STUDY ON SYSTEM ADEQUACY AND FLEXIBILITY OF THE MONTENEGRIN POWER SYSTEM

– Final Report –

Friday, September 30, 2022

This report made possible by the support of the American people through the United States Agency for

SUBAGREEMENT NO. USEA/USAID -2022-714-01

Prepared for:

United States Agency for International Development
and
United States Energy Association

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Abbreviations

AC	Alternating Current
aFRR	Automatic Frequency Restoration Reserve
BESS	Battery Energy Storage Systems
CF	Capacity Factor
CGES	Crnogorski elektroprenosni sistem
CMs	Capacity Mechanisms
CRM	Capacity Remuneration Mechanisms
CZC	Cross-zonal Capacity
DSR	Demand Side Response
EENS	Expected Energy Not Served
EKC	Electricity Coordinating Center
EMI	Electricity Market Initiative
ENS	Energy Not Supplied
ENTSO-E	European association for the cooperation of transmission system operators
ERAA	European Resource Adequacy Assessment
EU	European Union
EVA	Economic Viability Assessment
FB	Flow Based
FCR	Frequency Containment Reserve
FOR	Forced Outage Rate
FRR	Frequency Restoration Reserve
GHG	Greenhouse Gases
HPP	Hydro power plant
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
LLD	Loss of Load Duration
LOLE	Loss of Load Expectation
MAF	Mid-term Forecast
MC	Monte Carlo
ME	Montenegro
mFRR	Manual Frequency Restoration Reserve
MOR	Maintenance Outage Rate
NRAA	National Resource Adequacy Assessment
NTC	Net Transfer Capacity
PECD	Pan European Climate Database
PV	Photovoltaic
RES	Renewable Energy Sources
RoR	Run of River

RTE	Réseau de Transport d'Électricité
SEE	Southeast Europe
SRMC	Short-run Marginal Cost
TPP	Thermal Power Plant
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UCED	Unit Commitment and Economic Dispatch
USAID	US Agency for International Development
USEA	United States Energy Association
VRE	Variable Renewable Energy

1 EXECUTIVE SUMMARY

To reach carbon neutrality and energy security, Europe is increasing the pace of decarbonization and RES integration. In this new reality, resource adequacy has become a significant challenge. As designed by ENTSO-e, the European Resource Adequacy Assessment (ERAA) is part of a toolbox to address this challenge, and can be followed by a National Resource Adequacy Assessment (NRAA), which provides a more granular picture at the country level.

As an Energy Community (EnC) member, Montenegro (ME) has a legal responsibility to adopt, transpose and implement EU energy laws, such as the Clean Energy Package, which encompasses the ERAA/NRAA. This legal responsibility, in combination with Montenegro's and Southeast Europe's (SEE) plans for decarbonization and high-RES integration led to this Study, where we conducted the first NRAA for Montenegro, including a flexibility analysis.

We completed the NRAA in a four-step approach (**Figure 1**), covering Europe and two target years: 2025 and 2030.

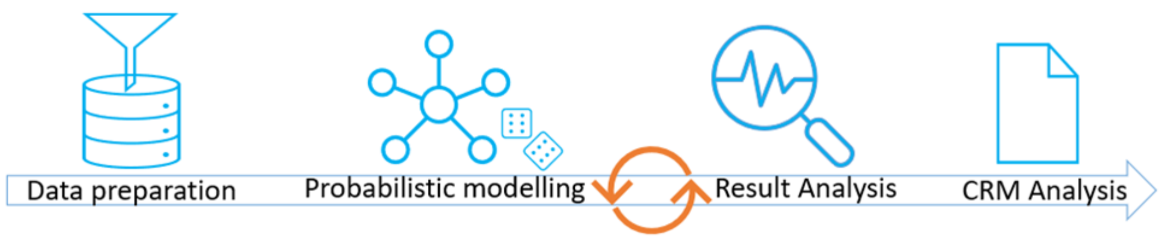

Figure 1: Main steps in ME NRAA

We completed the data preparation and defined the scenarios in close cooperation with CGES. We modeled SEE and ME on plant-by-plant level, using EMI and CGES data, respectively. We modeled the rest of Europe on a cluster level using data from ERAA 2021/2022. In total, we created 20 scenarios to cover three SEE decarbonization futures – expected, moderate and extreme, as well as three Montenegrin power system development scenarios – expected, alternative 1 (ALT1) and alternative 2 (ALT2).

We carried out probabilistic modelling by combining climate-dependent variables (Demand, wind, solar and HPP) with a number of TPP random outages, creating 700 Monte Carlo (MC) years – a number large enough to guarantee convergence and high confidence in the results.

We projected the main adequacy indicators, both Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS), for ME and SEE, followed by an assessment of the depth of ME's adequacy through an analysis of the hydro and thermal (HPP and TPP) margins (reserves).

This NRAA clearly shows that Montenegro does not have adequacy issues in any of the analyzed scenarios, even in the case of extreme SEE decarbonization.

In 2025, only Greece shows positive EENS and LOLE in SEE, but at a level far below the adequacy threshold of three hours for LOLE. Therefore, for all scenarios in 2025, the region does not show adequacy issues, due to minor differences between decarbonization scenarios in that year.

In 2030, the situation is the same for expected and moderate decarbonization. However, it is significantly different for extreme decarbonization due to greater TPP decommissioning, and all countries, except Montenegro and Albania, have adequacy issues. Each successive ME development scenario is more challenging, and incrementally raises the level of inadequacy in SEE. This is especially the case in ALT2, which includes slower HPP/RES development, the decommissioning of TPP Pljevlja, higher ME load, and only one pole of the ME-IT HVDC line.

Table 1: Adequacy Indicators for SEE Extreme Decarbonization in 2030

Market area	Expected ME		ALT1 ME		ALT2 ME	
	EENS (MWh/%[1])	LOLE (hours)	EENS (MWh/%)	LOLE (hours)	EENS (MWh/%)	LOLE (hours
AL	0/0	**0**	0/0	**0.0**	132/0.002	**2**
BA	15/0	**3.1**	66/0.001	**7**	1053/0.008	**44**
BG	1780/0.005	**5.7**	2333/0.006	**7**	2354/0.007	**15**
GR	1263/0.002	**1.1**	1568/0.003	**1.4**	1875/0.003	**2.4**
HR	1246/0.007	**8.7**	1758/0.009	**11.2**	2829/0.015	**26**
ME	**0/0**	**0**	**0/0**	**0.0**	**0/0**	**0**
MK	73/0.001	**2.1**	158/0.002	**3.6**	146/0.002	**5**
RO	1076/0.002	**5.8**	1600/0.002	**7.8**	1832/0.003	**12**
RS	9830/0.025	**7.4**	13369/0.034	**9.8**	28606/0.073	**19**
SI	3072/0.019	**6.2**	3740/0.023	**7.4**	5253/0.032	**11**
XK	223/0.003	**1.1**	561/0.008	**2.6**	2619/0.038	**7**

[1] As % of annual load

Given these results, we do not recommend that Montenegro consider a capacity mechanism at this time. However, this could change based on the development of the Montenegrin and European power systems. For that reason, this report explains the main principles of capacity mechanisms, including their types and best practices for potential future implementation.

After the NRAA, we conducted a flexibility analysis in line with the new ENTSO-e recommendation[2], to determine if there were any adequacy concerns raised by flexibility needs, using two indicators: ramping flexibility needs and scarcity period flexibility needs. Considering that Montenegro does not have adequacy issues, we were only able to assess the first of these indicators, which show that maximum ramping needs range from 187 MW to 796 MW, while during scarcity period, these needs are approximately 600 MW, which the ME system can provide.

Overall, the Montenegrin power system shows resilience for both adequacy and flexibility, in all proposed development scenarios and decarbonization paths. The reasons for such favorable results are the following:

- **Concerning hourly demand, the Montenegrin planned generation fleet is solid**
  We see this demonstrated in the HPP and TPP margins. While the TPP margin is usually low, because the cheap lignite TPP in ME almost always produces at its maximum, the weekly minimum HPP margins range from adequate to high in all scenarios (from 40 MW - 840 MW). However, even in the case of lower margins, Montenegro can rely on adequacy due to a second factor to meet its needs – its robust interconnections.

- **Montenegrin import capacity is high**
  ME's import capacity ranges from 2400 MW to 3000 MW, depending on the scenario, which is several times higher than the maximum hourly load, and thus provides a comfortable cushion to ensure that Montenegro will have adequate power supplies, even under an extreme decarbonization approach in SEE by 2030.

At the same time, considering the rapid pace of changes in the European energy sector, we would recommend the following:

- Introducing annual NRAA exercises for Montenegro, to complement the European-wide ERAA process. This can provide more detail on Montenegro's own needs and opportunities, and provide early notice of any adequacy concerns.
- Reviewing whether Montenegro's national energy legislation aligns with the EU legislation, especially concerning adequacy criteria.
- Carrying out a resource adequacy study for other countries in SEE, and the entire region. Doing so would provide recommendations on how to address the shortfalls that notably appear in the extreme decarbonization scenario, and identify whether capacity remuneration mechanisms might make sense on a collective basis.

[2] ENTSO-E Position Paper: Assessment of Future Flexibility Needs

2 Introduction

The latest EU regulations[3] and EnC decision[4] put additional responsibilities on the TSOs to assess and control system adequacy. As a consequence, CGES, the Montenegrin TSO, now needs to consider the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic criteria.

Until recently, the TSOs estimated system adequacy and flexibility in a deterministic manner (based on the worst-case scenario, no matter its probability), but as the generation mix evolves towards a higher share of renewables, the deterministic approach is becoming obsolete. This is due to the stochastic nature of renewable energy systems (RES), their intermittency, and the anticipated shift in power system operations to an open electricity market, which raises the risk to power system adequacy in the short, mid, and long run. Moreover, to integrate large amounts of RES, TSOs must also commission devices that can provide adequate power system flexibility.

Given the magnitude of expected changes in the European electricity sector - including the coupling of energy markets, the integration of RES, and efforts to decarbonize energy systems – it will be critical to upgrade the monitoring of system adequacy. With the new regulations in place, European resource adequacy assessments (previous known as MAF) are now required to consider these factors, amongst others:

- An Economic Viability Assessment (EVA) of resource capacities;
- Flow-Based (FB) modelling of the power network (when applicable);
- The impact of climate change on adequacy;
- An analysis of additional scenarios, including the presence or absence of Capacity Mechanisms (CMs);
- Consideration of energy sectoral integration.

Considering these profound changes and future requirements, CGES has turned to USEA/USAID for support in conducting a detailed probabilistic adequacy and flexibility assessment that will help prepare them for a very different future and protect reliability for all customers.

According to European rules, the optimal level of security of supply is the point at which the incremental cost of additional capacity to ensure customers against load curtailments is equal to the incremental cost of such load curtailments to customers. Considering the high value of the lost load, failing to fulfil this reliability standard would lead to substantial costs for the country’s economy, which could have social consequences, depending on the scale of the problem.

[3] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=en
[4] https://www.energy-community.org/news/Energy-Community-News/2021/11/30.html

In this context, the scope of this assignment consists of three main steps:

1. Power system adequacy analysis for Montenegro and the region, described in Chapter 3.
2. Power system flexibility analysis, described in Chapter 4.
3. Power system and market modelling and adequacy assessment training

Considering that this project consists of three separate but interdependent topics, we proposed a general project approach as given in **Figure 2**.

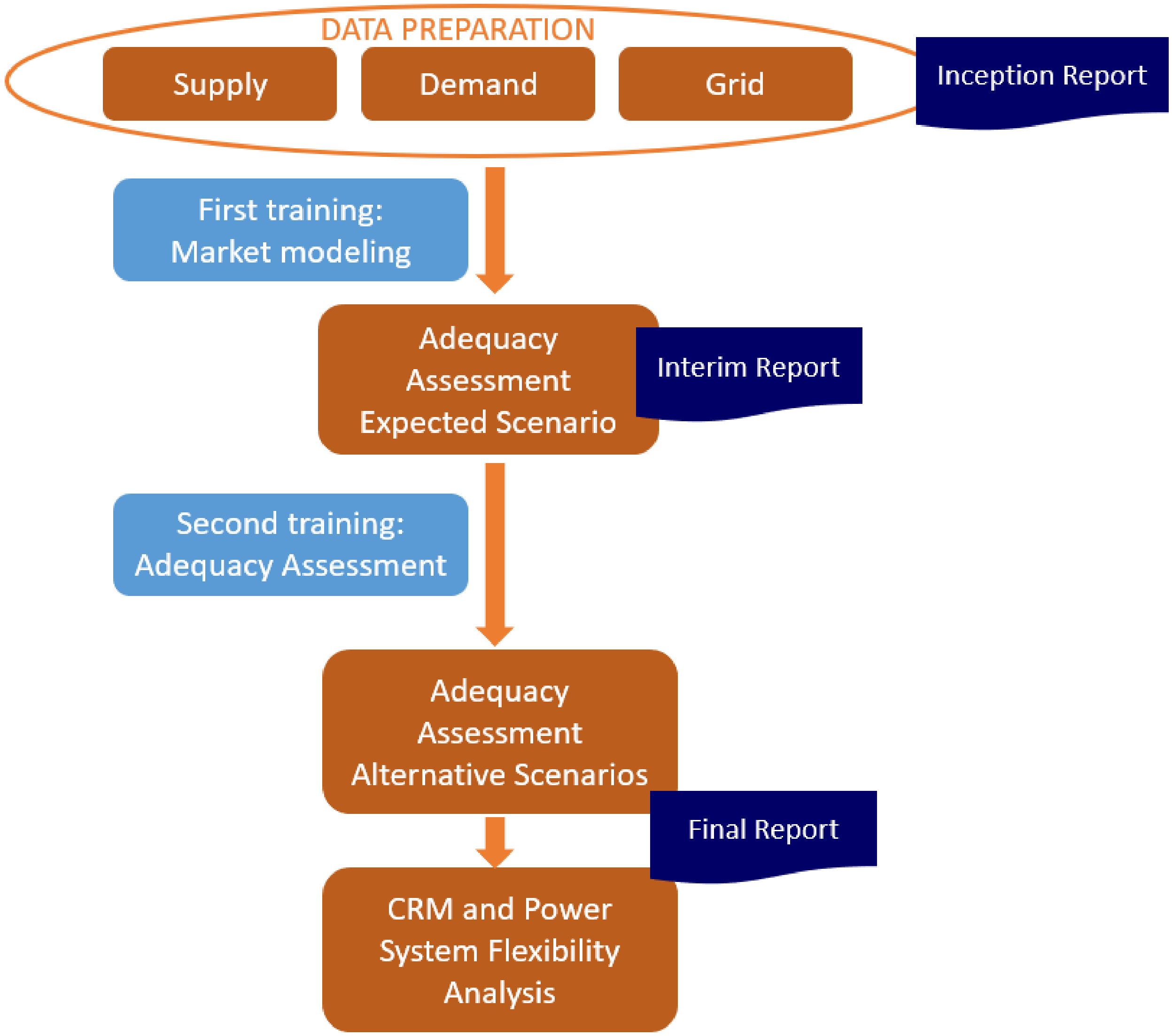

Figure 2 General CGES Project approach

As the outcome of the first step, data preparation, we issued an Inception Report with a detailed description of the input data, modelling assumptions and a description of the methodology we applied for adequacy assessments, flexibility analysis and training. This Inception Report, like others, was approved by CGES.

After the inception phase, we conducted the modelling phase, and in parallel, we initiated step three by conducting the first training on the power system and market modelling. The objective of the third step is to build CGES's capacity in Antares modelling, so that CGES may conduct such analysis on its own in the future. After each training session, we provided all training materials to the training participants.

After the first training, we conducted the first adequacy assessment, which covered the expected, Alt1 and Alt2 scenarios of ME power system development, in combination with the expected regional decarbonization scenario. This analysis was followed by an Interim Report, also approved by CGES.

We then organized the second training, which covered all aspects of adequacy assessment, and was designed to enable CGES to independently repeat ME system adequacy assessments.

Then we conducted an adequacy assessment of two additional scenarios, as well as CRM and flexibility analysis, and developed this Final Report.

3 National Resource Adequacy Assessment

3.1 Methodological Approach

Considering the main objectives of the project, we carried out the ME power system adequacy analysis following the methodology described in this chapter. The proposed methodology is independent of the applied software, and for this study, we used Antares SW.

The objective of the mid-term adequacy is to determine 5-10 years ahead whether the expected available supply and transmission capacities for ME are sufficient to cover demand under various conditions, and if not, to consider alternatives that could fill the gap.

The geographical scope of the analysis includes all of Europe, with different levels of modelling, as depicted in **Figure 3**.

Figure 3: Geographical Scope of ME NRAA

We modelled Montenegro on a plant-by-plant level using CGES data, while the EMI region is modelled on the same level, using the data from previous EMI studies. We modelled the rest of Europe on a cluster level, using publicly available data from ERAA 2021 and in some specific cases from ERAA 2022.

The temporal scope covers two target years (TYs), 2025 and 2030, and considers relevant techno-economic trends and policies. We conducted an hourly simulation for all TYs and scenarios.

The national resource adequacy assessment consists of the key steps in **Figure 4**.

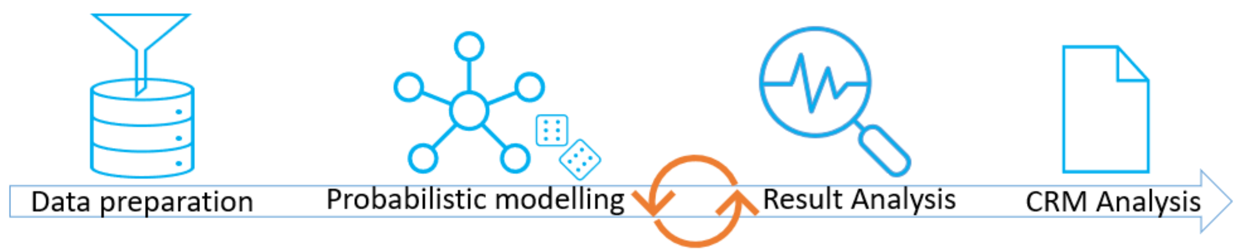

Figure 4 Main steps in ME NRAA

The first step is data preparation, followed by probabilistic modelling and the analysis of results for each scenario. As the last step, depending on the adequacy assessment results, we carried out a CRM analysis. The purpose of the CRM analysis is to evaluate options to meet a shortfall in resource adequacy and anticipate the need to add capacity resources.

3.1.1 Data Preparation

We conducted this process in close cooperation with CGES, including the collection of all relevant data and information necessary to model the power systems of Montenegro in both TYs and all scenarios. To model the SEE countries, we used an EMI database[5], and for the rest of Europe, we used the ERAA 2021 database. In the case of missing data, we made appropriate estimations. We provide detailed input data and other relevant information in ANNEX: INPUT DATA.

3.1.2 Probabilistic Modelling

As a general approach, to capture a full range of future conditions, we used a probabilistic Monte Carlo (MC) with Unit Commitment and Economic Dispatch (UCED) model, to ensure interzonal and intertemporal correlation of model variables and consider the specifics of the assessed geographical perimeter. We implemented the hourly resolution in the model and used the Monte-Carlo approach to reflect the variability of weather as well as the randomness of supply and transmission outages.

[5] EMI database was double-checked with ERAA 2021/ERAA 2022 data considering possible updates

We constructed 700 Monte Carlo years to assess adequacy risks for ME under various conditions for the analyzed timeframe, as depicted in**Figure 5**.

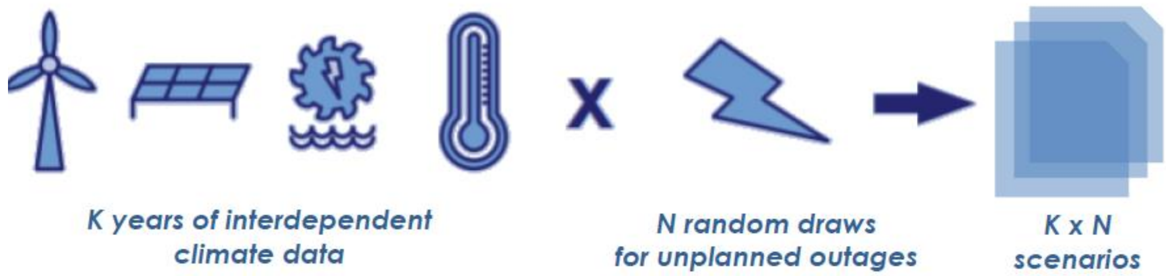

Figure 5 Probabilistic modelling general approach (source: ENTSO-E)

We constructed MC years by combining climate-dependent variables (wind, solar, hydro generation, and demand) and random outages, as follows:

- We selected 35 Climate years (1982-2016), one by one
- We then associated each climate year with random outage samples, i.e., randomly assigned unplanned outage patterns for the thermal units and interconnectors

The number of MC years that ensured convergence of the results was 700, by assessing the coefficient of variation (α) of the electric energy not served (EENS) metric and its change.

$$\propto_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

Where EENSN is the expectation estimate of ENS over N, the number of Monte Carlo years, i.e., $EENS_N = \frac{\sum_{i=1}^{N} ENS_i}{N}$, i=1…N, and Var[EENSN] is the variance of the expectation estimate, i.e., $Var[EENS_N] = \frac{Var[ENS]}{N}$.

Considering that we have no explicit target for α, to stop the MC simulations we used European TSO practices to decide on the number of MC years and reach a final convergence of the results. They recommend that a relative change of α should be smaller than 0.001.

We provide concrete results regarding convergence in Chapter 3.2.

3.1.3 Results Analysis

In probabilistic adequacy studies, the typical indicators for resource adequacy are either (1) the expectation of indicators (e.g., the EENS) or (2) a percentile of the independent indicator values (e.g. 95th percentile of the ENS values). We used the following indices to assess the adequacy levels of the Montenegrin power system for both TYs and all scenarios:

- **Loss of Load Expectation (LOLE) -** In a given geographical zone for a given period, this is the expected number of hours when there is a lack of market-based resources to cover the demand needs, within a sufficient transmission grid operational security limit.

- **Expected Energy Not Served (EENS) -** In a given geographical zone for a given period, this is the expected value of energy not to be supplied due to a lack of market-based resources, while complying with transmission grid operational security limits.

After assessing these indices, we compared them with European reliability standards – LOLE <= 3 hours to determine whether there is an adequacy issue (see detailed results in Chapter 3.2). This means that power would be available at least 99.965% of the time.

As an additional step, we assessed HPP and TPP margins in Montenegro, even if adequacy was not jeopardized.

Also, after we finished the adequacy assessment of all scenarios, we gave an overview of potential Capacity Mechanisms (CMs) that could address resource adequacy issues.

3.1.4 Capacity Mechanisms (CM)

This study covered the main principles of CMs, and investigated the positive effects of CM implementation, as well as the negative effects that could arise if the CM is not set up properly. We present different types of CMs implemented in Europe. These findings indicate the potential need to introduce and select a CM in Montenegro as a means of providing security of supply and sustainable power system development. Our analysis is in Chapter 3.3.

3.1.5 Scenarios

While acknowledging the project ToR, our analysis also took into account the latest changes in the Montenegrin power system (e.g., small HPP developments on hold; closure of the biggest industrial consumer). In doing so, the consultant cooperated with CGES to develop the following scenario matrix. The expected development scenario provides a base case for a group of key inputs, while alternatives 1 and 2 provide variations on those inputs, as described below.

Table 2: ME NRAA Scenario Matrix

ME development Scenario / Regional Scenario	Expected ME development For 2025 and 2030	Alternative ME development v1 For 2025 and 2030	Alternative ME development v2 For 2025 and 2030	Market Scenario Expected ME development Without Reserve For 2025 and 2030
SEE Expected decarbonization	Expected development of:	First Alternative development of:	Second Alternative development of:	Same as Expected, but without reserve

SEE moderate decarbonization	• Demand • TPP Pljevlja • HPPs • Small HPP • Wind • Solar • HVDC	• Demand • TPP Pljevlja • HPPs • Small HPP • Wind • Solar • HVDC	• Demand • TPP Pljevlja • HPPs • Small HPP • Wind • Solar • HVDC	
SEE extreme decarbonization				

This scenario matrix is tailor-made to cover diverse regional energy policies for decarbonization and different variants of Montenegrin power system development.

In total, when we combine three regional decarbonization scenarios, based on the previous EMI Study, with three possible ME development plans and two TYs, we conducted 18 different modeling and adequacy analyses.

In addition, we analyzed the expected development of the Montenegrin power system without a modelled reserve, in the expected decarbonization scenarios, and for two TYs, to extract meaningful market results (e.g., prices and exchanges). We conducted two market analyses.

We provided the input data required to model all the proposed scenarios in ANNEX: INPUT DATA and final Results in Chapter 3.2.

3.2 NRAA Results

In this chapter, we present the NRAA results. As mentioned, we carefully coordinated with CGES to decide upon and carry out such analysis for three national development plans, combined with three SEE decarbonization paths, for two target years. Notably, the expected ME development and SEE decarbonization scenarios are based on the TSOs' best estimates, so they should be considered the most plausible at present. Our added ME development and SEE decarbonization scenarios are sensitivity analyses which represent system adequacy "stress tests". Considering the number of scenarios (20 in total), we present the results in the following way:

- **The main storyline is given per ME development scenarios.**

The first analyzed scenario of Montenegro's power system development is based on the official Montenegrin development plan (**Table 3**). This plan envisaged the development of the HPP sector, with a significant RES increase and the second pole of ME-IT HVDC in 2030.

Table 3: Main input data for Expected development of ME power system

Expected	2025	2030
Demand [TWh]	**3.8**	**4**
TPP Pljevlja	In Service	In Service

HPP Komarnica	In Service	In Service
HPP Andrijevo	In Service	In Service
HPP Raslovici	In Service	In Service
HPP Milunovici	In Service	In Service
HPP Zlatica	In Service	In Service
HPP Krusevo	Out of service	In Service
New small HPP [MW]	36	36
Wind [MW]	272	272
Solar [MW]	165	673
HVDC [MW]	600	1200

The second analyzed scenario is based on an alternative version of the Montenegrin development plan provided by CGES. This plan envisages lower demand, and slower HPP development, with a slower RES increase compared to the expected scenario (**Table 4**).

Table 4: Main input data for ALT1 development of ME power system

Expected	2025	2030
Demand [TWh]	**3.32**	**3.53**
TPP Pljevlja	In Service	Out of Service
HPP Komarnica	Out of Service	In Service
HPP Andrijevo	Out of Service	Out of Service
HPP Raslovici	Out of Service	Out of Service
HPP Milunovici	Out of Service	Out of Service
HPP Zlatica	Out of Service	Out of Service
HPP Krusevo	Out of Service	In Service
New small HPP [MW]	36	36
Wind [MW]	272	272
Solar [MW]	50	200
HVDC [MW]	600	1200

The last analyzed scenario is based on a second alternative version of the Montenegrin development plan from CGES. This plan envisages the same demand, even slower development of the HPP sector and RES increase compared to the expected scenario. In both analyzed years only one pole of ME-IT HVDC is envisaged. Considering the highest demand, lowest installed capacities and NTC, this scenario is most challenging from an adequacy perspective (**Table 5**).

Table 5: Main input data for ALT2 development of ME power system

Expected	2025	2030
Demand [TWh]	**3.8**	**4**
TPP Pljevlja	In Service	Out of Service
HPP Komarnica	Out of Service	Out of Service
HPP Andrijevo	Out of Service	Out of Service
HPP Raslovici	Out of Service	Out of Service
HPP Milunovici	Out of Service	Out of Service
HPP Zlatica	Out of Service	Out of Service
HPP Krusevo	Out of Service	Out of Service
New small HPP [MW]	36	36
Wind [MW]	172	272
Solar [MW]	50	150
HVDC [MW]	600	600

- **Further, we combined each ME development scenario with three SEE decarbonization scenarios.**

  We first analyzed the expected level of SEE decarbonization. This plan represents the best estimation of the EMI TSOs regarding the decommissioning of coal and gas TPPs. Then, we conducted sensitivity analyses for greater (moderate) and extreme SEE decarbonization to observe the impact of decarbonization on resource adequacy. **Table 6** provides the total installed capacities in SEE for each decarbonization scenario and both target years.

Table 6: Installed Fossil TPP capacities in SEE decarbonization scenarios [MW]

Market Area	2025 Expected/Moderate/Extreme	2030 Expected/Moderate/Extreme
AL	*100/100/100/*	*300/200/100*
BA	*1765/1590/1487*	*1632/1442/1166*
BG	*6324/6324/4698*	*4698/4040/3440*
HR	*981/876/684*	*981/876/684*
GR	*7768/7768/7768*	*7768/7167/6493*
XK	*960/672/528*	*978/528/264*
MK	*763/763/586*	*586/586/586*
RS	*4560/4370/4270*	*4570/3840/2770*
RO	*8140/8140/8140*	*10055/8562/6899*
SI	*2167/2144/1732*	*1732/965/912*

- **We then present (Sections 2.2.1 – 2.2.3) adequacy results for all combinations of three ME development scenarios and three SEE decarbonization scenarios, consisting of:**

  - Convergence criteria – coefficient α and its relative change
  - Adequacy Indices – LOLE and EENS
  - TPP and HPP margins, which present TPP and HPP reserves calculated as the difference between available and dispatched capacity

- **We provide, in Section 2.2.4, market results only for the expected ME development and the SEE decarbonization scenarios, and they consist of:**

– Generation mix
– Prices
– Balances and exchanges

3.2.1 Expected development of Montenegrin power system

CONVERGENCE[6]

The criterion for accessing the degree of convergence can be used as the coefficient of variation (α), defined in the previous chapter 3.1.2. In order to define the number of Monte Carlo years that have to be simulated, the incremental coefficient of variation (i.e. relative change of α) is introduced and compared with a chosen threshold (θ):

$$\frac{|\alpha_n - \alpha_{n-1}|}{\alpha_{n-1}} \leq \theta$$

However, since still no explicit target is set in ERAA methodology, in order to stop the MC simulations, we have used a threshold θ = 0.001, currently proposed by Belgian TSO (Elia)7.

The relative change of α coefficient for 2025 is depicted in **Figure 6** for 700 MC years. Despite the spikes, caused by the 29th Climatic year (which is when European WPP production is lowest, and demand is highest), the coefficient of variation (α) decreases in general and satisfies proposed criterion if the number of MC years is 700.

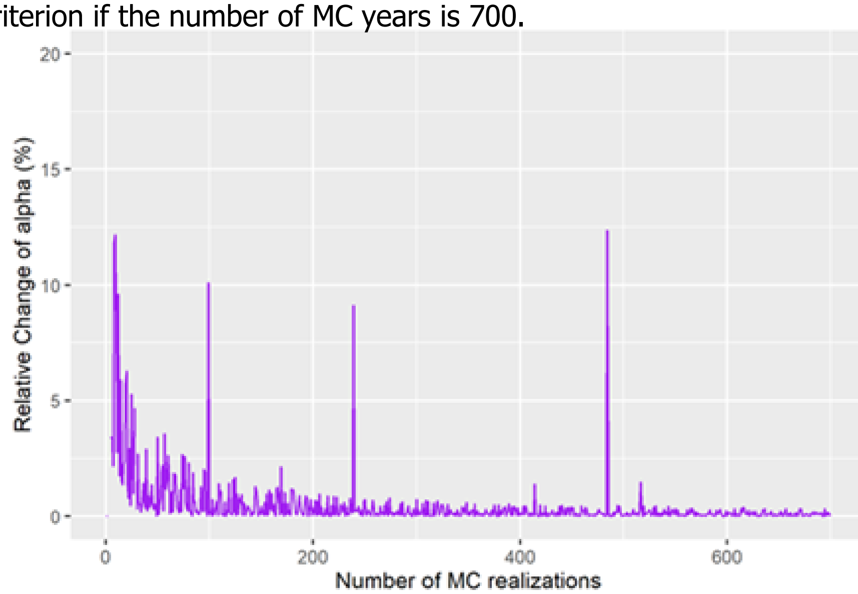

Figure 6: Convergence of the relative change alpha coefficient for 2025 and 700 MC

[6] In order to keep report well organized and reasonably short, we only present convergence for expected decarbonization in SEE

[7] Adequacy Flexibility study for Belgium 2022-2032

Just as for 2025, the convergency of the relative change of α coefficient for 2030 is depicted in **Figure 7** for 700 MC years. Despite some spikes, after these 700 years, the relative change of α is also small enough to consider that we have met the convergence criterion.

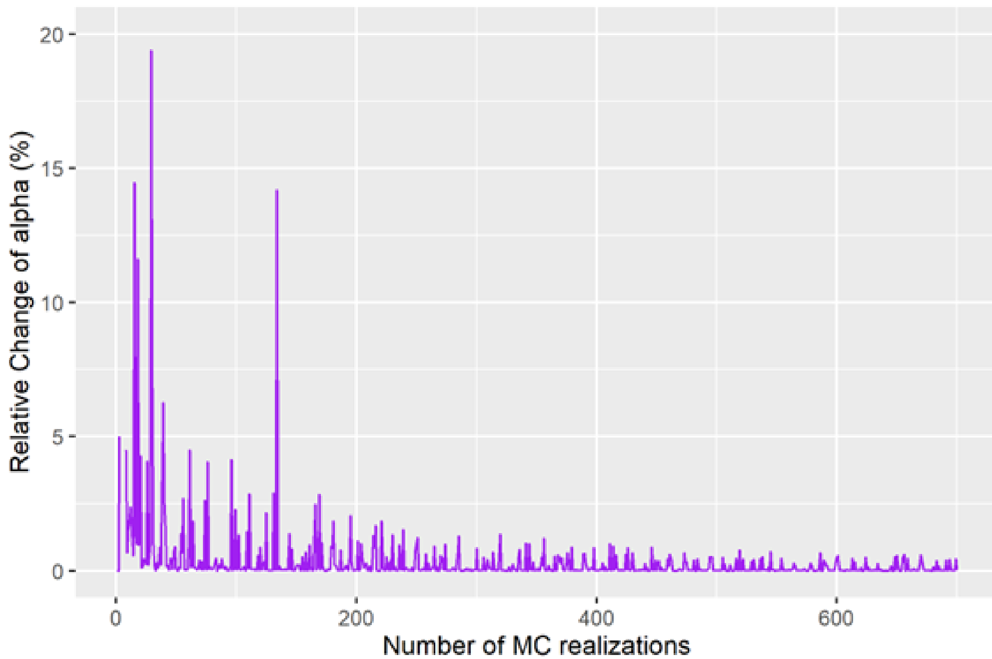

Figure 7: convergence of the relative change alpha coefficient for 2030 and 700 MC

ADEQUACY INDICATORS

After assuring convergence for 2025, we calculated the main adequacy indicators – EENS and LOLE, and present the results in **Table 7**.

In 2025, with expected ME development, under all three SEE decarbonization scenarios, in Montenegro and the rest of the SEE region, we detect no adequacy concerns. In each country, except in Greece, all indicators are zero. In Greece, EENS goes from 122 MWh to 229 MWh, while LOLE is around 0.2 hours, which is much less than the 3 hours reliability standard, so this result presents an acceptable adequacy risk.

Table 7: Main Adequacy indicators for Expected ME development in 2025

Market area	Expected decarbonization		Moderate decarbonization		Extreme decarbonization	
	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours
AL	0	0	0	0	0	0
BA	0	0	0	0	0	0
BG	0	0	0	0	0	0
GR	122	0.2	129	0.2	229	0.2
HR	0	0	0	0	0	0
ME	**0**	**0**	**0**	**0**	**0**	**0**
MK	0	0	0	0	0	0
RO	0	0	0	0	0	0
RS	0	0	0	0	0	0
SI	0	0	0	0	0	0
XK	0	0	0	0	0	0

Also, after assuring convergence for 2030, we calculated the main adequacy indicators – EENS and LOLE, and present the results in **Table 8**. In 2025, for the expected ME development scenario, and all three SEE decarbonization scenarios, in Montenegro, we detect no adequacy concerns. This is also the case in other SEE countries, with the notable exception of the extreme decarbonization scenario.

In that scenario, all countries except Montenegro and Albania show some adequacy issues. In fact, six of them – Bosnia, Bulgaria, Croatia, Romania, Serbia and Slovenia, but also notably, not Montenegro - have a LOLE higher than 3 hours in that situation. Serbia has the highest adequacy concerns detected in the Region, with LOLE = 7.4 hours and EENS = 9.8 GWh.

In other words, the extreme decarbonization scenario, in which approximately 75% of existing coal and lignite generation is decommissioned throughout SEE, could pose an adequacy risk, and SEE countries should pay attention to such risks in their planning efforts as they retire TPPs.

Table 8: Main Adequacy indicators for Expected ME development in 2030

Market area	**Expected decarbonization**		**Moderate decarbonization**		**Extreme decarbonization**	
	EENS (MWh)	**LOLE (hours**	**EENS (MWh)**	**LOLE (hours**	**EENS (MWh)**	**LOLE (hours**
AL	0	0	0	0	0	0
BA	0	0	0	0	15	3.1
BG	0	0	0	0	1780	5.7
GR	0	0	18	0.1	1263	1.1
HR	0	0	0	0	1246	8.7
ME	**0**	**0**	**0**	**0**	**0**	**0**
MK	0	0	0	0	73	2.1
RO	0	0	0	0	1076	5.8
RS	0	0	0	0	9830	7.4
SI	0	0	0	0	3072	6.2
XK	0	0	0	0	223	1.1

Margins for Montenegro

Even though adequacy concerns are not detected for Montenegro, we analyzed the “depth” of this adequacy, by calculating the weekly minimum of HPP and TPP hourly margins. HPP margins for 2025 are shown in **Figure 8**. The weekly Minimum HPP margin is going from 120 MW in the winter months to 790 MW in the summer season, while on average, the minimum HPP margins are 420 MW for Expected SEE decarbonization, 410 MW for Moderate SEE decarbonization and

350 MW for Extreme SEE decarbonization. Minimum weekly TPP margins are zero through the entire season, so they are not depicted. Both results are expected because high HPP margins are a consequence of seasonal storage HPPs, while the negligible TPP margins are a consequence of one TPP that produces power almost the entire time at maximum capacity due to its low costs[8].

These results tell us that for expected ME development, in any decarbonization path, margins in Montenegro are rather high. Also, Montenegro has 2400 MW of total import NTC. In 2025, these combined factors mean that Montenegrin power system adequacy, in this case, is very high.

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[8] TPP Pljevlja is not paying CO2 tax in 2025

Figure 8: Weekly minimum of HPP hourly margin in 2025 – Expected ME development

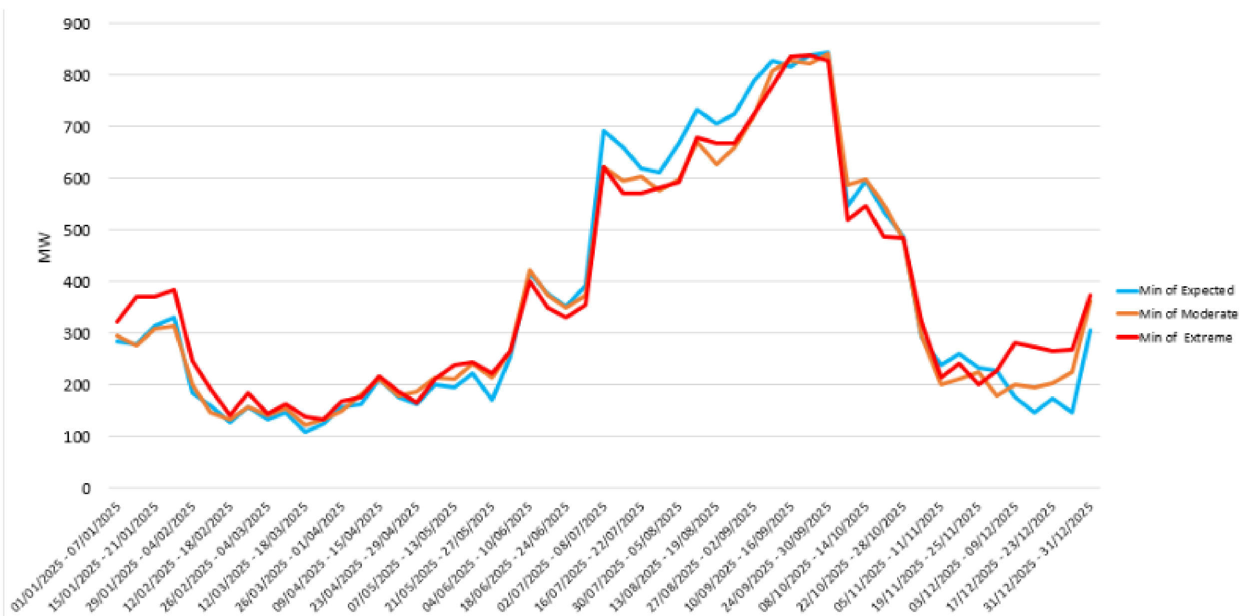


Figure 9. The weekly Minimum HPP margin is going from 110 MW in the winter months to 840 MW in the summer season, while on average, the minimum HPP margins are around 370 MW for all decarbonization scenarios. TPP margins for 2030 are shown in **Figure 10**. The weekly minimum TPP margin goes from 0 MW to 75 MW, while on average the minimum TPP margins are 5 MW - 10 MW for all decarbonization scenarios. HPP margins are high as in 2025, while TPP margin is now noticeable and higher than in 2025 because TPP Pljevlja costs are substantially higher due to payment of a CO2 "tax", so it is dispatched less.

These results point out that for expected ME development, in any SEE decarbonization path, margins in Montenegro are still high. Also in 2030, Montenegro has 3000 MW (due to the second pole of IT-ME HVDC) of total import NTC. All these combined means that Montenegrin power system adequacy, in this case, is rather high in 2030, and even higher than in 2025, under expected development conditions.

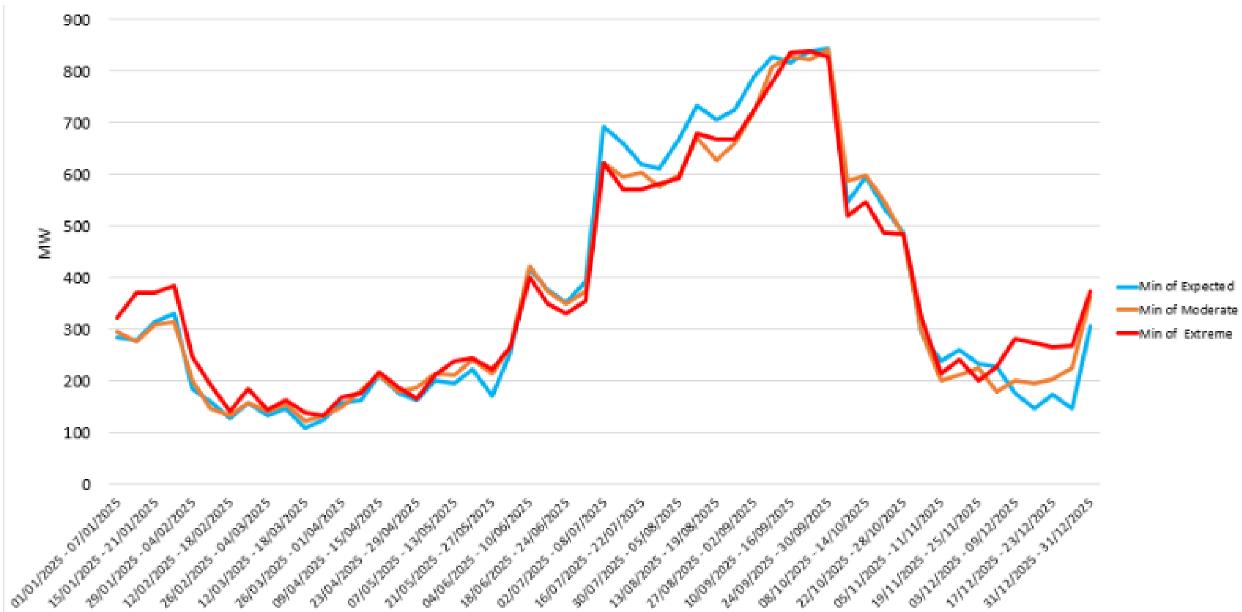


Figure 9: Weekly minimum of HPP hourly margin in 2030 – Expected ME development

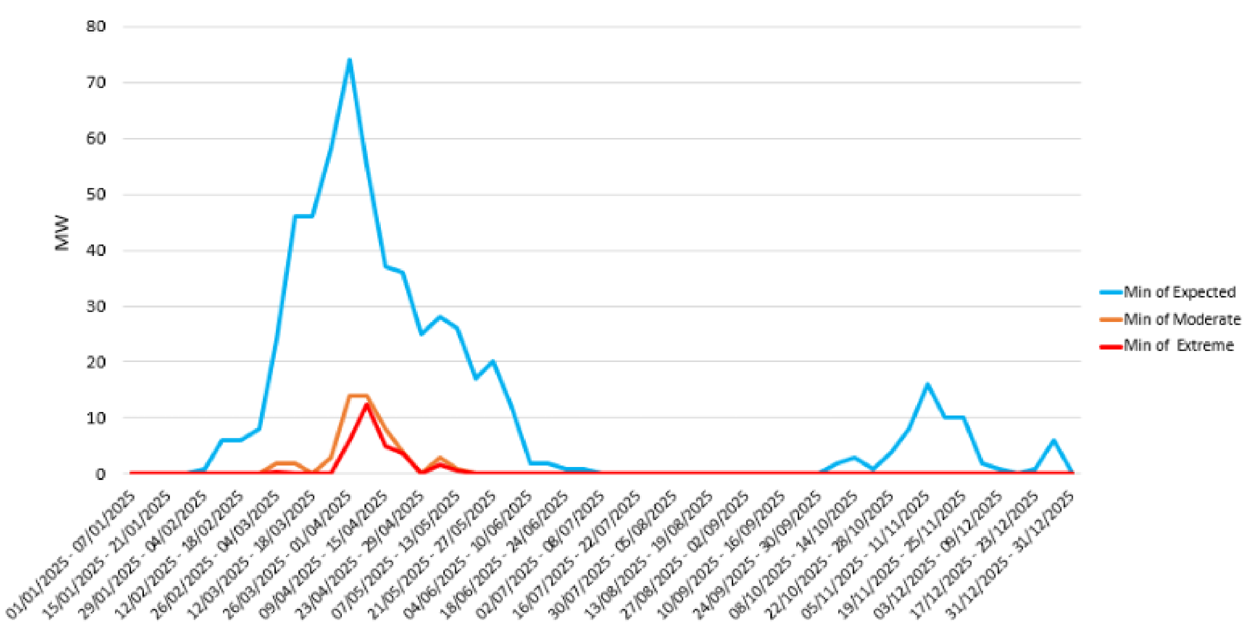


Figure 10: Weekly minimum of TPP hourly margin in 2030 – Expected ME development

3.2.2 ALT1 development of the Montenegrin power system

Adequacy indicators

In 2025, for the ALT1 ME development, in all three SEE decarbonization scenarios, in Montenegro and the rest of the SEE region, we detect no adequacy concerns. See **Table 9**. All indicators are zero, except in Greece, where EENS goes from 122 MWh to 216 MWh, while LOLE is around 0.2 hours, which is less than the 3 hours reliability standard, so this scenario presents an acceptable adequacy risk.

Table 9: Main Adequacy indicators for ALT1 ME development in 2025

Market area	Expected decarbonization		Moderate decarbonization		Extreme decarbonization	
	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours
AL	0	0	0	0	0	0
BA	0	0	0	0	0	0
BG	0	0	0	0	0	0
GR	**122**	**0.2**	**128**	**0.2**	**216**	**0.2**
HR	0	0	0	0	0	0
ME	**0**	**0**	**0**	**0**	**0**	**0**
MK	0	0	0	0	0	0
RO	0	0	0	0	0	0
RS	0	0	0	0	0	0
SI	0	0	0	0	0	0
XK	0	0	0	0	0	0

In 2030, for the ALT1 ME development and two of the SEE decarbonization scenarios, in Montenegro and all other SEE countries, we also detect no adequacy concerns. However, in the extreme decarbonization scenario, all countries except Montenegro and Albania show some adequacy issues, and seven of them – Bosnia, Bulgaria, Croatia, North Macedonia, Romania, Serbia and Slovenia - have LOLE higher than 3 hours. Croatia has the highest adequacy concerns detected in the Region, with LOLE of 11.2 hours and EENS of 1.8 GWh, followed by Serbia with LOLE of 9.8 hours and EENS of 13.4 GWh. **Clearly, adequacy is challenged in this scenario on a regional level.**

Table 10: Main Adequacy indicators for ALT1 ME development in 2030

Market area	Expected decarbonization		Moderate decarbonization		Extreme decarbonization	
	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours
AL	0	0	0	0	0	0.0
BA	0	0	0	0	66	7
BG	0	0	0	0	2333	7
GR	0	0	11	0.03	1568	1.4
HR	0	0	0	0	1758	11.2
ME	**0**	**0**	**0**	**0**	**0**	**0.0**
MK	0	0	0	0	158	3.6
RO	0	0	0	0	1600	7.8
RS	0	0	0	0	13369	9.8
SI	0	0	0	0	3740	7.4
XK	0	0	0	0	561	2.6

The adequacy indicators for ME ALT1 are the same as for expected ME development for both analyzed years and all three scenarios, while for the rest of the SEE region they are on the same level but slightly higher in 2030 ALT1 than in 2030 Expected, in the extreme SEE decarbonization.

MARGINS

As for the Expected ME development scenario, we analyzed the depth of this adequacy in this alternative, by calculating the weekly minimum of HPP and TPP hourly margins. HPP margins for 2025 are shown in **Figure 11** Weekly Minimum HPP margin is going from 40 MW in the winter months to almost 500 MW in the summer season, while on average, the minimum HPP margins are at the 200 MW level. The minimum weekly TPP margins are zero through the entire season, so they are not depicted. Both results are expected because the relatively high HPP margins are a consequence of seasonal storage HPPs, while the negligible TPP margins are a consequence of one TPP that is producing power almost the entire time at maximum capacity due to low costs[9].

These points out that for ALT1 ME development and in any SEE decarbonization path, similar to the Expected ME scenario, the adequacy margins in Montenegro are rather high. On top of this, Montenegro has 2400 MW of total import NTC in 2025. All these factors combined mean that the Montenegrin power system's adequacy, in this case, is also very high.

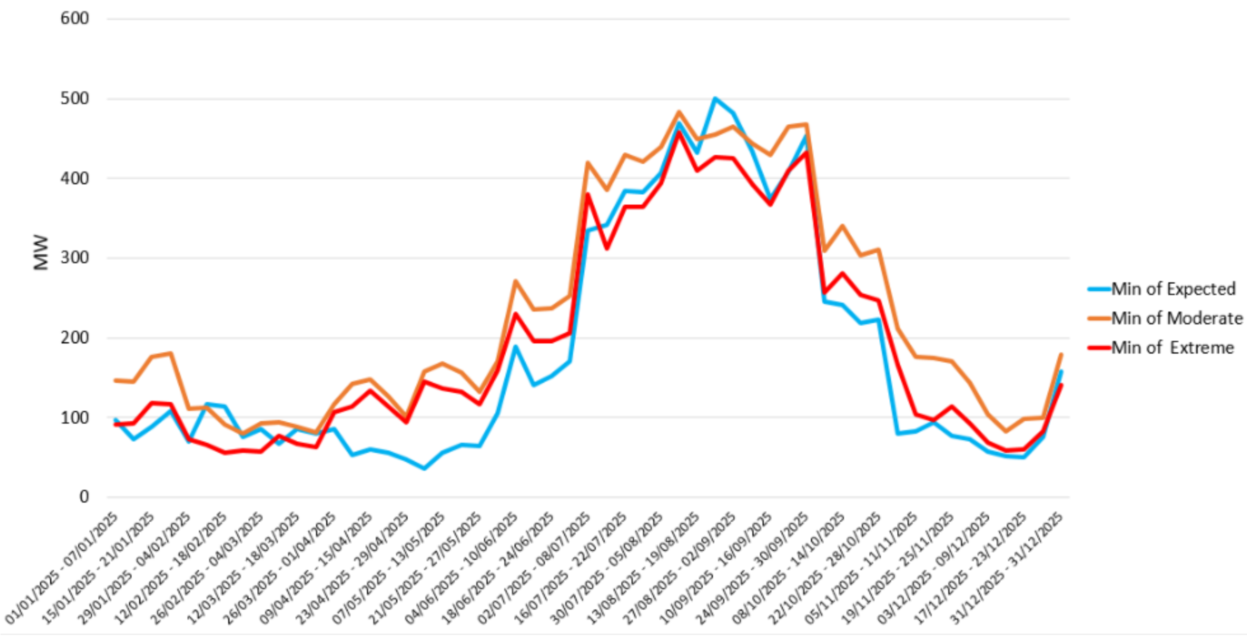


Figure 11: Weekly minimum of HPP hourly margin in 2025 – ALT1 ME development

HPP margins for 2030 are shown in **Figure 12**. The weekly minimum HPP margin goes from 95 MW in the winter months to 670 MW in the summer season, while on average, the minimum HPP

[9] TPP Pljevlja is not paying CO2 tax in 2025

margins are around 300 MW for all decarbonization scenarios. The HPP margins are higher than in 2025, while the TPP margin is zero because TPP Pljevlja is decommissioned.

These results point out that for expected ME development, in any SEE decarbonization path, the margins in Montenegro are still high. Also in 2030, Montenegro has 3000 MW (due to the second pole of the IT-ME HVDC) of total import NTC. All these factors combined mean that Montenegrin power system adequacy, in this case, is rather high, and even higher than in 2025.

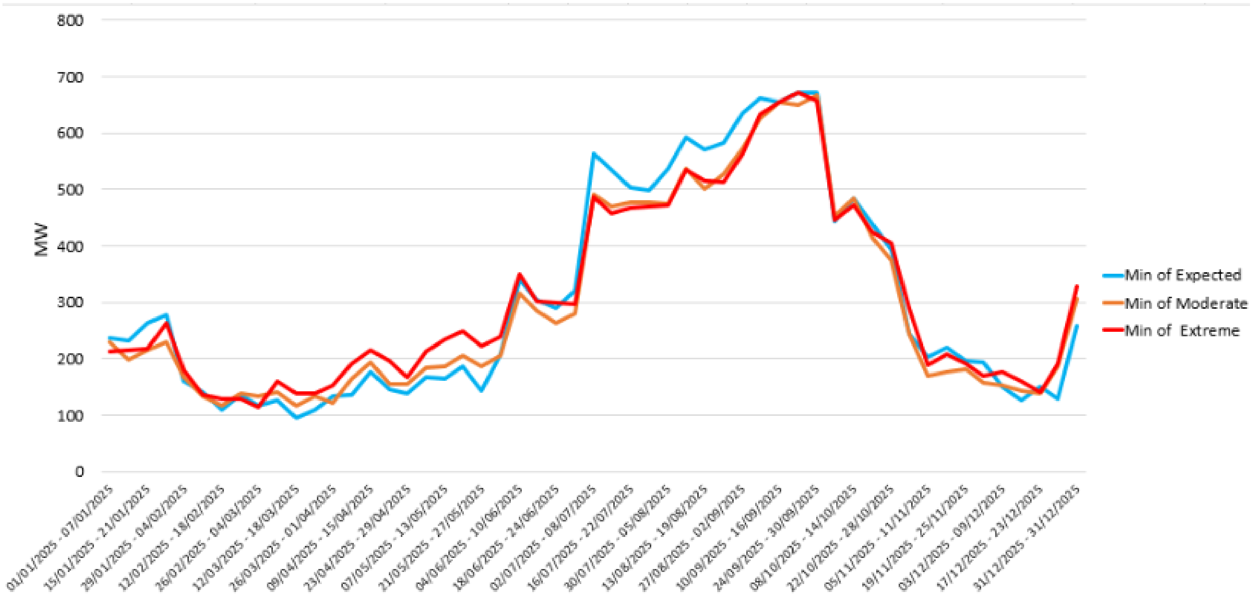


Figure 12: Weekly minimum of HPP hourly margin in 2030 – ALT1 ME development

3.2.3 ALT2 development of Montenegrin power system

ADEQUACY INDICATORS

In 2025, for the ALT2 ME development and all three SEE decarbonization scenarios, in Montenegro and the rest of the SEE region, there are no adequacy concerns detected. In each country, except in Greece, all indicators are zero. In Greece, EENS goes from 127 MWh to 219 MWh, while LOLE is around 0.2 hours, which is less than 3 hours reliability standard, so this result presents an acceptable adequacy risk.

Table 11: Main Adequacy indicators for ALT2 ME development in 2025

Market area	Expected decarbonization		Moderate decarbonization		Extreme decarbonization	
	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours
AL	0	0	0	0	0	0
BA	0	0	0	0	0	0
BG	0	0	0	0	0	0
GR	**127.1**	**0.2**	**138**	**0.2**	**219**	**0.2**
HR	0	0	0	0	0	0
ME	**0**	**0**	**0**	**0**	**0**	**0**
MK	0	0	0	0	0	0
RO	0	0	0	0	0	0
RS	0	0	0	0	0	0
SI	0	0	0	0	0	0
XK	0	0	0	0	0	0

In 2030, for the ALT2 ME development and all three SEE decarbonization scenarios, in Montenegro, we still detect no adequacy concerns. The same goes for other SEE countries, with exception of the extreme decarbonization scenario. In that scenario, all countries excluding Montenegro show notable adequacy issues. All of the others except Albania and Greece have LOLE higher than 3 hours. Bosnia has the highest adequacy concerns detected in SEE, with LOLE of 44 hours and EENS of 1 GWh, followed by Croatia with LOLE of 26 hours and EENS of 2.8 GWh. **This ALT2 scenario clearly poses considerable adequacy concerns regionwide.**

Table 12: Main Adequacy indicators for ALT2 ME development in 2030

Market area	Expected decarbonization		Moderate decarbonization		Extreme decarbonization	
	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours	EENS (MWh)	LOLE (hours
AL	0	0	0	0	132	2
BA	0	0	0	0	1053	44
BG	0	0	2	0.1	2354	15
GR	0	0	24	0.1	1875	2.4
HR	0	0	0	0	2829	26
ME	**0**	**0**	**0**	**0**	**0**	**0**
MK	0	0	0	0	146	5
RO	0	0	0	0	1832	12
RS	0	0	0	0	28606	19
SI	0	0	0	0	5253	11
XK	0	0	0	0	2619	7

Adequacy indicators for ME ALT2 are the same as in the case of expected ME and ALT1 development for both analyzed years and all decarbonization scenarios, while for the SEE extreme decarbonization scenario in 2030 the situation is different. In this case, **the entire SEE region shows high adequacy concerns with LOLE in most countries, with eight of the eleven above the 3-hour standard, and ranging from 5 hours to 44 hours.**

These results point out that the SEE extreme decarbonization scenario in combination with reduced import capability from Italy, and slower HPP and RES development in Montenegro could notably worsen the adequacy situation in the region, in comparison with the Expected and ALT1 ME development scenarios. **Montenegro is the only country that remains entirely resilient on adequacy issues under this scenario in 2030.**

MARGINS FOR MONTENEGRO

We analyzed the depth of adequacy for ALT2 by calculating the weekly minimum of HPP and TPP hourly margins. HPP margins for 2025 are shown in **Figure 13**. The weekly Minimum HPP margin ranges from 35 MW to 500 MW, while on average, the minimum HPP margins are 200 MW. The minimum weekly TPP margins are zero through the entire season, so they are not depicted. Both results are expected because the relatively high HPP margins are a consequence of seasonal storage HPPs, while the negligible TPP margins are a consequence of one TPP that produces power almost the entire time at maximum capacity due to low costs[10].

We conclude that for the ALT2 ME development scenario, in any SEE decarbonization path, similar to the Expected ME and ALT1 scenarios. On top of this, Montenegro has 2400 MW of total import NTC. By 2025, all these factors combined mean that Montenegrin power system adequacy, in this case, is still high.

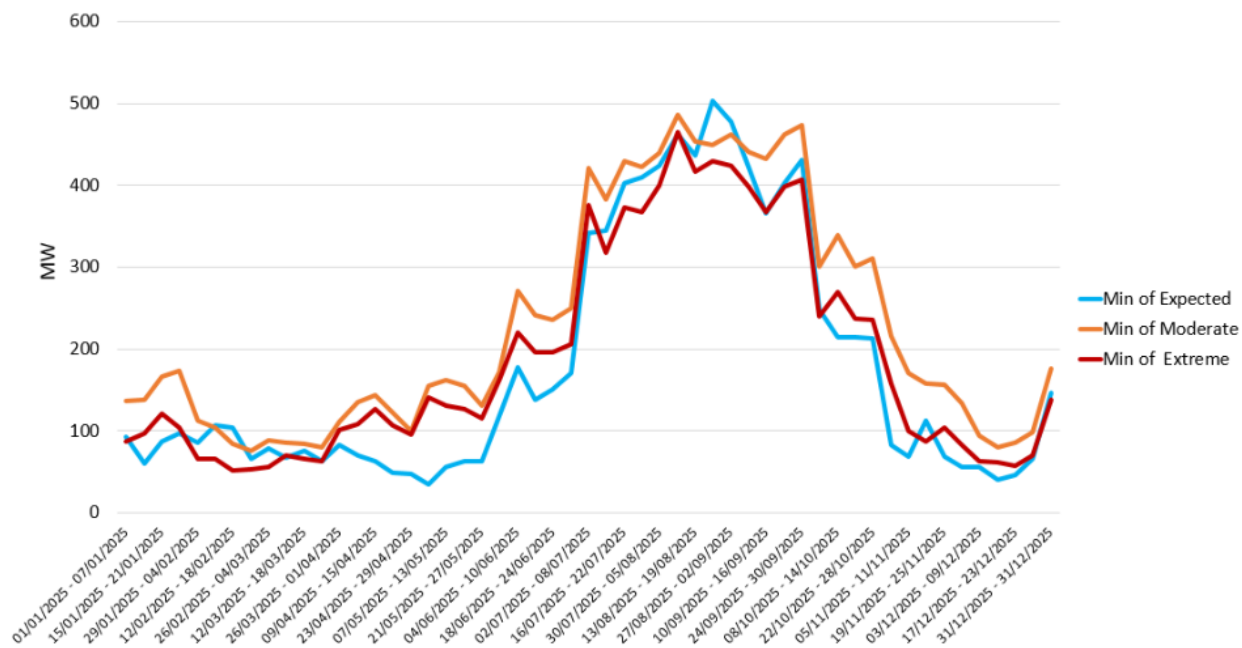


Figure 13: Expected HPP hourly margin in 2025 for ALT2 ME

The HPP margins for 2030 in ALT 2 are shown in **Figure 14**. The weekly Minimum HPP margin goes from 95 MW in spring to 670 MW in the summer season, while on average, the minimum HPP margins are around 300 MW for all decarbonization scenarios. HPP margins are higher than in 2025, while the TPP margin is zero because TPP Pljevlja is decommissioned. In 2030, Montenegro has 3000 MW (due to the second pole of IT-ME HVDC) of total import NTC. These factors combined mean that Montenegrin power system adequacy, in this case, is not jeopardized,

[10] TPP Pljevlja is not paying CO2 tax in 2025

even with only HPP margins left. It also points out how important the ability to import power is to Montenegro.

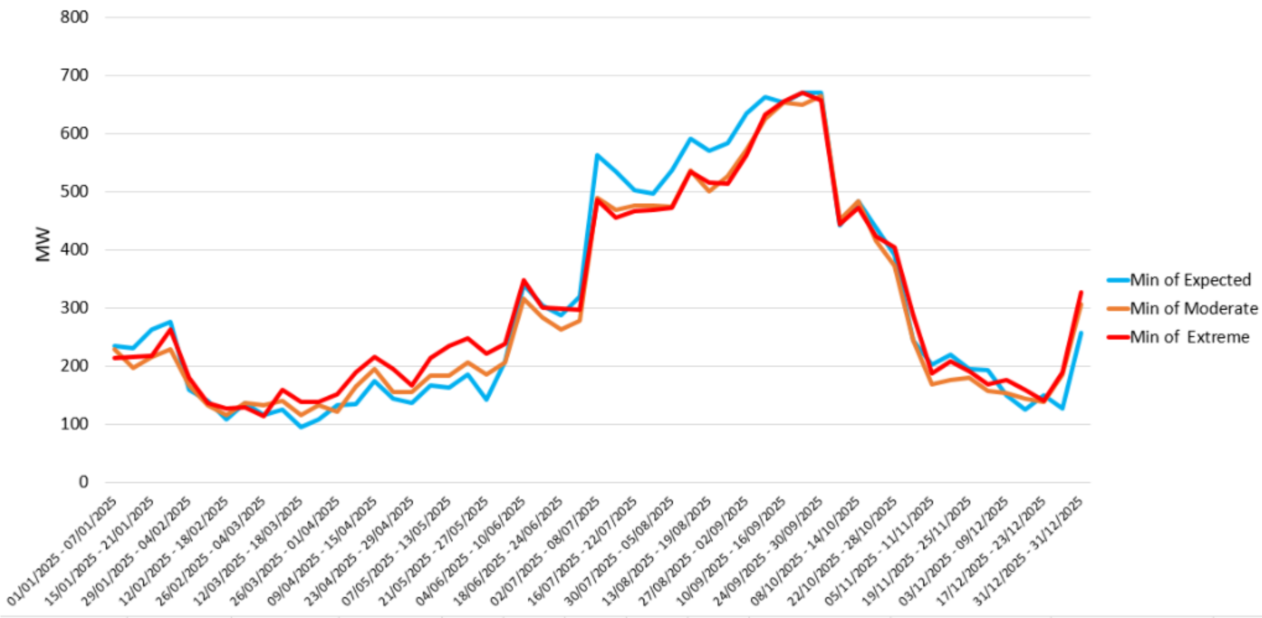


Figure 14: Expected HPP hourly margin in 2030 for ALT2 ME

3.2.4 Market Assessment for Expected ME Power System Development

2025

As agreed with CGES, for expected ME power system development, we analyzed not only the adequacy indicators but also the market ones. We did so by repeating the simulation of the same model, but without explicitly modelled reserves, because modeling reserve mostly as additional demand are giving non-realistic results for energy mix, prices, and exchanges.

The main market indicators for this analysis for SEE are shown in **Table 13**. Montenegro's annual demand is 3.8 TWh, generation is 4.8 TWh, and exports 1 TWh, while the average price is 82.6 €/MWh. The entire SEE demand is 261 TWh, while generation is 296.6 TWh, so on the annual level the region exports around 35.6 TWh. The average regional price is 84.9 €/MWh, with some countries (e.g., Croatia and Slovenia) higher than others. The average prices vary from 77.1 €/MWh – to 94.5 €/MWh.

Table 13: SEE Main market indicators in 2025, Expected ME Development

	GEN. TWh	DEMAND TWh	BALANCE TWh	LOWER PRICE €/MWh	AVERAGE PRICE €/MWh	HIGHER PRICE €/MWh
AL	8.9	7.9	1	72.3	82.7	97.13
BA	17.5	12.5	5	72.3	82.6	90.1
BG	31	34	-3	78.4	84.9	98.2
GR	71.2	56.9	14.3	77.6	83.4	96.6
HR	14.6	17.8	-3.2	89.3	92.3	95.4
ME	**4.8**	**3.8**	**1**	**72.3**	**82.6**	**90.9**
MK	7.6	7.9	-0.3	72.4	82.8	97.13
RO	64	62	2	78.3	84.8	91
RS	53	37	16	72.3	82.5	90.8
SI	16.4	14.9	1.5	91	93	95.5
XK	7.6	6.3	1.3	72.3	82.6	97
EMI	**296.6**	**261**	**35.6**	**77.1**	**84.9**	**94.5**

In **Figure 15** we depict the projected Montenegrin generation mix in 2025. Generation from TPP Pljevlja will be 1.4 TWh, while HPP generation will reach 2.7 TWh. RES generation would be 0.4 TWh from Wind and 0.2 TWh from Solar power plants.

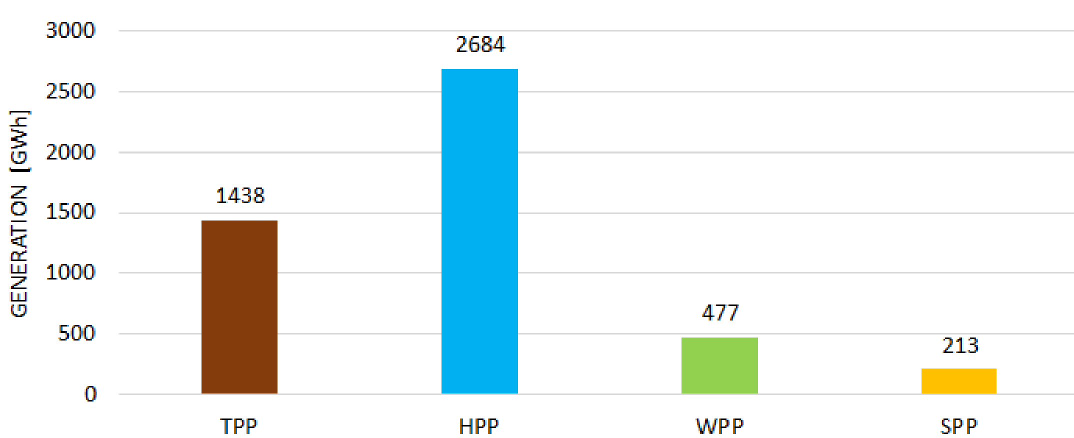
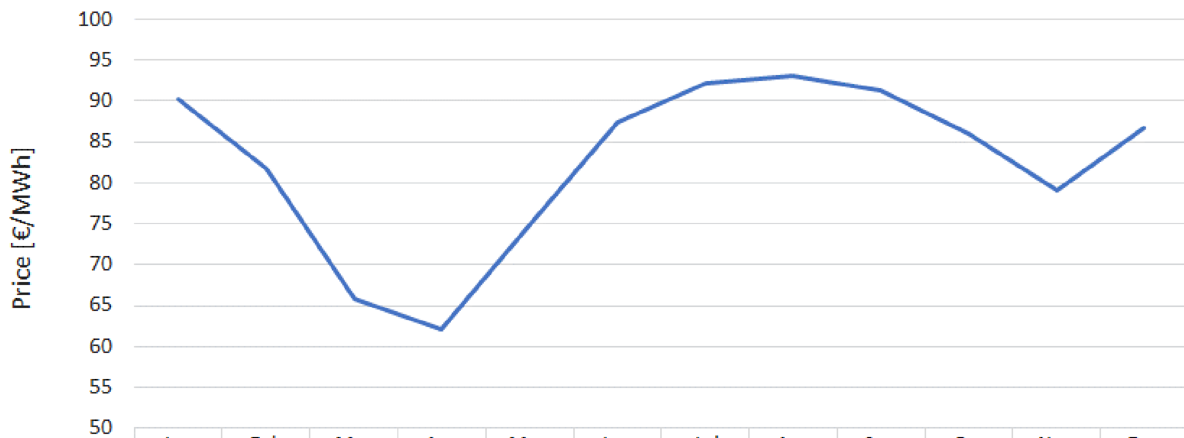


Figure 15: Montenegrin generation mix in 2025, Expected ME Development

Expected monthly prices in 2025 are presented in **Figure 16**. They vary from 65.8 €/ MWh to 93 €/ MWh in standard seasonal shape – they are lowest during spring and highest in summer, due to the level of demand.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Avg	Sep	Oct	Nov	Dec
Avg price	90.26	81.77	65.79	62.03	74.8	87.41	92.19	93.03	91.38	85.94	79.16	86.69

Figure 16: Average Monthly prices in Montenegro in 2025, Expected ME Development

Figure 17 shows Montenegro's annual exchanges with neighbouring power systems in 2025 Montenegro on an annual level imports 1 TWh from RS, XK and AL, while exporting 2 TWh to Italy and BiH. In sum, Montenegro remains a 1 TWh net exporter in 2030, while 1 TWh is transiting through the country.

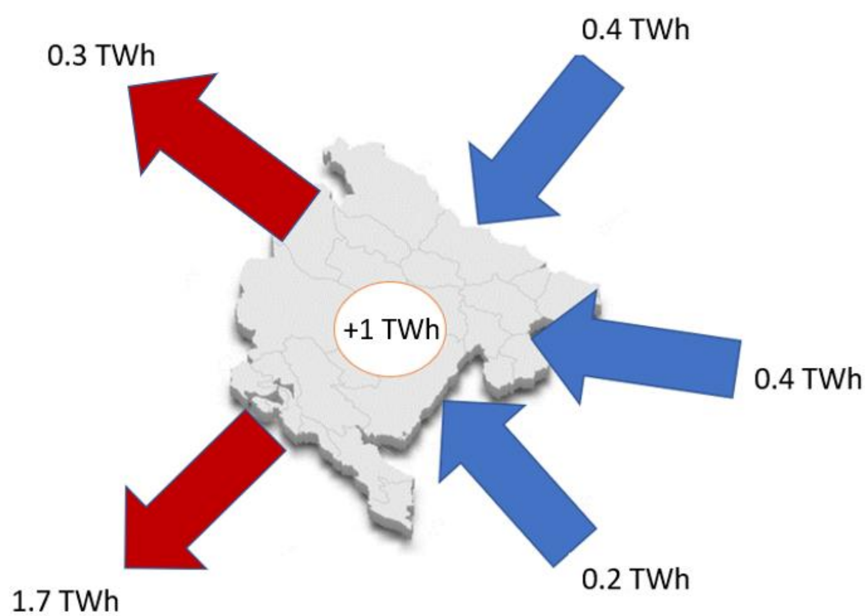


Figure 17: Montenegro's expected annual exchange with neighbors in 2025

2030

As we did for 2025, for the expected ME power system development scenario, we next analyzed the market indicators for 2030. We did so by repeating the model simulation, but without explicitly modelled reserves, same as for 2025 – in order to have more realistic results.

We show the main market Indicators for SEE in 2030 in

Table 14. Montenegro's annual demand is now 4.0 TWh, generation 5.3 TWh and exports 1.3 TWh, while the average wholesale price is 116.2 €/MWh. The entire SEE demand is 276.1 TWh, while generation is 309.4 TWh, so on an annual level the region exports around 33.3 TWh, which is several TWh less than in 2025. Prices vary from 108.9 €/MWh – to 145.4 €/MWh.

Table 14: SEE Main market indicators in 2030, Expected ME Development

	GEN. TWh	DEMAND TWh	BALANCE TWh	LOWER PRICE €/MWh	AVERAGE PRICE €/MWh	HIGHER PRICE €/MWh
AL	10.65	8.7	1.95	108.1	115.3	122.8
BA	8	12.6	-4.6	109.1	116.5	125.2
BG	37.1	36.2	0.9	108.2	115.3	122.8
GR	77	60.5	16.5	107	114	120.7
HR	15.7	18.5	-2.8	112.1	119.5	246.1
ME	**5.3**	**4**	**1.3**	**108.9**	**116.2**	**124.3**
MK	6.5	8.4	-1.9	108.2	115.3	122.8
RO	84.3	65.1	19.2	108	115.2	122.75
RS	44.4	39	5.4	108.2	115.2	122.8
SI	16.6	16.3	0.3	112.1	119.4	246.1
XK	3.8	6.8	-3	108.3	115.3	122.8
EMI	**309.4**	**276.1**	**33.3**	**108.9**	**116.1**	**145.4**

Figure 18 depicts the Montenegrin generation mix in 2030. Generation from TPP Pljevlja is on the 1 TWh level, while HPP generation is 2.9 TWh. RES generation is 0.5 TWh from Wind and 0.9 TWh from Solar power plants.

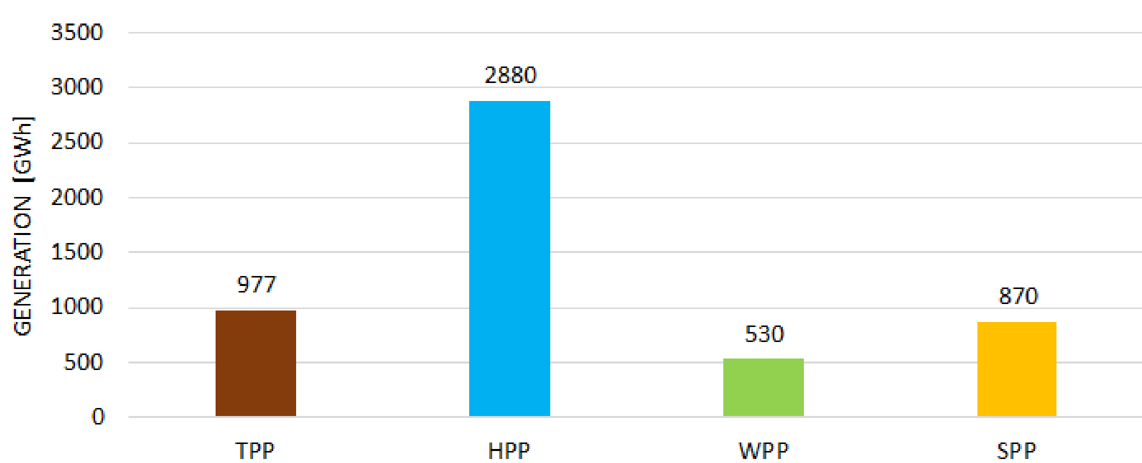


Figure 18: Montenegrin generation mix in 2030, Expected ME Development

Expected ME monthly prices for 2030 are presented in **Figure 19**. They vary from 98.6 €/ MWh to 126.6 €/ MWh in standard seasonal shape – lowest during spring and highest in summer, due to the level of demand.

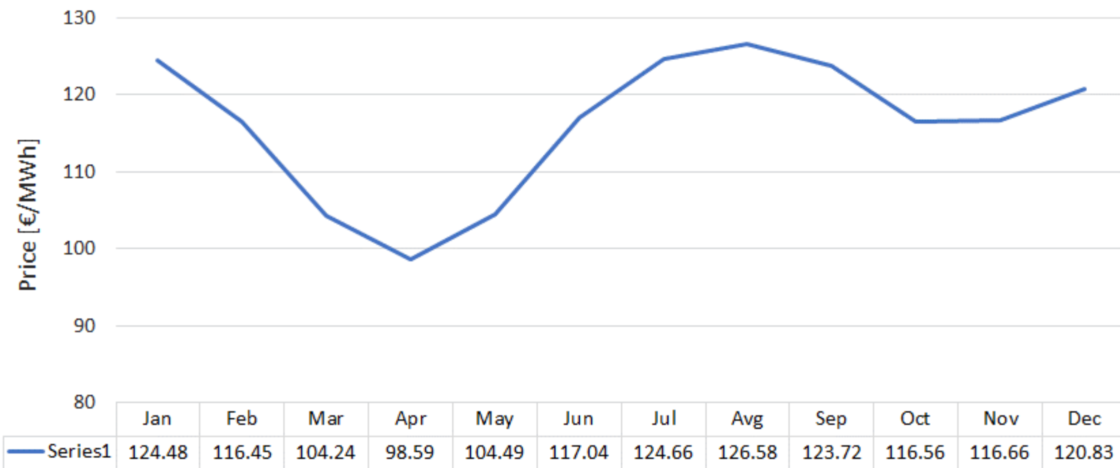


Figure 19: Average Monthly prices in Montenegro in 2030, Expected ME Development

Figure 20 shows annual exchanges with neighboring power systems in 2030. Montenegro on an annual level imports in total 4.6 TWh from RS, XK and AL, and exports 5.9 TWh to Italy and BiH. In sum, Montenegro is a 1.3 TWh net exporter, while 4.6 TWh is transiting through the country. The transit is much higher since this scenario includes a second HVDC line across the Adriatic.

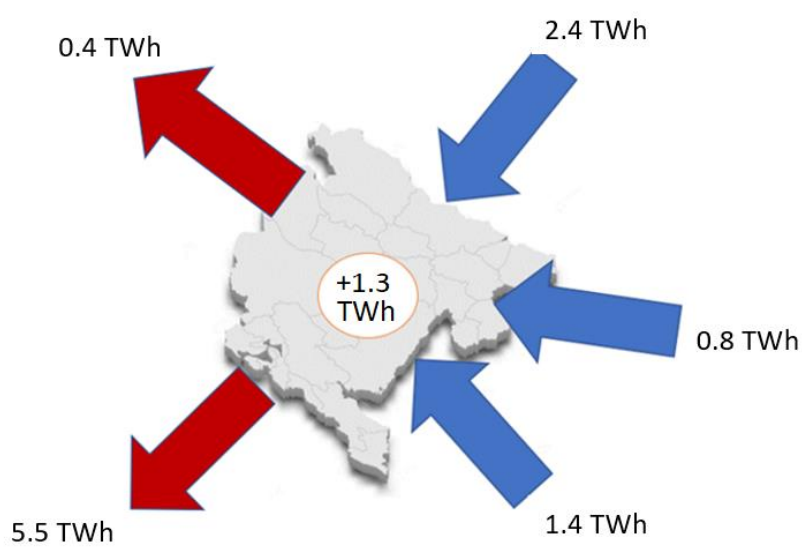


Figure 20: Expected annual exchange with neighbors in 2030, Expected ME Development

3.3 Capacity Mechanisms

European energy policies based on decarbonization are profoundly changing the dynamics and trends of the wholesale electricity markets in Europe. In theory, "energy-only" wholesale electricity markets could produce price signals sufficient to attract market players to invest in new power generation capacities. However, in practice, this is not always the case, as has been seen in a number of power systems in Europe.

The high level of uncertainty related to electricity market trends observed in the last decade has created significant risks for investment in conventional power generation. Those uncertainties were mainly influenced by partial distortion through renewable subsidies, as well as changes in regulations governing the CO2 market.

The introduction of a capacity mechanism represents one of the options for stimulating investments in power generation capacity and ensuring future power system adequacy. Currently, there are capacity mechanisms in numerous states in Europe (see **Figure 21**).

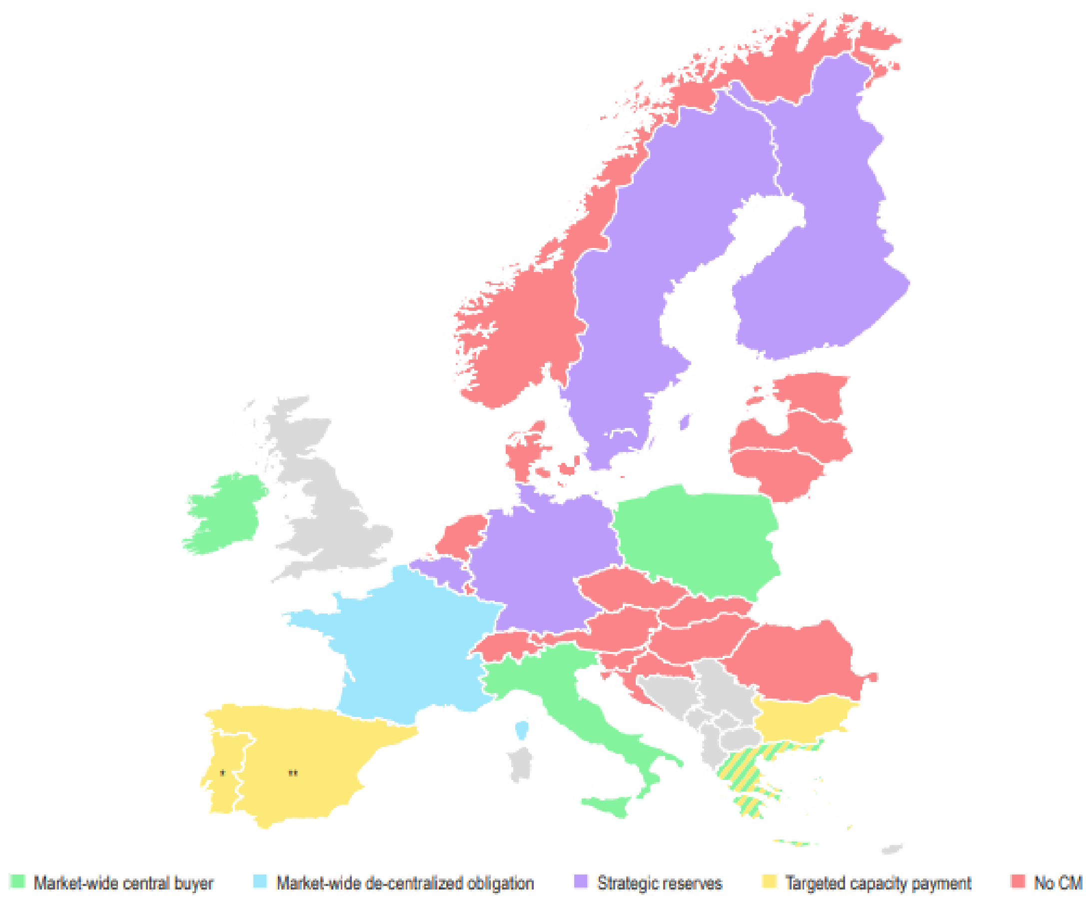


Figure 21 Overview of Implemented Capacity Mechanisms in Europe – 2020 [ACER]

To justify the need for state intervention and the implementation of capacity mechanisms, the measure and target for the security of supply needs to be defined, in order to assess whether the target can be reached without state intervention. If countries in SEE need a non-market, state intervention to assure the security of supply, they may wish to consider capacity mechanisms.

Considering that the results of the generation adequacy assessment did not detect adequacy issues in Montenegro by 2030, there is no need for Montenegro to consider a capacity mechanism at this time. However, this could change based on the development of the Montenegrin and European power systems. For that reason, in this chapter, we define the main principles of capacity mechanisms, including their types and best practices for implementation.

3.3.1 Definition and types of capacity mechanisms

ENTSO-E defines a capacity mechanism in its mid-term studies as:

Capacity Mechanism (CM): A temporary non-market measure to ensure the achievement of the necessary level of resource adequacy by remunerating resources for their availability, excluding measures relating to ancillary services or congestion management.

Therefore, a capacity mechanism aims at covering the risk of structural shortage in generation and helps to maintain the security of supply in critical periods.

This structural capacity shortage may be caused by the demand for power inducing significant peak loads in very few daily hours, with a high sensitivity to temperature. In other countries, a high share of renewable energies may induce shorter run times for conventional thermal generation units. In both cases, revenues for such generation units may be reduced to a few hours and be a barrier to economic viability or investments in generation, and require a process to replace or provide for an inadequate generation when it is needed most. Such resources are often long-term in nature and come from wholesale generators (e.g., peaking plants, storage), though increasingly, capacity can also come from demand-side resources.

These capacity mechanisms are quite different from balancing reserves, which a Transmission System Operator needs to procure in real time to compensate for residual imbalances from Balancing Responsible Parties, as stated by ENTSO-E. Such frequency ancillary services include the operational reserves referred to as the Frequency Containment Reserve, the automatic and manual Frequency Restoration Reserves and the Replacement Reserves. These operational reserves are ruled by a specific regulatory framework under ENTSO-E guidelines.

In different European countries, there are varying types of capacity mechanisms in place to tackle adequacy issues, and they take into account a wide range of sources of these issues according to the structure and specificities of the national electric systems and markets.

As an illustration of the variety of national capacity mechanisms, we present several examples:

- France faces a unique situation: 1) the annual peak load increases more quickly than the annual energy demand 2) France represents almost 50% of the European temperature sensitiveness.
- Great Britain needs to tackle the issue of decommissioning large thermal generation units and stimulate investments in generation.
- In Poland, there is significant demand growth, combined with ageing and polluting thermal generation units that have been decommissioned, and new investment is low.
- In Spain, it is necessary to contain price volatility and send appropriate market signals to actors that can provide available and flexible power.
- In Germany, North-South congestion is a major issue, and it is critical to ensure the availability of backup generation units.

All these issues can be addressed and mitigated using the most common types of capacity mechanisms, which we classify into two main categories: 1) volume-based and 2) price-based. For volume-based mechanisms, a centralized authority sets the required capacity, and the market sets the price. For price-based mechanisms, a national authority sets a fixed price, and the market drives the volumes or quantities (see **Figure 22**).

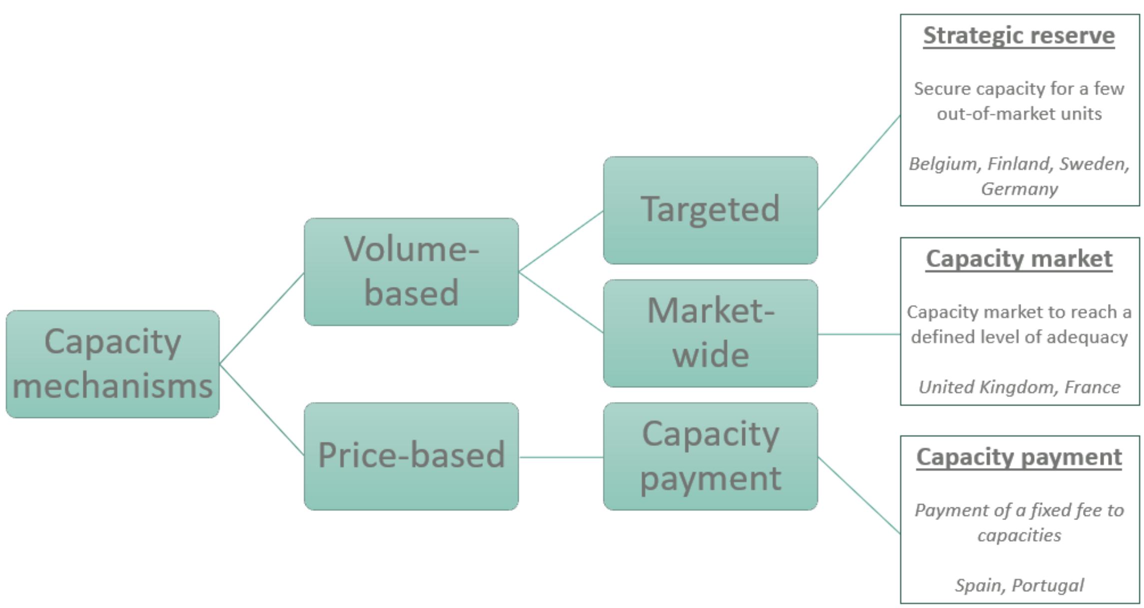


Figure 22 Different types of capacity mechanisms

3.3.2 Conditions, requirements and best practices on the European level

Given that Montenegro is an EU candidate state and part of the Energy Community, we here provide an overview of the best European practice and regulations related to the implementation of capacity mechanisms.

The electricity regulation 2019/943 (« Clean Energy Package ») defines a strict framework for the implementation of a Capacity Remuneration Mechanism (whatever its type). The implementation of a capacity mechanism requires:

1. An adequacy concern, proven by European Resource Adequacy Assessment (ERAA) or National Resource Adequacy Assessment (NRAA). As stated in EU regulations:

   Electricity regulation 2019/943 - Art. 21/4:

   The Member States shall not introduce capacity mechanisms where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment, have not identified a resource adequacy concern.

2. To prove there is an adequacy issue, ERAAs and NRAAs must follow a particular methodology

This methodology requires an Economic Viability Assessment (EVA) of potential capacities.

EVA is a step in the RAA process that assesses the profitability of potential capacity resources and provides guidance for decisions for retirement, mothballing and re-entry, renewal/extension and the building of new capacity resources.

Further, EVA is based on the difference between the revenues of a capacity provider and all costs they expect to incur, including:

- Variable costs include fuel costs, CO2 emission costs and variable O&M costs
- CAPEX Annuity and fixed O&M costs

It should be mentioned that the CAPEX annuity only applies to new capacities or to relevant investments in rehabilitating existing capacities, and does not include other revenue streams (like revenues from ancillary services).

According to this methodology, a capacity provider may be considered economically viable if its revenues are higher than (or equal to) its costs, including the application of a hurdle rate that represents the return or profit that such capacity resources would require for economic viability.

3. The removal of any market failure or distortion in the energy market

The EU regulation (Article 20.3) clearly states the measures to be considered in Market Reform Plans for that purpose:

(a) removing regulatory distortions;

(b) eliminating wholesale price restrictions ("caps");

(c) making sure that the value of reserves in the system is appropriately reflected in prices;

(d) increasing interconnection and internal grid capacity;

(e) enabling self-generation, storage, demand side measures and energy efficiency;

(f) ensuring cost-efficient and market-based procurement of balancing and ancillary services;

(g) and that price regulation is phased out or at least it is adjusted to bring it in line with Article. 5 of Directive (EU) 2019/944[2]

If such failures or distortions exist, there should be an implementation plan to define, correct and monitor them. In other words, states should attempt to fix and optimize their markets first. If adequacy concerns remain after taking these steps, states can consider the need for one or more capacity mechanisms. In addition, states should take the effects and resources in neighboring countries into account, after which they can introduce capacity mechanisms to eliminate residual adequacy concerns, while also improving the energy market.

The first capacity measure that states may consider is to implement strategic reserves. "Strategic reserve" means a capacity mechanism in which resources are only dispatched in case transmission system operators have exhausted their balancing resources between demand and supply. These capacities are considered out of the market, to limit any interference between the strategic reserve and the functioning of the electricity market. If such strategic reserves can tackle the adequacy concern, states should implement this measure. When this measure does not solve the adequacy concern, states can consider and move to other forms of capacity remuneration.

Finally, Article 22 of the European Regulation 2019/043 (Internal Market for Electricity) sets the design principles for capacity mechanisms in Europe, highlighting that they shall:

- *be temporary;*
- *not create undue market distortions and not limit cross-zonal trade;*
- *not go beyond what is necessary to address the adequacy concerns referred to in Art.20;*
- *select capacity providers by means of a transparent, non-discriminatory and competitive process;*
- *provide incentives for capacity providers to be available in times of expected system stress;*

- *ensure that the remuneration is determined through the competitive process;*
- *set out the technical conditions for the participation of capacity providers in advance of the selection process;*
- *be open to the participation of all resources that are capable of providing the required technical performance, including energy storage and demand side management;*
- *apply appropriate penalties to capacity providers that are not available in times of system stress.*

While Montenegro is secure (with no inadequacies detected) for the time being, this report identifies significant adequacy concerns for a number of states in SEE, under the extreme decarbonization scenario. Montenegro should continue to carefully observe the situation in the region and learn from others' experiences to identify the best CRM practices.

4 Power System Flexibility Analysis

Power system flexibility needs originate from deviations in the power system due to variability and the uncertain availability and variability of generation, demand and grid capacity over all time horizons. We use flexibility metrics to raise awareness of potential gaps which might appear due to this demand and supply variability and uncertainty.

Under this Study, the power system flexibility analysis assessed future flexibility needs related to the adequacy of the power system, in line with the latest ENTSO-E methodology and recommendations[11]. For this purpose, we used the results of ANTARES power system simulations to quantify additional flexibility indicators.

In that context, we assessed two flexibility metrics: (1) Ramping flexibility needs; and (2) Scarcity period flexibility needs.

The main input to the flexibility analysis represents the residual load curve. Residual load is the load left after subtracting VRE generation like wind, PV and run-of-river hydro from the demand. Residual load serves as a basis for flexibility analysis since it defines conditions to be met by dispatchable sources (e.g., TPP generation, demand response). **Figure 23** shows this concept.

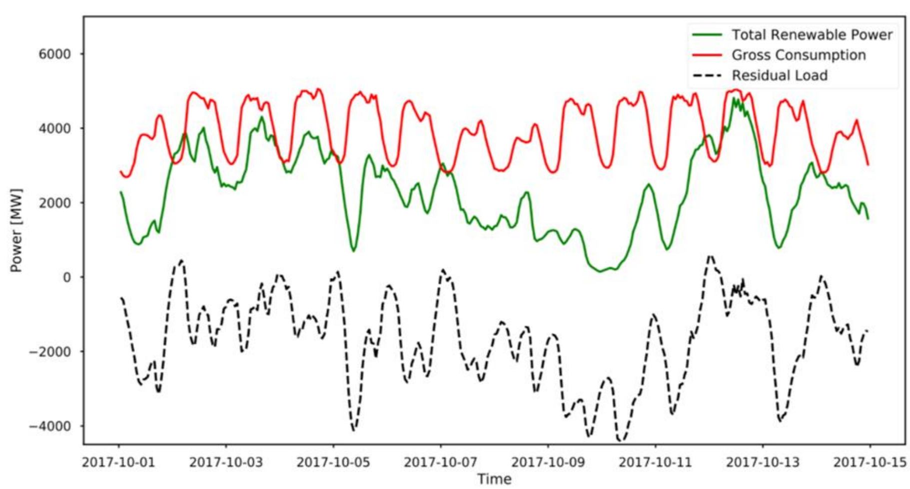


Figure 23: Residual Load Curve Construction

[11] ENTSO-E Position paper: Assessment of Future Flexibility Needs

4.1.1 Ramping flexibility needs

Ramping flexibility needs represent the metrics that measure large daily residual load gradients, for example, at sunset in regions with large PV generation capacities.

We assessed ramping flexibility needs using the following indicators:

- **The highest annual residual load MW ramps**, calculated as the differences between residual loads 1, 3 and 8 hours apart. The value can be normalized to the market zone's dispatchable capacity including demand response, accounting for forced outage derations.
- **The percent of loss of load expectation (LOLE) and expected energy not served (EENS) during the 5% highest ramp periods**. The metrics indicate how the ramping issue can also pose adequacy and economic problem.

We present the highest annual residual load MW ramps in 2025 and 2030 for the power system of Montenegro in **Figure 24** and **Figure 25**. As expected, the growth of consumption, as well as higher RES penetration increase the need for ramping flexibility. Clearly, 2030 is more critical than 2025 in all three hourly periods, with much higher MW ramping needs. Also, the base or expected scenario, characterized by a higher load compared to the ALT1 scenario, and a greater RES level compared to the ALT2 scenario, generates the most challenging ramping requirements.

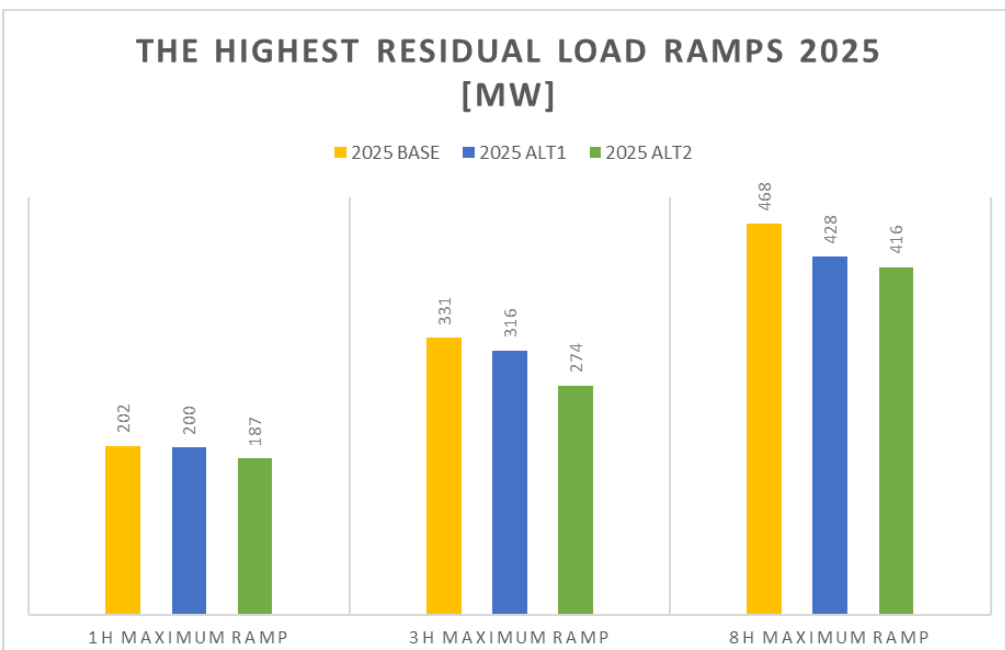


Figure 24: The highest residual load ramps for the power system of Montenegro in 2025

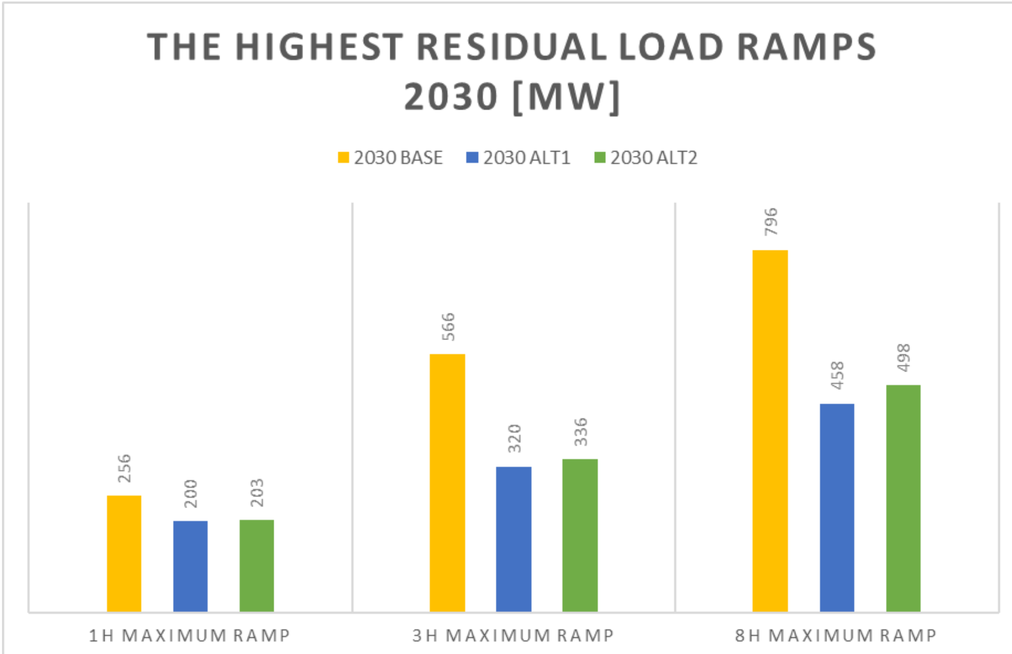


Figure 25 The highest residual load ramps for the power system of Montenegro in 2030

Even though maximum ramping needs go from 187 MW to 796 MW, the Montenegrin power system does not have problems with flexibility needs in the context of ramping, mainly because of high storage HPP and interconnection capacities in combination with relatively low hourly demand.

4.1.2 Scarcity period flexibility needs

Scarcity period flexibility needs are metrics focused on contiguous-day EENS problems during scarcity periods when Variable Renewable Energy (VRE) resources are not available for extended and continuous periods (e.g., very dry spells or numerous rainy days).

Scarcity period flexibility needs are assessed using the following indicators:

- **The maximum annual value of 120-hour residual load rolling averages**, including FCR and FRR requirements.
- **LOLE and EENS percentages over the maximum 120-hour average residual load periods**. The metrics indicate what fraction of overall adequacy concerns stem from seasonal scarcities involving extended periods of high residual load and low VRE generation.

We show the annual pattern of 120-hour residual load rolling averages in 2025 and 2030, under the climate conditions with the maximum value of the indicator for the power system of Montenegro, in **Figure 26** and **Figure 27**. The combination of high consumption with low RES development in the ALT2 scenario is why we see the highest observed 120-hour residual load average in this scenario. In general, the deviation between indicator values falls within 8% among different scenarios. We observed that for all but one scenario and year (2030 BASE), the maximum annual value of 120-hour residual load rolling averages occurs for "the climate year 1998" during the peak tourist summer season. For the 2030 BASE scenario, different climate years provide the maximum value of this indicator ("the climate year 1985"), for which the maximum annual value of 120-hour residual load rolling averages occurs in January.

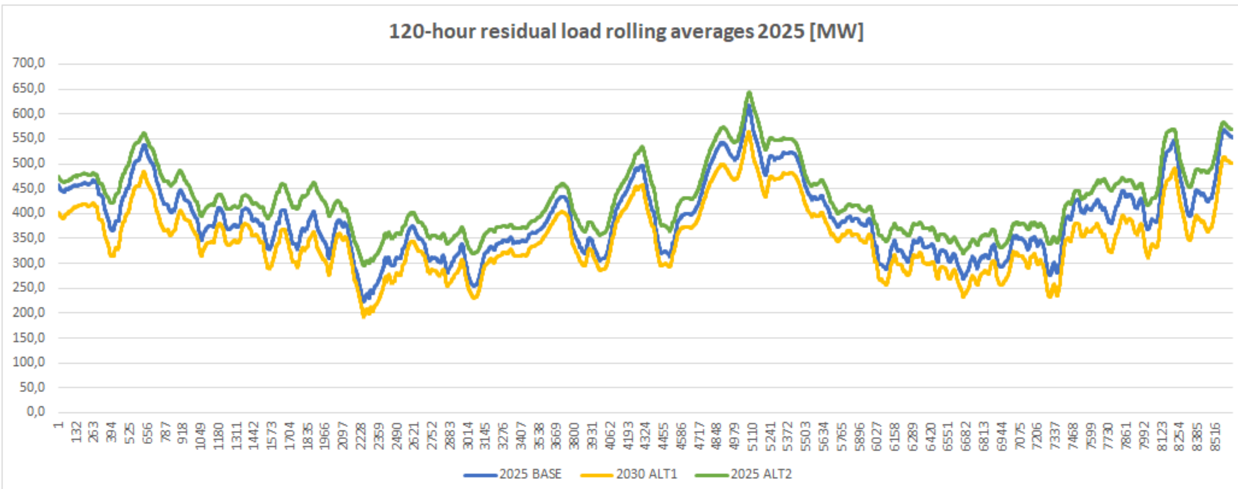


***Figure 26*: 120-hour residual load rolling averages for the power system of Montenegro in 2025**

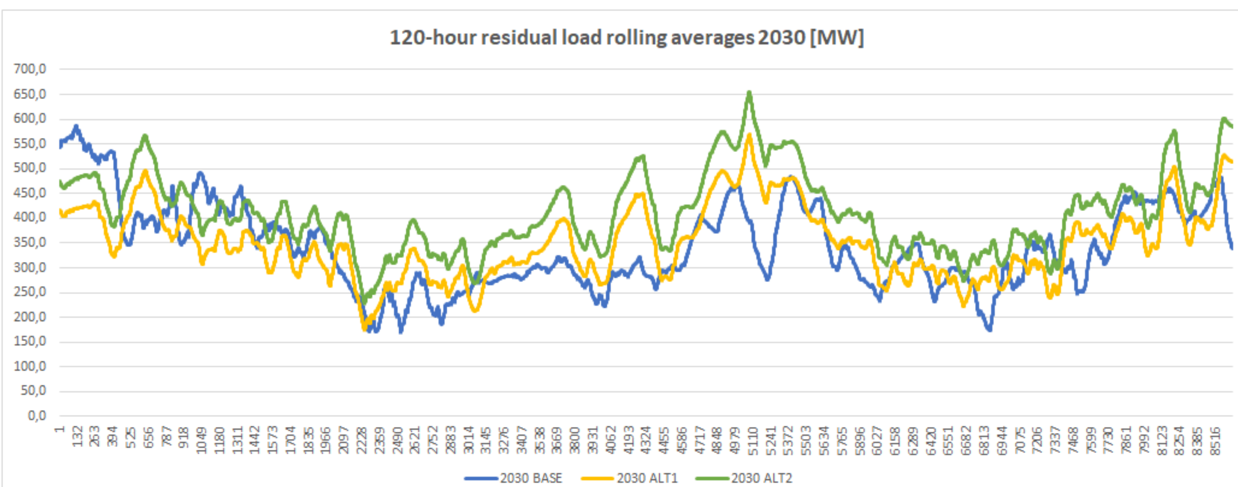


Figure 27: 120-hour residual load rolling averages for the power system of Montenegro in 2030

Table 15: Summary of the scarcity period needs indicator for residual load

The maximum annual value of 120-hour residual load rolling averages [MW]		
Scenario	**2025**	**2030**
BASE	617	588
ALT1	564	569
ALT2	644	654

As in the case of ramping needs, the Scarcity period needs of around 600 MWs do not present a problem for the Montenegrin power system, considering the country’s import and generation capabilities.

From the results of the adequacy analysis, it is clear that LOLE and EENS for Montenegro are zero in all the analyzed scenarios, so there are no adequacy issues at this time, and further investigation of LOLE and EENS due to ramping or scarcity is not required now. That is, flexibility needs for Montenegro, expressed as ramping and scarcity, are not currently expected to cause any adequacy concerns in 2025 or 2030.

5 Conclusions

After a comprehensive analysis of System Adequacy and Flexibility for Montenegro, taking the results from Chapter 3.2 and Chapter 4 into account, we can draw a few conclusions about Montenegrin and SEE resilience on adequacy issues, in the context of envisaged decarbonization.

- **Adequacy and Flexibility Concerns in 2025**

In 2025, for all three scenarios of Montenegrin power system development, and three scenarios of SEE decarbonization, Montenegro and other SEE countries do not show any adequacy concerns. The only country that has positive LOLE and EENS is Greece, and these values are below three hours, the level of LOLE that is considered critical.

The adequacy and flexibility in the decarbonization scenarios in 2025 are not much different from each other, considering that 2025 is just three years from now, so their influence on adequacy is limited. Similarly, the Montenegro scenarios in 2025 are not significant for the entire SEE.

Disclaimer:

We carried out the adequacy analysis for 2025 before the ongoing European energy crisis, with a “business as usual” approach. The magnitude and nature of this crisis could certainly influence power systems in the next few years and require a separate analysis.

- **Adequacy and Flexibility Concerns in 2030**

In 2030 situation is noticeably different. The first two decarbonization scenarios are very similar to 2025, with no adequacy concerns – for Montenegro and other SEE countries. However, for the extreme decarbonization scenario, the situation is different, as Table 16 shows. The 2030 extreme decarbonization envisages a sharp decrease in TPP capacities in most countries, which affects system adequacy.

For the Expected ME scenario, six countries have LOLE above three hours, and for ALT1 that number rises to seven. In the ALT2 scenario, only Montenegro, Greece and Albania have LOLE’s under three. Each successive ME development scenario is more challenging, and incrementally raises the level of inadequacy in SEE. This is especially the case in ALT2, which includes slower HPP/RES development, the decommissioning of TPP Pljevlja, higher ME load, and only one pole of the ME-IT HVDC. In this scenario, Bosnia has the highest LOLE (44 hours), while Serbia has the highest EENS (28,606 MWh or 0.073% of annual load).

Thus, we conclude that other states in SEE should consider whether this combination of conditions would cause them to take actions to eliminate system inadequacies and consider capacity mechanisms to address them. Also, we conclude that it would be valuable to carry out a resource adequacy study for the entire region, to gain

perspectives on how to address any shortfalls (such as using capacity remuneration mechanisms) on a collective basis.

Table 16: Adequacy Indicators for SEE Extreme Decarbonization in 2030

Market area	Expected ME		ALT1 ME		ALT2 ME	
	EENS (MWh/%)	LOLE (hours)	EENS (MWh/%)	LOLE (hours)	EENS (MWh/%)	LOLE (hours
AL	0/0	**0**	0/0	**0.0**	132/0.002	**2**
BA	15/0	**3.1**	66/0.001	**7**	1053/0.008	**44**
BG	1780/0.005	**5.7**	2333/0.006	**7**	2354/0.007	**15**
GR	1263/0.002	**1.1**	1568/0.003	**1.4**	1875/0.003	**2.4**
HR	1246/0.007	**8.7**	1758/0.009	**11.2**	2829/0.015	**26**
ME	**0/0**	**0**	**0/0**	**0.0**	**0/0**	**0**
MK	73/0.001	**2.1**	158/0.002	**3.6**	146/0.002	**5**
RO	1076/0.002	**5.8**	1600/0.002	**7.8**	1832/0.003	**12**
RS	9830/0.025	**7.4**	13369/0.034	**9.8**	28606/0.073	**19**
SI	3072/0.019	**6.2**	3740/0.023	**7.4**	5253/0.032	**11**
XK	223/0.003	**1.1**	561/0.008	**2.6**	2619/0.038	**7**

In all of these scenarios, Montenegro is the only country in SEE that has no adequacy issues detected - i.e., the EENS and LOLE are always zero. Also, the ramping requirements and scarcity periods do not produce any flexibility issues. The reasons behind this are the following:

- **Concerning hourly demand, the Montenegrin planned generation fleet is solid.**

  We see this demonstrated in the HPP and TPP margins. While the TPP margin is usually low, because the cheap lignite TPP in ME almost always produces at its maximum, the weekly minimum HPP margins are adequate to high in all scenarios (from 40 MW - 840

MW). However, even in the case of low margins, Montenegro can rely for adequacy on a second factor to meet its needs – its robust interconnections.

- **Montenegrin import capacity is high** – This ranges from 2400 MW to 3000 MW, depending on the scenario, which is several times higher than the maximum hourly load, and thus provides a comfortable cushion to ensure that Montenegro will have adequate power supplies, even under an extreme decarbonization approach in SEE by 2030.

Overall, the Montenegrin power system shows resilience regarding adequacy and flexibility issues, in all proposed development scenarios and decarbonization paths. In this light, we do not recommend now a Capacity Mechanism for Montenegro. At the same time, considering the rapid pace of changes in the European energy sector, we would recommend the following:

- Introducing annual NRAA exercises for Montenegro, to complement the European-wide ERAA process. This can provide more detail on Montenegro's own needs and opportunities, and provide early notice of any adequacy concerns.
- Reviewing whether Montenegro's national energy legislation aligns with the EU legislation, especially regarding the adequacy criteria.
- Carrying out a resource adequacy study for other countries in SEE, and for the entire region. Doing so would provide recommendations on how to address the shortfalls that notably appear in the extreme decarbonization scenario, and identify whether capacity remuneration mechanisms might make sense on a collective basis.

ANNEX: INPUT DATA

In this chapter, we present the input data and modelling assumptions we used in this project. We present CGES's input data for Montenegro in detail, for both TYs and three ME development scenarios, while we summarize the data covering the EMI region and the rest of Europe.

5.1 Montenegro

Demand for Power

CGES provided two forecasts of total annual demand for 2025 and 2030 TYs (see **Table 17**).

Table 17: Forecasted Annual Demand for Montenegro [in TWh]

	Development Scenario	2021	2025	2030	Growth rate 2021- 2030 [%]
Demand [TWh]	**Expected and Alt2**	3.37	3.8	4	1.9
	Alt 1		3.32	3.53	0.5

The first forecast, which envisages a 1.9 % level of demand growth, is based on the latest official Montenegrin TYNDP projections, while the second one, with a lower demand growth rate of 0.5%, is based on realized demand in the last few years. This spectrum enables CGES to assess resource adequacy for the full range of anticipated demand.

We used the first forecast in the expected and alt2 ME development scenario, while the second, lower forecast is used in the alt1 ME development scenario.

While CGES provided the annual values, we used hourly shapes from the ERAA 2021 for the 35 climatic years (1982-2016).

Thermal Power Plants

Montenegro has only one thermal power plant, Pljevlja, and we present the data essential for modelling this plant in **Table 18**.

Table 18: Essential Techno-economic Characteristics of TPP Pljevlja

Fuel Type	*Lignite*
No of units	*1*
Net Generation Capacities [MW]	*205*
Minimum Stable Level [MW]	*155*
Heat Rate at Pmax [GJ/MWh]	*10.9*
Heat Rate at Pmin [GJ/MWh]	*12.1*
CO2 emission [tonCO2/MWh]	*0.99*
Minimum down time [h]	*24*
Minimum up time [h]	*168*
Maintenance outage rate [%]	*13.5*
Forced outage rate [%]	*5*
Fuel price in 2025 and 2030 [€/GJ]	*1.8*
Variable Operating & Maintenance Costs [€/MWh]	*3.3*

While these techno-economic characteristics remain the same in all scenarios, the operational status of TPP Pljevlja differs in different Montenegrin development plans (see **Table 19**).

Table 19: TPP Pljevlja Operational Status in Different ME Power System Development Scenarios

	Development Scenario	**2025**	**2030**
TPP Pljevlja Operational Status	**Expected**	In Service	In Service
	Alt 1 and Alt2	In Service	Out of Service

Hydro Power Plants (HPPs)

Currently, Montenegro has two large HPPs: HPP Piva and HPP Perucica, plus 33 MW of small HPPs. The development of small HPPs is on hold due to environmental issues, and few large HPP projects are envisaged. We provide essential data for existing and future HPPs in **Table 20**. We modelled HPPs plant-by-plant, using three hydrological conditions (dry, average and wet). For Storage HPPs, we applied the "Energy model" approach, using generation targets, and for ROR HPPs, we forecasted them using a fixed generation time series on an hourly level.

Table 20: Essential Characteristics of Montenegrin HPPs

HPP name	Operational Status	Installed capacities
HPP Piva	***Existing***	***3 * 114 MW***
HPP Perucica	***Existing***	***5 * 38 MW + 3 * 58.5 MW***
HPP Komarnica	*Planned*	*3 * 57 MW*
HPP Andrijevo	*Planned*	*2 * 63.7 MW*
HPP Raslovici	*Planned*	*2 * 18.5 MW*
HPP Milunovici	*Planned*	*2 * 18.5 MW*
HPP Zlatica	*Planned*	*2 * 18.5 MW*
HPP Kruševo	*Planned*	*90 MW*
Small HPP	*Existing*[12]	*36 MW*

While the technical data remains the same for all TYs and scenarios, the installed capacities vary. Table 6 shows the operational status of all HPPs in both TYs and three ME development scenarios.

Table 21: HPP Operational status in different ME power system development scenarios

HPP	2025 Expected/Alt1/Alt2	2030 Expected/Alt1/Alt2

[12] Existing 33 MW, for 2025 and 2030 36 MW is planned

HPP Komarnica	*In Service/ Out of Service/Out of Service*	*In Service/In Service/Out of Service*
HPP Andrijevo	*In Service/ Out of Service/Out of Service*	*In Service/ Out of Service/Out of Service*
HPP Raslovici	*In Service/ Out of Service/Out of Service*	*In Service/ Out of Service/Out of Service*
HPP Milunovici	*In Service/ Out of Service/Out of Service*	*In Service/ Out of Service/Out of Service*
HPP Zlatica	*In Service/ Out of Service/Out of Service*	*In Service/ Out of Service/Out of Service*
HPP Kruševo	*Out of Service/ Out of Service/Out of Service*	*In Service/ In Service/Out of Service*

Renewable Energy Systems (RES)

Currently, Montenegro has only 118 MW of wind generation capacity but expects further RES development. CGES provided the expected installed RES capacities for both TYs and development scenarios, as shown in **Table 22**. As indicated, installed wind capacity is anticipated to more than double by 2025, and in the expected scenario, solar capacity is expected to grow considerably.

Table 22: Forecasted RES Installed Capacities in both TYs and all Three ME Development Scenarios [in MW]

RES	2025 Expected/Alt1/Alt2	2030 Expected/Alt1/Alt2
Wind	*272/272/172*	*272/272/272*
Solar	*165/50/50*	*673/200/150*

We used the hourly capacity factors (CFs) for Montenegro for both TYs and RES technologies from the ERAA 2021 database for the 1982-2016 period (**Table 23**). RES is modelled as fixed, must-run generation by combining the installed capacities and hourly CFs.

Table 23: Average Annual RES Capacity Factors in Both TYs

RES	2025	2030
Wind	*20.21 %*	*20.21 %*
Solar	*14.8 %*	*14.8 %*

Net Transfer Capacities (NTCs)

CGES provided forecast NTC values across the Montenegrin borders for both TYs (see **Table 24**).

While all other NTC values remain the same in all TYs and ME development scenarios, the HVDC capacities in 2030 for the alt2 scenario remain at 600 MW, while for the other scenarios it rises to 1200 MW, assuming the addition of 600 MW of transfer capacity to Italy by 2030.

Table 24: Forecasted NTCs Values Between Montenegro and Neighboring Market Areas [in MW]

Zone A	Zone B	2025		2030	
		A>B	B>A	A>B	B>A
ME	**RS**	300	500	300	500
ME	**BA**	700	700	700	700
ME	**AL**	300	300	300	300
ME	**XK**	300	300	300	300
ME	**IT**	600	600	1200	1200/600[13]

We modelled HVAC cross zonal capacities (CZC) without additional outage simulation (this is already embedded in the AC grid NTC values (N-1 criterion)), while we modelled the HVDC CZCs ME-IT with a defined percentage of outage rates, as given in ERAA 2021 input data.

[13] In 2030 for Alt2 ME development scenario 600 MW for ME-IT HVDC is envisaged

Reserves

CGES provided the forecasted reserve for both TYs and both directions, as presented in **Table 25**. We modelled Frequency Containment Reserve (FCR) + Frequency Restoration Reserve (FRR) as an additional hourly load.

Table 25: Forecasted Reserves in both TYs in Montenegro [in MW]

	2025		2030	
	Upward	Downward	Upward	Downward
FCR	5	5	6	6
aFRR	30	30	32	32
mFRR	20	30	20	30

5.2 EMI Region

This subchapter presents summarized input data for the SEE region regarding installed capacities by technology and demand levels. All presented data correspond to the SEE EMI market areas without Montenegro, and they are taken from previous EMI studies. During the modelling phase, we conducted an additional data check and in some cases updated the EMI model with the most recent publicly available forecasts.

Demand

Table 26 shows the projected annual demand for the neighbouring market areas in the SEE region used in models, as given in previous EMI studies or ERAA 2021.

Table 26: Projected Annual Electricity Consumption for Market Areas in Southeast Europe [in TWh]

	Market area	2025	2030
Demand [TWh]	**AL**	7.9	8.7
	BA	12.5	12.6
	BG	34	36

	HR	18.0	18.6
	GR	57.3	61
	XK	6.38	6.85
	MK	7.8	8.4
	RS	37.03	39.07
	RO	62	65.2
	SI	14.93	16.3

While this table provides annual values, we used the hourly shapes from ERAA 2021 for the 35 climatic years (1982-2016).

Thermal Power Plants

Table 27 shows projected TPP installed capacities for the neighboring market areas in the SEE region for both TYs and three decarbonization scenarios, based on previous EMI studies and consultant assessments.

Table 27: Installed Thermal Power Plant (TPP) Capacities (MW) in SEE Market Areas

Market Area	2025 Expected/Moderate/Extreme	2030 Expected/Moderate/Extreme
AL	*100/100/100/*	*300/200/100*
BA	*1765/1590/1487*	*1632/1442/1166*
BG	*6324/6324/4698*	*4698/4040/3440*
HR	*981/876/684*	*981/876/684*
GR	*7768/7768/7768*	*7768/7167/6493*

XK	*960/672/528*	*978/528/264*
MK	*763/763/586*	*586/586/586*
RS	*4560/4370/4270*	*4570/3840/2770*
RO	*8140/8140/8140*	*10055/8562/6899*
SI	*2167/2144/1732*	*1732/965/912*

We modelled TPPs on a plant-by-plant level, including detailed techno-economic parameters such as net generating capacity, minimum stable level, SRMC, unavailability, etc.

Hydro Power Plants (HPPs)

Table 28 shows expected HPP capacities in the SEE region, based on previous EMI studies.

Table 28: Expected Installed HPP Capacities in SEE Market Areas [in MW]

Market Area	2025	2030
AL	*2647*	*2949*
BA	*2308*	*2493*
BG	*2609*	*3207*
HR	*2119*	*3302*
GR	*3210*	*4545*
XK	*66*	*424*

MK	*694*	*900*
RS	*3043*	*3043*
RO	*6084*	*6742*
SI	*1334*	*1334*

We modelled EMI HPPs plant-by-plant, with three hydrological conditions (dry, average and wet). For Storage HPPs, we applied the "Energy model" approach, using generation targets, while for RoR HPPs, we modelled them with fixed generation time series on an hourly level.

Renewable Energy Systems (RES)

Table 29 and **Table 30** show the region's expected wind and solar capacities, from prior EMI studies. For 2030, these figures are approximately triple the current installed capacity for wind and quadruple the current installed capacity for solar.

Table 29: Installed Wind Power Plant (WPP) Capacities in SEE [in MW]

Market Area	2025	2030
AL	*80*	*384*
BA	*350*	*580*
BG	*749*	*948*
HR	*1000*	*1300*
GR	*5100*	*7000*

XK	*184*	*336*
MK	*180*	*443*
RS	*3898*	*4553*
RO	*4334*	*5255*
SI	*67*	*150*

Table 30: Installed Solar Power Plant (SPP) Capacities in SEE [in MW]

Market Area	2025	2030
AL	*50*	*445*
BA	*50*	*100*
BG	*1785*	*3216*
HR	*400*	*600*
GR	*5200*	*7700*
XK	*70*	*150*
MK	*203*	*563*
RS	*468*	*508*

RO	*3393*	*5054*
SI	*951*	*1866*

While we provided installed RES capacities in these tables, we used the hourly capacity factors for both TYs and both technologies from the ERAA 2021 database for the 1982-2016 period. We modelled RES as fixed, must-run generation by combining installed capacities and hourly CFs.

NTC, Reserves and Other

While we used the NTC data from prior EMI studies[14], the reserve and other data (e.g. Batteries, DSR) came from the ERAA 2021.

5.3 Rest Of Europe

Other European countries are modelled according to the data from ERAA 2021 for National Estimates scenarios for 2025 and 2030. The representation of other European countries explicitly modelled in ERAA 2021 includes the following modelling elements, levels, and characteristics:

1. Demand - PECD hourly demand time series from 1982-2016 (35 climate years).

2. Thermal power plants (including Nuclear) - Cluster level modelling with detailed techno-economic parameters (net generating capacity, minimum stable level, SRMC, unavailability (FOR and MOR)[15], etc.).

3. Hydro power plants (RoR and Storage) – Cluster level modelling with the main technical parameters; "energy model" approach - energy targets for Storage, and fixed generation with hourly resolution/generation with limited dispatch possibilities (throughout a day) for RoR; different hydrological conditions will be analyzed.

4. PSHPP - Consideration of technical constraints and unit availability as defined in ERAA 2021; optimization under the full unit commitment and economic dispatch algorithm.

5. Wind, Solar and Other[16] - Fixed, must-run generation; installed capacities provided by TSOs combined with hourly CF factors from the PECD database 1982-2016 (35 climate years)/available capacity.

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[14] We have not shown all markets' NTCs in this report for the sake of brevity
[15] Different distribution patterns of forced outages throughout a year
[16] Category "Other" covers other RES and other non-RES generation

6. Battery storages (BESS) – storages with dispatch optimized within the probabilistic assessment; the parameters of interest include: installed output capacity (MW), storage capacity (MWh) and roundtrip efficiency (%).

7. DSR - A part of demand explicitly modelled as price-elastic DSR with volume bands, price bands and actual availability [MW] for all hours of the year.

8. Transmission constraints – NTC values[17] for both directions per border with the hourly resolution, as given in ERAA 2021 input data; HVAC cross zonal capacities (CZC) are modelled without additional outage simulation (already embedded in AC grid NTC values (N-1 criterion)); HVDC CZCs are modelled with a defined percentage of outage rates in the ERAA 2021 input data.

9. Balancing reserve - FCR+FRR are modelled as additional load or curtailment of installed capacity of the hydro/thermal units; replacement reserve is considered through available capacity (without capacity curtailment).

Demand

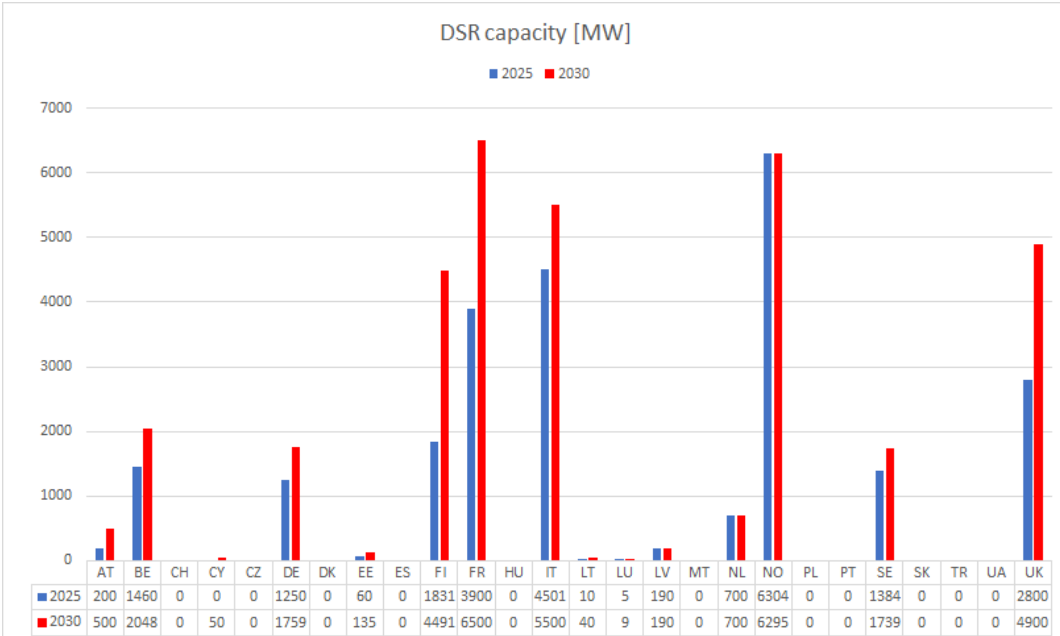
As shown in Figure 7, we consider each market's annual load, as well as the hourly load profiles, to a greater or lesser based on the market. We will further consider the evolution of the market, including the penetration of heat pumps, electric cars, batteries, and the evolution of baseload, etc.

	AT	BE	CH	CY	CZ	DE	DK	EE	ES	FI	FR	HU	IT	LT	LU	LV	MT	NL	NO	PL	PT	SE	SK	TR	UA	UK
2025	73	89	63	6	72	555	44	9	259	94	471	47	326	14	8	7	3	138	150	171	51	133	30	366	7	285
2030	83	95	64	6	74	585	53	9	263	108	479	51	331	15	9	8	4	140	164	182	56	152	31	427	8	307

Figure 28 Annual Load of Other EU countries in 2025 and 2030

[17] For the sake of brevity, we have not included NTC values for rest of Europe in this report. They can be downloaded at https://www.entsoe.eu/outlooks/eraa/eraa-downloads/

Figure 8 shows Demand Side Response capacities for other EU countries. In addition, we used the volume of DSR and price bands if they are defined in ERAA 2021, with hourly availability.



	AT	BE	CH	CY	CZ	DE	DK	EE	ES	FI	FR	HU	IT	LT	LU	LV	MT	NL	NO	PL	PT	SE	SK	TR	UA	UK
2025	200	1460	0	0	0	1250	0	60	0	1831	3900	0	4501	10	5	190	0	700	6304	0	0	1384	0	0	0	2800
2030	500	2048	0	50	0	1759	0	135	0	4491	6500	0	5500	40	9	190	0	700	6295	0	0	1739	0	0	0	4900

Figure 29 DSR Capacity of Other EU countries in 2025 and 2030

Generation Mix

The countries in Europe are well connected electrically, so changes in the generation mix (especially RES), consumption, fuel prices or CO2 emissions prices can have a significant impact on the electricity market of other European countries. In that light, the figures below represent data from the ERAA 2021 National Estimates scenario. This scenario follows the EU Climate and Energy targets (40% decrease in GHG emissions by 2030). Such goals imply the need to decommission TPPs (mostly older lignite-fired units) and the integration of substantial RES, primarily wind and solar. The integration of high VRE levels imposes the need for additional system flexibility, mainly in the form of new natural gas generation, greater balancing and BESS, since for pumped storage HPPs, the most favourable locations are largely taken.

We divide the generation development plans of the EU countries into four groups, as shown in **Figure 30 -Figure 33**, largely following the described processes.

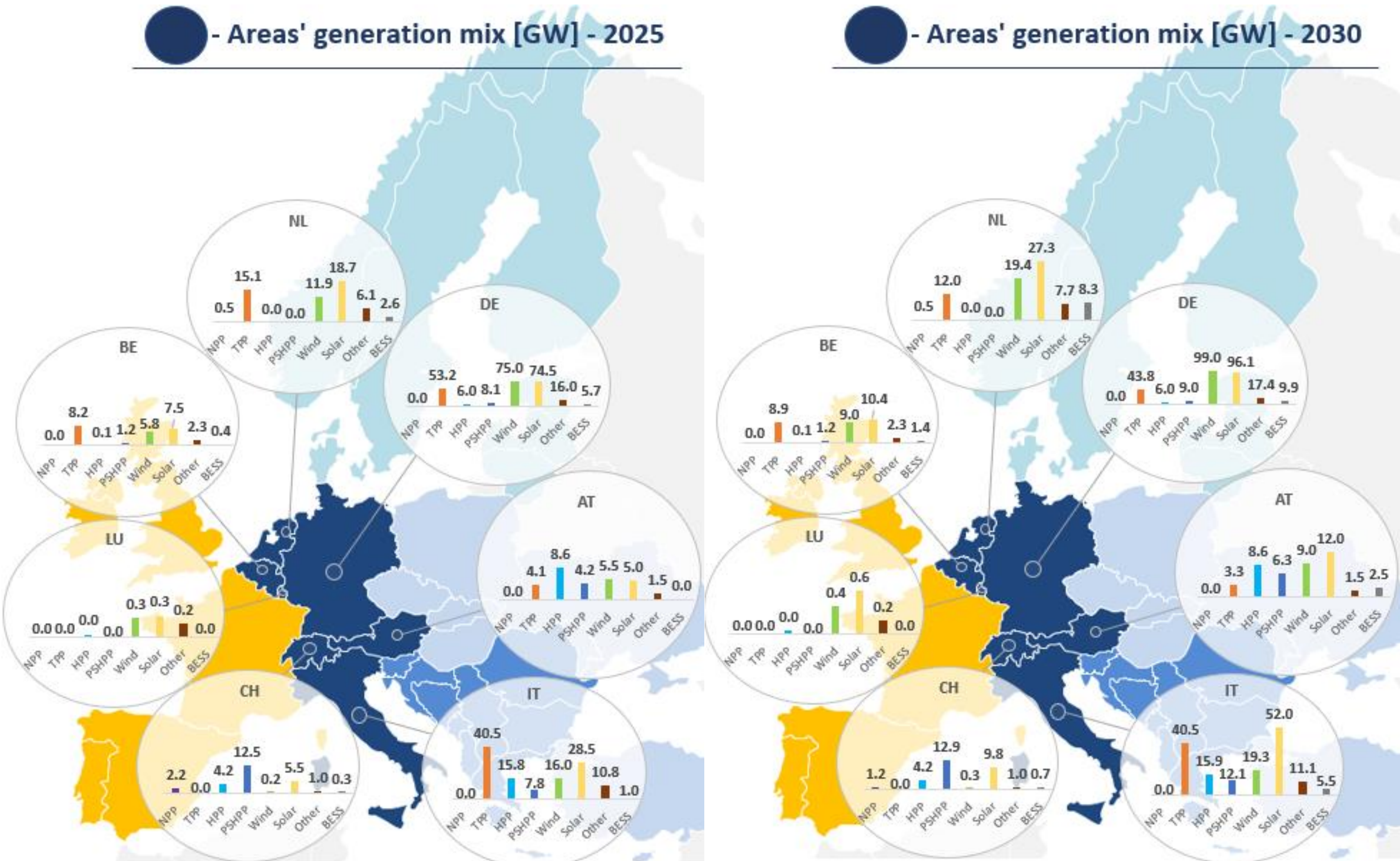


Figure 30 Generation Mixes of DE, AT, IT, CH, NL, BE and LU in 2025 and 2030

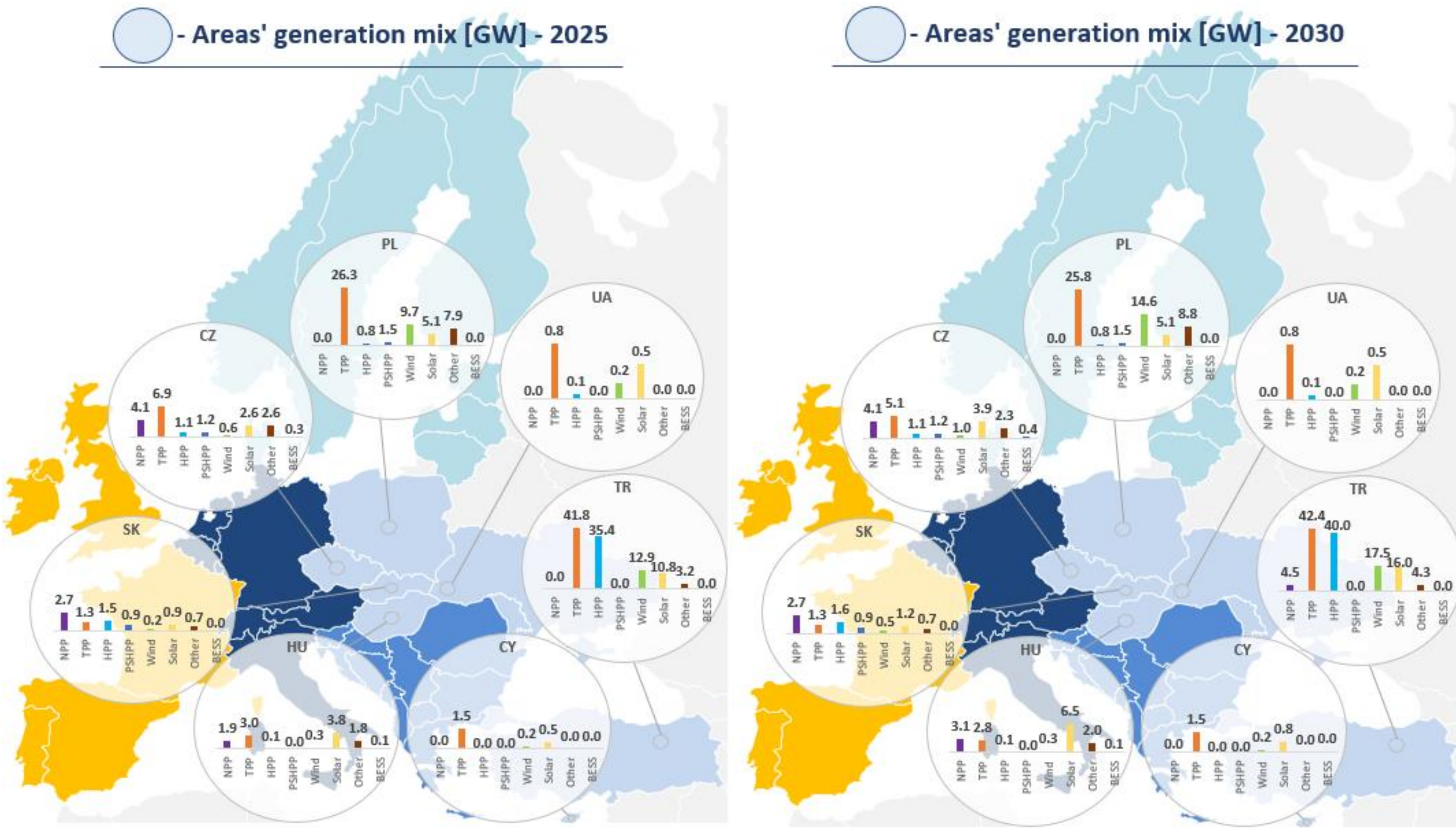


Figure 31 Generation Mixes of CZ, SK, PL, HU, UA, TR and CY in 2025 and 2030

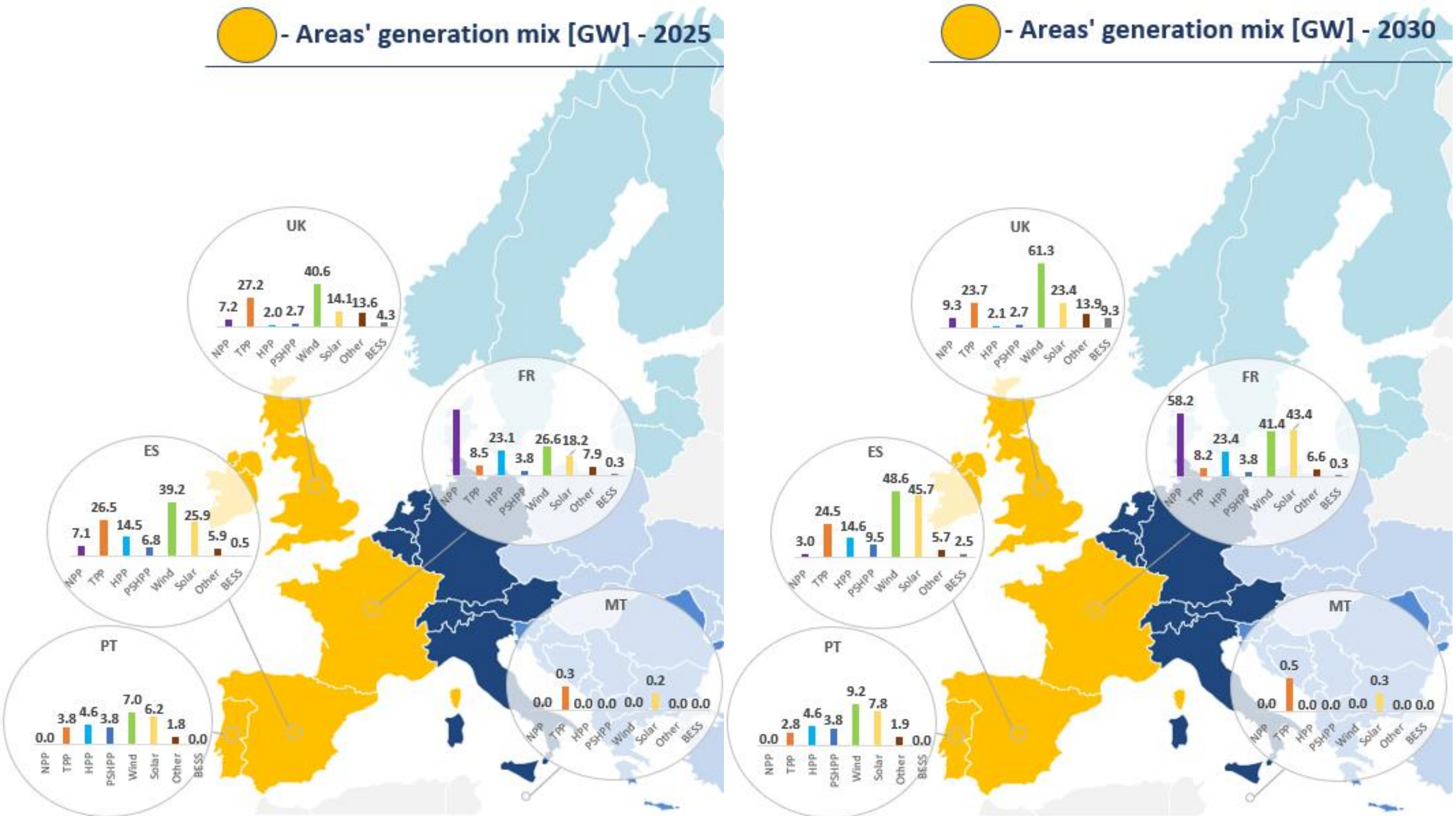


Figure 32 Generation Mixes of UK, FR, ES, PT and MT in 2025 and 2030

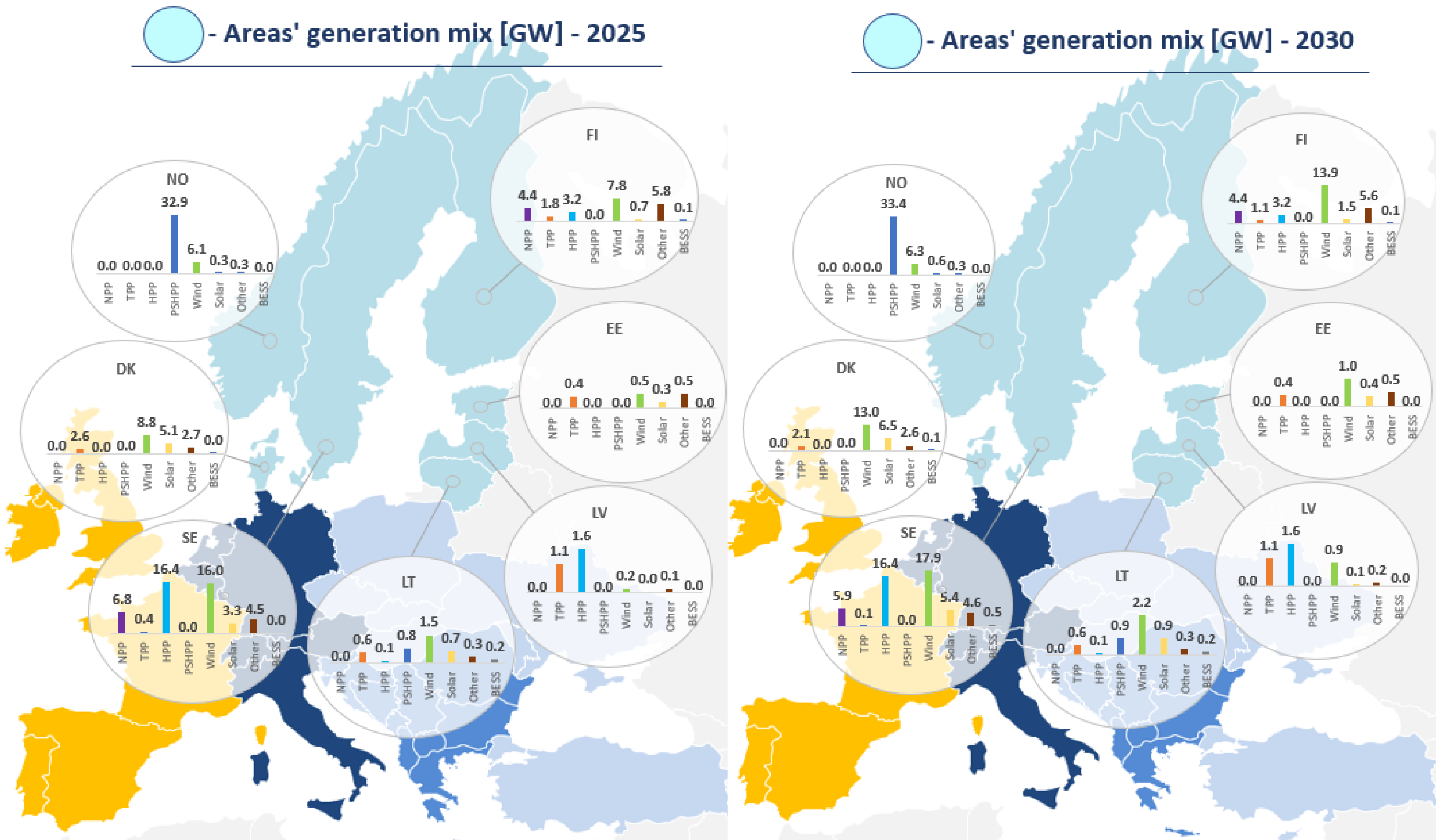


Figure 33 Generation Mixes of Nordic and Baltic countries in 2025 and 2030

European Reserves

We present the balancing reserves (FCR and FRR) in **Figure 34** and **Figure 35**

, and they show increasing or stagnating trends from 2025 to 2030, as a result of VRE integration dynamics projected for the same period.

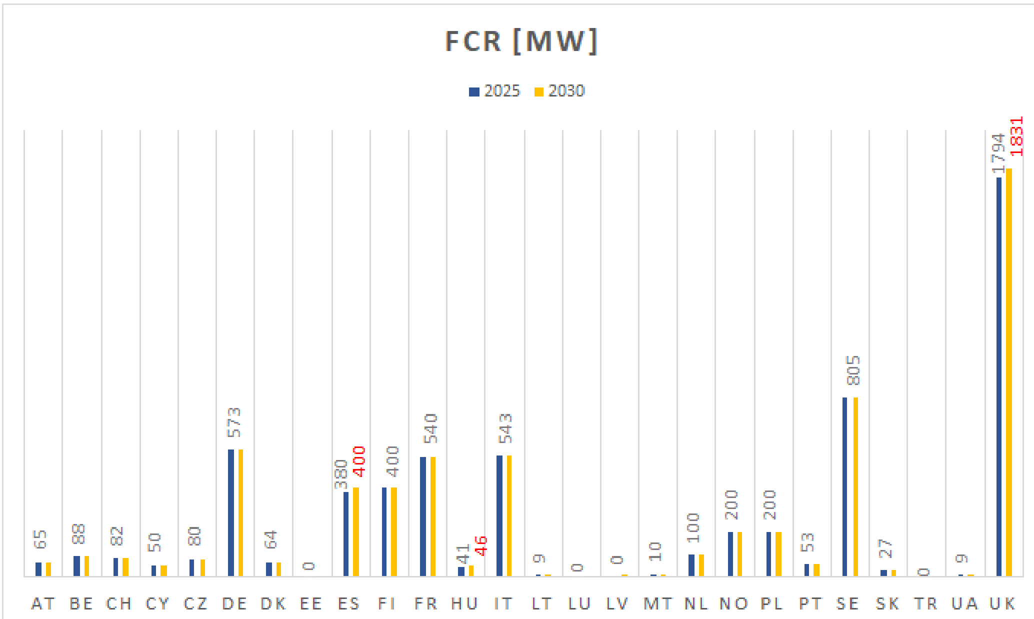


Figure 34 Frequency Containment Reserve (FCR) for other EU countries in 2025 and 2030

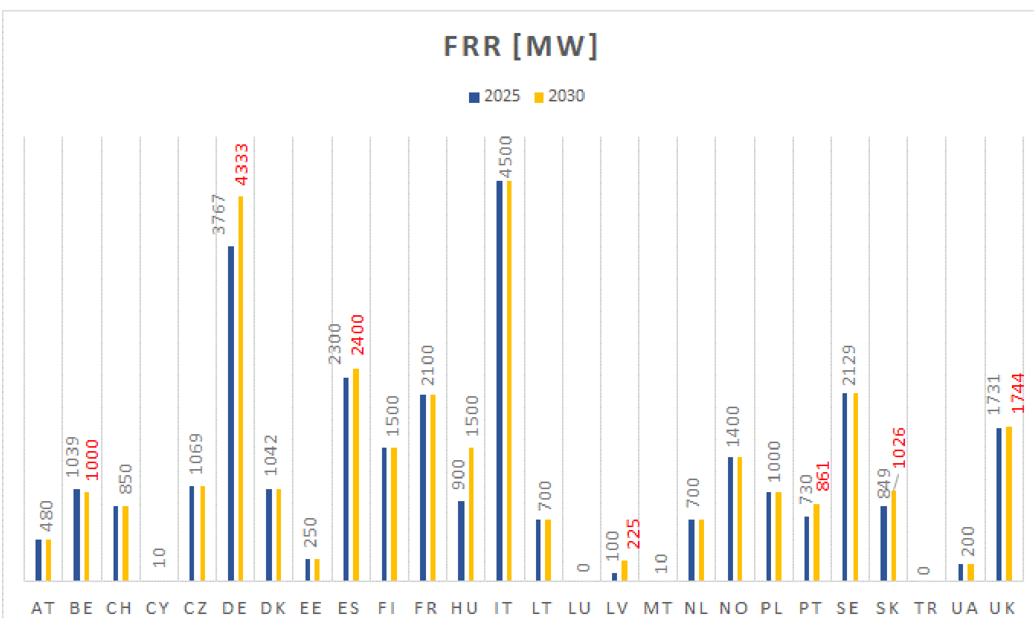


Figure 35 Frequency Restoration Reserve (FRR) for other EU countries in 2025 and 2030

5.4 Fuel And CO2 Prices

Fuel and CO2 prices are difficult to anticipate, given that a number of their fundamental drivers are only partly predictable. Nevertheless, for consistency, we used common sources and approaches regarding expected fuel and CO2 prices for these market simulations.

We applied the fuel prices in this study from ERAA 2021, as presented in **Table 31**.

Table 31 Fuel and CO2 Prices for National Estimates Scenario - 2025 and 2030

	Fuel Type	2025	2030
Fuel prices [€/netGJ]	**Nuclear**	0.5	0.5
	Lignite	1.4-3.1	1.4-3.1
	Hard coal	2.3	2.5
	Natural gas	5.6	8.9
	Light oil	12.9	13.8
	Heavy oil	10.6	11.3
	Oil shale	1.6	1.9

Notably, lignite prices vary for different countries, which is especially important for modelling the SEE lignite-based generation fleet.

Table 32: Lignite Prices in Different European Countries in 2025 and 2030

Lignite:	
- Group 1 (BG, MK and CZ)	1.40
- Group 2 (SK, DE, RS, PL, ME, UK, IE and BA)	1.80
- Group 3 (SI, RO and HU)	2.37
- Group 4 (GR and TR)	3.10

Considering current CO2 price trends and several analyses and predictions, we agreed in cooperation with CGES to use the following figures (**Table 33**) to reflect current industry trends, while at the same time not overestimating them.

We also agreed for the non-EU countries to apply the CO2 price only in 2030, as a more realistic target for full EU ETS or CBAM implementation.

Table 33: CO2 Prices to Apply in this Study

	2025	***2030***
C02 [€/tonne]	80[18]	105[19]

[18] Considering EEX Futures Market (https://www.eex.com/en/market-data/environmental-markets/derivatives-market)

[19] As an average of various C02 price projections for 2030:

- Minimum forecast, 70 €/tonne ENTSO-E ERAA
- Most of the publicly available sources forecast around 90-100 €/tonne (example https://www.euractiv.com/section/emissions-trading-scheme/interview/analyst-eu-carbon-price-on-track-to-reach-e90-by-2030/)
- The maximum forecast, publicly available is 140 €/tonne (example https://carbon-pulse.com/147214/)