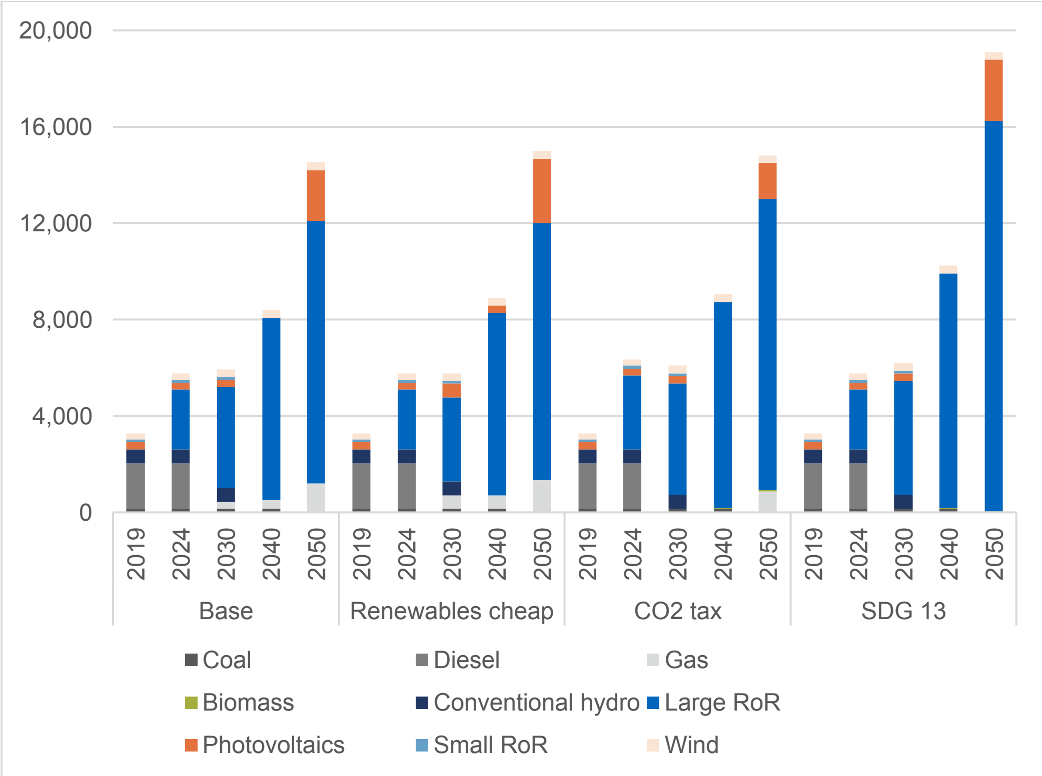

Figure 45 South installed capacity [MW]. Scenarios 1 – 4

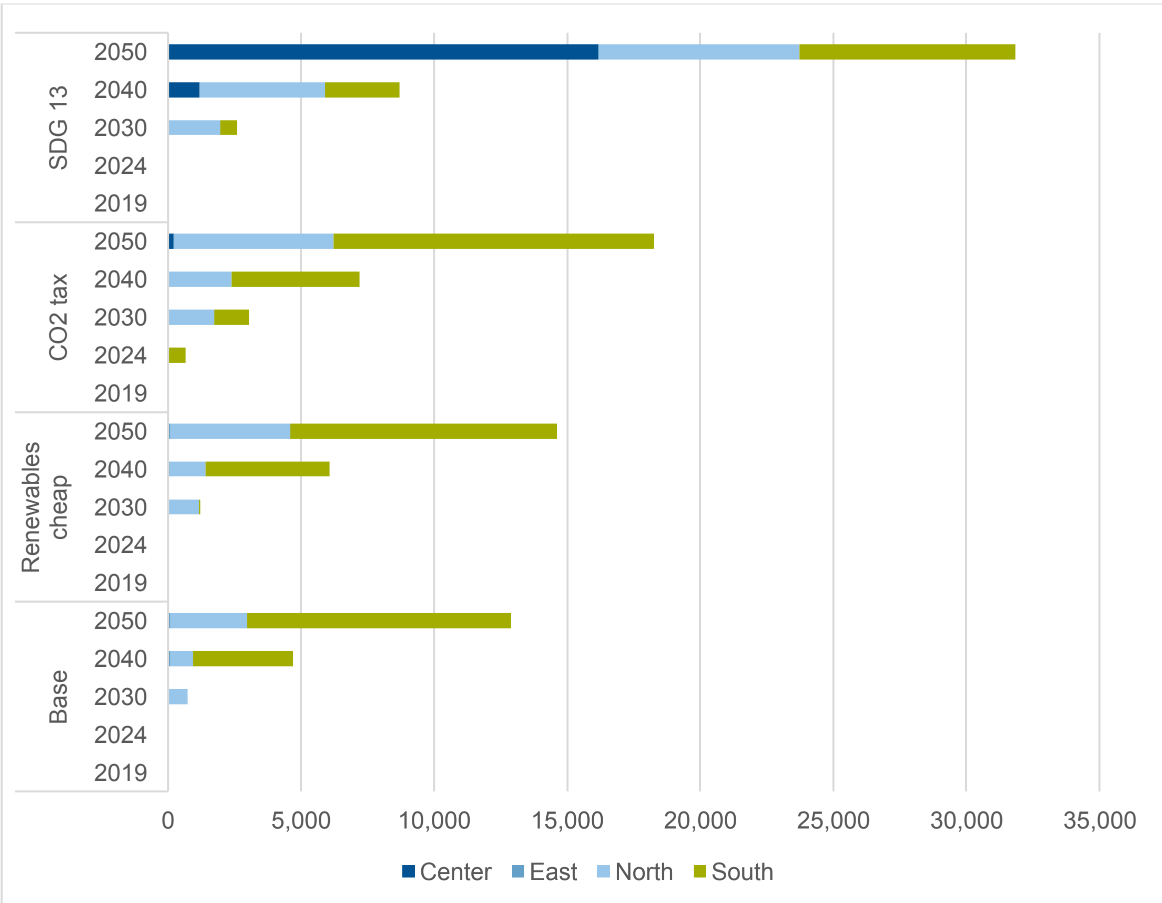

Figure 46 Lithium-ion storage capacity [MWh]. Scenarios 1 – 4

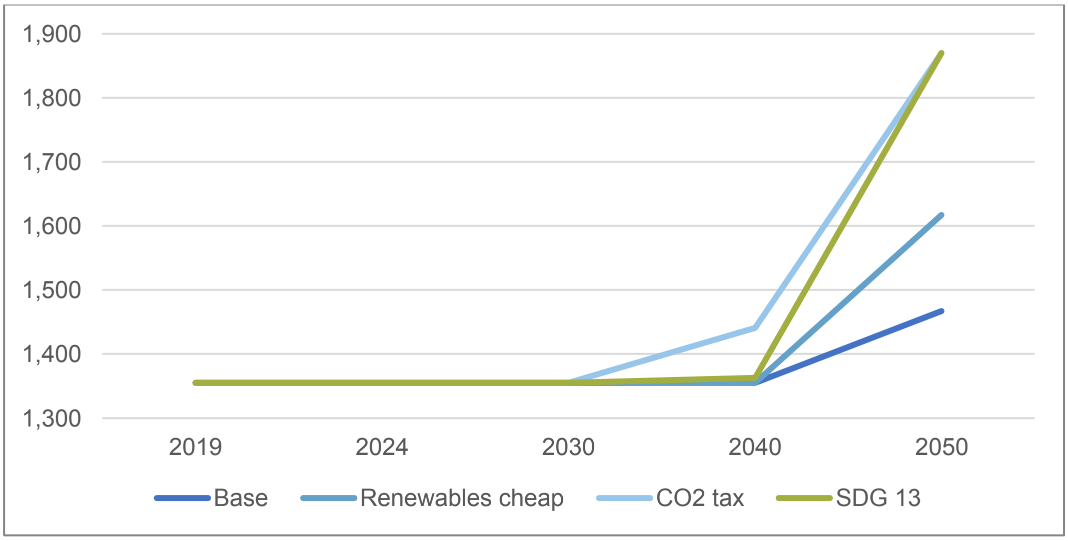

Figure 47 Transmission Center – North [MW]

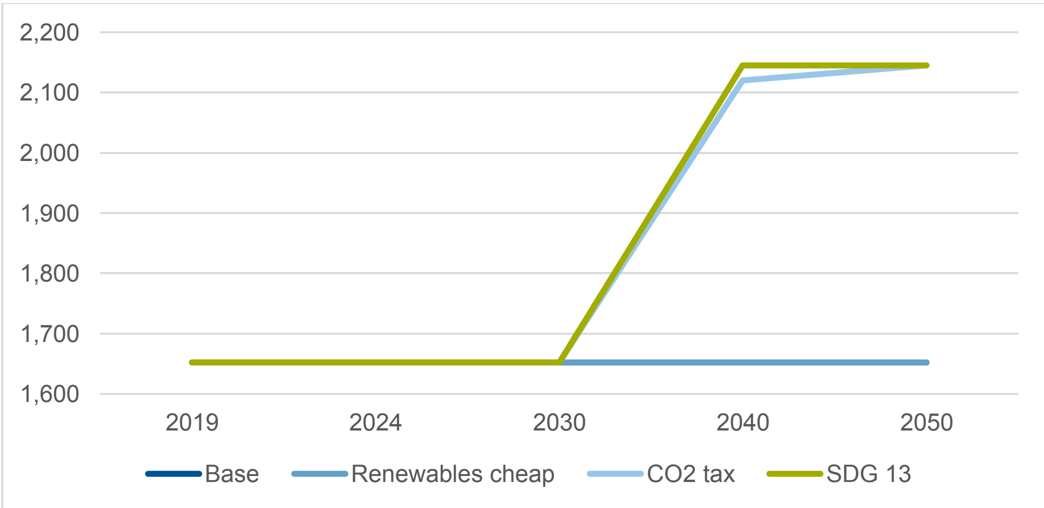

Figure 48 Transmission Center – South [MW]

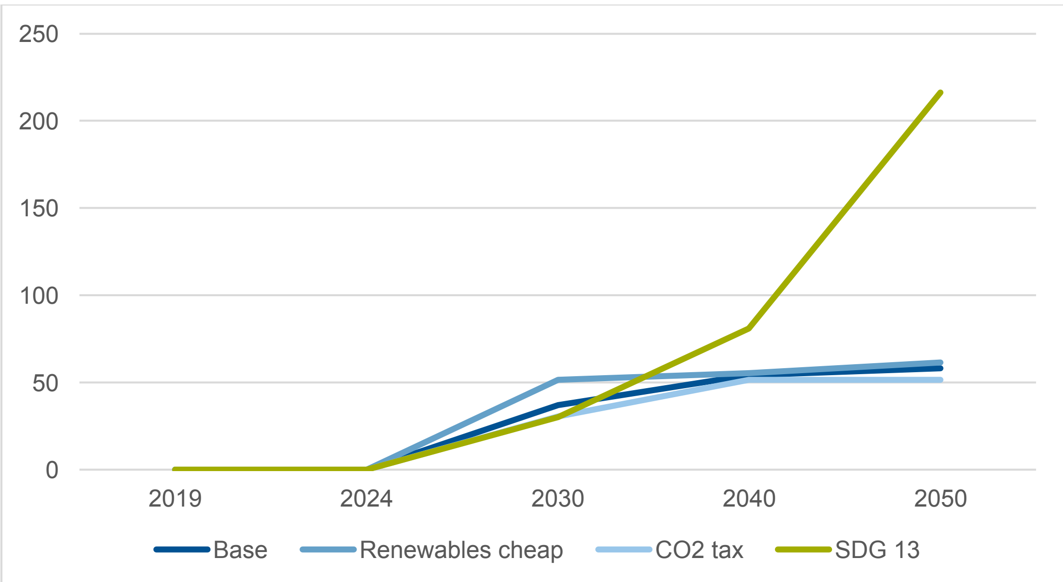

Figure 49 Transmission North – East [MW]

4.2.3. CO_2 emissions. Scenarios 1 – 4

A sudden drop in the CO_2 emissions is experienced by the system until the year 2024 for all scenarios. This is a consequence of the competitive prices of hydro, specially in eastern and southern areas. After this point, all scenarios but SDG 13 increase their emissions consistently. In terms of decarbonization, scenario 3 behaves best until the year 2030. For the last two modelled years, as expected, scenario 4 is preferred. The scenario renewables cheap, as noted previously, doesn't have a positive regarding this matter.

Figure 50 CO2 emitted [Tonnes]. Scenarios 1 – 4

4.2.4. Gas consumption. Scenarios 1 – 4

The total consumption of natural gas in scenario 2 surpasses the reserves planned for generation, just as happened for the base case, shrinking the percentage intended for export. In contrast, scenarios 3 and 4 allow for additional supply in gas trade. The amount of natural gas saved in scenario 4 with respect to the base case is of 1,74 EJ.

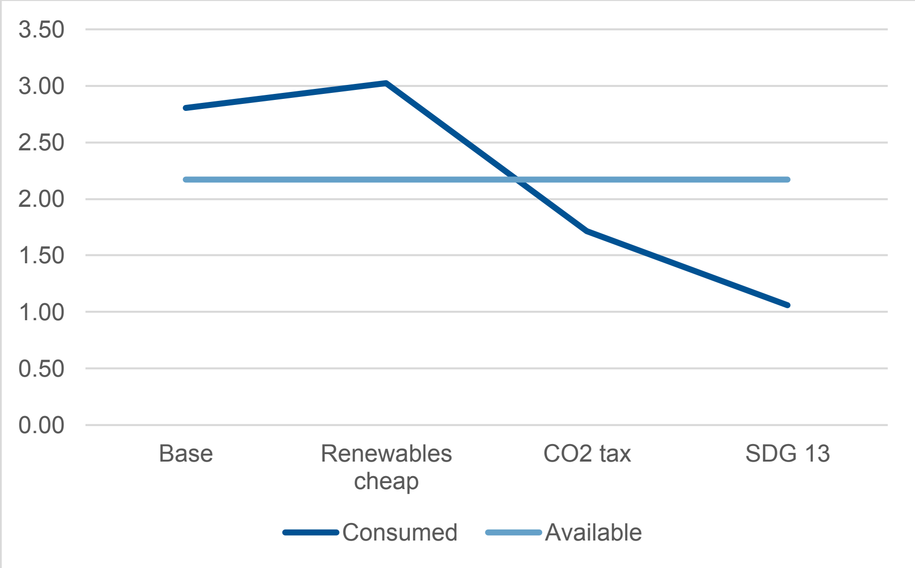

Figure 51 Natural gas consumed vs available [EJ]. Scenarios 1 – 4

4.2.5. Costs. Scenarios 1 – 4

The costs required to achieve a fully decarbonized system in 2050, scenario 4, are 85 billion USD, 20% higher than for the base case. However, the model does not consider the gained value that unconsumed natural gas reserves could provide if exported. For reference, considering the latest natural gas market price of 8 USD/MMBtu, the increase in exports could bring in 13 billion USD in gross revenue [54].

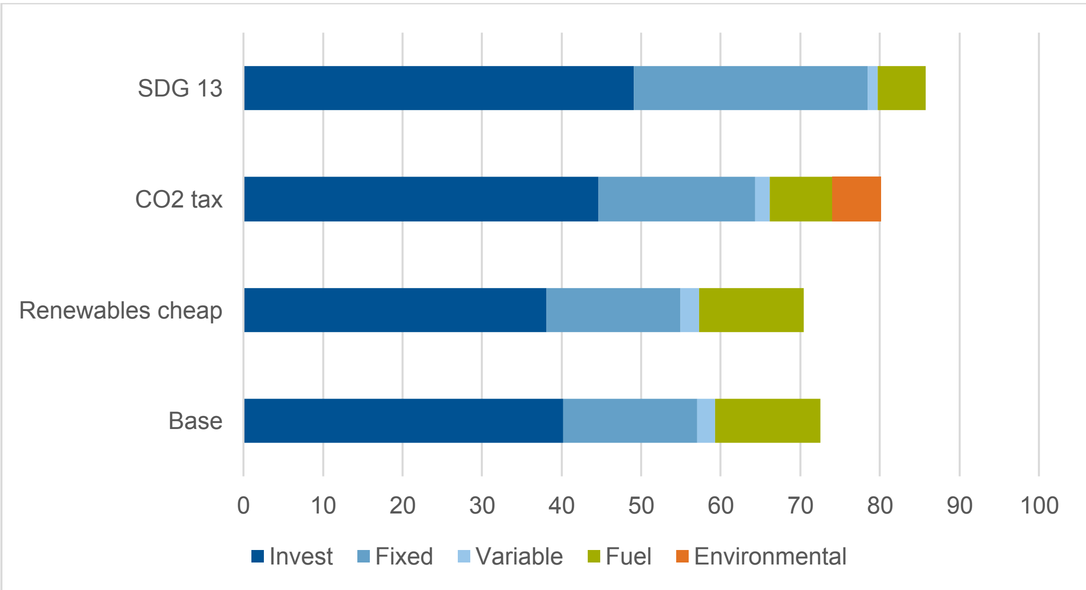

Figure 52 Costs [billion USD]. Scenarios 1 – 4

4.2.6. Scenarios 4 – 7

In this section, scenarios 5 – 7 are compared using scenario 4 or SDG 13 as the base.

The costs of a fully decarbonized system operating with only RER, scenario 5, are 13 billion USD higher than the cost-optimal carbon-neutral scenario, SDG 13. This is due to a combination of circumstances: an increase in the generation and storage capacity required, consequence of a worse performance of small over large RoR and the rise of PV in the system, and the higher installation costs for small hydro systems.

With the installation of the macrogrid, scenario 6, we manage to reduce significantly the storage and installation capacity with respect to scenario 4. Additionally, consequence of the revenue obtained from selling the electricity, the total costs are almost half of those of scenario SDG 13. Nevertheless, must be noted that this is a simplified scenario in which electricity can always be sold and bought for the constant prices listed in Table 2, with the only limitation imposed being the transmission power.

Finally, scenario 7, in which conventional hydro can be used throughout the whole model (with a capacity never greater than the currently installed) presents a 2 billion USD decrease, consequence of the reduction in generation capacity required due to the gained versatility in the hydro production. The energy stored in the reservoir's peaks in similar times for all years, but the peaks increase significantly in value, reaching its full capacity in 2040.

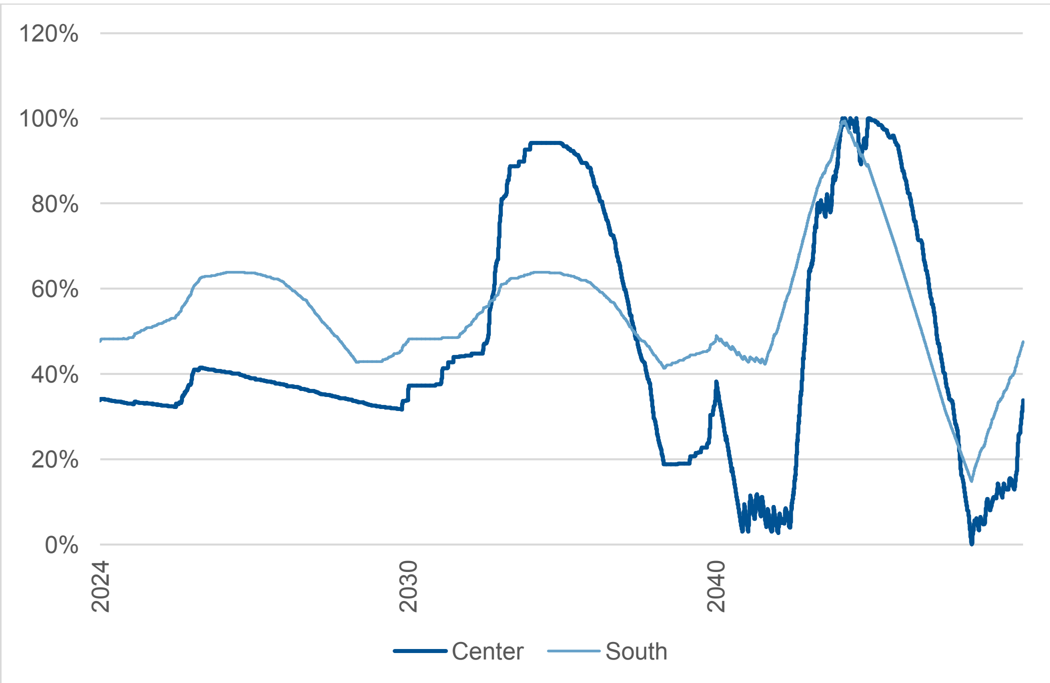

Figure 53 Reservoir storage level 2024 – 2040. Scenario 7

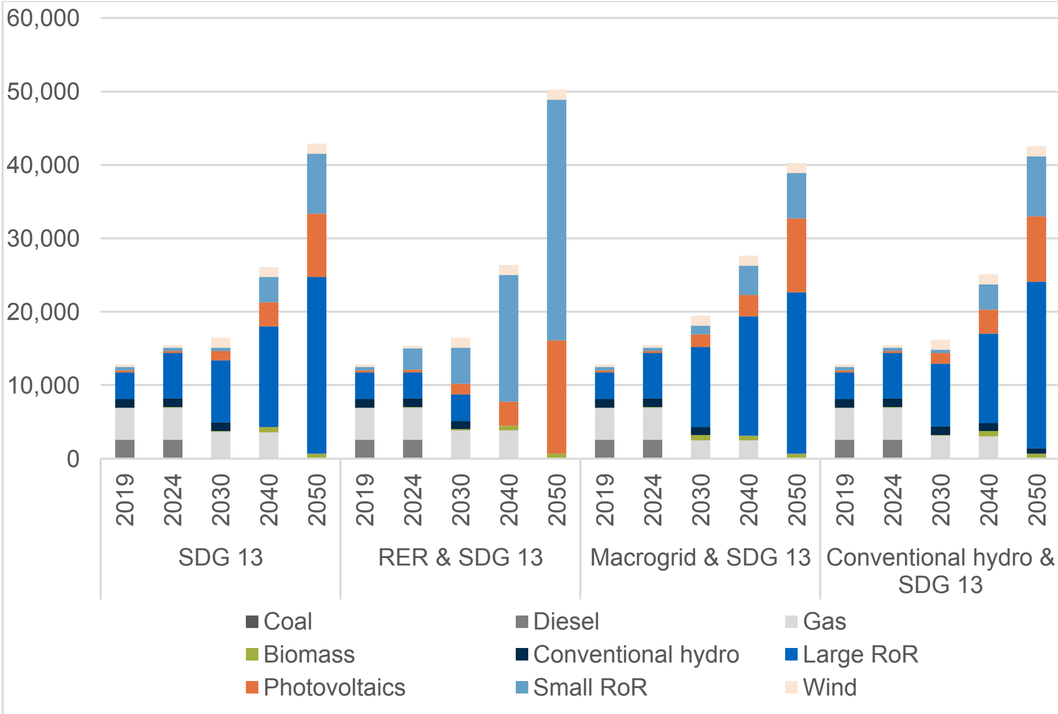

Figure 54 Total installed capacity [MW]. Scenarios 4 – 7

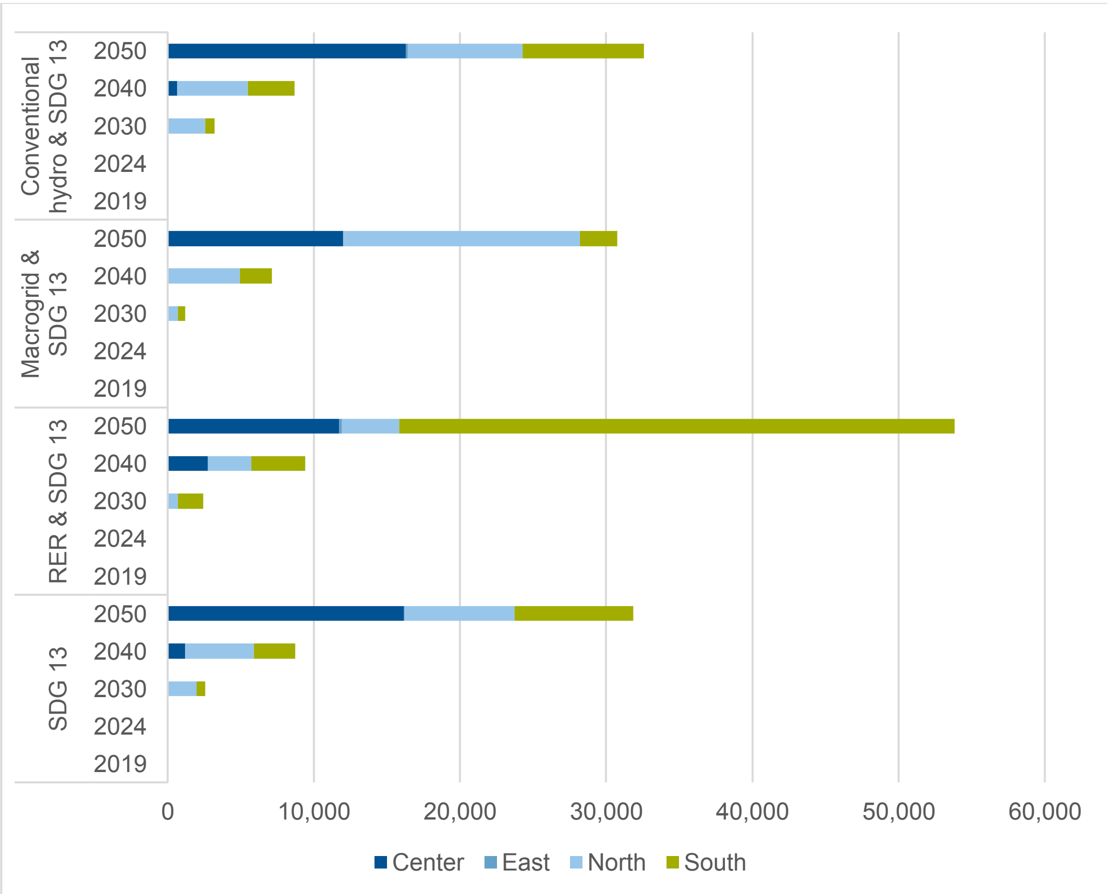

Figure 55 Storage capacity [MWh]. Scenarios 4 – 7

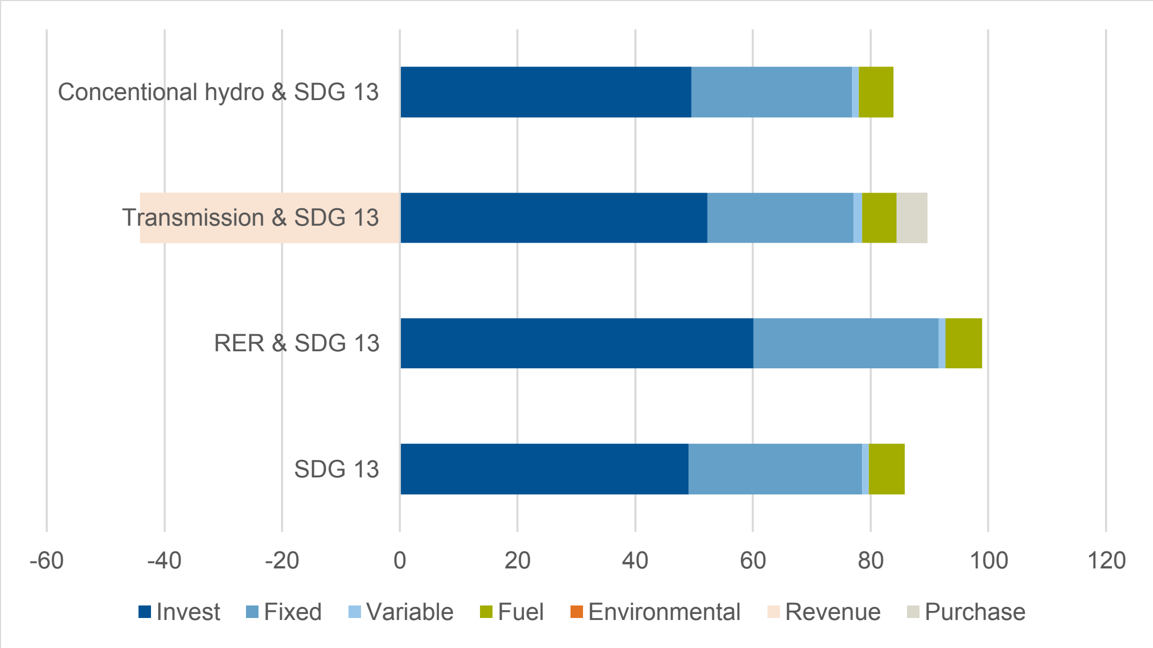

Figure 56 Costs comparison [billion USD]. Scenarios 4 – 7

5. Summary and Outlook

The study shows optimistic results concerning integration of renewables in the system.

Until 2030, the system, purely economically driven, experiences a reduction of fossil fuels to up to a third of the total installed capacity and an increase in renewables participation, lead by wind, and of large RoR, technology with the largest investment. Despite this, the steep increase of electrical demand expected in the last 20 years also entails greater dependence of fossil fuels, despite their share in the global system continues to decrease. The capacity increase in this period is lead by photovoltaics.

Important differences between regions are noted. The implementation of renewables is very successful in the north as the natural gas share continues to decrease. This is a consequence of a relatively high, diverse potential of renewables. The south despite having the largest RER potential, gains dependence on fossil fuels in the last modelled years because of the very steep demand growth experienced in the region, combined with a renewable fleet concentrated in PV and hydro exclusively. On the other hand, east and center depend the most on natural gas throughout the model, because of a moderate renewable potential and cheap fuel prices respectively. In addition, center acquires a regulatory role for the system because of its strategic position, with possibilities of electricity transmission to both north and south. As the grid mix gets cleaner, electricity exports from northern and southern regions, where of the most storage capacity concentrates, to east and center gain importance.

From the different scenarios analysed, results for the CO2 taxation proves specially promising as a compromise between economic and environmental performance. This scenario is very effective when it comes to decarbonization for the first 20 years but proves insufficient to achieve a carbon neutral system by 2050.

The report has certain limitations that could entail further research in the subject. First, no wind offshore is considered. This technology could raise the importance of wind energy in the system, currently with a minor role due to the scarce high quality onshore locations. Secondly, the macrogrid scenario presents constant prices for the electricity to be exchanged between countries. The demand behaviour of all states involved should be analysed in detail to deduce the actual variations of the prices within the year. Finally, no conventional hydro is considered throughout the report but in scenario 7, where its investment is limited, due to the environmental concerns these have raised in the area.

List of Figures

List of Abbreviations

COES	Committee for Economic Operation of the National Interconnected System	“Comité de Operación Económica del Sistema Interconectado Nacional”
IEA	International Energy Agency	
IRENA	International Renewable Energy Agency	
LT	Lifetime	
MINEM	Ministry of Energy and Mining	“Ministerio de Energía y Minas”
OSINERGMIN	Energy and Mining Investment Supervisory Agency	“Organismo Supervisor de la Inversión en Energía y Minería”
PV	Photovoltaics	
RE	Renewable Energy	
RER	Renewable Energy Resources	
RoR	Run off river	
SEIN	National Interconnected Electric System	“Sistema Eléctrico Interconectado Nacional”
SDG	Sustainable Development Goals	

List of Tables

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Annex A

Table 20 Hydro generation plants, own elaboration

Plant	Department	Region	Type	Max flow (m3/s)	Effective power (MW)
8 de agosto	Huanuco	Center	Small RoR	19,0	19,0
Ángel I	Puno	South	Small RoR	2,1	5,0
Ángel II	Puno	South	Small RoR	3,1	7,1
Ángel III	Puno	South	Small RoR	3,0	7,1
Aricota I	Tacna	South	Conventional	4,5	22,1
Aricota II	Tacna	South	Conventional	4,6	12,2
Cahua	Lima	Center	Conventional	24,3	45,4
Callahuanca	Lima	Center	Large RoR	24,4	84,5
Canchayllo	Junín	Center	Small RoR	7,0	5,2
Caña Brava	Cajamarca	North	Small RoR	19,4	5,7
Cañón del Pato	Ancash	Center	Conventional	75,6	265,6
Carhuac	Lima	Center	Large RoR	14,5	20,4
Carhuaquero	Cajamarca	North	Large RoR	21,1	94,5
Carhuaquero Iv	Cajamarca	North	Small RoR	2,6	10,0
Cerro del Águila	Huancavelica	Center	Large RoR	221,5	557,7
Chaglla	Huanuco	Center	Large RoR	148,4	470,4
Chancay	Lima	Center	Large RoR	3,4	20,0
Charcani I	Arequipa	South	Conventional	7,6	1,6
Charcani II	Arequipa	South	Conventional	6,0	0,6
Charcani III	Arequipa	South	Conventional	10,0	4,7
Charcani IV	Arequipa	South	Conventional	15,0	15,4
Charcani V	Arequipa	South	Conventional	26,2	146,6
Charcani VI	Arequipa	South	Conventional	15,0	8,9
Cheves	Lima	Center	Large RoR	33,4	176,3
Chimay	Junín	Center	Large RoR	95,6	152,3
El Carmen	Huanuco	Center	Small RoR	4,2	8,4
El Platanal	Lima	Center	Large RoR	41,0	222,5
Gallito Ciego	Cajamarca	North	Large RoR	41,1	35,3
Her 1	Lima	Center	Small RoR	17,0	0,7
Huampani	Lima	Center	Conventional	21,2	30,9
Huanchor	Lima	Center	Conventional	10,9	19,8
Huanza	Lima	Center	Large RoR	16,3	98,3
Huasahuasi I	Junín	Center	Small RoR	6,5	9,9
Huasahuasi II	Junín	Center	Small RoR	6,5	10,2
Huayllacho	Arequipa	South	Small RoR	0,2	0,2
Huinco	Lima	Center	Large RoR	27,2	277,9
Imperial	Lima	Center	Small RoR	7,5	4,0
La Joya	Arequipa	South	Small RoR	7,6	7,7
Las Pizarras	Cajamarca	North	Small RoR	23,0	19,2
M. Cerro del Águila	Huancavelica	Center	Small RoR	19,2	10,4
Machupicchu	Cusco	South	Conventional	55,8	168,8
Malpaso	Junín	Center	Large RoR	80,4	48,4
Mantaro	Huancavelica	Center	Large RoR	106,0	678,7
Marañón	Huanuco	Center	Small RoR	26,4	19,9
Matucana	Lima	Center	Conventional	15,8	137,0
Misapuquio	Arequipa	South	Small RoR	2,2	3,9
Moyopampa	Lima	Center	Conventional	19,3	69,1
Oroya	Junín	Center	Small RoR	6,6	9,1
P. Chaglla	Huanuco	Center	Small RoR	3,7	6,4

Pachachaca	Junín	Center	Small RoR	6,6	9,7
Pariac	Ancash	Center	Small RoR	2,2	5,0
Patapo	Lambayeque	North	Small RoR	8,0	1,0
Poechos II	Piura	North	Small RoR	60,9	9,6
Potrero	Cajamarca	North	Large RoR	18,4	20,2
Purmacana	Lima	Center	Small RoR	2,0	1,7
Quitaracsa	Ancash	Center	Large RoR	15,6	117,8
Renovandes H1	Junín	Center	Small RoR	7,7	19,6
Restitución	Huancavelica	Center	Large RoR	105,1	219,4
Roncador	Lima	Center	Small RoR	12,0	3,5
Rucuy	Lima	Center	Large RoR	3,5	20,0
Runatullo II	Junín	Center	Small RoR	7,2	20,0
Runatullo III	Junín	Center	Small RoR	5,5	20,0
San Antonio	Arequipa	South	Small RoR	2,4	0,6
San Gaban II	Puno	South	Conventional	19,9	115,7
San Ignacio	Arequipa	South	Small RoR	2,5	0,4
Santa Cruz I	Ancash	Center	Small RoR	6,5	6,6
Santa Cruz II	Ancash	Center	Small RoR	6,3	6,5
Santa Teresa	Cusco	South	Conventional	53,1	89,8
Yanango	Junín	Center	Large RoR	20,0	43,1
Yanapampa	Ancash	Center	Small RoR	19,9	3,9
Yarucaya	Lima	Center	Small RoR	10,0	15,0
Yaupi	Junín	Center	Large RoR	29,1	113,7
Yuncan	Pasco	Center	Large RoR	29,9	136,7
Zaña	Cajamarca	North	Small RoR	6,2	13,2