ENERGY TECHNOLOGY AND GOVERNANCE PROGRAM

Assessment of the Impact of High Levels of Decarbonization and Clean Energy on the Electricity Market and Network Operation in Southeast Europe

– Final Report –

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Assessment of the Impacts of High Levels of Decarbonization and Clean Energy on the Electricity Market and Network Operation in Southeast Europe

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ELECTRICITY MARKET INITIATIVE WORKING GROUP

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CONTENTS

ABBREVIATIONS

CCGT	–	Combine Cycle Gas Turbine
CCS	–	Carbone Capture and Storage
EEX	–	European Energy Exchange
EIHP	–	Energy Institute Hrvoje Požar
EKC	–	Electricity Coordinating Center
EMI	–	Electricity Market Initiative
EnCS	–	Energy Community Secretariat
EU	–	European Union
EU ETS	–	European Union Emissions Trading System
EXIST	–	Energy Exchange Istanbul
IPEX	–	Italian Power Exchange
MAF	–	Mid-term Adequacy Forecast (Pan-European assessment of power system resource adequacy prepared every year by ENTSO-E)
MC	–	Market Coupling
MO	–	Market Operator
NCV	–	Net Caloric Value
NTC	–	Net Transfer Capacity
OCGT	–	Open Cycle Gas Turbine
O&M	–	Operation and Maintenance
PEMDB	–	Pan-European Market Database (developed by ENTSO-E)
PMC	–	Partial Market Coupling
PSHPP	–	Pump Storage Hydro Power Plant
TANAP	–	Trans Anatolian Pipeline
TAP	–	Trans Anatolian Pipeline

RES	–	Renewable Energy Sources that in general include wind, solar and hydro capacities, but in this Study RES refers only to wind and solar as VRES (Variable RES) capacities
ROR	–	Run-of-River
TSO	–	Transmission System Operator
TYNDP	–	Ten-year Network Development Plan (Europe's Network Development Plan prepared bi-annually by ENTSO-E)
USAID	–	United States Agency for International Development
USEA	–	United States Energy Association
WB6	–	Western Balkans Six
WG	–	Working Group

Market areas/regions:

SEE	–	Southeast Europe
AL	–	OST market area
BA	–	NOSBiH market area
BG	–	ESO EAD market area
GR	–	ADMIE/IPTO market area
HU	–	Hungarian market area
HR	–	HOPS market area
XK	–	KOSTT market area
ME	–	CGES market area
MK	–	MEPSO market area
RO	–	Transelectrica market area
RS	–	EMS market area
SI	–	ELES market area

EMI WG members:

ADMIE/IPTO	–	Greece Independent Power Transmission Operator
Borzen	–	Slovenian Power Market Operator
CGES	–	Montenegrin Electric Transmission System Company
COTEE	–	Montenegrin Electricity Market Operator
ELES	–	Slovenian Electricity Transmission Company
EMS	–	Serbian Transmission System Operator
ESO EAD	–	Bulgarian Electricity System Operator
HOPS	–	Croatian Transmission System Operator
HROTE	–	Croatian Energy Market Operator
KOSTT	–	Kosovo Transmission System and Market Operator
MEMO		North Macedonian Electricity Market Operator
MEPSO	–	Macedonian Electricity Transmission System Operator
NOSBiH	–	Bosnia and Herzegovina Independent System Operator
OST	–	Albanian Transmission System Operator
Transelectrica	–	Romanian Transmission and System Operator

1. EXECUTIVE SUMMARY

The US Energy Association (USEA), in partnership with the US Agency for International Development (USAID), and working with its consultants, has completed this study for the 15 members of the Electricity Market Initiative (EMI), designed to evaluate the impacts and implications of deep decarbonization and clean energy integration on the markets and the grid of Southeast Europe (SEE).

Rationale and Background. As we enter 2022, we are at an inflection point with regard to electricity and natural gas issues in SEE, and there are a number of critical, multi-faceted issues facing EMI members, regulators, policy makers, and other stakeholders in the region. These include:

- Changing Generation Mix.
  - Can the tripling or quadrupling of renewable energy sources (RES) replace most if not all of the existing lignite and coal generation capacity? What other types of new capacity – particularly natural gas generation - may be required to meet customers' needs?
  - Do the EMI countries have the market, interconnection and permitting frameworks in place needed to attract, build and finance all the new RES projected by 2030?
- Impacts on Wholesale Power Prices.
  - To what extent will wholesale power prices change (rise), in conjunction with a tax on CO2, as a result of this myriad of transitions?
  - How much of a price increase is acceptable to achieve other objectives?
- Reducing CO2 Emissions.
  - What are the impacts of substantially changing the generation mix in SEE on reducing CO2 emissions to mitigate climate change?
  - Is the resulting level of emissions reduction acceptable? If we add substantial natural gas generation, what is the right level of fuel supply diversity?
- Satisfying Reliability Needs and Network Stability.
  - Can the existing grid and planned additions absorb all the projected RES and other generation capacity without overloads or reliability concerns?
  - Can we accept anything less than the current level of power system reliability?
- Relying on Others for Power Supplies.
  - What level of net electricity imports from other countries or regions will be required with this new generation mix?
  - What level of import dependence is appropriate or acceptable?

By evaluating the impacts of high levels of retirement and decommissioning of lignite and coal generation in SEE by 2030, this study answers the first questions in each issue above – the quantitative ones - but not the second question – the policy ones. However, the results of this analysis are intended to inform both the EMI members, and those who must answer the second set of questions.

Much has changed in the past year, as policy makers in several EMI countries have initiated or adopted National Energy Climate Plans (NECPs), passed climate-related legislation, and adopted green scenarios as their standard for planning. Ten-Year Network Development plans now anticipate retiring or decommissioning large shares of existing lignite and coal generation, and the EMI members need to understand the impacts of doing so, so in late 2020, USEA agreed – with support from its consultants EIHP and EKC - to study the impacts of strong actions to mitigate CO2 emissions.

In addition to helping the EMI members better plan their systems about a decade in advance to ensure longer-term stability, this study also reveals the major challenges of making that transition. The questions above show that this transition will require highly proactive involvement by the TSOs, generation companies (both public and private), NRAs, policy makers, and the private sector.

Approach. To develop this study, we started with the EMI members' current plans for their resource mix in 2030, and decreased the level of lignite and coal capacity in SEE well beyond those levels. In addition, this study includes high levels of RES (wind and solar) adoption, and a strong CO2 tax by 2030. The key factors we decided to measure included the impacts of such changes on wholesale power prices, CO2 emissions, the change in the generation mix, net electricity exchange, and the reliability of the grid.

As inputs and scenarios, this analysis projected the following:

- We more than tripled wind generation in SEE, and quadrupled solar capacity, from about 12 GW today to 42 GW in 2030. This was several GW higher than the reference case in EMI's 2020 RES study, reflecting how RES applications, projections, and targets continue to rise.

- We retired vast amounts of lignite and coal capacity, under three scenarios: a) reference (about a 50% reduction); b) moderate (about a 67% reduction); and c) aggressive (close to an 80% reduction), as shown in Figure 1 below. The reference case represents what is already in each country's resource plans, showing their existing high level of commitment to decarbonization.

							In comparison to 2030		In comparison to today (2018)		
Lignite + Coal	Total installed capacity in 2018	Total Decomisisoned capacity till 2030	Total NEW capacity till 2030	Total capacity in operation in 2030 in Referent scenario	Total capacity in operation in 2030 in Moderate scenario	Total capacity in operation in 2030 in Extreme scenario	Rate of capacity change - Moderate scenario	Rate of capacity change - Extreme scenario	Rate of capacity change - Referent scenario	Rate of capacity change - Moderate scenario	Rate of capacity change - Extreme scenario
OST	0	0	0	0	0	0					
NOSBiH	1,850	628	410	1,632	1,442	1,166	-11.6%	-28.6%	-11.8%	-22.1%	-37.0%
ESO EAD	3,920	3,920	0	0	0	0			-100.0%	-100.0%	-100.0%
IPTO/ADMIE	3,870	3,870	0	0	0	0			-100.0%	-100.0%	-100.0%
HOPS	297	0	0	297	192	0	-35.4%	-100.0%	0.0%	-35.4%	-100.0%
KOSTT	960	432	450	978	528	264	-46.0%	-73.0%	1.9%	-45.0%	-72.5%
CGES	225	0	0	225	225	0	0.0%	-100.0%	0.0%	0.0%	-100.0%
MEPSO	759	759	0	0	0	0			-100.0%	-100.0%	-100.0%
Transelectrica	4,105	1,870	0	2,264	771	428	-65.9%	-81.1%	-44.8%	-81.2%	-89.6%
EMS	4,034	263	656	4,428	3,632	2,508	-18.0%	-43.4%	9.8%	-10.0%	-37.8%
ELES	844	305	0	539	0	0	-100.0%	-100.0%	-36.1%	-100.0%	-100.0%
TOTAL	**20,864**	**12,047**	**1,516**	**10,363**	**6,790**	**4,366**	**-34.5%**	**-57.9%**	**-50.3%**	**-67.5%**	**-79.1%**

Figure 1 - Changes in Lignite and Coal Generation by EMI Member from Today to 2030 – EMI Scenarios

- To replace these retiring units, we also assessed the EMI countries' current plans to add 9 GW of natural gas generation (most of which is in Romania, Bulgaria and Greece); add 5 GW of hydro plants; and add one new nuclear plant, in addition to the large amount of RES additions mentioned above. Figure 2 below shows our final resource mix for 2030, for each scenario.

EMI Member	WPP installed capacity (MW)	SPP installed capacity (MW)	HPP installed capacity (MW)	TPP Capacity (MW)			TOTAL CAPACITY (MW)		
				Referent	Moderate	Extreme	Referent	Moderate	Extreme
AL	384	445	2949	300	200	100	4078	3978	3878
BA	580	100	2493	1632	1442	1166	4805	4615	4339
BG	948	3216	3207	4728	4070	3470	12099	11441	10841
HR	1300	600	3117	981	876	684	5998	5893	5701
GR	7000	7700	4545	7768	7167	6493	27013	26412	25738
XK	336	150	434	978	528	264	1898	1448	1184
MK	443	563	1086	586	586	586	2678	2678	2678
ME	243	250	1117	225	225	0	1835	1835	1610
RO	5255	5054	6784	10055	8562	6889	27148	25655	23982
RS	4553	508	3035	4829	4033	2909	12925	12129	11005
SI	150	1866	1295	1757	990	937	5068	4301	4248
TOTAL	**21192**	**20452**	**30062**	**33837**	**28678**	**23498**	**105545**	**100385**	**95204**

Figure 2 – Generation Resource Mix in Southeast Europe in 2030, by Scenario

- We employed a carbon tax of 67 Euros per ton in 2030, which significantly lowers the dispatch of lignite and coal. When the study began, this assumed price was higher than the current ETS level, but as the study progressed, carbon prices rose sharply, and exceeded this input in 2021.

- We upgraded and reinforced the regional network based upon the EMI members plans for such additions by 2030, and conducted our grid reliability analysis down to the 110 kV level.

- We evaluated conditions that included average and dry hydro, recognizing that the latter condition – not an uncommon one - would require much greater use of thermal resources and imports, and stress the markets and the grid to a greater extent.

- We surmised that all markets in SEE will be coupled by 2030 (one robust short-term market for power region-wide)

This work, using the Antares model for the market analysis, and PSS/E for the network work, created a robust and verified regional power system model consisting of:

- 8,578 buses
- 10,050 branches
- 3,360 loads
- 1,521 power plants
- 3,745 transformers

- 149 switched shunts
- 4 DC lines

USEA believes that this framework – developed in close collaboration with the EMI members - is the most comprehensive and reliable in the region. We intend to keep it up to date, while also training all EMI members to ensure that they have the ability to conduct their own studies using these tools.

Key Findings. From a broad perspective, here are the major conclusions of the analysis described above.

1. **The region cannot remove a huge percentage of the coal and lignite generation in SEE by 2030 without large increases in gas generation** (other technologies are not yet ready to fill the gap). In many ways, gas needs to be the bridge fuel to a decarbonized future. This also emphasizes the importance of a diversity of gas supply to meet the need for new gas generation, and the need for pipeline infrastructure and finances to realize those additions.

2. **Major increases in wind and solar renewables by 2030, while highly desirable, will not fill the gap from coal retirements**, due to their intermittency and low capacity factors (average of 20%).

3. **We need a competitive, geographically broad market and appropriate policies to mobilize the capital from the private sector required to finance this massive change in the generation mix.**

   A large market in SEE, where the borders are coupled and competitive, will attract the private sector, and support the EMI countries – especially the WB6 – to mobilize the capital and adopt the policies required for this transition. Separated markets will have the opposite effect.

   We estimate that to increase RES capacity (wind and solar) from about 12 GW today to 42 GW in 2030 – the EMI members' base case – will require $34 billion in new capital across the region, including $10 billion in the WB6 countries. Apart from the cost, it is not clear whether the investment climate, interconnection procedures, and permitting requirements are in place or sufficiently clear in a number of countries to enable these RES additions to come to fruition.

   The addition of 9 GW of natural gas generation could require another $9 billion, and the addition of 5 GW of hydro billions more, for a total of close to $50 billion required for regional changes in the generation mix alone.

4. **The lignite and coal units that remain will be competitive in the market, and will need to operate at high capacity factors to maintain system reliability for the time being**.

5. **With all these changes, wholesale power prices could rise 15% or more by 2030, particularly if carbon fees in Europe remains high (see Figure 3)**. The

transition is not free. This raises the question of whether regulators will agree to pass on these added costs to customers.

6. **Electricity imports to SEE could rise considerably as we decarbonize the region.** This leads to the question of where those imports will come from, and whether the neighboring countries will have enough power to export if they are going through the same transition.

   In the case of a "zero balance", where imports to SEE are not readily available, there would be some electric energy not served (EENS), plus much higher wholesale power prices. Increasing EENS could also lead to social unrest and turmoil, and is thus highly undesirable.

7. **Given the strong existing network and plans for new lines and substation additions, the wholesale grid remains reliable throughout this transition**, with only a few elements that appear overloaded, which TSOs and grid owners can readily address between now and 2030.

We now show through charts the figures that support these key findings.

Market Analysis. Figure 3 below summarizes many of the key results of our market analysis for Southeast Europe, across the full range of scenarios, followed by our summary of the future impacts.

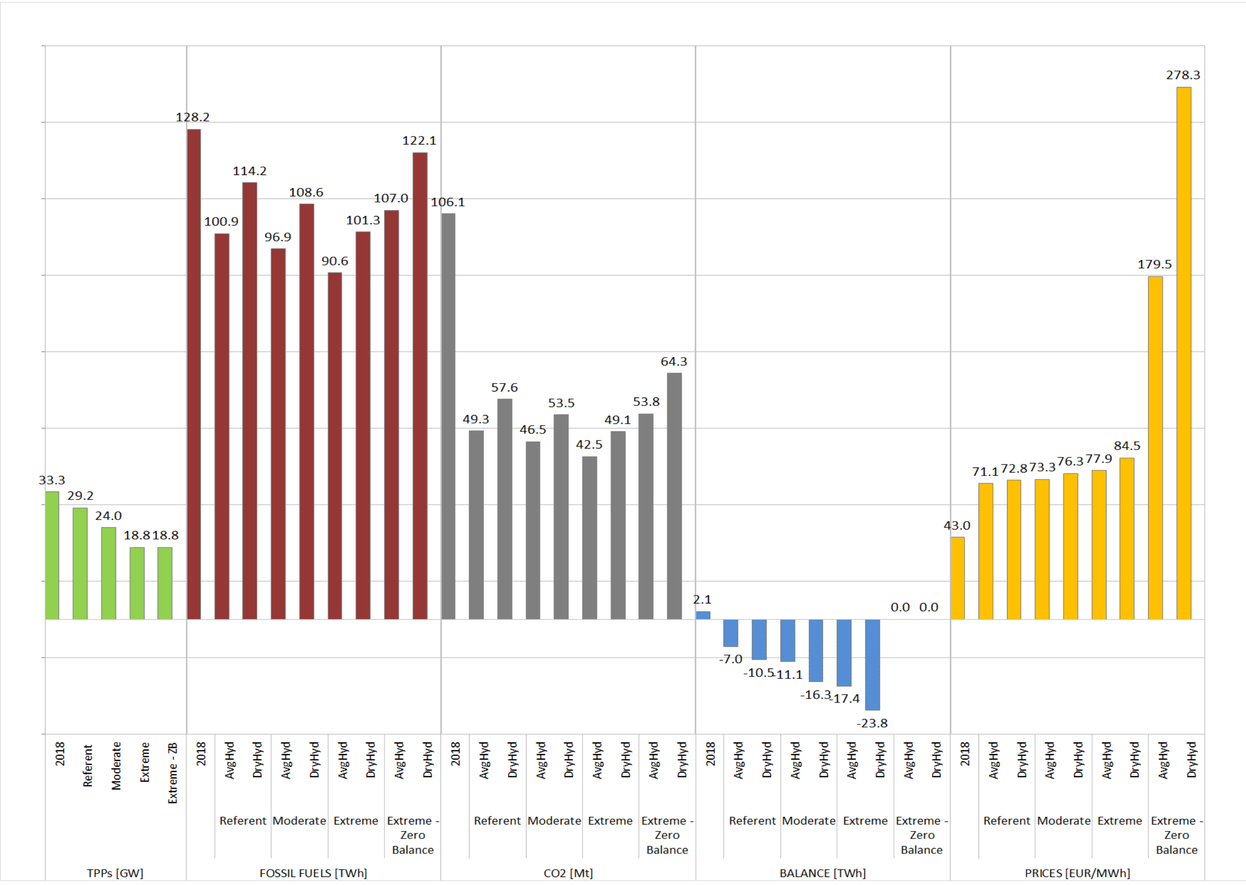


Figure 3 – Projected Market Changes in SEE by 2030

Thermal Generation. As shown in the first (green) columns on this chart, the total amount of thermal power plants (TPPs) does not fall nearly as much as the retirements of lignite and coal would suggest, because the EMI countries plan to add large amounts of natural gas generation. From 2018 to 2030, the installed capacity of TPPs would fall from 33 GW in 2018 to about 19 GW in 2030 (about 45%), even when we remove four-fifths of the lignite and coal capacity.

Fossil Generation. As shown in the second (brown) columns, total generation from fossil plants decreases with greater decarbonization, and it is always higher in dry hydrology conditions. It is noteworthy that when we assume limited ability for imports from outside SEE (the last two brown bars), the need for TPPs (even the most expensive ones) must rise to satisfy demand for power.

As a result of these changes, plus CO2 price impacts, the share of lignite and coal generation in 2030 falls sharply, and ranges from 6% to 10% of regional needs compared to about 40% in 2018, as shown in Figure 4 below.

CO2 Emissions. As shown in the grey columns, lower fossil generation leads to a substantial reduction in CO2 emissions, by about half. This is a much lower share than the reduction in lignite and coal capacity, due to gas additions and strong utilization of the remaining lignite units, which are in a better market position than the retired units.

Imports and Exports. The blue bars demonstrate that regional imports will increase substantially, going from a net export position to one in which the region imports up to 10% of its needs. Specific countries change from being importers to exporters, and vice versa, depending on the level of natural gas and renewable additions, lignite retirements and hydrology (assuming all renewable targets are met).

Wholesale Power Prices. The yellow bars show that wholesale power prices need to rise considerably to meet this future state (by 65% to 95% from 2018 to 2030, depending on the scenario). The greater the level of decarbonization, and the drier the hydrology, the higher the prices. By 2030, the prices in each EMI country are virtually identical, given our assumption that the markets between all 11 countries are coupled by then, plus the high level of interconnectivity.

The largest element of this price increase is the carbon tax. In 2018, there was no carbon tax in WB6 countries, and much lower CO2 prices in the EU countries. Renewables actually lower the wholesale price). This study used a projection of about 66 Euros per ton in 2030, and it could have been even higher, since current ETS prices have already exceeded that level.

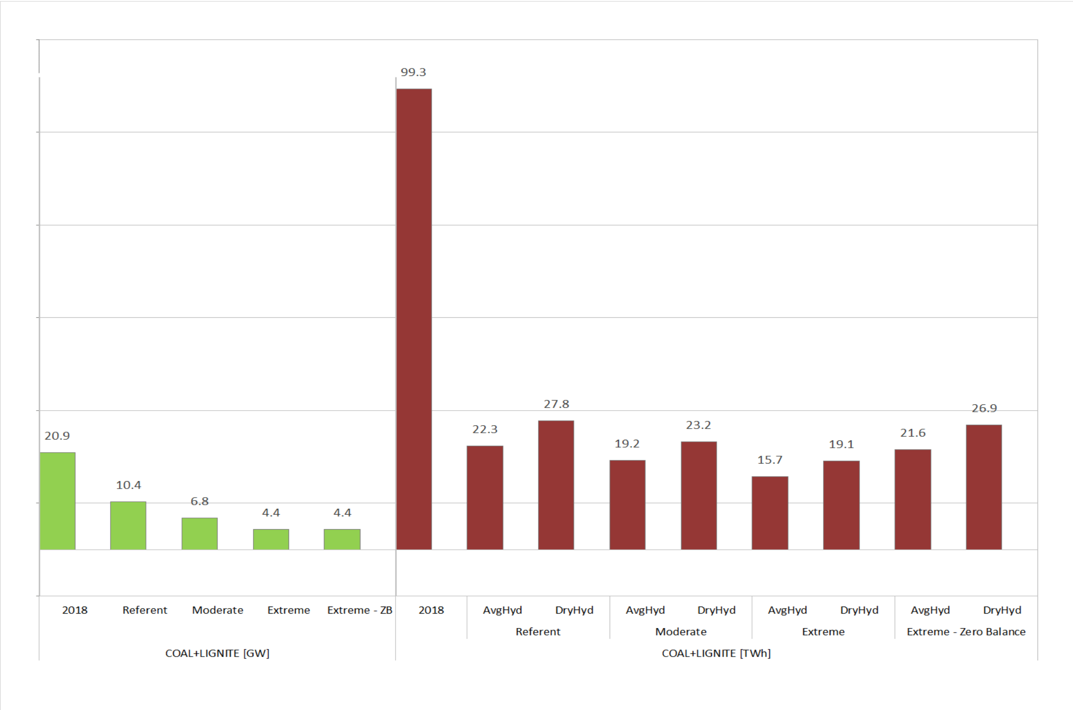


Figure 4 - Projected 2030 Changes in Coal and Lignite Capacity (GW) and Generation (GWh) Versus Today

As mentioned, natural gas becomes the bridge fuel, with substantial increases in capacity (GW) and output (TWh) required to meet customer demands, as shown in Figure 5 below. Output from gas-fired plants needs to triple, and comes close to quadrupling in some scenarios.

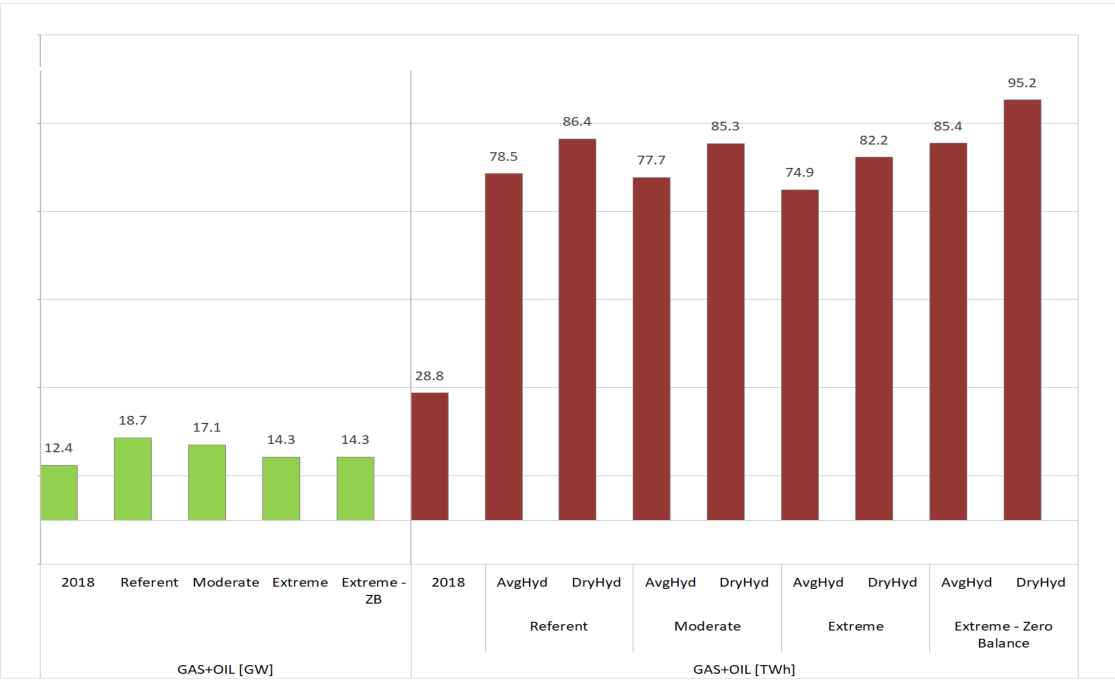
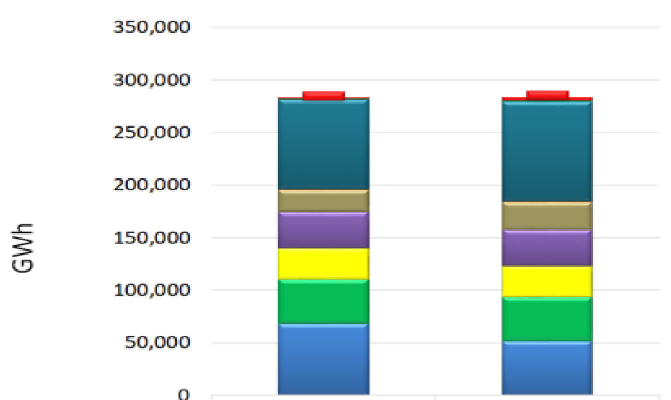


Figure 5 – Projected 2030 Changes in Natural Gas Capacity (GW) and Generation (GWh) Versus Today

As mentioned above, in the most extreme (but not implausible) case, in which other European countries do not have the option to export power needed for their citizens, SEE could experience a shortfall in the ability to satisfy customer demands. This is true even with all the additions of natural gas, renewables and hydro capacity planned by 2030 (see the level of Energy Not Served (ENS) in Figure 6 below).

While a small share of total consumption, this would have a major impact on power prices. Depending on how one values the load not served, or the level of emergency imports, annual wholesale prices could double or triple. This could further lead to social unrest and disruptions, and is clearly an undesirable outcome.

Some countries are much better positioned than others in this possible future condition. The EMI will be working with its members in the coming months and years on "resource adequacy and flexibility" studies to help ensure that they avoid such a situation.



	AvgHYd	DryHyd
	Extreme-zero Balance	
ENS	1,052	2,928
Other	1,022	1,027
Gas	85,285	94,938
Coal	640	935
Lignite	20,923	25,951
Nuclear	34,458	34,458
Solar	30,214	30,214
Wind	41,414	41,414
Hydro	68,492	51,676
Consumption	284,937	285,787

Figure 6 – Energy Not Served in Zero Balance and Hydro Scenarios

Finally, we conducted a highly detailed analysis of the impacts of lignite retirements, gas additions, renewable and hydro additions on the grid, across the thousands of network elements mentioned above. As in prior EMI studies, we found that the grid in SEE is extremely robust (much more so than other parts of Europe). Even in the most stressful scenarios, we found a maximum of 28 elements that would be stressed above their operating capacities in 2030, as shown in Figure 7 below. Of those, only 10 were overloaded beyond the standard of 130% of their limits.

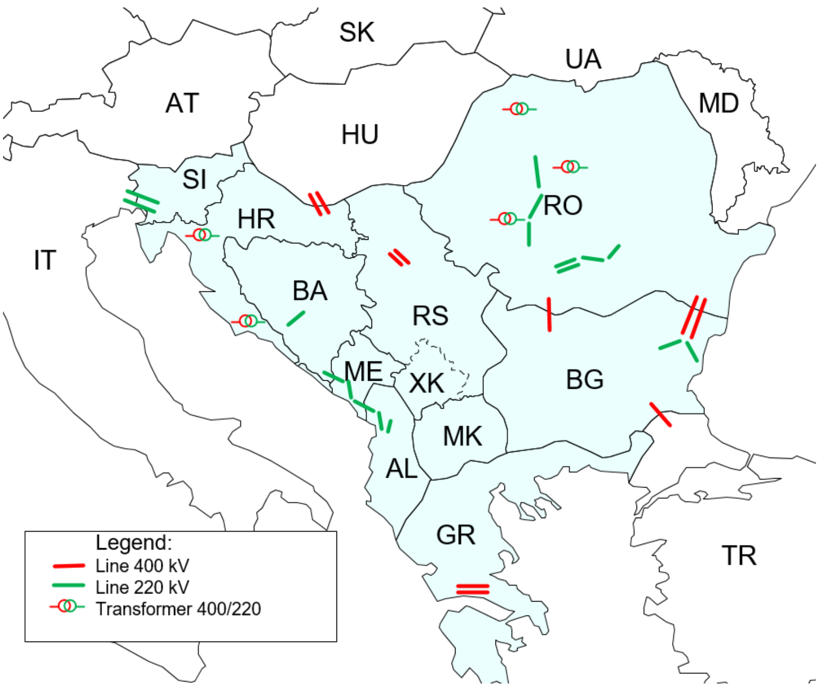


Figure 7 – Network Constraints in Southeast Europe in 2030 with Major Generation Changes

A number of these situations are within countries, while others cross borders. In many if not all cases, the EMI members were already aware of these potential bottlenecks. By highlighting these stresses, this study helps the EMI members ensure that these network elements do not limit the system's reliability, or its ability to support electricity markets, imports or exports in the future.

In sum, under the conditions we evaluated, we see no major new investments in the network in SEE required to accommodate all the changes that will take place through 2030.

2. INTRODUCTION

The primary goals of the Electricity Market Initiative (EMI), expressed in the EMI Work Plan, are to work with the transmission system operators (TSOs) and market operators (MOs) in Southeast Europe (SEE) to accelerate the regional integration of electricity markets, to benefit customers and to support the development of cleaner power systems. The figure below shows the 11 market areas in SEE on which the EMI focuses, and the 15 member companies in this program. With this level of participation, the EMI is one of the region's most comprehensive power system projects.

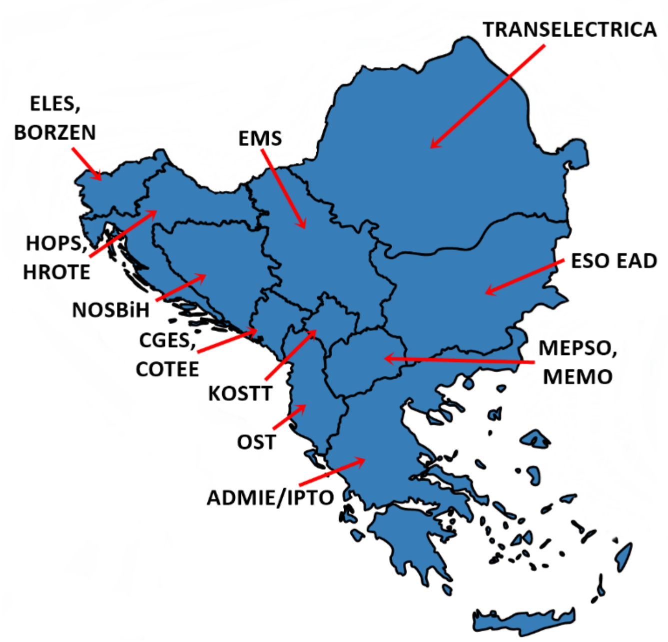


Figure 1: EMI Members

The large-scale integration of renewable energy systems (RES) in Southeast Europe (SEE) will be a significant challenge in the coming years. The EU Energy Law Package has set medium-term targets of 32% for the share of energy from RES in the EU's gross final consumption of energy in 2030, and the countries in SEE are mostly much lower than this target, especially those in the Western Balkans (WB6). Even though these countries are not EU members, as Energy Community contracting parties they are also obliged to fully transpose and implement EU energy policy. This means that the EMI working group activities should be harmonized, using this period as an opportunity for WB6 and all EMI members to learn from the best practices of those who implement the latest EU Energy Law package earlier, and take action.

In this context, in 2020 we carried out a Study under the EMI program to help all TSOs and MOs in the region assess the network and market implications of significant increases in RES development, develop strategies and identify investments that may accommodate such resources. This study addressed the impacts on electricity markets and prices in 2030 due to substantial RES and gas development, and how the transmission grid may need to adapt – both internally within the EMI members and between them - to successfully integrate these resources.

As one of the Study results, we found that RES integration and CO_2 taxes will have a large impact on the generation mix and TPP generation. With a higher CO_2 tax, lignite plants become much less competitive, and lignite and gas technologies can change their position in the regional merit order curve. In specific, lignite plants' capacity factor may decrease from 60-70% with a referent CO_2 tax to 35-50% with a high CO_2 tax. At gas plants, this change is the opposite, and their capacity factor increases from 16-30% in the referent CO_2 tax case to 36-50% in the high CO_2 tax case, showing that gas-fired generation can be a key transitional technology towards a high-RES power system.

These changes may jeopardize the economics of lignite generation, as well as older gas units. Thus, one of the conclusions of last year's EMI Study is that the TSOs, regulators and policy makers in the EMI region should consider options for additional older TPP plant retirements, and how to mitigate this effect to preserve the security of power supplies.

To follow up on this 2020 study and provide needed support to EMI members and other stakeholders in the region, this study focuses on decarbonization. In it, we analyze the market and network impacts in the SEE region with significant reductions in conventional units (especially coal, lignite and older gas units), plus substantial RES additions, as cross-border transactions and markets open up region-wide. This assessment takes into account the newest requirements for clean energy and the decarbonization of electricity production, as determined by the EU and Energy Community strategies, and each country's National Energy and Climate Plans (NECPs).

The NECPs constitute the framework for integrating energy and climate policies and driving the decarbonization of the energy sectors and the economy as a whole, in line with the 2015 Paris Agreement. These National Plans determine the measures and actions that have to be implemented to satisfy the agreed-upon goals with respect to decarbonization, energy efficiency, and energy security, as well as each country's internal market, research, innovation and competitiveness.

In addition to addressing how electricity markets, prices and the grid will be affected by greater decarbonization of the electricity sector by 2030, this Study addresses the gap in production that may emerge as we remove large amounts of carbon-intensive generation from the mix between now and 2030, and what may be required to fill such a gap.

This work also includes the transfer of and training in the tools required for EMI members to conduct their own internal decarbonization and related analyses over time.

3. STUDY OBJECTIVES

The objectives of this work were to analyze and quantify the impacts of substantial decarbonization of the electricity sector in the SEE region on both the electricity network and market operation, and to prepare the EMI members and regulators to deal with those impacts. It reflects both challenges at the individual EMI country level, as well as the regional impacts of such expansion.

To evaluate the impact of potentially significant decarbonization of the electricity sector, this project prepared two analyses:

- First, a study of the changes in the regional electricity market, with binding decarbonization measures, in addition to a rapidly growing share of RES generation; and
- Second, an analysis of the network impacts of such development, including where congestion may arise and new transmission elements may be required, at the 110 kV level and above.

Further, to model the neighboring ENTSO-E countries, as well as reflect the influence of the pan-European electricity market, this project used the official publicly available ENTSO-E data from the TYNDP (Ten Year Network Development Plan) and MAF (Midterm Adequacy Forecast).

The market analysis focused on the year 2030, and includes hourly simulations of the power system and provide results for each hour of the year, while the network analyses focused on snapshots of the grid's operation at moments when the network would be under stress, also in 2030.

For the regional market simulations, we conducted the analyses using the Antares software tool. This analysis enables the EMI to assess and understand the impacts of substantial decarbonization of the electricity sector on generation dispatch, wholesale market prices, country balances, cross-border flows and congestion costs. We captured both the currently projected levels of decarbonization embedded in the most recent resource plans, and went beyond those levels to evaluate the impacts of higher levels of decarbonization envisioned for all of the EMI markets.

For the regional network operation, our work utilized the PSS/E software tool to analyze the impact of greater decarbonization of the electricity sector on the grid. This analysis enables EMI members to better understand the effects of such decarbonization of the electricity sector on load flows, voltage profiles, secure grid operations and congestion in the regional transmission network. We ran these models sequentially, first determining the market results under numerous scenarios, and then analyzing whether those results are consistent with a robust and reliable network, also under a number of scenarios.

After completing this study, we will prepare a position paper on the impact of substantial decarbonization on the SEE electricity system, market operation and security of supply. If agreed between the EMI WG members, this paper will be designed to convey the basic messages of the EMI and this study to utility executives, national regulators, policy makers and the wider community.

Once the EMI team merges and tests them, we will transfer both the network and market models (in Antares and PSS/E forms) to the EMI members, with the necessary data and explanations required for them to use these tools for their own internal purposes and future analyses, and we will train them in the use of these tools.

4. SCOPE OF WORK

Due to the complexity of the study objectives, we divided this assignment into three main phases, with each phase consisting of several tasks, as follows:

Phase 1 – Development (update) of the SEE Electricity Market and Network Models

- Task 1.1 – Development (update) of SEE Antares Database and Market Model
  - Task 1.1.1 Define relevant input data and prepare questionnaires for data collection from the EMI members
  - Task 1.1.2 Collect data and prepare a common regional database
  - Task 1.1.3 Develop the regional market model for 2030 in Antares

- Task 1.2 – Development (update) of the Regional PSS/E Network Model
  - Task 1.2.1 The EMI will collect country models of the grid from each EMI member, with detail on their expected system load changes, network topology and generation expansion etc., and work to harmonize them.
  - Task 1.2.2 Merge the individual country models into a common regional PSS/E network model for 2030

The Consultants prepared the questionnaires and managed the data collection process for the EMI countries. After data collection, we merged the country market and network models and prepared common regional market and network models.

Phase 2 – Analysis of the Impact of Substantial Decarbonization of the Electricity Sector on SEE Electricity Markets and Network Operation

- Task 2.1 – Analysis of the impact of several levels of decarbonization of electricity sector on SEE Electricity Markets

  - Task 2.1.1 Define the modeling methodology and assumptions
  - Task 2.1.2 Prepare scenarios and running simulations
  - Task 2.1.3 Analyze the simulation results and prepare the draft and final reports, including results for each country
  - Task 2.1.4 Present and discuss the market results and implications at an EMI working group meeting

- Task 2.2 – Assessment of the impact of several levels of decarbonization of the electricity sector on the SEE Network down to the 110 kV level

  - Task 2.2.1 Define the network methodology and assumptions
  - Task 2.2.2 Prepare the scenarios and run simulations

- Task 2.2.3 Analyze the simulation results and prepare draft and final reports, including results for each country
- Task 2.2.4 Present and discuss the network results and implications at an EMI working group meeting

The Consultants ensured consistency, and jointly worked on the modeling methodology and assumptions relevant for the scenarios chosen for analysis.

Phase 3 – Delivery and Implementation of the Electricity Market and Network Models

- Task 3.1 Deliver the regional market and network models to the EMI participants
- Task 3.2 Train the EMI participants to use the Antares market model for clean energy and decarbonization analysis
- Task 3.3 Train the EMI participants to use the PSS/E network model for this analysis

We will soon transfer all models used for the decarbonization analyses to the EMI participants (in Antares and PSS/E forms), with the necessary data and explanations required for them to use for their own internal purposes and future analyses.

Altogether there are seven deliverables in this decarbonization project, as follows:

- D1. Inception Report: Report on data collection, scenarios and modeling methodology (finalized in August 2021)
- D2. Draft Report: Impact of greater decarbonization of electricity sector on EMI markets and the network (T2.1.4, T2.2.4) – THIS REPORT
- D3. Final Report: Based on comments received on the Draft Report
- D4. Delivery of a regional market model in Antares and a network model in PSS/E (T4.1)
- D5. Training session for the EMI members to utilize the models for decarbonization analysis
- D6 and D7. Draft and final position paper on the impacts and implications of substantial decarbonization on the SEE electricity system and market operation

5. PROJECT DEADLINES

The schedule for the study deliverables and deadlines are as follows:

Action	Deadlines	Status
Project kick-off	April 12th, 2021	DONE
Collect Input data	May 12th, 2021	DONE
D1.Submit Inception Report	June 12th, 2021	DONE
D2. Submit Draft report – Impact of greater decarbonization of the electricity sector on SEE Electricity Markets and Network Operation	October 30th, 2021	DONE
D3. Submit Final Report - Greater decarbonization of electricity sector impact on SEE Electricity Markets and Network Operation	November 12th, 2021	
D4. Deliver and Implement the Electricity Market and Network Models	December 12th, 2021	
D5. Conduct Training Session for EMI Members on using Models for Decarbonization Analysis	December 12th, 2021	
D6. Submit Draft Position Paper	February 11th, 2022	
D7. Submit Final Position Paper	February 25th, 2022	

6. DECARBONIZATION SCENARIOS AND METHODOLOGY

This Chapter discusses the study methodology and scenarios we have applied. The methodology is based on the principles from prior EMI activities and reports, as verified by the EMI working group, and we designed the scenarios to cover the primary uncertainties and combinations of the most important variables. We presented the Methodology and Scenarios in the Inception Report, discussed and agreed upon them with the EMI members, and applied them in these analyses.

6.1. Decarbonization scenarios

This study is designed to analyze the impact of substantial decarbonization in the region on electricity market and network operation. We simulated different levels of decarbonization by evaluating alternatives for thermal unit decommissioning. There are many TPPs in the region, and we selected the TPPs to be simulated as decommissioned in different countries based on three main criteria:

a) **Commissioning year** (older units are the first candidates for decommissioning)

b) **Heat rate levels** (less efficient units are the first candidates for decommissioning)

c) **Point of connection** (units that provide relevant voltage support and that provide heat as well of electricity are not considered the first candidates for decommissioning)

Since the TSOs and MOs must equally treat all network users and market participants, the Consultants used the criteria above to propose a list of TPPs to be treated as decommissioned in 2030, beyond those already selected in the TYNDPs and other official plans. **The EMI members carefully reviewed and approved this list, which is presented in Section 5.4.**

It is important to note that this selection is hypothetical and does not reflect or carry any legal requirement. It serves only for the EMI to test and understand the potential impacts on individual country markets, on the whole regional market, and on network operation under conditions of large-scale decarbonization. EMI member's approval of the decommissioning list is just an agreement that this list can be used for the "what-if" exercise in this Study, and does not suggest that this list represents the formal position of any of the EMI members.

For each market area, and for the SEE region as a whole, we modeled and analyzed three levels of thermal decommissioning:

- **Referent Decarbonization Scenario** - in line with data provided by the EMI members

  There is already some decommissioning of old thermal units in the referent (officially determined) plans of all EMI members. However, in most countries, this level is below the environmental requirements posed by the EU and the EnC.

- **Moderate Decarbonization Scenario** – This assumes additional decommissioning of thermal units based on the criteria above (commissioning year, efficiency,…). It includes, in most cases, decommissioning of TPPs commissioned more than 40 years ago.

- **Extreme Decarbonization Scenario** - This assumes additional decommissioning of thermal units that are "younger" and more efficient than in the moderate scenario, but which are still rather old and commissioned more than 30 years ago.

The proposed decommissioning capacities for each market area are given in Appendix.

While focused on analyzing the impacts of the reduced capacity in thermal units (mainly lignite and coal) on SEE's electricity market and network, this study also assessed alternative scenarios to test the impact of changes in two influential drivers: 1) hydro conditions, and 2) the EMI regional energy balance levels with neighboring regions.

The EMI WG members recognize that this work involves large optimizations, with several thousand elements, requiring hourly resolution. We carefully selected the proposed scenarios to provide EMI members with meaningful results and a clear evaluation of the potential impacts in 2030.

In all the scenarios, certain assumptions were the same, including: energy consumption; existing and planned RES and hydro generation capacities in SEE; detailed technical and economic inputs; and cross-border transmission capacities.

The scenarios we analyzed are plausible but not overly numerous, since we wanted to focus on whether the impacts and differences are meaningful more than their numbers. To do so, we modeled and analyzed eight market scenarios and 16 network scenarios, as described below.

By combining three decommissioning scenarios and other relevant variables, we developed the following **8 market scenarios** in consultation with EMI members:

1) Referent – average hydrology - all TPPs as defined in the initial models
2) Referent – dry hydrology - all TPPs as defined in the initial models
3) Moderate – average hydrology – moderately decreased TPP capacity
4) Moderate – dry hydrology - moderately decreased TPP capacity
5) Extreme – average hydrology – extremely decreased TPP capacity
6) Extreme – dry hydrology - extremely decreased TPP capacity
7) Extreme – average hydrology - extremely decreased TPP capacity, and the EMI region is balanced on an annual level (this represents regional self-sustainability)
8) Extreme – dry hydrology - extremely decreased TPP capacity, and the EMI region is balanced on an annual level (this represents regional self-sustainability)

The EMI region interacts with the rest of Europe and this interaction varies in different scenarios. In the first six scenarios we kept market-based exchange with rest of Europe where the only limiting factors are cross-border capacities modeled by NTCs. For the extreme scenario, we wanted to challenge the regional balance and see if the EMI region can be self-sustainable and if it could supply the total load on its own, if additional energy from the rest of Europe is not available.

We conducted grid analysis for 8 selected characteristic hours from the market results, with two analyses in each case (for a total of 16 scenarios):

- Load-flows and voltage profiles in the 400 kV, 220 kV and 110 kV network
- Contingency N-1 assessment

When we applied the above-mentioned principles, we proposed and agreed to evaluate the following 16 network scenarios:

1) Moderate - average hydrology – moderately decreased TPP capacity, referent RES – selected hour with maximum ratio between RES+HPP output and total demand – **n** available elements
2) Moderate - average hydrology – moderately decreased TPP capacity, referent RES – selected hour with maximum ratio between RES+HPP output and total demand – **n-1** available elements
3) Moderate - average hydrology – moderately decreased TPP capacity, referent RES – selected hour with maximum EMI region exchange – **n** available elements
4) Moderate - average hydrology – moderately decreased TPP capacity, referent RES – selected hour with maximum EMI region exchange – **n-1** available elements
5) Moderate - dry hydrology – moderately decreased TPP capacity, referent RES – selected hour with maximum ratio between RES+HPP output and total demand – **n** available elements
6) Moderate - dry hydrology – moderately decreased TPP capacity, referent RES – selected hour with maximum ratio between RES+HPP output and total demand – **n-1** available elements
7) Moderate - dry hydrology – moderately decreased TPP capacity, referent RES – selected hour with maximum EMI region exchange – **n** available elements
8) Moderate - dry hydrology – moderately decreased TPP capacity, referent RES – selected hour with maximum EMI region exchange – **n-1** available elements
9) Extreme – average hydrology – extremely decreased TPP capacity, referent RES – selected hour with maximum ratio between RES+HPP output and total demand – **n** available elements
10) Extreme – average hydrology – extremely decreased TPP capacity, referent RES – selected hour with max ratio between RES+HPP output and total demand – **n-1** available elements
11) Extreme – average hydrology – extremely decreased TPP capacity, referent RES – selected hour with maximum EMI region exchange – **n** available elements
12) Extreme – average hydrology – extremely decreased TPP capacity, referent RES – selected hour with maximum EMI region exchange – **n-1** available elements
13) Extreme – dry hydrology – extremely decreased TPP capacity, referent RES – selected hour with maximum ratio between RES+HPP output and total demand – **n** available elements
14) Extreme – dry hydrology – extremely decreased TPP capacity, referent RES – selected hour with maximum ratio between RES+HPP output and total demand – **n-1** available elements
15) Extreme – dry hydrology – extremely decreased TPP capacity, referent RES – selected hour with maximum EMI region exchange – **n** available elements
16) Extreme – dry hydrology – extremely decreased TPP capacity, referent RES – selected hour with maximum EMI region exchange – **n-1** available elements

As given above, we used scenarios "with the maximum ratio between RES+HPP output and total demand". Based on the operational experience in the region, we believe that this combination of inputs is the most stressful and pivotal for the network analysis in this study. Large RES and HPP generation combined with the lowest level of local demand leads to the highest network loading, so it was important to test the network under such extreme conditions.

This case alternates with the "maximum EMI region exchange‟ that represents the largest regional import or export assuming the largest cross-regional network loading. Since the regional network is quite large, these scenarios cover all operational challenges around the region under decarbonization conditions in 2030.

6.2. Approach and methodology

As indicated above, we divided our approach into two types of simulations:

1. Market and
2. Network simulations.

In general, several factors drove the simulations of electricity markets in SEE:

1. Electricity demand (both hourly load and total consumption);
2. Hydro conditions (this is critical for several EMI members, particularly Albania, where generation is almost entirely from hydropower);
3. RES generation capacities;
4. Non-RES (conventional generation) generation capacities;
5. Fuel prices (gas, coal);
6. CO_2 emission prices;
7. Available transmission interconnection capacities.

In addition, the network simulations were driven by:

1. Electricity demand level (hourly load), particularly at times of maximum and minimum load
2. Dispatch of the generating units (taking into account the above-mentioned drivers)
3. The development status and changes to the regional networks (down to the 110 kV level)
4. Topology and operational status of the network elements

To minimize uncertainties in this study, we consistently defined the decommissioning scenarios for each country. Moreover, we presented the input data, methodology and scenarios for each market area to the WG members in the Inception Report, and they have reviewed and approved these items. This consistent approach - with input data submitted and verified by all SEE TSOs and MOs - is the most reliable path to this kind of analysis in the region.

In addition, based on the market and network models we developed for the decommissioning analyses, the EMI TSOs and MOs will be able to conduct their own country-specific analyses, for internal planning, regulatory and policy purposes, using the same framework and verified inputs from the region. Once we complete this analysis, we will train the EMI members in how to do so.

Based on the verified input data, and the market and network models we developed in Antares and PSS/E, we conducted this forecast analysis focused on the impacts of substantial decarbonization of the power sector for the year 2030.

6.3. Other modeling assumptions

6.3.1. CO_2 pricing level

In addition to the above-described assumptions related to main variables, we based all scenarios on the same CO_2 price, one which deviates from the ENTSO-e TYNDP2020. At the time we were preparing the Inception Report, the CO_2 price level was approximately 55 €/t, which was already higher than CO_2 price in the "Distributed Energy" Scenario from TYNDP2020 of 53 €/t). For our analysis, we adopted the CO_2 price at the time of the Inception report preparation, and increased it based on an average expected inflation of 2% at the regional level. This lead to a CO_2 price level of 65.73 €/t in 2030, which we applied for all market areas and all scenarios in this Study.

This approach provides consistency, keeping in mind that half of the EMI region are EU member states, while the other half are non-EU countries still not obliged to implement the EU's emission trading scheme. Also, using a single CO_2 price enabled a clear comparison of decommissioning scenarios and outputs.

6.3.2. Different hydro conditions

Hydro conditions can be critical for a number of EMI members, due to their high share of hydro generation, and it can meaningfully affect regional flows and balance positions. Thus, we evaluated the impact of decarbonization and thermal units decommissioning, along with changes in hydro conditions and the EMI regional energy balance levels. Our hydro scenarios included the following:

- Average hydro conditions and
- Dry hydro conditions.

The TSOs provided most of the inputs and assumptions on generation from HPPs in different hydro conditions for each country/market area.

6.3.3. Different EMI regional energy balance levels

One of the issues for policy consideration involves the extent to which a market should rely on others for its power supplies. The EMI is committed to SEE regional integration, and reducing the thermal units in different decommissioning scenarios would change the regional balance of imports and exports. In the high decommissioning scenario, we tested the region's self-sustainability. To do so, we added two scenarios in which the EMI region is considered as self-sustainable, and the annual exchange with other regions have been set to zero. Based on this rationale, our scenarios included:

- Market-based exchanges of the EMI region
- Neutral (zero annual exchange of the EMI region)

6.4. TPP decommissioning scenarios

As presented above, for each market area and for SEE as a whole, we modeled and analyzed three TPP decommissioning scenarios – referent, moderate and extreme.

We started from the referent scenario provided by the EMI members. In the other two scenarios (moderate and extreme) we further reduced TPP capacity. This subchapter provides a detailed overview of the proposed decommissioned TPP units through 2030 in the moderate and extreme scenarios, and its decrease compared to the referent scenario. All TPP capacities are given as sent-out or net capacity (without self-consumption).

Table 1 presents the total installed TPP capacity in the EMI region in 2030, including the **agreed total decommissioned TPP capacities** that have been analyzed in this study for each market area, and the rate of capacity change in the moderate and extreme scenarios.

*Table 1: TPPs commissioning and decommissioning in the EMI region **2018-2030** in the referent, moderate and extreme scenarios*

							In comparison to 2030		In comparison to today (2018)		
All TPP technologies	Total installed capacity in 2018	Total Decomisisoned capacity till 2030	Total NEW capacity till 2030	Total capacity in operation in 2030 in Referent scenario	Total capacity in operation in 2030 in Moderate scenario	Total capacity in operation in 2030 in Extreme scenario	Rate of capacity change - Moderate scenario	Rate of capacity change - Extreme scenario	Rate of capacity change - Referent scenario	Rate of capacity change - Moderate scenario	Rate of capacity change - Extreme scenario
OST	0	0	300	300	200	100	-33.3%	-66.7%			
NOSBiH	1,850	628	410	1,632	1,442	1,166	-11.6%	-28.6%	-11.8%	-22.1%	-37.0%
ESO EAD	6,846	4,019	1,901	4,728	4,070	3,470	-13.9%	-26.6%	-30.9%	-40.5%	-49.3%
IPTO/ADMIE	9,771	4,268	2,265	7,768	7,167	6,493	-7.7%	-16.4%	-20.5%	-26.6%	-33.5%
HOPS	1,924	1,085	142	981	876	684	-10.7%	-30.3%	-49.0%	-54.5%	-64.5%
KOSTT	960	432	450	978	528	264	-46.0%	-73.0%	1.9%	-45.0%	-72.5%
CGES	225	0	0	225	225	0	0.0%	-100.0%	0.0%	0.0%	-100.0%
MEPSO	1,274	957	269	586	586	586	0.0%	0.0%	-54.0%	-54.0%	-54.0%
Transelectrica	8,198	2,676	4,552	10,055	8,562	6,889	-14.9%	-31.5%	22.7%	4.4%	-16.0%
EMS	4,252	263	839	4,829	4,033	2,909	-16.5%	-39.8%	13.6%	-5.1%	-31.6%
ELES	2,134	516	139	1,757	990	937	-43.7%	-46.7%	-17.7%	-53.6%	-56.1%
TOTAL	**37,433**	**14,844**	**11,267**	**33,837**	**28,678**	**23,498**	**-15.2%**	**-30.6%**	**-9.6%**	**-23.4%**	**-37.2%**

*Table 2: TPP commissioning and decommissioning in the EMI region in **2030** in the moderate and extreme scenarios*

Market area	Total TPP installed capacity in 2030 (MW) -Referent scenario	TPP capacity decommissioned in the Moderate scenario (MW)	Additional TPP capacity decommissioned in the Extreme scenario (MW)	Total TPP capacity in operation in the Moderate scenario (MW)	Total TPP capacity in operation in the Extreme scenario (MW)	Rate of TPP capacity decrease - Moderate scenario	Rate of TPP capacity decrease - Extreme scenario
OST	300	100	100	200	100	-33.3%	-66.7%
NOSBiH	1,632	190	276	1,442	1,166	-11.6%	-28.6%
ESO EAD	4,728	658	600	4,070	3,470	-13.9%	-26.6%
IPTO/ADMIE	7,768	600	674	7,167	6,493	-7.7%	-16.4%
HOPS	981	105	192	876	684	-10.7%	-30.3%
KOSTT	978	450	264	528	264	-46.0%	-73.0%
CGES	225	0	225	225	0	0.0%	-100.0%
MEPSO	586	0	0	586	586	0.0%	0.0%
Transelectrica	10,055	1,493	1,672	8,562	6,889	-14.9%	-31.5%
EMS	4,829	795	1,124	4,033	2,909	-16.5%	-39.8%
ELES	1,757	767	53	990	937	-43.7%	-46.7%
TOTAL	**33,837**	**5,159**	**5,181**	**28,678**	**23,498**	**-15.2%**	**-30.6%**

In addition to the two decarbonization scenarios ("moderate" and "extreme"), we provide in the following tables the TPP capacities for each market area that are already planned to be decommissioned by 2030 due to its lifetime ending.

These values show the actual regional decarbonization activities already planned by local authorities.

In summary, today in the EMI region there are 37.4 GW of total installed TPP capacity. Among them, there are 121 TPP units with total capacity of 14.8 GW already planned to be decommissioned by 2030. At the same time, there are plans to commission 11.2 GW of new TPP units. We do not make judgements about the realization of these plans, and have relied on the official TSO data and verified models, in which the total TPP installed capacity in 2030 is planned to be 33.8 GW. And that is our referent scenario.

Within this study, we proposed to decommission an additional 5.1 GW (15.2% of the total installed TPP capacity) in the moderate scenario, and 10.3 GW (30.6% of the total installed TPP capacity in the region) in the extreme scenario in the EMI region. In sum, we decommission half of the current coal and lignite TPPS in the referent case; two-thirds in the moderate case, and nearly four-fifths in the extreme case. This excludes co-generation units. There is little room for further decarbonization without cutting off gas-fired or co-gen units.

As mentioned, the 15 GW of TPP capacities that are already planned to be decommissioned by 2030 are substantially replaced with 11 GW of new TPP capacities (largely natural gas) by 2030, so the reduction of the TPP capacities from today till 2030 in the referent scenario is only 9.6%. Our proposed further decommissioning in the moderate and extreme scenarios reduces TPP capacities by 23% and 37% in comparison to today's level.

The largest decommissioning shares are in the CGES and KOSTT market areas (between 46% and 73% for KOSTT, and 100% for CGES, respectively), due to the size and small number of TPP units.

The largest TPP capacity (MW) decommissioned in an individual market areas is for Transelectrica (1,493 MW to 3,165 MW) and EMS (795 MW to 1,919 MW).

Except where noted, "TPPs" refer to changes for all thermal technologies: lignite, coal, gas and nuclear, and the level of reduction in capacity (below 30%) could be considered modest. This is due to the high number of new gas units expected by 2030 in SEE, with a total capacity of 9 GW that replaces the decommissioning of 1.5 GW of old gas units. This increases the total capacity in gas units in the EMI region by over 70%, as can be seen in the following table. **The ability of this level of gas generation to actually come to fruition greatly affects the future reliability and the balance of the electricity system in SEE.**

*Table 3: Gas-fired TPPs commissioning and decommissioning in the EMI region **2018-2030** in the referent, moderate and extreme scenarios*

							In comparison to 2030		In comparison to today (2018)		
Gas	Total installed capacity in 2018	Total Decomisisoned capacity till 2030	Total NEW capacity till 2030	Total capacity in operation in 2030 in Referent scenario	Total capacity in operation in 2030 in Moderate scenario	Total capacity in operation in 2030 in Extreme scenario	Rate of capacity change - Moderate scenario	Rate of capacity change - Extreme scenario	Rate of capacity change - Referent scenario	Rate of capacity change - Moderate scenario	Rate of capacity change - Extreme scenario
OST	0	0	300	300	200	100	-33.3%	-66.7%			
NOSBiH	0	0	0	0	0	0					
ESO EAD	926	99	1,901	2,728	2,070	1,470	-24.1%	-46.1%	194.6%	123.5%	58.7%
IPTO/ADMIE	5,213	0	2,265	7,478	6,927	6,303	-7.4%	-15.7%	43.5%	32.9%	20.9%
HOPS	883	341	142	684	684	684	0.0%	0.0%	-22.6%	-22.6%	-22.6%
KOSTT	0	0	0	0	0	0					
CGES	0	0	0	0	0	0					
MEPSO	317	0	269	586	586	586	0.0%	0.0%	85.0%	85.0%	85.0%
Transelectrica	2,672	824	3,887	5,689	5,689	4,359	0.0%	-23.4%	112.9%	112.9%	63.1%
EMS	218	0	183	401	401	401	0.0%	0.0%	83.9%	83.9%	83.9%
ELES	542	211	139	470	242	189	-48.5%	-59.8%	-13.3%	-55.4%	-65.1%
TOTAL	**10,770**	**1,475**	**9,086**	**18,335**	**16,798**	**14,092**	**-8.4%**	**-23.1%**	**70.2%**	**56.0%**	**30.8%**

With regard to nuclear units, there are no expectations to decommission any units in the region, and one new unit is expected in the Transelectrica market area by 2030. With regard to fuel oil, we expect no new units, and anticipate that more than 80% of the currently operating fuel oil capacity will be decommissioned by 2030 in the referent case.

Clearly, the main focus of decommissioning in SEE is on lignite and coal units (see Table 4 below).

*Table 4: Lignite and coal-fired TPPs commissioning and decommissioning in the EMI region **2018-2030** in the referent, moderate and extreme scenarios*

							In comparison to 2030		In comparison to today (2018)		
Lignite + Coal	Total installed capacity in 2018	Total Decomisisoned capacity till 2030	Total NEW capacity till 2030	Total capacity in operation in 2030 in Referent scenario	Total capacity in operation in 2030 in Moderate scenario	Total capacity in operation in 2030 in Extreme scenario	Rate of capacity change - Moderate scenario	Rate of capacity change - Extreme scenario	Rate of capacity change - Referent scenario	Rate of capacity change - Moderate scenario	Rate of capacity change - Extreme scenario
OST	0	0	0	0	0	0					
NOSBiH	1,850	628	410	1,632	1,442	1,166	-11.6%	-28.6%	-11.8%	-22.1%	-37.0%
ESO EAD	3,920	3,920	0	0	0	0			-100.0%	-100.0%	-100.0%
IPTO/ADMIE	3,870	3,870	0	0	0	0			-100.0%	-100.0%	-100.0%
HOPS	297	0	0	297	192	0	-35.4%	-100.0%	0.0%	-35.4%	-100.0%
KOSTT	960	432	450	978	528	264	-46.0%	-73.0%	1.9%	-45.0%	-72.5%
CGES	225	0	0	225	225	0	0.0%	-100.0%	0.0%	0.0%	-100.0%
MEPSO	759	759	0	0	0	0			-100.0%	-100.0%	-100.0%
Transelectrica	4,105	1,870	0	2,264	771	428	-65.9%	-81.1%	-44.8%	-81.2%	-89.6%
EMS	4,034	263	656	4,428	3,632	2,508	-18.0%	-43.4%	9.8%	-10.0%	-37.8%
ELES	844	305	0	539	0	0	-100.0%	-100.0%	-36.1%	-100.0%	-100.0%
TOTAL	**20,864**	**12,047**	**1,516**	**10,363**	**6,790**	**4,366**	**-34.5%**	**-57.9%**	**-50.3%**	**-67.5%**	**-79.1%**

Table 4 shows that the EMI region already plans to decommission 50% of operating capacities in lignite and coal. On top of this, in the moderate and extreme scenarios we envisage a further capacity reduction in 2030 of 35% and almost 58%, which leads to a reduction of capacity in lignite and coal by 67% and 79%, respectively, compared to today. **These reductions are significant** – there would be 3.5 GW more decommissioned capacity in the moderate scenario, and 6 GW more in the extreme scenario, in comparison to the referent scenario for 2030, and 13.6 GW more decommissioned in the moderate scenario, and 16 GW in the extreme scenario, compared to 2018.

An Appendix provides details on the proposed TPP units to be decommissioned in each area by 2030.

6.5. Electricity market and transmission network scenarios

Based on all the above-mentioned indicators, Figure 2 below provides an overview of all 8 electricity market scenarios, with scenario-specific assumptions regarding the levels of decarbonization under different hydro conditions and EMI regional balance levels.

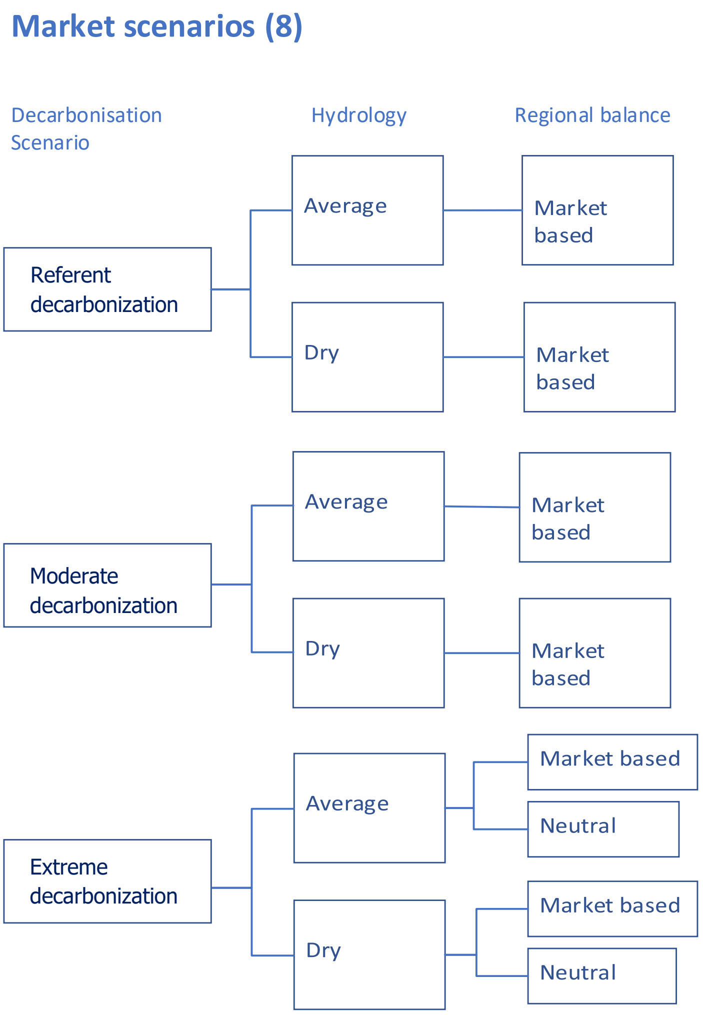


Figure 2: Set of scenarios with scenario-specific assumptions

As shown above, the EMI region interacts with the rest of Europe, and this interaction varies in different scenarios. In the first six scenarios we utilize a market-based exchange with rest of Europe, where the only limiting factors are cross-border capacities modeled by NTCs. Despite the benefits that arise from market integration, there is a real question for each country of the desired level of import dependence. So, in the extreme scenario, we have included a scenario that challenged the regional balance, to see if the EMI region can be self-sustainable and if it could supply the total load on its own, if additional energy from the rest of Europe is not available. We are not projecting that SEE will want to disallow imports from its neighbors, but rather provide the EMI members with an assessment of what would occur if these 11 market areas adopt a policy to self-supply their needs as a region. We call this the "neutral" or "zero-based" scenario in our analytic results below.

Figure 3 below shows the 16 transmission network analysis scenarios, with specific assumptions for the levels of decarbonization under different hydro conditions and EMI regional balance levels. The number of scenarios is higher for the network analyses than for the market analyses, since we needed more scenarios to cover the full range of network element availability.

One set of network scenarios assumes full availability for all network elements, while the other assumes that one key network element is unavailable (the n-1 security criterion). All Network Codes (Rules for transmission system operation), require that the transmission network operate without limit, when any one element is not available. Under these Codes, at a minimum the unplanned outage or maintenance of any single network element (e.g., a line or substation) should not cause a problem in the operation of the rest of the network or disrupt customer service.

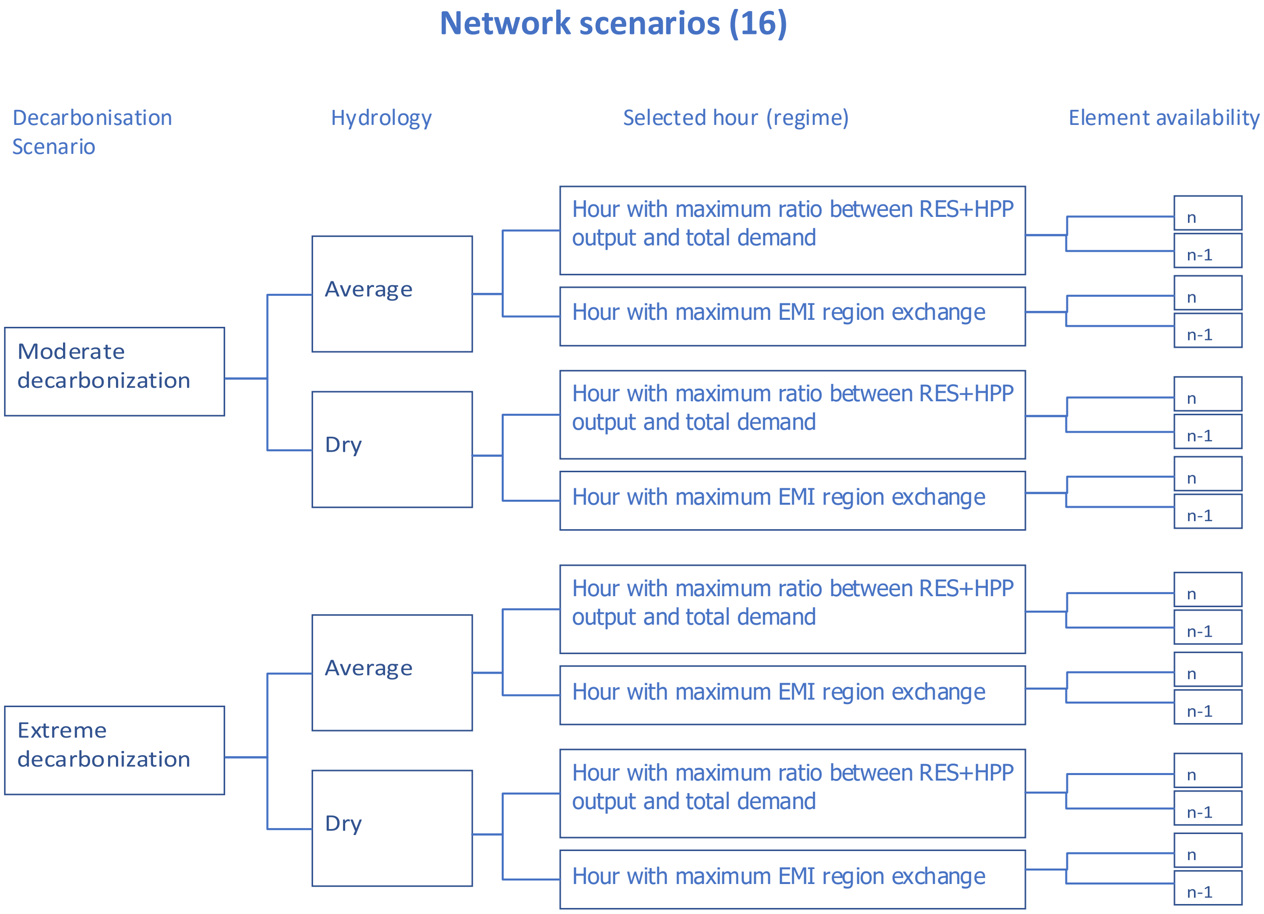


Figure 3: Set of network scenarios with scenario-specific assumptions for 2030

These scenarios provided the EMI participants with a wide range of network conditions based on the levels of decarbonization under different hydro conditions, EMI regional balance levels and network availability. While this provides a broad set of analytic conditions, these inputs are uncertain, so this approach may not identify all potential bottlenecks in the network in 2030.

In sum, this EMI study assesses eight market scenarios and 16 network scenarios. Every scenario provides eight outputs in 2030 (four for the market, and four for the network simulations):

1. Wholesale day-ahead market prices for the region and for each country
2. Changes in the electricity generation mix for the region and by country
3. Changes in thermal generation and total CO_2 emissions
4. Imports and exports for the regional and each country
5. Load flows in the SEE transmission network
6. Voltage profiles on all transmission network nodes
7. Transmission network losses for the region and for each country

8. Network bottlenecks under security (N-1) conditions.

With this large set of outputs, it is a challenge to structure and prioritize all the key messages. Each network scenario gives the EMI participants a clear picture of power flows, cross-border exchanges, voltage violations, network losses and bottlenecks, regionwide and in each country, under that scenario's conditions. The EMI members can compare these results with their TYNDPs, and use this work to further detect issues and alleviate the impacts of the regional RES integration on their networks, based on the application of a verified regional electricity market and network model.

7. MARKET ANALYSES

7.1. Modelling assumptions

The creation of the EMI market modeling database for the SEE region included these activities:

- Definition of the relevant input data needed for the market analyses on the regional level in the selected software tool – Antares[1].
- Collection of input data focused on 2030 from the TSOs and MOs through a comprehensive spreadsheet.
- Clarification of any missing input data and suggestions for solutions, including sources such as the Ten Year Network Development Plans (TYNDPs), Mid-Term Adequacy Forecasts (MAFs), and other publicly available sources, as well as the Consultants' databases.

We used the following approach to model the EMI power systems and neighboring areas:

- We represent the market areas of the EMI members - OST, NOSBiH, ESO EAD, HOPS, ADMIE/IPTO, KOSTT, MEPSO, CGES, Transelectrica, EMS and ELES - on a plant-by-plant basis, and modeled their demand and non-dispatchable generation on an hourly level.
- We model Hungary's, Ukraine's and Moldova's market area by technology cluster (hydro types, thermal by fuel type, nuclear, RES), and model demand and non-dispatchable generation on an hourly level.
- We model Turkey, Central Europe and Italy as spot markets, where the market price is insensitive to SEE price fluctuations, and is constrained by cross-border transmission capacity.

We included these technical and economic parameters in the regional market model for 2030:

1. Thermal power plants (TPPs)

- General data (plant name, number of units, fuel type)
- Operational status in 2030 for each unit
- Maximum net output power per unit
- Minimum net output power per unit
- Heat rates at maximum net output power per unit
- Fuel cost per unit
- Variable O&M costs per unit
- Outage rates (FOR, MOR) and maintenance periods per unit

1 Antares – probabilistic software tool for simulation of power system operation on the basis of day-ahead market principles, developed by RTE (French TSO).

- CO_2 emission factor per unit
- Operational constraints (minimum up/down time) per unit
- Must-run constraints per unit

2. Hydro power plants (HPPs)

- General data (plant name, number of units)
- Operational status in 2030 for each unit
- Plant type (run of river, storage or pumped storage plant)
- Maximum net output power per unit
- Minimum net output power per unit
- Biological minimum production
- Maximum net output power per unit in the case of pumped storage plants
- Minimum net output power per unit in case of pumped storage plants
- Monthly generations for 2 hydro conditions: average and dry

3. Renewable energy sources (RES) for the Referent and High Scenarios

- Installed capacities (solar)
- Installed capacities (wind)
- Hourly capacity factor for 3 characteristic climatic years: 1982, 1984 and 2007 (solar)[2]
- Hourly capacity factor for 3 characteristic climatic years: 1982, 1984 and 2007 (wind)

4. Demand in the Referent and Low demand scenarios

- Annual consumption expected in 2030 (TWh)
- Hourly load profiles for 3 characteristic climatic years: 1982, 1984 and 2007

5. Network transmission capacity (NTC)

- NTC values applied as cross-border limits for energy exchange (see also Table 5 below)[3]

The primary data source was spreadsheets that the national TSOs and MOs completed. For any unavailable data, we used other verified and publicly available official data, along with the consultants' documents and estimates, while maintaining the consistency of the input dataset. This data mainly originates from ENTSO-E's TYNDPs and MAF datasets, such as capacity factors for wind and solar power plants. In this way we developed a consistent set of harmonized and verified inputs among all EMI TSOs and MOs, as well as with relevant ENTSO-E development documents. Based on all the inputs and coordination with the EMI members, we believe this modeling framework to be among, if not the best, for the entire region.

An Appendix fully describes our approach in gathering the data and relevant items in support of this EMI analysis, including: load, wind and solar profiles; hydro power plant generation; thermal power plants; fuel and CO_2 prices; neighboring power systems and external markets; and NTCs.

2 These are the characteristic climatic years used in preparation of the TYNDP 2018 report, since they have been determined to be adequate to demonstrate the range of impacts of 34 climatic years on the results.
3 As agreed in the ENTSO-E level for TYNDP 2020, some of which were modified in TSO discussions.

We provide the relevant NTC values and our summary of the load and generation capacities for each border and market areas in the next two sections.

7.1.1. Harmonized NTC values

Future NTC values are important inputs, subject to many uncertainties, including internal network development, internal generation unit commitments, coupling developments, MACZT regulations, realization of new cross-border interconnection capacities, demand growth, and more. The TSOs provided the NTC values for 2030 in this study – in agreement with their neighbors - and have been embedded in the EMI's Antares market model. Due to these uncertainties, NTC values need to be regularly updated and submitted to ENTSO-E. Table 5 below provides the NTC values implemented in our study.

We use available transmission capacities for the borders as equal to summarized NTCs, and assumed this capacity is fully available for commercial exchanges for the entire calculation period.

A single regional market model represents all of the generation and transmission cross-border capacities for the selected modeling year – 2030. We did not model the individual internal transmission network in the market simulation, as it is not relevant for this regional analysis and perspective (internal networks are included in the network model – PSS/E). However, any EMI member can easily update the regional market model with local specifics and use this tool for internal simulations and analyses. This is an important outcome of the EMI project.

Table 5: Summarized NTC values between SEE power systems

NTC (MW) in 2030		NTC (MW) in 2030	
AL - GR	400	ME - AL	450
AL - ME	450	ME - BA	750
AL - MK	500	ME - IT	1000
AL - XK	650	ME - RS	600
CE_HU - HU	800	ME - XK	300
CE_SI - SI	950	MK - AL	1000
BA - HR	1200	MK - BG	800
BA - ME	800	MK - GR	850
BA - RS	1100	MK - RS	400
BG - GR	1700	MK - XK	330
BG - MK	800	RO - BG	2600
BG - RO	2600	RO - HU	1400
BG - RS	800	RO - RS	2000
BG - TR	900	RS - BA	1200
GR - AL	400	RS - BG	800
GR - BG	1400	RS - HR	500
GR - IT	500	RS - HU	1000
GR - MK	1100	RS - ME	600
GR - TR	660	RS - MK	400
HR - BA	1200	RS - RO	2000
HR - HU	1700	RS - XK	300
HR - RS	500	SI - CE_SI	950
HR - SI	2000	SI - HR	2000
HU - CE_HU	800	SI - HU	1200
HU - HR	1700	SI - IT	730
HU - RO	1300	TR - BG	500
HU - RS	1000	TR - GR	580
HU - SI	1200	XK - AL	500
IT - GR	500	XK - ME	300
IT - ME	1000	XK - MK	350
IT - SI	660	XK - RS	400
UA-RO	200	MD-RO	600
RO-UA	200	RO-MD	600
UA-MD	400	UA-HU	1253
MD-UA	800	HU-UA	1253

7.1.2. Summary of SEE Regional Market Models

In this chapter, we review the expected power system status in 2030 for each EMI member, in alphabetical order, along with an overview of the data, assumptions and proxies that we used to update the existing market model for 2030, developed using Antares.

In specific, we present an overview of the expected development of power consumption and generation for each technology in each SEE market area, and the entire region (Tables 21 to 27). We begin with the outlook for changes in the demand for power, by market and region-wide.

Table 6: Total annual demand - SEE

EMI Member	Demand in 2018 (TWh)	Referent scenario annual growth rate	Demand in 2030 (TWh)
AL	7.2	2.34%	9.5
BA	12.6	0.62%	13.57
BG	34.1	0.76%	37.35
HR	18.2	0.18%	18.6
GR	51.6	1.89%	64.62
XK	5.58	1.72%	6.85
MK	7.39	1.47%	8.8
ME	3.4	2.79%	4.73
RO	57.9	1.01%	65.3
RS	34.9	0.72%	38.04
SI	14.4	1.64%	17.5
TOTAL	**247.27**	**1.19%**	**284.86**

Table 6 shows that we expect **total regional demand growth from 2018 – 2030 in the range of 37 TWh, or an annual growth of 1.19%** in total electricity demand in 2018. Annual growth rates per market area in the referent scenario show a wide range, from 0.18% (HR) to 2.79% (ME).

The next four tables summarize the changes expected across the market areas in SEE in installed generation capacities per technology from 2018 to 2030.

Table 7 indicates that EMI members **expect a significant increase in wind capacity in the coming decade, about 14,175 MW, reaching a total of three times more WPP than in 2018**. In a number of cases, the 2018 starting point for installed wind generation was zero or near zero. The largest growth of WPP capacities in absolute terms by 2030 is expected in GR (4,698 MW), while in relative terms, the largest growth is anticipated in RS (4,352 MW), or 22 times more WPP capacity in 2030 compared with 2018. In the WB6 countries, the expected growth is from 441 MW to 6,539 MW of wind capacity, which is a fifteen-fold increase.

Table 7: Installed wind power plant (WPP) capacities – SEE

EMI Member	Installed WPP capacity (MW)	Added WPP installed capacity (MW) from 2018 – 2030	Total WPP installed capacity (MW) in 2030
	Current (2018)	Referent RES	Referent RES
AL	0	384	384
BA	51	529	580
BG	712	236	948
HR	582	718	1300
GR	2302	4698	7000
XK	34	302	336
MK	37	406	443
ME	118	125	243
RO	2977	2278	5255
RS	201	4352	4553
SI	3	147	150
TOTAL	**7017**	**14175**	**21192**

Even more rapid development is expected in solar power capacity. There will be an **additional 15,305 MW of SPP in the region, reaching a total of four times more than in 2018**, as given in the following table. By far the largest installed SPP capacity is expected in Greece (7,700 MW), followed by Romania (5,054 MW) and Bulgaria (3,216 MW). In 2030, these three market areas combined are expected to comprise 78% of all SPP capacity in the SEE region. The WB6 countries expect to grow their installed solar capacity from 40 MW to 2,000 MW, which is a modest 13% of the regional SPP total, but represents a growth of 50 times the current SPP capacity.

Table 8: Installed solar power plant (SPP) capacities – SEE

EMI Member	SPP installed capacity (MW)	Added SPP installed capacity (MW) from 2018 – 2030	Total SPP installed capacity (MW) in 2030
	Current (2018)	Referent RES	Referent RES
AL	0	445	445
BA	10	90	100
BG	1059	2157	3216
HR	60	540	600
GR	2445	5255	7700
XK	7	143	150
MK	17	546	563
ME	0	250	250
RO	1262	3792	5054
RS	6	502	508
SI	281	1585	1866
TOTAL	**5147**	**15305**	**20452**

The following table shows expected changes in total installed hydro capacity by 2030. All EMI members, except BG, are planning to increase total HPP capacity. The most significant changes in the period 2018-2030, in absolute terms, are expected in GR, AL and HR. In SEE as a whole, the total increase in HPP capacity will be significant. **The TSOs expect 5,237 MW of new HPPs capacity by 2030, which is about 20% higher than in 2018.**

Table 9: Installed hydro power plant (HPP) capacities – SEE

EMI Member	HPP installed capacity (MW) in 2018	Added HPP installed capacity (MW) from 2018 - 2030	Total HPP installed capacity (MW) in 2030
AL	1912	1037	2949
BA	2100	393	2493
BG	3207	0	3207
HR	2164	953	3117
GR	3413	1132	4545
XK	64	370	434
MK	693	393	1086
ME	649	468	1117
RO	6420	364	6784
RS	3018	17	3035
SI	1185	110	1295
TOTAL	**24825**	**5237**	**30062**

The following four tables summarize all the above-mentioned values for installed electricity generation capacities and technologies.

Table 10 presents the installed capacities in SEE in 2018, and Table 11 presents the expected total installed generation capacities in SEE in 2030, which could range from 95,204 MW to 105,545 MW.

Table 10: Installed capacities per technologies – SEE 2018

EMI Member 2018	Total WPP installed capacity (MW)	Total SPP installed capacity (MW)	Total HPP installed capacity (MW)	Total TPP Net output power (MW)	Total installed capacity (MW)
AL	0	0	1912	0	1912
BA	51	10	2100	1850	4011
BG	712	1059	3207	6846	11824
HR	582	60	2164	1924	4730
GR	2302	2445	3413	9771	17931
XK	34	7	64	960	1065
MK	37	17	693	1274	2021
ME	118	0	649	225	992
RO	2977	1262	6420	8198	18857
RS	201	6	3018	4252	7477
SI	3	281	1185	2134	3603
TOTAL	**7017**	**5147**	**24825**	**37434**	**74423**

Table 11: Total generation capacities (MW) per technologies and TPP decommissioning scenario in 2030

EMI Member	Total WPP installed capacity (MW)	Total SPP installed capacity (MW)	Total HPP installed capacity (MW)	Total TPP Net Output Power (MW)			TOTAL (MW)		
				Referent	Moderate	Extreme	Referent	Moderate	Extreme
AL	384	445	2949	300	200	100	4078	3978	3878
BA	580	100	2493	1632	1442	1166	4805	4615	4339
BG	948	3216	3207	4728	4070	3470	12099	11441	10841
HR	1300	600	3117	981	876	684	5998	5893	5701
GR	7000	7700	4545	7768	7167	6493	27013	26412	25738
XK	336	150	434	978	528	264	1898	1448	1184
MK	443	563	1086	586	586	586	2678	2678	2678
ME	243	250	1117	225	225	0	1835	1835	1610
RO	5255	5054	6784	10055	8562	6889	27148	25655	23982
RS	4553	508	3035	4829	4033	2909	12925	12129	11005
SI	150	1866	1295	1757	990	937	5068	4301	4248
TOTAL	**21192**	**20452**	**30062**	**33837**	**28678**	**23498**	**105545**	**100385**	**95204**

As mentioned above, the expected capacities in wind and solar in 2030 are now higher in almost all market areas in comparison with data provided by the EMI members last year (2020), for our RES Integration Study. Last year's total capacities in wind and solar were:

- Wind capacities in the referent case: 18,138 MW

- Wind capacities in the high RES case: 22,574 MW
- Solar capacities in the referent case: 15,101 MW
- Solar capacities in the high RES case: 21,321 MW

The expected (referent) level of wind and solar capacities in 2030 are now each several thousand MW higher than expected just last year, and are close to last year's high cases. This points to the rapid expansion and changes in the region with respect to these types of RES capacities.

7.2. Market Simulation Results Summary

We have focused the presentation of the market results on the relevant power system operation indicators and impacts of the power sectors' decarbonization scenarios among the EMI members. As explained above, we analyzed three levels of power sector decarbonization in 2030:

- **Referent decarbonization scenario** - in line with data provided by the EMI members

  There is already considerable decommissioning of old thermal units in the referent (officially determined) plans of all EMI members. However, in most countries, this level is below the environmental requirements required by the EU and the EnC.

- **Moderate decarbonization scenario** – This Scenario assumes more decommissioning of thermal units (compared to the referent one) based on the criteria above (commissioning year, efficiency,…). It mostly includes decommissioning of TPPs more than 40 years old.

- **Extreme decarbonization scenario** - This Scenario assumes additional decommissioning of thermal units that are "younger" and more efficient than the units in the moderate scenario, but which are more than 30 years old.

Table 1 above presents the total installed TPP capacity in the EMI region in 2030, including the **agreed values of the total decommissioned TPP capacities** in each scenario.

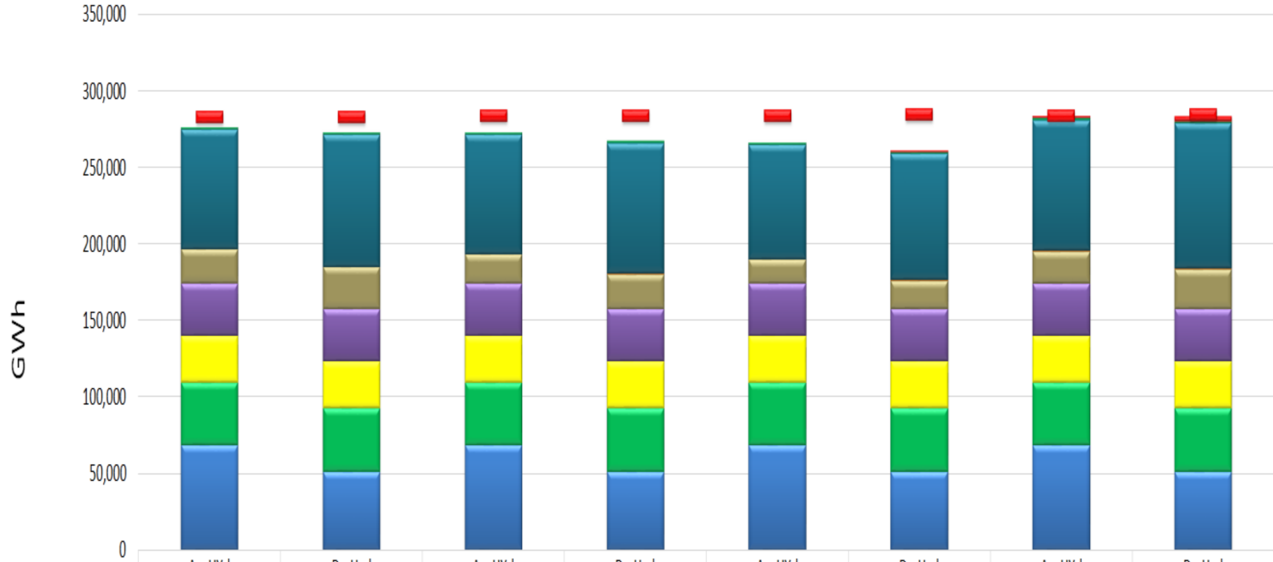
As a **fourth Scenario**, we analyzed Extreme decarbonization with constrained imports from the rest of Europe, assuming that hourly exchanges are free, but that the annual balance of the region is kept at zero. This represents a scenario with regional self-sustainability.

For each scenario, we present these indicators for each market area and for the region:

1. Generation mix, which gives an overview of the system's generation technologies
2. Generation from fossil plants, with particular attention to lignite, coal gas and oil-fired units
3. CO_2 emissions in metric tons (Mt)
4. Balance of the market area: Sum of the exports and imports of the zone
5. Wholesale market prices

We analyzed the different levels of decarbonization in 2030 with one assumption related to expected CO2 emission tax (65.73 EUR/tCO2), and two hydro conditions (average and dry).

Under these conditions, we present the projected (2030) generation mix for the whole EMI region in Figure 4, and the main regional indicators in Figure 5.



	Referent		Moderate		Extreme		Extreme-zero Balance	
	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd
ENS	0	0	0	0	0	4	1,052	2,928
Other	1,011	1,014	1,013	1,016	1,017	1,020	1,022	1,027
Gas	78,511	86,414	77,662	85,349	74,895	82,215	85,285	94,938
Coal	327	327	333	353	348	401	640	935
Lignite	22,022	27,468	18,892	22,876	15,366	18,699	20,923	25,951
Nuclear	34,458	34,458	34,458	34,458	34,458	34,458	34,458	34,458
Solar	30,214	30,214	30,214	30,214	30,214	30,214	30,214	30,214
Wind	41,414	41,414	41,414	41,414	41,414	41,414	41,414	41,414
Hydro	68,492	51,676	68,492	51,676	68,492	51,676	68,492	51,676
Consumption	284,047	284,289	284,379	285,033	284,782	285,839	284,937	285,787

Figure 4: Generation mix in the EMI region in 2030

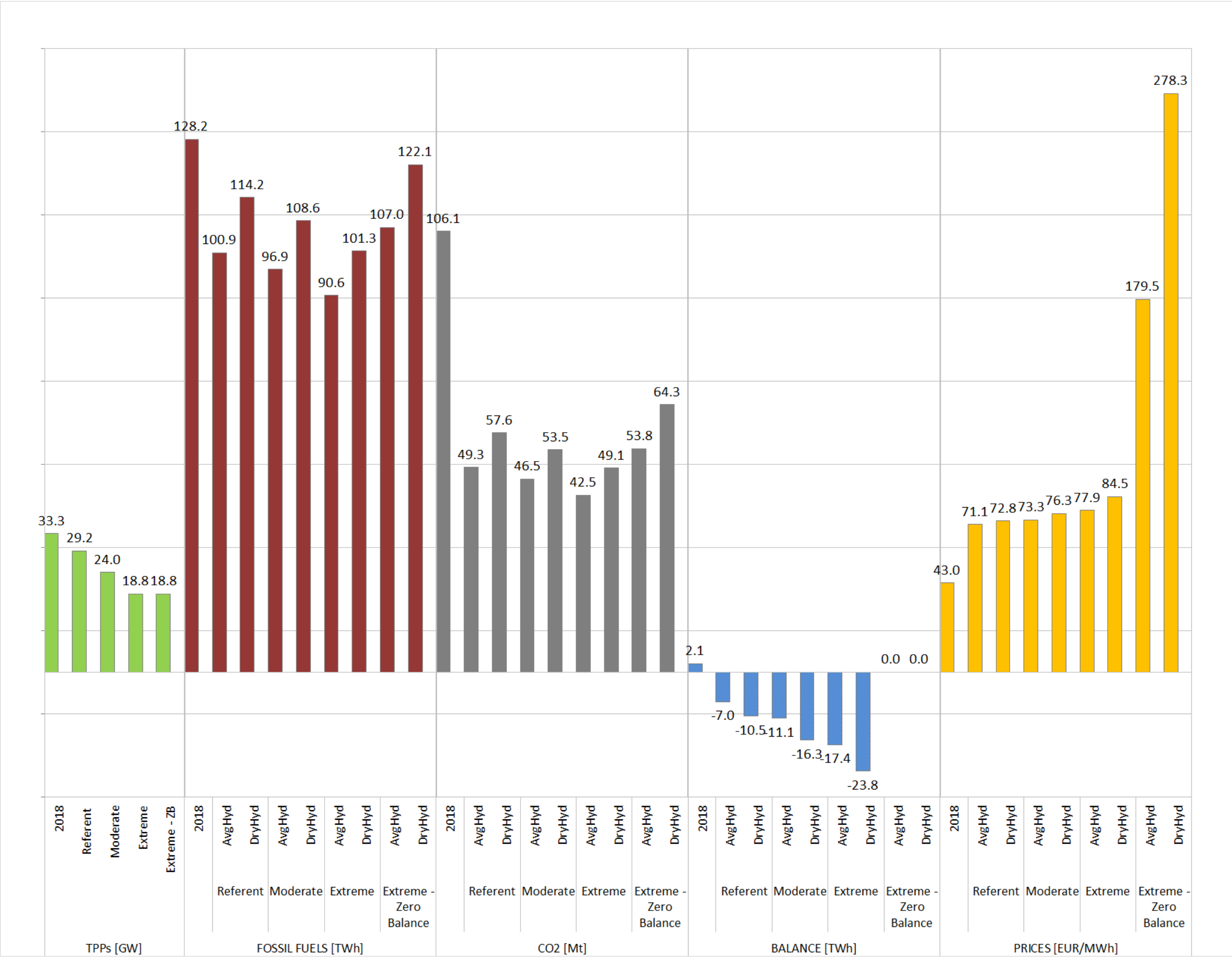


Figure 5: Main system operating indicators in the EMI region in 2030 – all fossil fuel technologies

From these scenarios, we have conclusions that fall into several categories: 1) Generation mix by technology; 2) CO2 emissions; 3) Exports and imports to the region; 4) Wholesale prices; and 5) Exports and imports by market area.

1. Generation mix by technology

- Total generation from fossil plants (lignite + coal + gas + oil) decreases with deeper decarbonization, but in all scenarios, it is higher in dry hydrology conditions. The lowest fossil generation can be expected in the Extreme scenario (91 TWh), while the highest is again in Extreme scenario, in the case with limited exchanges with the rest of Europe (122 TWh). In this constrained case, all internal regional generation is used to supply the load, even the most expensive fossil units in some critical hours, which increases this type of generation. Total values show that, with different levels of decarbonization and no constraints with respect to exchanges with the rest of Europe, generation from fossil plants would be reduced between 11% and 29% in comparison to 2018 [4]).

- Generation from fossil plants is lower, but not dramatically so compared to 2018, but its structure changes considerably, from lignite + coal plants to mostly generation from gas. This change leads to substantial reductions in both lignite generation and CO2 emissions.
- National development plans already include plans for decarbonization of the power sector, so capacities in lignite and coal are significantly decreased in 2030 compared to 2018. According to these plans, these capacities fall from 21 GW in 2018 to 10 GW in 2030. This reduces the generation from this technology. Further, the CO_2 emission tax of 65 EUR/tCO2 substantially affects lignite and coal generation. The CO2 tax may jeopardize the financial viability of lignite and coal plants since their generation is quite low, even in the referent scenario. Figure 6 shows all the changes in lignite and coal generation in our scenarios.
- **The maximum share of lignite and coal generation in 2030 in our scenarios ranges from 6% to 10% of total regional consumption, a significant decrease from around 40% in 2018.** Capacity factors decrease with deeper decarbonization, but not significantly, since reduction of capacities in the region provides better market position for the remaining units. Their capacity factor drops from 54% in 2018 to 25% in the Referent scenario with average hydrology in 2030, but, in case of dry hydrology in the Extreme scenario with constrained exchanges, their capacity factor rises as high as 70%.

[4] Installed capacities, generation and balances from 2018 are taken directly from ENTSO-E Facts Sheet.

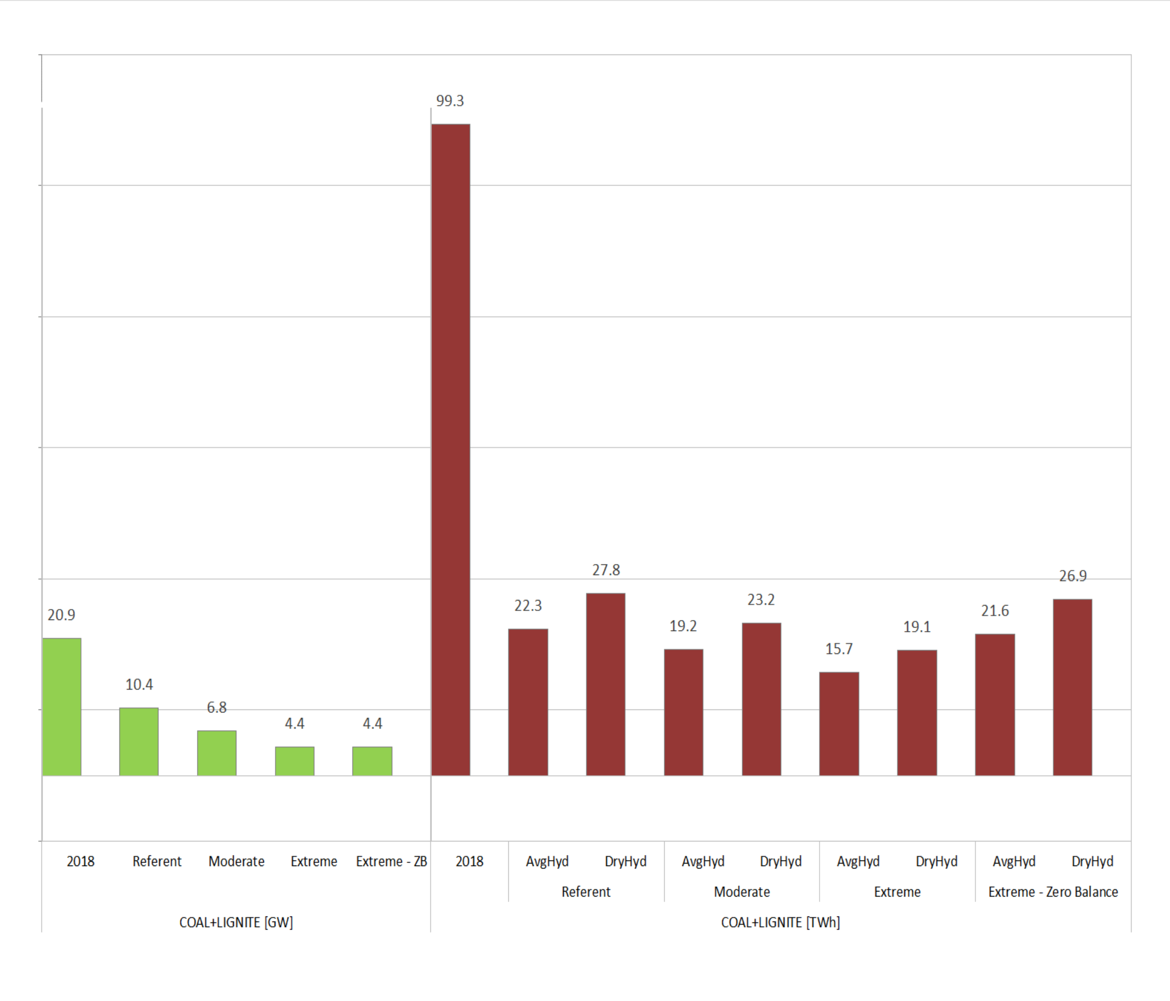


Figure 6: Capacity and generation from lignite + coal fired plants in the EMI region in 2018 and 2030

- **The main generation technology in the region in 2030 shifts to gas, which supplies around 30% of regional consumption, and this share is almost constant among the analyzed scenarios.** This is the consequence of ambitious plans for construction of new gas plants (mainly in the ESO EAD, IPTO and Transelectrica market areas) that includes 9 GW in new gas plants (and decommissioning of only 1,5 GW). Gas + oil fired plants capacity in 2018 is around 12 GW, while in 2030 it is expected to be above 18 GW (less than 0.5GW in oil) in the EMI region. Generation from gas increases significantly – from 28 TWh to a range of 78 to 95 TWh, depending on the scenario and hydrology.
- **The ability of the region to meet load in 2030 without substantial increases in imports (the region is already import-dependent as Figure 5 shows) depends highly on this sharp increase in bringing new gas generation on line.**

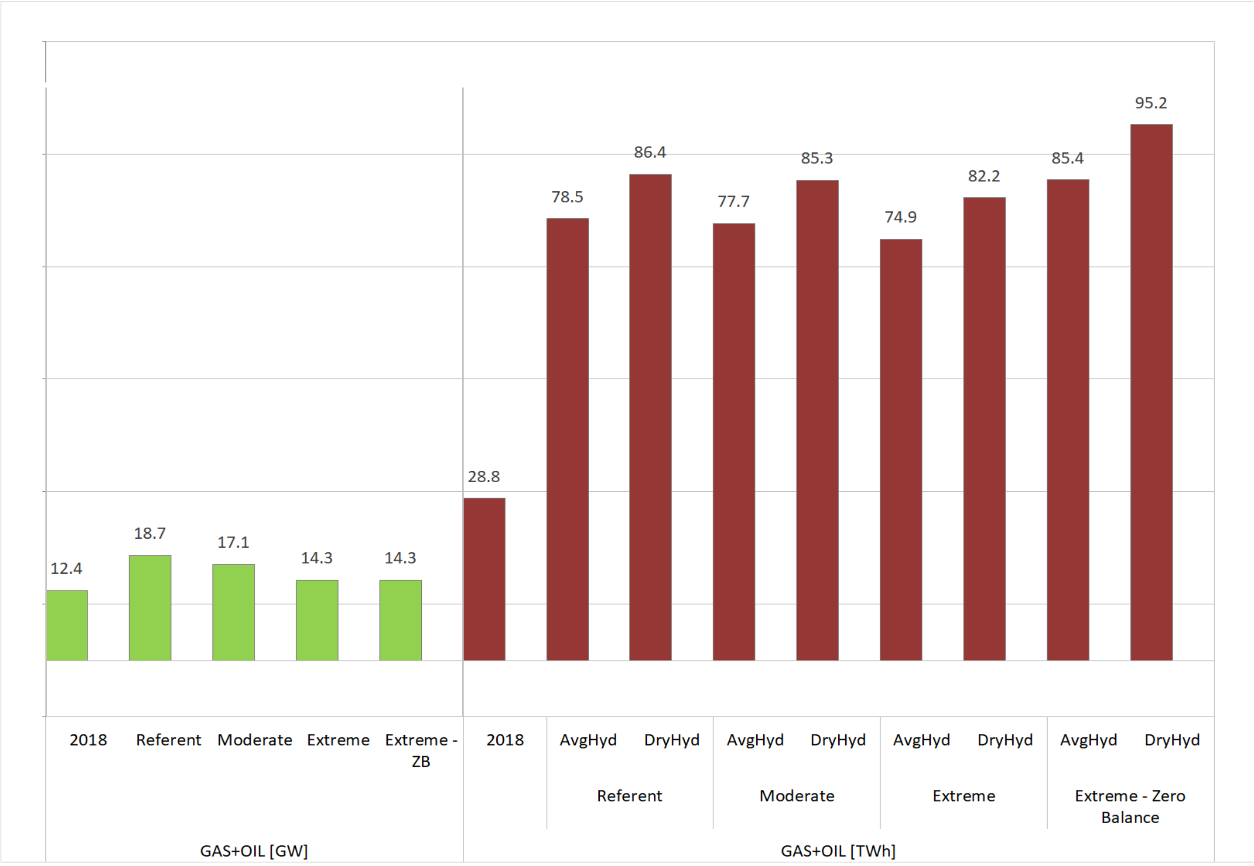


Figure 7: Capacity and generation from gas fired plants in the EMI region in 2018 and 2030

- The next highest share of generation in 2030 is from RES (wind + solar). Generation from wind and solar sources of 71 TWh supplies around 26% of total regional consumption. In comparison to RES generation in 2018 (22 TWh), the sum of wind and solar generation in 2030 is more than three times higher.
- Hydro generation has a share between 18% and 24% depending on the hydrology. This generation is slightly increased from 2018 given the modest development of new hydro plants in the region planned for the period from now to 2030.
- Concerning nuclear technology, by 2030 one new unit is expected in the Transelectrica market area and this brings a modest increase in nuclear generation in comparison to today. It should be noted that nuclear, hydro and RES generation are constant for all the analyzed scenarios with respect to hydrology; only fossil generation varies between the scenarios.

2. CO2 emissions

- CO2 emissions decrease with the decrease of generation from fossil plants, and because of the major shift to natural gas from lignite generation. In each scenario, CO2 emissions are higher in dry hydro conditions. The range of CO2 emission is 42 Mt to 64 Mt, the lowest in the Extreme scenario, when TPP generation is the lowest, and it is the highest in the same Extreme scenario but in the case with zero net exchange with the rest of Europe.

- Across our projections, the level of regional CO2 emissions falls from 40% to 60% from 2018[5] to 2030, as shown in Figure 5, regardless of the scenario. **However, for both the region and for a number of market areas, the percentage decrease in CO2 emissions – in both the Moderately Aggressive and the Extreme scenarios - is not as great as the 67% and nearly 80% decrease in lignite and coal capacity in those scenarios.**

  These differences are for two main reasons: 1) there is a considerable amount of generation from natural gas added in SEE, especially in the Transelectrica and IPTO market areas, and in others as well; and 2) the new gas generation, and the lignite and coal generation that remains after other plants are decommissioned gets heavily used to ensure the security of supply in SEE in 2030, and thus often generates at high capacity factors.

3. Exports and imports to the region

- With deeper decarbonization, reduced TPPs capacity and high operating costs (due to high CO2 emission tax), the EMI region becomes an importer. Figure 5 shows that imports from the rest of Europe are between 7 and 24 TWh, depending on the scenario. These imports are between 2% and 8% of regional consumption, which does not seem so high, though as mentioned above, it depends on the actual construction of much more gas generation.
- The level of imports is influenced not only by internal regional generating capacities and operating costs, but also by the prices in external spot markets, and the available transfer capacities at the borders between markets (both in the region and outside).
- The Extreme scenario with zero regional balance shows that generation from fossil plants needs to increase within the region to supply the load if there are import constraints from the rest of Europe. In this case, regional generation rises by 16-20 TWh (6-8%) compared to the Extreme scenario, but this increase is not enough, and there would be hours during the year in which load is not met, likely at quite a high cost (which we evaluate below).

4. Wholesale prices

- Wholesale prices in 2030 are within a range of 10-15 EUR/MWh in all scenarios except the ones with constraints in exchange with the rest of Europe. With higher levels of decarbonization and dry hydro conditions, imports increase and prices increase as well, from 71.1 EUR/MWh to 84.5 EUR/MWh. When moving from the referent case to the extreme case, in the case of average hydrology, prices increase by 6.8 EUR/MWh or 9.5%, while with dry hydrology, the increase is 11.7 EUR/MWh or 16%. Obviously, thermal capacities are more important in dry hydrology conditions than in average ones.
- Wholesale prices among market areas in the EMI region will be quite similar, as there is a high level of regional price convergence. The highest price differences among the market areas are just 0.7 EUR/MWh in the Referent Scenario, and 1.0 EUR/MWh in the Extreme

[5] CO2 emission from 2018 is assessment based on generation of different technologies from 2018 (ENTSO-E FactSheet) and standard emission factors.

scenario in 2030. When compared to the prices from 2018[6](see the figure below), we project an increase from 30% to over 100%, mainly driven by the CO2 emission price increase.

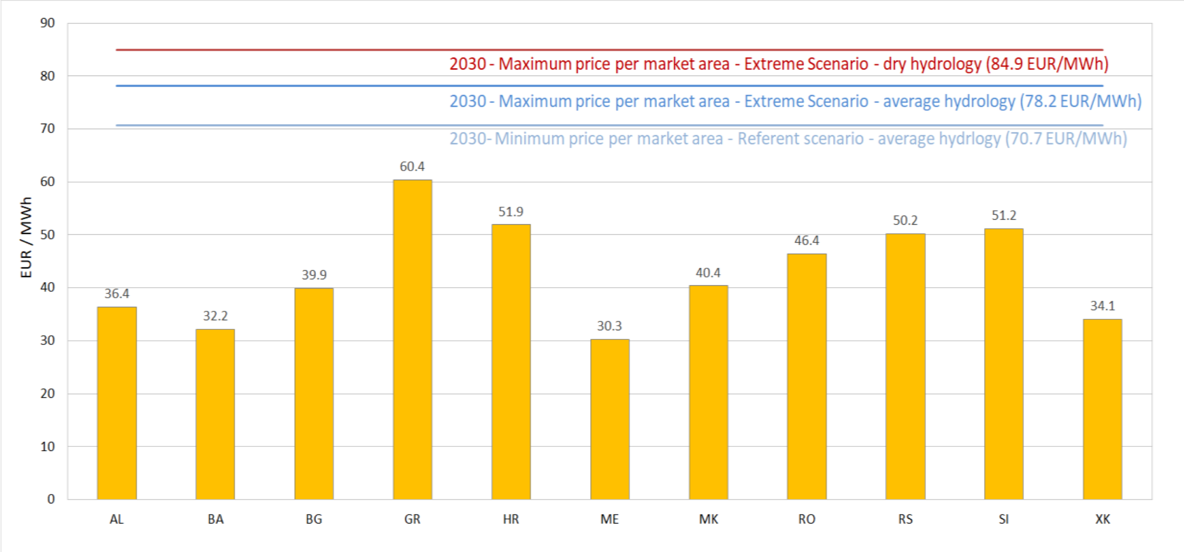


Figure 8: Wholesale market prices in 2018

- Constraints in exchanges with the rest of Europe lead to wholesale prices that are more than two times higher than in the same Extreme scenario. This sharp increase in prices is caused by the penalty on prices for non-supplied consumption, in which we apply a cost for the Value-of-Loss-Load (VOLL) or Load curtailment of 1000 EUR/MWh[7].

  As the following diagrams show, the hours with non-supplied consumption in 2030 would occur in the winter (December, January, February) and summer (July, August). In total, in the average hydrology case there are 340 hours with the risk of not supplying the load, while with dry hydrology, this number of hours rises to 830.

[6] Prices for 2018 are taken from ACER Market Monitoring Report 2018, as well as additional publicly available sources (Energy Community, IENE,…). It should be noted that for the market areas without power exchanges in 2018 (AL, BA, ME, MK, XK), prices present average production costs. Therefore, values for 2018 and 2030 are not fully comparable.

[7] VOLL is estimated by the Consultant based on available data from EnC and ENTSO-E. The cost to customers and to the economy as a whole of a lack of electricity is considerable, and can lead to considerable societal disruption. Moreover, this value is growing a dependence on electricity increases (e.g., electric vehicles). The price of 1000 EUR/MWh that we apply is at the lower end of the value range.

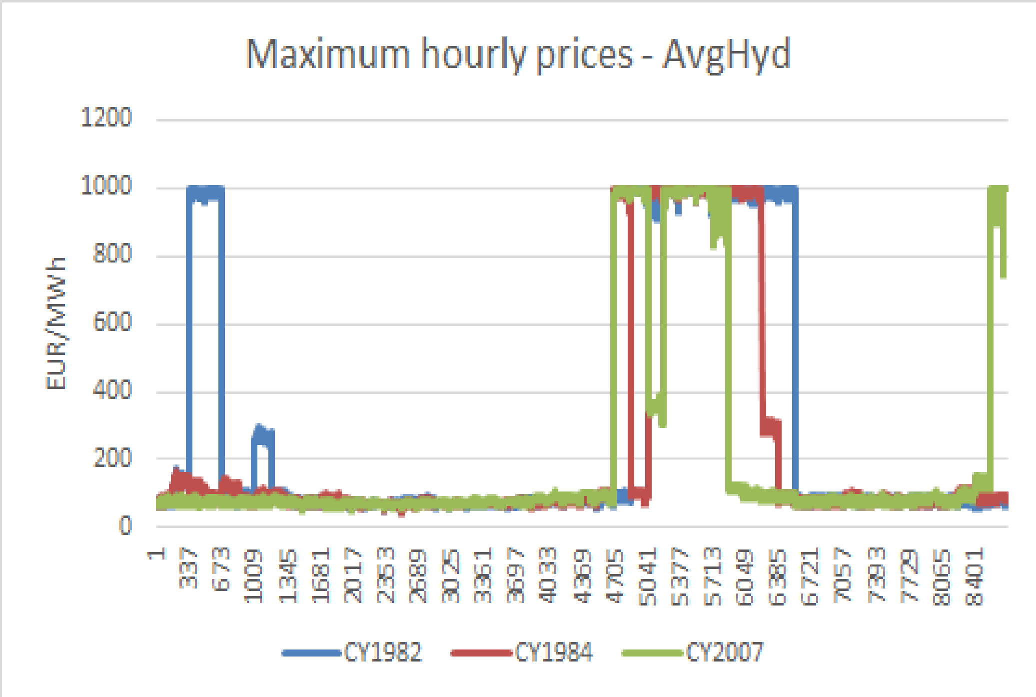


Figure 9: Hourly prices in Extreme Scenario with zero balance – average hydrology

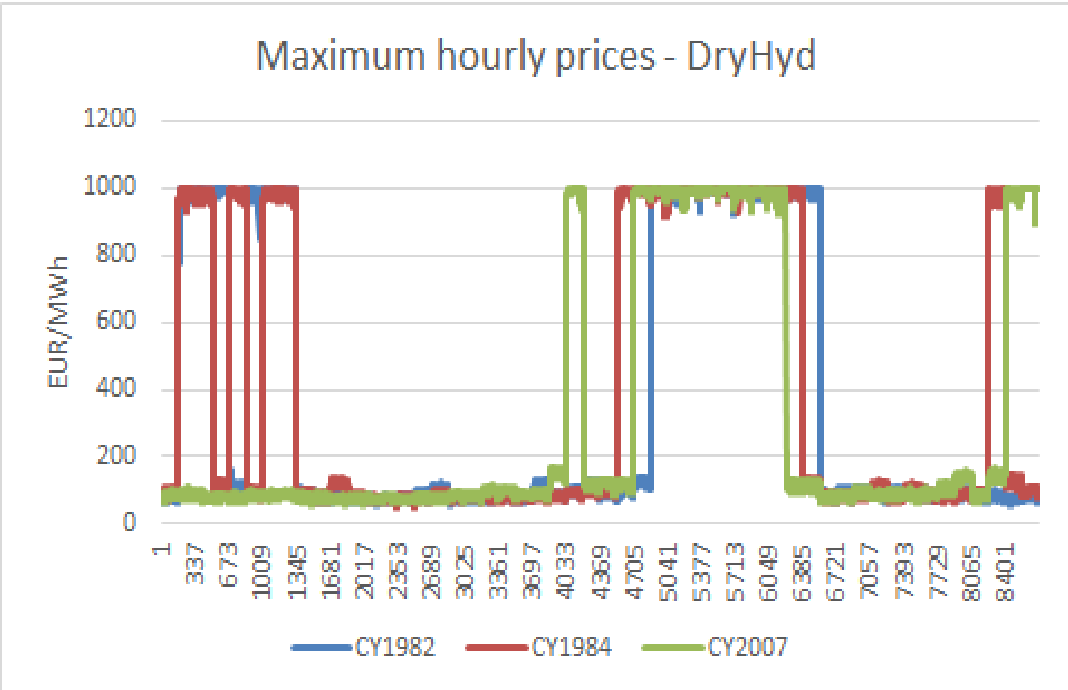


Figure 10: Hourly prices in the extreme decommissioning with zero balance scenario – dry hydrology

If we apply an "emergency import" price that is two times higher than marginal costs[8], instead of implementing a strong VOLL penalty, the average annual wholesale price in 2030

[8] As it could be expected that emergency imports will be applied in the hours with load supply risk (instead of load curtailment and implementation of the VOLL), we calculated the average annual prices with emergency import prices assumed to be two times higher than marginal costs in corresponding hours.

would decrease from 179.5 EUR/MWh to 107.3 EUR/MWh in the average hydrology case, and from 278.3 EUR/MWh to 129.5 EUR/MWh in the dry hydrology situation.

5. Exports and imports by market area

- A number of factors affect exports and imports from the region and from individual market areas. Changes in the balance positions for all market areas, under average and dry hydro conditions (Figure 11), shows that in almost all market areas, deeper decarbonization leads to a decrease in exports or an increase in imports.
- In contrast, in the market areas with lignite/coal generation like NOSBIH and EMS, deeper regional decarbonization provides a better market position for their remaining lignite units. Similarly, under dry hydrology, the lack of hydro generation moves the regional merit order curve to the right, again providing a better market position for fossil units in some of the market areas (as e.g., in EMS).
- A similar development occurs in the OST market area, where gas units become competitive when there is deeper decarbonization in the region.

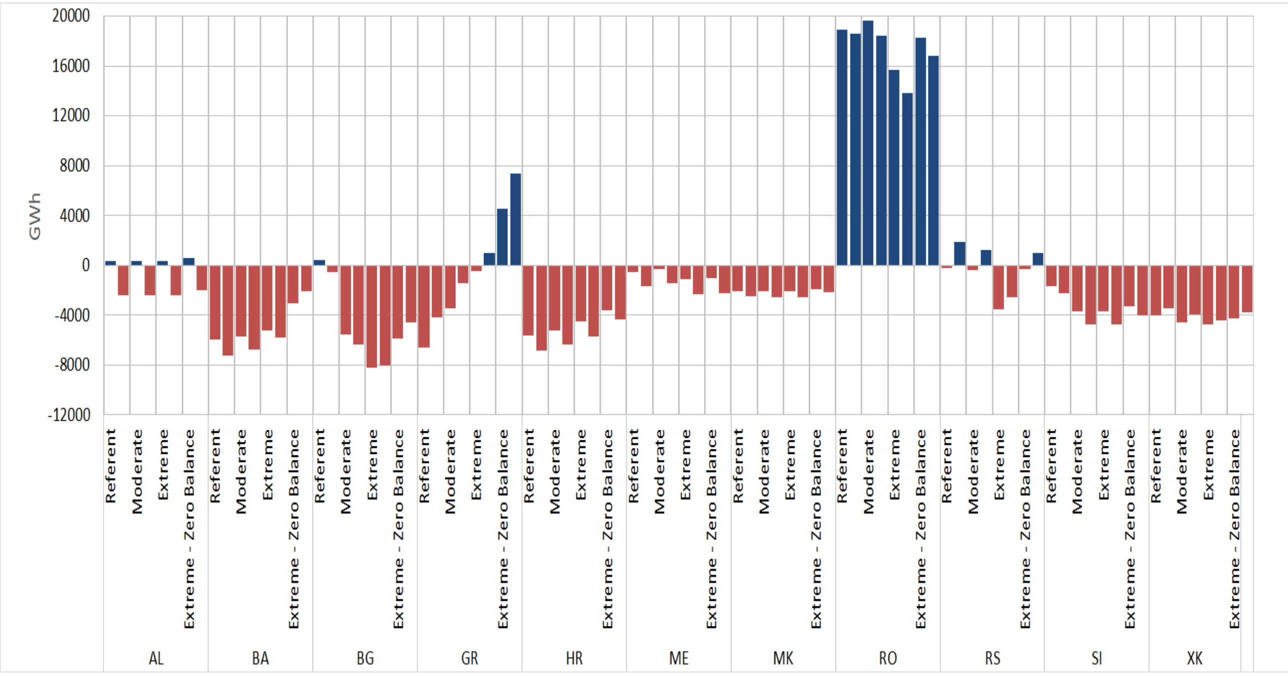


Figure 11: Balance positions for each market area in 2030

- As mentioned, national development plans already include significant decarbonization of the power sector, and according to these plans, capacity in fossil plants in 2030 will be lower in comparison to today in almost all market areas, except in OST, Transelectrica and EMS. In the OST and EMS market areas, in the Referent Scenario there is 300 MW and 600 MW more in fossil plants than today (although in different technologies), respectively. This additional capacity enables the OST and EMS market areas to be almost balanced in most scenarios.

- The Transelectrica market area plans to add more than 3.8 GW in new, efficient gas units, as well as add a new nuclear unit in Cernavoda (670 MW), and decommission 2.6 GW of old, inefficient lignite. According to these plans, Transelectrica should have 1.8 GW more capacity in 2030 in new competitive units. With this major shift, Transelectrica becomes a large regional exporter. Further decarbonization there would reduce their exports, but in all scenarios, the Transelectrica market area remains an exporter.
- As mentioned above, Figure 12: shows that in all market areas, deeper decarbonization leads to increased engagement and higher capacity factors for the remaining fossil plants, including existing and new plants (including gas), sometimes quite significantly. In general, the capacity factors for the EMI market areas in 2030 in our scenarios range from 20% and 80%. Higher engagement of gas units (see Figure 7) generally drives these capacity factors.
- Lower capacity factors compared to other markets can be expected in the OST and NOSBIH market areas in all scenarios due to non-competitive thermal units there.

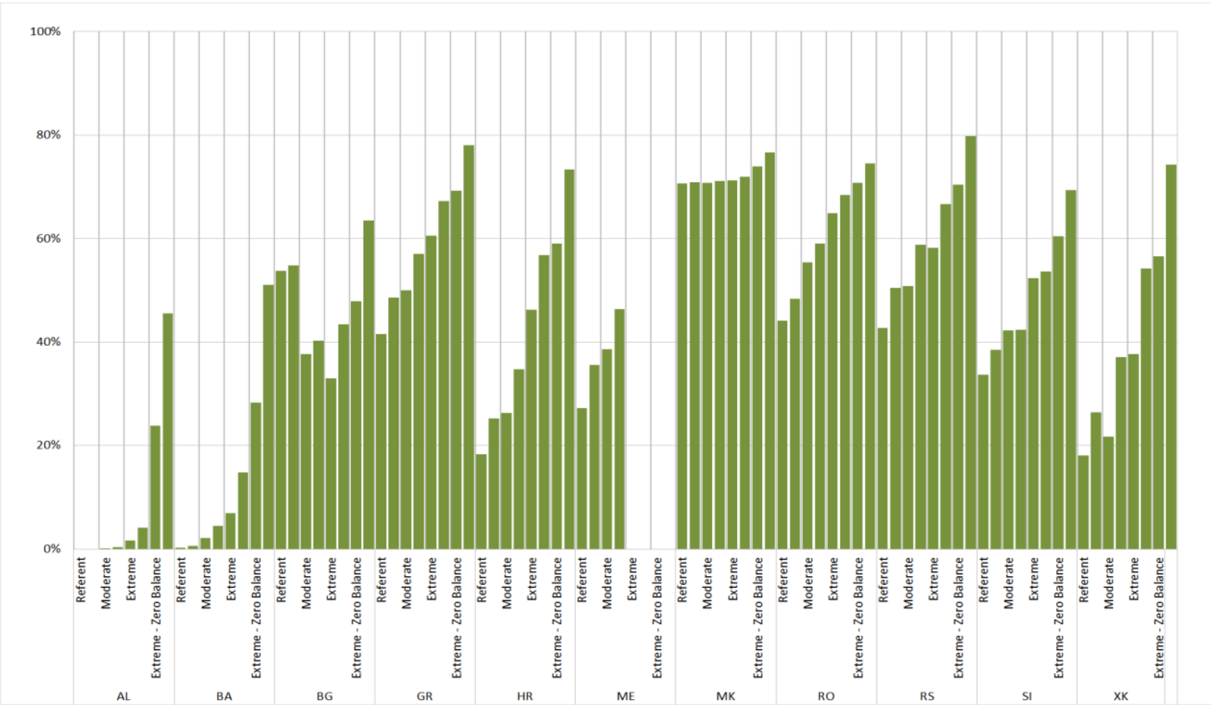


Figure 12: Capacity factors of fossil fuel fired plants generation per market areas in 2030

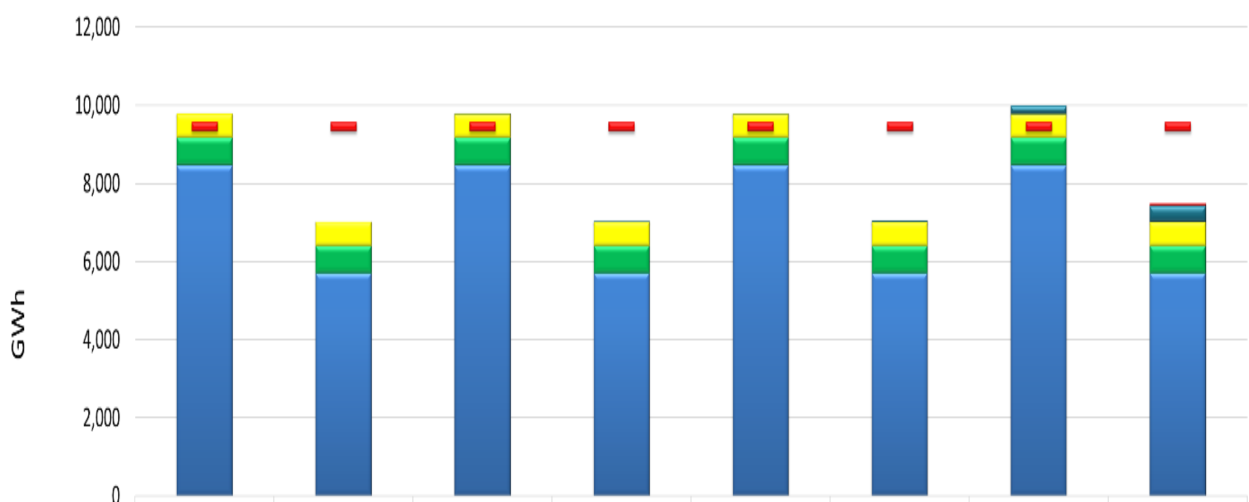
We note that the analyses we carried out present the generation/supply optimization simulations with a one-hour time step, in line with typical wholesale DA market principles, including the assumption of inelastic demand and a perfect market forecast. These simplifying assumptions are typical for planning studies and a longer timeframe (2030 in our case), in which we seek to capture key market shifts rather than simulate daily operations. The absence of spillages shows that existing flexibility and exports can cope with RES' hourly variability (with a perfect forecast). We did not simulate inter-hourly variability or deviations of the RES generation and load due to forecast errors, as these factors are part of a balancing market, and were beyond the scope of this work.

7.3. Market Simulation results per market areas

In this chapter, we present the market simulation results for each market area in 2030. There are meaningful differences between each market's and each scenario's: generation mix; generation from TPPs; emissions from fossil fuels; and surplus or deficit position. In these figures, we indicate the surplus or deficit as the difference between the demand presented with a red horizontal line above each of the projected stacks of generation. As will be seen below, by 2030 there are very few differences between the expected annual wholesale prices in SEE across all scenarios, due to low levels of congestion in the region, which leads to a high level of price convergence.

7.3.1. OST Market Area

In the following figures, we present the main results of the market analysis for the OST market area, including the generation mix and other indicators.



	AL				AL			
	Referent		Moderate		Extreme		Extreme-zero Balance	
	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd
ENS	0	0	0	0	0	0	0	56
Other	0	0	0	0	0	0	0	0
Gas	0	0	0	7	15	36	208	399
Coal	0	0	0	0	0	0	0	0
Lignite	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0
Solar	606	606	606	606	606	606	606	606
Wind	703	703	703	703	703	703	703	703
Hydro	8,473	5,711	8,473	5,711	8,473	5,711	8,473	5,711
Consumption	9,442	9,442	9,442	9,442	9,442	9,442	9,442	9,442

Figure 13: Generation mix in the OST market area in 2030

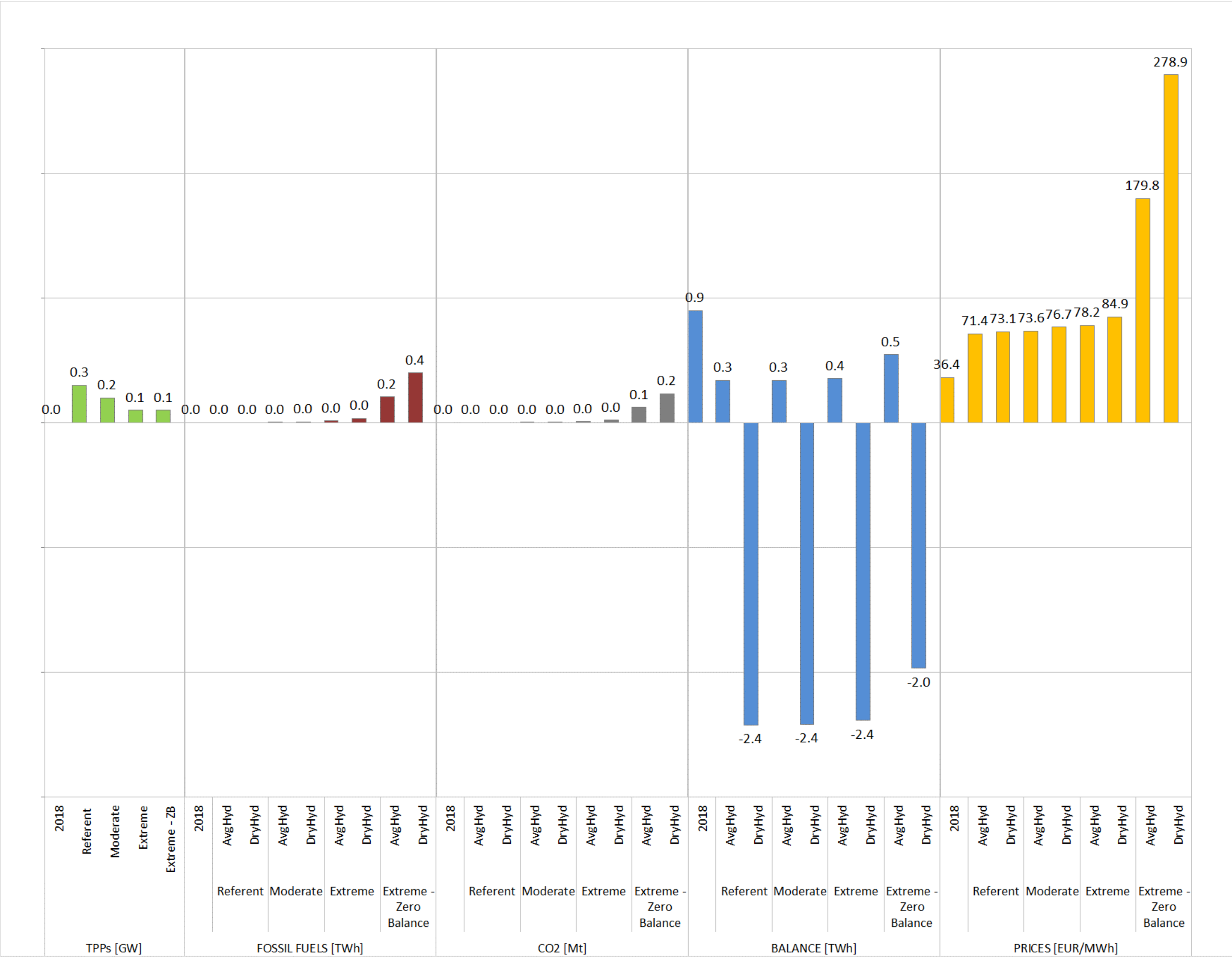


Figure 14: Main system operating indicators in the OST market area in 2030

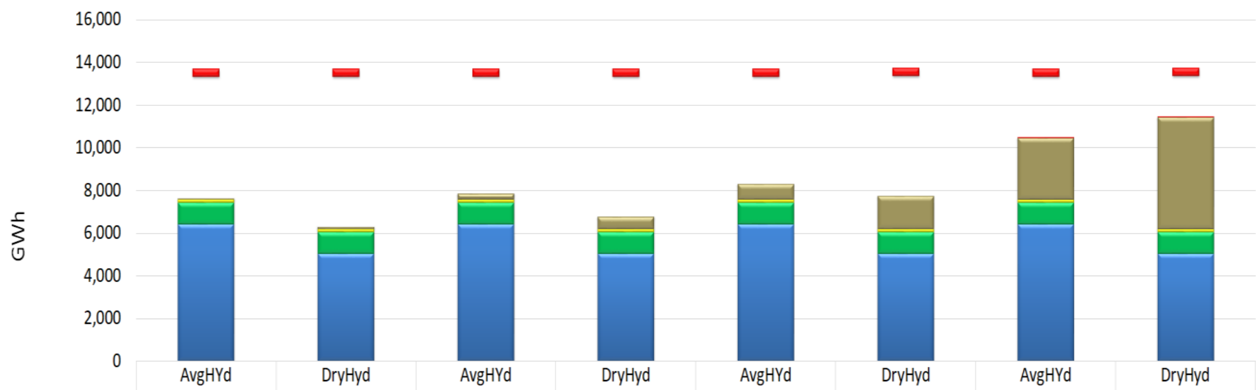
By analyzing these results, we conclude the following for the OST market area in 2030 using different levels of decarbonization:

- While the OST market area abounds in hydro plants, in 2030 we expect thermal capacity of 100 to 300 MW, a significant increase compared to the 0 MW in operation in 2018.
- The new gas fired TPP Vlora is expected to come on-line by 2030. While the plant would reach 300 MW in the Referent case, in the Moderate and Extreme scenarios, this capacity would decrease to 200 MW and 100 MW, respectively.
- Thermal generation is the highest in the Extreme scenario under the zero balance scenario. While somewhat counter-intuitive, since this case has the most decommissioned lignite plants, in this scenario, all available thermal capacities inside the SEE region are highly dispatched. As a result, in this case the thermal unit in the OST market area generates around 400 GWh and reaches a 45% capacity factor.
- In the OST market area, CO_2 emission change linearly based on the thermal generation since there is only one type of thermal units, and no switching between gas and coal units. Since TPP generation is low in all scenarios except the Extreme one with zero balance, CO_2 emissions are also low, reaching 0.2 Mt at most.

- From being an exporter in 2018 of 13% of consumption, the OST market area changes in 2030 under dry conditions to become an importer of 21% to 26% (2.0 to 2.4 TWh) of customers' needs across these scenarios. In average hydro conditions, the OST market area remains an exporter, with net exports of 0.3 to 0.5 TWh, or around 3% to 5% of total consumption in 2030.
- Wholesale prices range from 71.4 to 84.9 EUR/MWh, nearly the same as other market areas in SEE, since a low level of congestion allows prices to converge. Deeper decarbonization leads to engagement of more expensive sources, and prices increase.
- Prices rise dramatically in the Extreme scenario with zero regional balance, as we assume a Value of Lost Load (VOLL) of 1000 EUR/MWh in hours when demand is higher than supply which, and that significantly increases average annual prices to 179.8 and 278.9 EUR/MWh, depending on the hydrology. If emergency imports cost double the marginal price, then wholesale prices in the OST market area would be 107.5 and 129.6 EUR/MWh.
- In all scenarios, in the OST market area and all across SEE, dry hydro conditions lead to higher generation from TPPs, higher CO_2 emissions and higher prices. Average hydrology conditions, on the other hand, lead to a higher generation from HPPs, resulting in lower CO_2 emissions, and prices where the OST market area becomes an exporter.

7.3.2. NOSBIH Market Area

In the following figures, we present the main results of the market analysis for the NOSBIH market area, including the generation mix and other indicators.



	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd
	Referent		Moderate		Extreme		Extreme-zero Balance	
	BA				BA			
ENS	0	0	0	0	0	0	6	39
Other	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0
Lignite	33	89	264	557	714	1,512	2,887	5,213
Nuclear	0	0	0	0	0	0	0	0
Solar	135	135	135	135	135	135	135	135
Wind	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021
Hydro	6,417	5,053	6,417	5,053	6,417	5,053	6,417	5,053
Consumption	13,529	13,531	13,533	13,541	13,541	13,568	13,543	13,568

Figure 15: Generation mix in the NOSBIH market area in 2030

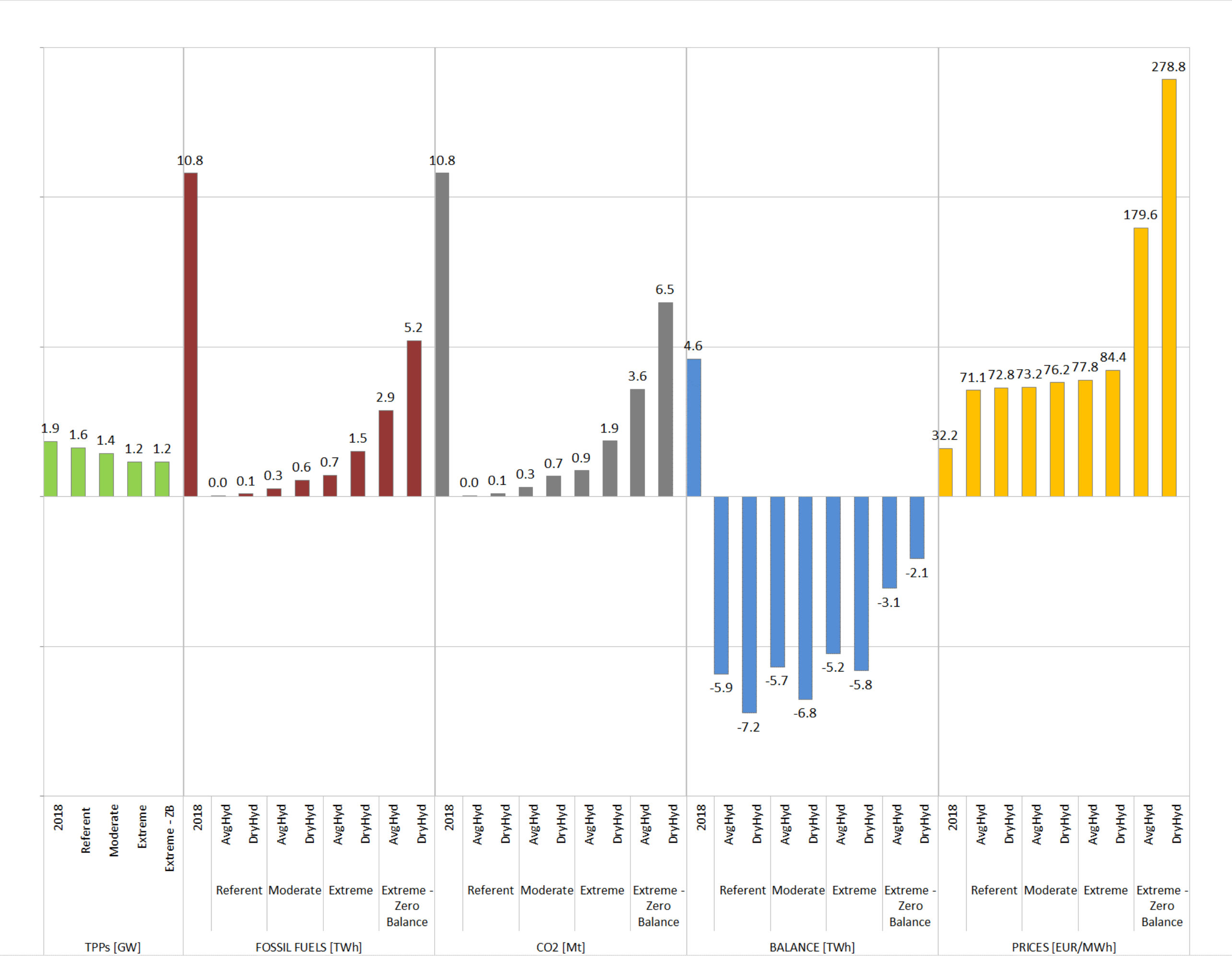


Figure 16: Main system operating indicators in the NOSBIH market area in 2030

By analyzing these results, we can make these conclusions for the NOSBiH market area in 2030 with different levels of decarbonization:

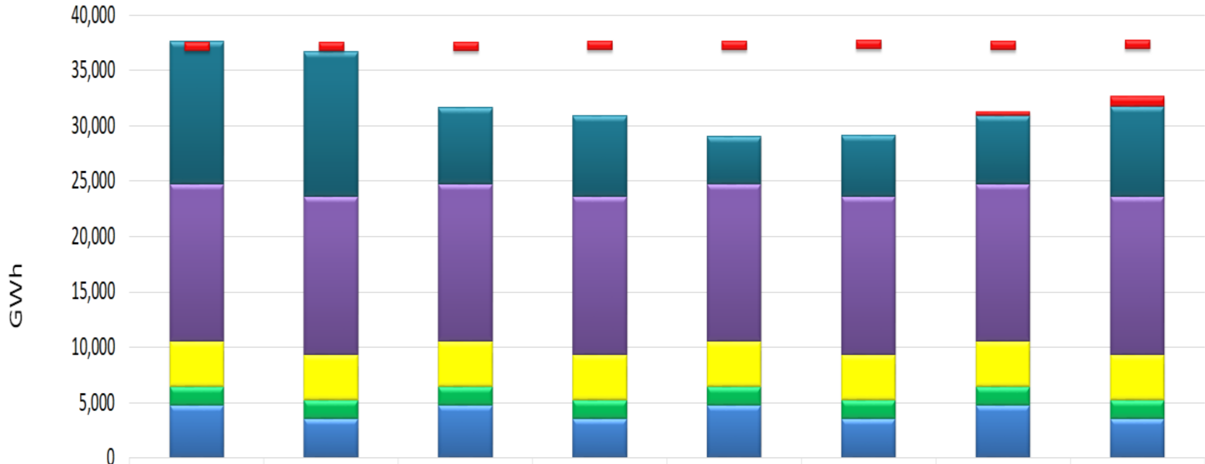
- In 2030, we expect thermal capacities between 1.2 and 1.6 GW, a reduction of 13% to 35% from the 1.9 GW in operation in 2018.
- With the high CO2 price (65.73 EUR/tCO2) in our analyses, generation from coal (lignite) in the NOSBIH market area falls almost to zero in the Referent scenario, as these thermal units become uncompetitive with other sources in the region. In the Moderate and Extreme decarbonization scenarios, reduced thermal capacities in the whole SEE region provides more room for thermal units in the NOSBIH market area, and their output increases.
- Thermal generation is the highest in the Extreme scenario with zero balance. In this scenario, all available capacities inside the SEE region are used as much as possible and the thermal units in the NOSBIH market area generate 5.2 TWh, and reach a 50% capacity factor.
- CO2 emissions follow changes in thermal generation, and CO2 emissions steadily increase in these scenarios. In the NOSBIH market area, CO2 emissions change linearly with thermal generation, since there is only one type of thermal technology, and no switching between gas and coal units' engagement. CO2 emissions are also low, reaching 6.5 Mt at most, compared to 10.5 Mt in 2018.

- In all scenarios when needed energy can be freely imported from the rest of Europe, the NOSBIH market area is an importer, of 5.2 to 7.2 TWh across the scenarios and hydrology. From being an exporter in 2018 of 35% of its consumption, the NOSBIH market area in 2030 becomes an importer relying on imports for 15% to 53% across these scenarios.
- In the Extreme scenario with zero regional balance, imports are the lowest, and with dry regional hydrology in that scenario, the NOSBIH market area imports just 2.1 TWh.
- Prices range from 71 to 84 EUR/MWh, similar to other market areas in SEE, since there is very little congestion, and prices converge. Deeper decarbonization leads to the use of more expensive sources of power, and wholesale prices increase.
- In the Extreme scenario with zero regional balance, prices take into account an assumed Value of Lost Load (VOLL) of 1000 EUR/MWh in the hours when demand is higher than supply, which causes average annual prices to rise sharply to 179.6 and 278.8 EUR/MWh, depending on hydrology. If there are emergency imports instead, and those prices are double the marginal costs, the average annual wholesale prices would rise to 107.3 and 129.4 EUR/MWh (depending on hydrology).

In all scenarios, dry hydrological conditions lead to higher generation from TPPs, higher CO2 emissions, higher imports and higher prices. Only in the Extreme scenario with zero reginal balance would imports decrease in dry hydrological conditions. In this case, the increase in thermal generation exceeds the decrease in hydro generation, and reduces imports.

7.3.3. ESO EAD Market Area

In the following figures, we present the main results of the market analysis for the ESO EAD market area, including generation mix and other indicators.



	BG				BG			
	Referent		Moderate		Extreme		Extreme-zero Balance	
	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd
ENS	0	0	0	0	0	0	348	885
Other	0	0	0	0	0	0	0	0
Gas	12,833	13,110	6,826	7,306	4,244	5,586	6,164	8,180
Coal	0	0	0	0	0	0	0	0
Lignite	0	0	0	0	0	0	0	0
Nuclear	14,261	14,261	14,261	14,261	14,261	14,261	14,261	14,261
Solar	4,039	4,039	4,039	4,039	4,039	4,039	4,039	4,039
Wind	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678
Hydro	4,830	3,623	4,830	3,623	4,830	3,623	4,830	3,623
Consumption	37,227	37,231	37,249	37,310	37,287	37,436	37,289	37,410

Figure 17: Generation mix in the ESO EAD market area in 2030

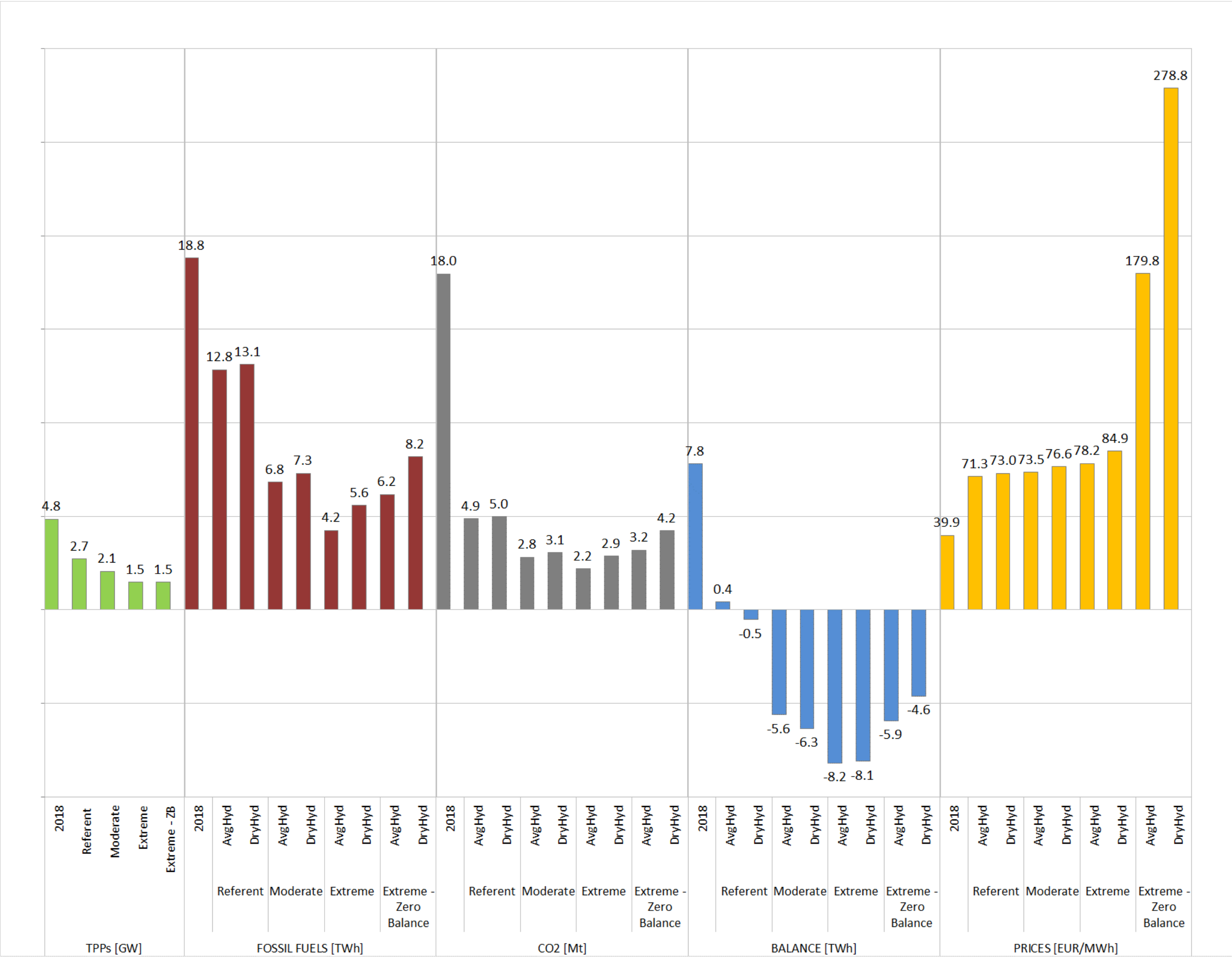


Figure 18: Main system operating indicators in the ESO EAD market area in 2030

By analyzing these results, we conclude the following for the ESO EAD market area in 2030 under different levels of decarbonization:

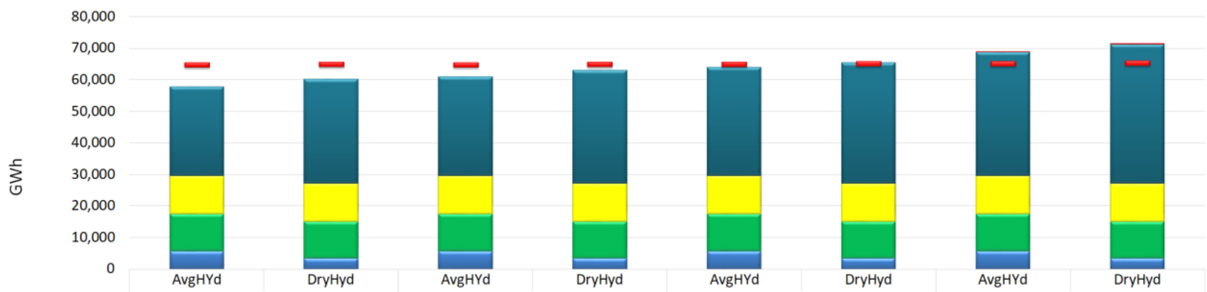
- In 2030, we expect fossil generation between 1.5 GW and 2.7 GW, a decrease of 44% to 69% compared to the 4.8 GW in operation in 2018.
- Nuclear generation stays constant, with 2 GW capacity. These units, due to low operating costs, generate at the same level in all scenarios - 14.26 TWh.
- The decommissioning of TPPs in 2030 plus a relatively high CO2 price (65.73 EUR/tCO2), reduces generation from fossil units in the ESO EAD market area in all cases compared to fossil generation in 2018, and for TPPs overall. On the other hand, irrespective of decommissioning, thermal generation is higher under dry hydro conditions, as expected.
- Thermal generation in the extreme scenario with zero balance is higher than in case of extreme scenario without such a constraint. In this scenario, all available capacities inside the SEE region, as well as the ESO EAD market area, are engaged to cover the deficit that cannot be imported from surrounding markets.
- CO2 emissions follow the changes in TPP generation, and CO2 emissions steadily decrease in the analyzed scenarios. In the ESO EAD market area, CO2 emissions linearly depend on

the level of thermal generation. The maximum CO2 emissions are expected in the Referent Scenario, when it reaches 5.0 Mt (compared to 18 Mt in 2018).

- In almost all scenarios, ESO EAD market area becomes a net importer, with imports ranging from 0.5 TWh to 8.2 TWh (1% to 22% of consumption) depending on hydrology. In 2018 ESO market area was net exporter at the level of 7.8 TWh. In these cases, imports are always higher with reduced HPP generation in dry circumstances.
- In the extreme scenario with zero regional balance, imports decrease due to a greater opportunity for thermal units here, but under dry hydrology conditions, the ESO EAD market area still imports 4.6 TWh (12% of total consumption).
- Prices range from 71.3 to 84.9 EUR/MWh, similar to other market areas in the SEE region, since congestion is low, and prices converge. Deeper decarbonization leads to the engagement of more expensive sources, and prices increase.
- In the extreme scenario with zero regional balance, Value of Lost Load (VOLL) prices of 1000 EUR/MWh in the hours when demand is higher than supply significantly increases the average annual prices to 179.8 and 278.8 EUR/MWh, depending on hydrology. With emergency imports and prices at twice the marginal level, the annual wholesale prices would be 107.5 and 129.6 EUR/MWh, depending on hydrology.
- In all scenarios, dry hydro leads to higher TPP generation, higher CO2 emissions, and higher prices. The situation is similar with balances, except in the extreme scenario with zero regional balance, when imports fall in dry hydro conditions. In this case, the increase in TPP generation in the ESO EAD market area exceeds the decrease in hydro, and imports fall.

7.3.4. IPTO Market Area

In the following figures, we present the main results of the market analysis for the IPTO market area, including the generation mix and other indicators.



	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd
	Referent		Moderate		Extreme		Extreme-zero Balance	
	GR				GR			
ENS	0	0	0	0	0	0	64	283
Other	0	0	0	0	0	0	0	0
Gas	28,256	33,059	31,396	35,841	34,423	38,248	39,249	44,063
Coal	0	0	0	0	0	0	0	0
Lignite	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0
Solar	12,093	12,093	12,093	12,093	12,093	12,093	12,093	12,093
Wind	11,742	11,742	11,742	11,742	11,742	11,742	11,742	11,742
Hydro	5,768	3,405	5,768	3,405	5,768	3,405	5,768	3,405
Consumption	64,735	64,889	64,846	65,029	64,961	65,168	65,099	65,315

Figure 19: Generation mix in the IPTO market area in 2030

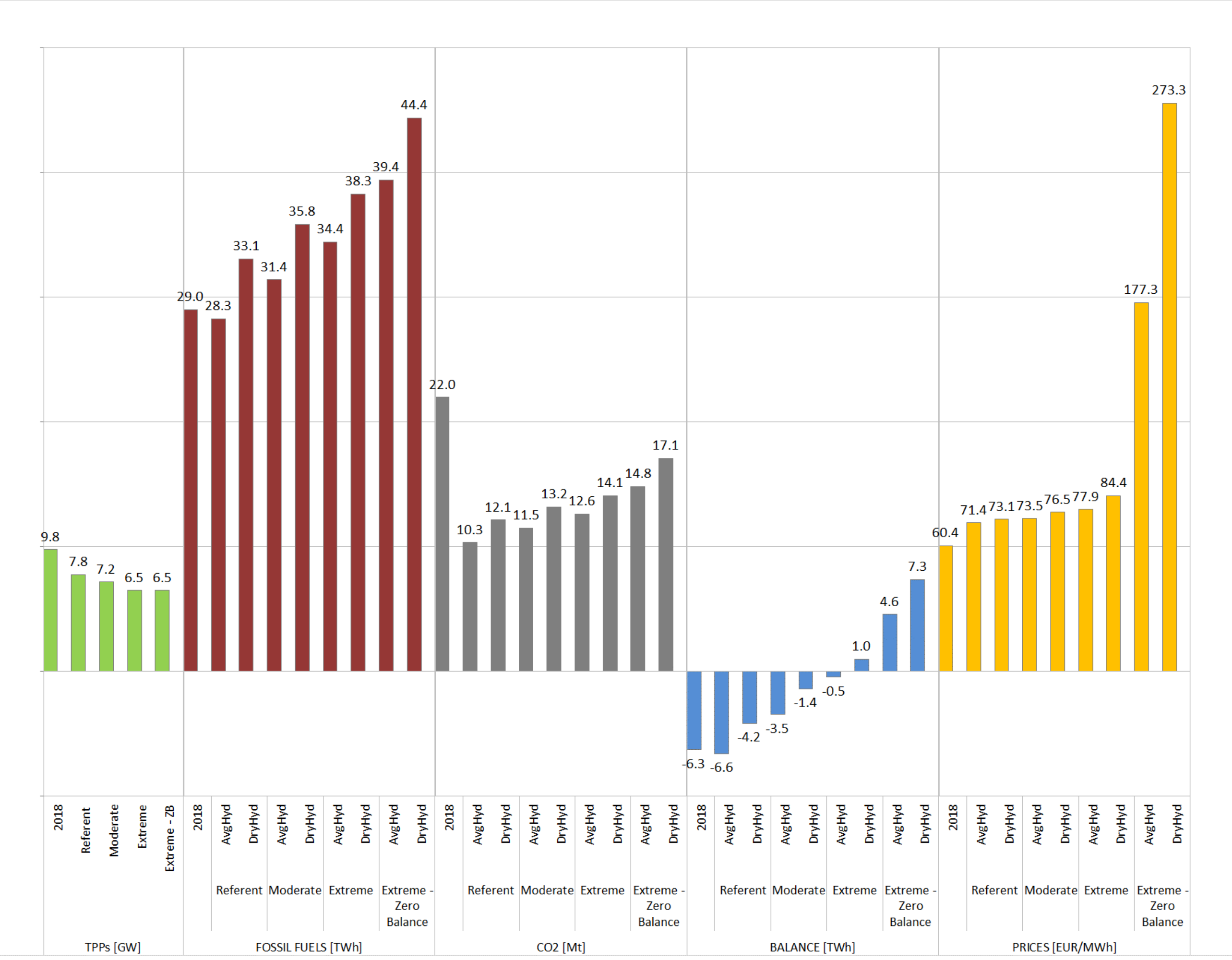


Figure 20: Main system operating indicators in the IPTO market area in 2030

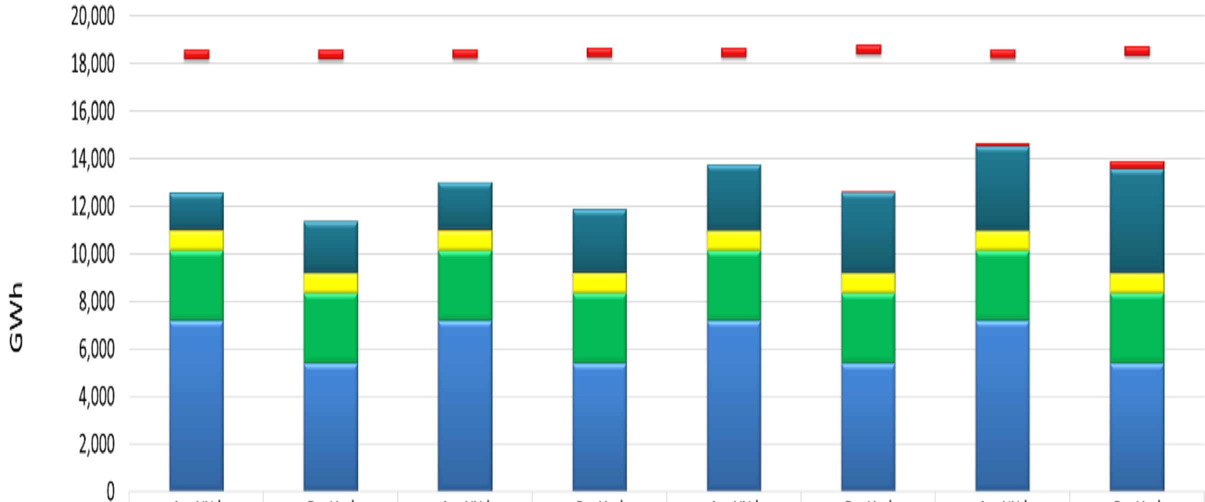
By analyzing these results, we conclude the following for the IPTO market area in 2030 with different levels of decarbonization:

- Gas fired thermal power plants and renewables (wind and solar) dominate the generation mix of the IPTO market area in 2030, while the contribution of hydro is relatively small.
- In 2030 thermal capacities can be expected to range from 6.5 GW to 7.8 GW, a decrease of 20.5% to 33.5% compared to the 9.8 GW in operation in 2018.
- Total installed fossil capacity (GW) falls in all scenarios, but total annual generation (TWh) from these plants is higher in 2030 compared to 2018. This is because our assumed decommissioning of TPPs, plus the CO2 price (65.73 EUR/tCO2) applied in our analyses, cause relatively high market prices in the SEE region and in the IPTO market area. This makes gas plants in the IPTO market area more competitive, and increases their generation when moving from the Referent to the Extreme scenario, and from average to dry hydrology.
- Thermal generation is the highest in the Extreme scenario with zero balance constraints (about 44.4 TWh). In that case, in addition to increased generation from gas plants, oil units are engaged as much as possible to minimize unsupplied energy. Oil plants become competitive only for the Extreme scenario with a zero balance constraint, when generation from this technology presents the last resource to supply the load. In other scenarios, oil units are extra marginal on the merit order curve.

- CO_2 emission follows the changes in thermal generation and CO_2 emission steadily increase in analyzed scenarios. In case of IPTO market area CO_2 emission linearly depends on the thermal generation, since there is no generation type switch and the main technology is gas. CO_2 emissions are relatively high in all scenarios reaching the maximum of about 17 Mt in the Extreme scenario with zero balance constraint, compared to 22 Mt in 2018.
- The IPTO market area, which is currently a net electricity importer, significantly reduces its imports in moving from the Referent to the Extreme scenario, and becomes a net exporter of electricity in the Extreme scenario and under dry hydro conditions.
- In the Extreme scenario with zero balance constraint, when the deficit of energy cannot be freely imported from the rest of the Europe, the balance position of the IPTO market area is the opposite of today (2018), In such a scenario, gas plants in the IPTO market area become more competitive, leading to net electricity exports of about 7.3 TWh in dry hydro conditions.
- In the Extreme scenario and average hydro conditions, the IPTO market area is almost balanced, with net electricity imports of 0.5 TWh.
- Wholesale prices range from 71.4 to 84.4 EUR/MWh, similar to other market areas in the SEE region, given low congestion, and price convergence. Deeper decarbonization leads to the engagement of more expensive sources to meet demand, so prices increase.
- In the Extreme scenario with zero regional balance, prices take into account an assumed Value of Lost Load (VOLL) price of 1000 EUR/MWh in the hours when demand is higher than supply, which significantly increases average annual prices to 177.3 and 273.3 EUR/MWh, depending on the hydrology. In such a case, the IPTO market area is faced with unsupplied energy of 64 GWh and 283 GWh for the average and dry hydrology, respectively.
- With emergency imports, and prices twice the marginal level, the average annual wholesale prices would rise less sharply, to 107.3 and 128.6 EUR/MWh (depending on the hydrology).

7.3.5. HOPS Market Area

In the following figures, we present the main results of the market analysis for the HOPS market area, including the generation mix and other indicators.



	HR				HR			
	Referent		Moderate		Extreme		Extreme-zero Balance	
	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd
ENS	0	0	0	0	0	2	114	315
Other	0	0	0	0	0	0	0	0
Gas	1,574	2,168	2,014	2,653	2,772	3,404	3,538	4,390
Coal	1	1	5	14	0	0	0	0
Lignite	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0
Solar	840	840	840	840	840	840	840	840
Wind	2,960	2,960	2,960	2,960	2,960	2,960	2,960	2,960
Hydro	7,190	5,392	7,190	5,392	7,190	5,392	7,190	5,392
Consumption	18,364	18,365	18,403	18,457	18,450	18,581	18,410	18,518

Figure 21: Generation mix in the HOPS market area in 2030

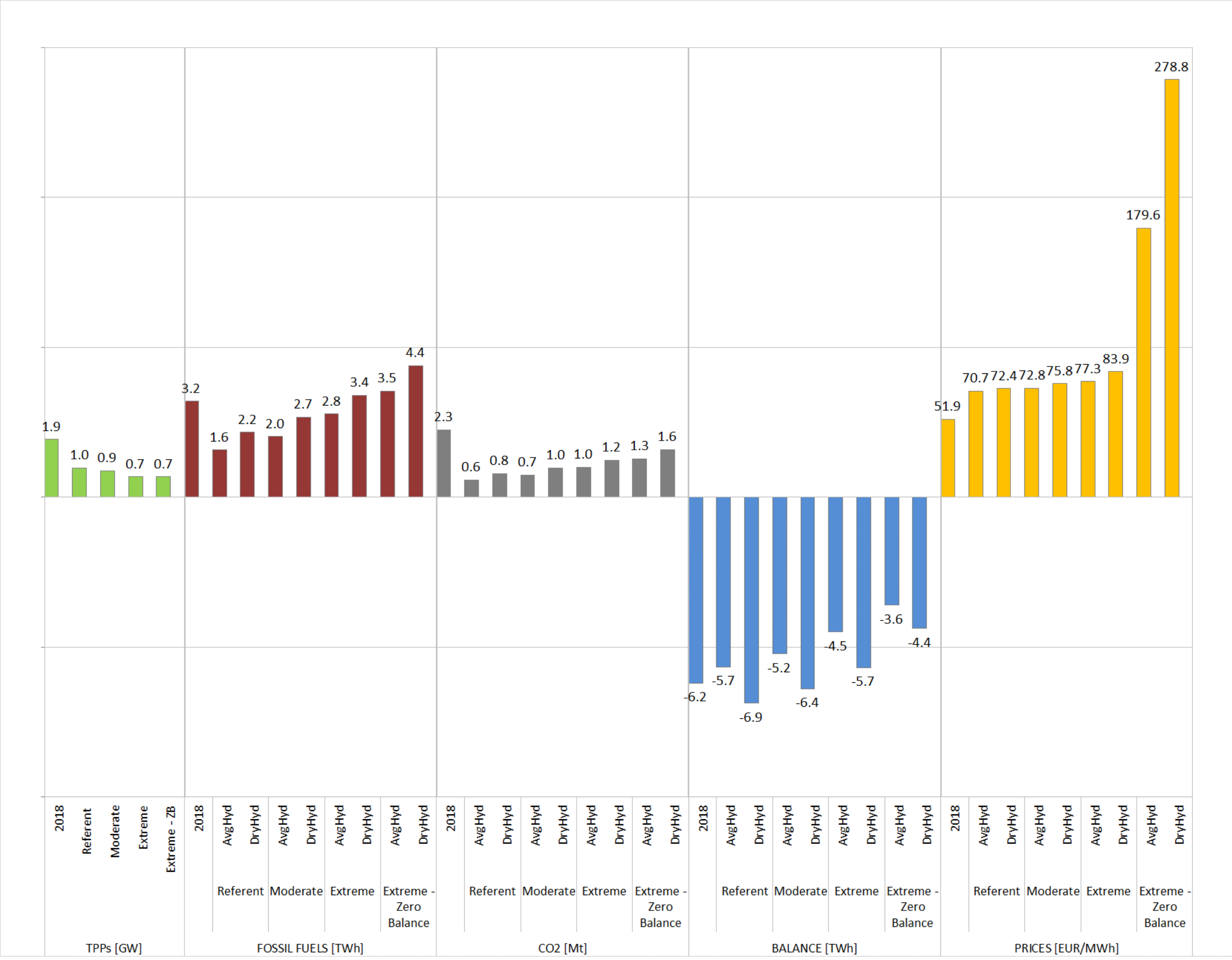


Figure 22: Main system operating indicators in the HOPS market area in 2030

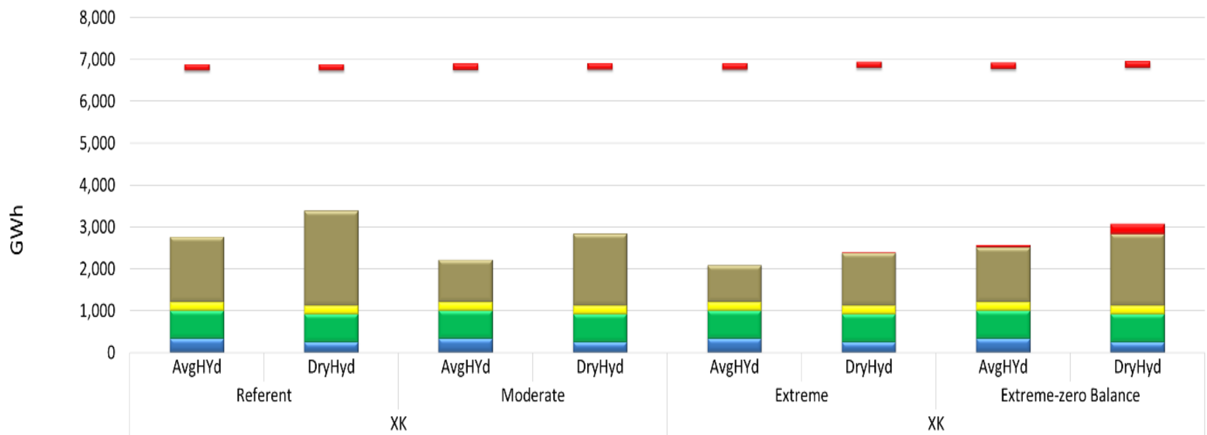
By analyzing these results, we conclude the following for the HOPS market area in 2030 with different levels of decarbonization:

- In 2030 we expect thermal capacities between 684 and 981 MW, which is a decrease of 49% to 65% with respect to the 1,924 MW in operation in 2018.
- The generation from TPPs in the HOPS market area is lower compared to 2018 in all scenarios except the Extreme scenario with dry hydrology and the Extreme scenario with zero regional balance. Gas plants are dominant in the generation mix for all the analyzed scenarios, ranging from 1.6 TWh in the Referent case to 3.4 TWh in the Extreme decarbonization scenarios.
- Thermal generation is the highest in the Extreme scenario with a zero regional balance. In this scenario, all available capacities in the SEE region are used as much as possible and, thermal units in the HOPS market area generate 4.4 TWh, and reach a 73% capacity factor.
- CO_2 emissions follow the changes in thermal generation, and so CO_2 emission increase in the analyzed scenarios, reaching 1.6 Mt in the Extreme scenario with zero regional balance.
- In 2018, the HOPS market area imported 34% of its total electricity consumption. In all scenarios in 2030, the HOPS market area is still a significant importer, with imports between 4.5 and 6.9 TWh (24% to 38% of consumption) for all scenarios and hydrologies, when needed energy can be imported. Imports to the HOPS market area are always higher with reduced generation from HPPs in dry hydrological conditions.

- In the Extreme scenario with zero regional balance, imports are the lowest, and with dry hydrology, the HOPS market area imports the least – 3.6 TWh. This is due to the greater room to use expensive thermal units from this market area, with constrained imports.
- Prices range from 70.7 to 83.9 EUR/MWh, similar to other market areas in the SEE region, given low levels of congestion and price convergence. Deeper decarbonization leads to the engagement of more expensive sources of generation, and prices increase.
- In the Extreme scenario with zero regional balance, we assumed a price for the Value of Lost Load (VOLL) of 1000 EUR/MWh in the hours when demand is higher than supply, which significantly increases the average annual prices to 179.6 and 278.8 EUR/MWh, depending on the hydrology. In this case, the HOPS market area faces unsupplied energy of 114 GWh and 315 GWh for the average and dry hydrology conditions, respectively.
- With emergency imports, and prices that are double the marginal costs, the average annual wholesale prices would be 107.3 and 129.4 EUR/MWh, depending on the hydrology.
- In all scenarios, dry hydrological conditions lead to higher generation from TPPs, higher CO_2 emission, higher imports and higher prices.

7.3.6. KOSTT Market Area

In the following figures, we present the main results of the market analysis for the KOSTT market area, including the generation mix and other indicators.



	Referent AvgHYd	Referent DryHyd	Moderate AvgHYd	Moderate DryHyd	Extreme AvgHYd	Extreme DryHyd	Extreme-zero Balance AvgHYd	Extreme-zero Balance DryHyd
ENS	0	0	0	0	0	0	56	238
Other	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0
Lignite	1,550	2,262	1,003	1,718	870	1,253	1,307	1,717
Nuclear	0	0	0	0	0	0	0	0
Solar	205	205	205	205	205	205	205	205
Wind	666	666	666	666	666	666	666	666
Hydro	339	252	339	252	339	252	339	252
Consumption	6,809	6,810	6,816	6,831	6,829	6,868	6,843	6,875

Figure 23: Generation mix in the KOSTT market area in 2030

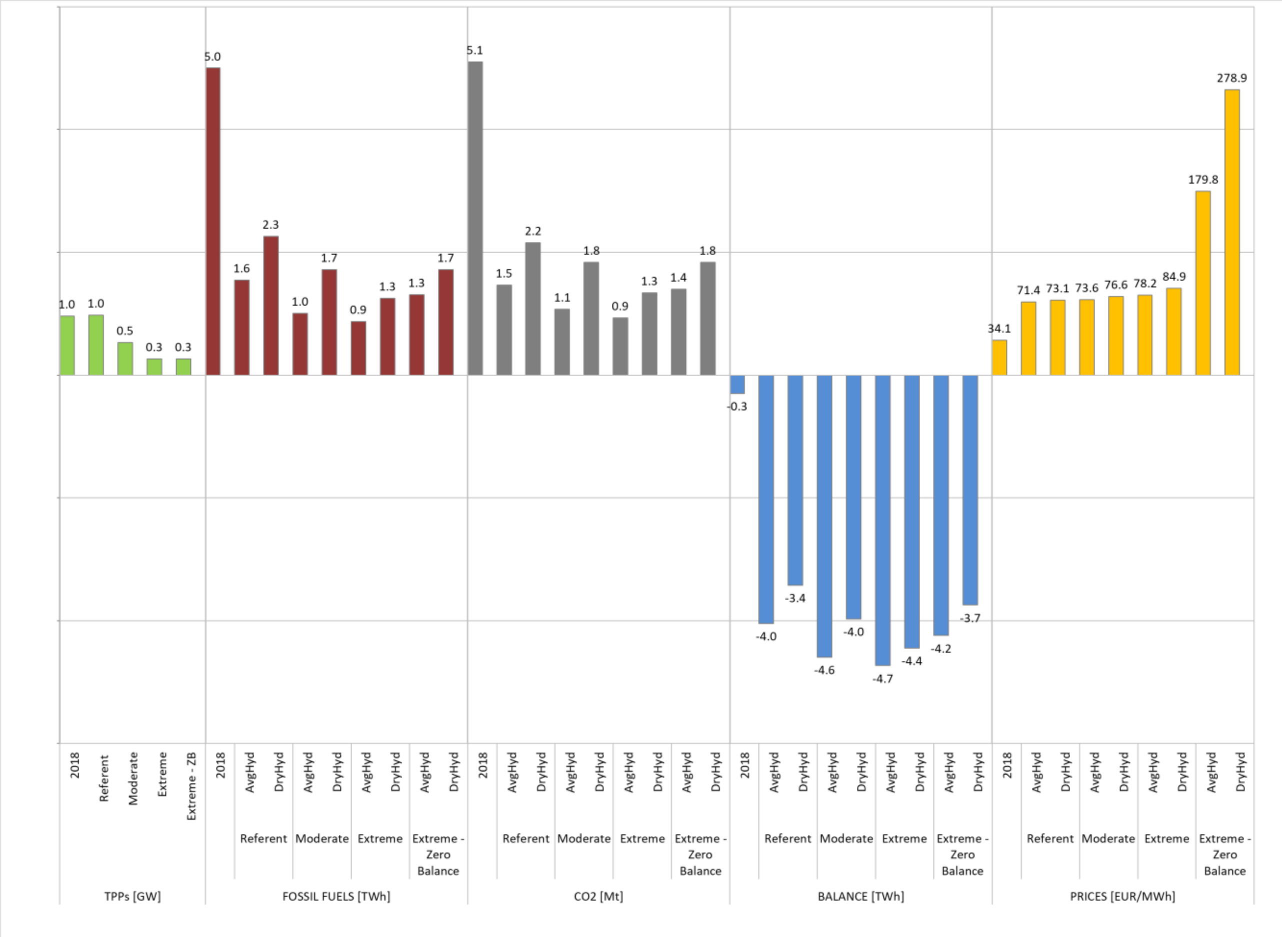


Figure 24: Main system operating indicators in the KOSTT market area in 2030

By analyzing these results, we conclude the following for the KOSTT market area in 2030 with different levels of decarbonization:

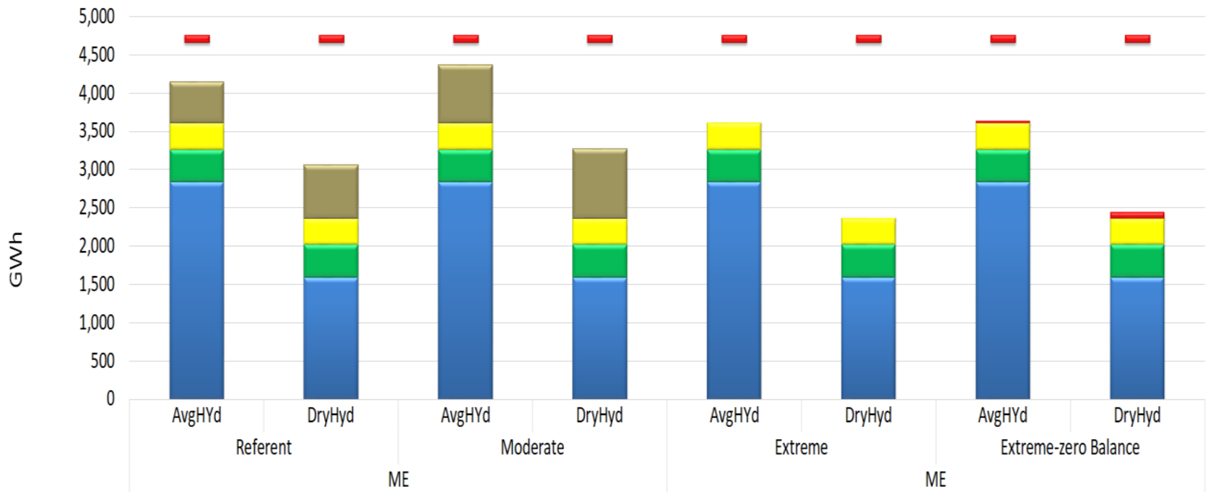
- In 2030, we expect thermal capacities to amount to 264 MW in the Extreme scenarios, 528 MW in the Moderate scenario and 978 MW in the referent scenario. This represents a decrease in the Moderate and Extreme scenarios of 45% and 72%, and an increase of 2% in the Referent scenario with respect to the 960 MW in operation in 2018. The slight increase in the Referent scenario is a result of decommissioning TPP Kosovo A (432 MW) and commissioning the new TPP Kosova e Re (450 MW) in 2023.
- TPP generation in the KOSTT market area is lower compared to 2018 in all scenarios, as the high CO_2 price (65.73 EUR/tCO_2) reduces generation from coal (lignite) units. With this CO_2 price, these thermal units become rather expensive and uncompetitive with other sources in the region, so the KOSTT market area has high levels of imports in all scenarios.
- TPP generation is highest in the Referent scenario – 2.3 TWh in dry hydrology conditions – since TPP capacities are highest in this scenario (978 MW). In general, thermal generation is higher in dry hydrology scenarios due to the low engagement of HPPs under these conditions.
- CO_2 emissions follows the changes in thermal generation and CO_2 emission increase in analyzed scenarios, reaching 2.2 Mt in the dry Referent scenario compared to 5.1 Mt in 2018.
- In 2018 KOSTT market area abounded with domestic lignite and large thermal capacities, resulting with just a 5% share of imports in electricity consumption. In 2030, the KOSTT market area will import between 3.4 and 4.7 TWh (50% to 69% of consumption) for all

scenarios and hydrologies. Due to the higher thermal generation in dry conditions, imports are always lower then. In the Referent scenario, imports are the lowest and when the region is dry, the KOSTT market area imports the least – 3.4 TWh.

- Prices range from 71.4 to 84.9 EUR/MWh, similar to other market areas in the SEE region, given low congestion, so prices converge. Deeper decarbonization leads to the engagement of more expensive sources, so prices increase.
- In the Extreme scenario with zero regional balance, we assumed a Value of Lost Load (VOLL) of 1000 EUR/MWh when demand is higher than supply, and this significantly increases the average annual prices to 179.8 and 278.9 EUR/MWh, depending on hydrology. With emergency imports that cost twice the marginal price, annual wholesale prices would be 107.5 and 129.6 EUR/MWh, depending on the hydrology.
- In all scenarios, dry conditions lead to higher generation from TPPs, higher CO_2 emission and higher prices. With balances, the increase in thermal generation in the KOSTT market area is more than the decrease in hydro generation, so imports fall.

7.3.7. CGES Market Area

In the following figures, we present the main results of the market analysis for the CGES market area, including the generation mix and other indicators.



	ME Referent AvgHYd	ME Referent DryHyd	ME Moderate AvgHYd	ME Moderate DryHyd	ME Extreme AvgHYd	ME Extreme DryHyd	ME Extreme-zero Balance AvgHYd	ME Extreme-zero Balance DryHyd
ENS	0	0	0	0	0	0	31	77
Other	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0
Lignite	537	701	762	914	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0
Solar	341	341	341	341	341	341	341	341
Wind	423	423	423	423	423	423	423	423
Hydro	2,844	1,600	2,844	1,600	2,844	1,600	2,844	1,600
Consumption	4,710	4,710	4,710	4,710	4,710	4,710	4,710	4,710

Figure 25: Generation mix in the CGES market area in 2030

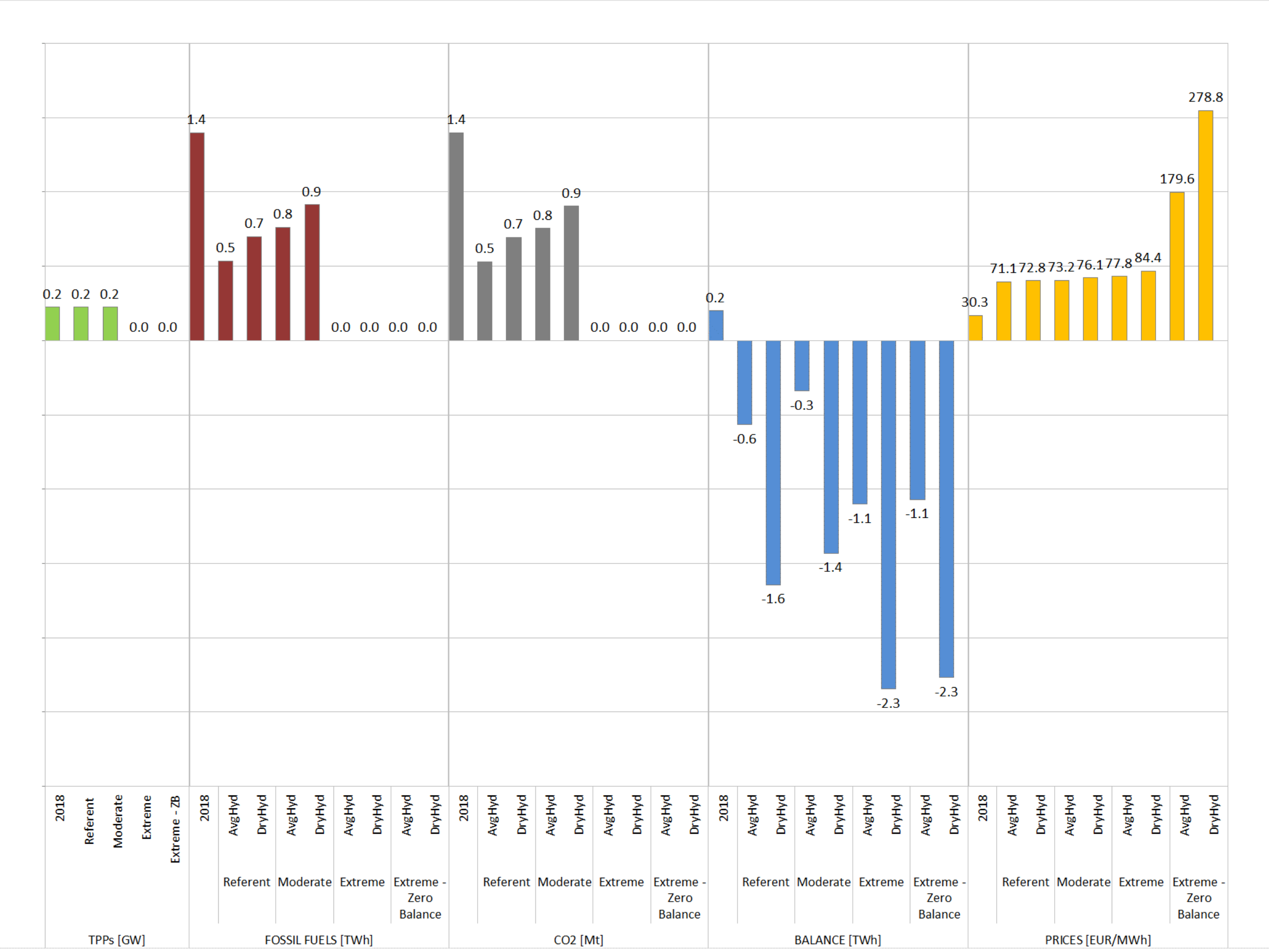


Figure 26: Main system operating indicators in the CGES market area in 2030

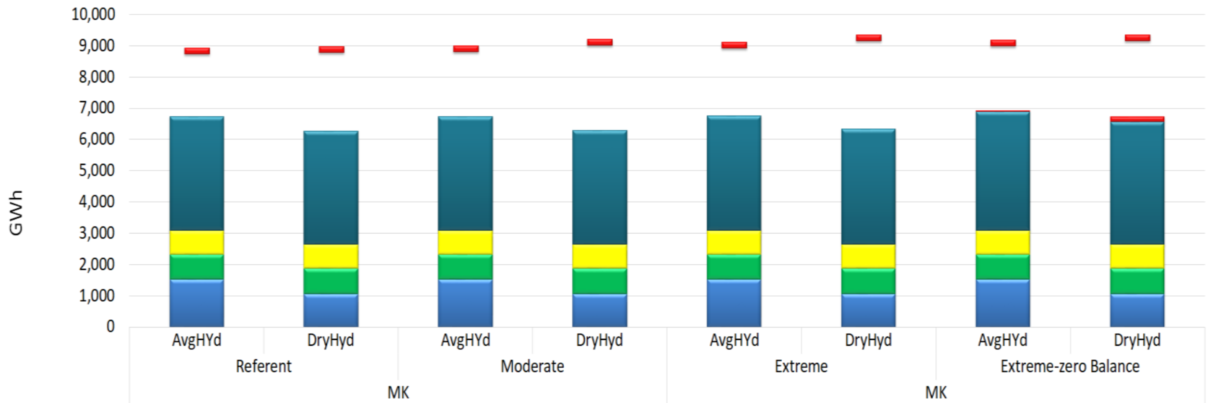
By analyzing these results, we conclude the following for the CGES market area in 2030 with different levels of decarbonization:

- Hydro resources dominate the generation mix in the CGES area in 2030 in all scenarios.
- In the CGES market area, we expect the only thermal unit (Pljevlja 1) to be decommissioned in the Extreme scenario, so the capacity in fossil units drops to zero.
- The applied CO2 price (65.73 EUR/tCO2) reduces generation from lignite units in the CGES market area from 1.4 TWh to 0.5 TWh in the Referent scenario. With this CO2 price, the thermal power plant in the CGES market area (i.e., Plevlja 1) becomes more expensive and less competitive. In the Moderate decarbonization scenario, however, the generation from TPPs increases due to the regional reduction in thermal capacities, which provides more opportunity for the thermal unit in the CGES market.
- As expected, thermal generation in the CGES market area is higher with dry hydro conditions, compared to the average.
- In the Extreme scenarios (with and without the regional zero balance constraint), there are no thermal capacities, and so there is zero generation from fossil plants.
- CO2 emissions follows the changes in thermal generation and CO2 emission steadily increase in analyzed scenarios (Referent and Moderate), reaching 0.9 Mt in Moderate scenario in combination with dry hydrology. In case of CGES market area CO2 emission linearly depends on the thermal generation since there is only one power plant in the power system.

- In all scenarios, the CGES market area imports electricity, ranging from 0.3 TWh to 2.3 TWh for all scenarios and hydrology when there are no import constraints. In these cases, the imports are always higher in dry hydrological conditions. In the Extreme scenarios, imports are at the maximum of 1.1 TWh for average hydro, and 2.3 TWh for dry hydrology. In the Extreme case, imports to the CGES market area reach 50% of total consumption.
- Prices range from 71.1 to 84.4 EUR/MWh, similar to other market areas in the SEE region, given that the low level of congestion leads to price convergence.
- In the Extreme scenario with zero regional balance, prices take into account assumed the Value of Lost Load (VOLL) of 1000 EUR/MWh in the hours when demand is higher than supply, which significantly increases average annual prices to 179.6 and 278.8 EUR/MWh, depending on hydrology. At the same time, unsupplied energy in the CGES market area would reach 31 GWh and 77 GWh for average and dry hydrology, respectively.
- With emergency imports at twice the marginal price, wholesale annual prices here would be 107.3 and 129.4 EUR/MWh (depending on the hydrology).

7.3.8. MEPSO Market Area

In the following figures, we present the main results of the market analysis for the MEPSO market area, including the generation mix and other indicators.



	AvgHYd (Referent)	DryHyd (Referent)	AvgHYd (Moderate)	DryHyd (Moderate)	AvgHYd (Extreme)	DryHyd (Extreme)	AvgHYd (Extreme-zero Balance)	DryHyd (Extreme-zero Balance)
ENS	0	0	0	0	0	0	38	161
Other	0	0	0	0	0	0	0	0
Gas	3,625	3,634	3,632	3,649	3,652	3,689	3,790	3,934
Coal	0	0	0	0	0	0	0	0
Lignite	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0
Solar	766	766	766	766	766	766	766	766
Wind	811	811	811	811	811	811	811	811
Hydro	1,523	1,065	1,523	1,065	1,523	1,065	1,523	1,065
Consumption	8,836	8,900	8,927	9,134	9,024	9,276	9,103	9,269

Figure 27: Generation mix in the MEPSO market area in 2030

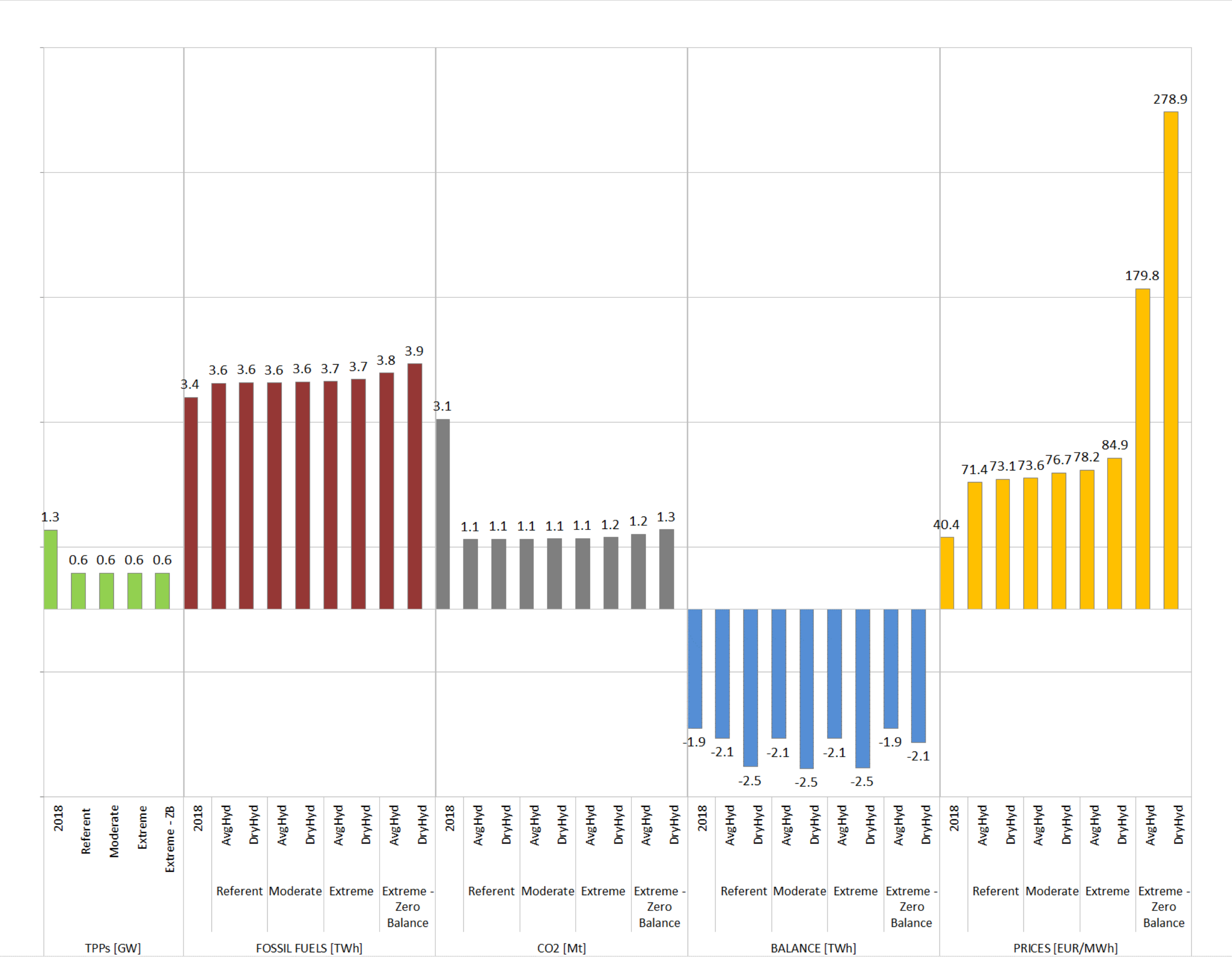


Figure 28: Main system operating indicators in the MEPSO market area in 2030

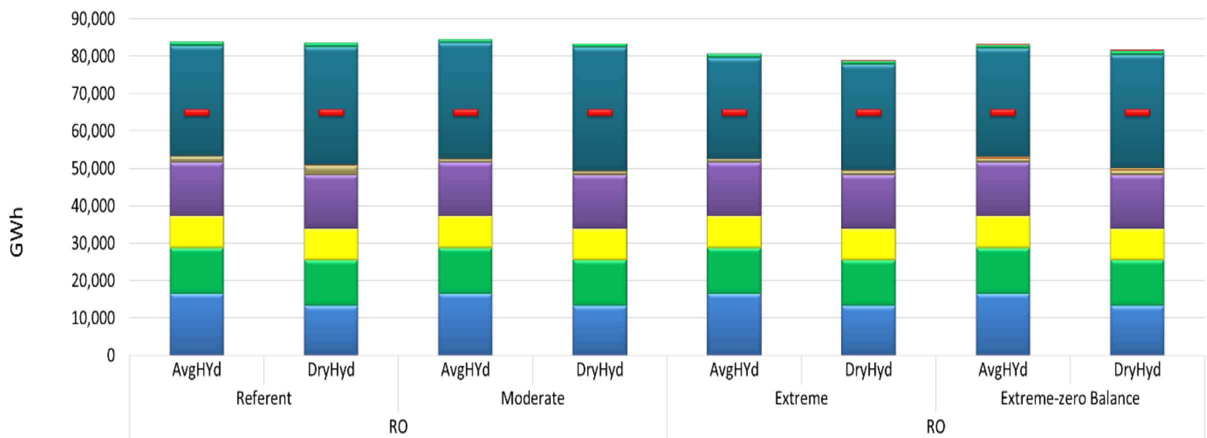
By analyzing these results, we conclude the following for the MEPSO market area in 2030 in case of different levels of decarbonization:

- In 2030, thermal capacities in the MEPSO market area are the same for the Referent, Moderate and Extreme scenario - 586 MW in gas units, because under all scenarios, there is a significant planned transition in generation technologies, with the decommissioning of 759 MW in lignite units and 198 MW in oil units. At the same time, plans include 269 MW in new gas units by 2030. In total, with these changes, the total capacity in fossil units will fall by 54% with respect to 1,274 MW in operation in 2018.
- However, reduced capacities in the SEE region and increased CO2 tax provides more opportunity for the gas units in the MEPSO market area, and generation from TPPs is higher in 2030 compared to level in 2018.
- TPP generation is highest in the Extreme scenario with zero regional balance (around 3.9 TWh) and slightly increases from the Referent to Extreme scenarios, as well as from average to dry hydrology.
- CO2 emissions follows the changes in thermal generation and therefore are practically the same for all analyzed scenarios.

- In all scenarios, the MEPSO market area is an electricity importer, with import between 1.9 TWh and 2.5 TWh for all scenarios and hydrology conditions (in 2018 MEPSO imported 1.9 TWh). Electricity import is higher with dry hydrology, as expected. Reliance on imports ranges from 21% and 27%.
- In the Extreme scenario with zero regional balance, imports are lowest, and with average hydrology, the MEPSO market area imports about 1.9 TWh. This is again due to the higher opportunity for expensive thermal units, though the differences between scenarios are small.
- Prices range from 71.4 to 84.9 EUR/MWh, similar to other market areas in SEE due to low congestion leading to price convergence. Deeper decarbonization leads to the engagement of more expensive sources, and prices increase.
- In the Extreme scenario with zero regional balance, prices take into account an assumed Value of Lost Load (VOLL) of 1000 EUR/MWh in the hours when demand is higher than supply which significantly increases the average annual prices to 179.8 and 278.9 EUR/MWh, depending on hydrology. In that case, unsupplied energy in MEPSO market area reaches 38 GWh for average hydrology, and 161 GWh when it is dry.
  With emergency import prices at twice the marginal cost, the average annual wholesale prices would be 107.5 and 129.6 EUR/MWh (depending on the hydrology).

7.3.9. Transelectrica Market Area

In the following figures, we present the main results of the market analysis for the Transelectrica market area, including the generation mix and other indicators.



	Referent AvgHYd	Referent DryHyd	Moderate AvgHYd	Moderate DryHyd	Extreme AvgHYd	Extreme DryHyd	Extreme-zero Balance AvgHYd	Extreme-zero Balance DryHyd
	RO				RO			
ENS	0	0	0	0	0	2	103	294
Other	1,011	1,014	1,013	1,016	1,017	1,020	1,022	1,027
Gas	29,402	31,555	30,918	32,949	26,833	28,204	28,975	30,228
Coal	154	154	157	166	174	224	452	725
Lignite	1,703	2,560	911	971	1,006	1,075	1,104	1,206
Nuclear	14,267	14,267	14,267	14,267	14,267	14,267	14,267	14,267
Solar	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491
Wind	12,246	12,246	12,246	12,246	12,246	12,246	12,246	12,246
Hydro	16,591	13,272	16,591	13,272	16,591	13,272	16,591	13,272
Consumption	64,942	64,942	64,942	64,942	64,942	64,942	64,942	64,942

Figure 29: Generation mix in the Transelectrica market area in 2030

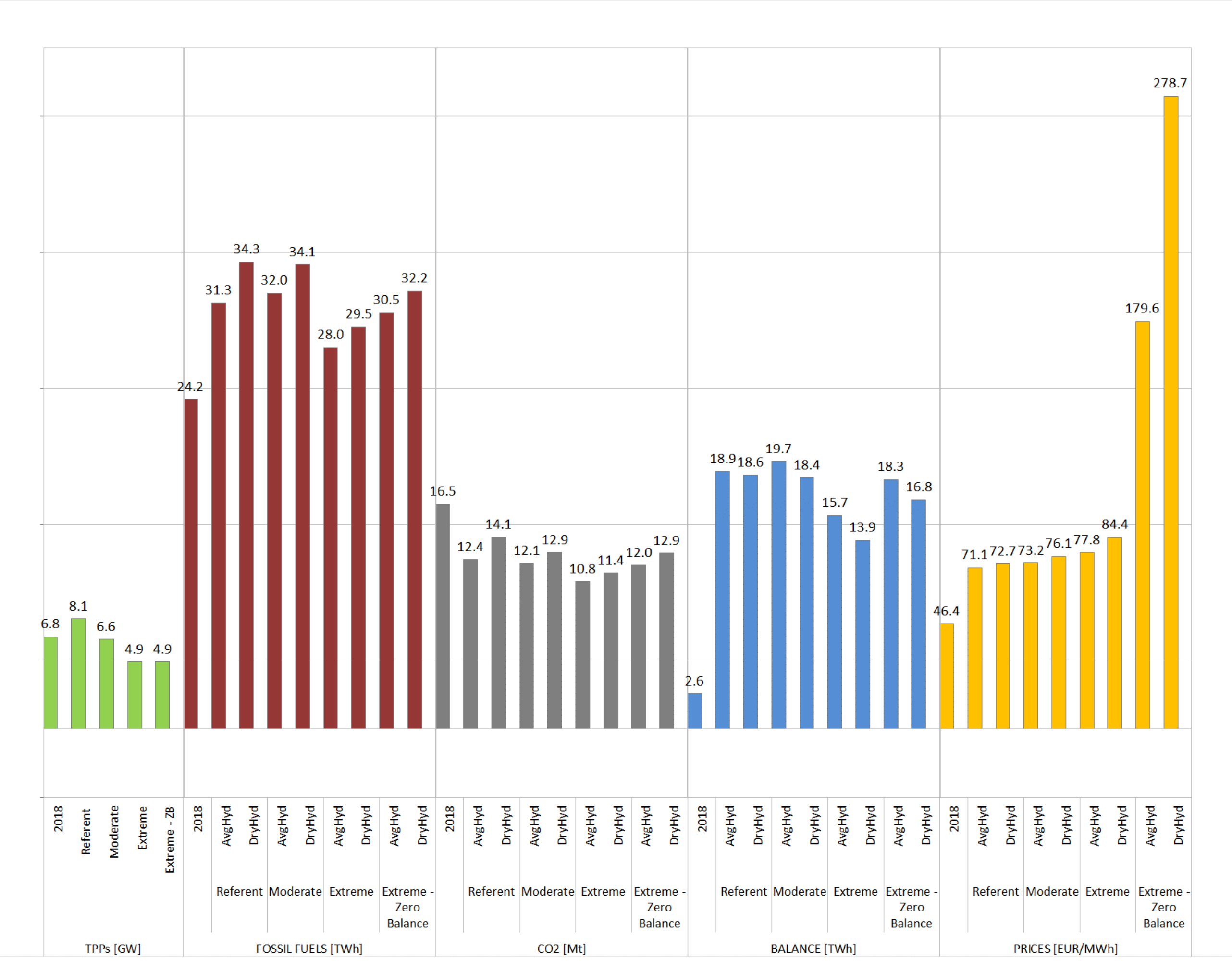


Figure 30: Main system operating indicators in the Transelectrica market area in 2030

By analyzing these results, we conclude the following for the Transelectrica market area in 2030 with different levels of decarbonization:

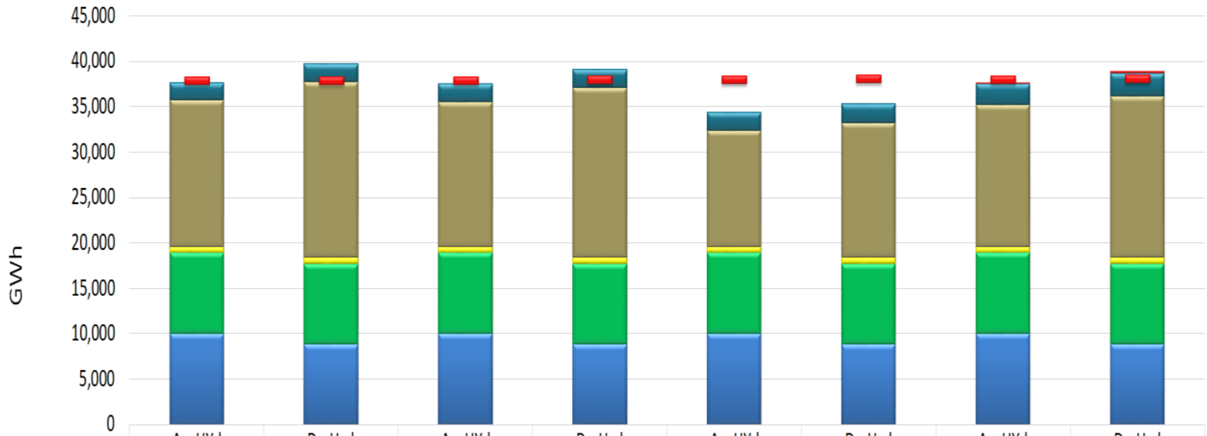
- Gas plants dominate the power generation mix in the Transelectrica market area in 2030.
- In 2030, we expect thermal capacities between 4.9 GW and 8.1 GW. This is a decrease in the Moderate and Extreme scenario of 3% to 28%, and an increase of 20% in the Referent scenario with respect to 6.8 GW in operation in 2018. However, total annual generation from these power plants is higher than in 2018 in all cases.
- This occurs because the decommissioning of TPPs plants in 2030, as well as the relatively high CO_2 price (65.73 EUR/tCO_2) in our analyses causes relatively high market prices in the SEE region and the Transelectrica market area. Therefore, gas plants become more competitive and increase their generation when moving from the Referent to the Extreme scenario, and from average to dry hydrology. Thermal generation is highest in the Referent scenario (about 34.3 TWh), because this case has the highest share of fossil fuel capacities.
- CO_2 emissions follow the changes in thermal generation, and are relatively high in all scenarios, reaching a high of 14.1 Mt in the Referent scenario, compared to 16.5 Mt in 2018.
- The Transelectrica market area is a significant net electricity exporter, with expected exports of 13.9 to 19.7 TWh, or 21% to 30% of consumption in 2030. This is due to high levels of

nuclear, natural gas and RES generation, which enable the Transelectrica market area to export more when there is dry hydrology regionwide. In 2018 the Transelectrica market area was also an exporter, at a lower level - around 4%

- Prices range from 71.1 to 84.4 EUR/MWh, similar to other SEE market areas, since low levels of congestion lead to price convergence. Deeper decarbonization leads to the engagement of more expensive sources, and prices increase.
- In the Extreme scenario with zero regional balance, we apply a Value of Lost Load (VOLL) of 1000 EUR/MWh in the hours when demand exceeds supply, which significantly increases the values of average annual prices to 179.6 and 278.7 EUR/MWh, depending on hydrology. With emergency imports, and prices at twice the level of marginal costs, the prices would be 107.3 and 129.3 EUR/MWh, depending on hydrology.

7.3.10. EMS Market Area

In the following figures, we present the main results of the market analysis for the EMS market area, including the generation mix and other indicators.



	RS				RS			
	Referent		Moderate		Extreme		Extreme-zero Balance	
	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd	AvgHYd	DryHyd
ENS	0	0	0	0	0	0	94	205
Other	0	0	0	0	0	0	0	0
Gas	1,934	2,000	1,986	2,050	2,057	2,128	2,309	2,533
Coal	0	0	0	0	0	0	0	0
Lignite	16,145	19,362	15,952	18,716	12,776	14,859	15,624	17,814
Nuclear	0	0	0	0	0	0	0	0
Solar	686	686	686	686	686	686	686	686
Wind	8,877	8,877	8,877	8,877	8,877	8,877	8,877	8,877
Hydro	10,038	8,847	10,038	8,847	10,038	8,847	10,038	8,847
Consumption	37,932	37,936	37,962	38,021	38,001	38,124	38,027	38,119

Figure 31: Generation mix in the EMS market area in 2030

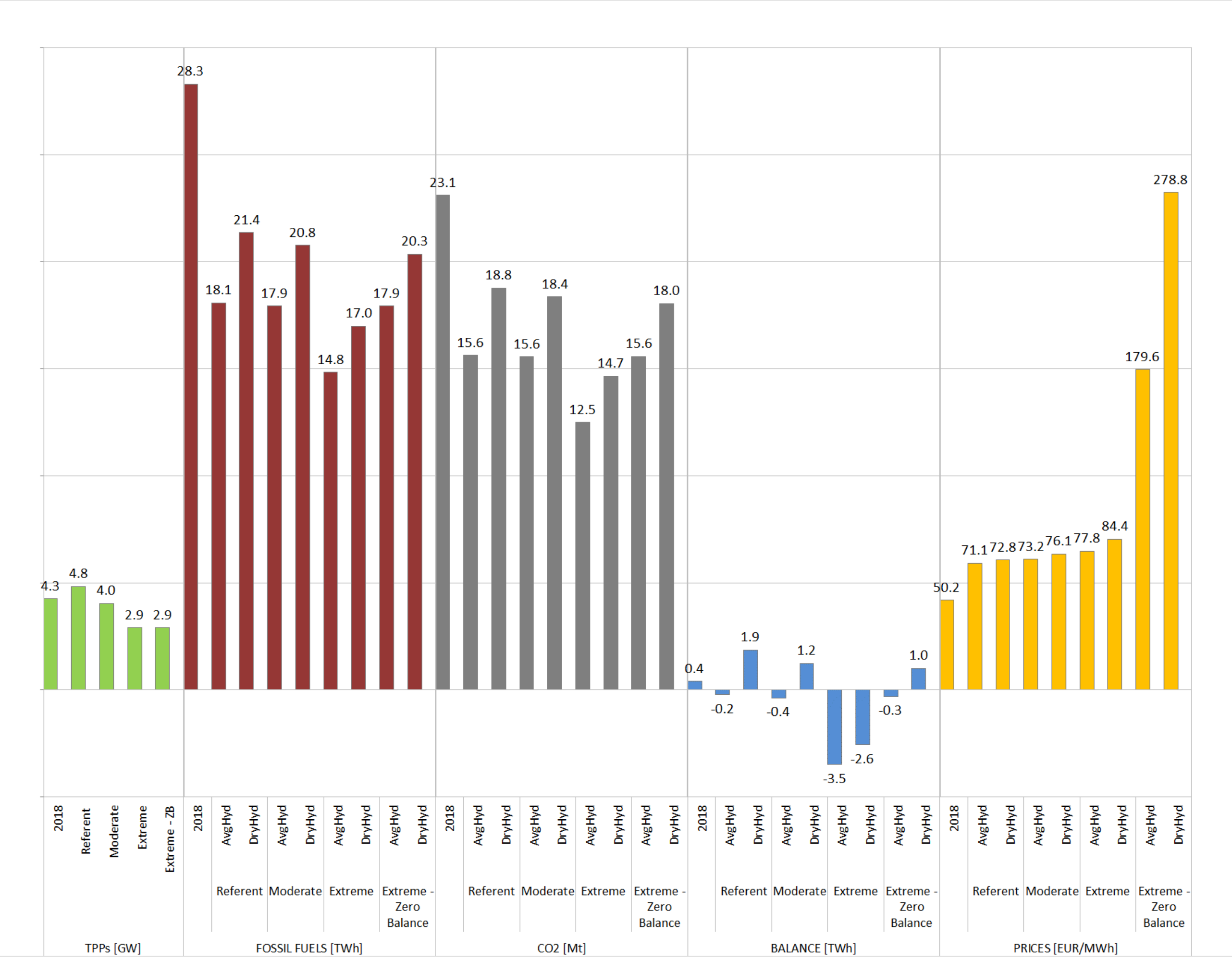


Figure 32: Main system operating indicators in the EMS market area in 2030

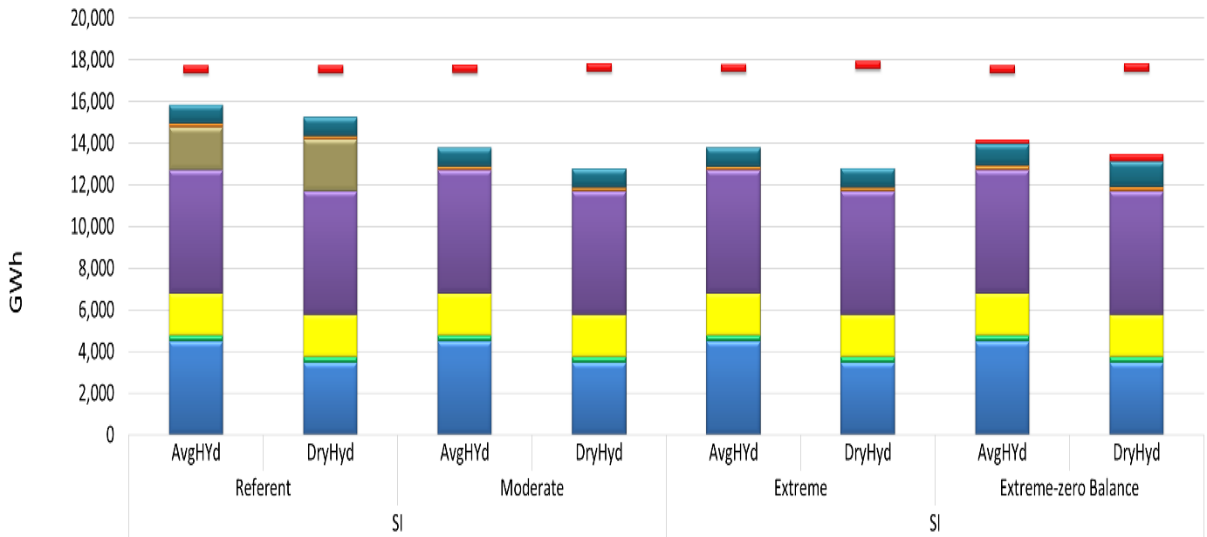
By analyzing these results, we conclude the following for the EMS market area in 2030 with different levels of decarbonization:

- Lignite plants dominate the generation mix in the EMS market area in all scenarios in 2030.
- In 2030 we expect thermal capacities between 2.9 GW and 4.8 GW. We expect an additional 656 MW in lignite units, and 183 MW in gas units, and modest lignite decommissioning of 263 MW. This leads to total fossil capacity in the Referent scenario (4.8 GW) that is higher than today, while in the Moderate and Extreme scenarios, it is lower than today's 4.3 GW.
- Despite adding new TPPs in the Referent scenario, the high CO2 price (65.73 EUR/tCO2) reduces thermal generation in the EMS market area by more than 36% with average hydrology, compared with 2018.
- Generation in the Moderate scenario is only slightly reduced while 800 MW less is available in EMS market area. This shows that the remaining TPP capacity has a better position in the EMS market area, and become more competitive. In this situation they operate with higher capacity factors and generate almost the same as in the Referent scenario. Further decommissioning of 1.1 GW in the Extreme scenario reduces TPP generation to 14.8 TWh, which is the lowest level in all scenarios, about half the level of 2018.
- Thermal generation in the Extreme scenario with a regional zero balance is approximately at the same level as in the Referent scenario, pointing to the significantly better position of TPPs in the EMS market in this constrained case.

- CO_2 emissions follow the changes in thermal generation, reaching a maximum of 18.8 Mt in the Referent scenario and dry hydrology. Emissions are similar in the Moderate scenarios for dry hydrology, while the minimum of 12.5 Mt occurs in the Extreme decommissioning scenario and average hydrology.
- The EMS market area has a variable annual balance from one scenario to another. In all scenarios the TPPs there become more competitive in dry hydro conditions, and exports increase or imports decrease regardless of the decarbonization scenario.
- The relatively high level of thermal capacities in the Referent and Moderate scenarios (more than 4 GW) leads to a nearly-balanced operation of EMS market area.
- By contrast, in the Extreme scenario, the significant decrease in thermal capacities changes the position of the EMS market area from exporting (or balanced) to importing. In this scenario, imports to the EMS market area reach 3.5 TWh, or 9% of consumption.
- For the Extreme scenario with zero balance constraint, TPPs from the EMS market area become more competitive and generate more electricity despite reduced installed capacity. This changes the balance position of this market area from importing to balanced.
- Prices range from 71.1 to 84.4 EUR/MWh, similar to other SEE market areas, since congestion is low, and prices converge. Deeper decarbonization engages more expensive units, and prices increase.
- In the Extreme scenario with zero regional balance constraint, we apply a price for the Value of Lost Load (VOLL) of 1000 EUR/MWh in the hours when demand is higher than supply which significantly increases the values of average annual prices to 179.6 and 278.8 EUR/MWh, depending on the hydrology. In this case, the unsupplied energy in the EMS market area is 94 GWh and 205 GWh under average and dry hydrology, respectively.
- With emergency imports, and prices at twice the level of marginal costs, the annual wholesale prices would be 107.3 and 129.4 EUR/MWh (depending on the hydrology)

7.3.11. ELES Market Area

In the following figures, we present the main results of the market analysis for the ELES market area, including the generation mix and other indicators.



	SI Referent AvgHYd	SI Referent DryHyd	SI Moderate AvgHYd	SI Moderate DryHyd	SI Extreme AvgHYd	SI Extreme DryHyd	SI Extreme-zero Balance AvgHYd	SI Extreme-zero Balance DryHyd
ENS	0	0	0	0	0	0	198	376
Other	0	0	0	0	0	0	0	0
Gas	888	888	890	893	900	921	1,051	1,212
Coal	172	172	172	173	174	178	188	210
Lignite	2,055	2,493	0	0	0	0	0	0
Nuclear	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930
Solar	2,013	2,013	2,013	2,013	2,013	2,013	2,013	2,013
Wind	288	288	288	288	288	288	288	288
Hydro	4,482	3,457	4,482	3,457	4,482	3,457	4,482	3,457
Consumption	17,522	17,534	17,550	17,616	17,594	17,725	17,531	17,619

Figure 33: Generation mix in the ELES market area in 2030

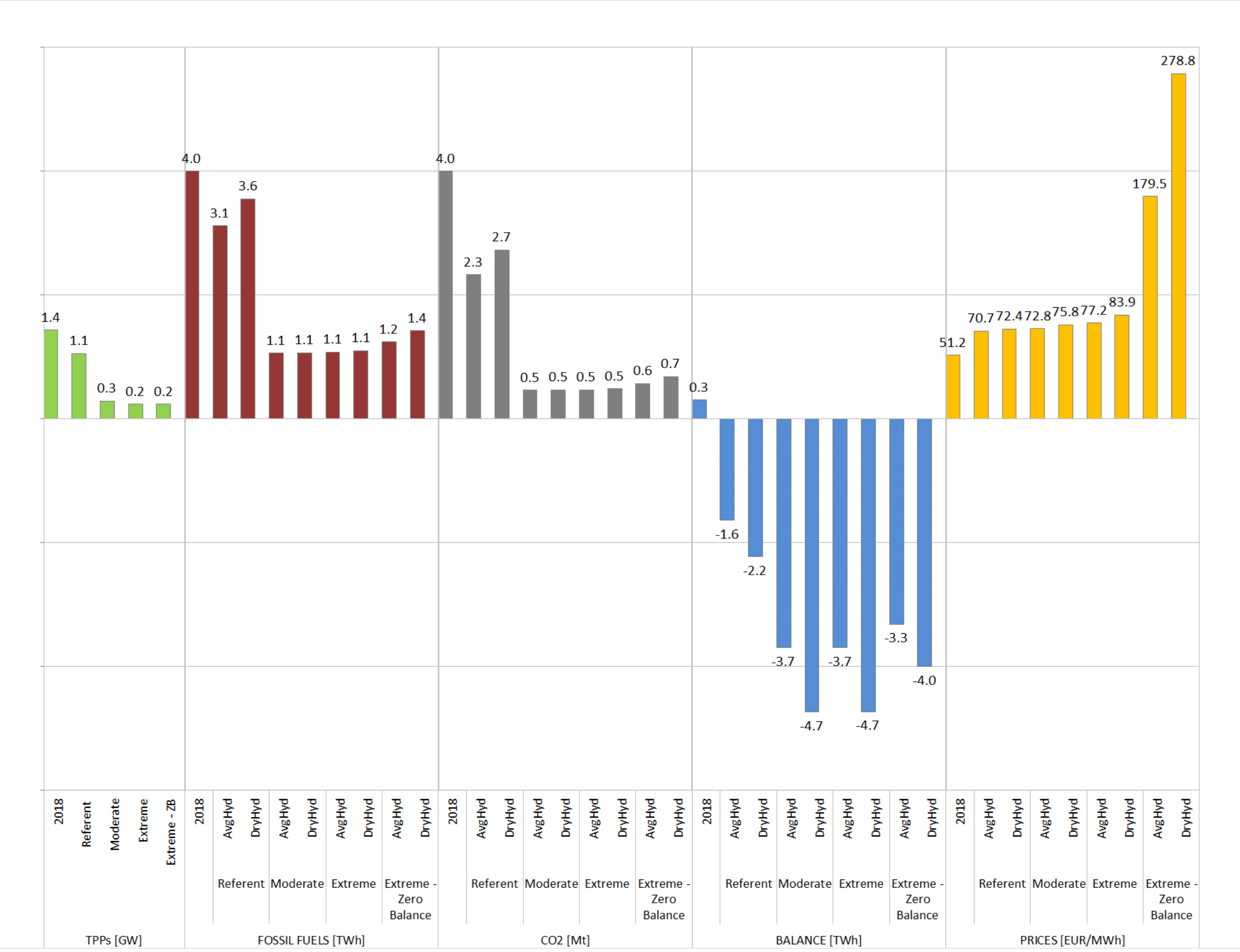


Figure 34: Main system operating indicators in the ELES market area in 2030

By analyzing these results, we conclude the following for the ELES market area in 2030 with different levels of decarbonization:

- In 2030 we expect thermal capacities of 0.2 to 1.1 GW, a decrease of 21% to 86% with respect to the 1.4 GW in operation in 2018.
- The CO_2 price (65.73 EUR/tCO_2) applied in our analyses will reduce generation from coal (lignite) units in the ELES market area to zero in the Moderate and Extreme scenarios, since these thermal units become uncompetitive. TPP generation is the highest in the Referent scenario where units in the ELES market area generate 3.6 TWh in dry hydrology conditions.
- CO_2 emissions follows the changes in thermal generation in the ELES market area, including the reduction of coal generation, and higher levels of competitive gas generation. This leads to the highest CO_2 emissions in the Referent scenario – 2.7 Mt in dry conditions, and 0.5 Mt in the Moderate and Extreme scenarios, when coal and lignite generation is reduced to zero.
- From being an exporter in 2018 of 4% of its consumption, in 2030 the ELES market area becomes an importer, from 1.6 to 4.7 TWh (9% - 27% of consumption) for all scenarios and hydrologies when energy can be readily imported. Imports are always higher with reduced generation from HPPs in dry conditions. In the Referent scenario, imports are the lowest, and under average hydrology, the ELES market area imports the least.

- Prices range from 70.7 to 83.9 EUR/MWh, similar to other SEE market areas, given low congestion and price convergence. Deeper decarbonization leads to the engagement of more expensive sources, and prices increase.
- In the Extreme scenario with zero regional balance, prices assumed for Value of Lost Load (VOLL) of 1000 EUR/MWh in the hours when demand is higher than supply will significantly increase average annual prices to 179.5 and 278.8 EUR/MWh, depending on hydrology. With emergency imports, and prices at twice the level of marginal costs, the average wholesale prices would be 107.3 and 129.4 EUR/MWh (depending on hydrology).
- In the Referent and Extreme scenario with the zero balance constraint, dry hydro conditions lead to higher TPP generation, higher CO_2 emissions, higher import and higher prices. This also applies to imports and prices in the Moderate and Extreme scenarios, but generation from TPPs remains the same in both hydro conditions, leading to the same CO_2 emissions.

8. NETWORK MODELING ASSUMPTIONS

For the purpose of this study, we created Regional Transmission System Models (RTSMs) for the following cases:

- the third Wednesday in January 2030 at 18:00 (CET) (considered as the maximum load regime);
- the third Wednesday in May 2030 at 04:00 am (CET) (considered as the minimum load regime).

Each of these regimes included the expected/forecasted level of RES integration for 2030.

To create a regional EMI network model, it was necessary to collect individual models from all participating TSOs, and merge them into a single regional one.

The first step in the process of collecting national models was to prepare and deliver *Guidelines for construction and usage of regional models* to the EMI members' TSOs, with necessary descriptions, instructions and recommendations. The Guidelines are very detailed, identifying all the data needed to model each element in the power system. It also includes descriptions and instructions related to modeling each national system as a part of the regional system (e.g., level of modeling, node number ranges, area numbers, etc.).

The second step was to collect the models from the participating TSOs for specific regimes, in accordance with the Guidelines. We checked each national TSO model and requested several updates and clarifications.

The third step was to merge the collected models into regional models and adjust the balances of external systems in order to achieve a balance for each regional model (there are different models for maximum and minimum load).

We used the adjusted regional models for detailed AC load flow simulations. This was based on the generation dispatch we obtained from the market simulation scenarios with different levels of RES, different hydrological conditions, and different levels of consumption and CO_2 emission prices.

To prepare for these comprehensive simulations, we conducted a preliminary test analysis with our initially created regional transmission grid models. The results are given below.

8.1. Level of modeling for grid analyses

The level of grid modeling of power systems in these countries is very detailed, and includes:

- The complete transmission network at the voltage level of 110 kV and above
    - If there are parallel branches, we model each branch separately (i.e., we did not model parallel branches as one equivalent or aggregated branch)
- Every conventional generation unit connected to the transmission grid is modeled at the generation voltage level, and connected to the system through a step-up transformer

    - Where there are power plants with multiple conventional units, each unit is modeled separately (i.e., we did not model multiple generation units as one equivalent unit)
- Every wind and solar power plant connected to the transmission grid is modeled as one unit at the point of common coupling (PCC), where generation from all units are collected, and this "unit" is connected to the transmission grid through a step-up transformer
- There are no equivalents with regard to the network in the areas of the participating TSOs

8.1.1. Modeling of distributed generation

In the case of distributed generation (i.e., generation which is installed on the lower voltage (distribution) network, but which is not included in the TSO models), it was necessary to model its influence on the system. Therefore, each TSO had to identify which nodes in the transmission network are expected to be influenced by distributed generation, and the extent of that influence.

In these nodes, it was necessary to model equivalent generators, with the proper estimated active power range, but without reactive power regulation.

We modeled these equivalent generators separately, for each fuel/technology type. It was possible to model several equivalent generators at one node, but it was necessary to differentiate among fuel/technology types.

8.1.2. Modeling of the tie-lines

To better organize reports and handle models, we modeled each tie-line with a fictitious node (the so-called *X-node* or *border node*), which is on the border between countries/TSOs (see Figure 35).

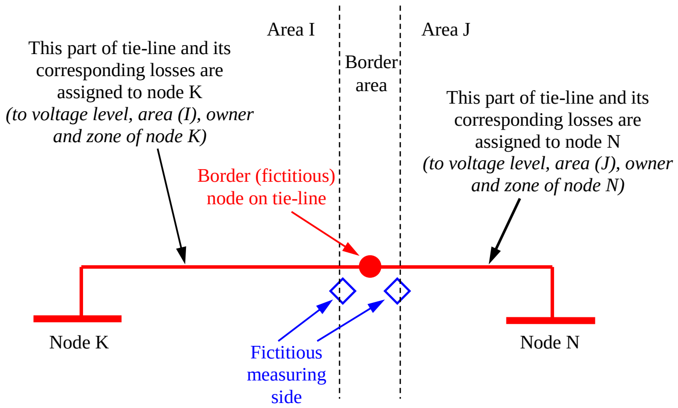


Figure 35: Modeling of tie-lines

Practically, each tie-line is divided in two parts. We assigned each border node to a fictitious border area and we placed the measuring point of each part of tie-line on their side of the border node. With this approach, we can assign losses in each part of tie-line to the corresponding area.

In the case of tie-lines connecting areas within the system of interest (e.g., tie-lines between the EMI members) these fictitious border nodes do not have any load or generation. Therefore, the areas containing such nodes should be shown in the area summary report with all zero data (zero generation, zero load, zero losses and zero net interchange).

In contrast, for the tie-lines between EMI members and external systems, the border nodes need to have some equivalent load, which represents power exchanged on the corresponding tie-lines.

8.2. Description of reports in format of PSS®E outputs

This subchapter summarizes the reports which are commonly used to describe particular national/TSO models and regional models. For a better understanding, we have prepared each sample report and inserted the figure with a detailed explanation of all parts of the data.

For any type of branch, the assignment to the node and its area, zone, owner and voltage level depends on the branch's defined measuring point. Since the measuring point defines the place where we measure the power interchange between two nodes, we assign each branch to a node (and therefore to its area, zone, owner and voltage level) on the opposite side of the measuring point. For a clear explanation, we provide an example of a small part of the grid in Figure 36.

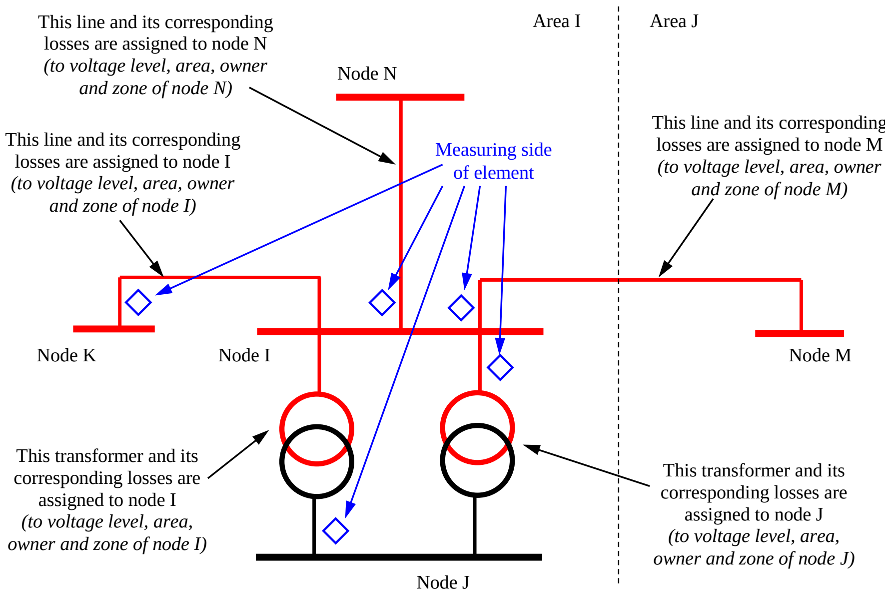


Figure 36: Explanation of rules for assignment branches to nodes and their areas, zones, owners and voltage levels

In the case of three winding transformers, we define two measuring points, so that such a transformer, and its losses, is assigned to the node on the side where there is no measuring point.

When reporting power flows, PSS®E shows power flows registered on the branch measuring side.

Tie-lines are modeled with border nodes, which are placed on the border between two TSOs, which means that each tie-line is modeled as two lines, the first one from the border node to the corresponding substation in one area, and the second one from the border node to the corresponding substation in the other area. The measuring point on each of these two lines is inside the border nodes, so losses in each line are assigned to the corresponding area. We show an example of such modeling in subchapter 8.1.2 Modeling of the tie-lines (Figure 35 above).

8.2.1. Area summary report

We use an area summary report to show summary data for each selected area. Figure 37 shows an example of an area summary report, with a detailed description of the data columns in such a report.

Reader should keep in mind that total losses include two parts, i.e., for one area total losses are the sum of the data in the column "TO LOSSES" and "TO LINE SHUNTS" for the corresponding area.

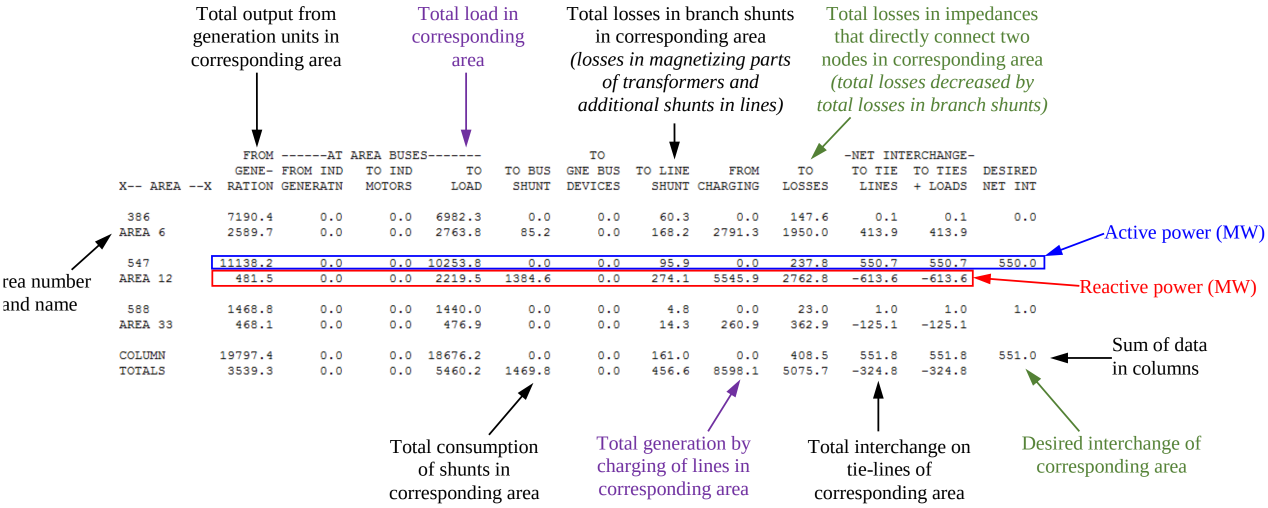


Figure 37: Description of data shown in area summary report from PSS®E

8.2.2. Report from contingency analysis

We show an example of a report from the contingency analysis in Figure 38, in four main parts.

The first part is related to the monitored branches with loading above the defined threshold. The amount of power flow shown is in MVAs on the measuring side of the branch.

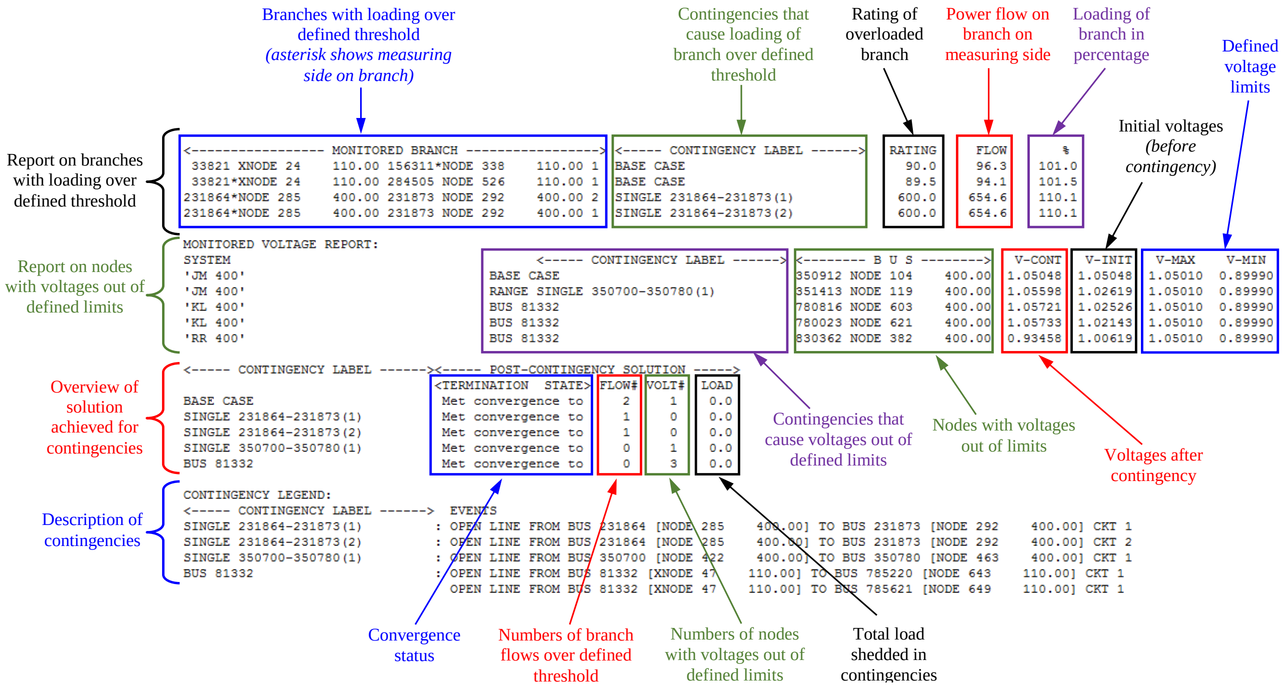


Figure 38: Description of data shown in report from contingency analysis, in format of PSS®E report

Usually, we use a threshold of 100% to list branches of a defined rating, which means that we would only show overloaded branches in the report. However, the user can define other threshold values (for example, an 80% threshold would show all highly-loaded branches, including overloaded ones).

The second part shows monitored nodes with voltages out of the defined limits, and we show the voltage limits for each node in these data.

The third part provides solution information (convergence) for each analyzed contingency, and an overview of the results (e.g., the number of shown branches and nodes with voltage overshots).

Finally, the fourth part describes each analyzed contingency.

8.3. Overview of SEE regional transmission grid models

After collecting and checking all the national/TSO models, we prepared each one to merge into a regional model, while respecting each market's load regime and RES development scenario. When we created the regional model, we checked for system adequacy, including a load-flow calculation and security assessment.

The following subchapters provide brief information about the regional transmission models that the EMI has created from the TSOs' national models to support our network analysis.

We created the regional models by merging all the collected national models. The number of elements in the regional models are shown in Table 12.

Table 12: Number of elements in the regional models

8480 BUSES	1463 PLANTS	1245 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
3392 LOADS	47 FIXED SHUNTS	151 SWITCHED SHUNTS		
9746 BRANCHES	3663 TRANSFORMERS	2 DC LINES	1 FACTS DEVICES	0 GNE DEVICES

In addition to a summary for each area, and an analysis of the voltage profile, for each regional model we assessed steady-state security against single outages as well. This assessment included analyses of the grid conditions in case of a single outage of branches with regional importance. We included these branches in the list of outages and in the list of monitoring elements:

- all 400 kV lines
- all 220 kV lines
- all transformers 400/220 kV
- all tie-lines among TSOs in EMI area

In the case of parallel branches, we considered the outage of each single branch.

Voltage profile and security assessment are related to high voltage grid only (220 and 400kV) as part of grid with regional importance. All problems related to lower voltage level should be considered as local problems.

8.3.1. Maximum load regime

We show a summary of each country's network data, as reported from PSS®E, for the time of maximum load in 2030, in Table 13. The first row for each country represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 13: Summaries of all areas in regional model – maximum load 2030

X-- AREA --X	FROM GENE-RATION	FROM IND GENERATN (at area buses)	TO IND MOTORS (at area buses)	TO LOAD (at area buses)	TO BUS SHUNT	TO GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	-NET INTERCHANGE- TO TIE LINES	-NET INTERCHANGE- TO TIES + LOADS	DESIRED NET INT
10	1148.5	0.0	0.0	1873.0	0.0	0.0	4.9	0.0	27.7	-757.0	-757.0	-757.0
AL	139.2	0.0	0.0	506.4	-51.2	0.0	29.4	672.8	314.1	13.3	13.3	
13	3188.0	0.0	0.0	2327.0	0.0	0.0	15.5	0.0	75.5	770.0	770.0	770.0
BA	628.9	0.0	0.0	453.6	0.0	0.0	158.3	1052.3	789.0	280.2	280.2	
14	5990.6	0.0	0.0	5785.7	0.0	0.0	59.2	0.0	127.6	18.0	18.0	18.0
BG	1882.3	0.0	0.0	2204.2	83.3	0.0	158.8	2817.8	1672.2	581.6	581.6	
16	3138.3	0.0	0.0	2630.0	0.0	0.0	4.7	0.0	88.4	415.2	415.2	415.0
HR	-239.2	0.0	0.0	620.5	109.5	0.0	22.9	1589.1	778.0	-180.9	-180.9	
30	9154.4	0.0	0.0	8374.0	0.0	0.0	0.0	0.0	179.4	601.0	601.0	601.0
GR	224.2	0.0	0.0	4124.6	1814.3	0.0	22.6	7924.1	2045.3	141.4	141.4	
37	1473.9	0.0	0.0	1582.4	0.0	0.0	2.1	0.0	26.5	-137.0	-137.0	-137.0
MK	333.9	0.0	0.0	502.8	0.0	0.0	9.8	496.3	273.9	43.8	43.8	
38	1428.3	0.0	0.0	704.0	0.0	0.0	4.4	0.0	39.8	680.0	680.0	680.0
ME	339.3	0.0	0.0	240.8	68.0	0.0	30.1	440.0	429.7	10.7	10.7	
44	11132.2	0.0	0.0	10253.9	0.0	0.0	96.9	0.0	231.5	549.9	549.9	550.0
RO	224.2	0.0	0.0	2219.6	1301.9	0.0	275.8	5577.6	2747.8	-743.4	-743.4	
46	9311.1	0.0	0.0	6711.1	0.0	0.0	33.4	0.0	166.7	2400.0	2400.0	2400.0
RS	1642.0	0.0	0.0	1512.0	0.0	0.0	192.1	2150.7	2295.3	-206.7	-206.7	
47	1467.7	0.0	0.0	1440.0	0.0	0.0	4.9	0.0	21.9	1.0	1.0	1.0
XK	432.3	0.0	0.0	476.9	0.0	0.0	14.5	262.5	351.5	-148.0	-148.0	
49	1956.0	0.0	0.0	2123.3	0.0	0.0	7.9	0.0	34.6	-209.8	-209.8	-210.0
SI	-69.6	0.0	0.0	307.9	0.0	0.0	54.5	681.9	521.4	-271.6	-271.6	
COLUMN	49389.0	0.0	0.0	43804.3	0.0	0.0	233.7	0.0	1019.6	4331.4	4331.4	4331.0
TOTALS	5537.4	0.0	0.0	13169.2	3325.8	0.0	968.6	23665.1	12218.3	-479.4	-479.4	

Level of active power losses in area of interest is around 2.86%. Value of total active power losses is 1 253.3 MW, while total load is 43 804.3 MW.

We provide a summary of the voltage profile for the HV grid in Table 14. This table shows data per each area, at voltage levels of 400 kV and 220 kV (if exists). For each system and voltage level, we show the number of nodes in operation, along with the minimum voltage, maximum voltage, and average voltage.

Table 14: Summary of the voltage profile for the maximum load regime

Area	400 kV nodes				220 kV nodes			
	Nodes	Vmin (pu)	Vavg (pu)	Vmax (pu)	Nodes	Vmin (pu)	Vavg (pu)	Vmax (pu)
AL	9	1,00447	1,01169	1,02631	29	1,00153	1,00932	1,02386
BA	13	1,01743	1,03058	1,03987	26	1,01839	1,06451	1,08367
BG	22	1,01983	1,02787	1,04538	39	0,96671	1,01553	1,04576
HR	10	1,00861	1,02186	1,03866	22	1,01063	1,04021	1,13320
GR	75	0,99429	1,01947	1,03343				
MK	9	1,00862	1,02119	1,03086				
ME	6	1,00599	1,02218	1,03593	5	1,01396	1,03277	1,05395
RO	45	0,99071	1,00439	1,01978	73	1,01101	1,03860	1,06000
RS	46	0,98538	1,01341	1,03765	43	1,00073	1,03020	1,05513
XK	5	1,00653	1,01176	1,01603	11	0,97794	0,99540	1,01451
SI	9	0,99630	1,01181	1,02342	6	1,01977	1,03171	1,04204

Below, we also display this data graphically. Figure 39 shows the voltage profile summary for the 400 kV grid, while Figure 40 shows this profile for the 220 kV grid. To provide a better overview, both figures also show lines for the allowed minimum and maximum operational voltage levels.

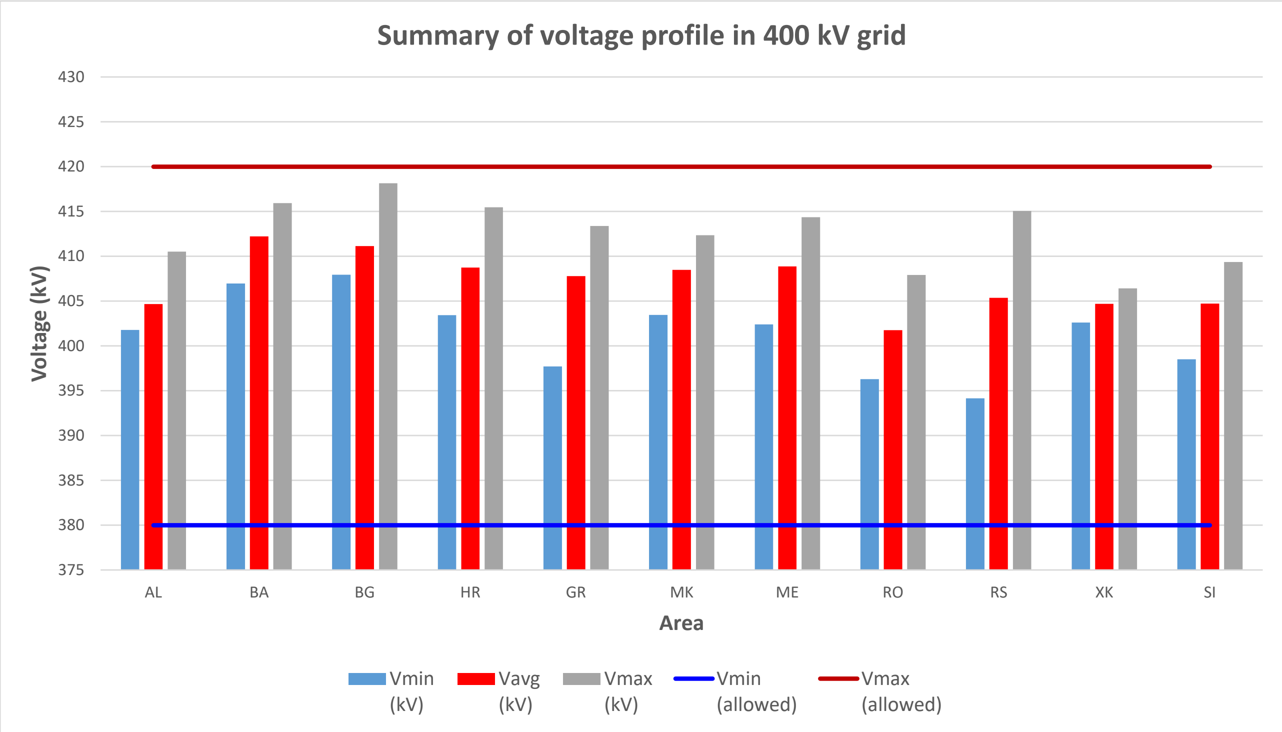


Figure 39: Summary of the voltage profile in the 400 kV grid – maximum load 2030,

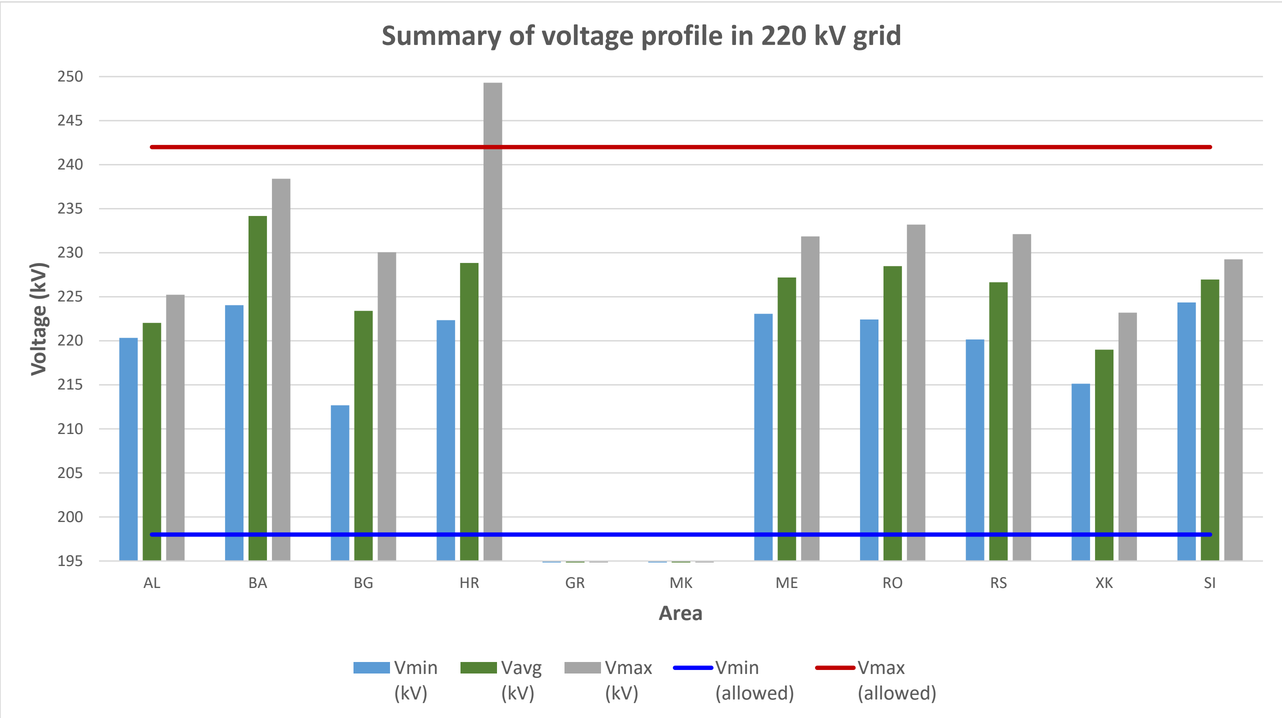


Figure 40: Summary of voltage profile in 220 kV grid – maximum load 2030

This shows that voltages in the 400 kV grid are within allowed limits. However, in the 220 kV grid, HOPS (HR) has one node with voltage above the upper limit, the Plat substation in southern Croatia.

There are no overloaded HV branches.

We show the aggregated border exchanges for the maximum load regime in the following figure.

Figure 41: Aggregated border exchanges – maximum load 2030

Aggregated border exchanges are shown in arrows. The direction of arrows is fixed, and the values inside can be positive and negative. A negative value means that the aggregated border active power flow has the opposite direction than the arrow shows. Below the 2-character ISO code for each area/country there is TSO balance, which represents the total imports and exports as the sum of all the aggregated border power flows from the corresponding TSO.

We show the initial results from the (N-1) contingencies in Table 15, based on PSS®E analysis.

Table 15: Results from contingency (N-1) assessment– maximum load 2030

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>   RATING     FLOW       %
 141045*VMAIZ11     400.00 141060 VMAIZ51     400.00 1  SINGLE 141045-141065(1)            519.0     564.0    105.6
  32201 XPA_DI21    220.00 492020*DIVACA220   220.00 1  SINGLE 491030-491040(1)            365.8     392.1    104.5
  32201 XPA_DI21    220.00 492020*DIVACA220   220.00 1  SINGLE 491030-491040(2)            365.8     392.1    104.5
 162040*HMELIN21    220.00 161035 HMELIN11    400.00 2  BUS 16131                          150.0     192.4    126.6
 161035*HMELIN11    400.00 162040 HMELIN21    220.00 2  BUS 16131                          150.0     187.8    120.3
  16231*XPE_DI21    220.00 162050 HPEHLI21    220.00 1  BUS 32101                          365.8     399.3    108.4
  16231*XPE_DI21    220.00 492020 DIVACA220   220.00 1  BUS 32101                          365.8     399.3    108.4
  32201 XPA_DI21    220.00 492020*DIVACA220   220.00 1  BUS 32101                          365.8     790.3    216.0
 162040*HMELIN21    220.00 161035 HMELIN11    400.00 2  BUS 32101                          150.0     177.6    117.6
 161035*HMELIN11    400.00 162040 HMELIN21    220.00 2  BUS 32101                          150.0     172.6    111.7

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                       Met convergence to     0     0    0.0
 SINGLE 141045-141065(1)         Met convergence to     1     0   38.0
 SINGLE 491030-491040(1)         Met convergence to     1     0    0.0
 SINGLE 491030-491040(2)         Met convergence to     1     0    0.0
 BUS 16131                       Met convergence to     2     0    0.0
 BUS 32101                       Met convergence to     5     0    0.0

CONTINGENCY LEGEND:
<----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 141045-141065(1)        : OPEN LINE FROM BUS 141045 [VMAIZ11     400.00] TO BUS 141065 [VMAIZ61     400.00] CKT 1
 SINGLE 491030-491040(1)        : OPEN LINE FROM BUS 491030 [DIVACA400   400.00] TO BUS 491040 [PST_DIV     400.00] CKT 1
 SINGLE 491030-491040(2)        : OPEN LINE FROM BUS 491030 [DIVACA400   400.00] TO BUS 491040 [PST_DIV     400.00] CKT 2
 BUS 16131                      : OPEN LINE FROM BUS 16131 [XME_DI11    400.00] TO BUS 161035 [HMELIN11    400.00] CKT 1
                                  OPEN LINE FROM BUS 16131 [XME_DI11    400.00] TO BUS 491030 [DIVACA400   400.00] CKT 1
 BUS 32101                      : OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 321346 [REDIPUGLIA  400.00] CKT 1
                                  OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 491040 [PST_DIV     400.00] CKT 1
```

There are two tie-lines of 220 kV voltage level which are overloaded. The 220 kV Divaca (SI) – Padriciano (IT) tie-line is significantly overloaded (around 116%) if there is an outage of the 400 kV Divaca (SI) – Redipuglia (IT) tie-line. An agreement between ELES (SI) and TERNA (IT) is such that an outage on one of these tie-lines can lead to automatic disconnection of the other, to prevent possible significant overloadings that can damage the equipment.

Also, the 220 kV Divaca (SI) – Padriciano (IT) tie-line is overloaded around 5% in an outage on one of two parallel phase-shift transformers on the 400 kV Divaca (SI) – Redipuglia (IT) tie-line.

The second overloaded tie-line 220 kV is Pehlin (HR) – Divaca (SI), overloaded around 8% in case of an outage of the 400 kV Divaca (SI) – Redipuglia (IT) tie-line.

Bulgaria has one critical element. Line 400 kV in Bulgaria, Maritsa Iztok 1 – Maritsa Iztok 5 is slightly overloaded (around 6%) in the case of an outage of line 400 kV Maritsa Iztok 1 – Maritsa Iztok 6.

In Croatia, the critical element is the transformer 400/220 kV in Meline. This transformer is highly overloaded (around 27%) in the case of an outage of the tie-line 400 kV Meline (HR) – Divaca (SI). Also, this transformer is overloaded around 18% in the case of an outage of the 400 kV Divaca (SI) – Redipuglia (IT) tie-line.

In general, this analysis proves that the network in SEE can readily accommodate the anticipated maximum loads, with exception of just few local contingencies listed above.

8.3.1. Minimum load regime

We summarize the SEE area totals, as reported from PSS®E, for the minimum load 2030 regime in Table 16. For each market area, the first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 16: Summaries of all areas in regional model – minimum load 2030

X-- AREA --X	FROM GENE-RATION	------AT AREA BUSES------- FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	TO GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	-NET INTERCHANGE- TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	702.6	0.0	0.0	560.7	0.0	0.0	5.3	0.0	6.6	130.0	130.0	130.0
AL	-123.5	0.0	0.0	158.5	555.1	0.0	32.5	746.4	82.3	-205.6	-205.6	
13	1560.4	0.0	0.0	1105.0	0.0	0.0	16.6	0.0	38.3	400.5	400.5	400.0
BA	-90.9	0.0	0.0	227.5	0.0	0.0	169.9	1115.8	377.2	250.4	250.4	
14	3984.0	0.0	0.0	2725.7	0.5	0.0	62.5	0.0	49.2	1146.1	1146.1	1146.0
BG	934.4	0.0	0.0	1038.8	1343.6	0.0	167.8	2995.4	795.0	584.6	584.6	
16	1193.7	0.0	0.0	1405.0	0.0	0.0	5.1	0.0	63.1	-279.5	-279.5	-280.0
HR	-224.7	0.0	0.0	331.4	114.3	0.0	24.4	1691.8	532.4	464.5	464.5	
30	5504.0	0.0	0.0	5168.7	0.0	0.0	0.0	0.0	100.3	235.0	235.0	235.0
GR	-1504.4	0.0	0.0	2654.0	2110.8	0.0	22.1	8285.5	1917.0	77.2	77.2	
37	576.9	0.0	0.0	628.1	0.0	0.0	2.3	0.0	5.4	-59.0	-59.0	-59.0
MK	0.0	0.0	0.0	148.6	0.0	0.0	10.8	546.1	74.6	312.1	312.1	
38	286.9	0.0	0.0	343.0	0.0	0.0	4.7	0.0	9.2	-70.0	-70.0	-70.0
ME	-25.4	0.0	0.0	121.3	156.8	0.0	33.1	477.7	96.0	45.0	45.0	
44	5763.1	0.0	0.0	5163.5	0.0	0.0	89.6	0.0	159.0	351.0	351.0	350.0
RO	-811.9	0.0	0.0	1670.2	1964.1	0.0	210.4	5680.3	1908.9	-885.3	-885.3	
46	5331.6	0.0	0.0	2708.0	0.0	0.0	33.6	0.0	94.5	2495.5	2495.5	2495.0
RS	-123.9	0.0	0.0	825.5	111.0	0.0	150.4	2236.3	1219.8	-194.3	-194.3	
47	731.4	0.0	0.0	700.0	0.0	0.0	5.5	0.0	5.9	20.0	20.0	20.0
XK	-73.7	0.0	0.0	233.6	0.0	0.0	16.1	291.0	101.6	-134.1	-134.1	
49	1610.0	0.0	0.0	1483.1	0.0	0.0	8.0	0.0	25.9	93.0	93.0	93.0
SI	-401.5	0.0	0.0	226.3	94.9	0.0	55.6	696.9	387.3	-468.6	-468.6	
COLUMN	27244.7	0.0	0.0	21990.9	0.5	0.0	233.2	0.0	557.5	4462.5	4462.5	4460.0
TOTALS	-2445.5	0.0	0.0	7635.8	6450.6	0.0	893.2	24763.2	7492.2	-154.0	-154.0	

The level of active power losses in the area of interest is around 3.60%. The value of total active power losses is 790.7 MW, while the total load is 21,990.9 MW. Even though a judgment about network losses is best conducted over a yearly period, these two snapshots (maximum and minimum system load) prove that active power losses in the SEE network are expected to range from 2.8% to 3.6%, which is relatively low and quite acceptable under these conditions.

We summarize the voltage profile for the HV grid in Table 17, with data for each area, and voltage levels for both the 400 kV and 220 kV networks (if exists). For each system and voltage level, we show the numbers of nodes in operation, with the maximum, minimum and average voltage values.

Table 17: Summary of voltage profile for minimum load regime 2030

Area	400 kV nodes				220 kV nodes			
	Nodes	Vmin (pu)	Vavg (pu)	Vmax (pu)	Nodes	Vmin (pu)	Vavg (pu)	Vmax (pu)
AL	9	1,04522	1,05320	1,05959	29	1,06598	1,07354	1,07923
BA	13	1,04963	1,05655	1,06194	26	1,06551	1,09682	1,10651
BG	22	1,02750	1,05132	1,06653	39	1,03200	1,04836	1,06035
HR	10	1,04042	1,05175	1,05956	22	1,05116	1,08109	1,19513
GR	75	1,01524	1,04710	1,06999				
MK	9	1,06206	1,06912	1,07226				
ME	6	1,06148	1,06626	1,06980	5	1,06481	1,07603	1,08578
RO	44	0,99593	1,01037	1,02388	68	1,02040	1,04862	1,06943
RS	46	1,01741	1,03245	1,05632	43	1,03648	1,06081	1,09308
XK	5	1,05575	1,05918	1,06301	11	1,04195	1,05494	1,07039
SI	9	1,00724	1,02073	1,03147	6	1,03723	1,04716	1,05279

Below we show these data graphically, depicting the voltage profile summary for the 400 kV and 220 kV grids. For a better overview, both figures include lines that show the allowed operational maximum and minimum voltages.

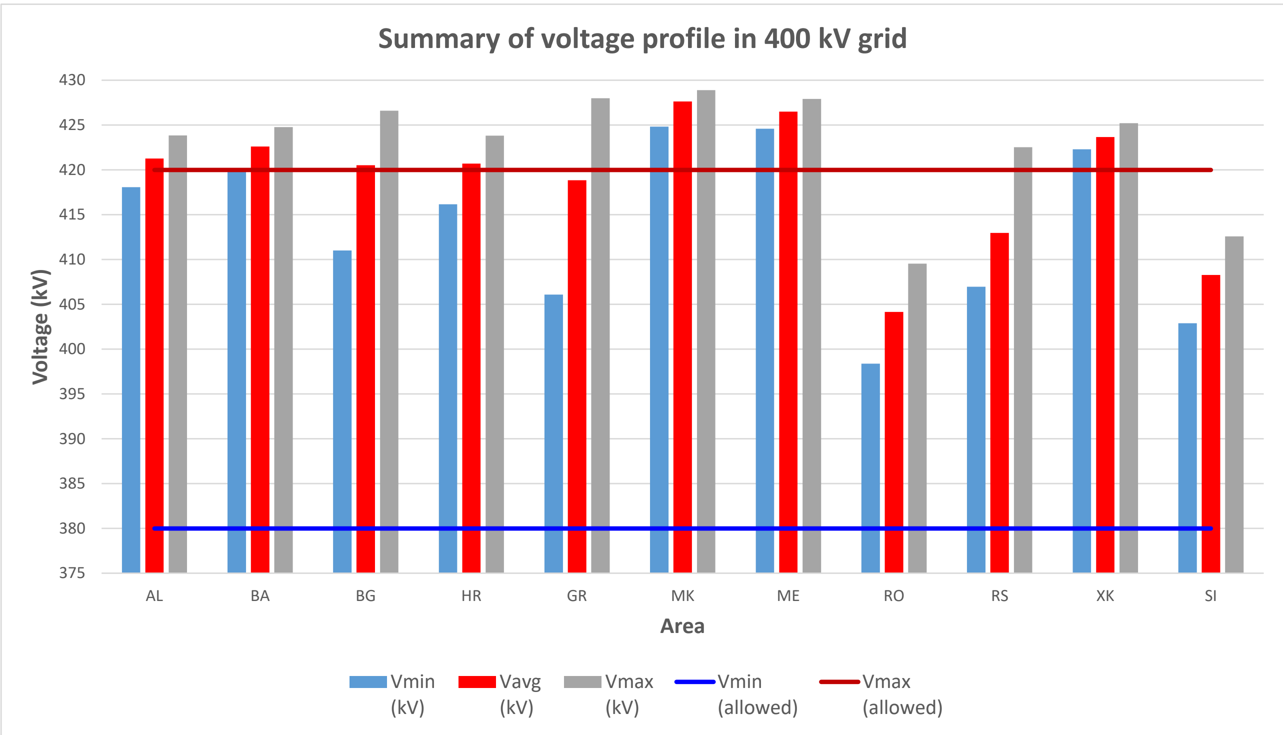


Figure 42: Summary of voltage profile in 400 kV grid – minimum load 2030

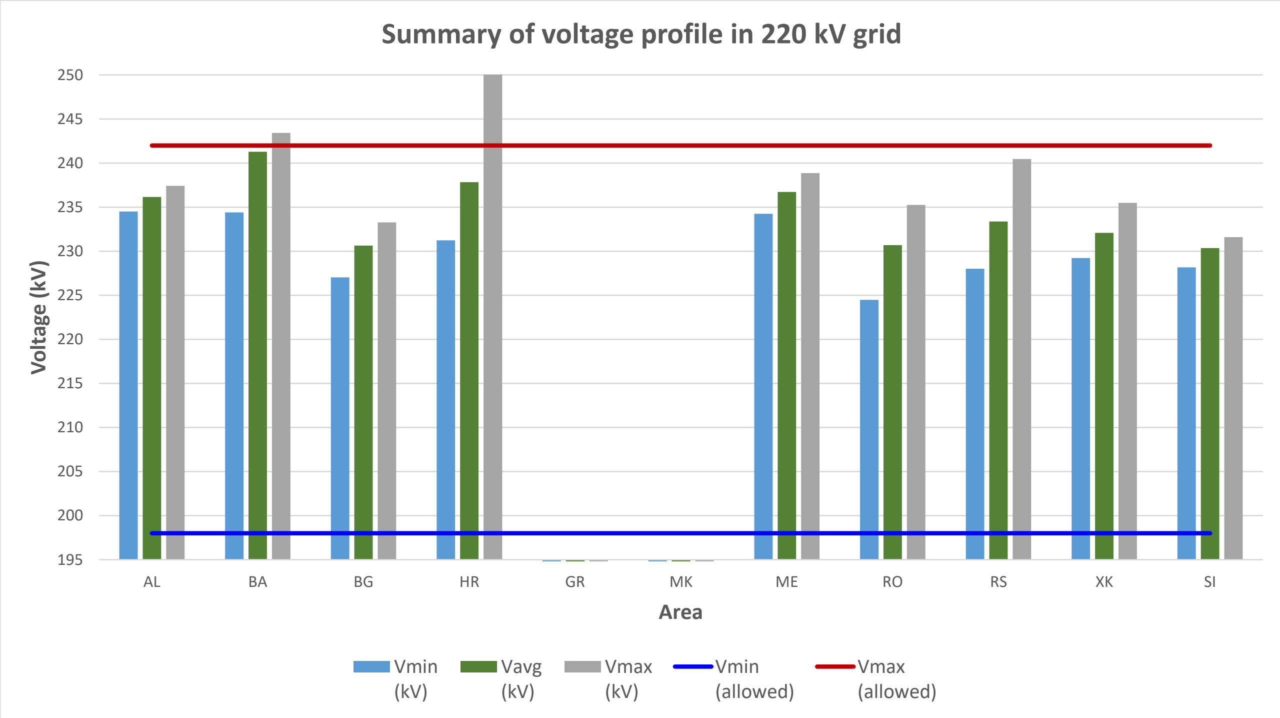


Figure 43: Summary of voltage profile in 220 kV grid – minimum load 2030

This work shows that voltages in the 400 kV grid are very high. Except for Romania and Slovenia, all other systems have nodes with voltages above the allowed maximum value. In six of the areas, even the average values are above the allowed maximum limit. This is a well-known problem with operational practice, and a recent study proposed necessary measures to solve these problems.

The situation is better on the 220 kV grid, where high voltages appear only in HOPS and NOSBiH.

There are no overloaded HV branches.

We show the aggregated border exchanges for the minimum load regime on the following Figure.

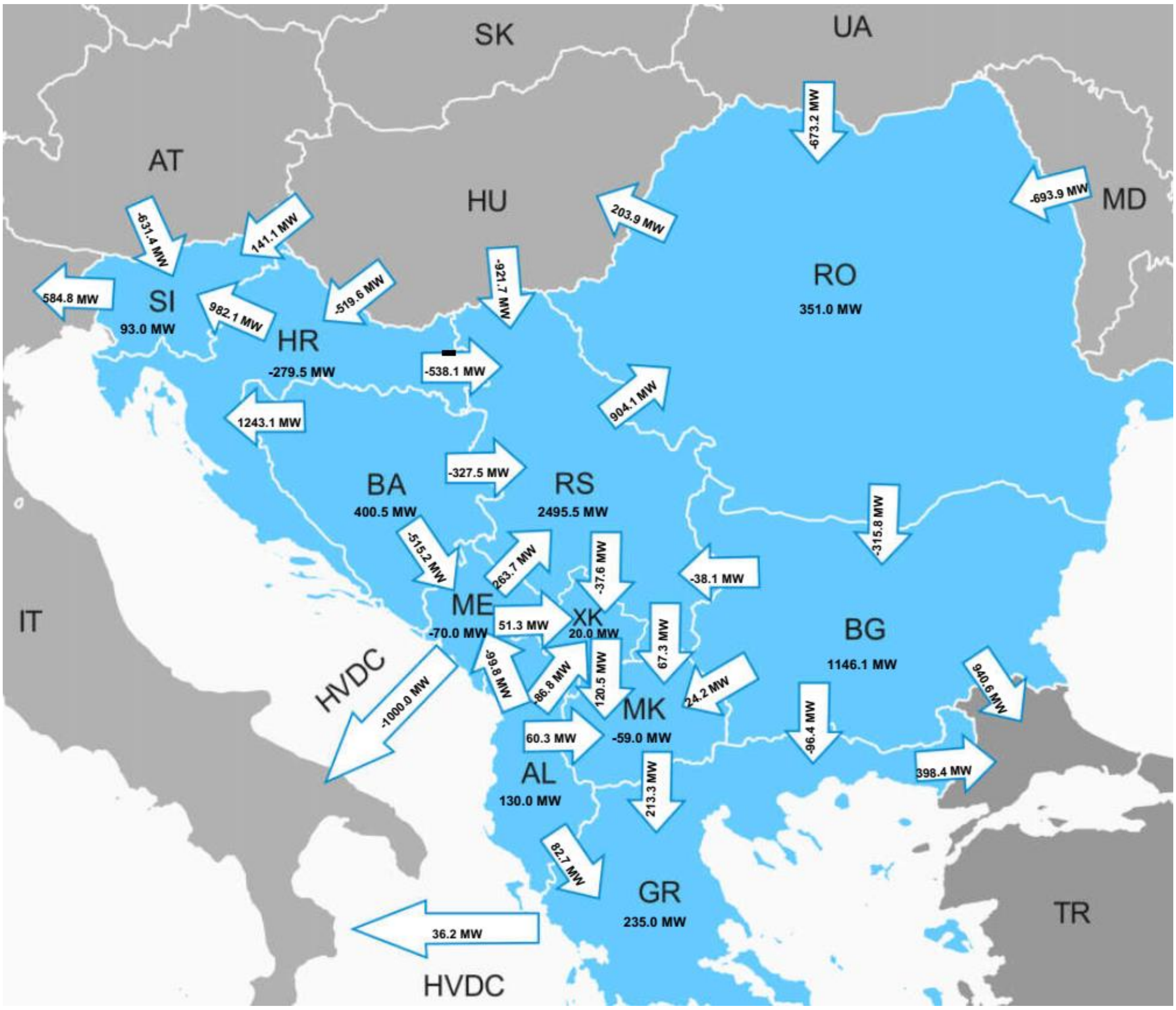


Figure 44: Aggregated border exchanges – minimum load 2030

The arrows indicate aggregated border exchanges. A negative value means that the aggregated border active power flow has the opposite direction than the arrow shows. Below the 2-character ISO code for each area/country there is the TSO balance, which represent total imports and exports as sum of all aggregated border power flows from the corresponding TSO.

We show the initial results from (N-1) contingencies in Table 18, based on PSS®E analysis.

Table 18: Results from contingency (N-1) assessment– minimum load 2030

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>   RATING     FLOW       %
 162040*HMELIN21    220.00 161035 HMELIN11    400.00 2  BUS 16131                          150.0     182.8     115.8
 161035*HMELIN11    400.00 162040 HMELIN21    220.00 2  BUS 16131                          150.0     179.5     110.1
  32201 XPA_DI21    220.00 492020*DIVACA220   220.00 1  BUS 32101                          365.8     431.1     112.0

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                       Met convergence to     0    82    0.0
 BUS 16131                       Met convergence to     2     0    0.0
 BUS 32101                       Met convergence to     1     1    0.0

CONTINGENCY LEGEND:
 <----- CONTINGENCY LABEL ------>  EVENTS
 BUS 16131                      : OPEN LINE FROM BUS 16131 [XME_DI11    400.00] TO BUS 161035 [HMELIN11    400.00] CKT 1
                                  OPEN LINE FROM BUS 16131 [XME_DI11    400.00] TO BUS 491030 [DIVACA400   400.00] CKT 1
 BUS 32101                      : OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 321346 [REDIPUGLIA  400.00] CKT 1
                                  OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 491040 [PST_DIV     400.00] CKT 1
```

This shows that the Divaca (SI) tie-line – Padriciano (IT) 220 KV is overloaded around 12% when there is an outage of the 400 kV Divaca (SI) – Redipuglia (IT) tie-line. An agreement between ELES (SI) and TERNA (IT) allows that an outage of one of these tie-lines can be followed by automatic disconnection of the other, to prevent significant overloadings, which can damage the equipment.

There is one critical element in Croatia – the 400/220 kV transformer in Meline, which is overloaded around 16% during an outage of 400 kV Meline (HR) – Divaca (SI) tie-line.

Similar to the previously analyzed maximum load regime, this analysis proves that the network in SEE can fully accommodate the anticipated minimum loads, with the exception of the one local contingency listed above.

9. NETWORK ANALYSES

Network analyses results are given in this chapter. There are altogether 16 network scenarios, as given on the following figure. For easier following, scenarios with n and n-1 available network elements in the same decarbonization, hydrology and hourly regimes will be reported in the same subchapter. Therefore, we'll have 8 subchapters for 16 network scenarios.

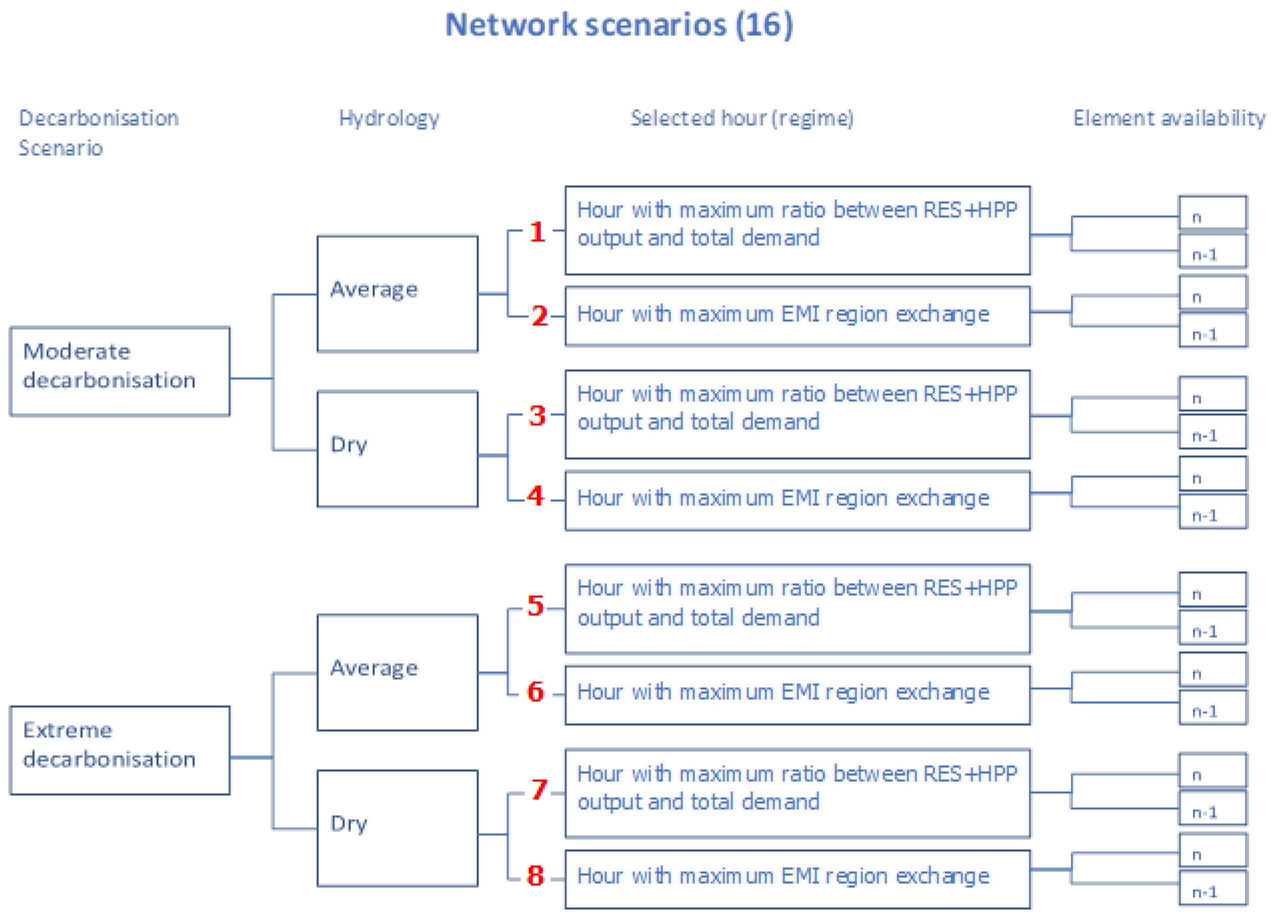


Figure 45: Network analyses scenarios for 2030

9.1. Moderate decarbonization - Average hydrology – hour with maximum ratio between RES+HPP output and total demand

As usual, we first provide regional summary report, with basic data for each area including generation, demand, losses and net interchange. We present the regional and area summaries for the first network analysis as follows:

X-- AREA --X	FROM GENE-RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	TO GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	-NET INTERCHANGE- TO TIE LINES	-NET INTERCHANGE- TO TIES + LOADS	DESIRED NET INT
10	2417.5	0.0	0.0	1121.0	0.0	0.0	5.5	0.0	51.0	1240.0	1240.0	1240.0
AL	289.4	0.0	0.0	287.4	498.7	0.0	33.0	670.9	539.0	-397.8	-397.8	
13	1533.9	0.0	0.0	1327.0	0.0	0.0	12.9	0.0	97.9	96.1	96.1	96.0
BA	311.5	0.0	0.0	188.9	0.0	0.0	131.5	1033.7	674.3	350.5	350.5	
14	3612.2	0.0	0.0	3957.2	0.5	0.0	53.2	0.0	143.3	-542.0	-542.0	-542.0
BG	1616.6	0.0	0.0	904.9	1230.8	0.0	129.1	2768.8	1692.4	428.3	428.3	
16	4021.2	0.0	0.0	2141.0	0.0	0.0	4.6	0.0	186.5	1689.1	1689.1	1689.0
HR	14.1	0.0	0.0	492.6	109.6	0.0	22.3	1544.2	1608.8	-674.9	-674.9	
30	5144.3	0.0	0.0	6751.6	0.0	0.0	0.0	0.0	182.7	-1790.0	-1790.0	-1790.0
GR	-252.3	0.0	0.0	2572.6	1998.8	0.0	22.0	7893.3	2277.6	770.0	770.0	
37	889.2	0.0	0.0	887.5	0.0	0.0	1.9	0.0	28.8	-29.0	-29.0	-29.0
MK	-74.3	0.0	0.0	153.1	0.0	0.0	8.4	489.4	271.7	-18.0	-18.0	
38	1355.9	0.0	0.0	414.0	0.0	0.0	4.5	0.0	33.4	904.0	904.0	904.0
ME	161.9	0.0	0.0	110.3	137.3	0.0	31.0	437.3	340.2	-19.7	-19.7	
44	12866.7	0.0	0.0	7813.0	0.0	0.0	88.7	0.0	301.9	4663.1	4663.1	4663.0
RO	408.4	0.0	0.0	2256.6	1759.4	0.0	253.3	4991.6	3080.6	-1949.8	-1949.8	
46	3617.9	0.0	0.0	3856.0	0.0	0.0	29.9	0.0	91.0	-359.0	-359.0	-359.0
RS	285.9	0.0	0.0	716.5	99.8	0.0	114.5	2131.6	1044.0	442.7	442.7	
47	287.4	0.0	0.0	610.0	0.0	0.0	5.1	0.0	12.3	-340.0	-340.0	-340.0
XK	111.2	0.0	0.0	204.1	0.0	0.0	15.0	268.1	114.2	46.0	46.0	
49	1620.1	0.0	0.0	2220.0	0.0	0.0	7.8	0.0	39.3	-647.0	-647.0	-647.0
SI	125.1	0.0	0.0	292.0	92.6	0.0	54.1	675.5	511.0	-149.1	-149.1	
COLUMN	37366.4	0.0	0.0	31098.3	0.5	0.0	214.1	0.0	1168.2	4885.4	4885.4	4885.0
TOTALS	2997.5	0.0	0.0	8178.8	5927.0	0.0	814.0	22904.3	12153.8	-1171.8	-1171.8	

Figure 46: Area summary report with Moderate decarbonization - Average hydrology – hour with maximum ratio between RES+HPP output and total demand 2030

In this analysis the total regional load is 31,098 MW, while total generation is 37,366 MW. Clearly, the largest net exporters in the region in this scenario are Romania (4,663 MW) and Croatia (1,689 MW), while the largest importer is Greece (-1,790 MW). It is interesting to note that this selected hour with large Croatian export is representing total annual balance, since Croatia is annual net importer. This specific hour was selected on the criteria given above.

In total, in this scenario, the EMI region has a surplus of 4,885 MW.

The following figure shows the cross-border power exchange map for this scenario with moderate decarbonization - average hydrology – the hour with the maximum ratio between RES+HPP output and total demand. This is the scenario with the greatest regional exports. Through HVDC submarine cables to Italy in this scenario, SEE is exporting 1000 MW (ME-IT) + 500 MW (GR – IT). In addition, we note significant exchange to Italy from Slovenia (789 MW), and on the other side of the region, more than 1,500 MW exported to Turkey.

Figure 47: Cross-border exchanges (MW) and directions between the countries in the scenario: Moderate decarbonization - Average hydrology – hour with maximum ratio between RES+HPP output and total demand 2030

The following two figures show the 400 kV and 220 kV voltage profiles with maximum, minimum and average values in each country. All voltages in 400 kV network in the aforementioned categories are within limits save for Romania where the minimum value is below the allowed threshold.

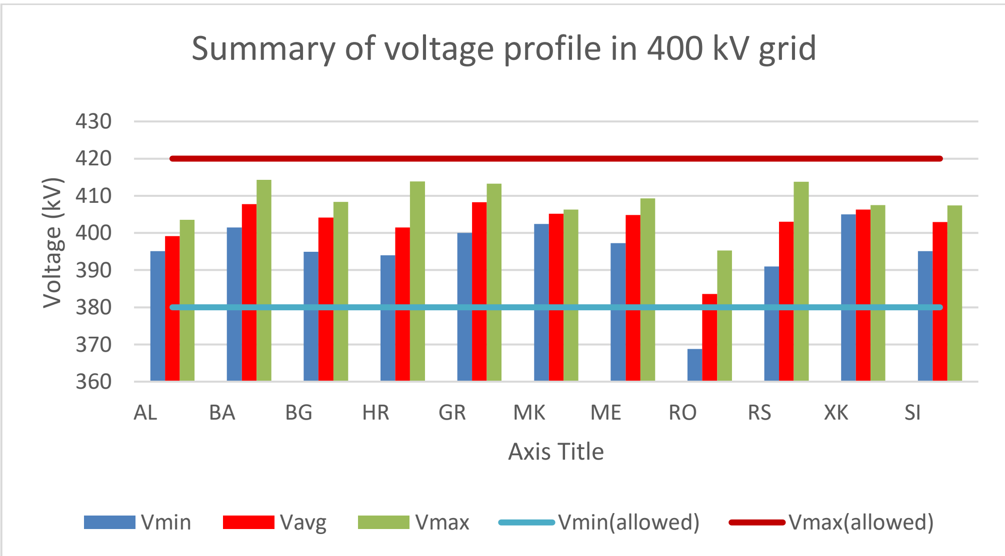


Figure 48: 400 kV voltage profiles (minimum, maximum and average) per country in this scenario (Moderate decarbonization - Average hydrology – hour with maximum ratio between RES+HPP output and total demand) 2030

Voltage profiles in the 220 kV network are also within limits in all countries in this scenario, with the exception of Croatia, where the south wing of the network (SS Plat 220 kV), as usual suffers from high voltage.

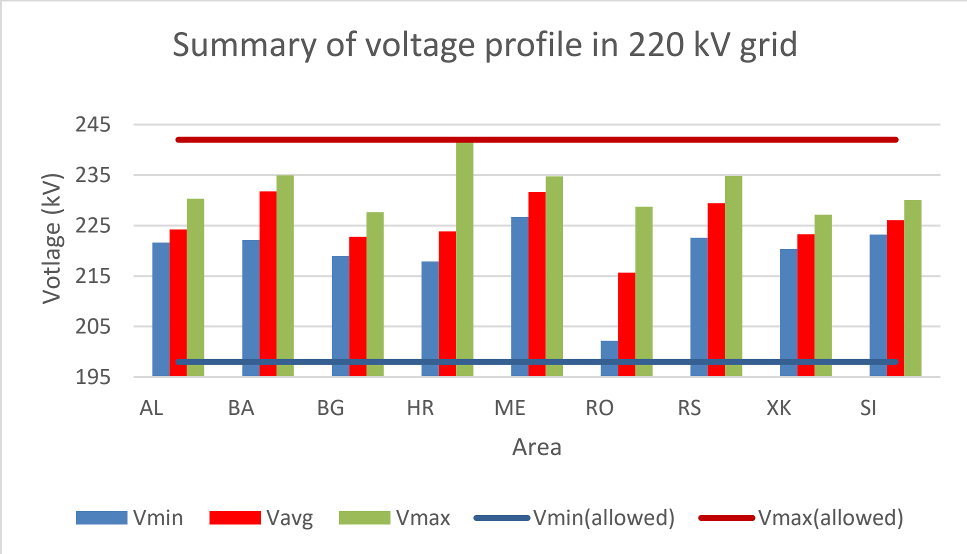


Figure 49: 220 kV voltage profiles (minimum, maximum and average) per country in this scenario (Moderate decarbonization - Average hydrology – hour with maximum ratio between RES+HPP output and total demand) 2030

In this scenario there are just four 400 kV and 220 kV network elements loaded more than 80%, as given in the following table:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	CKT	MW	MVAR	MVA	RATING	%I	MW LOSS	MVAR LOSS
14122	[XKO_TI11 400,00]	141000	[VAEC_41 400,00]	1	947,01	-412,85	1033,09	1109	**93,99**	2,82	27,94
38030	[XVI_LA1M 400,00]	381030	[0LASTV11 400,00]	1	-1000	-50	1001,25	1108,5	**90,94**	0	0
137230	[WPOSUS22 220,00]	133220	[WRPJAB2 220,00]	1	268,58	-77,68	279,59	301	**89,54**	6,56	34,26
448055	[RSLATI2A 220,00]	448056	[RGRADI2 220,00]	1	-330,74	51,99	334,8	351,4	**100,46**	2,14	12,65

Figure 50: List of 400 and 220 kV elements loaded more than 80% in this scenario (Moderate decarbonization - Average hydrology – hour with maximum ratio between RES+HPP output and total demand) 2030

The contingency n-1 analysis report for this scenario is as follows:

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING    FLOW      %
 448055 RSLATI2A     220.00 448056*RGRADI2      220.00 1  BASE CASE                        351.4    335.9    100.7
 102010 AVDEJA2      220.00 102012*AVDJRI2      220.00 1  SINGLE 102005-102012(1)          325.4    345.6    104.4
 161025*HKONJS11     400.00 3WNDTR KONJSKO AT1   WND 1 1  SINGLE 133220-137230(1)          400.0    400.9    101.5
 161025*HKONJS11     400.00 3WNDTR KONJSKO AT2   WND 1 2  SINGLE 133220-137230(1)          400.0    400.9    101.5
 133220 WRPJAB2      220.00 137230*WPOSUS22     220.00 1  SINGLE 161000-161060(1)          301.0    323.7    104.5
 133220 WRPJAB2      220.00 137230*WPOSUS22     220.00 1  SINGLE 161025-162030-166283(1)   301.0    314.0    101.0
 161025*HKONJS11     400.00 3WNDTR KONJSKO AT2   WND 1 2  SINGLE 161025-162030-166283(1)   400.0    507.2    127.3
 162030*HKONJS21     220.00 3WNDTR KONJSKO AT2   WND 2 2  SINGLE 161025-162030-166283(1)   400.0    491.4    121.2
 133220 WRPJAB2      220.00 137230*WPOSUS22     220.00 1  SINGLE 161025-162030-166290(2)   301.0    314.0    101.0
 161025*HKONJS11     400.00 3WNDTR KONJSKO AT1   WND 1 1  SINGLE 161025-162030-166290(2)   400.0    507.2    127.3
 162030*HKONJS21     220.00 3WNDTR KONJSKO AT1   WND 2 1  SINGLE 161025-162030-166290(2)   400.0    491.4    121.2
 133220 WRPJAB2      220.00 137230*WPOSUS22     220.00 1  SINGLE 162025-162030(1)          301.0    347.8    111.5
 448057*RCRAIO2A     220.00 448060 RISALN2A     220.00 1  SINGLE 448055-448056(1)          351.4    358.6    106.6
 448058*RCRAIO2B     220.00 448060 RISALN2A     220.00 1  SINGLE 448055-448056(1)          351.4    367.1    109.2
 448056*RGRADI2      220.00 448060 RISALN2A     220.00 1  SINGLE 448055-448058(1)          351.4    513.4    155.7
 448057*RCRAIO2A     220.00 448060 RISALN2A     220.00 1  SINGLE 448056-448060(1)          351.4    345.4    102.3
 448058*RCRAIO2B     220.00 448060 RISALN2A     220.00 1  SINGLE 448056-448060(1)          351.4    353.5    104.7
 448058 RCRAIO2B     220.00 448060*RISALN2A     220.00 1  SINGLE 448057-448058(1)          351.4    419.1    123.4
 448058*RCRAIO2B     220.00 448060 RISALN2A     220.00 1  SINGLE 448057-448060(1)          351.4    414.9    123.1
 448057*RCRAIO2A     220.00 448060 RISALN2A     220.00 1  SINGLE 448058-448060(1)          351.4    413.6    122.7
  14122*XKO_TI11     400.00 141000 VAEC_41      400.00 1  SINGLE 448973-448974(1)         1109.0   1122.6    102.7
  14122*XKO_TI11     400.00 141000 VAEC_41      400.00 1  SINGLE 460010-460015(1)         1109.0   1155.5    106.0
  14122*XKO_TI11     400.00 141000 VAEC_41      400.00 1  SINGLE 460010-460040(1)         1109.0   1170.5    107.2
 133220 WRPJAB2      220.00 137230*WPOSUS22     220.00 1  BUS 13101                        301.0    357.9    115.4
  14122*XKO_TI11     400.00 141000 VAEC_41      400.00 1  BUS 14121                       1109.0   1156.0    106.3
  14124*XVA_MG11     400.00 141115 VVARNA1      400.00 1  BUS 14121                       1380.0   1471.3    112.2
  14121*XDO_MG11     400.00 141035 VDOBRU1      400.00 1  BUS 14124                       1380.0   1395.4    106.6
  14122*XKO_TI11     400.00 141000 VAEC_41      400.00 1  BUS 14124                       1109.0   1193.5    110.1
  14141 XMI_HA11     400.00 141055*VMAIZ31      400.00 1  BUS 14142                       1200.0   1255.5    103.1
  16231 XPE_DI21     220.00 162050*HPEHLI21     220.00 1  BUS 16131                        365.8    373.0    102.1
  16231*XPE_DI21     220.00 492020 DIVACA220    220.00 1  BUS 16131                        365.8    372.9    101.9
 161035*HMELIN11     400.00 3WNDTR MELINA TR2    WND 1 2  BUS 16131                        150.0    227.4    155.3
 162040*HMELIN21     220.00 3WNDTR MELINA TR2    WND 2 2  BUS 16131                        150.0    222.7    147.7
  16231 XPE_DI21     220.00 162050*HPEHLI21     220.00 1  BUS 32101                        365.8    382.7    104.3
  16231*XPE_DI21     220.00 492020 DIVACA220    220.00 1  BUS 32101                        365.8    381.2    104.2
  32201 XPA_DI21     220.00 492020*DIVACA220    220.00 1  BUS 32101                        365.8    601.9    163.8
 161035*HMELIN11     400.00 3WNDTR MELINA TR2    WND 1 2  BUS 32101                        150.0    156.8    106.2
 162040*HMELIN21     220.00 3WNDTR MELINA TR2    WND 2 2  BUS 32101                        150.0    152.9    101.0
  14122*XKO_TI11     400.00 141000 VAEC_41      400.00 1  BUS 44101                       1109.0   1184.7    108.8

 LOSS OF LOAD REPORT:
 <-------- B U S --------> <----- CONTINGENCY LABEL ------> LOAD(MW)

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                       Met convergence to     1    14    0.0
 SINGLE 102005-102012(1)         Met convergence to     1     0    0.0
 SINGLE 133220-137230(1)         Met convergence to     2     0    0.0
 SINGLE 161000-161060(1)         Met convergence to     1     0    0.0
 SINGLE 161025-162030-166283(1)  Met convergence to     3     0    0.0
 SINGLE 161025-162030-166290(2)  Met convergence to     3     0    0.0
 SINGLE 162025-162030(1)         Met convergence to     1     0    0.0
 SINGLE 448055-448056(1)         Met convergence to     3     1    0.0
 SINGLE 448055-448058(1)         Met convergence to     1     2    0.0
 SINGLE 448056-448060(1)         Met convergence to     3     0    0.0
 SINGLE 448057-448058(1)         Met convergence to     1     0    0.0
 SINGLE 448057-448060(1)         Met convergence to     1     0    0.0
 SINGLE 448058-448060(1)         Met convergence to     2     0    0.0
 SINGLE 448973-448974(1)         Met convergence to     1     3    0.0
 SINGLE 460010-460015(1)         Met convergence to     1     2    0.0
 SINGLE 460010-460040(1)         Met convergence to     1     2    0.0
 BUS 13101                       Met convergence to     1     0    0.0
 BUS 14121                       Met convergence to     2     3    0.0
 BUS 14124                       Met convergence to     2     3    0.0
 BUS 14142                       Met convergence to     1     0    0.0
 BUS 16131                       Met convergence to     4     0    0.0
 BUS 32101                       Met convergence to     5     0    0.0
 BUS 44101                       Met convergence to     1     3    0.0
 IT-SI BOTH LINES                Blown up              --    --     --

CONTINGENCY LEGEND: from list of total 793 analyzed contingencies)
 (selected 22 contingecies (1 contingencies with convergence problems not included) appeared above)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 102005-102012(1)         : OPEN LINE FROM BUS 102005 [AKOMAN2     220.00] TO BUS 102012 [AVDJRI2     220.00] CKT 1
 SINGLE 133220-137230(1)         : OPEN LINE FROM BUS 133220 [WRPJAB2     220.00] TO BUS 137230 [WPOSUS22    220.00] CKT 1
 SINGLE 161000-161060(1)         : OPEN LINE FROM BUS 161000 [HLIKA 11    400.00] TO BUS 161060 [HVELEB12    400.00] CKT 1
 SINGLE 161025-162030-166283(1)  : OPEN LINE FROM BUS 161025 [HKONJS11    400.00] TO BUS 162030 [HKONJS21    220.00] TO BUS
166283 [HKONJS_1     30.000] CKT 1
 SINGLE 161025-162030-166290(2)  : OPEN LINE FROM BUS 161025 [HKONJS11    400.00] TO BUS 162030 [HKONJS21    220.00] TO BUS
166290 [HKONJS_2     30.000] CKT 2
 SINGLE 162025-162030(1)         : OPEN LINE FROM BUS 162025 [HEZAKU22    220.00] TO BUS 162030 [HKONJS21    220.00] CKT 1
 SINGLE 448055-448056(1)         : OPEN LINE FROM BUS 448055 [RSLATI2A    220.00] TO BUS 448056 [RGRADI2     220.00] CKT 1
```

```
SINGLE 448055-448058(1)        : OPEN LINE FROM BUS 448055 [RSLATI2A    220.00] TO BUS 448058 [RCRAIO2B    220.00] CKT 1
SINGLE 448056-448060(1)        : OPEN LINE FROM BUS 448056 [RGRADI2     220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
SINGLE 448057-448058(1)        : OPEN LINE FROM BUS 448057 [RCRAIO2A    220.00] TO BUS 448058 [RCRAIO2B    220.00] CKT 1
SINGLE 448057-448060(1)        : OPEN LINE FROM BUS 448057 [RCRAIO2A    220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
SINGLE 448058-448060(1)        : OPEN LINE FROM BUS 448058 [RCRAIO2B    220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
SINGLE 448973-448974(1)        : OPEN LINE FROM BUS 448973 [RCERNA1     400.00] TO BUS 448974 [RMEDGI1     400.00] CKT 1
SINGLE 460010-460015(1)        : OPEN LINE FROM BUS 460010 [JBOR 21     400.00] TO BUS 460015 [JHDJE111    400.00] CKT 1
SINGLE 460010-460040(1)        : OPEN LINE FROM BUS 460010 [JBOR 21     400.00] TO BUS 460040 [JNIS2 11    400.00] CKT 1
BUS 13101                      : OPEN LINE FROM BUS 13101 [XMO_KO11    400.00] TO BUS 137100 [WMOST41     400.00] CKT 1
                                 OPEN LINE FROM BUS 13101 [XMO_KO11    400.00] TO BUS 161025 [HKONJS11    400.00] CKT 1
BUS 14121                      : OPEN LINE FROM BUS 14121 [XDO_MG11    400.00] TO BUS 141035 [VDOBRU1     400.00] CKT 1
                                 OPEN LINE FROM BUS 14121 [XDO_MG11    400.00] TO BUS 448974 [RMEDGI1     400.00] CKT 1
BUS 14124                      : OPEN LINE FROM BUS 14124 [XVA_MG11    400.00] TO BUS 141115 [VVARNA1     400.00] CKT 1
                                 OPEN LINE FROM BUS 14124 [XVA_MG11    400.00] TO BUS 448974 [RMEDGI1     400.00] CKT 1
BUS 14142                      : OPEN LINE FROM BUS 14142 [XMI_HA12    400.00] TO BUS 141055 [VMAIZ31     400.00] CKT 1
                                 OPEN LINE FROM BUS 14142 [XMI_HA12    400.00] TO BUS 540004 [4HAMITABAT  400.00] CKT 1
BUS 16131                      : OPEN LINE FROM BUS 16131 [XME_DI11    400.00] TO BUS 161035 [HMELIN11    400.00] CKT 1
                                 OPEN LINE FROM BUS 16131 [XME_DI11    400.00] TO BUS 491030 [DIVACA400   400.00] CKT 1
BUS 32101                      : OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 321346 [REDIPUGLIA  400.00] CKT 1
                                 OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 491040 [PST_DIV     400.00] CKT 1
BUS 44101                      : OPEN LINE FROM BUS 44101 [XPF_DJ11    400.00] TO BUS 448004 [RP.D.F1     400.00] CKT 1
                                 OPEN LINE FROM BUS 44101 [XPF_DJ11    400.00] TO BUS 460015 [JHDJE111    400.00] CKT 2
```

Figure 51: Contingency (n-1) analysis report for this scenario in 2030

In this scenario there are 22 contingency events. There are three cases with overloading higher than 130% (given above in red and here treated as severe). These network elements are candidates for further assessment to consider what adjustment if any may be advisable (e.g., redispatch, line upgrade, new line, storage, etc.). However, it is beyond the scope of this study to analyze the solution for every single contingency listed above. Here we detect all potential network issues in the decarbonization process.

9.2. Moderate decarbonization - Average hydrology – maximum EMI regional electricity exchange

The regional and area summaries for the second set of network scenario (moderate decarbonization - average hydrology – maximum EMI regional electricity exchange) are given as follows:

X-- AREA --X	FROM AT AREA BUSES GENE-RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	TO GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	NET INTERCHANGE TO TIE LINES	NET INTERCHANGE TO TIES + LOADS	DESIRED NET INT
10	1067.8	0.0	0.0	1066.0	0.0	0.0	5.2	0.0	46.6	-50.0	-50.0	-50.0
AL	172.9	0.0	0.0	273.3	646.4	0.0	31.2	638.9	424.7	-563.8	-563.8	
13	812.5	0.0	0.0	1145.0	0.0	0.0	13.1	0.0	31.5	-377.1	-377.1	-377.0
BA	-36.2	0.0	0.0	186.5	0.0	0.0	133.9	1079.8	283.0	440.1	440.1	
14	2239.8	0.0	0.0	3757.7	0.5	0.0	54.7	0.0	67.8	-1641.0	-1641.0	-1641.0
BG	1246.6	0.0	0.0	848.3	1292.9	0.0	129.2	2901.2	731.5	1146.0	1146.0	
16	623.9	0.0	0.0	1530.0	0.0	0.0	5.1	0.0	64.0	-975.2	-975.2	-975.0
HR	-222.0	0.0	0.0	352.0	109.4	0.0	24.5	1687.6	547.6	432.0	432.0	
30	2610.2	0.0	0.0	6007.4	0.0	0.0	0.0	0.0	145.8	-3543.0	-3543.0	-3543.0
GR	-525.8	0.0	0.0	2597.5	1994.6	0.0	19.0	7917.3	2064.5	715.9	715.9	
37	725.4	0.0	0.0	853.0	0.0	0.0	2.0	0.0	20.3	-150.0	-150.0	-150.0
MK	25.4	0.0	0.0	157.6	0.0	0.0	9.7	490.4	253.1	95.4	95.4	
38	195.6	0.0	0.0	368.0	0.0	0.0	3.2	0.0	33.4	-209.1	-209.1	-209.0
ME	4.5	0.0	0.0	109.9	139.7	0.0	24.3	430.9	311.6	-150.1	-150.1	
44	7325.2	0.0	0.0	6322.0	0.0	0.0	93.3	0.0	171.7	738.2	738.2	738.0
RO	-717.1	0.0	0.0	1846.6	1854.3	0.0	266.9	5273.8	1637.5	-1048.8	-1048.8	
46	1953.9	0.0	0.0	3295.0	0.0	0.0	28.2	0.0	110.5	-1479.8	-1479.8	-1480.0
RS	-86.5	0.0	0.0	711.7	99.6	0.0	107.7	2098.2	1137.7	-45.0	-45.0	
47	220.8	0.0	0.0	475.0	0.0	0.0	5.0	0.0	11.8	-271.0	-271.0	-271.0
XK	131.1	0.0	0.0	159.7	0.0	0.0	14.6	260.6	128.7	88.8	88.8	
49	1684.6	0.0	0.0	2113.0	0.0	0.0	8.2	0.0	26.5	-463.1	-463.1	-463.0
SI	-148.5	0.0	0.0	277.9	96.1	0.0	56.5	707.0	299.7	-171.8	-171.8	
COLUMN	19459.7	0.0	0.0	26932.0	0.5	0.0	218.1	0.0	729.9	-8420.9	-8420.9	-8421.0
TOTALS	-155.7	0.0	0.0	7521.2	6233.1	0.0	817.6	23485.6	7819.6	938.5	938.5	

Figure 52: Area summary report Moderate decarbonization - Average hydrology – maximum EMI regional electricity exchange 2030

In this scenario, the total regional load is 26,932 MW, while total generation is 19,459 MW. All areas in the region are importers, while the largest importer is Greece (-3,543 MW). In total, in this scenario with maximum EMI regional electricity exchange, the EMI region has a deficit of 8,421 MW.

The following figure shows the cross-border power exchange map for this scenario, with moderate decarbonization - average hydrology – for the hour with the maximum ratio between RES+HPP output and total demand. This is the scenario with the greatest regional exchange (import). Through the HVDC submarine cables to Italy in this scenario, SEE is exporting 1000 MW (ME-IT) + 500 MW (GR – IT). In addition, there is significant exchange from Austria to Slovenia (1007 MW), and on the other side of the region, more than 1,000 MW imported from Turkey.

Figure 53: Cross-border exchanges (MW) and directions between the countries in the scenario: Moderate decarbonization - Average hydrology – maximum EMI regional electricity exchange 2030

The following two figures show the 400 kV and 220 kV voltage profiles with the maximum, minimum and average values in each country. All voltages in 400 kV network in the aforementioned categories are within limits, except for Croatia, where the maximum value in 2030 is above the allowed threshold.

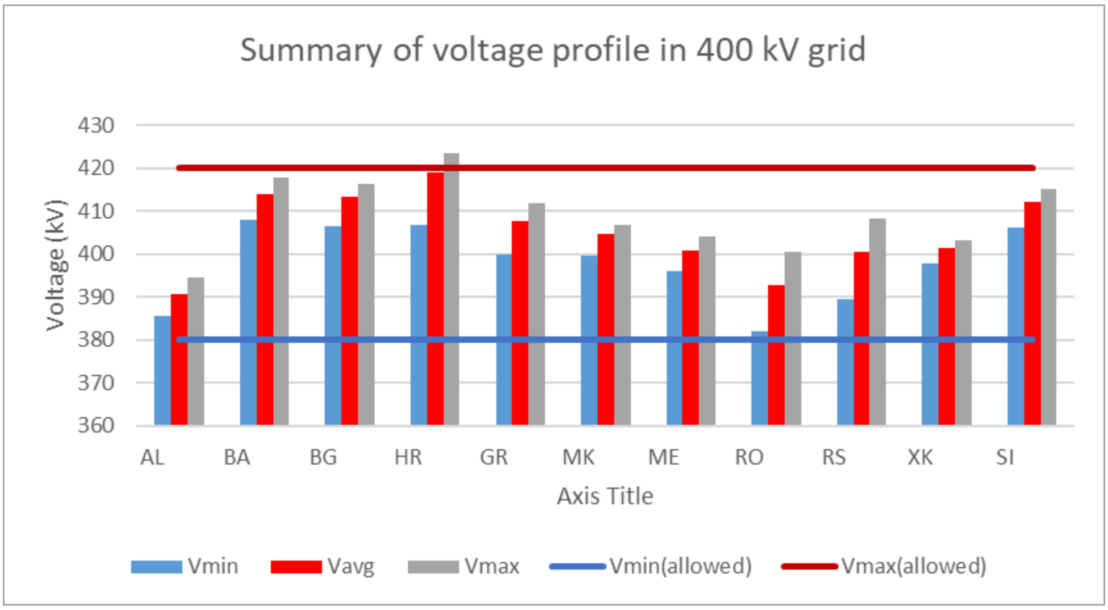


Figure 54: 400 kV voltage profiles (minimum, maximum and average) per country in this scenario (Moderate decarbonization - Average hydrology – maximum EMI regional electricity exchange) 2030

The voltage profiles in the 220 kV network are mainly within limits in all countries in this scenario, except for BiH and Croatia, where the south wing of the network, as usual, suffers from high voltage.

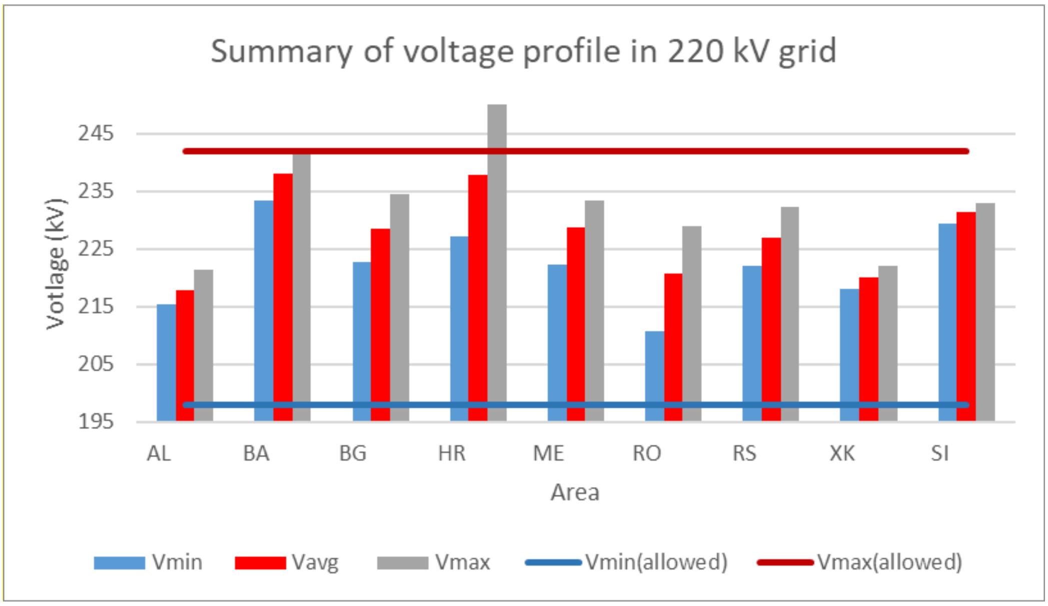


Figure 55: 220 kV voltage profiles (minimum, maximum and average) per country in this scenario (Moderate decarbonization - Average hydrology – maximum EMI regional electricity exchange) in 2030

There are three 400 kV and 220 kV elements that are loaded more than 80%, as follows:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	CKT	MW	MVAR	MVA	RATING	%I	MW LOSS	MVAR LOSS
10210	[XKO_PO21 220,00]	102015	[AKOPLI2 220,00]	1	222,75	1,08	222,76	274,4	81	1,38	7,15
10210	[XKO_PO21 220,00]	382030	[0PODG121 220,00]	1	-222,75	-1,08	222,76	274,4	81	1,71	9,35
38030	[XVI_LA1M 400,00]	381030	[0LASTV11 400,00]	1	1000	-50	1001,25	1108,5	90,16	0	0

Figure 56: List of 400 and 220 kV elements loaded more than 80% in this scenario (Moderate decarbonization - Average hydrology – maximum EMI regional electricity exchange) in 2030

The contingency n-1 analysis report for this scenario is given as follows:

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>   RATING    FLOW      %
 13222 XTR_PE21    220.00 382000*0HPERU21    220.00 1  SINGLE 381030-381060(A)          274.4    291.4    105.2
 382000 0HPERU21    220.00 382030*0PODG121    220.00 1  SINGLE 381030-381060(A)          274.4    275.3    102.0
  10210*XKO_PO21    220.00 102015 AKOPLI2     220.00 1  BUS 10110                        274.4    416.6    153.9
  10210*XKO_PO21    220.00 382030 0PODG121    220.00 1  BUS 10110                        274.4    416.6    153.9
 102010 AVDEJA2     220.00 102015*AKOPLI2     220.00 1  BUS 10110                        278.2    405.2    148.9
  16102*XER_PE12    400.00 161015 HERNES11    400.00 2  BUS 16101                       1330.2   1435.6    107.2
  16102 XER_PE12    400.00 311181*MPECSO11    400.00 2  BUS 16101                       1385.6   1448.2    102.9
  16101*XER_PE11    400.00 161015 HERNES11    400.00 1  BUS 16102                       1330.2   1435.6    107.2
  16101 XER_PE11    400.00 311181*MPECSO11    400.00 1  BUS 16102                       1385.6   1448.2    102.9

 LOSS OF LOAD REPORT:
 <-------- B U S --------> <----- CONTINGENCY LABEL ------> LOAD(MW)

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                       Met convergence to     0     1    0.0
 SINGLE 381030-381060(A)         Met convergence to     2     1    0.0
 BUS 10110                       Met convergence to     3     1    0.0
 BUS 16101                       Met convergence to     2     0    0.0
 BUS 16102                       Met convergence to     2     0    0.0

CONTINGENCY LEGEND: from list of total 791 analyzed contingencies)
 (selected 4 contingecies appeared above)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 381030-381060(A)         : OPEN LINE FROM BUS 381030 [0LASTV11    400.00] TO BUS 381060 [0PODG211    400.00] CKT A
 BUS 10110                       : OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 101005 [AVDJRI1     400.00] CKT 1
                                   OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 381060 [0PODG211    400.00] CKT 1
 BUS 16101                       : OPEN LINE FROM BUS 16101 [XER_PE11    400.00] TO BUS 161015 [HERNES11    400.00] CKT 1
                                   OPEN LINE FROM BUS 16101 [XER_PE11    400.00] TO BUS 311181 [MPECSO11    400.00] CKT 1
 BUS 16102                       : OPEN LINE FROM BUS 16102 [XER_PE12    400.00] TO BUS 161015 [HERNES11    400.00] CKT 2
                                   OPEN LINE FROM BUS 16102 [XER_PE12    400.00] TO BUS 311181 [MPECSO11    400.00] CKT 2
```

Figure 57: Contingency (n-1) analysis report for Moderate decarbonization - Average hydrology – maximum EMI regional electricity exchange in 2030

In this scenario there are 4 contingency events that provoke overloading in the network. There are three cases with overloading higher than 130% (given above in red), which would be candidates for further analysis to determine how or whether to resolve these situations (e.g., with upgrades, redispatching, storage, etc.)

9.3. Moderate decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand

The next set of scenarios assumes moderate decarbonization - dry hydrology – maximum ratio between RES+HPP output and total demand. The regional and area summaries for this third set of network scenario are as follows:

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
10	568.9	0.0	0.0	1080.0	0.0	0.0	5.3	0.0	23.6	-540.0	-540.0	-540.0
AL	44.3	0.0	0.0	276.9	485.5	0.0	31.6	646.2	213.0	-316.5	-316.5	
13	886.4	0.0	0.0	1502.0	0.0	0.0	12.6	0.0	46.9	-675.0	-675.0	-675.0
BA	44.3	0.0	0.0	191.0	0.0	0.0	128.4	1045.6	355.6	414.8	414.8	
14	3745.3	0.0	0.0	3905.7	0.5	0.0	54.6	0.0	99.4	-315.0	-315.0	-315.0
BG	1566.6	0.0	0.0	895.3	1263.6	0.0	132.4	2829.0	1244.8	859.5	859.5	
16	2093.1	0.0	0.0	2200.0	0.0	0.0	4.7	0.0	84.4	-196.1	-196.1	-196.0
HR	-347.4	0.0	0.0	506.2	110.8	0.0	23.1	1604.5	643.0	-25.9	-25.9	
30	7003.2	0.0	0.0	8135.6	0.0	0.0	0.0	0.0	322.5	-1455.0	-1455.0	-1455.0
GR	-90.4	0.0	0.0	2295.2	1844.9	0.0	18.2	7389.0	2800.4	339.9	339.9	
37	958.0	0.0	0.0	915.0	0.0	0.0	2.0	0.0	10.0	31.0	31.0	31.0
MK	-67.4	0.0	0.0	157.6	0.0	0.0	9.6	487.3	162.5	90.3	90.3	
38	323.9	0.0	0.0	465.0	0.0	0.0	3.2	0.0	34.7	-179.1	-179.1	-179.0
ME	5.7	0.0	0.0	110.3	137.5	0.0	24.1	426.8	293.2	-132.7	-132.7	
44	10125.9	0.0	0.0	7476.0	0.0	0.0	87.4	0.0	237.5	2325.0	2325.0	2325.0
RO	82.9	0.0	0.0	2163.9	1744.8	0.0	249.3	4926.8	2545.8	-1694.0	-1694.0	
46	4572.5	0.0	0.0	4169.9	0.0	0.0	29.1	0.0	93.6	279.9	279.9	280.0
RS	-0.1	0.0	0.0	783.5	100.0	0.0	123.4	2127.8	1095.2	25.5	25.5	
47	330.9	0.0	0.0	756.0	0.0	0.0	4.9	0.0	9.0	-439.0	-439.0	-439.0
XK	140.4	0.0	0.0	252.0	0.0	0.0	14.5	259.6	108.5	25.1	25.1	
49	2459.3	0.0	0.0	2167.0	0.0	0.0	8.0	0.0	17.3	267.0	267.0	267.0
SI	-251.8	0.0	0.0	285.0	94.7	0.0	55.4	692.6	208.8	-203.2	-203.2	
COLUMN	33067.4	0.0	0.0	32772.3	0.5	0.0	211.9	0.0	979.0	-896.3	-896.3	-896.0
TOTALS	1126.9	0.0	0.0	7916.9	5781.7	0.0	809.8	22435.1	9670.8	-617.1	-617.1	

Figure 58: Area summary report for Moderate decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand 2030

In this scenario, the total regional load is 32,772 MW, while total generation is 33,067 MW. The largest regional importer is again Greece (-1,455 MW), while the largest exporter is Romania (2.325 MW). In total, in this scenario, the EMI region has a deficit of just 896 MW.

The following figure shows the cross-border power exchange map for this scenario with moderate decarbonization - average hydrology – for the hour with the maximum ratio between RES+HPP output and total demand. This is the scenario with quite low regional imports - only 896 MW. Through HVDC submarine cables to Italy in this scenario, SEE exports 1000 MW (ME-IT) + 500 MW (GR – IT). In addition, we note significant exports to Turkey, of more than 1,500 MW.

Figure 59: Cross-border exchanges (MW) and directions between the countries in the scenario: Moderate decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand 2030

The following two figures show the 400 kV and 220 kV voltage profiles with maximum, minimum and average values in each country. All voltages in 400 kV network in the aforementioned categories are within limits, except for Romania, where the minimum value is below the allowed threshold.

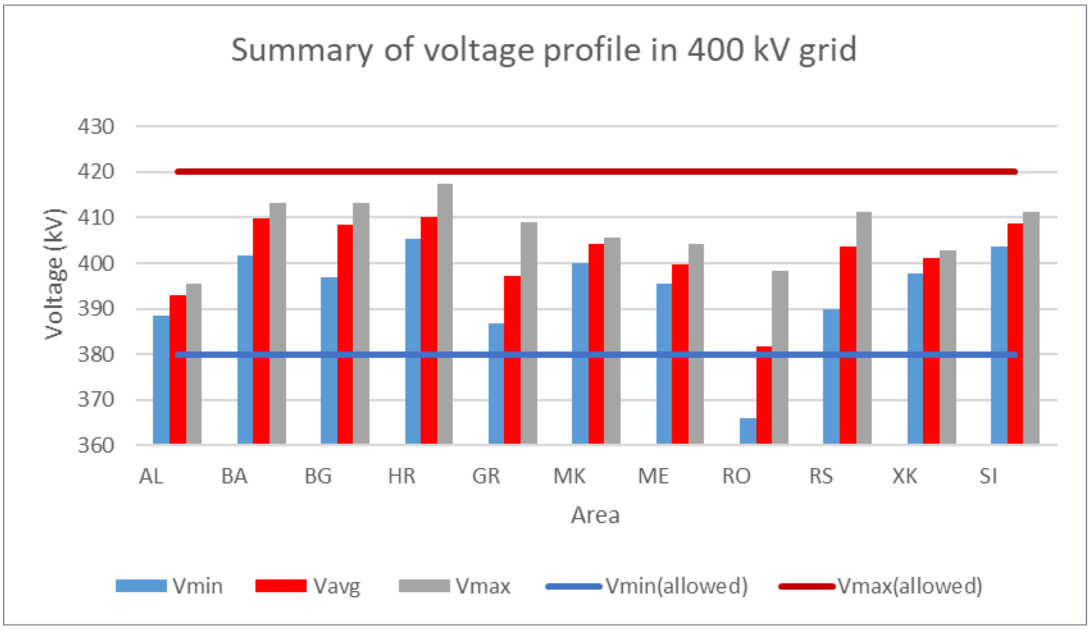


Figure 60: 400 kV voltage profiles (minimum, maximum and average) per country in this scenario (Moderate decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand) 2030

Voltage profiles in the 220 kV network are now also within limits in all countries.

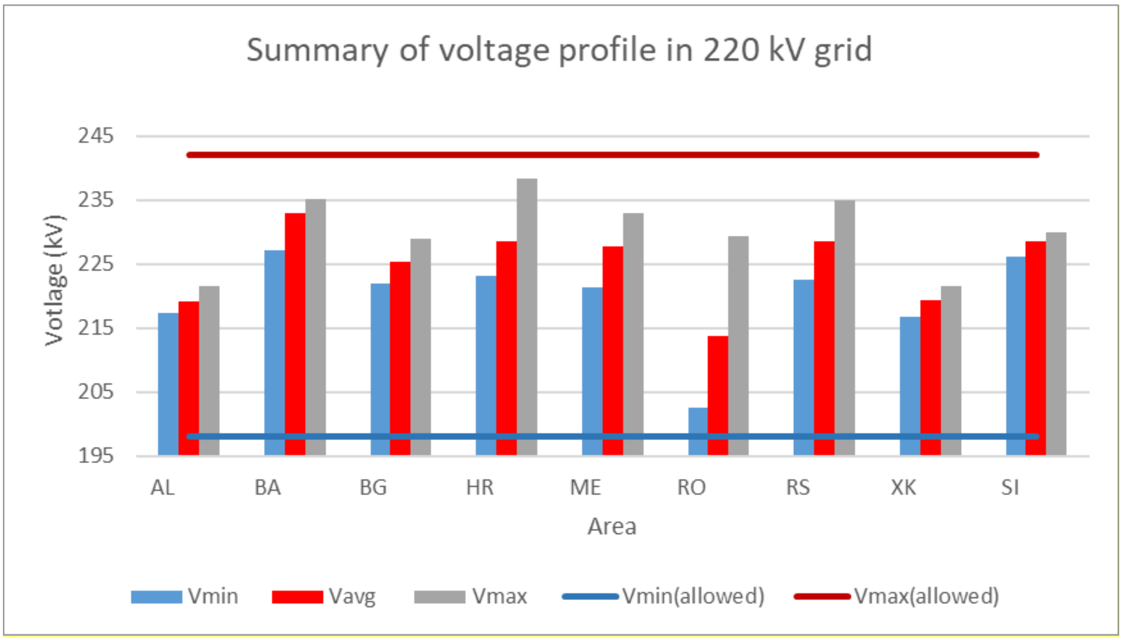


Figure 61: 220 kV voltage profiles (minimum, maximum and average) per country in this scenario (Moderate decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand) 2030

In this scenario there is just one transmission element loaded more than 80%:

FRM BUS	FROM BU SEXNAME	TO BUS	TO BUS EXNAME	CKT	MW	MVAR	MVA	RATING	%I	MW LOSS	MVAR LOSS
38030	[XVI_LA1M 400,00]	381030	[0LASTV11 400,00]	1	1000	-50	1001,25	1108,5	90,89	0	0

Figure 62: List of 400 and 220 kV elements loaded more than 80% in this scenario (Moderate decarbonization - Average hydrology – hour with maximum ratio between RES+HPP output and total demand) 2030

The contingency n-1 analysis report for this scenario is given as follows:

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING    FLOW      %
 10210*XKO_PO21    220.00 102015 AKOPLI2     220.00 1  BUS 10110                          274.4    375.3    138.6
 10210 XKO_PO21    220.00 382030*0PODG121    220.00 1  BUS 10110                          274.4    379.1    138.7
 102010 AVDEJA2     220.00 102015*AKOPLI2     220.00 1  BUS 10110                          278.2    368.7    134.9

 LOSS OF LOAD REPORT:
 <-------- B U S --------> <----- CONTINGENCY LABEL ------> LOAD(MW)

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                       Met convergence to     0    19    0.0
 BUS 10110                       Met convergence to     3     3    0.0

CONTINGENCY LEGEND: from list of total 791 analyzed contingencies)
 (selected 1 contingecies appeared above)
 <----- CONTINGENCY LABEL ------>  EVENTS
 BUS 10110                      : OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 101005 [AVDJRI1     400.00] CKT 1
                                  OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 381060 [0PODG211    400.00] CKT 1
```

Figure 63: Contingency (n-1) analysis report for this scenario 2030

In this scenario there is just 1 contingency event that provoke overloading in the network, where all three overloadings are higher than 130% (given above in red). These situations are candidates for further analysis to determine how or whether to resolve them (e.g., with upgrades, new lines, redispatching, storage, etc.)

9.4. Moderate decarbonization - Dry hydrology – maximum EMI regional electricity exchange

The following set of scenarios assume moderate decarbonization - dry hydrology – maximum EMI regional electricity exchange. Regional and area summaries for the fourth set of network scenario are given as follows:

	FROM ------AT AREA BUSES-------				TO				-NET INTERCHANGE-			
X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	1771.7	0.0	0.0	1870.0	0.0	0.0	5.2	0.0	73.6	-177.2	-177.2	-177.0
AL	698.7	0.0	0.0	479.5	485.0	0.0	31.1	637.3	709.1	-368.7	-368.7	
13	3123.6	0.0	0.0	2168.0	0.0	0.0	14.9	0.0	63.0	877.7	877.7	878.0
BA	719.2	0.0	0.0	424.5	0.0	0.0	151.5	1062.8	771.9	434.2	434.2	
14	3721.0	0.0	0.0	5200.0	0.0	0.0	51.8	0.0	169.0	-1699.8	-1699.8	-1700.0
BG	1526.2	0.0	0.0	1884.5	75.8	0.0	121.4	2630.2	2068.4	6.3	6.3	
16	1596.5	0.0	0.0	2616.0	0.0	0.0	4.8	0.0	72.3	-1096.6	-1096.6	-1096.0
HR	-288.1	0.0	0.0	601.9	107.4	0.0	23.5	1629.6	597.5	11.3	11.3	
30	8824.8	0.0	0.0	8796.6	0.0	0.0	0.0	0.0	187.3	-159.0	-159.0	-159.0
GR	-433.7	0.0	0.0	2179.3	2186.5	0.0	21.6	8265.7	2679.2	765.4	765.4	
37	1074.4	0.0	0.0	1465.0	0.0	0.0	2.0	0.0	24.4	-417.0	-417.0	-417.0
MK	375.6	0.0	0.0	468.1	0.0	0.0	9.6	485.7	293.4	90.2	90.2	
38	268.7	0.0	0.0	830.0	0.0	0.0	3.1	0.0	52.9	-617.3	-617.3	-617.0
ME	110.6	0.0	0.0	240.7	66.5	0.0	22.8	420.2	486.7	-286.0	-286.0	
44	8778.2	0.0	0.0	8900.0	0.0	0.0	91.7	0.0	197.8	-411.3	-411.3	-411.0
RO	784.5	0.0	0.0	2555.4	1820.9	0.0	262.4	5179.4	2455.5	-1130.3	-1130.3	
46	5354.2	0.0	0.0	6158.3	0.0	0.0	32.9	0.0	155.8	-992.8	-992.8	-992.0
RS	1982.6	0.0	0.0	1452.1	0.0	0.0	181.6	2119.5	1932.4	535.9	535.9	
47	644.7	0.0	0.0	1215.0	0.0	0.0	4.7	0.0	26.1	-601.1	-601.1	-601.0
XK	382.4	0.0	0.0	402.9	0.0	0.0	13.9	252.4	331.8	-113.8	-113.8	
49	1819.8	0.0	0.0	2210.0	0.0	0.0	8.0	0.0	33.9	-432.1	-432.1	-432.0
SI	6.5	0.0	0.0	290.7	94.9	0.0	55.6	695.5	347.5	-86.6	-86.6	
COLUMN	36977.6	0.0	0.0	41428.9	0.0	0.0	219.2	0.0	1056.0	-5726.4	-5726.4	-5724.0
TOTALS	5864.7	0.0	0.0	10979.6	4837.0	0.0	895.0	23378.2	12673.5	-142.2	-142.2	

Figure 64: Area summary report with moderate decarbonization - dry hydrology – maximum EMI regional electricity exchange 2030

In this scenario, the total regional load is 41,428 MW, while total generation is 36,977 MW. In this scenarios all regional countries are importers, except BiH. The largest regional importer is Bulgaria (-1,700 MW), while BiH exports 878 MW. In total, in this maximum regional exchange scenario, the EMI region has a deficit of 5,724 MW.

The following figure shows the cross-border power exchange map for this scenario with moderate decarbonization - average hydrology – the hour with the maximum ratio between RES+HPP output and total demand. This is the scenario with the greatest regional exports, as there are large external regional exchanges to Turkey, Italy, Hungary and Austria.

Figure 65: Cross-border exhanges (MW) and directions between the countries in the scenario: Moderate decarbonization - Dry hydrology – maximum EMI regional electricity exchange 2030

The following two figures show the 400 kV and 220 kV voltage profiles with the maximum, minimum and average values in each country. The voltage profiles in the 400 kV network are within limits in all countries in this scenario.

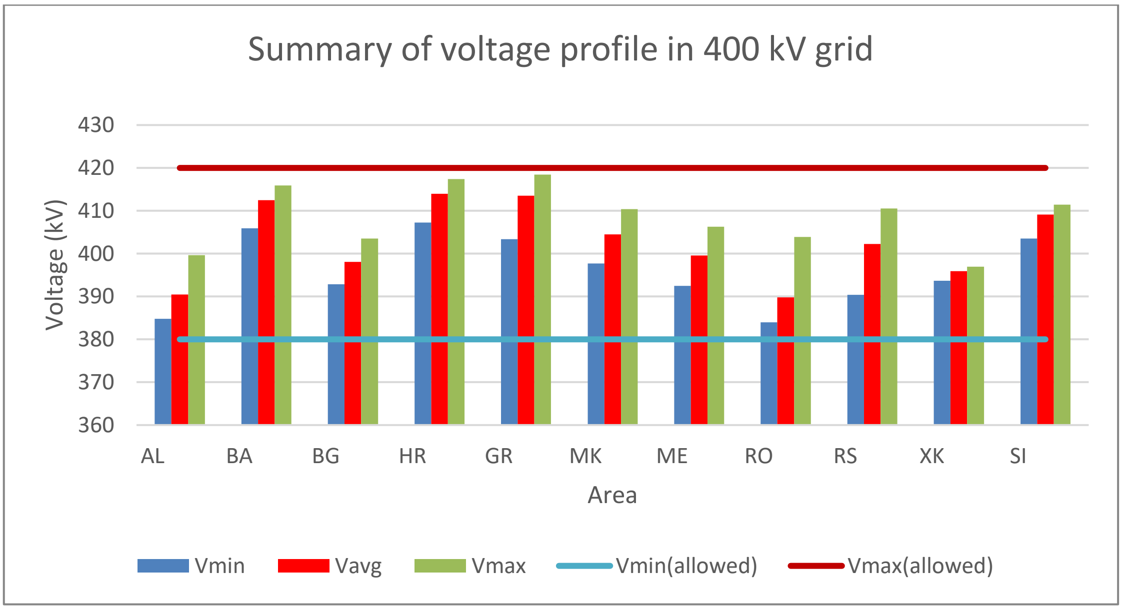


Figure 66: 400 kV voltage profiles (minimum, maximum and average) per country in this scenario (Moderate decarbonization - Dry hydrology – minimum EMI regional electricity exchange) 2030

The voltage profiles in the 220 kV network are mainly within limits in all countries in this scenario, except for Croatia and Romania, where the south wing of the Croatian network, as usual, suffers from high voltage, and the minimum voltage in Romania is somewhat below the allowed threshold.

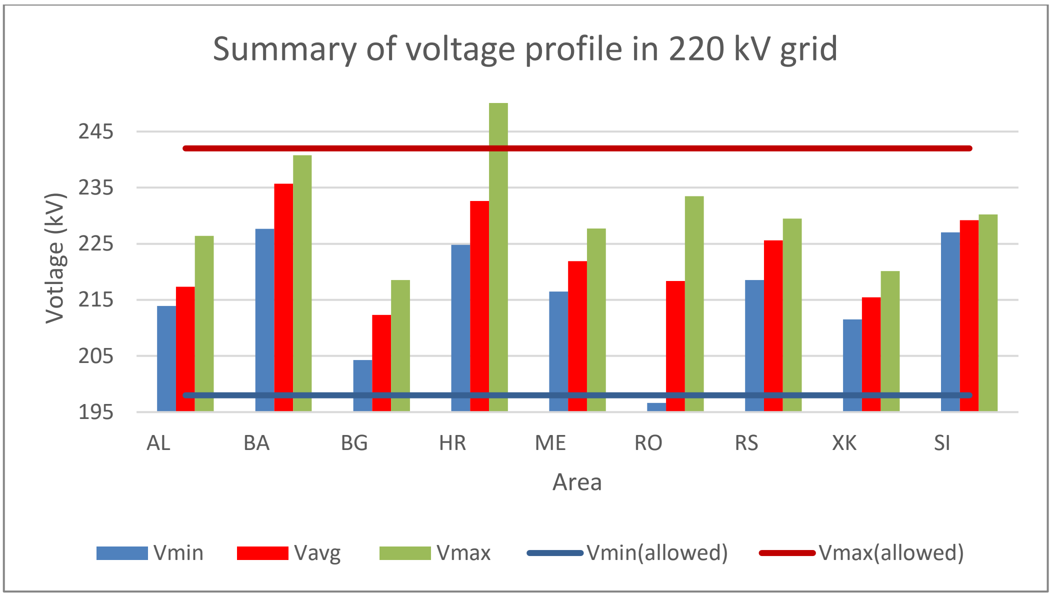


Figure 67: 220 kV voltage profiles (minimum, maximum and average) per country in this scenario (Moderate decarbonization - Dry hydrology – minimum EMI regional electricity exchange) 2030

There are six 400 kV and 220 kV elements loaded more than 80%. One 220 kV line in Romania is overloaded (107,7%):

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	CKT	MW	MVAR	MVA	RATING	%I	MW LOSS	MVAR LOSS
13222	[XTR_PE21 220,00]	130215	[WTREBI2 220,00]	1	-269,71	-47,42	273,84	301	87,78	2,38	13
13222	[XTR_PE21 220,00]	382000	[0HPERU21 220,00]	1	269,71	47,42	273,84	274,4	96,29	4,92	26,83
102010	[AVDEJA2 220,00]	102012	[AVDJRI2 220,00]	1	283,08	38,92	285,74	325,4	88,01	0,46	2,57
142060	[VDOBRU2 220,00]	142250	[VVARNA2 220,00]	1	-310,04	51,38	314,27	360	88,77	1,02	6,95
448067	[RMINTI2A 220,00]	448068	[RMINTI2B 220,00]	1	341,68	93,04	354,12	333,4	107,7	0	0,27
448094	[RROSIO2 220,00]	448039	[RROSIO1 400,00]	1	-318,65	-85,57	329,94	400	83,13	0,78	35,21

Figure 68: List of 400 and 220 kV elements loaded more than 80% in this scenario (Moderate decarbonization - Average hydrology – hour with maximum ratio between RES+HPP output and total demand) 2030

The contingency n-1 analysis report for this scenario is given as follows:

<------------------ MONITORED BRANCH		------------------>			<----- CONTINGENCY LABEL ------>	RATING	FLOW	%
102010 AVDEJA2	220.00	102012*AVDJRI2	220.00	1	SINGLE 102005-102012(1)	325.4	396.1	123.0
102010 AVDEJA2	220.00	102012*AVDJRI2	220.00	1	SINGLE 102010-102040(1)	325.4	398.2	123.0
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 130120-130215-130820(1)	274.4	283.5	103.2
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 130135-133120(1)	274.4	277.8	101.1
142060 VDOBRU2	220.00	142250*VVARNA2	220.00	1	SINGLE 142085-142250(1)	360.0	413.2	116.7
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 370660-378335-378336(1)	274.4	276.6	101.0
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 381010-381030(A)	274.4	279.7	102.1
13222*XTR_PE21	220.00	130215 WTREBI2	220.00	1	SINGLE 381030-381060(A)	301.0	363.9	118.3
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 381030-381060(A)	274.4	349.3	130.0
382000 0HPERU21	220.00	382030*0PODG121	220.00	1	SINGLE 381030-381060(A)	274.4	283.9	108.0
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 381050-381070(1)	274.4	279.9	102.5
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 382020-382040(1)	274.4	277.2	101.2
448003*RMINTI1	400.00	448067 RMINTI2A	220.00	1	SINGLE 448003-448034(1)	400.0	415.6	108.7
448039*RROSIO1	400.00	448094 RROSIO2	220.00	1	SINGLE 448036-448037(1)	400.0	401.8	102.2
448039*RROSIO1	400.00	448094 RROSIO2	220.00	1	SINGLE 448036-448087(2)	400.0	417.5	106.4
448036*RIERNU1	400.00	448087 RIERNU2	220.00	2	SINGLE 448039-448094(1)	400.0	380.2	100.8
448068 RMINTI2B	220.00	448097*RAL.JL2	220.00	1	SINGLE 448039-448094(1)	323.1	278.7	106.1
448055 RSLATI2A	220.00	448056*RGRADI2	220.00	1	SINGLE 448055-448058(1)	351.4	352.8	102.2
448056 RGRADI2	220.00	448060*RISALN2A	220.00	1	SINGLE 448055-448058(1)	351.4	426.3	122.5
448057 RCRAIO2A	220.00	448060*RISALN2A	220.00	1	SINGLE 448056-448060(1)	351.4	362.7	104.2
448058 RCRAIO2B	220.00	448060*RISALN2A	220.00	1	SINGLE 448056-448060(1)	351.4	367.5	105.6
448058 RCRAIO2B	220.00	448060*RISALN2A	220.00	1	SINGLE 448057-448060(1)	351.4	460.9	132.1
448057 RCRAIO2A	220.00	448060*RISALN2A	220.00	1	SINGLE 448058-448060(1)	351.4	460.1	131.9
448066*RPESTI2	220.00	448067 RMINTI2A	220.00	1	SINGLE 448067-448068(1)	351.4	342.6	101.3
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 460026-460045(1)	274.4	275.6	100.5
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	SINGLE 460090-460095(1)	274.4	275.4	100.3
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	BUS 1321	274.4	284.5	103.8
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	BUS 3801	274.4	275.5	100.6
448039*RROSIO1	400.00	448094 RROSIO2	220.00	1	BUS 4421	400.0	401.6	104.0
10210*XKO_PO21	220.00	102015 AKOPLI2	220.00	1	BUS 10110	274.4	340.5	126.8
10210 XKO_PO21	220.00	382030*0PODG121	220.00	1	BUS 10110	274.4	341.1	126.9
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	BUS 10110	274.4	287.0	104.5
102010 AVDEJA2	220.00	102012*AVDJRI2	220.00	1	BUS 10110	325.4	411.5	127.9
102010 AVDEJA2	220.00	102015*AKOPLI2	220.00	1	BUS 10110	278.2	325.7	119.3
13222*XTR_PE21	220.00	130215 WTREBI2	220.00	1	BUS 13110	301.0	360.6	115.9
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	BUS 13110	274.4	347.0	127.4
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	BUS 16121	274.4	275.4	100.3
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	BUS 30111	274.4	287.2	105.5
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	BUS 31101	274.4	276.4	100.8
13222 XTR_PE21	220.00	382000*0HPERU21	220.00	1	BUS 38030	274.4	276.9	101.4

LOSS OF LOAD REPORT:

<--------- B U S --------> <----- CONTINGENCY LABEL ------> LOAD(MW)

<----- CONTINGENCY LABEL ------>	<----- POST-CONTINGENCY SOLUTION -----> <TERMINATION STATE>	FLOW#	VOLT#	LOAD
BASE CASE	Met convergence to	1	0	0.0
SINGLE 102005-102012(1)	Met convergence to	1	0	0.0
SINGLE 102010-102040(1)	Met convergence to	1	0	0.0
SINGLE 130120-130215-130820(1)	Met convergence to	1	0	0.0
SINGLE 130135-133120(1)	Met convergence to	1	0	0.0
SINGLE 142085-142250(1)	Met convergence to	1	0	0.0
SINGLE 370660-378335-378336(1)	Met convergence to	1	0	7.5
SINGLE 381010-381030(A)	Met convergence to	1	0	0.0
SINGLE 381030-381060(A)	Met convergence to	3	0	0.0
SINGLE 381050-381070(1)	Met convergence to	1	0	0.0
SINGLE 382020-382040(1)	Met convergence to	1	0	0.0
SINGLE 448003-448034(1)	Met convergence to	1	0	0.0
SINGLE 448036-448037(1)	Met convergence to	1	1	0.0
SINGLE 448036-448087(2)	Met convergence to	1	0	0.0
SINGLE 448039-448094(1)	Met convergence to	2	2	0.0
SINGLE 448055-448058(1)	Met convergence to	2	0	0.0
SINGLE 448056-448060(1)	Met convergence to	2	0	0.0
SINGLE 448057-448060(1)	Met convergence to	1	0	0.0
SINGLE 448058-448060(1)	Met convergence to	1	0	0.0
SINGLE 448067-448068(1)	Met convergence to	1	0	0.0
SINGLE 448068-448097(1)	Blown up	--	--	--
SINGLE 448089-448097(1)	Blown up	--	--	--
SINGLE 460026-460045(1)	Met convergence to	1	0	0.0
SINGLE 460090-460095(1)	Met convergence to	1	0	0.0
BUS 1321	Met convergence to	1	0	0.0
BUS 3801	Met convergence to	1	0	0.0
BUS 4421	Met convergence to	1	3	0.0
BUS 10110	Met convergence to	5	0	0.0
BUS 13110	Met convergence to	2	0	0.0
BUS 16121	Met convergence to	1	0	0.0
BUS 30111	Met convergence to	1	0	-500.0
BUS 31101	Met convergence to	1	0	0.0
BUS 38030	Met convergence to	1	1	******

CONTINGENCY LEGEND: from list of total 794 analyzed contingencies)

(selected 30 contingecies (2 contingencies with convergence problems not included) appeared above)

```
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 102005-102012(1)          : OPEN LINE FROM BUS 102005 [AKOMAN2     220.00] TO BUS 102012 [AVDJRI2     220.00] CKT 1
 SINGLE 102010-102040(1)          : OPEN LINE FROM BUS 102010 [AVDEJA2     220.00] TO BUS 102040 [ATIRA12     220.00] CKT 1
 SINGLE 130120-130215-130820(1)   : OPEN LINE FROM BUS 130120 [WTREBI1     400.00] TO BUS 130215 [WTREBI2     220.00] TO BUS
130820 [WTREBI_1    31.500] CKT 1
 SINGLE 130135-133120(1)          : OPEN LINE FROM BUS 130135 [WVISEG1     400.00] TO BUS 133120 [WTUZL41     400.00] CKT 1
 SINGLE 142085-142250(1)          : OPEN LINE FROM BUS 142085 [VMADAR2     220.00] TO BUS 142250 [VVARNA2     220.00] CKT 1
 SINGLE 370660-378335-378336(1)   : OPEN LINE FROM BUS 370660 [BITOLA 2    400.00] TO BUS 378335 [YBTLG       15.000] TO BUS
378336 [YBTLG       15.000] CKT 1
 SINGLE 381010-381030(A)          : OPEN LINE FROM BUS 381010 [0BREZN11    400.00] TO BUS 381030 [0LASTV11    400.00] CKT A
 SINGLE 381030-381060(A)          : OPEN LINE FROM BUS 381030 [0LASTV11    400.00] TO BUS 381060 [0PODG211    400.00] CKT A
 SINGLE 381050-381070(1)          : OPEN LINE FROM BUS 381050 [0PLJE211    400.00] TO BUS 381070 [0RIBAR11    400.00] CKT 1
 SINGLE 382020-382040(1)          : OPEN LINE FROM BUS 382020 [0MOJKO21    220.00] TO BUS 382040 [0TPLJE21    220.00] CKT 1
 SINGLE 448003-448034(1)          : OPEN LINE FROM BUS 448003 [RMINTI1     400.00] TO BUS 448034 [RSIBIU1     400.00] CKT 1
 SINGLE 448036-448037(1)          : OPEN LINE FROM BUS 448036 [RIERNU1     400.00] TO BUS 448037 [RGADAL1     400.00] CKT 1
 SINGLE 448036-448087(2)          : OPEN LINE FROM BUS 448036 [RIERNU1     400.00] TO BUS 448087 [RIERNU2     220.00] CKT 2
 SINGLE 448039-448094(1)          : OPEN LINE FROM BUS 448039 [RROSIO1     400.00] TO BUS 448094 [RROSIO2     220.00] CKT 1
 SINGLE 448055-448058(1)          : OPEN LINE FROM BUS 448055 [RSLATI2A    220.00] TO BUS 448058 [RCRAIO2B    220.00] CKT 1
 SINGLE 448056-448060(1)          : OPEN LINE FROM BUS 448056 [RGRADI2     220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
 SINGLE 448057-448060(1)          : OPEN LINE FROM BUS 448057 [RCRAIO2A    220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
 SINGLE 448058-448060(1)          : OPEN LINE FROM BUS 448058 [RCRAIO2B    220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
 SINGLE 448067-448068(1)          : OPEN LINE FROM BUS 448067 [RMINTI2A    220.00] TO BUS 448068 [RMINTI2B    220.00] CKT 1
 SINGLE 460026-460045(1)          : OPEN LINE FROM BUS 460026 [JJAGO412    400.00] TO BUS 460045 [JNIS2 12    400.00] CKT 1
 SINGLE 460090-460095(1)          : OPEN LINE FROM BUS 460090 [JRPMLA12    400.00] TO BUS 460095 [JSMIT211    400.00] CKT 1
 BUS 1321                         : OPEN LINE FROM BUS 1321 [XVI_BB11    400.00] TO BUS 130135 [WVISEG1     400.00] CKT 1
                                    OPEN LINE FROM BUS 1321 [XVI_BB11    400.00] TO BUS 460175 [JBBAST11    400.00] CKT 1
 BUS 3801                         : OPEN LINE FROM BUS 3801 [XPL_BI11    400.00] TO BUS 381050 [0PLJE211    400.00] CKT A
                                    OPEN LINE FROM BUS 3801 [XPL_BI11    400.00] TO BUS 460175 [JBBAST11    400.00] CKT 1
 BUS 4421                         : OPEN LINE FROM BUS 4421 [XSV_BA11; OV400.00] TO BUS 448014 [RSUCEA1     400.00] CKT 1
                                    OPEN LINE FROM BUS 4421 [XSV_BA11; OV400.00] TO BUS 639997 [5BALTDC1    400.00] CKT 1
 BUS 10110                        : OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 101005 [AVDJRI1     400.00] CKT 1
                                    OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 381060 [0PODG211    400.00] CKT 1
 BUS 13110                        : OPEN LINE FROM BUS 13110 [XTR_PG11    400.00] TO BUS 130120 [WTREBI1     400.00] CKT 1
                                    OPEN LINE FROM BUS 13110 [XTR_PG11    400.00] TO BUS 381030 [0LASTV11    400.00] CKT 1
 BUS 16121                        : OPEN LINE FROM BUS 16121 [XER_SM11    400.00] TO BUS 161015 [HERNES11    400.00] CKT 1
                                    OPEN LINE FROM BUS 16121 [XER_SM11    400.00] TO BUS 460095 [JSMIT211    400.00] CKT 1
 BUS 30111                        : OPEN LINE FROM BUS 30111 [XAR_GA1G    400.00] TO BUS 301601 [GKARAC11    400.00] CKT 1
 BUS 31101                        : OPEN LINE FROM BUS 31101 [XNA_BE11    400.00] TO BUS 311021 [MBEKO 11    400.00] CKT 1
                                    OPEN LINE FROM BUS 31101 [XNA_BE11    400.00] TO BUS 448009 [RNADAB1     400.00] CKT 1
 BUS 38030                        : OPEN LINE FROM BUS 38030 [XVI_LA1M    400.00] TO BUS 381030 [0LASTV11    400.00] CKT 1
```

Figure 69: Contingency (n-1) analysis report for this scenario 2030

In this scenario there is an extensive list of 30 contingency events that provoke overloading in the network, where two overloadings are higher than 130% (given above in red). These are situations where there further analysis may be merited to determine how and whether to resolve this situation (e.g., with upgrades, new lines, redispatching, storage, etc.)

9.5. Extreme decarbonization - Average hydrology – maximum ratio between RES+HPP output and total demand

This scenario assumes average hydrology – with the maximum ratio between RES+HPP output and total demand. We provide regional and area summaries for this fifth scenario as follows:

	FROM ------AT AREA BUSES-------				TO					-NET INTERCHANGE-		
X-- AREA --X	GENE-RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	727.5	0.0	0.0	1168.0	0.0	0.0	5.2	0.0	19.3	-465.0	-465.0	-465.0
AL	144.8	0.0	0.0	299.5	483.8	0.0	31.3	641.2	217.1	-245.7	-245.7	
13	156.7	0.0	0.0	1495.0	0.0	0.0	12.2	0.0	51.5	-1402.0	-1402.0	-1402.0
BA	331.7	0.0	0.0	190.9	0.0	0.0	125.1	986.3	520.1	481.9	481.9	
14	3559.9	0.0	0.0	3809.2	0.5	0.0	54.7	0.0	168.5	-472.9	-472.9	-473.0
BG	2008.1	0.0	0.0	894.3	1201.2	0.0	144.2	2694.7	2179.9	283.1	283.1	
16	726.1	0.0	0.0	2140.0	0.0	0.0	4.6	0.0	115.4	-1533.9	-1533.9	-1534.0
HR	-145.5	0.0	0.0	492.4	99.5	0.0	22.3	1534.1	1051.8	-277.4	-277.4	
30	6140.6	0.0	0.0	7152.4	0.0	0.0	0.0	0.0	220.2	-1232.0	-1232.0	-1232.0
GR	-97.2	0.0	0.0	2568.4	1947.9	0.0	19.9	7794.7	2474.2	687.1	687.1	
37	818.1	0.0	0.0	1287.3	0.0	0.0	1.9	0.0	28.8	-500.0	-500.0	-500.0
MK	-39.5	0.0	0.0	148.6	0.0	0.0	7.9	469.9	287.5	-13.6	-13.6	
38	350.7	0.0	0.0	564.0	0.0	0.0	3.1	0.0	25.6	-242.0	-242.0	-242.0
ME	31.6	0.0	0.0	110.3	135.4	0.0	23.2	411.5	219.1	-44.9	-44.9	
44	8517.0	0.0	0.0	6100.0	0.0	0.0	87.7	0.0	200.3	2129.1	2129.1	2129.0
RO	-53.6	0.0	0.0	1785.6	1746.2	0.0	251.1	4952.1	2363.3	-1247.6	-1247.6	
46	3566.5	0.0	0.0	3945.3	0.0	0.0	27.0	0.0	178.2	-583.9	-583.9	-584.0
RS	660.1	0.0	0.0	747.1	94.6	0.0	104.7	1989.0	1954.6	-252.0	-252.0	
47	176.9	0.0	0.0	780.0	0.0	0.0	4.7	0.0	18.2	-626.0	-626.0	-626.0
XK	285.6	0.0	0.0	259.9	0.0	0.0	14.0	251.1	207.9	54.8	54.8	
49	1752.7	0.0	0.0	1925.0	0.0	0.0	7.8	0.0	43.9	-224.0	-224.0	-224.0
SI	-18.4	0.0	0.0	253.2	92.0	0.0	53.7	670.8	505.2	-251.6	-251.6	
COLUMN	26492.8	0.0	0.0	30366.2	0.5	0.0	209.0	0.0	1069.8	-5152.6	-5152.6	-5153.0
TOTALS	3107.7	0.0	0.0	7750.2	5800.5	0.0	797.6	22395.3	11980.7	-825.8	-825.8	

Figure 70: Area summary report in Extreme decarbonization scenario - Average hydrology – maximum ratio between RES+HPP output and total demand 2030

In this scenario, the total regional load is 30,366 MW, while total generation is 26,492 MW. In this scenario all regional countries are importers, except Romania. The largest regional importer is Greece (-1,232 MW), while Romania exports 2,129 MW. In total, in this scenario, the EMI region has large exchange (deficit) of 5,153 MW.

Figure 71: Cross-border exchanges (MW) and directions between the countries in the scenario: Extreme decarbonization scenario - Average hydrology – maximum ratio between RES+HPP output and total demand 2030

The following two figures show the 400 kV and 220 kV voltage profiles with the maximum, minimum and average values in each country. All voltages in 400 kV network in the aforementioned categories are within limits, except for Romania, where the minimum value is below the allowed threshold.

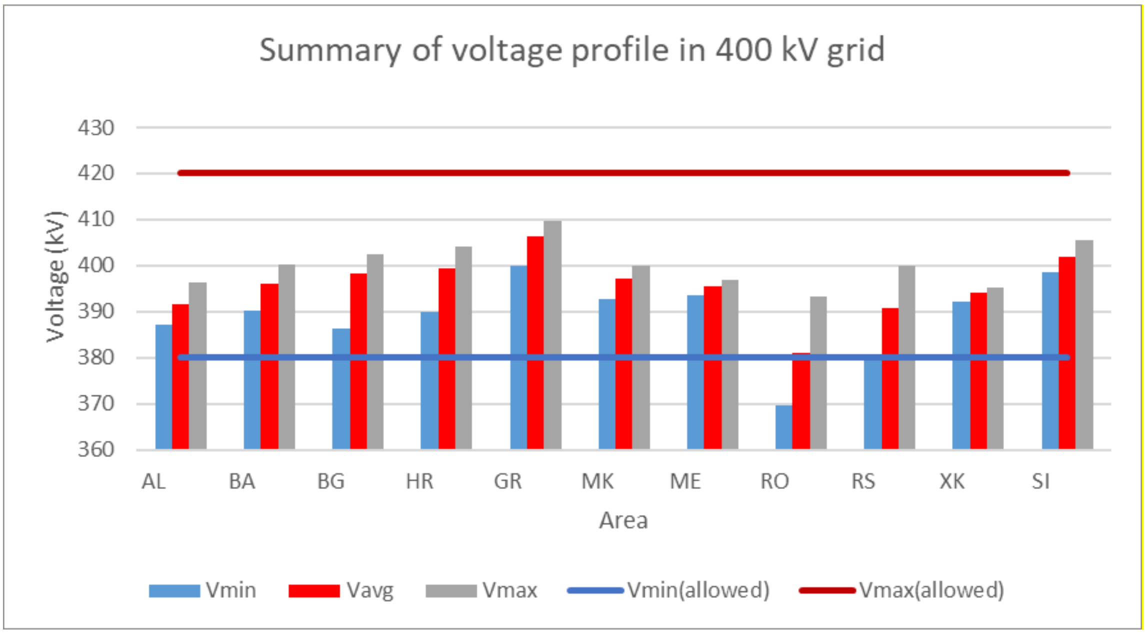


Figure 72: 400 kV voltage profiles (minimum, maximum and average) per country in this scenario (Extreme decarbonization scenario - Average hydrology – maximum ratio between RES+HPP output and total demand) 2030

As in the previous scenarios, voltage profiles in the 220 kV network are within limits in all countries except in Croatia, where the south wing of the network, as usual, suffers from high voltage.

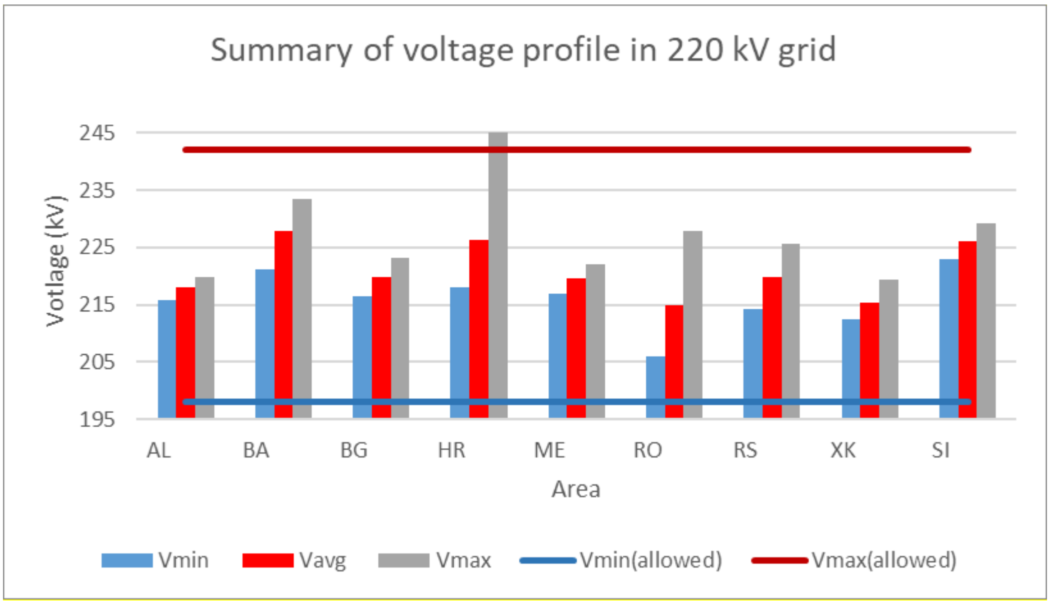


Figure 73: 220 kV voltage profiles (minimum, maximum and average) per country in this scenario (Extreme decarbonization scenario - Average hydrology – maximum ratio between RES+HPP output and total demand) 2030

There are two transmission elements loaded more than 80% (i.e., the double circuit Croatia - Hungary (84,51%) interconnection line:

FRMBUS	FROMBUSEXNAME	TOBUS	TOBUSEXNAME	CKT	MW	MVAR	MVA	RATING	%I	MWLOSS	MVARLOSS
16101	[XER_PE11 400,00]	161015	[HERNES11 400,00]	1	1102,12	0,94	1102,12	1330,21	84,51	10,2	107,73
16102	[XER_PE12 400,00]	161015	[HERNES11 400,00]	2	1102,12	0,94	1102,12	1330,21	84,51	10,2	107,73

Figure 74: List of 400 and 220 kV elements loaded more than 80% in this scenario (Extreme decarbonization scenario - Average hydrology – maximum ratio between RES+HPP output and total demand) 2030

The contingency n-1 analysis report for this scenario is given as follows:

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING    FLOW      %
 10210*XKO_PO21    220.00 102015 AKOPLI2      220.00 1  BUS 10110                      274.4    303.2    113.0
  10210 XKO_PO21    220.00 382030*0PODG121     220.00 1  BUS 10110                      274.4    304.6    113.1
 102010 AVDEJA2     220.00 102015*AKOPLI2      220.00 1  BUS 10110                      278.2    297.3    109.4
  14124*XVA_MG11    400.00 141115 VVARNA1      400.00 1  BUS 14121                     1380.0   1590.1    126.2
  14121*XDO_MG11    400.00 141035 VDOBRU1      400.00 1  BUS 14124                     1380.0   1504.0    119.8
  14141 XMI_HA11    400.00 141055*VMAIZ31      400.00 1  BUS 14142                     1200.0   1211.5    100.8
  16102*XER_PE12    400.00 161015 HERNES11     400.00 2  BUS 16101                     1330.2   1820.5    142.0
  16102*XER_PE12    400.00 311181 MPECSO11     400.00 2  BUS 16101                     1385.6   1820.5    136.3
  16101*XER_PE11    400.00 161015 HERNES11     400.00 1  BUS 16102                     1330.2   1820.5    142.0
  16101*XER_PE11    400.00 311181 MPECSO11     400.00 1  BUS 16102                     1385.6   1820.5    136.3
  32201 XPA_DI21    220.00 492020*DIVACA220    220.00 1  BUS 32101                      365.8    482.9    129.2

 LOSS OF LOAD REPORT:
 <-------- B U S --------> <----- CONTINGENCY LABEL ------> LOAD(MW)

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                 <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                        Met convergence to     0    22    0.0
 SINGLE 370350-370360(1)          Blown up              --    --     --
 BUS 10110                        Met convergence to     3     6    0.0
 BUS 14121                        Met convergence to     1     9    0.0
 BUS 14124                        Met convergence to     1    11    0.0
 BUS 14142                        Met convergence to     1     2    0.0
 BUS 16101                        Met convergence to     2     4    0.0
 BUS 16102                        Met convergence to     2     4    0.0
 BUS 32101                        Met convergence to     1     0    0.0
 IT-SI BOTH LINES                 Blown up              --    --     --

CONTINGENCY LEGEND: from list of total 787 analyzed contingencies)
 (selected 7 contingecies (2 contingencies with convergence problems not included) appeared above)
 <----- CONTINGENCY LABEL ------>  EVENTS
 BUS 10110                       : OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 101005 [AVDJRI1     400.00] CKT 1
                                   OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 381060 [0PODG211    400.00] CKT 1
 BUS 14121                       : OPEN LINE FROM BUS 14121 [XDO_MG11    400.00] TO BUS 141035 [VDOBRU1     400.00] CKT 1
                                   OPEN LINE FROM BUS 14121 [XDO_MG11    400.00] TO BUS 448974 [RMEDGI1     400.00] CKT 1
 BUS 14124                       : OPEN LINE FROM BUS 14124 [XVA_MG11    400.00] TO BUS 141115 [VVARNA1     400.00] CKT 1
                                   OPEN LINE FROM BUS 14124 [XVA_MG11    400.00] TO BUS 448974 [RMEDGI1     400.00] CKT 1
 BUS 14142                       : OPEN LINE FROM BUS 14142 [XMI_HA12    400.00] TO BUS 141055 [VMAIZ31     400.00] CKT 1
                                   OPEN LINE FROM BUS 14142 [XMI_HA12    400.00] TO BUS 540004 [4HAMITABAT  400.00] CKT 1
 BUS 16101                       : OPEN LINE FROM BUS 16101 [XER_PE11    400.00] TO BUS 161015 [HERNES11    400.00] CKT 1
                                   OPEN LINE FROM BUS 16101 [XER_PE11    400.00] TO BUS 311181 [MPECSO11    400.00] CKT 1
 BUS 16102                       : OPEN LINE FROM BUS 16102 [XER_PE12    400.00] TO BUS 161015 [HERNES11    400.00] CKT 2
                                   OPEN LINE FROM BUS 16102 [XER_PE12    400.00] TO BUS 311181 [MPECSO11    400.00] CKT 2
 BUS 32101                       : OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 321346 [REDIPUGLIA  400.00] CKT 1
                                   OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 491040 [PST_DIV     400.00] CKT 1
```

Figure 75: Contingency (n-1) analysis report for Extreme decarbonization scenario - Average hydrology – maximum ratio between RES+HPP output and total demand 2030

In this scenario there are seven contingency events that overload the network, where four overloadings are higher than 130% (given above in red).

9.6. Extreme decarbonization - Average hydrology – maximum EMI regional electricity exchange

This scenario assumes extreme decarbonization - average hydrology – maximum EMI regional electricity exchange. Regional and area summaries for the sixth scenario are given as follows:

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
10	1662.5	0.0	0.0	1958.0	0.0	0.0	5.3	0.0	39.0	-339.9	-339.9	-340.0
AL	600.9	0.0	0.0	502.0	488.4	0.0	31.9	649.5	416.8	-188.7	-188.7	
13	2138.8	0.0	0.0	2258.0	0.0	0.0	13.6	0.0	45.2	-177.9	-177.9	-178.0
BA	524.6	0.0	0.0	417.8	0.0	0.0	138.7	1056.6	610.2	414.5	414.5	
14	4872.1	0.0	0.0	6325.8	0.0	0.0	48.8	0.0	305.0	-1807.4	-1807.4	-1807.0
BG	1896.6	0.0	0.0	2133.2	-194.3	0.0	122.4	2338.0	3435.7	-1262.5	-1262.5	
16	1556.6	0.0	0.0	2863.0	0.0	0.0	4.8	0.0	72.7	-1383.8	-1383.8	-1384.0
HR	-214.0	0.0	0.0	658.7	107.7	0.0	23.3	1617.8	591.1	23.0	23.0	
30	10043.0	0.0	0.0	9920.4	0.0	0.0	0.0	0.0	228.6	-106.0	-106.0	-106.0
GR	1053.0	0.0	0.0	4110.2	1789.9	0.0	22.8	7777.3	2391.8	515.6	515.6	
37	1047.7	0.0	0.0	1238.0	0.0	0.0	2.0	0.0	19.7	-212.0	-212.0	-212.0
MK	311.3	0.0	0.0	402.4	0.0	0.0	9.4	471.9	222.6	148.8	148.8	
38	486.6	0.0	0.0	702.0	0.0	0.0	3.9	0.0	30.6	-249.9	-249.9	-250.0
ME	143.1	0.0	0.0	227.6	69.2	0.0	25.4	436.3	279.9	-22.6	-22.6	
44	11751.9	0.0	0.0	9500.0	0.0	0.0	91.6	0.0	346.7	1813.6	1813.6	1813.0
RO	1662.7	0.0	0.0	2720.3	0.0	0.0	263.3	5162.1	4304.2	-463.1	-463.1	
46	5525.5	0.0	0.0	6240.3	0.0	0.0	31.5	0.0	139.2	-885.5	-885.5	-886.0
RS	1582.9	0.0	0.0	1425.1	0.0	0.0	164.9	2100.8	1883.9	209.8	209.8	
47	415.1	0.0	0.0	1288.0	0.0	0.0	4.7	0.0	20.3	-898.0	-898.0	-898.0
XK	372.2	0.0	0.0	426.9	0.0	0.0	13.9	253.7	261.6	-76.6	-76.6	
49	1838.7	0.0	0.0	2455.0	0.0	0.0	8.0	0.0	38.7	-663.0	-663.0	-663.0
SI	48.3	0.0	0.0	322.9	94.5	0.0	55.3	691.3	381.2	-114.3	-114.3	
COLUMN	41338.5	0.0	0.0	44748.5	0.0	0.0	214.2	0.0	1285.7	-4909.9	-4909.9	-4911.0
TOTALS	7981.6	0.0	0.0	13347.1	2355.5	0.0	871.3	22555.2	14779.0	-816.0	-816.0	

Figure 76: Area summary report in Extreme decarbonization - Average hydrology – maximum EMI regional electricity exchange 2030

In this scenario, the total regional load is 44,748 MW, while total generation is 41,338 MW. In this scenario again, all regional countries are importers, except Romania (1,813 MW). The largest regional importer is Bulgaria (-1,807 MW). In total, in this scenario, the EMI region has a large deficit of 4,911 MW.

Figure 77: Cross-border exchanges (MW) and directions between the countries in the scenario: Extreme decarbonization - Average hydrology – maximum EMI regional electricity exchange 2030

The following two figures show the 400 kV and 220 kV voltage profiles with maximum, minimum and average values in each country. All voltages in 400 kV network in the aforementioned categories are within limits, except for Romania and Bulgaria where the minimum value is below the allowed threshold.

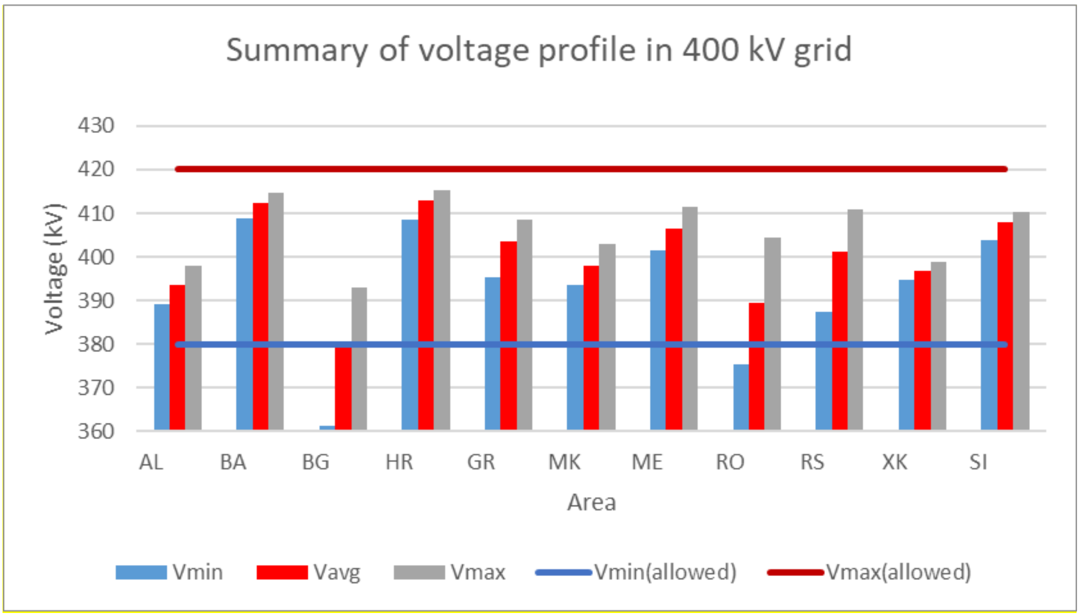


Figure 78: 400 kV voltage profiles (minimum, maximum and average) per country in this scenario (Extreme decarbonization - Average hydrology – maximum EMI regional electricity exchange) in 2030

In the 220 kV network there are three things to notice: the maximum voltage in Croatia is above the allowed threshold while in Bulgaria the voltages are below the allowed threshold.

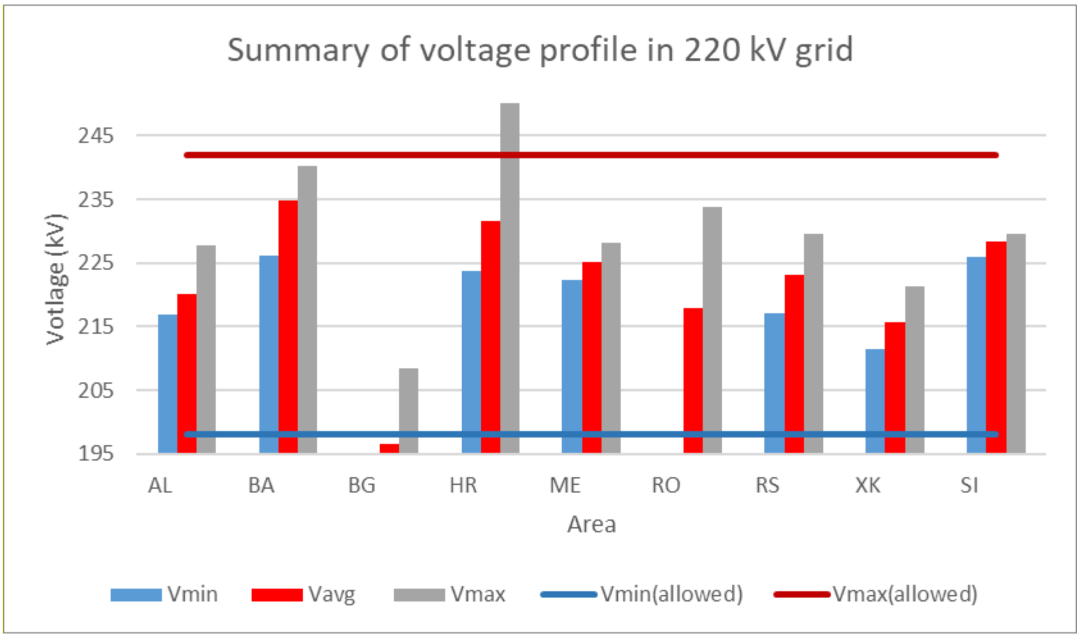


Figure 79: 220 kV voltage profiles (minimum, maximum and average) per country in this scenario (Extreme decarbonization - Average hydrology – maximum EMI regional electricity exchange) in 2030

There are seven transmission elements loaded more than 80%, with one 400 kV internal Romania line overladed (110,13%):

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	CKT	MW	MVAR	MVA	RATING	%I	MW LOSS	MVAR LOSS
14124	[XVA_MG11 400,00]	141115	[VVARNA1 400,00]	1	1158,75	91,04	1162,32	1380	92,03	16,83	244,35
300079	[GKQESS11 400,00]	300117	[GELPE11 400,00]	1	-383,98	13,21	384,2	476	80,25	0,21	0,85
448036	[RIERNU1 400,00]	448087	[RIERNU2 220,00]	2	261,89	178,51	316,95	400	81,53	0,57	26,85
448067	[RMINTI2A 220,00]	448003	[RMINTI1 400,00]	1	-313,68	-104,83	330,74	400	83,36	0,79	35,42
448067	[RMINTI2A 220,00]	448068	[RMINTI2B 220,00]	1	336,74	138,69	364,18	333,4	110,13	0	0,28
448068	[RMINTI2B 220,00]	448097	[RAL,JL2 220,00]	1	274,87	124,53	301,76	323,1	94,19	12,76	70,33
448094	[RROSIO2 220,00]	448039	[RROSIO1 400,00]	1	-319,68	-116,52	340,25	400	84,86	0,82	36,73

Figure 80: List of 400 and 220 kV elements loaded more than 80% in this scenario (Extreme decarbonization - Average hydrology – minimum EMI regional electricity exchange) in 2030

The contingency n-1 analysis report for this scenario is given as follows:

```
<---------------- MONITORED BRANCH ----------------> <----- CONTINGENCY LABEL ------>  RATING    FLOW      %
 142085*VMADAR2     220.00 142250 VVARNA2     220.00 1  SINGLE 142060-142085(2)          360.1    307.7    102.7
 142060*VDOBRU2     220.00 142250 VVARNA2     220.00 1  SINGLE 142085-142250(1)          360.0    358.4    112.6
 300786*GANIKO11    400.00 301501 GKDIST11    400.00 2  SINGLE 300786-301501(1)         1400.0   1413.9    100.8
 300786*GANIKO11    400.00 301501 GKDIST11    400.00 1  SINGLE 300786-301501(2)         1400.0   1413.9    100.8
 448068 RMINTI2B    220.00 448097*RAL.JL2     220.00 1  SINGLE 448009-448096(1)          323.1    302.9    109.7
 448068 RMINTI2B    220.00 448097*RAL.JL2     220.00 1  SINGLE 448034-448036(1)          323.1    284.1    101.3
 448003*RMINTI1     400.00 448067 RMINTI2A    220.00 1  SINGLE 448036-448087(2)          400.0    396.0    100.7
 448039*RROSIO1     400.00 448094 RROSIO2     220.00 1  SINGLE 448036-448087(2)          400.0    504.6    127.0
 448068 RMINTI2B    220.00 448097*RAL.JL2     220.00 1  SINGLE 448036-448087(2)          323.1    315.1    117.0
 448003*RMINTI1     400.00 448067 RMINTI2A    220.00 1  SINGLE 448045-448062(1)          400.0    423.4    108.3
 448055 RSLATI2A    220.00 448056*RGRADI2     220.00 1  SINGLE 448055-448058(1)          351.4    368.2    106.5
 448056 RGRADI2     220.00 448060*RISALN2A    220.00 1  SINGLE 448055-448058(1)          351.4    437.5    125.6
 448057 RCRAIO2A    220.00 448060*RISALN2A    220.00 1  SINGLE 448056-448060(1)          351.4    357.4    102.5
 448058 RCRAIO2B    220.00 448060*RISALN2A    220.00 1  SINGLE 448056-448060(1)          351.4    363.5    104.3
 448058 RCRAIO2B    220.00 448060*RISALN2A    220.00 1  SINGLE 448057-448058(1)          351.4    368.3    105.3
 448058 RCRAIO2B    220.00 448060*RISALN2A    220.00 1  SINGLE 448057-448060(1)          351.4    449.3    128.6
 448057 RCRAIO2A    220.00 448060*RISALN2A    220.00 1  SINGLE 448058-448060(1)          351.4    448.3    128.3
 448003*RMINTI1     400.00 448067 RMINTI2A    220.00 1  SINGLE 448062-448063(1)          400.0    424.5    108.7
 448066*RPESTI2     220.00 448067 RMINTI2A    220.00 1  SINGLE 448067-448068(1)          351.4    338.7    100.1
 448003*RMINTI1     400.00 448067 RMINTI2A    220.00 1  SINGLE 448067-448071(1)          400.0    390.6    100.1
 448036*RIERNU1     400.00 448087 RIERNU2     220.00 2  SINGLE 448083-448084(1)          400.0    430.8    111.9
 448068 RMINTI2B    220.00 448097*RAL.JL2     220.00 1  SINGLE 448083-448084(1)          323.1    280.3    100.2
 448003*RMINTI1     400.00 448067 RMINTI2A    220.00 1  SINGLE 448087-448088(1)          400.0    408.5    105.8
 448039*RROSIO1     400.00 448094 RROSIO2     220.00 1  SINGLE 448087-448088(1)          400.0    442.0    112.5
 448068 RMINTI2B    220.00 448097*RAL.JL2     220.00 1  SINGLE 448087-448088(1)          323.1    326.9    130.1
 448068 RMINTI2B    220.00 448097*RAL.JL2     220.00 1  SINGLE 448088-448089(1)          323.1    289.5    104.8
 448068 RMINTI2B    220.00 448097*RAL.JL2     220.00 1  SINGLE 448089-448091(1)          323.1    283.6    103.1
 448068 RMINTI2B    220.00 448097*RAL.JL2     220.00 1  SINGLE 448091-448093(1)          323.1    293.3    108.2
  10210*XKO_PO21    220.00 102015 AKOPLI2     220.00 1  BUS 10110                        274.4    290.8    105.3
  10210 XKO_PO21    220.00 382030*0PODG121    220.00 1  BUS 10110                        274.4    292.5    105.4
  14124 XVA_MG11    400.00 141115*VVARNA1     400.00 1  BUS 14122                       1380.0   1256.8    104.8
  14141 XMI_HA11    400.00 141055*VMAIZ31     400.00 1  BUS 14142                       1200.0   1178.8    104.9
  14141 XMI_HA11    400.00 141055*VMAIZ31     400.00 1  BUS 30121                       1200.0   1236.6    109.3

 LOSS OF LOAD REPORT:
 <-------- B U S --------> <----- CONTINGENCY LABEL ------> LOAD(MW)

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                       Met convergence to     1    15    0.0

CONTINGENCY LEGEND: from list of total 787 analyzed contingencies)
 (selected 25 contingecies (9 contingencies with convergence problems not included) appeared above)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 142060-142085(2)        : OPEN LINE FROM BUS 142060 [VDOBRU2     220.00] TO BUS 142085 [VMADAR2     220.00] CKT 2
 SINGLE 142085-142250(1)        : OPEN LINE FROM BUS 142085 [VMADAR2     220.00] TO BUS 142250 [VVARNA2     220.00] CKT 1
 SINGLE 300786-301501(1)        : OPEN LINE FROM BUS 300786 [GANIKO11    400.00] TO BUS 301501 [GKDIST11    400.00] CKT 1
 SINGLE 300786-301501(2)        : OPEN LINE FROM BUS 300786 [GANIKO11    400.00] TO BUS 301501 [GKDIST11    400.00] CKT 2
 SINGLE 448009-448096(1)        : OPEN LINE FROM BUS 448009 [RNADAB1     400.00] TO BUS 448096 [RORADE1     400.00] CKT 1
 SINGLE 448034-448036(1)        : OPEN LINE FROM BUS 448034 [RSIBIU1     400.00] TO BUS 448036 [RIERNU1     400.00] CKT 1
 SINGLE 448036-448087(2)        : OPEN LINE FROM BUS 448036 [RIERNU1     400.00] TO BUS 448087 [RIERNU2     220.00] CKT 2
 SINGLE 448045-448062(1)        : OPEN LINE FROM BUS 448045 [RURECH2     220.00] TO BUS 448062 [RTG.JI2     220.00] CKT 1
 SINGLE 448055-448058(1)        : OPEN LINE FROM BUS 448055 [RSLATI2A    220.00] TO BUS 448058 [RCRAIO2B    220.00] CKT 1
 SINGLE 448056-448060(1)        : OPEN LINE FROM BUS 448056 [RGRADI2     220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
 SINGLE 448057-448058(1)        : OPEN LINE FROM BUS 448057 [RCRAIO2A    220.00] TO BUS 448058 [RCRAIO2B    220.00] CKT 1
 SINGLE 448057-448060(1)        : OPEN LINE FROM BUS 448057 [RCRAIO2A    220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
 SINGLE 448058-448060(1)        : OPEN LINE FROM BUS 448058 [RCRAIO2B    220.00] TO BUS 448060 [RISALN2A    220.00] CKT 1
 SINGLE 448062-448063(1)        : OPEN LINE FROM BUS 448062 [RTG.JI2     220.00] TO BUS 448063 [RPAROS2     220.00] CKT 1
 SINGLE 448067-448068(1)        : OPEN LINE FROM BUS 448067 [RMINTI2A    220.00] TO BUS 448068 [RMINTI2B    220.00] CKT 1
 SINGLE 448067-448071(1)        : OPEN LINE FROM BUS 448067 [RMINTI2A    220.00] TO BUS 448071 [RTIMIS2     220.00] CKT 1
 SINGLE 448083-448084(1)        : OPEN LINE FROM BUS 448083 [RSTEJA2     220.00] TO BUS 448084 [RGHEOR2     220.00] CKT 1
 SINGLE 448087-448088(1)        : OPEN LINE FROM BUS 448087 [RIERNU2     220.00] TO BUS 448088 [RCTURZ2     220.00] CKT 1
 SINGLE 448088-448089(1)        : OPEN LINE FROM BUS 448088 [RCTURZ2     220.00] TO BUS 448089 [RCLUJF2     220.00] CKT 1
 SINGLE 448089-448091(1)        : OPEN LINE FROM BUS 448089 [RCLUJF2     220.00] TO BUS 448091 [RTIHAU2     220.00] CKT 1
 SINGLE 448091-448093(1)        : OPEN LINE FROM BUS 448091 [RTIHAU2     220.00] TO BUS 448093 [RBAIA 2     220.00] CKT 1
 BUS 10110                      : OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 101005 [AVDJRI1     400.00] CKT 1
                                  OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 381060 [0PODG211    400.00] CKT 1
 BUS 14122                      : OPEN LINE FROM BUS 14122 [XKO_TI11    400.00] TO BUS 141000 [VAEC_41     400.00] CKT 1
                                  OPEN LINE FROM BUS 14122 [XKO_TI11    400.00] TO BUS 448001 [RTANTA1     400.00] CKT 1
 BUS 14142                      : OPEN LINE FROM BUS 14142 [XMI_HA12    400.00] TO BUS 141055 [VMAIZ31     400.00] CKT 1
                                  OPEN LINE FROM BUS 14142 [XMI_HA12    400.00] TO BUS 540004 [4HAMITABAT  400.00] CKT 1
 BUS 30121                      : OPEN LINE FROM BUS 30121 [XNS_BA11    400.00] TO BUS 300010 [GSANTA11    400.00] CKT 1
                                  OPEN LINE FROM BUS 30121 [XNS_BA11    400.00] TO BUS 540019 [4BABAESKI   400.00] CKT 1
```

Figure 81: Contingency (n-1) analysis report for Extreme decarbonization - Average hydrology – minimum EMI regional electricity exchange in 2030

In this scenario there is a list of 25 contingency events that cause overloading in the network, where just one overloading is higher than 130% (given in red).

9.7. Extreme decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand

This scenario assumes extreme decarbonization - dry hydrology – maximum ratio between RES+HPP output and total demand. Regional and area summaries for the seventh scenario are given as follows:

	FROM	------AT AREA BUSES-------				TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
10	695.5	0.0	0.0	1168.0	0.0	0.0	5.2	0.0	21.3	-499.0	-499.0	-499.0
AL	189.2	0.0	0.0	299.5	478.9	0.0	31.1	635.3	234.2	-219.0	-219.0	
13	141.3	0.0	0.0	1505.0	0.0	0.0	12.0	0.0	59.2	-1434.9	-1434.9	-1435.0
BA	350.7	0.0	0.0	191.0	0.0	0.0	122.8	983.6	583.2	437.3	437.3	
14	3536.3	0.0	0.0	3829.2	0.5	0.0	53.9	0.0	175.7	-522.9	-522.9	-523.0
BG	2068.1	0.0	0.0	894.3	1185.1	0.0	142.4	2661.0	2269.4	237.8	237.8	
16	590.3	0.0	0.0	2059.0	0.0	0.0	4.6	0.0	117.5	-1590.8	-1590.8	-1591.0
HR	-131.0	0.0	0.0	473.7	100.0	0.0	22.3	1533.7	1058.2	-251.5	-251.5	
30	6364.3	0.0	0.0	7175.5	0.0	0.0	0.0	0.0	218.8	-1030.0	-1030.0	-1030.0
GR	-120.7	0.0	0.0	2578.5	1925.7	0.0	20.4	7775.9	2365.7	765.0	765.0	
37	816.1	0.0	0.0	1290.3	0.0	0.0	1.8	0.0	31.9	-508.0	-508.0	-508.0
MK	-83.3	0.0	0.0	148.6	0.0	0.0	6.5	460.2	319.4	-97.6	-97.6	
38	362.9	0.0	0.0	574.0	0.0	0.0	3.0	0.0	27.9	-242.0	-242.0	-242.0
ME	40.8	0.0	0.0	110.3	133.4	0.0	23.0	406.2	237.6	-57.3	-57.3	
44	8481.0	0.0	0.0	6307.0	0.0	0.0	86.6	0.0	219.4	1868.1	1868.1	1868.0
RO	75.3	0.0	0.0	1842.5	1725.6	0.0	248.1	4887.6	2466.2	-1319.6	-1319.6	
46	4674.7	0.0	0.0	4009.3	0.0	0.0	27.7	0.0	201.6	436.1	436.1	436.0
RS	1015.3	0.0	0.0	768.2	92.5	0.0	107.6	1999.1	2255.9	-209.6	-209.6	
47	175.9	0.0	0.0	780.0	0.0	0.0	4.7	0.0	21.3	-630.0	-630.0	-630.0
XK	322.6	0.0	0.0	259.9	0.0	0.0	13.8	247.1	233.8	62.2	62.2	
49	1723.1	0.0	0.0	1924.0	0.0	0.0	7.7	0.0	45.3	-254.0	-254.0	-254.0
SI	-10.5	0.0	0.0	253.0	91.9	0.0	53.6	670.1	517.9	-256.9	-256.9	
COLUMN	27561.6	0.0	0.0	30621.3	0.5	0.0	207.3	0.0	1140.0	-4407.4	-4407.4	-4408.0
TOTALS	3716.4	0.0	0.0	7819.6	5733.1	0.0	791.5	22259.9	12541.4	-909.3	-909.3	

Figure 82: Area summary report with Extreme decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand in 2030

In this scenario, the total regional load is 30,621 MW, while total generation is 27,561 MW. In this scenario again, all regional countries are importers, except Romania (1,868 MW). The largest regional importer is Bulgaria (-1,591 MW). In total, in this scenario, the EMI region has a deficit of 4,408 MW.

The following figure shows the cross-border power exchange map for this scenario with moderate decarbonization - average hydrology – hour with maximum ratio between RES+HPP output and total demand.

Figure 83: Cross-border exchanges (MW) and directions between the countries in the scenario: Extreme decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand in 2030

The following two figures show the 400 kV and 220 kV voltage profiles with maximum, minimum and average values in each country. All voltages in 400 kV network in the aforementioned categories are within limits save for Romania and Serbia where the minimum value is below the allowed threshold.

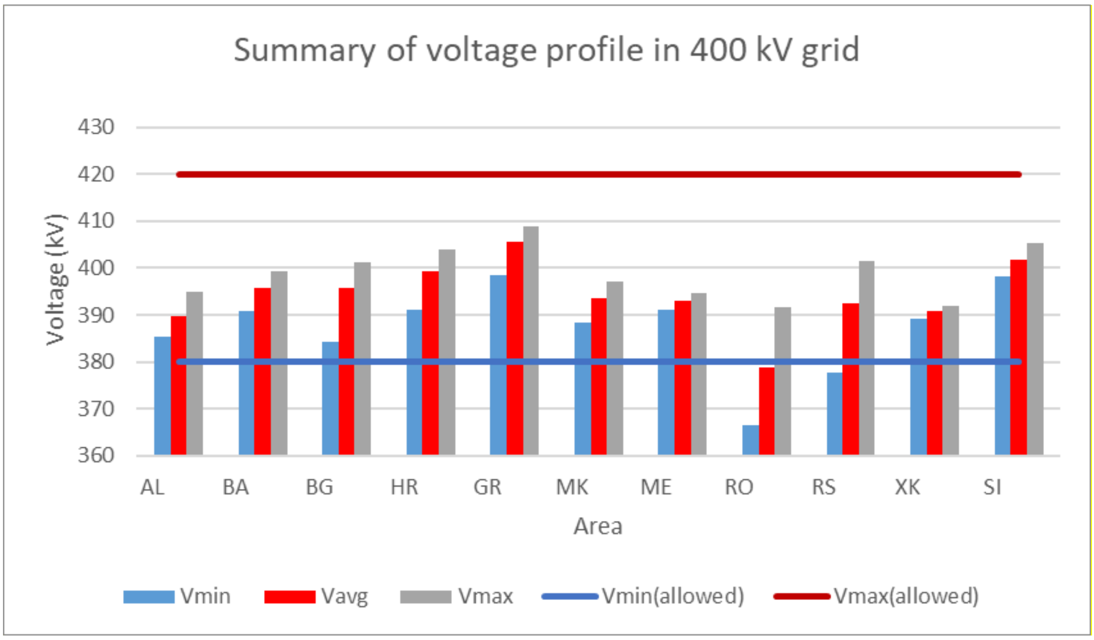


Figure 84: 400 kV voltage profiles (minimum, maximum and average) per country in this scenario (Extreme decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand) in 2030

As in the other previous scenarios, voltage profiles in the 220 kV network are within limits in all countries in this scenario, with the exception of Croatia, as usual.

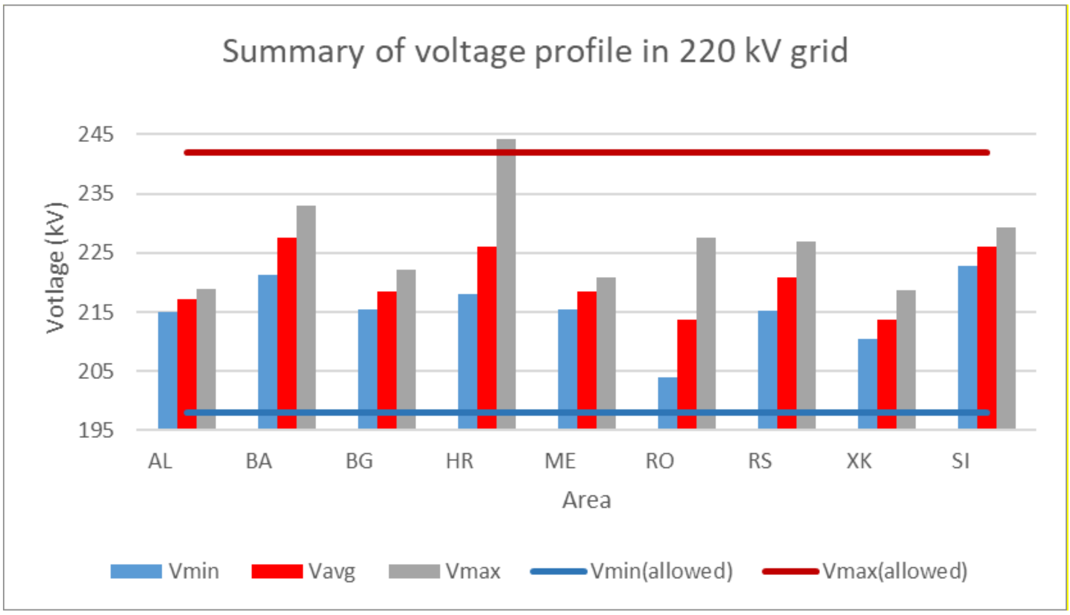


Figure 85: 220 kV voltage profiles (minimum, maximum and average) per country in this scenario (Extreme decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand) in 2030

There are just two transmission elements loaded more than 80%, again, double circuit interconnection line Croatia - Hungary (83,42%):

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	CKT	MW	MVAR	MVA	RATING	%I	MW LOSS	MVAR LOSS
16101	[XER_PE11 400,00]	161015	[HERNES11 400,00]	1	1090,76	-4,46	1090,77	1330,21	**83,42**	9,94	104,96
16102	[XER_PE12 400,00]	161015	[HERNES11 400,00]	2	1090,76	-4,46	1090,77	1330,21	**83,42**	9,94	104,96

Figure 86: List of 400 and 220 kV elements loaded more than 80% in this scenario (Extreme decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand) 2030

The contingency n-1 analysis report for this scenario is given as follows:

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING   FLOW    %
 460065*JOBREN12    400.00 460090 JRPMLA12    400.00 1  SINGLE 460060-460085(2)         1330.2  1593.6  121.2
 460060*JOBREN11    400.00 460085 JRPMLA11    400.00 2  SINGLE 460065-460090(1)         1330.2  1595.0  121.3
  10210*XKO_PO21    220.00 102015 AKOPLI2     220.00 1  BUS 10110                        274.4   321.6  120.7
  10210 XKO_PO21    220.00 382030*0PODG121    220.00 1  BUS 10110                        274.4   323.0  120.8
 102010 AVDEJA2     220.00 102015*AKOPLI2     220.00 1  BUS 10110                        278.2   315.5  116.9
  14124*XVA_MG11    400.00 141115 VVARNA1     400.00 1  BUS 14121                       1380.0  1595.6  127.4
  14121*XDO_MG11    400.00 141035 VDOBRU1     400.00 1  BUS 14124                       1380.0  1508.8  121.0
  14141 XMI_HA11    400.00 141055*VMAIZ31     400.00 1  BUS 14142                       1200.0  1227.9  102.6
  16102*XER_PE12    400.00 161015 HERNES11    400.00 2  BUS 16101                       1330.2  1803.2  140.1
  16102*XER_PE12    400.00 311181 MPECSO11    400.00 2  BUS 16101                       1385.6  1803.2  134.5
  16101*XER_PE11    400.00 161015 HERNES11    400.00 1  BUS 16102                       1330.2  1803.2  140.1
  16101*XER_PE11    400.00 311181 MPECSO11    400.00 1  BUS 16102                       1385.6  1803.2  134.5
  32201 XPA_DI21    220.00 492020*DIVACA220   220.00 1  BUS 32101                        365.8   481.8  128.9

 LOSS OF LOAD REPORT:
 <-------- B U S --------> <----- CONTINGENCY LABEL ------> LOAD(MW)

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                       Met convergence to     0    31    0.0
 SINGLE 370350-370360(1)         Blown up              --    --     --
 SINGLE 460060-460085(2)         Met convergence to     1     0    0.0
 SINGLE 460065-460090(1)         Met convergence to     1     0    0.0
 BUS 10110                       Met convergence to     3     2    0.0
 BUS 14121                       Met convergence to     1     5    0.0
 BUS 14124                       Met convergence to     1     7    0.0
 BUS 14142                       Met convergence to     1     0    0.0
 BUS 16101                       Met convergence to     2     0    0.0
 BUS 16102                       Met convergence to     2     0    0.0
 BUS 32101                       Met convergence to     1     0    0.0
 IT-SI BOTH LINES                Blown up              --    --     --

CONTINGENCY LEGEND: from list of total 787 analyzed contingencies)
 (selected 9 contingecies (2 contingencies with convergence problems not included) appeared above)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 460060-460085(2)         : OPEN LINE FROM BUS 460060 [JOBREN11    400.00] TO BUS 460085 [JRPMLA11    400.00] CKT 2
 SINGLE 460065-460090(1)         : OPEN LINE FROM BUS 460065 [JOBREN12    400.00] TO BUS 460090 [JRPMLA12    400.00] CKT 1
 BUS 10110                       : OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 101005 [AVDJRI1     400.00] CKT 1
                                   OPEN LINE FROM BUS 10110 [XKA_PG11    400.00] TO BUS 381060 [0PODG211    400.00] CKT 1
 BUS 14121                       : OPEN LINE FROM BUS 14121 [XDO_MG11    400.00] TO BUS 141035 [VDOBRU1     400.00] CKT 1
                                   OPEN LINE FROM BUS 14121 [XDO_MG11    400.00] TO BUS 448974 [RMEDGI1     400.00] CKT 1
 BUS 14124                       : OPEN LINE FROM BUS 14124 [XVA_MG11    400.00] TO BUS 141115 [VVARNA1     400.00] CKT 1
                                   OPEN LINE FROM BUS 14124 [XVA_MG11    400.00] TO BUS 448974 [RMEDGI1     400.00] CKT 1
 BUS 14142                       : OPEN LINE FROM BUS 14142 [XMI_HA12    400.00] TO BUS 141055 [VMAIZ31     400.00] CKT 1
                                   OPEN LINE FROM BUS 14142 [XMI_HA12    400.00] TO BUS 540004 [4HAMITABAT  400.00] CKT 1
 BUS 16101                       : OPEN LINE FROM BUS 16101 [XER_PE11    400.00] TO BUS 161015 [HERNES11    400.00] CKT 1
                                   OPEN LINE FROM BUS 16101 [XER_PE11    400.00] TO BUS 311181 [MPECSO11    400.00] CKT 1
 BUS 16102                       : OPEN LINE FROM BUS 16102 [XER_PE12    400.00] TO BUS 161015 [HERNES11    400.00] CKT 2
                                   OPEN LINE FROM BUS 16102 [XER_PE12    400.00] TO BUS 311181 [MPECSO11    400.00] CKT 2
 BUS 32101                       : OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 321346 [REDIPUGLIA  400.00] CKT 1
                                   OPEN LINE FROM BUS 32101 [XRE_DI11    400.00] TO BUS 491040 [PST_DIV     400.00] CKT 1
```

Figure 87: Contingency (n-1) analysis report for Extreme decarbonization - Dry hydrology – maximum ratio between RES+HPP output and total demand 2030

In this scenario there is a list of 9 contingency events that provoke overloading in the network, where overloading higher than 130% are found on 400 kV interconnection line Croatia – Hungary (given above in red).

9.8. Extreme decarbonization - Dry hydrology – maximum EMI regional electricity exchange

This scenario assumes extreme decarbonization - Dry hydrology – maximum EMI regional electricity exchange. Regional and area summaries for the last network scenario are given as follows:

	FROM ------AT AREA BUSES-------				TO					-NET INTERCHANGE-		
X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	662.7	0.0	0.0	1330.0	0.0	0.0	5.6	0.0	22.1	-695.0	-695.0	-695.0
AL	187.2	0.0	0.0	341.0	512.8	0.0	33.6	686.4	203.4	-217.1	-217.1	
13	1178.8	0.0	0.0	1673.0	0.0	0.0	15.2	0.0	33.8	-543.2	-543.2	-543.0
BA	105.5	0.0	0.0	210.6	0.0	0.0	155.5	1094.2	389.3	444.3	444.3	
14	2923.2	0.0	0.0	3982.5	0.5	0.0	53.7	0.0	83.4	-1196.9	-1196.9	-1197.0
BG	979.9	0.0	0.0	907.0	1253.8	0.0	121.3	2795.1	1106.6	386.2	386.2	
16	1101.7	0.0	0.0	2460.0	0.0	0.0	4.9	0.0	75.6	-1438.8	-1438.8	-1438.0
HR	-282.2	0.0	0.0	566.0	110.4	0.0	23.8	1656.4	627.0	47.1	47.1	
30	10478.4	0.0	0.0	8195.7	0.0	0.0	0.0	0.0	248.6	2034.0	2034.0	2034.0
GR	-93.1	0.0	0.0	2659.8	1941.9	0.0	21.0	7836.8	3237.0	-116.0	-116.0	
37	638.4	0.0	0.0	1056.0	0.0	0.0	2.1	0.0	15.3	-435.0	-435.0	-435.0
MK	28.9	0.0	0.0	157.6	0.0	0.0	9.9	503.2	173.5	191.1	191.1	
38	182.4	0.0	0.0	563.0	0.0	0.0	3.3	0.0	21.2	-405.1	-405.1	-405.0
ME	38.0	0.0	0.0	110.3	150.2	0.0	24.2	457.2	210.7	-0.2	-0.2	
44	6997.8	0.0	0.0	7697.0	0.0	0.0	96.0	0.0	129.9	-925.1	-925.1	-925.0
RO	-138.5	0.0	0.0	2224.7	1900.3	0.0	275.1	5435.8	1601.8	-704.5	-704.5	
46	3445.5	0.0	0.0	4432.1	0.0	0.0	31.5	0.0	76.4	-1094.5	-1094.5	-1094.0
RS	277.2	0.0	0.0	788.5	103.7	0.0	122.2	2207.2	1050.9	419.1	419.1	
47	71.1	0.0	0.0	716.0	0.0	0.0	5.2	0.0	5.9	-656.0	-656.0	-656.0
XK	64.7	0.0	0.0	238.9	0.0	0.0	15.3	275.4	70.9	15.0	15.0	
49	1794.5	0.0	0.0	2010.0	0.0	0.0	8.1	0.0	37.5	-261.1	-261.1	-261.0
SI	-30.3	0.0	0.0	264.4	95.3	0.0	56.0	699.5	361.6	-108.0	-108.0	
COLUMN	29474.5	0.0	0.0	34115.3	0.5	0.0	225.6	0.0	749.8	-5616.7	-5616.7	-5615.0
TOTALS	1137.4	0.0	0.0	8468.8	6068.4	0.0	857.8	23647.2	9032.6	357.1	357.1	

Figure 88: Area summary report with Extreme decarbonization - Dry hydrology – maximum EMI regional electricity exchange in 2030

In this scenario, the total regional load is 34,115 MW, and total generation is 29,474 MW. In this scenario again, all regional countries are importers, except Greece (2,034 MW). The largest regional importer is Croatia (-1,438 MW), and the overall EMI region has a large deficit of 5,615 MW.

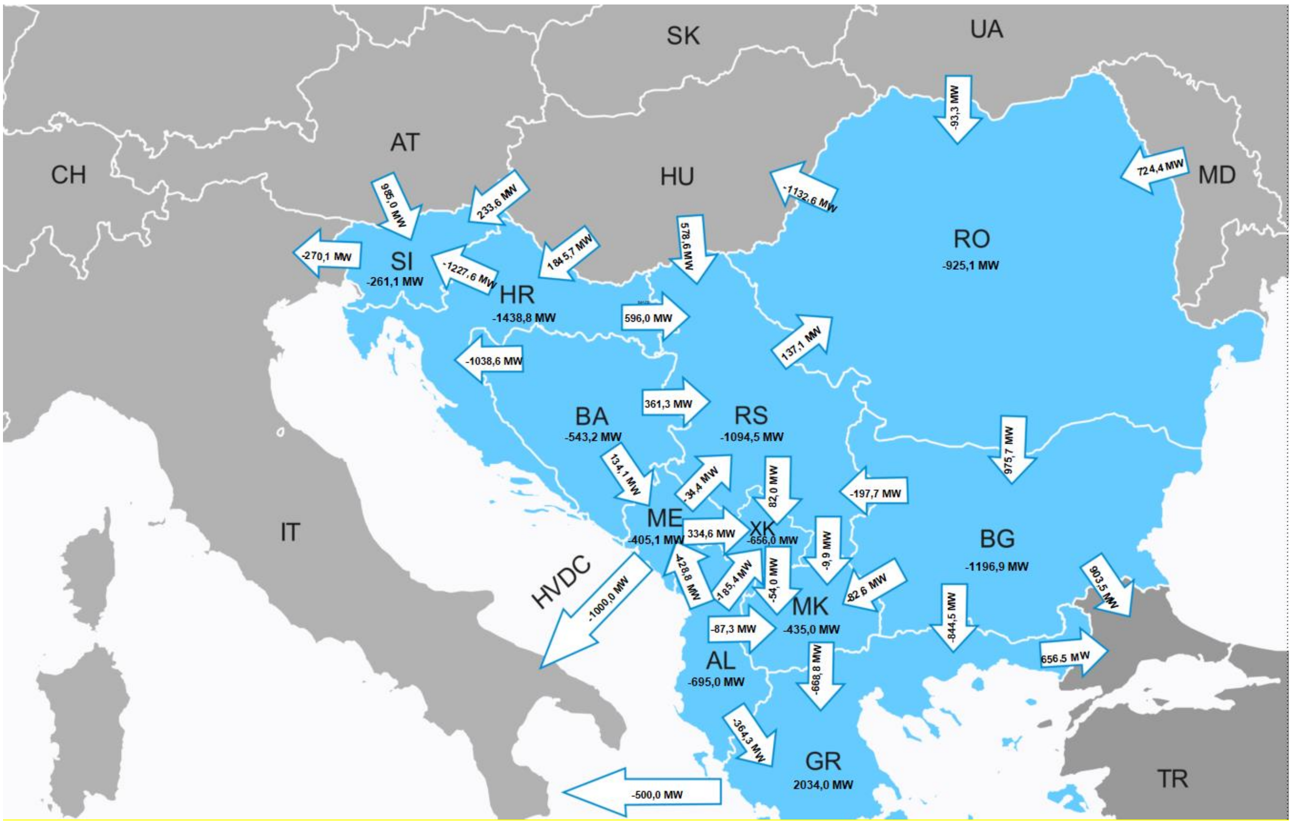


Figure 89: Cross-border exchanges (MW) and directions between the countries in the scenario: Extreme decarbonization - Dry hydrology – maximum EMI regional electricity exchange in 2030

The following two figures show the 400 kV and 220 kV voltage profiles with maximum, minimum and average values in each country. The voltage profiles in 400 kV network are within limits except for maximum voltages in BiH and Croatia with a borderline values in Montenegro and Serbia.

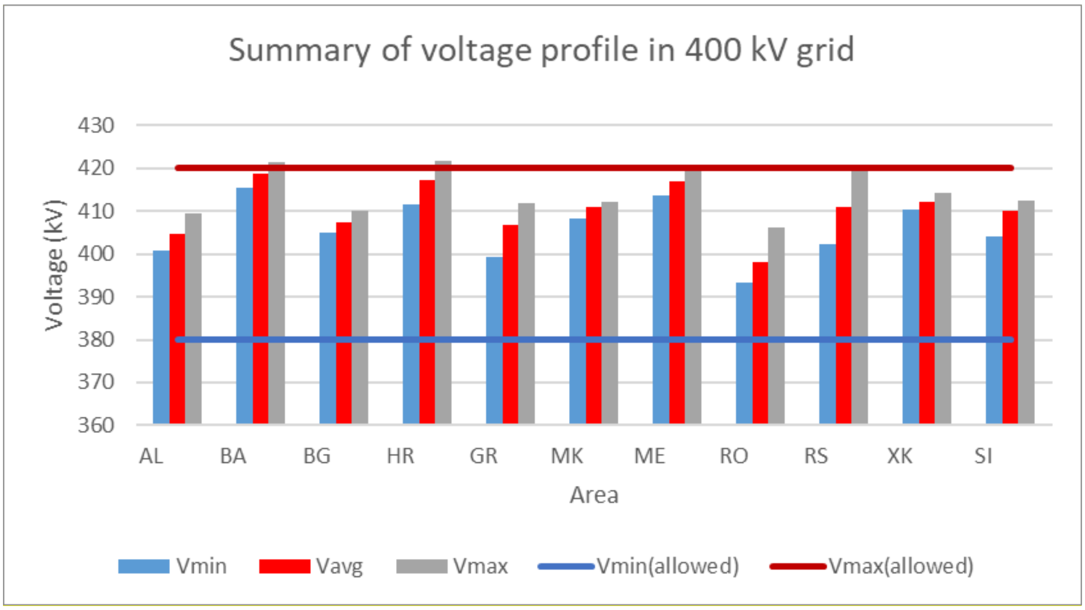


Figure 90: 400 kV voltage profiles (minimum, maximum and average) per country in this scenario (Extreme decarbonization - Dry hydrology – maximum EMI regional electricity exchange) in 2030

As in the other previous scenarios, voltage profiles in the 220 kV network are within limits in all countries in this scenario, with the exception of Croatia and BiH where the maximum value is above the allowed threshold.

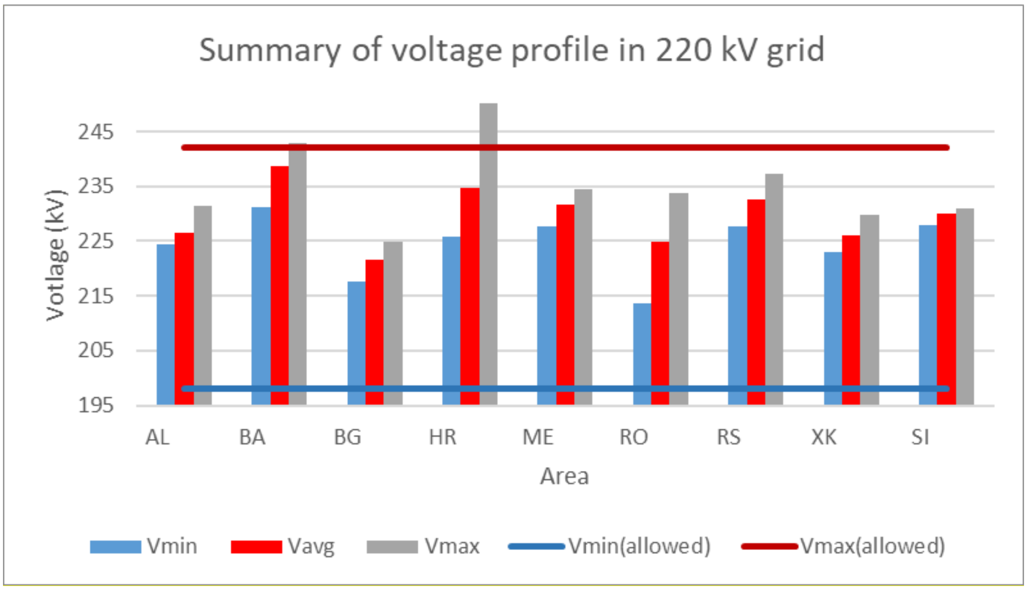


Figure 91: 220 kV voltage profiles (minimum, maximum and average) per country in this scenario (Extreme decarbonization - Dry hydrology – maximum EMI regional electricity exchange) in 2030

There are just three transmission elements loaded more than 80%:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	CKT	MW	MVAR	MVA	RATING	%I	MW LOSS	MVAR LOSS
38030	[XVI_LA1M 400,00]	381030	[OLASTV11 400,00]	1	1000	-50	1001,25	1108,5	86,94	0	0
300079	[GKQESS11 400,00]	300117	[GELPE11 400,00]	1	-382,8	102,73	396,35	476	81,15	0,21	0,89
448067	[RMINTI2A 220,00]	448068	[RMINTI2B 220,00]	1	290,99	57,98	296,71	333,4	86,39	0	0,17

Figure 92: List of 400 and 220 kV elements loaded more than 80% in this scenario (Extreme decarbonization - Dry hydrology – maximum EMI regional electricity exchange) in 2030

The contingency n-1 analysis report for this scenario is given as follows:

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING    FLOW       %
 161035*HMELIN11     400.00 3WNDTR MELINA TR2   WND 1 2  SINGLE 161035-162040-166282(1)       150.0     163.3    105.0
 448089 RCLUJF2      220.00 448097*RAL.JL2      220.00 1  SINGLE 448068-448097(1)             323.1     254.7    108.4

 LOSS OF LOAD REPORT:
 <-------- B U S --------> <----- CONTINGENCY LABEL ------> LOAD(MW)

 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                 <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                        Met convergence to     0     4    0.0
 SINGLE 161035-162040-166282(1)   Met convergence to     1     0    0.0
 SINGLE 448003-448034(1)          Met convergence to     1     0    0.0
 SINGLE 448009-448096(1)          Met convergence to     1     0    0.0
 SINGLE 448068-448097(1)          Met convergence to     1     0    0.0
 SINGLE 448089-448097(1)          Met convergence to     1     0    0.0

CONTINGENCY LEGEND: from list of total 794 analyzed contingencies)
 (selected 5 contingecies appeared above)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 161035-162040-166282(1)  : OPEN LINE FROM BUS 161035 [HMELIN11    400.00] TO BUS 162040 [HMELIN21    220.00] TO BUS
166282 [HMELIN_2    31.000] CKT 1
 SINGLE 448003-448034(1)         : OPEN LINE FROM BUS 448003 [RMINTI1     400.00] TO BUS 448034 [RSIBIU1     400.00] CKT 1
 SINGLE 448009-448096(1)         : OPEN LINE FROM BUS 448009 [RNADAB1     400.00] TO BUS 448096 [RORADE1     400.00] CKT 1
 SINGLE 448068-448097(1)         : OPEN LINE FROM BUS 448068 [RMINTI2B    220.00] TO BUS 448097 [RAL.JL2     220.00] CKT 1
 SINGLE 448089-448097(1)         : OPEN LINE FROM BUS 448089 [RCLUJF2     220.00] TO BUS 448097 [RAL.JL2     220.00] CKT 1
```

Figure 93: Contingency (n-1) analysis report for Extreme decarbonization - Dry hydrology – maximum EMI regional electricity exchange in 2030

In this scenario there is a list of 5 contingency events that cause overloading in the network, where no overloading higher than 130%.

9.9. Concluding remarks on the decarbonization impact on SEE network operation

In this subchapter we summarize the impact of different decarbonization scenarios on the operation of the network in SEE in these two areas:

1. map of critical network elements (contingency map)
2. list of critical network elements (contingencies list)

Altogether the contingencies appear on 28 elements in the region that could be critical in the future due to decarbonization scenarios analyzed in this study. Among them there are:

- **7 critical tie lines,**
- **16 internal lines, and**
- **5 transformers (in Konjsko (HR) the problem is the same on 2 parallel transformers)**

The five critical tie lines are found in the 400 kV network and two on the 220 kV network. These elements are located on the following borders:

- **Bulgaria – Romania (3 tie lines)**
- **Bulgaria – Turkey**
- **Croatia - Hungary**
- **Albania – Montenegro and**
- **BiH – Montenegro**

The 16 critical internal lines are also found both in the 400 kV network (2 lines) and the 220 kV network (12 lines). These elements are located in these countries:

- **Serbia (1 line on 400 kV level)**
- **Greece (1 line on 400 kV level)**
- **Albania (2 lines on 220 kV level)**
- **Romania (6 lines on 220 kV level)**
- **Bulgaria (2 lines on 220 kV level)**
- **Montenegro (1 lines on 220 kV) and**
- **Bosnia and Herzegovina (1 lines on 220 kV)**

Three transformers are critical in the region, with two in Croatia, and three in Romania.

Among the 28 critical elements there are 10 elements with severe overloading (130% of rated current) in one or more scenarios.

The following figure shows the geographical dispersion of critical elements in the EMI region. It seems that all EMI TSOs, except MEPSO and KOSTT **can expect to face network bottlenecks in the analyzed decarbonization in 2030.**

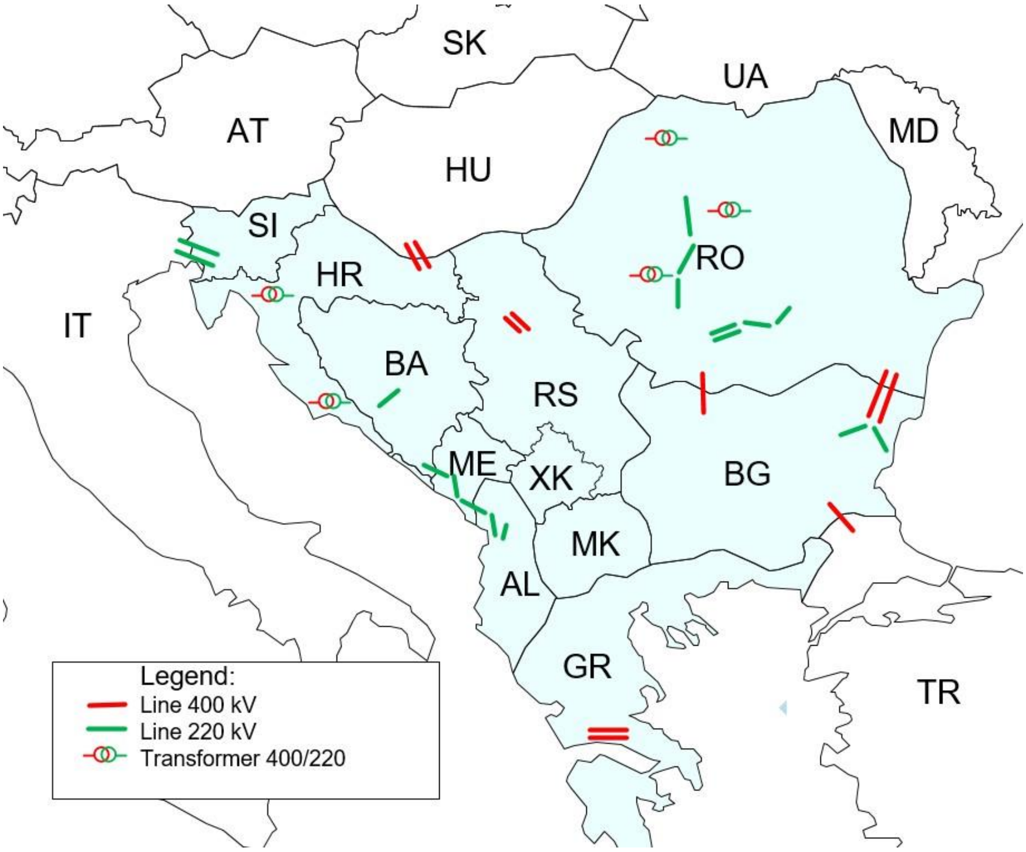


Figure 94: Geographical distribution of the critical transmission network elements in the region in all analyzed scenarios 2030

The following table gives the details of the critical elements in all scenarios.

Critical element			Area/Border	Scenario							
				Moderate decarbonisation				Extreme decarbonisation			
				Average hydrology		Dry hydrology		Average hydrology		Dry hydrology	
Type	Voltage	Connected nodes		MAX RATIO 1	MAX EXC 2	MAX RATIO 3	MAX EXC 4	MAX RATIO 5	MAX EXC 6	MAX RATIO 7	MAX EXC 8
Tie-lines	400 kV	Dobrudzha - Medigidia Sud	BG-RO						101,3		
		Ernestinovo - Peks (circuit 1 and 2)	HR-HU		107,2			**140,4**		**138,8**	
		Kozloduy - Tantareni	BG-RO	106,6							
		Maritsa Iztok 3 - Hamitabat	BG-TR	102,5						101,0	
		Varna - Medigidia Sud	BG-RO						101,3		
	220 kV	Koplik - Podgorica	AL-ME		**153,9**	**137,0**	**126,9**	109,9		117,1	
		Padriciano - Divaca	IT-SI	**163,7**				**129,2**		128,9	
		Pehlin - Divaca	IT-SI	104,2							
		Trebinje - Perucica	BA-ME		105,2		118,3				
Internal lines	400 kV	Ag.Nikolaos - Distomo (circuit 1 and 2)	GR						100,7		
		Obrenovac - RP Mladost (circuit 1 and 2)	RS							119,6	
	220 kV	Perucica - Podgorica 1	ME		102,0		108,0				
		V.Dejes - Koplik	AL		**148,9**	**133,3**	119,3	106,2		113,2	
		V.Dejes - Vdjri	AL	104,1			127,9				
		Cluj Floresti - Alba Iulia	RO								108,4
		Craiova Nord - Isalnita (circuit 1 and 2)	RO	121,9			**132,1**		121,4		
		Gradiste - Isalnita	RO	**152,8**			122,5		120,0		
		Mintia - Alba Iulia	RO				106,1		119,2		
		Pestis - Mintia	RO				101,3		100,1		
		Slatina - Gradiste	RO	**178,0**			102,2		101,7		
		Dobrudzha - Varna	BG				116,7		105,7		
		Madara - Varna	BG								
		RP Jablanica - Posusje	BA	115,5							
Transformers	400/220 kV	Konjsko (TR1 and TR2)	HR	**127,3**							
	400/220 kV	Melina	HR	**155,3**							105,0
	400/220 kV	Iernut	RO				100,8		**126,1**		
	400/220 kV	Mintia	RO				108,7		102,9		
	400/220 kV	Rosiori	RO				106,4		115,2		

Legend: Overloading in Base case (N-0)
Very high overload

In these conditions, we did not detect a central corridor or trans-regional set of bottlenecks that would suggest the need for a large coordinated regional program of high-voltage additions. **Rather, with only 28 bottlenecks in the region in all scenarios in 2030, we conclude that while selected upgrades and de-bottlenecking make sense, the SEE regional network overall is robust enough for the future planned decarbonization and RES absorption process.**

9.10. Individual network area analyses

Since the EMI members are focused on the impact of decarbonization on their internal network operation, network losses and voltage profiles, we have compared the network overviews between our scenarios in the following subchapters, separately for each TSO area.

In each subchapter, the first two figures show the transmission network losses in each area in all analyzed scenarios. For a more detailed loss analysis, we would need to evaluate a yearly timeframe; however, these indicative figures allow us to follow the impact of the decarbonization scenarios on the level of losses in each country, and its percentage of the total system load. We note that network losses strongly depend on the geographic dispersion of RES sites and the internal power flows, as well as the market's daily and seasonal consumption curves.

The other two figures in each subchapter below provide an overview of the voltage profiles in each area for all analyzed cases. The voltage profile in every area is dominantly within the allowed range, while network losses significantly depend on the scenario, as expected. Here we have analyzed just the power losses in each snapshot/scenarios, and not yearly energy losses. Each EMI member can review these results to determine whether further analysis may be warranted.

9.10.1. OST (AL) Network Area

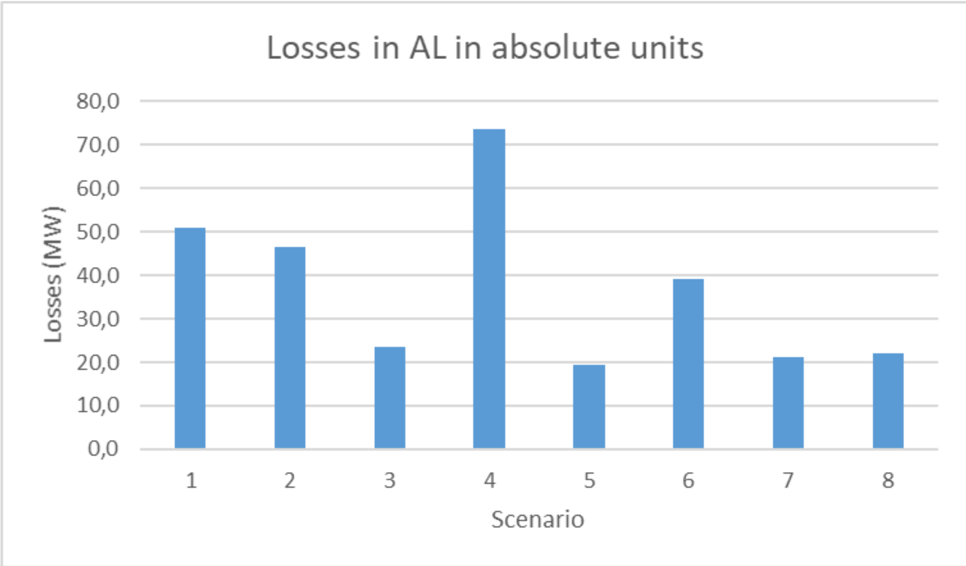


Figure 95: Transmission network losses in absolute value in the AL area in all analyzed network scenarios 2030

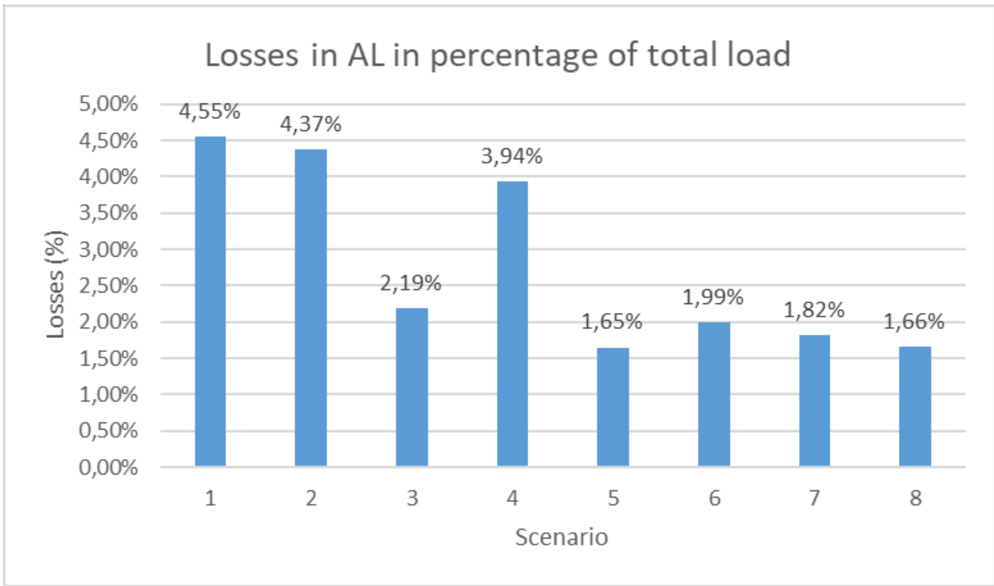


Figure 96: Transmission network losses in the AL area relative to system load in all analyzed scenarios 2030

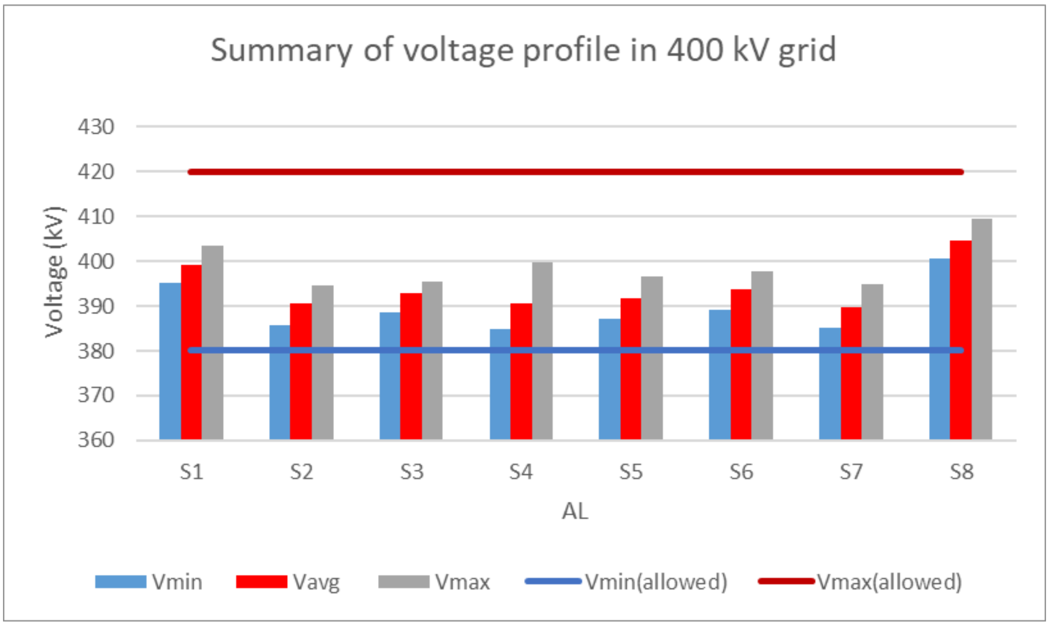


Figure 97: 400 kV voltage profiles (minimum, maximum and average) in the AL area in all analyzed scenarios 2030

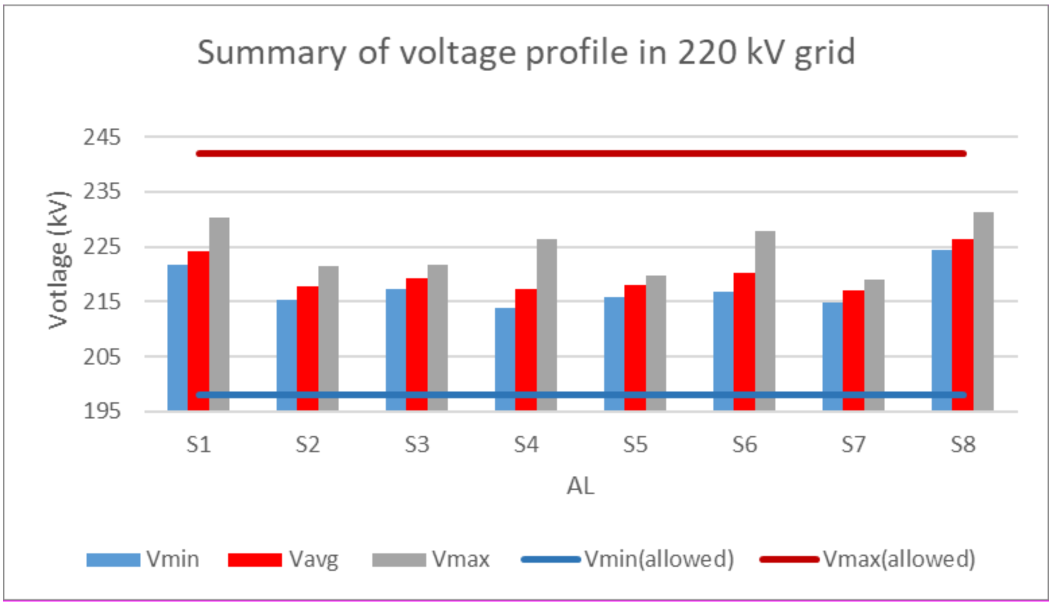


Figure 98: 220 kV voltage profiles (minimum, maximum and average) in the AL area in all analyzed scenarios 2030

9.10.2. NOS BiH (BA) Network Area

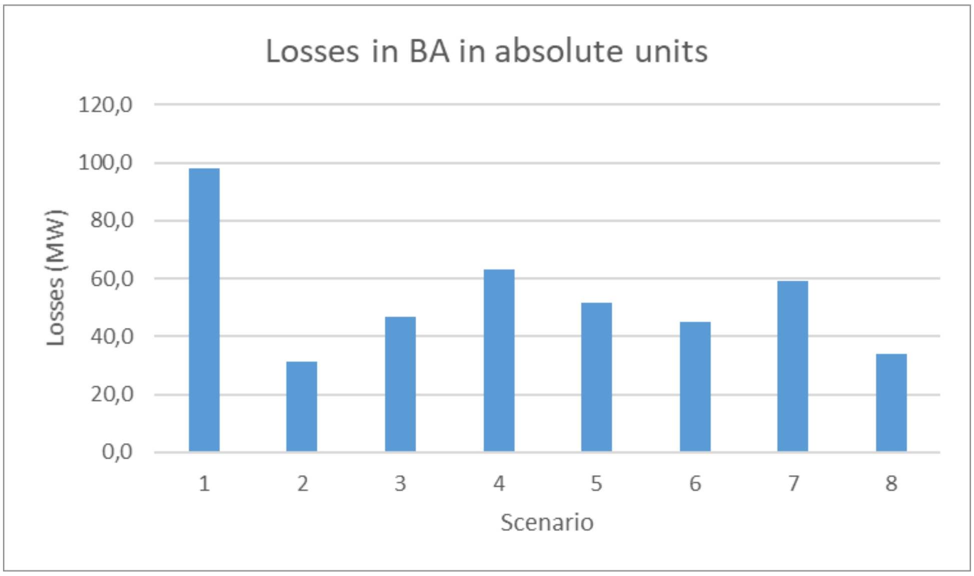


Figure 99: Transmission network losses in absolute value in the BiH area in all analyzed network scenarios 2030

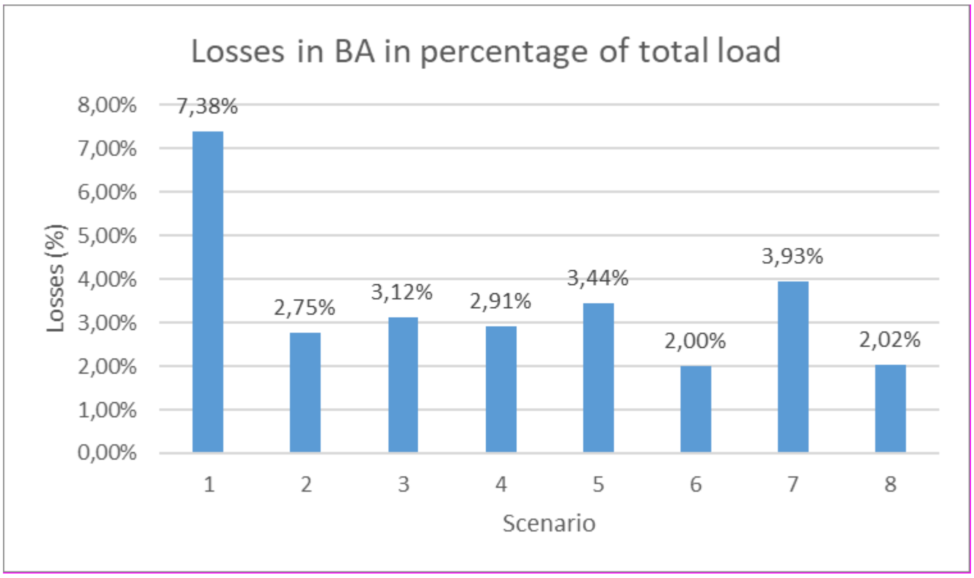


Figure 100: Transmission network losses in the BiH area relative to system load in all analyzed scenarios 2030

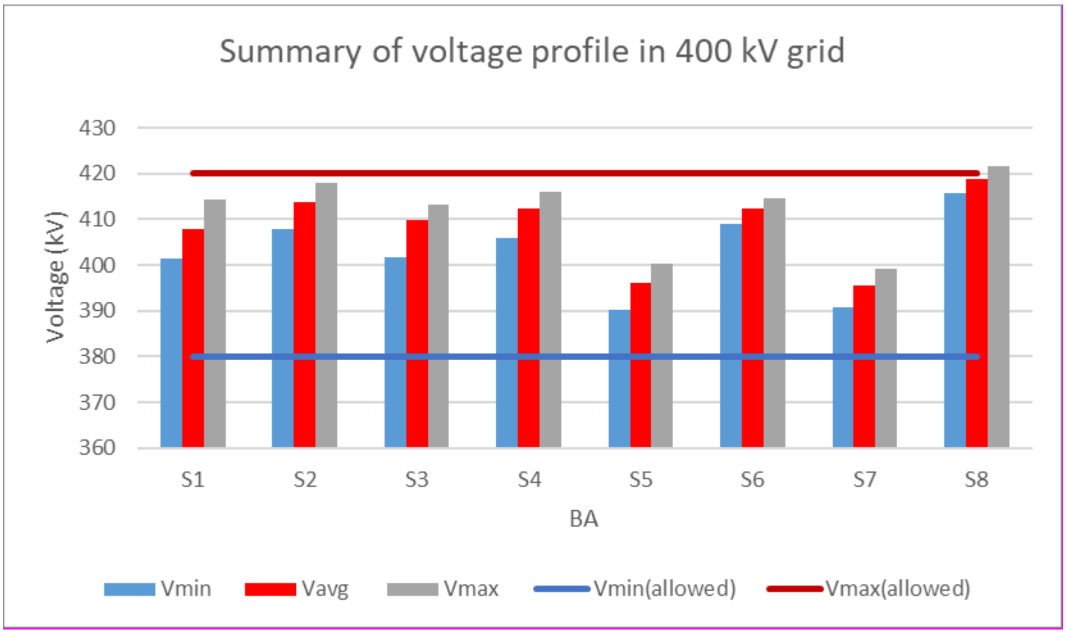


Figure 101: 400 kV voltage profiles (minimum, maximum and average) in the BiH area in all analyzed scenarios 2030

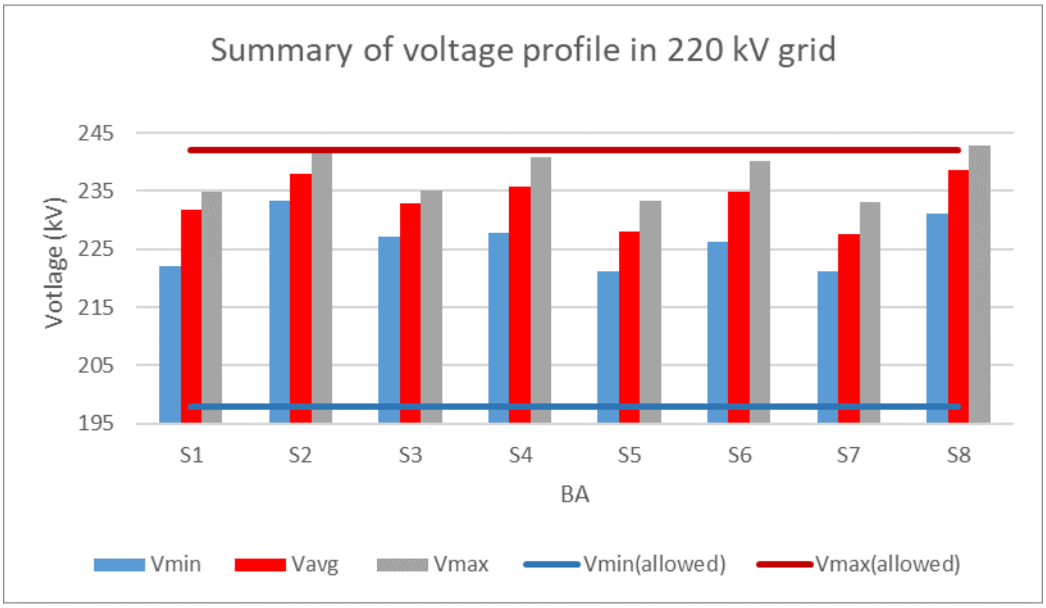


Figure 102: 220 kV voltage profiles (minimum, maximum and average) in the BiH area in all analyzed scenarios 2030

9.10.3. ESO (BG) Network Area

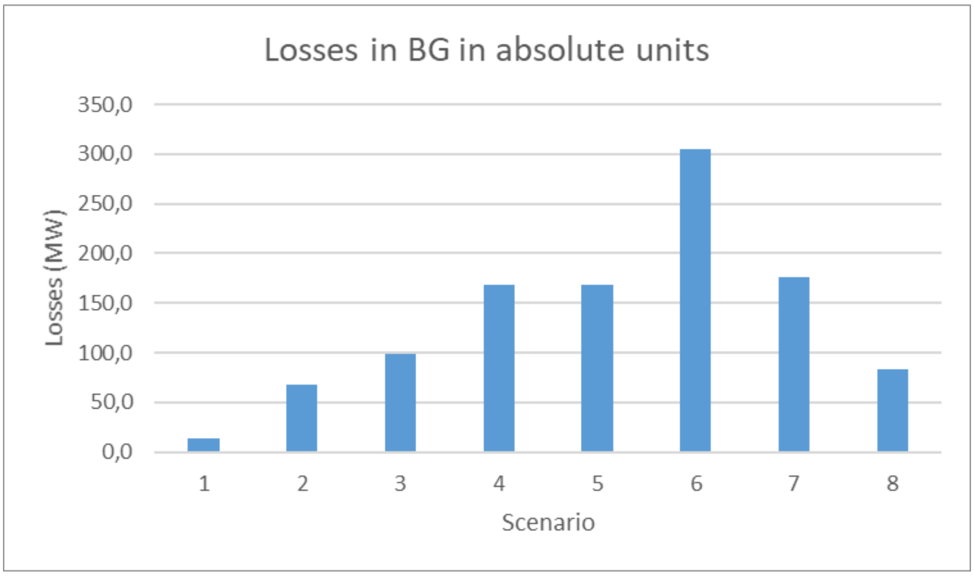


Figure 103: Transmission network losses in absolute value in the BG area in all analyzed network scenarios 2030

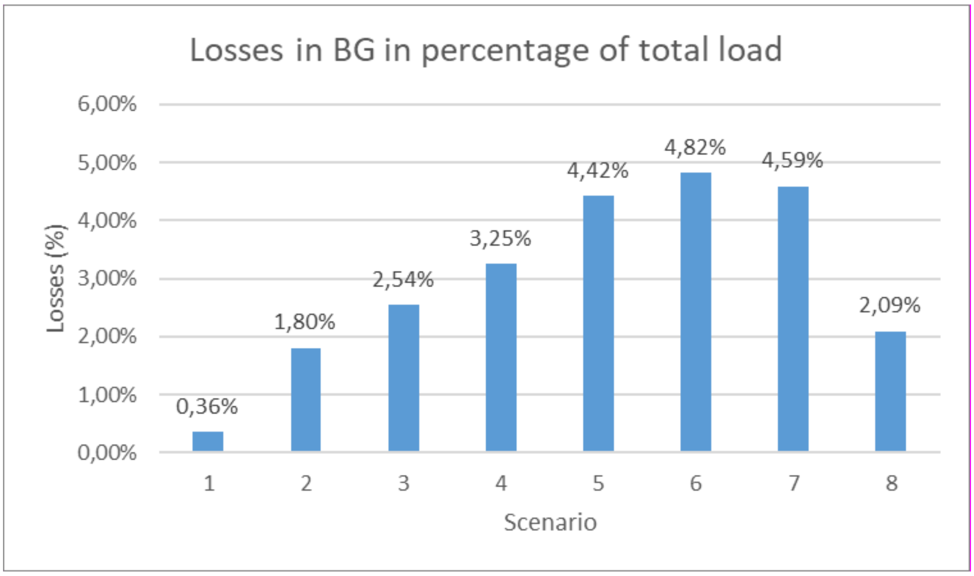


Figure 104: Transmission network losses in the BG area relative to system load in all analyzed scenarios 2030

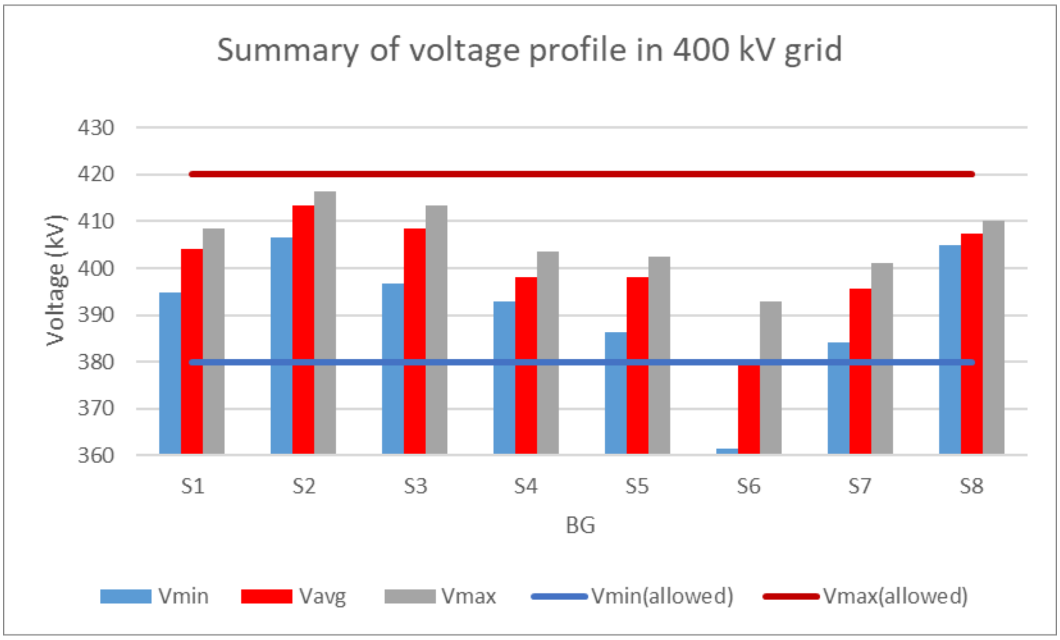


Figure 105: 400 kV voltage profiles (minimum, maximum and average) in the BG area in all analyzed scenarios 2030

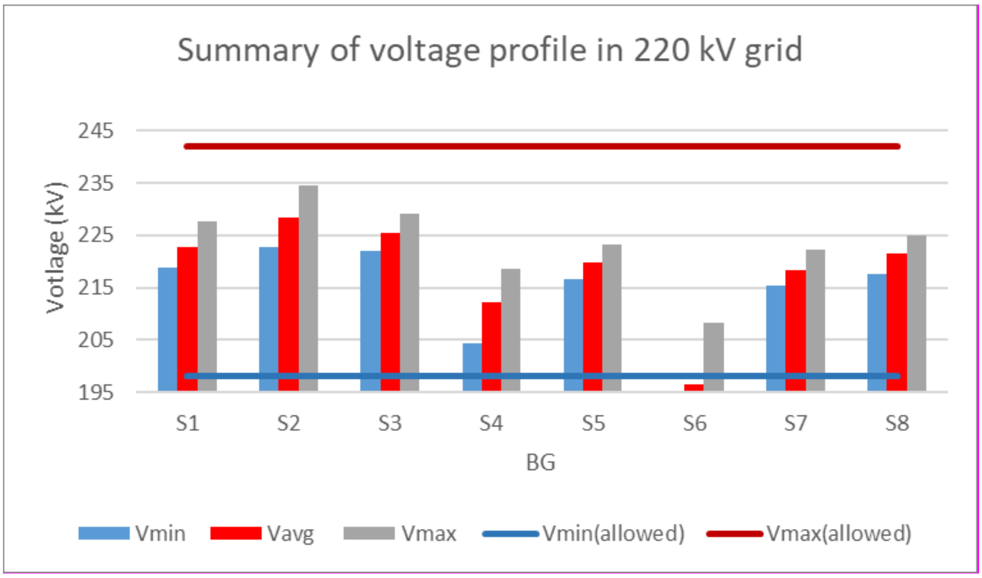


Figure 106: 220 kV voltage profiles (minimum, maximum and average) in the BG area in all analyzed scenarios 2030

9.10.4. IPTO (GR) Network Area

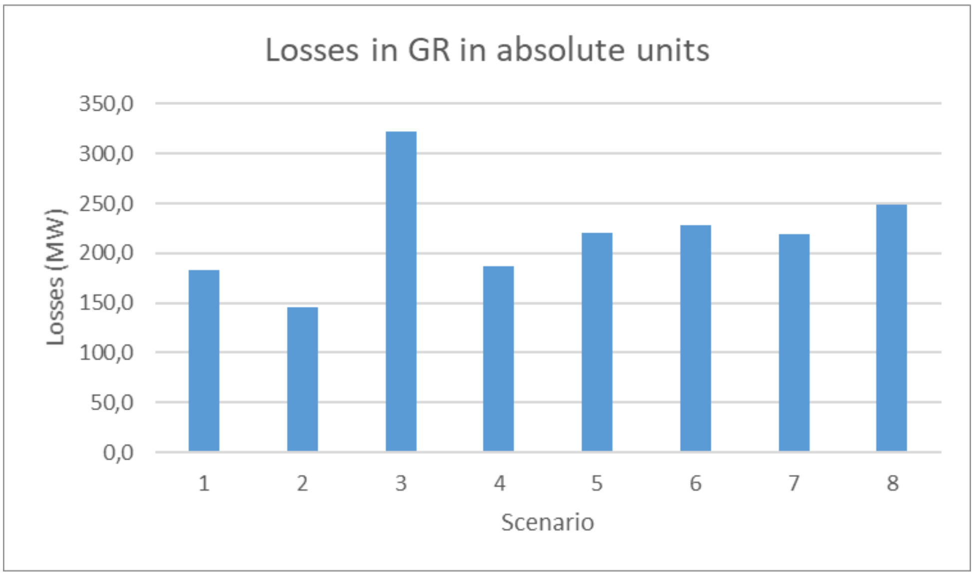


Figure 107: Transmission network losses in absolute value in the GR area in all analyzed network scenarios 2030

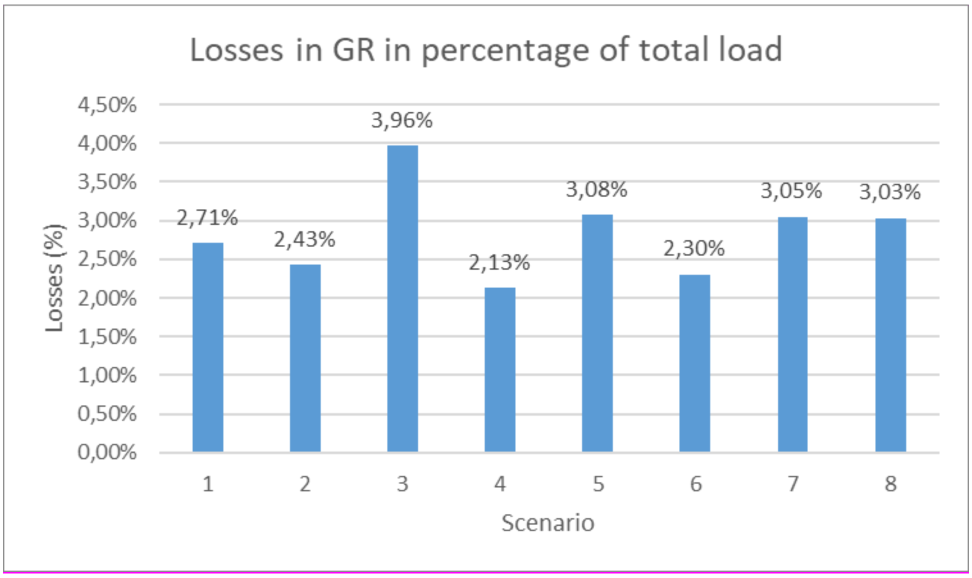


Figure 108: Transmission network losses in the GR area relative to system load in all analyzed scenarios 2030

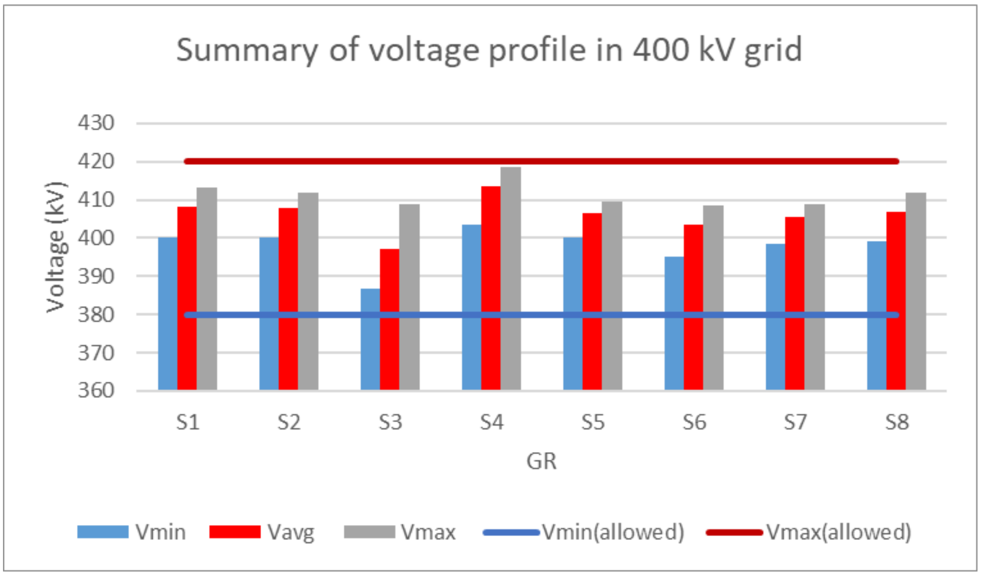


Figure 109: 400 kV voltage profiles (minimum, maximum and average) in the GR area in all analyzed scenarios 2030

9.10.5. HOPS (HR) Network Area

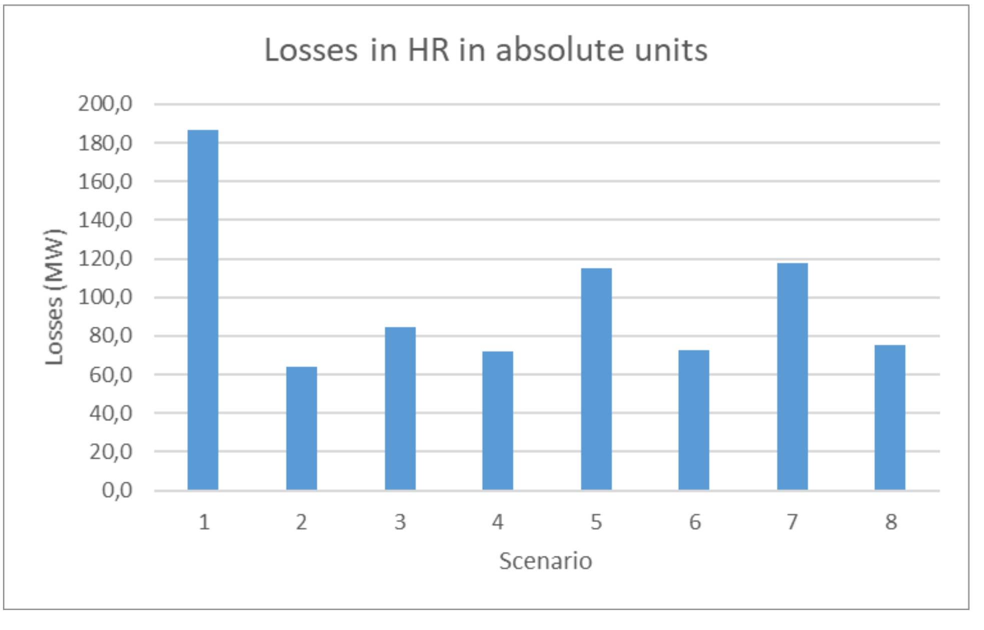


Figure 110: Transmission network losses in absolute value in the HR area in all analyzed network scenarios 2030

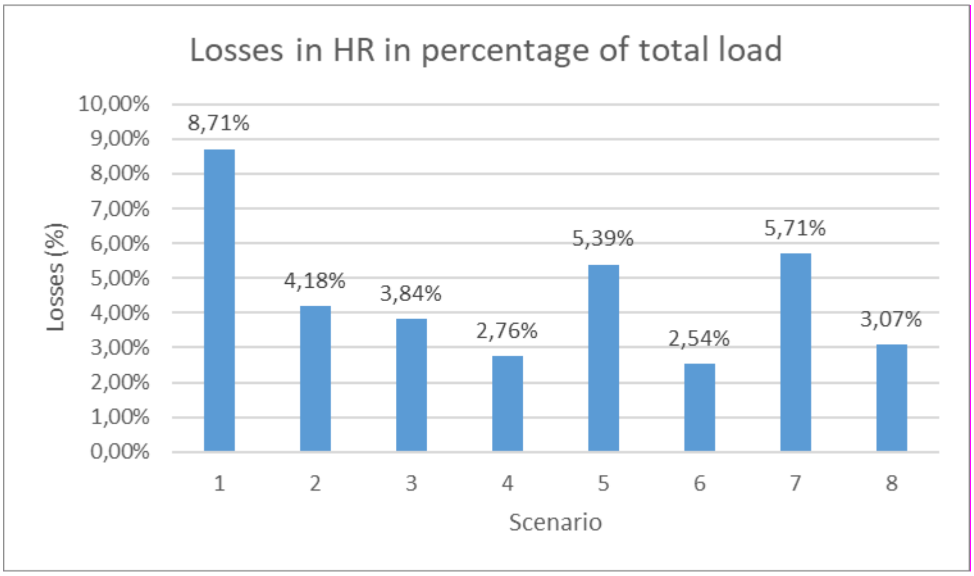


Figure 111: Transmission network losses in the HR area relative to system load in all analyzed scenarios 2030

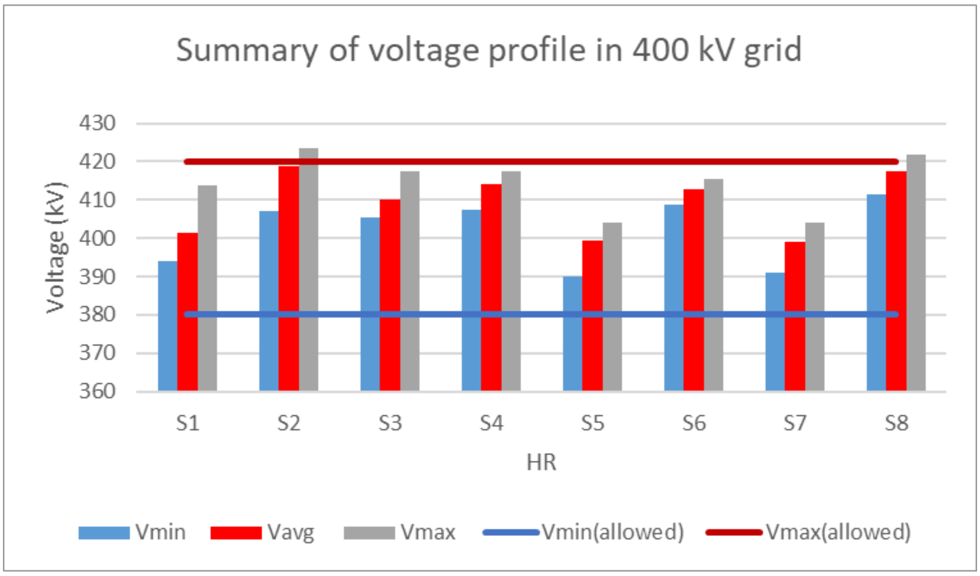


Figure 112: 400 kV voltage profiles (minimum, maximum and average) in the HR area in all analyzed scenarios 2030

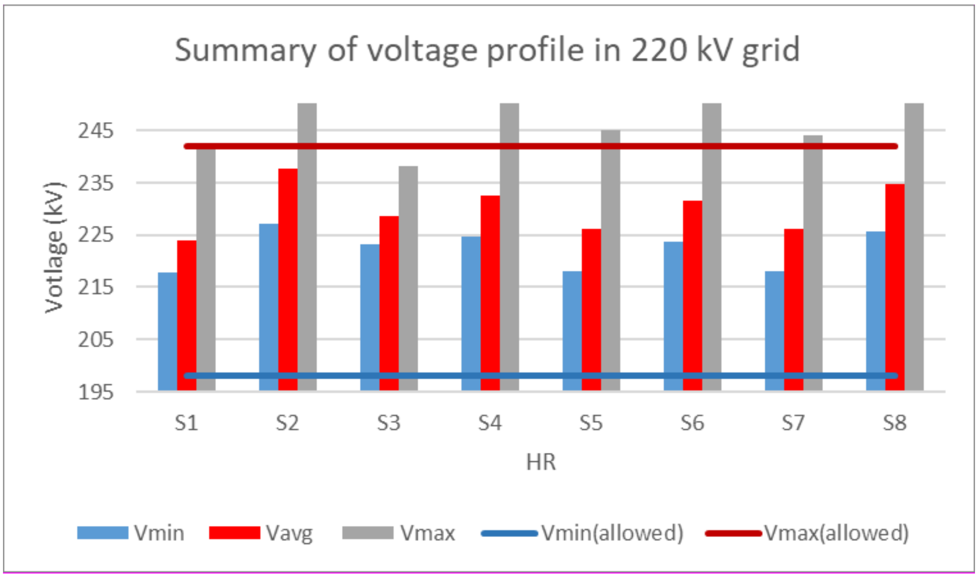


Figure 113: 220 kV voltage profiles (minimum, maximum and average) in the HR area in all analyzed scenarios 2030

9.10.6. CGES (ME) Network Area

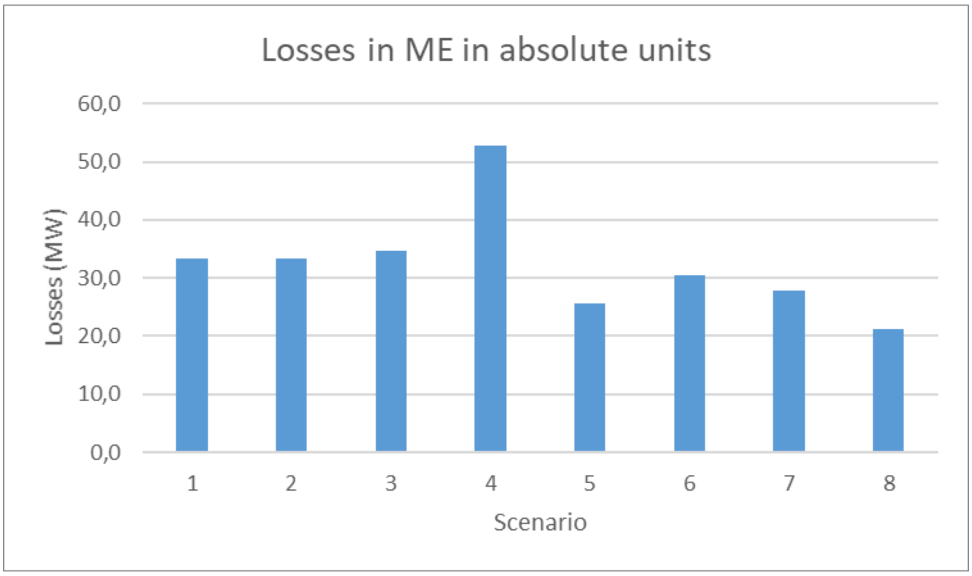


Figure 114: Transmission network losses in absolute value in the ME area in all analyzed network scenarios 2030

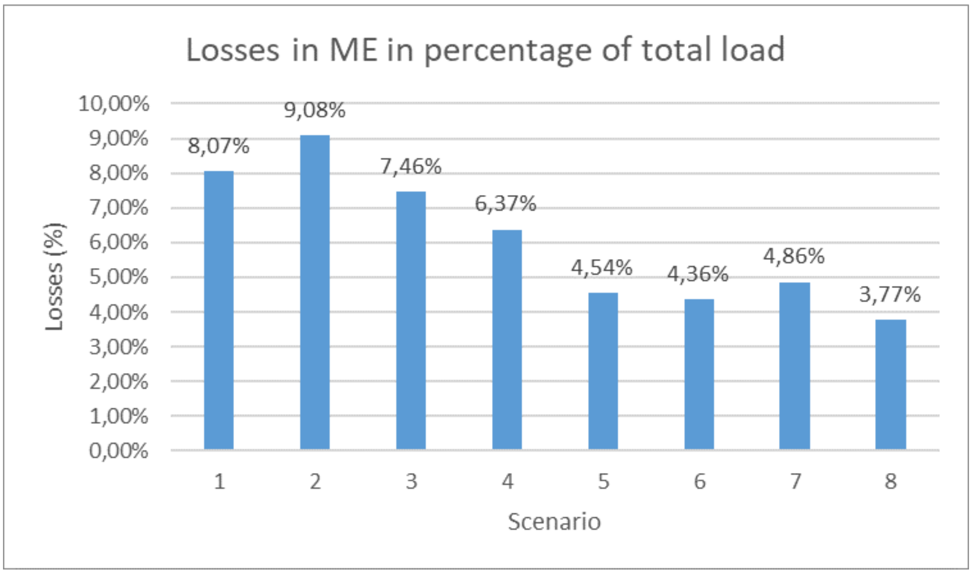


Figure 115: Transmission network losses in the ME area relative to system load in all analyzed scenarios 2030

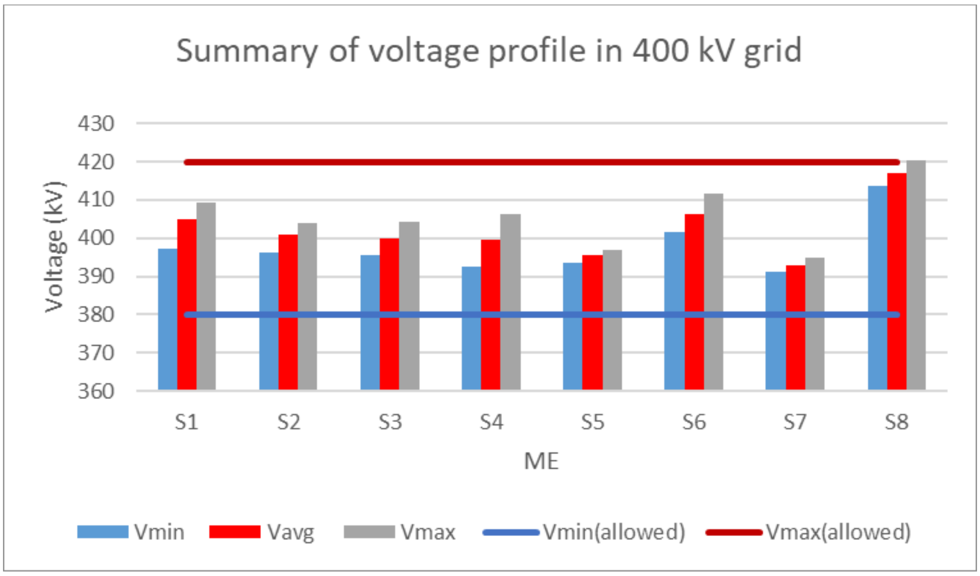


Figure 116: 400 kV voltage profiles (minimum, maximum and average) in the ME area in all analyzed scenarios 2030

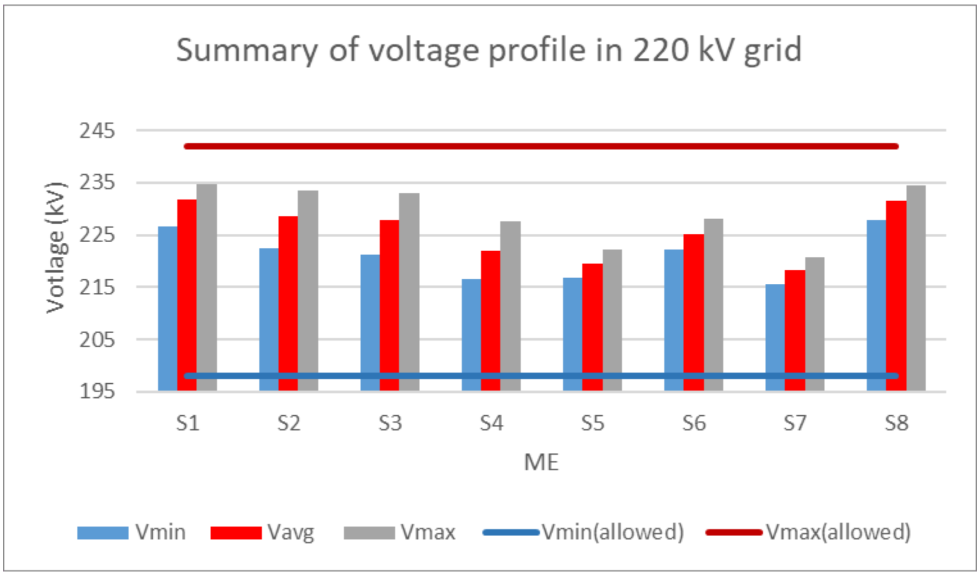


Figure 117: 220 kV voltage profiles (minimum, maximum and average) in the ME area in all analyzed scenarios 2030

9.10.7. MEPSO (MK) Network Area

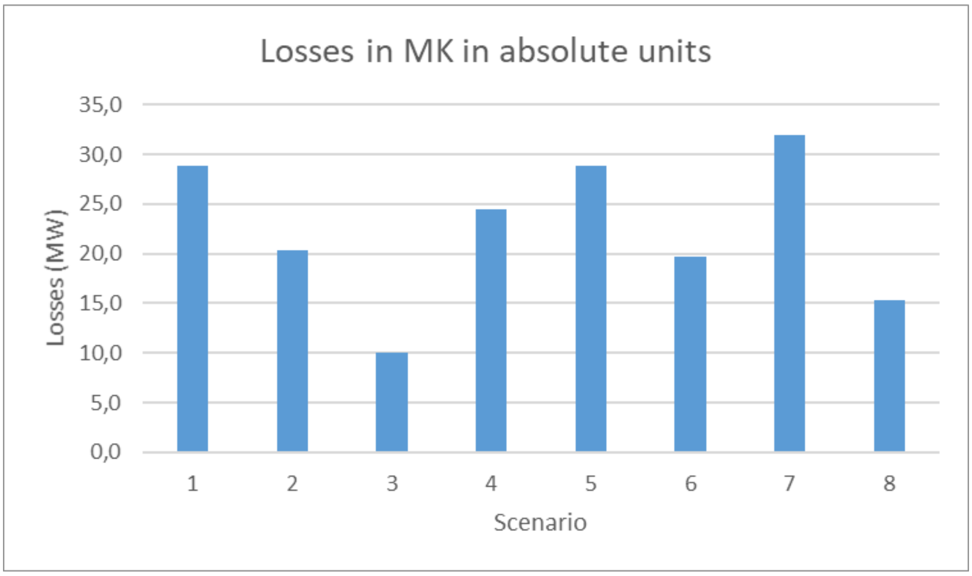


Figure 118: Transmission network losses in absolute value in the MK area in all analyzed network scenarios 2030

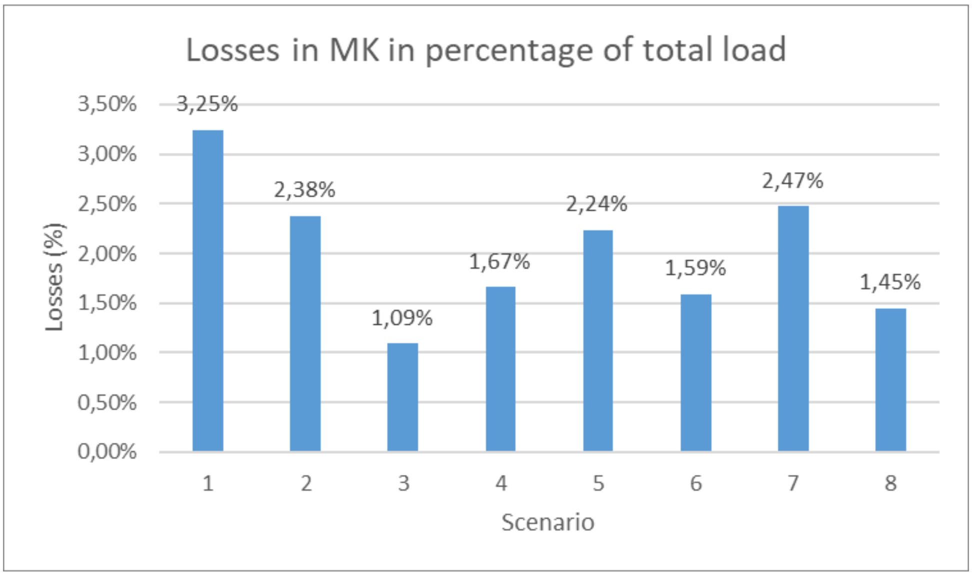


Figure 119: Transmission network losses in the MK area relative to system load in all analyzed scenarios 2030

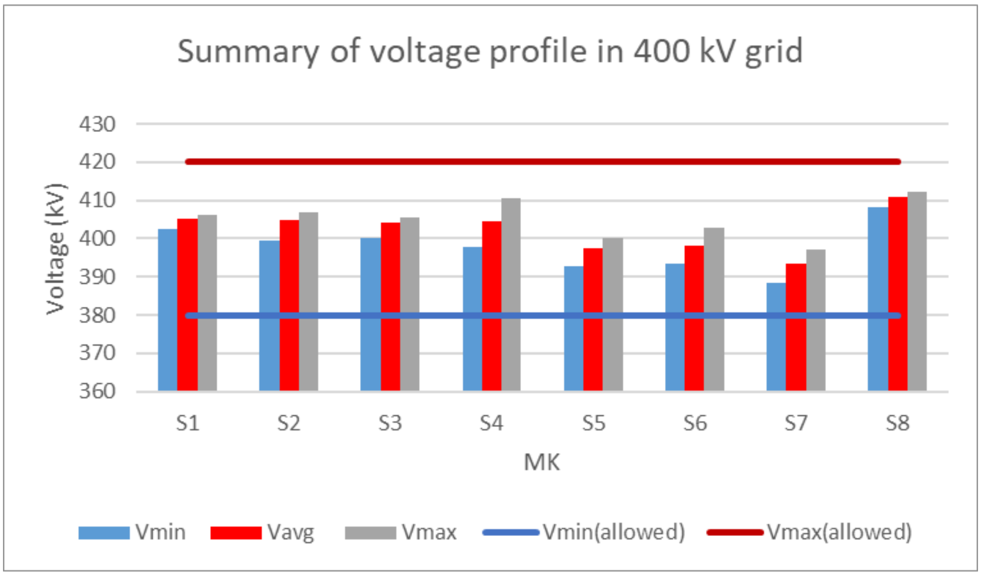


Figure 120: 400 kV voltage profiles (minimum, maximum and average) in the MK area in all analyzed scenarios 2030

9.10.8. Transelectrica (RO) Network Area

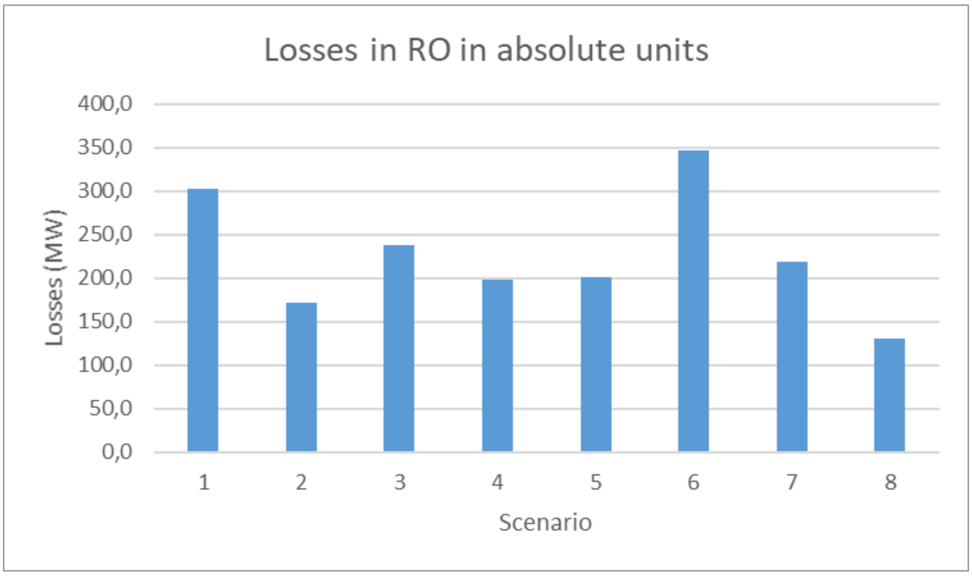


Figure 121: Transmission network losses in absolute value in the RO area in all analyzed network scenarios 2030

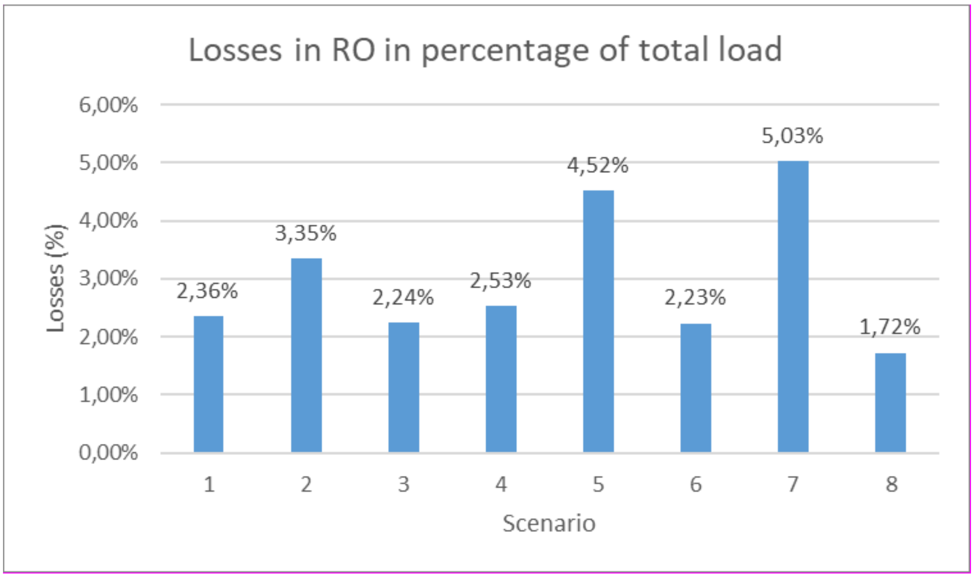


Figure 122: Transmission network losses in the RO area relative to system load in all analyzed scenarios 2030

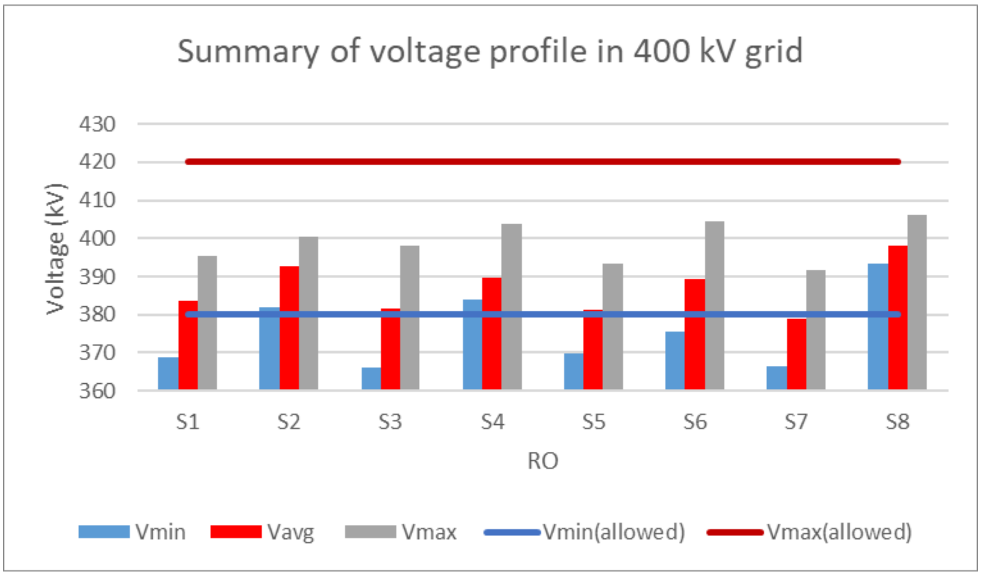


Figure 123: 400 kV voltage profiles (minimum, maximum and average) in the RO area in all analyzed scenarios 2030

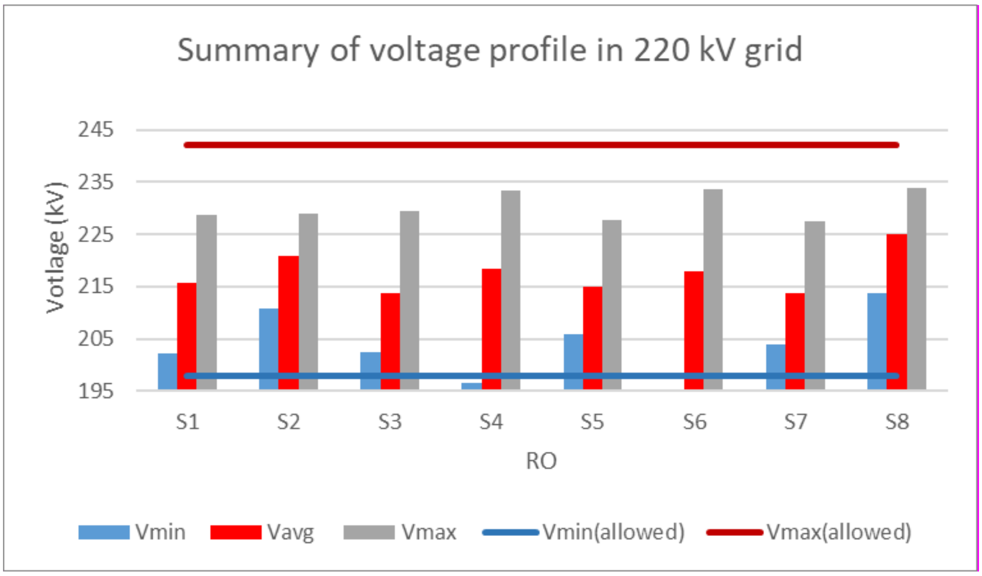


Figure 124: 220 kV voltage profiles (minimum, maximum and average) in the RO area in all analyzed scenarios 2030

9.10.9. EMS (RS) Network Area

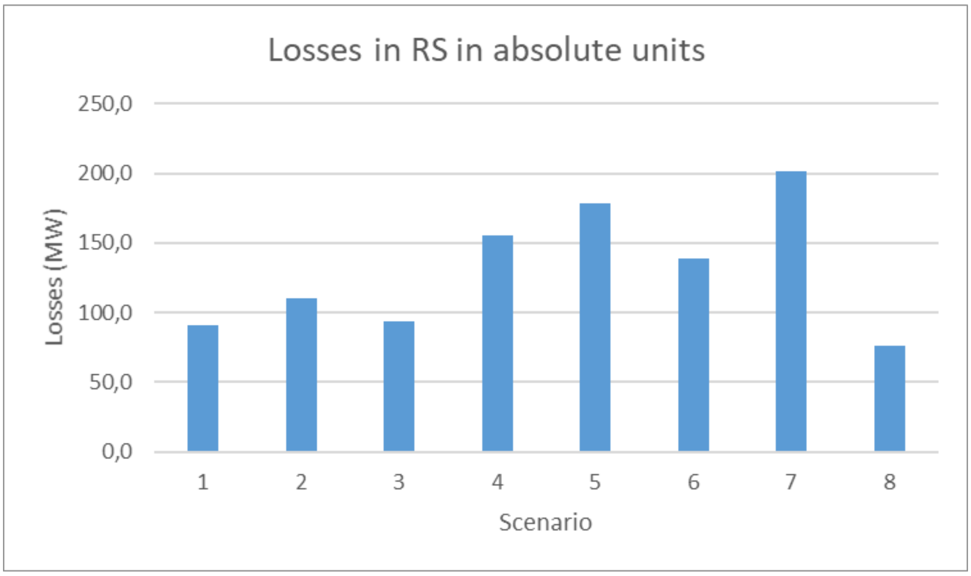


Figure 125: Transmission network losses in absolute value in the RS area in all analyzed network scenarios 2030

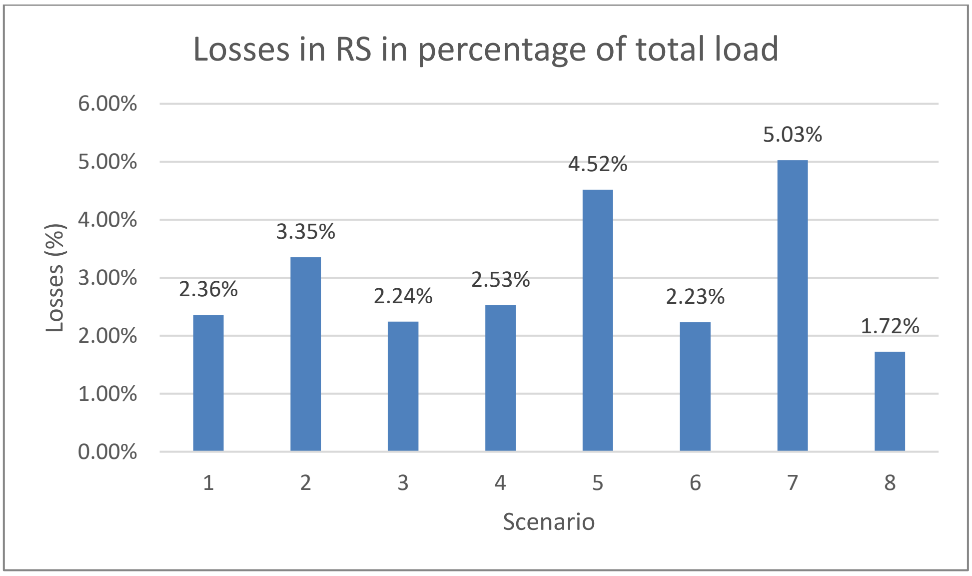


Figure 126: Transmission network losses in the RS area relative to system load in all analyzed scenarios 2030

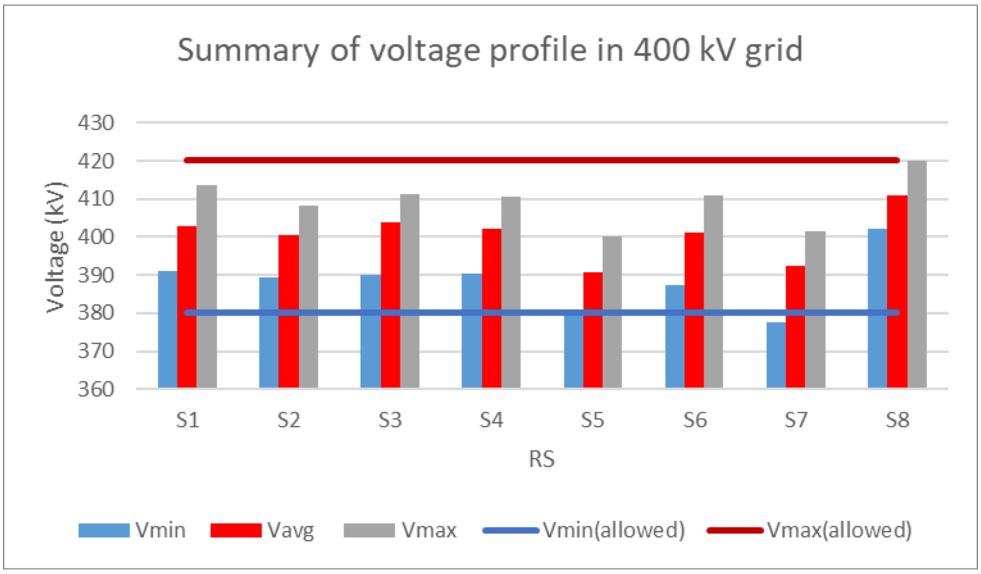


Figure 127: 400 kV voltage profiles (minimum, maximum and average) in the RS area in all analyzed scenarios 2030

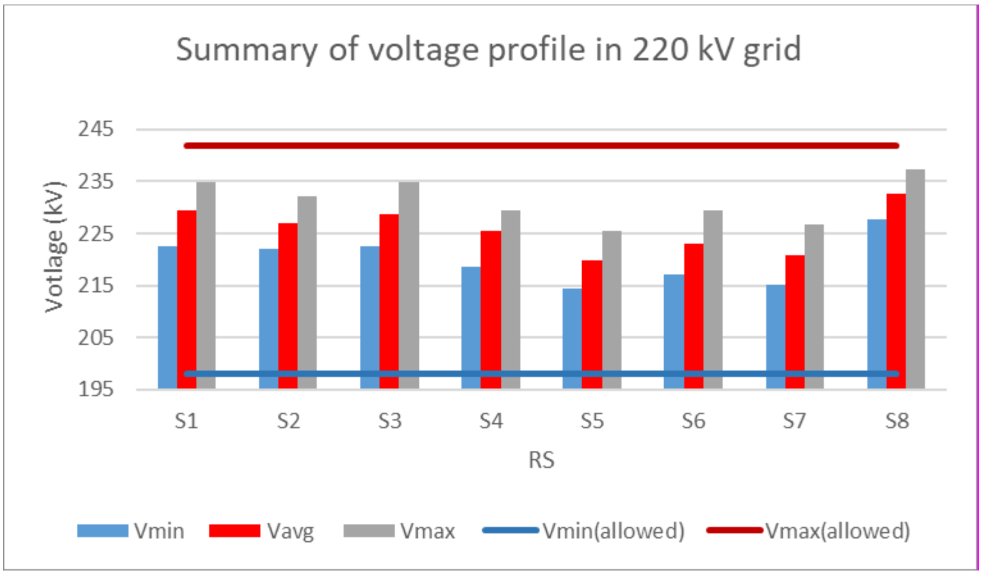


Figure 128: 220 kV voltage profiles (minimum, maximum and average) in the RS area in all analyzed scenarios 2030

9.10.10. ELES (SI) Network Area

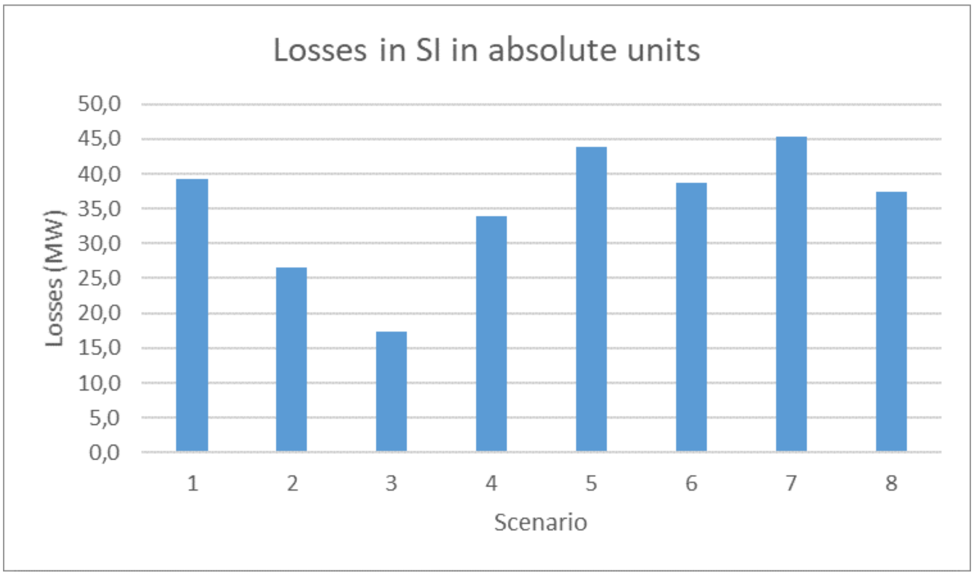


Figure 129: Transmission network losses in absolute value in the SI area in all analyzed network scenarios 2030

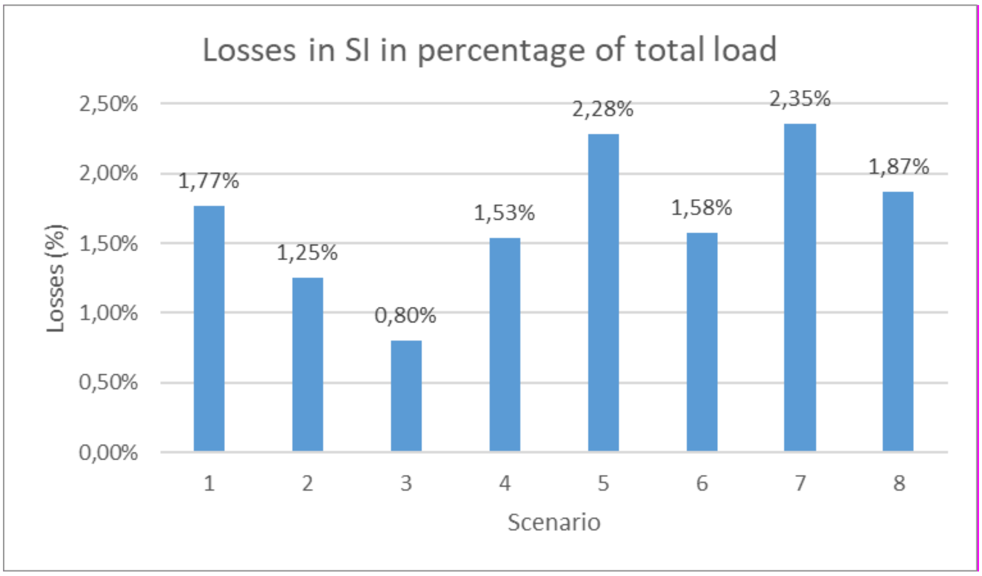


Figure 130: Transmission network losses in the SI area relative to system load in all analyzed scenarios 2030

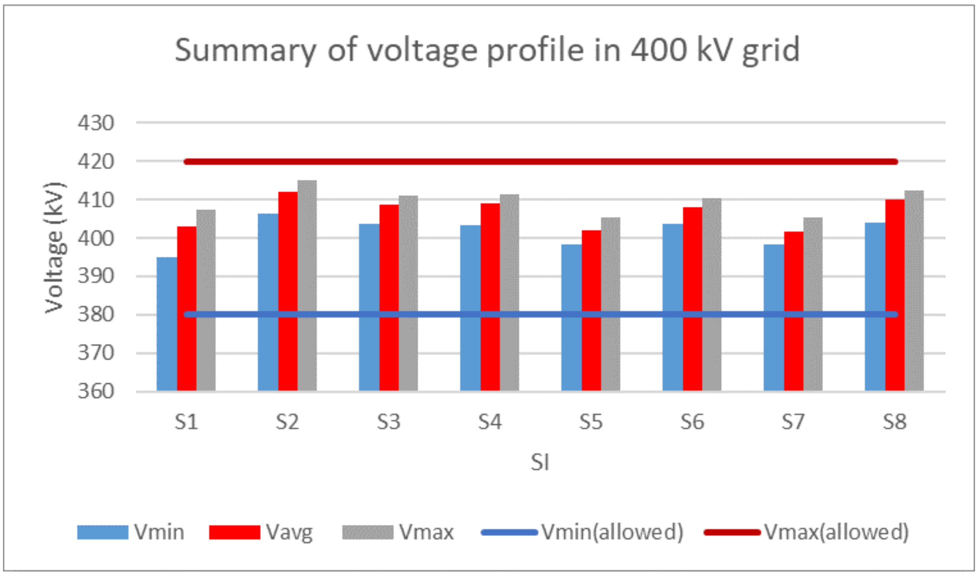


Figure 131: 400 kV voltage profiles (minimum, maximum and average) in the SI area in all analyzed scenarios 2030

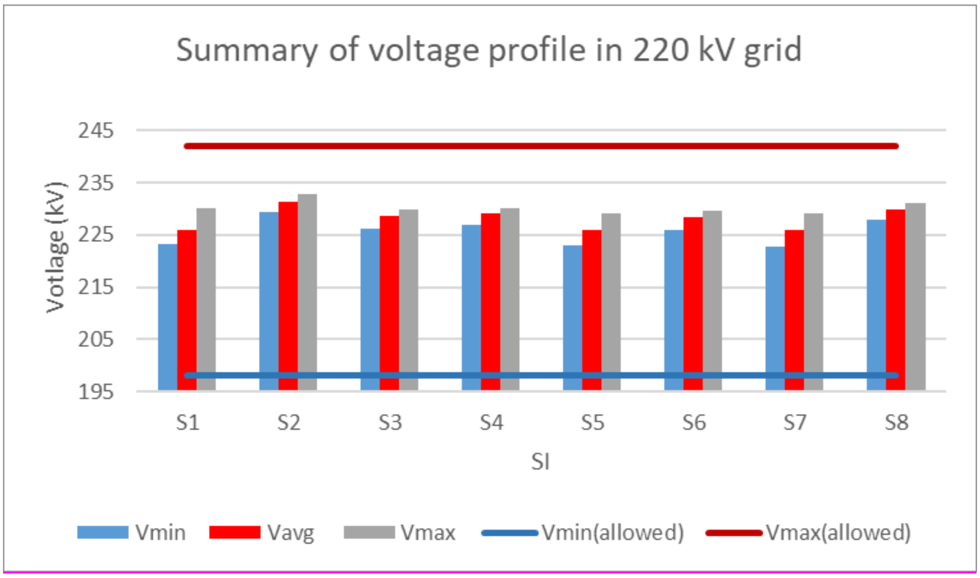


Figure 132: 220 kV voltage profiles (minimum, maximum and average) in the SI area in all analyzed scenarios 2030

9.10.11. KOSTT (XK) Network Area

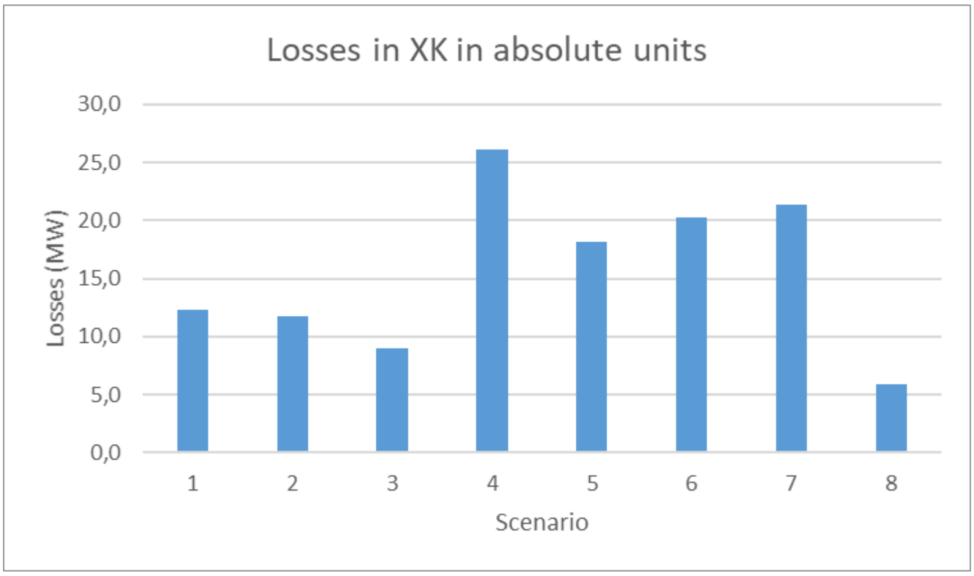


Figure 133: Transmission network losses in absolute value in the XS area in all analyzed network scenarios 2030

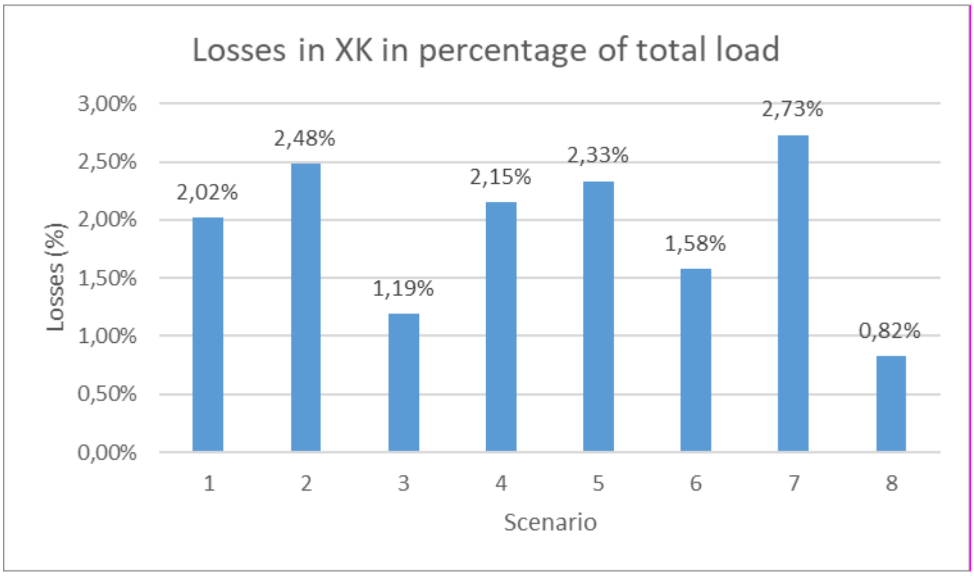


Figure 134: Transmission network losses in the XS area relative to system load in all analyzed scenarios 2030

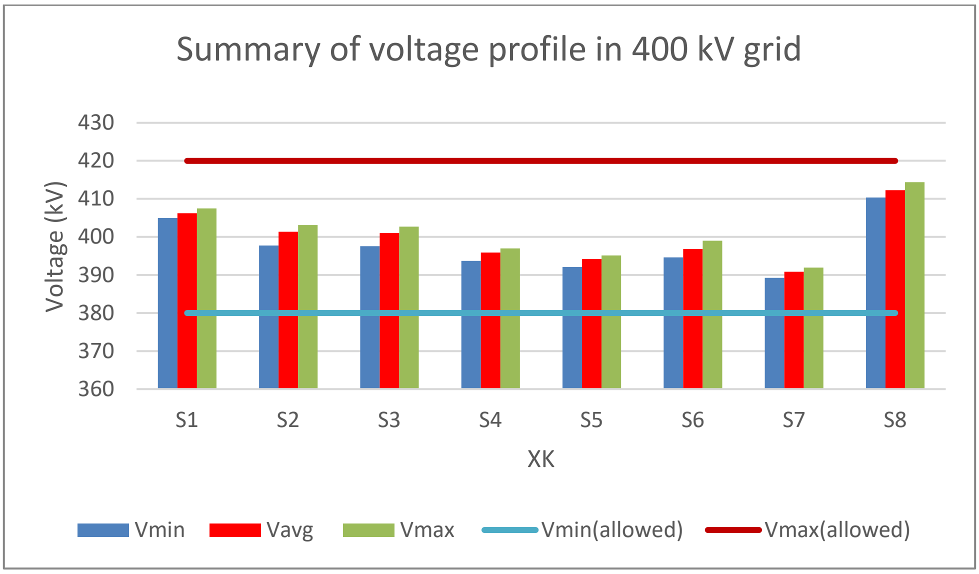


Figure 135: 400 kV voltage profiles (minimum, maximum and average) in the XS area in all analyzed scenarios 2030

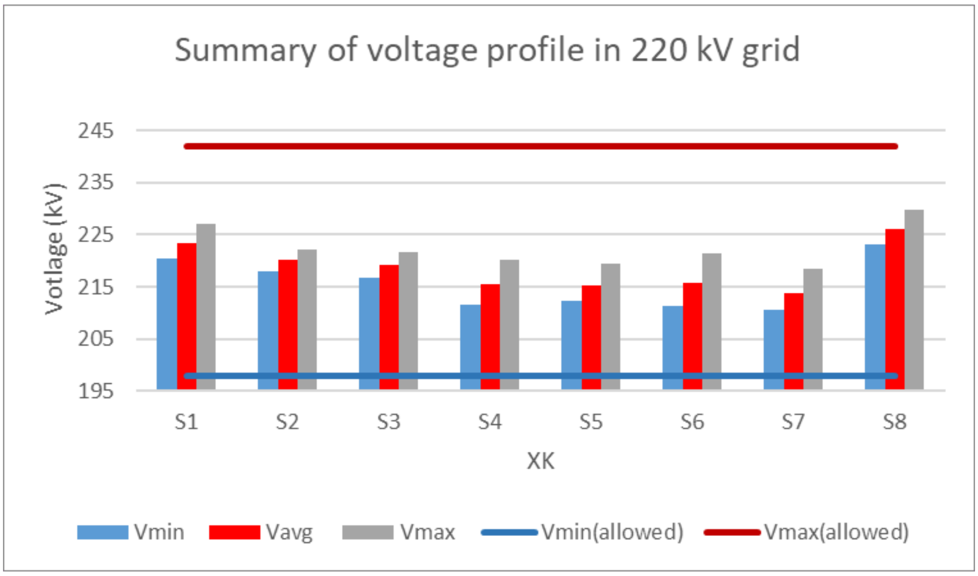


Figure 136: 220 kV voltage profiles (minimum, maximum and average) in the XS area in all analyzed scenarios 2030

10. CONCLUSIONS

This Study is designed to help the EMI members better prepare for additional clean energy and high levels of decarbonization of the electricity sector, plus large-scale RES integration, and anticipate the changes in network and market operation that will take place as cross-border transactions and markets open up region-wide.

In specific, this study is designed to address both how electricity markets and prices will be affected by greater decarbonization of the electricity sector by 2030, and also how the transmission grid will need to adapt – both within the EMI countries and between them - to these changes. It also addresses the gap in production that may emerge as we remove large amounts of carbon-intensive generation from the mix between now and 2030, and what may be required to fill such a gap.

Based on the TSO inputs and verifications we analyzed the 3 different levels of decarbonization in 2030 (referent, moderate and extreme) with one assumption related to expected CO2 emission tax (65.73 EUR/tCO2), and two hydro conditions (average and dry). As a fourth scenario, we investigated the impact of extreme decarbonization in the case of limited regional import from the rest of Europe.

As general conclusions of this Study, there are several relevant points:

- The ability of the region to meet load in 2030 without substantial increases in imports depends highly on sharp increase in the construction and operation of new gas generation. Natural gas becomes a bridge fuel in SEE by 2030. Whether new gas generation plus other supply changes can meet long-term emissions targets is unclear. Currently, Europe is facing big challenges with gas supply. Potential solutions of these challenges are out of scope of this study, but other USAID/USEA regional studies will discuss this issue, too.
- All of our scenarios (reference, moderately aggressive, and extreme) have over 50% reductions in the level of lignite capacity from plant decommissioning and retirements; the extreme scenario is nearly 80%.
- The share of lignite and coal generation in 2030 ranges from 6% to 10% of total regional consumption, which represents a significant decrease from around 40% in 2018 (and more than 60% in the WB6 countries).
- From today to 2030, EMI members expect natural gas capacity to increase by more than 9 GW, or more than 50%, throughout SEE, largely in Romania and Greece. As a result, we expect generation from gas to increase by 50 GWh, or almost 3 times in the reference case.
- Gas becomes the main generation technology in the region, and will provide 30% of regional consumption in 2030, versus 12% in 2018.
- This increase in gas generation to meet electricity demand means that policy makers may need to consider alternative sources of natural gas, assess whether sufficient pipeline capacity exists, and determine if LNG imports may be desirable to meet these requirements.
- Across all scenarios, the decarbonization of the power sector would decrease CO2 emissions by 40%-60% in comparison to 2018.

- With deeper decarbonization, the EMI region will import power from the rest of Europe of between 7 and 24 TWh (2% to 8% of total regional consumption).
- At the same time, with deeper decarbonization, internal fossil fired capacities are utilized with higher capacity factors providing more energy but also more CO2 emission. With the aim to reduce this impact, additional import should be enabled and additional cross border capacities should be considered especially at the western borders of the region.
- With higher decarbonization, imports increase and prices increase as well, to the range from 71.1 EUR/MWh to 84.5 EUR/MWh. When compared to the prices in 2018, the increase ranges from more than 65% to over 100%, mainly driven by CO2 emission prices.
- With extreme decarbonization levels, the security of supply in the region could be endangered if imports from the rest of Europe is limited.

In this study we analyzed 8 carefully selected network scenarios. Altogether the contingencies appear on 28 elements in the region that could be critical in the future due to decarbonization scenarios analyzed in this study. Among them there are:

- 7 critical tie lines,
- 16 internal lines, and
- 5 transformers.

The five critical tie lines are found in the 400 kV network and two on the 220 kV network. These elements are located on the following borders:

- Bulgaria – Romania (3 tie lines)
- Bulgaria – Turkey
- Croatia - Hungary
- Albania – Montenegro and
- BiH – Montenegro

The 16 critical internal lines are also found both in the 400 kV network (2 lines) and the 220 kV network (12 lines). These elements are located in these countries:

- Serbia (1 line on 400 kV level)
- Greece (1 line on 400 kV level)
- Albania (2 lines on 220 kV level)
- Romania (6 lines on 220 kV level)
- Bulgaria (2 lines on 220 kV level)
- Montenegro (1 lines on 220 kV) and

- Bosnia and Herzegovina (1 lines on 220 kV)

Five transformers are critical in the region, with two in Croatia, and three in Romania. Among the 28 critical elements there are 10 elements with severe overloading (130% of rated current) in one or more scenarios.

In these conditions, we did not detect a central corridor or trans-regional set of bottlenecks that would suggest the need for a large coordinated regional program of high-voltage additions. Rather, with only 28 bottlenecks found in the region in all scenarios, we conclude that while selected upgrades and de-bottlenecking make sense, the SEE regional network overall is initially robust enough for the future planned RES absorption and decarbonization process.

11. APPENDIX

11.1.Market modeling assumptions

11.1.1. Load, Wind and Solar Hourly Profiles

The TSOs provided annual demands for the Referent demand scenario. If the TSOs and MOs could not provide hourly load profiles for the 1982, 1984 and 2007 climatic years, we utilized hourly load profiles from the previous EMI study.

For the Referent RES capacities, the TSOs provided the expected installed RES capacities for 2030.

In addition, if the EMI members did not provide wind and/or solar hourly capacity factors, we used data from the previous EMI2020 or data based on publicly available databases from ETH Zurich[9].

11.1.2. Generation from Hydro Power Plants (HPPs)

In the case of HPPs, if EMI members did not provide data on monthly generation in different hydro conditions, we estimated generation based on the Consultant's experience and the generation of similar HPPs. If only average hydrology data are available, dry (and wet generations, if needed) were generally assumed to be 25% lower and higher. This assumption is based on historical data and wet and dry hydro generations submitted for some of the areas, and this enables a harmonized approach for the entire region.

11.1.3. Technical and economic parameters – thermal power plants

Unless specified differently in the TSOs' spreadsheets, we applied general technical and economic parameters for all TPPs, as shown in the following tables).

9 https://www.renewables.ninja/

Table 19: General technical and economic parameters for TPPs to be used in this study

Category #	Fuel	Type	Efficiency range in NCV terms	Standard efficiency in NCV terms	CO_2 emission factor	Variable O&M cost	Min Time on	Min Time off	Heat Rate (GJ/MWh)
			%	%	kg / Net GJ	Euro/MWh	hours	hours	%
1	Nuclear	-	30% - 35%	33%	0	9	12	12	10.9
2	Hard coal	old 1	30% - 37%	35%	94	3.3	8	8	10.3
3		old 2	38% - 43%	40%		3.3	6	6	9.0
4		New	44% - 46%	46%		3.3	5	5	7.8
5		CCS	30% - 40%	38%	9.4	6.6	7	7	9.5
6	Lignite	old 1	30% - 37%	35%	101	3.3	11	11	10.3
7		old 2	38% - 43%	40%		3.3	9	9	9.0
8		New	44% - 46%	46%		3.3	8	8	7.8
9		CCS	30% - 40%	38%	10.1	6.6	10	10	9.5
10	Gas	conventional old 1	25% - 38%	36%	57	1.1	5	5	10.0
11		conventional old 2	39% - 42%	41%		1.1	5	5	8.8
12		CCGT old 1	33% - 44%	40%		1.6	3	3	9.0
13		CCGT old 2	45% - 52%	48%		1.6	3	3	7.5
14		CCGT new	53% - 60%	58%		1.6	2	2	6.2
15		CCGT CCS	43% - 52%	51%	5.70	3.2	4	4	7.1
16		OCGT old	35% - 38%	35%	57	1.6	1	1	10.3
17		OCGT new	39% - 44%	42%		1.6	1	1	8.6
18	Light oil	-	32% - 38%	35%	78	1.1	1	1	10.3
19	Heavy oil	old 1	25% - 37%	35%	78	3.3	3	3	10.3
20		old 2	38% - 43%	40%		3.3	3	3	9.0
21	Oil shale	old	28% - 33%	29%	100	3.3	11	11	12.4
22		new	34% - 39%	39%		3.3	8	8	9.2

Table 20: Additional technical parameters for TPPs to be used in this study

Category #	Fuel	Type	Unavailability				Minimum stable generation
			Forced outage		Planned outage		
			annual rate	Mean time to repair	annual rate	winter	
			%	Days	number of days	% of annual number of days	(% of max power)
1	Nuclear	-	5%	7	54	15%	50%
2	Hard coal	old 1	10%	1	27	15%	43%
3		old 2	10%	1	27	15%	43%
4		new	7.50%	1	27	15%	43%
5		Lignite CCS	7.50%	1	27	15%	43%
6	Lignite	old 1	10%	1	27	15%	43%
7		old 2	10%	1	27	15%	43%
8		new	7.50%	1	27	15%	43%
9		Hard coal CCS	7.50%	1	27	15%	43%
10	Gas	conventional old 1	8%	1	27	15%	35%
11		conventional old 2	8%	1	27	15%	35%
12		CCGT old 1	8%	1	27	15%	35%
13		CCGT old 2	8%	1	27	15%	35%
14		CCGT new	5%	1	27	15%	35%
15		CCGT CCS	5%	1	27	15%	35%
16		OCGT old	8%	1	13	15%	30%
17		OCGT new	5%	1	13	15%	30%
18	Light oil	-	8%	1	13	15%	35%
19	Heavy oil	old 1	10%	1	27	15%	35%
20		old 2	10%	1	27	15%	35%
21	Oil shale	old	10%	1	27	15%	40%
22		new	7.50%	1	27	15%	40%

11.1.3.1. Fuel and CO_2 prices

For fuel prices we needed to use consistent and comparable generation costs for all market areas in SEE. For this purpose, we applied the 2030 fuel prices from the common database in the TYNDP 2020 (see next table).

Table 21: Fuel and CO_2 prices in 2030 from TYNDP 2020

		2020	2021	2023	2025	2030	2040
					BE / G2C	NT / DE / GA	NT / DE / GA
€/GJ	Nuclear	0.47	0.47	0.47	0.47	0.47	0.47
	Lignite	1.1	1.1	1.1	1.1	1.1	1.1
	Oil shale	2.3	2.3	2.3	2.3	2.3	2.3
	Hard Coal	3.0	3.12	3.4	3.79	4.3	6.91
	Natural Gas	5.6	5.8	6.1	6.46	6.91	7.31
	Light Oil	12.9	14.1	16.4	18.8	20.5	22.2
	Heavy Oil	10.6	11.1	12.2	13.3	14.6	17.2

For the same reason, we assumed the CO_2 price to be the same, for the entire EMI region. However, in this study we did not use CO_2 price as foreseen in results ENTSO-e TYNDP2020 but the price of 65.73 €/t, as it was explained in more details in Chapter 6.3.1.

While the CO_2 tax must be applied for all EU member states there is still a question about its application for non-EU countries. After discussion with EMI members (in 2020), considering that we are analyzing the year 2030, we all agreed to apply the same CO_2 tax to all EMI market areas. This approach assures consistency of the operating costs level and comparable results with ENTSO-E projections. Modeling of some market areas with the CO_2 price and some without would create a substantial advantage for those countries not in the ETS system, and it seems reasonable that all SEE EMI members will be part of the EU ETS by 2030.

11.1.3.2. Neighboring power systems

As mentioned above, the SEE region in this project considers 11 power systems, in which the electricity market has been modeled on a plant-by-plant level of detail, with a simplified, but adequate representation of the transmission network.

The SEE region exchanges power with other countries and regions through the grid, so to achieve better modeling accuracy and to capture the exchange with other regions, it is important for the EMI work to include neighboring power systems in our market model. To do so, this project used publicly available ENTSO-E data from the TYNDP and MAF.

We selected two approaches to model the neighboring systems:

- external electricity markets, and
- power systems modeled on a technology level.

We explain each approach below.

11.1.3.3. External electricity markets

Our model of the power systems in Central Europe (i.e. Austria and Germany), Italy and Turkey consideres them as spot markets, in which market prices are insensitive to SEE price fluctuations and constrained by net transmission capacity (NTC) in terms of energy exchange with the SEE region.

For these power systems, our modeling uses assumptions of wholesale market prices in 2030 are based on the results from the TYNDP 2020 Scenario Report, which contains average yearly marginal cost indicators for all market zones in ENTSO-E. Namely, as described in section 6.3.1 we have adopted higher level of CO_2 price in 2030 than it was assumed in TYNDP2020 "Distributed Energy" Scenario. Therefore, it is not justified to use the prices on external markets which are determined with lower level of CO_2 price and in the same time perform analyses in the EMI region with higher level of CO_2 prices. This could lead to higher level of electricity prices in EMI region than on external markets and consequently is very likely that increase of import in the EMI region would occur.

Thus we performed analysis of the impact of the CO_2 price level increase from 53 €/t to 65.72 €/t on the yearly prices on the external markets. From the results of ENTSO-e TYNDP2020 "Distributed Energy" Scenario we estimated the total cost of each power system (total cost of each analyzed market area – Germany, Austria, Italy, except Turkey). We also calculated the additional increase in emission cost, since the total amount of emission was known and taken from the results TYNDP2020 "Distributed Energy" Scenario as well. On the basis of total system cost and the additional emission cost (due to CO_2 price level increase) we calculated the total system cost for the higher level of CO_2 price (65.73 €/t). After the total system cost for the higher level of CO_2 price was determined, we calculated the yearly price in each market zone related to the external market.

The following table shows the average yearly wholesale prices in the modelled external markets related to applied CO_2 price: 65.73 €/t, while for Turkey we used yearly price as in the "Distributed Energy" scenario. It should be mentioned, that although the price for Turkey is extremely high, we decided to use it having in mind that these ENTSO-E simulation results are the only valid source we can reference to. Anyhow, the impact of this price is not significant and similar results would be obtained even for the significantly lower prices. Namely, as long as the price in Turkey is higher than prices in the SEE region, the impact is negligible.

Table 22: Average 2030 yearly price on external markets

Market	Price (€/MWh) Modified Distributed Energy Scenario CO_2 price (65.73 EUR/t)
Central Europe	58.73
Italy	60.26
Turkey	189

In order to model the variation of hourly prices throughout the year, we used a time series of observed market prices at respective electricity markets in the last three years to create an hourly profile. With the aim to exclude the impact of extreme operating, climatic and hydro conditions, hourly profile of electricity prices for Central Europe have been determined as the hourly average of the market prices observed for 3 years (from 2017 to 2019) on the European Energy Exchange (EEX), i.e. EPEX SPOT prices for Germany and Austria. For the Italian power market, we used a time series of observed market prices at the Italian Power Exchange (IPEX), and for Turkey, modelled hourly prices are based on the observed market on EXIST (Energy Exchange Istanbul).

These hourly profiles have been scaled to corresponding average prices expected in 2030 in the previous table.

11.1.3.4. Power systems modeled on a technology level

Since Hungary is highly interconnected with several EMI members, we included the Hungarian power system in the regional market model to take into account the exchange of power between the SEE region and Hungarian market area. In addition, we expect that in 2030, Ukraine and Moldova will be synchronously connected with ENTSO-E, and so we have modeled the Ukrainian and Moldovan power systems as well.

The Hungarian, Ukrainian and Moldovan power systems have been modeled with expected demand/supply scenarios (based on TYNDP 2020 "Distributed Energy" for HU, and Business As Usual scenarios for UA and MD), but with CO_2 price of 65.73 EUR/t as applied for all EMI members.

11.2. TPPs decommissioning per market areas

11.2.1. OST market area

In OST market area there are no other options but to propose changes of planned TPP commissioning. In fact, in the case of the OST market area, our decommissioning scenarios assumes that TPPs will not be commissioned as given in the plan (300 MW in total). In the moderate scenario, we assume the commissioning of only one new TPP (total TPP capacity will be 200 MW), while in the extreme scenarios, there will be none of the new planned TPPs in operation in 2030 (total TPP capacity will be 100 MW).

Table 23: Decommissioned TPP units in the OST market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
TPP Vlora	1	100	-	100	100
	2	100	-	-	100
TOTAL				**100**	**200**

11.2.2. NOSBiH market area

In the NOSBiH market area, there are 6 TPPs in total, with 1,632 MW of total modeled capacity in 2030. The following table gives the list of those TPPs that are candidates for decommissioning due to its lifetime ending and our two decommissioning scenarios.

We propose to conduct the analysis with TPP Tuzla 6 (190 MW) as decommissioned in the moderate scenario and in addition, TPP Gacko (276 MW) decommissioned in the extreme scenario.

This would lead to a total of 466 MW in decommissioned TPP capacity in the extreme decommissioning scenario in 2030, and would decommission 11.6% and 28.6% of the total installed TPP capacities in the moderate and extreme scenarios, respectively.

Table 24: Decommissioned TPP units in the NOSBiH market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
TPP Gacko	1	276	-	-	276
TPP Tuzla	3	85	85	-	-
	4	175	175	-	-
	5	180	180	-	-
	6	190	-	190	190
TPP Kakanj	5	103	103	-	-
	6	85	85	-	-
TOTAL			**628**	**190**	**466**

11.2.3. ESO EAD market area

In the ESO EAD market area, there are 4,728 MW of total modeled TPP capacity in 2030. The following table gives the list of those TPPs that are candidates for decommissioning due to their lifetime ending and our two decommissioning scenarios.

Since significant part of generation fleet is planned for decommissioning according to referent scenario and all lignite and coal fired units are planned to be out of operation in 2030, only decommissioning of gas fired units are proposed in moderate and extreme scenarios: 1258 MW in moderate and additional 600 MW in extreme scenario. In addition, introduction of new gas fired units is proposed by ESO EAD at the level of 600 MW which will be applied for both scenarios. Finally, total of 658 MW in moderate and 1258 MW in extreme scenario will be decommissioned in ESO EAD market area in comparison to 4,728 MW of total modeled TPP capacity in 2030.

Based on these assumptions, total TPP capacities will be 4070 MW in moderate scenario and 3470 MW in extreme scenario. This will present a decrease of 14% and 27% of total capacity in moderate and extreme scenarios, respectively.

Table 25: Decommissioned TPP units in the ESO EAD market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
TPP MI2	1	154	154	-	-
	2	138	138	-	-
	3	154	154	-	-
	4	154	154	-	-
	5	200	200	-	-
	6	200	200	-	-
	7	202	202	-	-
	8	202	202	-	-
TPP MI3	1	202	202	-	-
	2	202	202	-	-
	3	202	202	-	-
	4	202	202	-	-
TPP AES	1	300	300	-	-
	2	300	300	-	-
TPP Bobov Dol	1	169	169	-	-
	2	169	169	-	-
	3	169	169	-	-
TPP Varna	4	197	-	197	197
	5	197	197	-	-
	6	197	-	197	197
TPP Maritsa 3	1	90	90	-	-
TPP Ruse	4	100	100	-	-
	5	52	52	-	-
	6	52	52	-	-
TPP Republika	1	20	20	-	-
	2	20	20	-	-
	3	45	45	-	-
TPP Sliven	1	27	25	-	-
TPP Sofia Iztok	1	22	22	-	-
	2	22	22	-	-
TPP Lukoil Neftohim	2	10	10	-	-
TPP Plovdiv	2	25	25	-	-
	3	20	20	-	-
TPP MI2	1	230	-	230	230
	2	230	-	230	230
TPP MI3	1	202	-	202	202
	2	202	-	202	202
TPP AES	1	300	-	-	300
	2	300	-	-	300
TOTAL			**4019**	**1258**	**1858**

11.2.4. IPTO/ADMIE market area

In the IPTO/ADMIE market area, there are 7,768 MW of total modeled TPP capacity in 2030. The following table provides the list of those TPPs that are candidates for decommissioning due to their lifetime ending (4,268 MW) and our two decommissioning scenarios.

The analyses will be carried out with additional decommissioning of old gas fired units. TPPs capacity will be decreased for 600 MW in moderate scenario and additionaly for 723 MW in extreme scenario.

This would result in the decommissioning of 8% of total installed TPP capacities in the moderate scenario, and 16% in the extreme scenario.

Table 26: Decommissioned TPP units in the IPTO/ADMIE market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
AG.Dimitrios	1	274	274	-	-
AG.Dimitrios	2	274	274	-	-
AG.Dimitrios	3	283	283	-	-
AG.Dimitrios	4	283	283	-	-
AG.Dimitrios	5	342	342	-	-
Amyntaio	1	273	273	-	-
Amyntaio	2	273	273	-	-
Kardia	1	271	271	-	-
Kardia	2	271	271	-	-
Kardia	3	280	280	-	-
Kardia	4	280	280	-	-
Megalopoli	3	255	255	-	-
Megalopoli	4	255	255	-	-
Meliti	1	256	256	-	-
Komotini	1	476	-	-	476
Lavrio	1	550	-	550	550
HERON I	1	49	-	-	49
HERON I	2	49	-	-	49
HERON I	3	49	-	-	49
LIN_ST2	1	13	13	-	-
LIN_ST3	1	13	13	-	-
ATHER_D1	1	49	49	-	-
ATHER_D2	1	49	49	-	-
LIN_D1	1	11	11	-	-
LIN_D2	1	11	11	-	-
LIN_D3	1	10	10	-	-
LIN_D4	1	10	10	-	-
ATHER_ST1	1	47	47	-	-
ATHER_ST2	1	46	46	-	-
LIN_ST4	1	23	23	-	-
LIN_ST5	1	23	23	-	-
LIN_ST6	1	22	22	-	-
CHAN_GT4	1	18	18	-	-
CHAN_GT5	1	27	27	-	-
LIN_GT1	1	13	13	-	-
LIN_GT2	1	13	13	-	-
CHAN_GT11	1	50	-	50	50
CHAN_GT12	1	50	-	-	50
TOTAL			**4,268**	**600**	**1273**

11.2.5. HOPS market area

In the HOPS market area, there are 981 MW of total modeled capacity in 2030. The following table provides the list of those TPPs that are candidates for decommissioning due to their lifetime ending (1,085 MW) and our two decommissioning scenarios.

We propose to conduct the analysis with just 105 MW more as decommissioned in the moderate scenario and 297 MW more in the extreme scenario.

This would result in the decommissioning of 10.7% of total installed TPP capacities in the moderate scenario, and 30.3% in the extreme scenario.

Table 27: Decommissioned TPP units in the HOPS market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
EL-TO Zagreb blok A	1	12	12	-	-
EL-TO Zagreb blok B	1	31	31	-	-
EL-TO Zagreb blok H,J	1	23.5	23.5	-	-
	2	23.5	23.5	-	-
TE-TO Zagreb blok C	1	110	110	-	-
TE-TO Osijek Blok 45 MW	1	45	45	-	-
TE-TO Osijek PTA-1	1	24	24	-	-
TE-TO Osijek PTA-2	1	24	24	-	-
KTE Jertovec, KB1	1	33.7	33.7	-	-
KTE Jertovec, KB2	1	33.7	33.7	-	-
KTE Jertovec, PT1	1	12.8	12.8	-	-
KTE Jertovec, PT2	1	12.8	12.8	-	-
TE Plomin 1	1	105	-	105	105
TE Plomin 2	1	192	-	-	192
TE Rijeka	1	303	303	-	-
TE Sisak 1	1	198	198	-	-
TE Sisak 2	1	198	198	-	-
TOTAL			**1,085**	**105**	**297**

11.2.6. KOSTT market area

In the KOSTT market area, there are 978 MW of total modeled TPP capacity in 2030. The following table gives the list of those TPPs that are candidates for decommissioning due to its lifetime ending (432 MW) and our two decommissioning scenarios.

We propose to conduct the analysis by decommissioning 450 MW of TPPs in moderate and 714 MW of TPPs in the extreme scenarios. In fact in both proposed scenarios our assumption is that new lignite fired unit will not be in operation in 2030. This assumes that the KOSTT market area will higly reduce its TPP capacities in 2030 in comparison to today. The KOSTT market area is an extreme case in our decarbonization study due to its dominant share of lignite-fired TPPs. However, this analysis is meant to test market and network conditions in the region in an extreme decarbonization case, not considering other power system operation, reserve or security of supply aspects.

This would result in the decommissioning of 54% of total installed TPP capacities in the moderate and extreme scenarios, while the rest is planned to be decommissioned anyway due to its lifetime.

Table 28: Decommissioned TPP units in the KOSTT market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
TPP Kosovo B	1	264	0	0	264
	2	264	0	0	0
TPP Kosovo A	1	144	144	-	-
	2	144	144	-	-
	3	144	144	-	-
TPP Kosovo e Re	1	450	0	450	450
TOTAL			**432**	**450**	**714**

11.2.7. CGES market area

In the CGES market area, there is just one TPP with 225 MW of total modeled capacity in 2030. We propose to decommission it in the extreme scenario, which would result with 0% of total installed TPP capacities decommissioning in the moderate scenario, and 100% in the extreme scenario.

Table 29: Decommissioned TPP units in the CGES market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
Pljevlja 1	1	225	-	-	225
TOTAL			**225**	**-**	**225**

11.2.8. MEPSO market area

In the MEPSO market area, there are 586 MW of total modeled capacity in 2030. According to the data provided by TSO based on the latest NCEP, only gas fired units are in operation in 2030, where some of them also provide heat. Having this in mind, there are no adequate TPPs candidates for decommissioning in this market area. Thus, in both scenarios (moderate and extreme) we propose to use the same level of TPP installed capacity.

Table 30: Decommissioned TPP units in the MEPSO market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
-	-	-	-	-	-
TOTAL			-	-	-

11.2.9. Transelectrica market area

In the Transelectrica market area, there are 10,055 MW of total modeled capacity in 2030. The following table gives the list of those TPPs that are candidates for decommissioning due to their lifetime ending (2,676.4 MW) and our two decommissioning scenarios.

We propose to conduct the analysis with 1,493.3 MW more as decommissioned in the moderate scenario and 3,165.3 MW more in the extreme scenario.

This would result in the decommissioning of 14.9% of total installed TPP capacities in the moderate scenario, and 31.5% in the extreme scenario.

Table 31: Decommissioned TPP units in the Transelectrica market area in 2030

TPP	Units	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
TPP Turceni	cc1	400			
	4	298		298	298
	5	298		298	298
	7	302	302	-	-
TPP Rovinari	3	294	294	-	-
	4	298		298	298
	5	298		298	298
	6	298		298	298
TPP Isalnita	7	292	292	-	-
	8	292	292	-	-
TPP Craiova	1	120	120	-	-
	2	120	120	-	-
TPP Mintia	2	170			170
	4	130	130	-	-
	5	170	170	-	-
	6	150	150	-	-
TPP Paroseni	4	130	-	-	130
TPP Iernut	5	188.4	188.4	-	-
TPP Grozavesti	1	44	44	-	-
	2	44	44	-	-
TPP Bucuresti Sud	3	92	92	-	-
	4	92	92	-	-
TPP Galati	1	96	96	-	-
	2	58	58	-	-
	3	96	96	-	-
	4	96	96	-	-
TPP Veolia Iasi	2	43	-	-	43
TPP Veolia Brazi	6	98	-		98
TPP Petrobrazi	1	24	-		24

	2	24	-		24
TPP Romgaz	1	900	-		900
Other lignite	1	3.3	-	3.3	3.3
Other gas DET1		60	-	-	60
Other gas DET2		152	-	-	152
Other gas DET4		7	-	-	7
Other gas DET5		64	-	-	64
TOTAL			**2,676.4**	**1,493.3**	**3,165.3**

11.2.10. EMS market area

In the EMS market area, there are 4,829 MW of total modeled capacity in 2030. The following table gives the list of those TPPs that are candidates for decommissioning due to its lifetime ending (262.5 MW) and our two decommissioning scenarios.

We propose to conduct the analysis with 795.3 MW more as decommissioned in the moderate scenario, and 1,919.7 MW more in the extreme scenario.

This would result in decommissioning 16.5% of total installed TPP capacities in the moderate scenario, and 39.8% in the extreme scenario.

Table 32: Decommissioned TPP units in the EMS market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decommissioned due to the end of a lifetime	Decommissioning scenario	
				Moderate [MW]	Extreme [MW]
Kolubara A	3	58	58	-	-
	4	99.5	99.5	-	-
Morava	1	105	105	-	-
TENT A	1	195	-	195	195
	2	195	-	195	195
	3	298.1		-	298.1
	4	310		-	310
	5	311.8	-	311.8	311.8
	6	315.3		-	315.3
Kostolac A	1	93.5	-	93.5	93.5
Kostolac A	2	201	-		201
TOTAL			**262.5**	**795.3**	**1919.7**

11.2.11. ELES market area

In the ELES market area, there are 1,757 MW of total modeled TPP capacity in 2030. The following table gives the list of those TPPs that are candidates for decommissioning due to their lifetime ending (516 MW) and our two decommissioning scenarios.

We propose to conduct the analysis with 767 MW more as decommissioned in the moderate scenario and 820 MW more in the extreme scenario. This would result in the decommissioning of 44% of total installed TPP capacities in the moderate scenario, and 47% in the extreme scenario.

Table 33: Decommissioned TPP units in the ELES market area in 2030

TPP	Unit	Net nominal Output Power [MW]	Decomissioned due to the end of a lifetime	Decomissioning scenario	
				Moderate [MW]	Extreme [MW]
TES 5	1	305	305	-	-
TES PT 51	1	42	42	-	-
TES PT 52	1	42	42	-	-
TES 6	1	539	-	539	539
PPE	1	58	58	-	-
TEB-PB1	1	23	23	-	-
TEB-PB2	1	23	23	-	-
TEB-PB3	1	23	23	-	-
TEB-PB4	1	114	-	114	114
TEB-PB5	1	114	-	114	114
TEB-PB6	1	53	-	-	53
TEB-PB7	1	50	-	-	-
TETOL 3	1	45	-	-	-
TOTAL			**516**	**767**	**820**

12. TABLE OF FIGURES

13. TABLE OF TABLES