ENERGY TECHNOLOGY AND GOVERNANCE PROGRAM

Assessment of the Impacts of Large-Scale Renewables and Gas Integration in Southeast Europe in 2030

– Final Report –

ELECTRICITY MARKET INITIATIVE WORKING GROUP

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CONTENTS

ABBREVIATIONS

CCGT	–	Combine Cycle Gas Turbine
CCS	–	Carbon 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	–	Independent Power Transmission Operator for Greece
Borzen	–	Slovenian Power Market Operator
CGES	–	Montenegrin Electric Transmission System
COTEE	–	Montenegro Electricity Market Operator
ELES	–	Electricity Transmission Company of Slovenia
EMS	–	Serbian Transmission System Operator
ESO EAD	–	Electricity System Operator of Bulgaria
HOPS	–	Croatian Transmission System Operator
HROTE	–	Croatian Energy Market Operator
KOSTT	–	Kosovo Transmission System and Market Operator
MEPSO	–	Electricity Transmission System Operator of Macedonia
NOSBiH	–	Independent System Operator in Bosnia and Herzegovina
OST	–	Albanian Transmission System Operator
Transelectrica	–	Romanian Transmission and System Operator

1. INTRODUCTION

The primary goal of the Electricity Market Initiative (EMI), expressed in the EMI Work Plan, is 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 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.

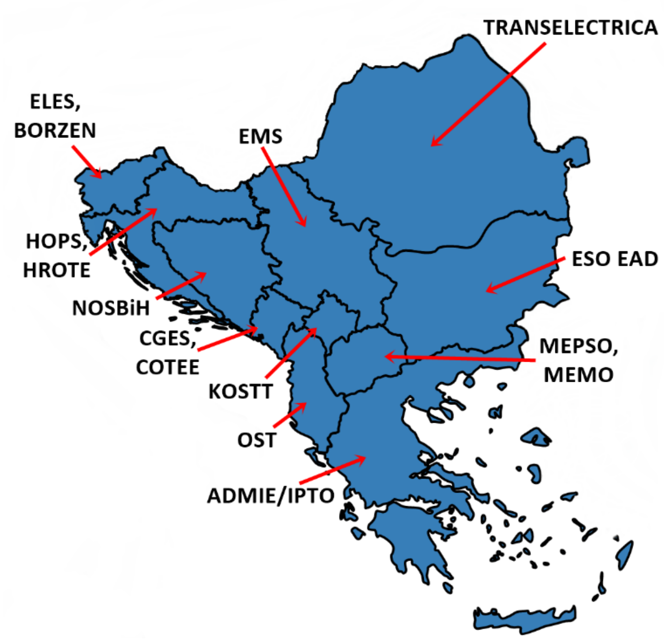


Figure 1: EMI Members

The newly adopted EU Energy Law (the "Clean Energy for all Europeans") package has set a medium-term target of 32% for the share of energy from renewable energy systems in the EU's gross final consumption of energy (not only electricity) by 2030. The EMI members are mostly below this target, especially those in the Western Balkans (WB6). Some of the EMI members are from EU member states (Slovenia, Croatia, Bulgaria, Romania and Greece), while all others aspire to join the EU, being contracting parties of the Energy Community. The Energy Community Treaty is a binding international agreement that obliges all parties to fully transpose and implement the EU legal framework with regard to electricity markets, RES integration, environmental protection and competition. Therefore, the WB6 members have essentially the same targets as EU members, but with some time delay for its implementation. This means that the EMI working group must be harmonized in its future electricity sector targets, using this period as an opportunity to learn from the best practices of those who implement the Energy Law earlier.

In our 2019 regional survey, the EMI members identified RES integration as their highest priority and long-term concern. Other regions of Europe and the world have shown that the integration of large-scale RES is a significant market and network challenge, albeit one they are dealing with. So, we launched this study in March 2020 and completed this draft report in October

2020 to help all TSOs and MOs in SEE to assess the network and market implications of significant RES increases, develop strategies, and identify investments that may accommodate such resources. **It is also important to note that, within this Study, as RES capacities, we consider only wind and solar capacities (and not hydro).**

In addition, new gas generation is likely to replace some older coal and oil-fired power plants in SEE. So, this study also evaluates the addition of significant new gas generation, which it is reasonable to presume will occur by 2030, from the TAP and TANAP pipelines, LNG and other sources.

This is the first regional study to combine detailed market and network analysis in a sufficient level of detail to support the both market integration and network upgrades on both the regional and internal country levels. Thus, this EMI work will promote the integration of electricity markets region-wide (as envisioned in the EMI MOU). Further, it will identify prime opportunities to enhance and upgrade the network to transfer power (including RES and gas generation in particular) seamlessly across borders.

This Study has four main objectives:

1. To analyze and quantify the impacts of large-scale RES and gas integration in SEE on the:
   - electricity network and
   - electricity market operation
2. To prepare the EMI members to deal with those impacts, including:
   - preparations to accommodate coupling
   - improvements to EMI members' TYNDPs and filings with regard to regulations and network facilities
3. To reflect the challenges of large-scale RES and additional gas deployment at the:
   - individual EMI member level,
   - regional impacts of such expansion.
4. To support EMI members in decisions regarding grid upgrades, including:
   - upgrades to internal transmission network lines at the 400, 220 and 110 kV levels
   - upgrades to raise NTCs and expand electricity trading across borders
   - upgrades to substations to accommodate new RES and gas generation

This Study seeks to provide these benefits for EMI members and customers region-wide:

1. Optimize the use of generation region-wide
2. Better utilize internal and cross-border grids

3. Anticipate the need for network and interconnection investments
4. Determine the RES impact on the wholesale power prices and conventional generation
5. Show the potential to considerably lower emissions
6. Reduce if not eliminate seams, and increase resilience
7. Attract private sector investment and promote competition
8. Enable EMI members and regulators to be even more effective in their respective roles

In specific, this study addresses the impacts on electricity markets and prices due to substantial RES and gas development, and how the transmission grid will need to adapt – both internally within the EMI members and between them - to successfully integrate these resources. To do so, this project conducted two interconnected analyses:

1) A study of the changes in the regional electricity market, as they add a rapidly growing share of RES and some gas generation; and
2) An assessment of the network impacts of such development, including where congestion may arise and new transmission network elements may be required.

The market analysis carried out hourly simulations of the power system and provided results for each hour of the year, while the network analyses was focused on snapshots of the grid's operation at moments when the network could be under stress, both for the year 2030.

The market analysis will enable EMI members to assess and understand the impacts of large-scale RES and gas integration on wholesale market prices, energy mix, area balances, cross-border energy exchanges, CO_2 emissions and congestion costs.

The network analysis will enable EMI members to better understand the effects of large-scale RES and gas integration impact on load flows, voltage profiles, secure grid operations and congestion in the regional transmission network, and the impact of large-scale RES development in neighboring countries, on their internal networks.

In addition to large-scale RES integration, part of this study is dedicated to potential natural gas system development, and the impact that new gas fired power plants could have on power system and market operation in the region.

Once this study is finished and adopted, we will transfer both the network and market models (in Antares and PSS/E forms) to the EMI members, with the necessary data, training and explanations required for EMI participants to use them for their own internal purposes and future analyses.

This Draft Report includes 8 chapters, 297 figures and 197 tables. It provides a detailed overview of the collected input data, electricity market and network models, methodology and software solutions applied. It shows the results of the market and network analyses for a number of operational regimes or scenarios (which the EMI members agreed upon) in the SEE power system in 2030, with different levels of RES integration. The results will inform the EMI members' next steps in market integration, and our next collaborative steps together.

2. MARKET MODELING 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 represented the market areas of OST, NOSBiH, ESO EAD, HOPS, ADMIE/IPTO, KOSTT, MEPSO, CGES, Transelectrica, EMS and ELES on a plant-by-plant level of detail, and modeled their demand and non-dispatchable generation on an hourly level.
- We modeled Hungary's, Ukraine's and Moldova's market area by technology cluster (hydro types, thermal by fuel type, nuclear, RES), and modeled demand and non-dispatchable generation on an hourly level.
- We modeled Turkey, Central Europe and Italy as spot markets in which 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 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
- CO2 emission factor per unit
- Operational constraints (minimum up/down time) 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).

- 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[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. Thus, the data mainly originated from the ENTSO-E TYNDPs and MAF datasets, such as capacity factors for wind and solar power plants. In several cases, we asked the TSOs for clarifications (e.g., NTCs), and adjusted those figures. In this way we have consistent, harmonized and verified inputs among all EMI TSOs and MOs, as well as with relevant ENTSO-E development documents.

The six sub-sections below describe our approach in gathering the data and relevant items in support of the 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.

2.1. Load, Wind and Solar Hourly Profiles

The TSOs provided annual demands for the Referent demand scenario, while for the Alternative (Low) demand scenario, either the TSOs provided such a projection or if not, we use 50% of the referent growth rate. 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. In the low demand scenarios, we calculated total consumption using a reduced annual growth rate and applied the same hourly profiles.

For the Referent RES scenario, the TSOs provided the expected installed RES capacities for 2030. For the High RES scenario, we first used TSO projections, or as a backup, we added 25% to the RES capacities in the Referent RES scenario.

In addition, if the EMI members did not provide wind and/or solar hourly capacity factors, we also used data from the previous EMI study, based on publicly available databases from ETH Zurich[4].

2.2. 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) are 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.

2.3. 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 (Table 1 and Table 2).

4 https://www.renewables.ninja/

Table 1: General technical and economic parameters for TPPs from TYNDP 2018 common base

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 2: Additional technical parameters for TPPs from TYNDP 2018 common base

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%

2.3.1. Fuel and CO_2 prices

For fuel prices and CO_2 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 (Table 3).

Table 3: 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		
€/tCO_2	CO_2 price	19.7	20.4	21.7	23	56	27	53	35	75	100	80

Table 5: Fuel prices in TYNDP 2020 scenarios

For the same reason, we assumed the CO_2 price to be the same as applied in TYNDP 2020. For the Referent $C0_2$ scenario, we used 27 €/t$C0_2$, the same as in the National Trends scenario from TYNDP 2020. For the Alternative $C0_2$ scenario we used 53 €/t$C0_2$, the same as in the Distributed Energy scenario from TYNDP 2020.

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, 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.

2.3.2. 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.

2.3.3. External electricity markets

Our model of the power systems in Central Europe (i.e. Austria and Germany), Italy and Turkey considered 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 used assumptions of wholesale market prices in 2030 from the TYNDP 2020 Scenario Report, which contains average yearly marginal cost indicators for all market zones in ENTSO-E. We used average yearly prices obtained for the "National Trends" and "Distributed Energy" Scenarios to scale the different prices separately for each market.

Table 4 shows average yearly wholesale prices in the modelled external markets for two different Scenarios related to CO_2 price development: referent (27 Eur/t as in "National Trends" scenario) and high (53 Eur/t, as in "Distributed Energy" scenario).

Wholesale market prices for TR market area presented in Table 4 are extraordinary high, but these prices were obtained from market simulations of the whole ENTSO-E within TYNDP 2020. We are aware that this high price is the driver for large amounts of exports from the SEE region towards TR, but in order to use consistent prices for external markets, we used prices from this source.

As long as these prices in 2030 are above those in SEE (e.g., half or less of the figures shown), this report's analytic results would be the same, since the TR market area would still be an area to which SEE would export power. As the TR market adds significant new capacity, which is expected by 2040, their wholesale prices and the dynamics of trade with SEE could change.

Table 4: Average 2030 yearly price on external markets for different CO_2 scenarios

Market	Price (€/MWh)	
	Referent CO_2 price (27 EUR/t)	High CO_2 price (53 EUR/t)
Central Europe	36.58	57.62
Italy	48.41	58.70
Turkey	189	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 different CO_2 scenarios given in Table 4.

2.3.4. 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 National Trends for HU, and Business As Usual scenarios for UA and MD), but with two levels of CO_2 prices in line with the referent and alternative CO_2 scenarios applied for all EMI members (see chapter 2.4).

The details on power systems modeled on a technology level are given in the Interim Report.

2.4. Harmonized NTC values

Future NTC values are input data for this Study, and are subject to many uncertainties, including internal network development, internal generation unit commitments, realization of new cross-border interconnection capacities, demand growth, and more. The NTC values for 2030 in this study were provided by the TSOs – in agreement with their neighbors - and have been included in the EMI's Antares market model. Due to the mentioned uncertainties, NTC values are regularly updated and submitted to ENTSO-e. NTC values for every border are determined by the TSOs on both sides of the border and mutually harmonized. The Table below provides the harmonized and consolidated NTC values implemented in our study (Table 5).

We used 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.

The Antares model included the power systems of all the EMI WG members and the neighboring markets, with generation capacities and a simplified representation of the transmission network and cross-border capacities, represented as NTC values.

A single regional market model represented all generation and transmission cross-border capacities for the selected modeling year – 2030 - based on the data presented in this chapter. The internal transmission network have not been modeled in the market simulator since 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	
AL - GR	250
AL - ME	450
AL - MK	500
AL - XK	650
CE_HU - HU	800
CE_SI - SI	950
BA - HR	1200
BA - ME	800
BA - RS	1100
BG - GR	1350
BG - MK	500
BG - RO	1500
BG - RS	400
BG - TR	900
GR - AL	250
GR - BG	800
GR - IT	500
GR - MK	1100
GR - TR	660
HR - BA	1200
HR - HU	1700
HR - RS	500
HR - SI	2000
HU - CE_HU	800
HU - HR	1700
HU - RO	1300
HU - RS	600
HU - SI	1200
IT - GR	500
IT - ME	1000
IT - SI	660
UA-RO	773
RO-UA	773
UA-MD	400
MD-UA	800

NTC (MW) in 2030	
ME - AL	450
ME - BA	750
ME - IT	1000
ME - RS	600
ME - XK	300
MK - AL	1000
MK - BG	400
MK - GR	850
MK - RS	180
MK - XK	220
RO - BG	1400
RO - HU	1400
RO - RS	1400
RS - BA	1200
RS - BG	400
RS - HR	500
RS - HU	600
RS - ME	600
RS - MK	300
RS - RO	1100
RS - XK	300
SI - CE_SI	950
SI - HR	2000
SI - HU	1200
SI - IT	730
TR - BG	500
TR - GR	580
XK - AL	500
XK - ME	300
XK - MK	350
XK - RS	400
MD-RO	950
RO-MD	950
UA-HU	1253
HU-UA	1253

2.5. Summary of SEE regional market models

In this chapter, we review the expected power system status in the year 2030 for each EMI member, in alphabetical order, along with an overview of the data, assumptions and proxies that we used to develop the corresponding market model with the Antares software tool.

We presented all relevant parameters in the Interim Report so that the reader could check their plausibility and confirm their usability for the upcoming forecasts and analyses.

Below, we present an overview of the expected development of power consumption and generation for different technologies in each SEE market area, and for the entire region (Tables 6 through 14).

Table 6: Referent and low demand scenarios - SEE

EMI Member	Demand in 2018 (TWh)	Referent scenario		Low demand scenario	
		Growth rate from 2018 to 2030	Demand in 2030 (TWh)	Growth rate from 2018 to 2030	Demand in 2030 (TWh)
AL	7.2	2.34%	9.5	1.17%	8.27
BA	12.6	0.62%	13.57	0.31%	13.08
BG	34.1	0.76%	37.35	0.38%	35.69
HR	18.2	0.18%	18.6	0.09%	18.4
GR	51.6	1.60%	62.44	1.15%	59.22
XK	5.58	1.90%	6.85	0.95%	6.22
MK	7.2	2.07%	9.2	1.85%	8.96
ME	3.4	2.79%	4.73	1.39%	4.01
RO	57.9	0.81%	63.5	0.40%	60.7
RS	34.9	0.92%	38.95	0.46%	36.88
SI	14.4	1.28%	16.61	0.64%	15.51
TOTAL	**247.08**	**1.09%**	**281.3**	**0.65%**	**266.94**

Table 6 shows that we expect **total regional demand growth from 2018 – 2030 in the range of 20 – 34 TWh (referent vs low demand growth scenarios), or a growth of 8.0% - 13.7%** of total electricity demand registered in 2018. Annual growth rates per market area in the referent scenario show a wide range, from 0.18% (HR) to 2.79% (ME). In the low demand growth scenario, annual growth rates per market area range from 0.09% (HR) to 1.85% (MK).

The next four tables summarize the changes expected across market areas in SEE in installed generation capacities per technology from 2018 to 2030. As Table 7 indicates, EMI members **expect a significant increase in wind power capacity in the coming decade, in the range of 11,121 to 15,557 MW (referent vs high RES scenario), reaching a total of 2.58 to 3.22 times more WPP than in 2018**. In a number of cases in SEE, 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 (referent scenarios) to 6,498 MW (high RES scenario)), while in relative terms, the largest growth is anticipated in RS (2,691 MW in the referent scenario), or 14.4 times more WPP capacity in 2030 than in 2018, and 3,414 MW in the high RES scenario, or 18 times more WPP than in 2018).

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	High RES	Referent RES	High RES
AL	0	384	480	384	480
BA	51	529	599	580	650
BG	712	175	397	887	1109
HR	582	718	918	1300	1500
GR	2302	4698	6498	7000	8800
XK	34	302	466	336	500
MK	37	269	329	306	366
ME	118	125	186	243	304
RO	2977	1223	2123	4200	5100
RS	201	2691	3414	2892	3615
SI	3	7	147	10	150
TOTAL	**7017**	**11121**	**15557**	**18138**	**22574**

Even more rapid development is expected in solar power capacity. There will be an **additional 9,954 to 16,174 MW (referent vs high RES scenario) of SPP in the region, reaching a total of 2.93 to 4.14 times more than in 2018**, as given in the following table. By far the largest installed SPP capacity (and almost half of the regional new SPP capacity) is expected in Greece (5,255 MW to 7,155 MW), followed by Bulgaria. In 2030, these two market areas combined are expected to comprise 70% and 62% of SPP capacity in the referent and high RES scenarios.

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	High RES	Referent RES	High RES
AL	0	445	557	445	557
BA	10	90	190	100	200
BG	1059	1870	2602	2929	3661
HR	60	540	740	600	800
GR	2445	5255	7155	7700	9600
XK	7	143	243	150	250
MK	17	386	533	403	550
ME	0	250	313	250	313
RO	1262	738	2438	2000	3700
RS	6	26	34	32	40
SI	281	211	1369	492	1650
TOTAL	**5147**	**9954**	**16174**	**15101**	**21321**

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, the total increase in installed HPP capacity will be significant. In absolute terms **5,219 MW of new HPP is expected by 2030, which is a growth of 21%** compared to HPP capacities 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	1138	3302
GR	3413	1132	4545
XK	64	360	424
MK	693	207	900
ME	649	468	1117
RO	6420	322	6742
RS	3018	13	3031
SI	1185	149	1334
TOTAL	**24825**	**5219**	**30044**

Finally, the following table here shows expected changes (both positive and negative) in total installed capacities in thermal power, including nuclear power plants, from 2018 to 2030. Five EMI members are planning to decrease total TPP capacity (BG, HR, SI, MK, GR), five members are planning to increase it (RS, AL, XK, BiH, RO), while ME is the only area with no expected TPP capacity changes by 2030. The most significant change in this period, in absolute terms, is observed in GR. GR plans to decommission 1,905 MW of TPPs by 2030, which is in line with their targets for large expected growth of SPPs and WPPs. On the other hand, the largest TPP increase, in absolute terms, is expected in RS, with a capacity increase of 519 MW.

For the entire EMI region, the **total decrease in installed TPP capacity will be significant, 2,744 MW, but it is just 7% of total installed TPP capacity in 2018.** So, despite large scale RES integration targets and plans, EMI members are not giving up on TPP generation. **Given the impacts of ETS emissions prices, increased RES and gas generation on the capacity factors for TPPs discussed in this report (particularly lignite generation), TPP retirements by 2030 could well be higher than these official figures.**

Table 10: Installed thermal power plant (TPP) capacities – SEE

Market area	TPP installed capacity (MW) in 2018	Installed TPP capacity change (MW) 2018 - 2030	Total installed TPP capacity (MW) in 2030
AL	0	300	300
BA	1850	82	1932
BG	7442	-173	7269
HR	1924	-943	981
GR	9791	-1905	7886
XK	960	18	978
MK	1274	-511	763
ME	225	0	225
RO	8198	438	8636
RS	4320	519	4839
SI	2410	-569	1841
TOTAL	**38394**	**-2744**	**35650**

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

The status of installed capacities in SEE in 2018 is presented in Table 11 and Table 12. Total installed generation capacities in SEE in 2030 is expected in the range of 98,375 MW to 109,031 MW. In other words, the High RES scenario assumes 10,656 MW of additional installed generation capacities in SEE, or an additional 10% compared to the Referent RES scenario, as shown in Table 13.

Table 11: 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 installed TPP capacity (MW)	Total installed capacity (MW)
AL	0	0	1912	0	1912
BA	51	10	2100	1850	4011
BG	712	1059	2649	7442	11862
HR	582	60	2164	1924	4730
GR	2302	2445	3413	9791	17951
XK	36	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	4320	7545
SI	3	281	1185	2410	3879
TOTAL	**7019**	**5147**	**24267**	**38394**	**74827**

Table 12: Technologies share (%) in total generation capacities in 2018 – SEE

EMI Member 2018	Total WPP installed capacity share (%)	Total SPP installed capacity share (%)	Total HPP installed capacity share (%)	Total installed TPP capacity share (%)
AL	0.0	0.0	100.0	0.0
BA	1.3	0.2	52.4	46.1
BG	6.0	9.0	22.3	62.7
HR	12.3	1.3	45.8	40.7
GR	12.8	13.6	19.0	54.5
XK	3.2	0.7	6.0	90.1
MK	1.8	0.8	34.3	63.0
ME	11.9	0.0	65.4	22.7
RO	15.8	6.7	34.0	43.5
RS	2.7	0.1	40.0	57.3
SI	0.1	7.2	30.5	62.1
TOTAL	**9.4**	**6.96**	**32.4**	**51.3**

Table 13: Total generation capacities (MW) per technologies in 2030 in Referent RES and High RES scenario – SEE

EMI Member	Total WPP installed capacity (MW)		Total SPP installed capacity (MW)		Total HPP installed capacity (MW)	Total TPP installed capacity (MW)	TOTAL (MW)	
	Referent RES	High RES	Referent RES	High RES			Referent RES	High RES
AL	384	480	445	557	2949	300	4078	4286
BA	580	650	100	200	2493	1932	5105	5275
BG	887	1109	2929	3661	2649	7269	13734	14688
HR	1300	1500	600	800	3302	981	6183	6583
GR	7000	8800	7700	9600	4545	7886	27131	30831
XK	336	500	150	250	424	978	1888	2152
MK	306	366	403	550	900	763	2372	2579
ME	243	304	250	313	1117	225	1835	1959
RO	4200	5100	2000	3700	6742	8636	21578	24178
RS	2892	3615	32	40	3031	4839	10794	11525
SI	10	150	492	1650	1334	1841	3677	4975
TOTAL	**18138**	**22574**	**15101**	**21321**	**29486**	**35650**	**98375**	**109031**

Changes from 2018 to 2030 are significant in almost all power systems. **In the Referent case, total installed capacities will increase by 31% or 23.5 GW**, with a decrease in TPPs and an increase in all other technologies. The main change is expected in RES capacities. As described above, wind and solar capacities will increase 3 to 4 times (with respect to the referent or high RES scenario in 2030) while capacities in HPPs (mainly small HPPs) will increase 20%. This change in the technological structure of the power systems will cause significant changes in power markets and system operation, and will present a challenge for system operators.

However, the dominant installed generation capacity in SEE will remain in TPPs: 36.2% in the Referent RES scenario and 32.7% in the High RES scenario in 2030. The highest TPP shares are found in BG, XK and RS. The second largest generation portfolio will remain in HPPs: 30% in the Referent RES scenario and 27.0% in the High RES scenario in 2030. From 2018 to 2030, the share of HPPs will decrease 3%, while the share of TPPs will decrease almost 20%. The share of wind and solar capacities will increase from 14% to 34% or 40% in the next 10 years, depending on the aggressiveness of the RES development, and the changes caused by the RES transition is the primary focus of this analysis.

WPP installed capacity shares in SEE range from 18.4% in the Referent RES scenario to 20.7% in the High RES scenario. The highest WPP shares in 2030 are found in RS (26.8% to 31.4%), GR (25.8% to 28.5%) and HR (21.0% to 22.8%).

SPP installed capacity shares in SEE range from 15.4% in the Referent RES scenario to 19.6% in the High RES scenario. The highest SPP shares are found, as expected, in the south of the region: in GR (28.4% to 31.1%), MK (17.0% to 21.3%) and BG (21.3% to 24.9%).

Table 14: Technologies share (%) in total generation capacities in 2030 in Referent RES and High RES scenario – SEE

EMI Member	Total WPP installed capacity share (%)		Total SPP installed capacity share (%)		Total HPP installed capacity share (%)		Total installed TPP capacity share (%)	
	Referent RES	High RES	Referent RES	High RES	Referent RES	High RES	Referent RES	High RES
AL	9.4	11.2	10.9	13.0	72.3	68.8	7.4	7.0
BA	11.4	12.3	2.0	3.8	48.8	47.3	37.8	36.6
BG	6.5	7.6	21.3	24.9	19.3	18.0	52.9	49.5
HR	21.0	22.8	9.7	12.2	53.4	50.2	15.9	14.9
GR	25.8	28.5	28.4	31.1	16.8	14.7	29.1	25.6
XK	17.8	23.2	7.9	11.6	22.5	19.7	51.8	45.4
MK	12.9	14.2	17.0	21.3	37.9	34.9	32.2	29.6
ME	13.2	15.5	13.6	16.0	60.9	57.0	12.3	11.5
RO	19.5	21.1	9.3	15.3	31.2	27.9	40.0	35.7
RS	26.8	31.4	0.3	0.3	28.1	26.3	44.8	42.0
SI	0.3	3.0	13.4	33.2	36.3	26.8	50.1	37.0
TOTAL	**18.4**	**20.7**	**15.4**	**19.6**	**30.0**	**27.0**	**36.2**	**32.7**

This data from the EMI members is the starting point for this report. As requested by the EMI members, this analysis projected the utilization of various power plants and types of plants in a regional market, in which all the existing and new capacity competes to meet customer demand for energy (kWh) on a hourly basis in 2030, under a number of potential scenarios.

This work, combined with the model and data we will transfer, provides EMI members with the ability to anticipate significant changes on their systems and customers that they could not previously capture, given the data requirements and analytic complexity, on a regional and inter-regional basis.

3. NETWORK MODELING ASSUMPTIONS

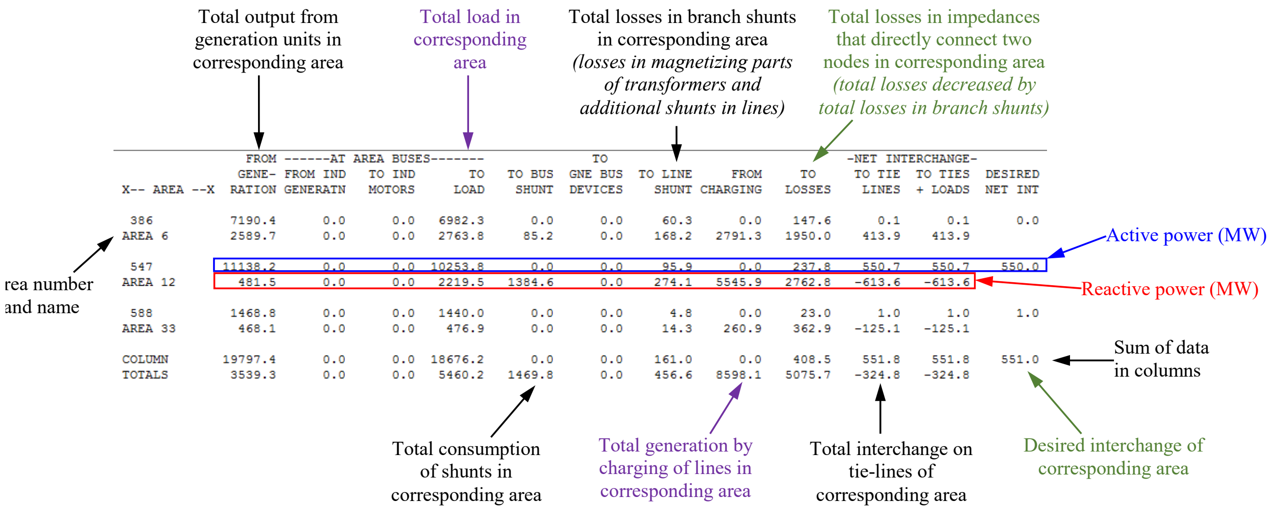
3.1. Description of the PSS®E output format

This subchapter provides description of reports which are commonly used in description of particular national/TSO models as well as in description of regional models. For better understanding, each sample report is prepared and inserted into the figures, with explanation of all parts of the data.

3.1.1. Area summary report

We use an area summary report to showing summary data for each area. The following figure shows an example, with a detailed description of the data columns shown in such reports.

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



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	TO TIES + LOADS	DESIRED NET INT
386	7190.4	0.0	0.0	6982.3	0.0	0.0	60.3	0.0	147.6	0.1	0.1	0.0
AREA 6	2589.7	0.0	0.0	2763.8	85.2	0.0	168.2	2791.3	1950.0	413.9	413.9	
547	11138.2	0.0	0.0	10253.8	0.0	0.0	95.9	0.0	237.8	550.7	550.7	550.0
AREA 12	481.5	0.0	0.0	2219.5	1384.6	0.0	274.1	5545.9	2762.8	-613.6	-613.6	
588	1468.8	0.0	0.0	1440.0	0.0	0.0	4.8	0.0	23.0	1.0	1.0	1.0
AREA 33	468.1	0.0	0.0	476.9	0.0	0.0	14.3	260.9	362.9	-125.1	-125.1	
COLUMN	19797.4	0.0	0.0	18676.2	0.0	0.0	161.0	0.0	408.5	551.8	551.8	551.0
TOTALS	3539.3	0.0	0.0	5460.2	1469.8	0.0	456.6	8598.1	5075.7	-324.8	-324.8	

Figure 2: Description of data shown in area summary report from PSS®E

3.1.1. Subsystem summary (summary per voltage levels)

We show an example of the subsystem summary (summary for selected parts of the system) in Figure 3. This report contains two parts. The upper part provides summary information which are similar as data shown in area summary, with some additional data (separate data for each type of loads in the subsystem (constant power load, constant current load and constant admittance load) and consumption of shunts which are part of FACTS devices). If whole area is selected as subsystem, then data in this part are the same as data shown in area summary table.

The lower part of the table contains data for each voltage level in the selected subsystem. In this part, the data related to the columns "TO LOSSES", "TO LINE SHUNTS", and "FROM CHARGINGS" are distributed between each voltage level.

Since lines connect nodes of the same voltage level, it is clear how lines are assigned to voltage levels. With regard to transformers, we also assign transformers to a voltage level.

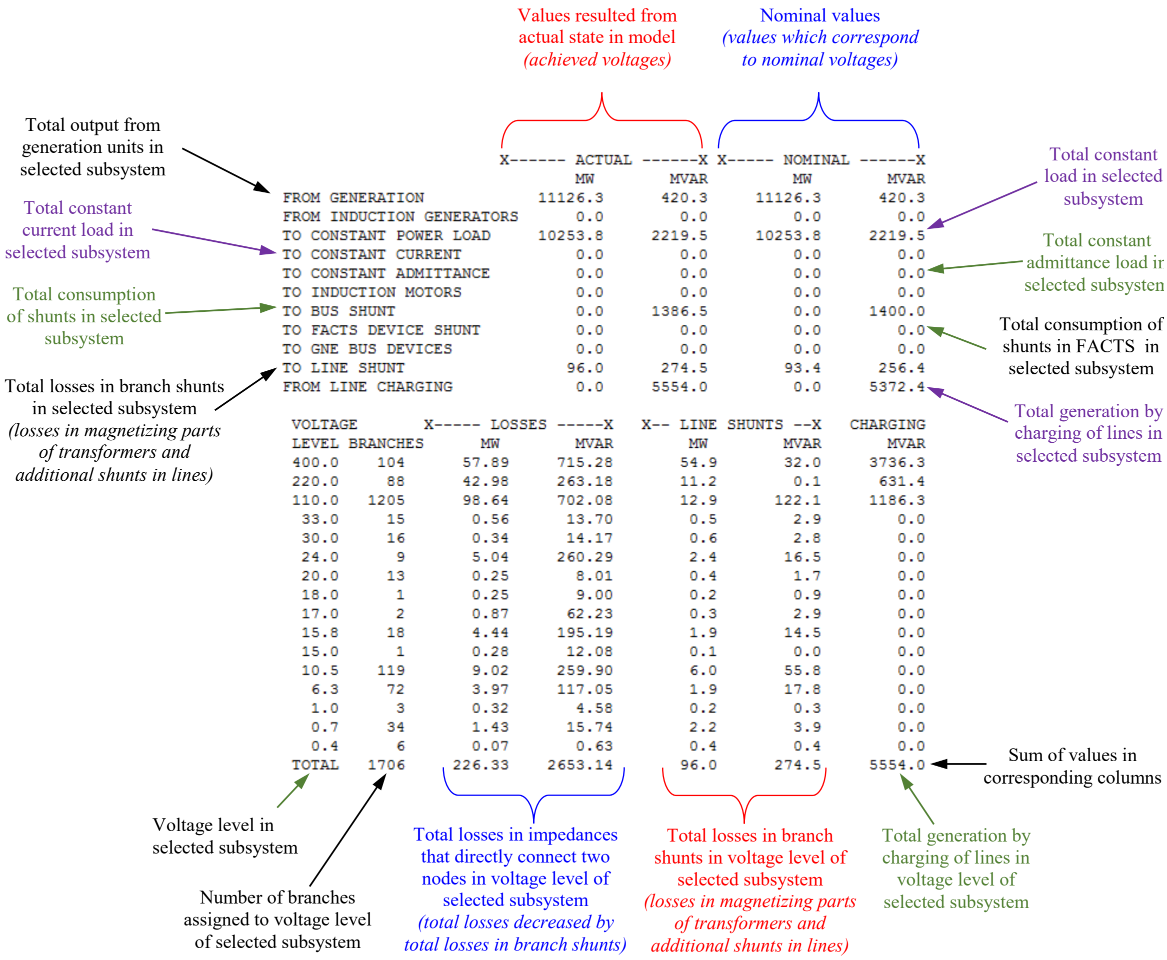


Figure 3: Description of data shown in subsystem summary report from PSS®E

For any type of branch, the assignment to a voltage level depends on the defined measuring point on the branch. Since the measuring point defines the place where the power interchange between two nodes is registered, we assign each branch to a node (and therefore to voltage level as well), on the opposite side of the measuring point. For a clearer explanation, we provide an example of a small part of the grid in Figure 4.

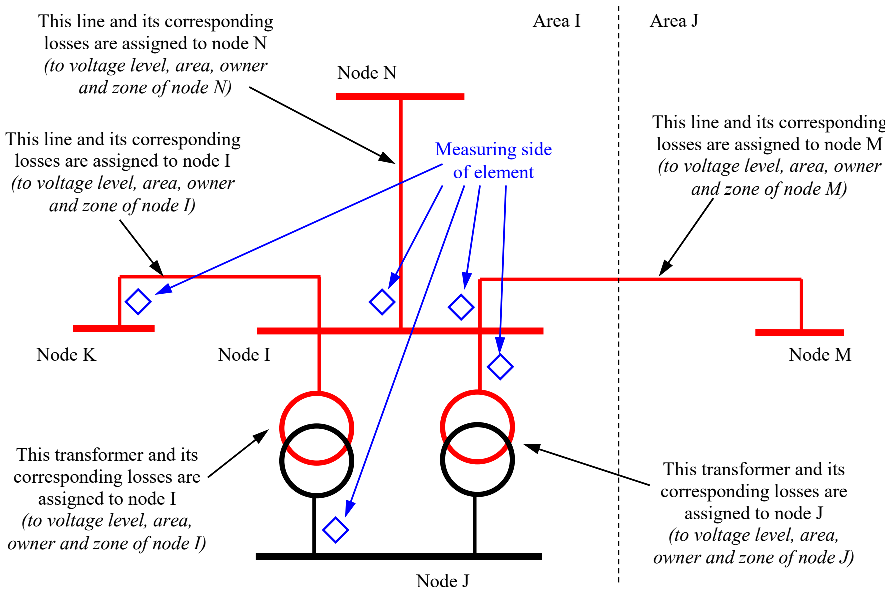


Figure 4: Description of rules for assignment branches to voltage levels

3.1.2. Contingency analysis report

We show an example of a report from a contingency analysis in Figure 5, with four main parts.

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

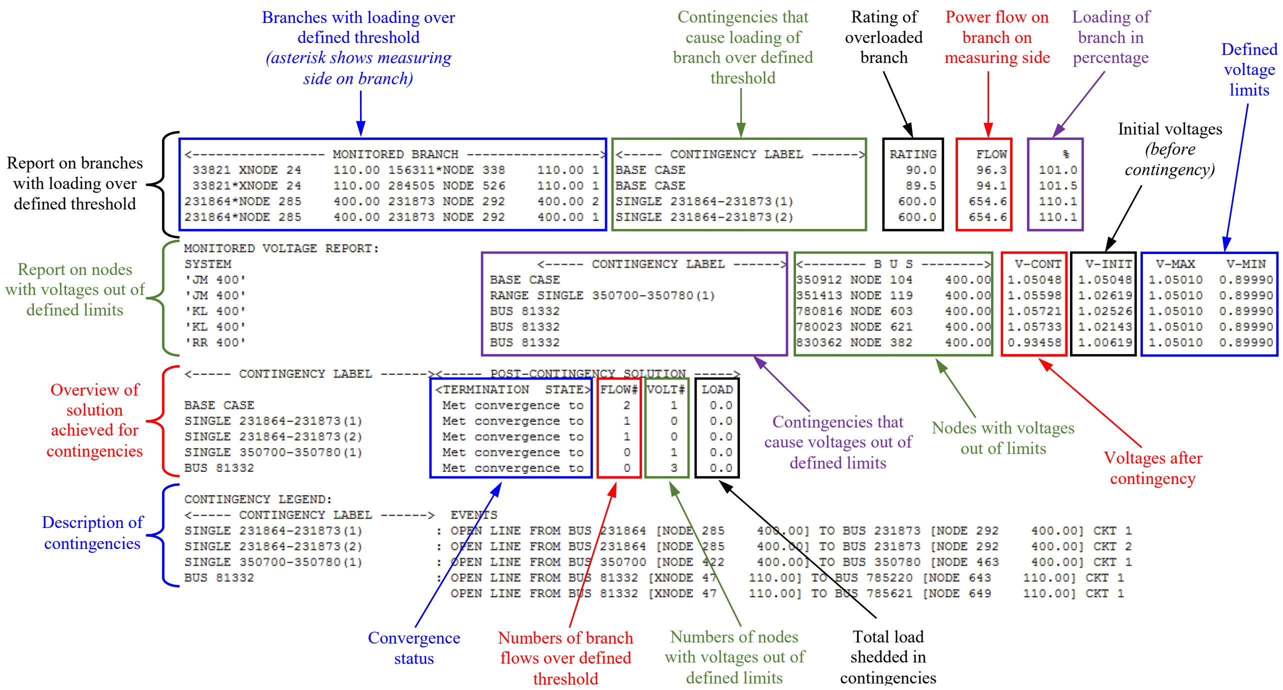


Figure 5: Description of data shown in report from contingency analysis, in format of PSS®E report

Usually, the threshold for listing branches is 100% of the defined rating, which means that the report would only show overloaded braches. However, the user can define other thresholds (for example, a threshold of 80% would show all branches which are highly loaded, including overloaded ones).

The second part shows the monitored nodes with voltages outside of defined limits. For a better understanding, we show the voltage limits for each node within these data.

The third part provides information about achieving a solution (convergence report) for each analyzed contingency and overview of the results (the number of shown branches and nodes with voltage overshots).

Finally, the fourth part provides a description of each analyzed contingency.

3.2. Summary of the initial SEE regional grid models

For the purpose of this study, we needed to create initial Regional Transmission System Models (RTSMs) for the following referent 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 has two variants related to RES integration, which are:

- the expected/forecasted level of RES integration (MW) for 2030, and
- a higher level of RES integration for 2030, either one specified by the TSO, or as a default, a level 25% higher than the expected level

To create a regional EMI network model, we needed to collect individual network 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 were very detailed, identifying all the data needed to model each element in the power system. It also included descriptions and instructions related to modeling each national system as a part of the region (e.g., level of modeling, node number ranges, area numbers, etc.)

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

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, and for referent and high RES).

We then 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, hydro conditions, levels of consumption, and CO2 emission prices.

To prepare for these comprehensive simulations with the regional network models, we conducted a preliminary analysis of the country TSO models, and present the results below.

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.

Besides summarizing each area, and analyzeing their voltage profile, for each regional model we assessed steady-state security against single outages. This assessment included analyses of grid conditions in case of single branch outages of regional importance. We included the following branches in the list of outages, as well as in the list of monitored 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 branch.

The voltage profile and security assessment are related to the high voltage grid (220 and 400 kV) only as part of the grid with regional importance. We considered all problems related to lower voltage levels as local problems.

In the Interim Report we provided detailed output on the power system balance, network losses, voltage profile and n-1 contingency analysis, and checked them for the base cases. This proved that the basic models are reliable and convenient for the more detailed scenario analyses.

3.2.1. Maximum load regime – referent RES

We show a summary of each country's network data, as reported from PSS®E, for the time of maximum load in 2030, for the referent RES level, in Table 15. 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 15: Summaries of all areas in regional model – maximum load 2030, referent RES

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	TO TIE LINES (NET INTERCHANGE)	TO TIES + LOADS (NET INTERCHANGE)	DESIRED NET INT
10	1147.7	0.0	0.0	1873.0	0.0	0.0	4.9	0.0	26.8	-757.0	-757.0	-757.0
AL	138.7	0.0	0.0	506.4	-51.1	0.0	29.4	673.1	308.6	18.6	18.6	
13	3182.6	0.0	0.0	2328.0	0.0	0.0	15.7	0.0	68.7	770.1	770.1	770.0
BA	626.4	0.0	0.0	458.4	0.0	0.0	160.5	1052.9	759.2	301.1	301.1	
14	7190.6	0.0	0.0	6982.3	0.0	0.0	60.5	0.0	147.7	0.1	0.1	0.0
BG	2597.7	0.0	0.0	2763.8	85.2	0.0	175.3	2791.1	1951.3	413.3	413.3	
16	3135.8	0.0	0.0	2630.0	0.0	0.0	4.7	0.0	86.0	415.1	415.1	415.0
HR	-223.9	0.0	0.0	620.5	109.4	0.0	22.7	1580.7	757.2	-152.9	-152.9	
30	9163.0	0.0	0.0	8374.0	0.0	0.0	0.0	0.0	188.0	601.0	601.0	601.0
GR	248.6	0.0	0.0	4124.6	1815.1	0.0	22.6	7920.3	2097.6	108.9	108.9	
37	720.8	0.0	0.0	1393.0	0.0	0.0	2.1	0.0	12.7	-687.0	-687.0	-687.0
MK	225.0	0.0	0.0	488.8	0.0	0.0	8.5	494.8	149.9	72.6	72.6	
38	1457.5	0.0	0.0	838.0	0.0	0.0	4.4	0.0	48.1	567.0	567.0	567.0
ME	348.3	0.0	0.0	285.6	0.0	0.0	30.0	440.7	508.2	-34.9	-34.9	
44	11138.2	0.0	0.0	10253.8	0.0	0.0	95.9	0.0	237.8	550.7	550.7	550.0
RO	482.1	0.0	0.0	2219.5	1384.6	0.0	274.1	5545.8	2762.8	-613.1	-613.1	
46	8422.4	0.0	0.0	6782.0	0.0	0.0	29.6	0.0	162.1	1448.7	1448.7	1450.0
RS	1623.9	0.0	0.0	1374.3	0.0	0.0	173.9	1834.7	2114.7	-204.3	-204.3	
47	1468.8	0.0	0.0	1440.0	0.0	0.0	4.8	0.0	23.0	1.0	1.0	1.0
XK	468.1	0.0	0.0	476.9	0.0	0.0	14.3	260.9	362.9	-125.1	-125.1	
49	2074.3	0.0	0.0	2228.1	0.0	0.0	7.6	0.0	48.7	-210.0	-210.0	-210.0
SI	171.5	0.0	0.0	354.3	0.0	0.0	49.1	674.1	691.9	-249.6	-249.6	

In comparison to corresponding data from the collected national/TSO models, we see that losses (and therefore total generation) are slightly changed. This is due to the influence of the regional model (especially the neighboring TSOs), and is caused by changing voltage profile and loop flows.

We provide a summary of the voltage profile for the HV grid in Table 16. This table shows data per each area, at voltage levels of 400 kV and 220 kV (if it 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 16: Summary of the voltage profile for the maximum load regime – referent RES scenario

Area	400 kV nodes				220 kV nodes			
	Nodes	Vmin (kV)	Vavg (kV)	Vmax (kV)	Nodes	Vmin (kV)	Vavg (kV)	Vmax (kV)
AL	9	402,10	404,87	410,16	29	220,34	221,98	225,14
BA	13	407,14	412,41	416,03	26	224,57	234,05	237,76
BG	22	404,69	410,46	418,76	39	209,53	221,57	228,80
HR	10	400,74	407,84	414,91	22	222,25	228,05	248,81
GR	75	397,68	407,50	412,78	0			
MK	7	401,91	406,54	410,81	0			
ME	6	405,24	409,24	413,03	5	221,12	226,33	231,72
RO	45	394,70	398,91	403,95	73	220,84	226,82	231,86
RS	46	390,00	405,48	415,00	42	216,31	225,60	230,95
XK	5	401,16	403,58	405,13	11	213,89	217,93	222,87
SI	9	391,73	402,56	408,00	6	221,72	224,30	226,73

Below, we also display this data graphically. Figure 6 shows the voltage profile summary for the 400 kV grid, while Figure 7 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.

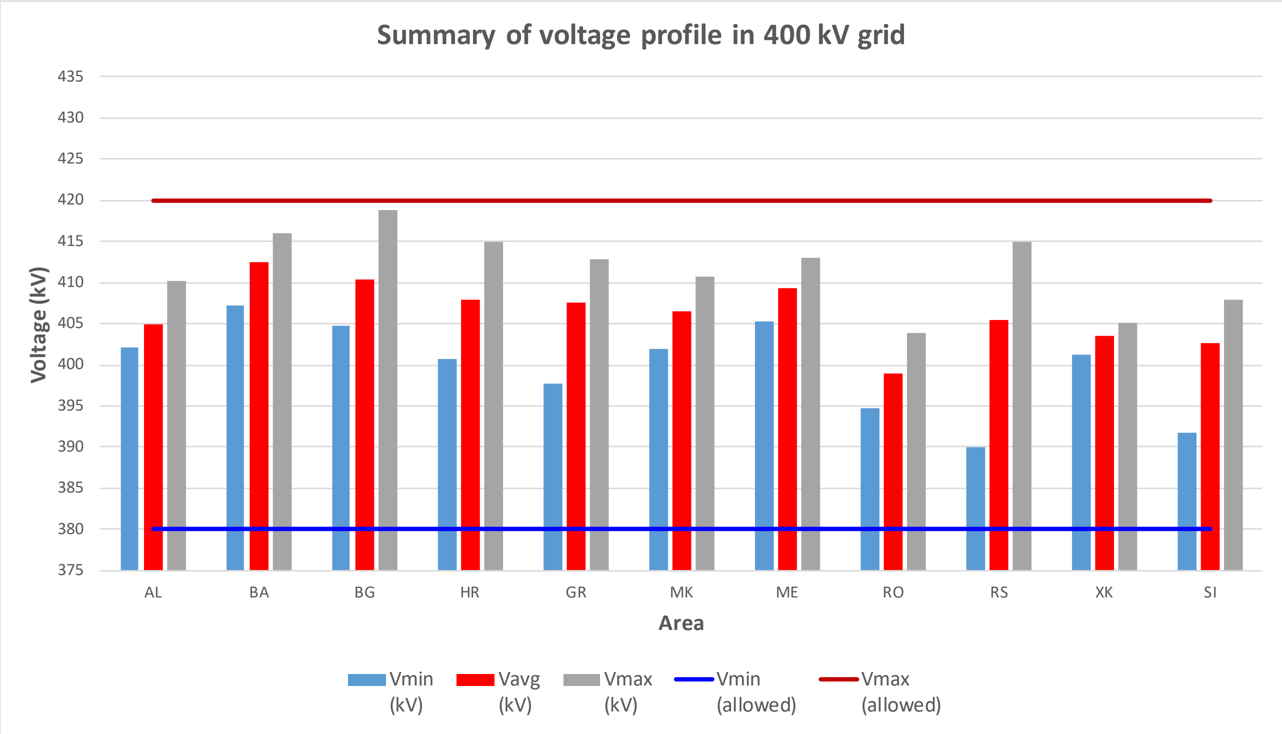


Figure 6: Summary of the voltage profile in the 400 kV grid – maximum load 2030, referent RES

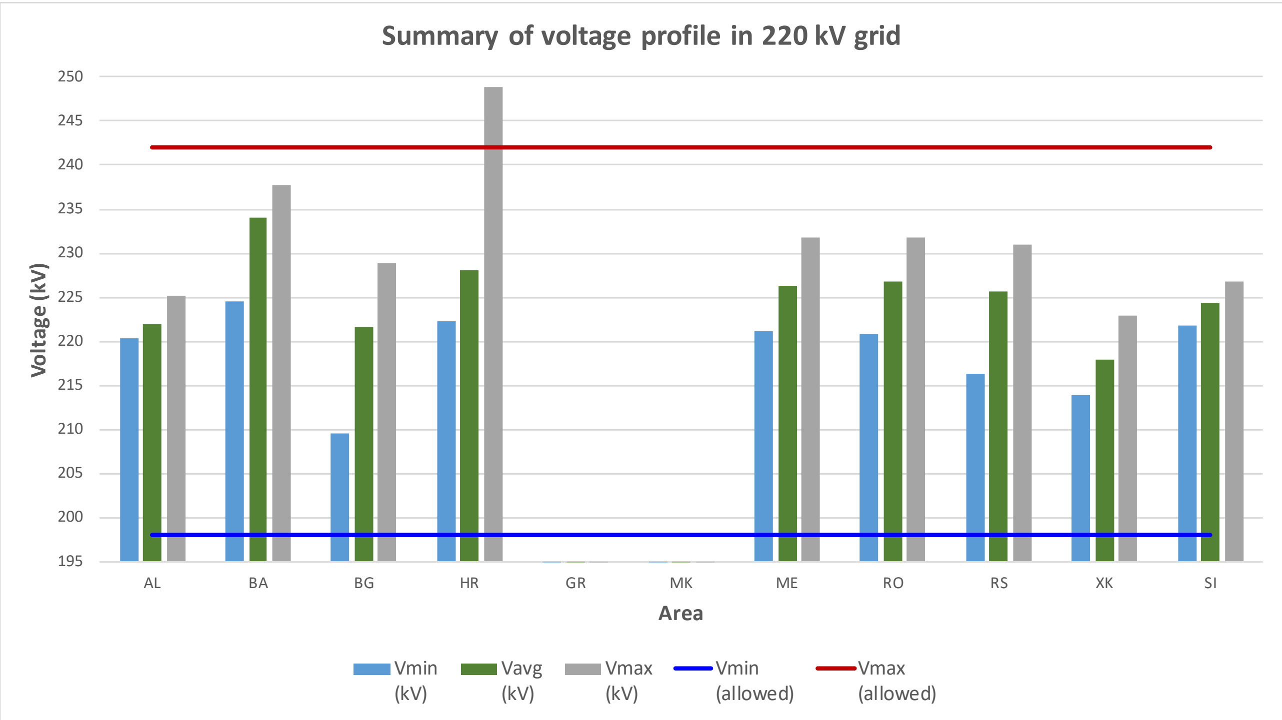


Figure 7: Summary of voltage profile in 220 kV grid – maximum load 2030, referent RES

It can be seen that **voltages in the 400 kV grid are within allowed limits**. However, **in the 220 kV grid, HOPS (HR) has some nodes with the voltages above the upper voltage limit**. The location with overly-high voltage is at the Plat substation, in southern Croatia.

There are no overloaded HV branches in this model.

Aggregated border exchanges for the maximum load regime, referent RES, are shown in Figure 8.

Figure 8: Aggregated border exchanges – maximum load 2030, referent RES

We show aggregated border exchanges with arrows. The direction of arrows is fixed and values inside the arrows can be positive or negative. 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 represents the total import/export, as the sum of all the aggregated border power flows from the corresponding TSOs.

Our initial findings from a review of the (N-1) contingencies is that there are no outages which cause overloads in the HV grid.

3.2.2. Maximum load regime – high RES

We provide a summary of the area totals from PSS®E, for the maximum load 2030 regime in the high RES variant, in Table 17. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 17: Summaries of all areas in regional model – maximum load 2030, high RES

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	1144.5	0.0	0.0	1873.0	0.0	0.0	4.8	0.0	23.8	-757.0	-757.0	-757.0
AL	108.0	0.0	0.0	506.4	-51.2	0.0	28.9	672.3	284.2	12.0	12.0	
13	3185.4	0.0	0.0	2327.0	0.0	0.0	15.7	0.0	72.6	770.1	770.1	770.0
BA	643.7	0.0	0.0	458.4	0.0	0.0	160.2	1051.1	774.0	302.1	302.1	
14	7187.8	0.0	0.0	6982.3	0.0	0.0	60.9	0.0	144.4	0.1	0.1	0.0
BG	2492.0	0.0	0.0	2763.8	85.2	0.0	185.5	2793.2	1906.2	344.6	344.6	
16	3218.9	0.0	0.0	2630.0	0.0	0.0	4.7	0.0	90.1	494.1	494.1	494.0
HR	-218.9	0.0	0.0	620.5	109.3	0.0	22.7	1577.4	786.8	-180.8	-180.8	
30	9174.7	0.0	0.0	8374.0	0.0	0.0	0.0	0.0	199.6	601.1	601.1	601.0
GR	104.9	0.0	0.0	4124.6	1797.8	0.0	22.6	7947.6	2006.5	101.1	101.1	
37	721.1	0.0	0.0	1393.0	0.0	0.0	2.1	0.0	13.0	-687.0	-687.0	-687.0
MK	226.6	0.0	0.0	488.8	0.0	0.0	8.5	494.5	153.0	70.8	70.8	
38	1457.0	0.0	0.0	838.0	0.0	0.0	4.4	0.0	47.6	567.0	567.0	567.0
ME	350.7	0.0	0.0	285.6	0.0	0.0	30.0	440.5	501.4	-25.9	-25.9	
44	11313.4	0.0	0.0	10229.8	0.0	0.0	96.9	0.0	236.7	750.0	750.0	750.0
RO	603.4	0.0	0.0	2205.2	1393.4	0.0	279.7	5597.5	2815.5	-492.8	-492.8	
46	8420.7	0.0	0.0	6782.0	0.0	0.0	29.7	0.0	159.6	1449.4	1449.4	1450.0
RS	1540.8	0.0	0.0	1374.3	0.0	0.0	174.1	1837.8	2095.8	-265.6	-265.6	
47	1469.3	0.0	0.0	1440.0	0.0	0.0	4.8	0.0	23.6	1.0	1.0	1.0
XK	465.6	0.0	0.0	476.9	0.0	0.0	14.3	260.6	369.4	-134.4	-134.4	
49	2074.5	0.0	0.0	2228.1	0.0	0.0	7.5	0.0	48.9	-210.0	-210.0	-210.0
SI	189.4	0.0	0.0	354.3	0.0	0.0	49.0	673.4	697.6	-238.1	-238.1	

In comparison to data from the national/TSO models, the losses (and therefore total generation) have slightly changed. This is due to the influence of the regional model (especially neighboring TSOs), and is caused by the change in voltage profiles and loop flows.

We summarize the voltage profile for the HV grid at maximum load and high RES in Table 18. This table shows data for each area at the 400 kV and 220 kV voltage levels (if they exist). For each system and voltage level, we also show the number of nodes in operation, minimum voltage, maximum voltage, and average voltage levels.

Table 18: Summary of voltage profile for maximum load regime – high RES scenario

Area	400 kV nodes				220 kV nodes			
	Nodes	Vmin (kV)	Vavg (kV)	Vmax (kV)	Nodes	Vmin (kV)	Vavg (kV)	Vmax (kV)
AL	9	401,79	404,57	409,93	29	220,07	221,71	224,68
BA	13	406,75	412,15	415,99	26	224,13	233,80	237,51
BG	22	404,16	410,44	418,84	39	209,82	221,67	228,80
HR	10	399,95	407,26	414,92	22	221,90	227,54	248,59
GR	75	397,85	407,07	412,46	0			
MK	7	401,81	406,47	410,63	0			
ME	6	404,91	409,05	413,00	5	220,80	226,16	231,68
RO	45	394,39	400,62	410,55	73	219,89	228,67	239,39
RS	46	390,37	405,87	415,06	42	216,44	225,69	231,02
XK	5	401,03	403,39	404,94	11	213,65	217,74	222,71
SI	9	390,73	402,31	408,00	6	221,51	224,09	226,62

Graphically, Figure 9 shows the voltage profile summary for the 400 kV grid, while Figure 10 shows this data for the 220 kV grid. To provide a better overview, both figures show the allowed operational minimum and maximum voltages.

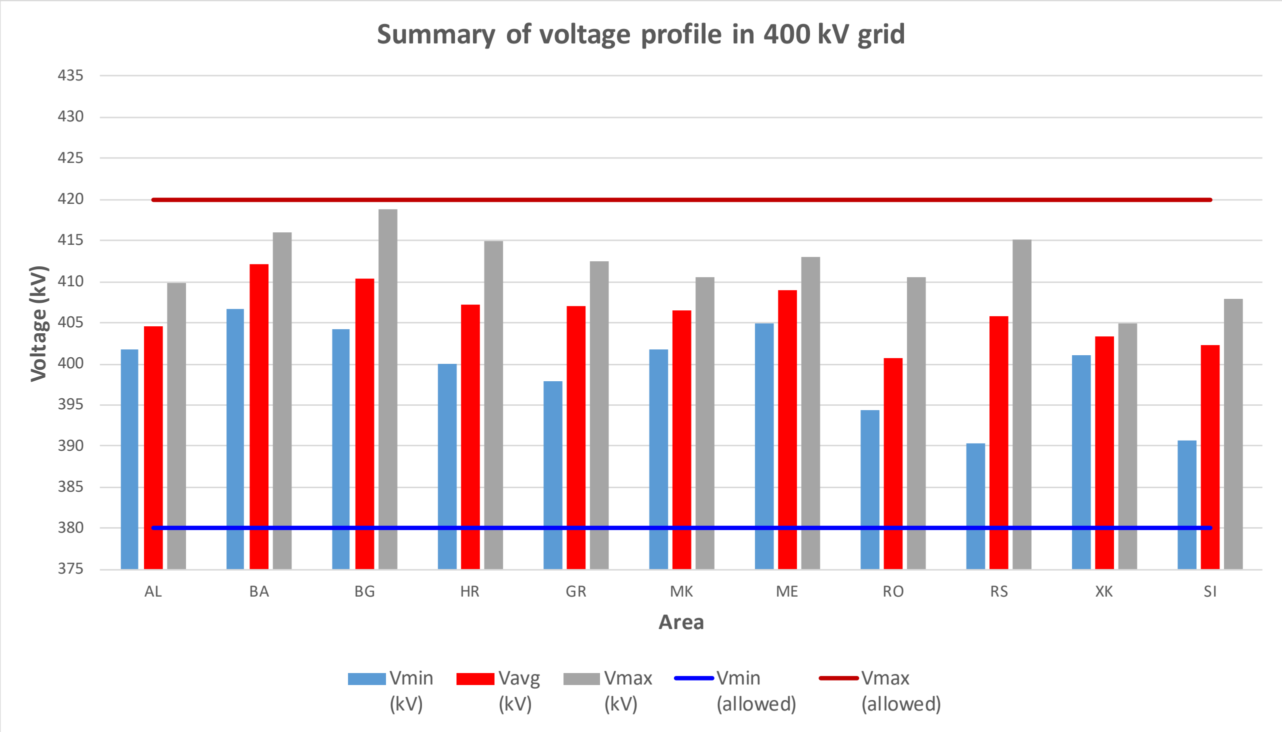


Figure 9: Summary of voltage profile in 400 kV grid – maximum load 2030, high RES

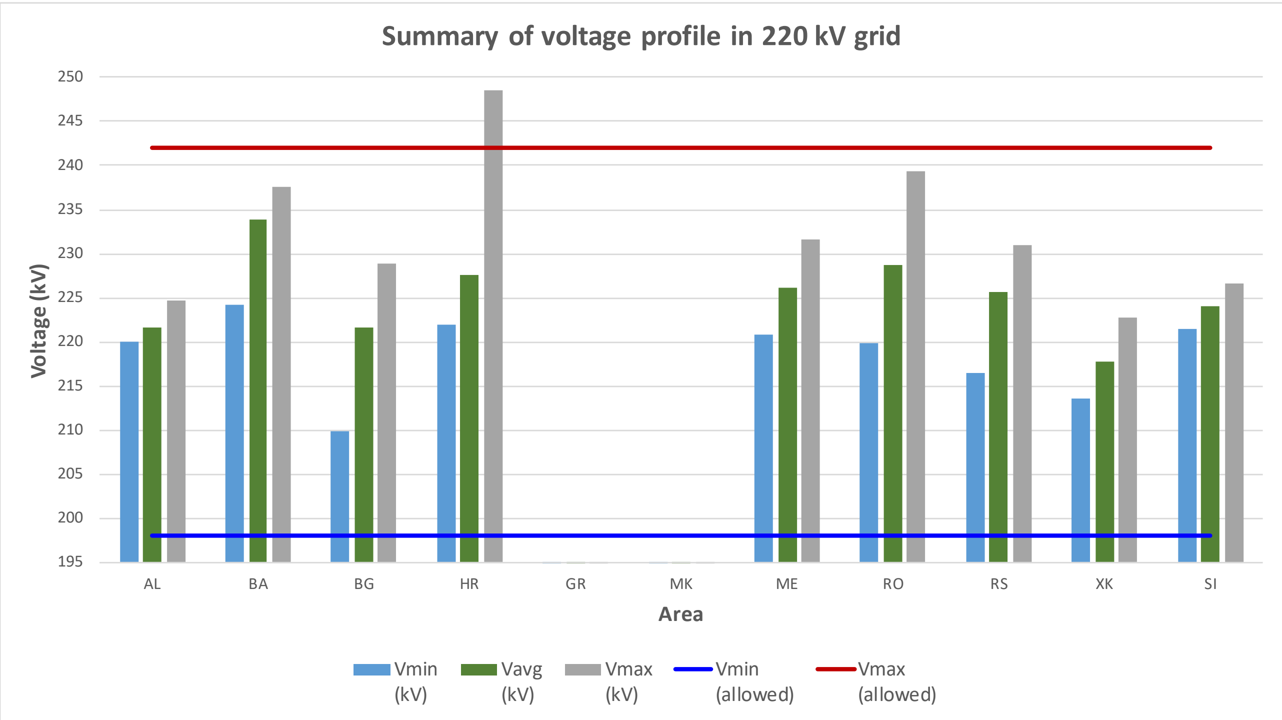


Figure 10: Summary of voltage profile in 220 kV grid – maximum load 2030, high RES

Voltages in the **400 kV grid are within allowed limits, and in the 220 kV grid, there are nodes in the HOPS (HR) grid with voltage above the upper limit**. The location with overly high voltage is at the Plat substation in southern Croatia.

There are no overloaded HV branches.

We show the aggregated border exchanges for the maximum load regime, high RES, in Figure 11.

Figure 11: Aggregated border exchanges – maximum load 2030, high RES

We show the aggregated border exchanges using arrows. 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 represents the total import/export as the sum of all aggregated border power flows from the corresponding TSOs.

Our initial results from looking at the (N-1) contingencies shows that there are no outages which cause overloads in the HV grid.

3.2.3. Minimum load regime – referent RES

We summarize the SEE area totals, as reported from PSS®E, for minimum load 2030 regime in the referent RES case, in Table 19. 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 19: Summaries of all areas in regional model – minimum load 2030, referent RES

X-- AREA --X	FROM GENE-RATION	------AT AREA FROM IND GENERATN	BUSES------- 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	702.4	0.0	0.0	560.7	0.0	0.0	5.3	0.0	6.4	130.0	130.0	130.0
AL	-109.3	0.0	0.0	158.5	551.1	0.0	32.3	740.5	81.4	-192.0	-192.0	
13	1546.1	0.0	0.0	1105.0	0.0	0.0	17.2	0.0	23.9	400.0	400.0	400.0
BA	-203.3	0.0	0.0	232.3	0.0	0.0	175.7	1135.8	290.8	233.8	233.8	
14	3236.4	0.0	0.0	3142.3	0.5	0.0	63.0	0.0	30.6	0.0	0.0	0.0
BG	516.7	0.0	0.0	1243.8	1312.2	0.0	182.9	2928.9	542.3	164.5	164.5	
16	1171.2	0.0	0.0	1405.0	0.0	0.0	5.3	0.0	40.9	-280.0	-280.0	-280.0
HR	-230.7	0.0	0.0	331.4	392.2	0.0	25.7	1770.1	355.4	434.7	434.7	
30	5503.7	0.0	0.0	5168.7	0.0	0.0	0.0	0.0	99.9	235.1	235.1	235.0
GR	-1523.7	0.0	0.0	2653.9	2108.8	0.0	22.1	8277.5	1913.4	55.6	55.6	
37	578.9	0.0	0.0	632.3	0.0	0.0	2.3	0.0	4.2	-60.0	-60.0	-60.0
MK	9.6	0.0	0.0	242.1	0.0	0.0	9.6	546.4	62.5	241.8	241.8	
38	694.7	0.0	0.0	410.0	0.0	0.0	4.3	0.0	19.3	261.0	261.0	261.0
ME	-42.1	0.0	0.0	138.6	0.0	0.0	28.9	473.8	199.9	64.4	64.4	
44	5719.1	0.0	0.0	5163.5	0.0	0.0	90.1	0.0	115.3	350.1	350.1	350.0
RO	-803.7	0.0	0.0	1665.2	2159.9	0.0	210.9	5754.3	1462.0	-547.4	-547.4	
46	3963.5	0.0	0.0	2663.5	0.0	0.0	31.6	0.0	68.5	1200.0	1200.0	1200.0
RS	-163.5	0.0	0.0	785.3	0.0	0.0	129.0	1954.4	908.4	-31.7	-31.7	
47	731.0	0.0	0.0	700.0	0.0	0.0	5.5	0.0	5.5	20.0	20.0	20.0
XK	-51.9	0.0	0.0	233.6	0.0	0.0	16.0	289.0	98.6	-111.1	-111.1	
49	1686.2	0.0	0.0	1587.9	0.0	0.0	8.4	0.0	23.9	66.0	66.0	66.0
SI	-412.2	0.0	0.0	272.7	0.0	0.0	54.3	749.9	354.4	-343.7	-343.7	

In comparison to the corresponding data from the national/TSO models, the losses (and therefore total generation) are slightly changed. This results from the influence of the regional model (especially the impact of neighboring TSOs), caused by changing voltage profile and loop flows.

We provide a summary of the voltage profile for the HV grid in Table 20. This table shows data for each area, and includes voltage levels for both the 400 kV as well as 220 kV nodes (if they exist). For each system and voltage level, we show the numbers of nodes in operation, along with the maximum, minimum and average voltage values.

Table 20: Summary of voltage profile for minimum load regime – referent RES scenario

Area	400 kV nodes				220 kV nodes			
	Nodes	Vmin (kV)	Vavg (kV)	Vmax (kV)	Nodes	Vmin (kV)	Vavg (kV)	Vmax (kV)
AL	9	416,42	419,66	422,15	29	232,60	235,18	236,51
BA	13	421,99	425,09	427,65	26	238,77	243,34	244,75
BG	22	412,19	417,74	422,45	39	224,15	226,52	229,95
HR	10	426,83	429,88	433,22	22	237,39	241,86	263,40
GR	75	405,91	418,40	426,92	0			
MK	7	424,15	425,99	427,30	0			
ME	6	420,26	423,79	425,46	5	231,41	234,25	236,74
RO	44	400,62	404,70	410,12	68	226,56	231,84	235,50
RS	46	410,00	415,23	424,07	42	227,40	233,54	239,60
XK	5	420,88	422,28	423,64	11	228,46	231,23	234,60
SI	9	417,66	423,89	427,99	6	235,84	237,59	239,28

Below we show these data graphically. Figure 12 shows the voltage profile summary for the 400 kV grid, while Figure 13 shows the voltage profile summary for the 220 kV grid. For a better overview, both figures include lines that show the allowed operational maximum and minimum voltages.

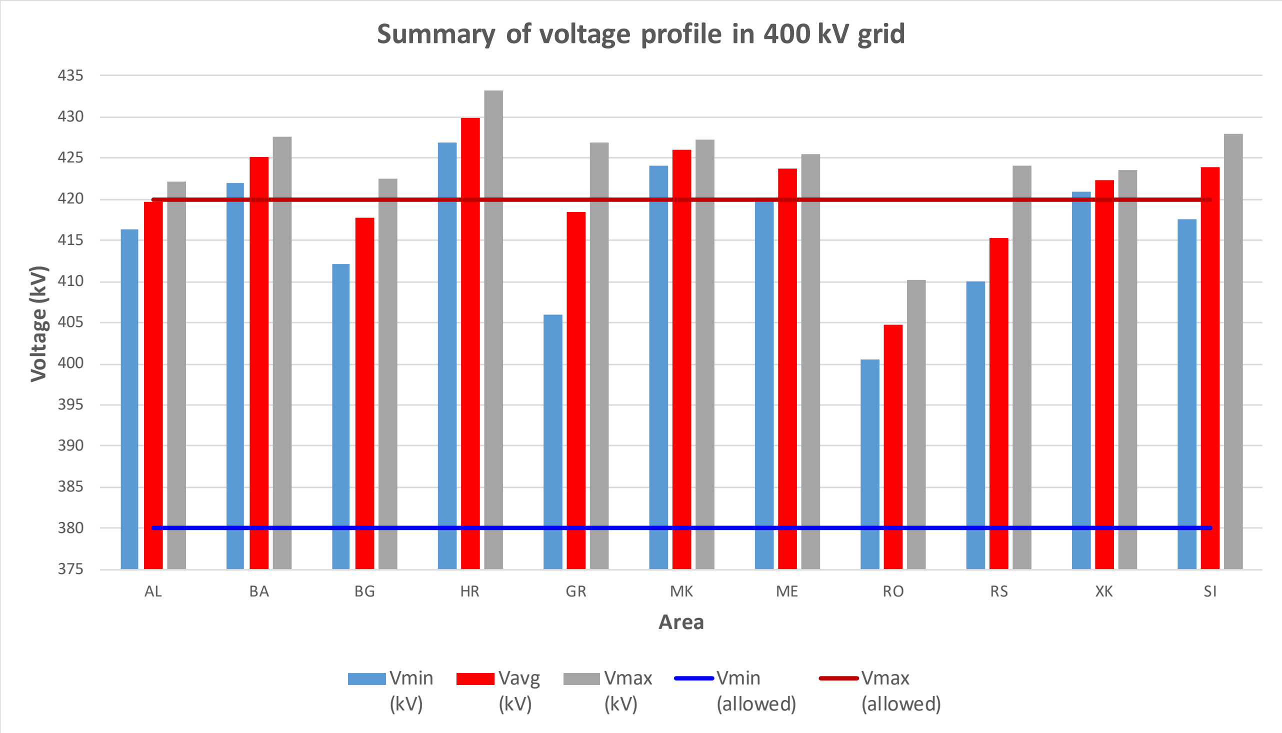


Figure 12: Summary of voltage profile in 400 kV grid – minimum load 2030, referent RES

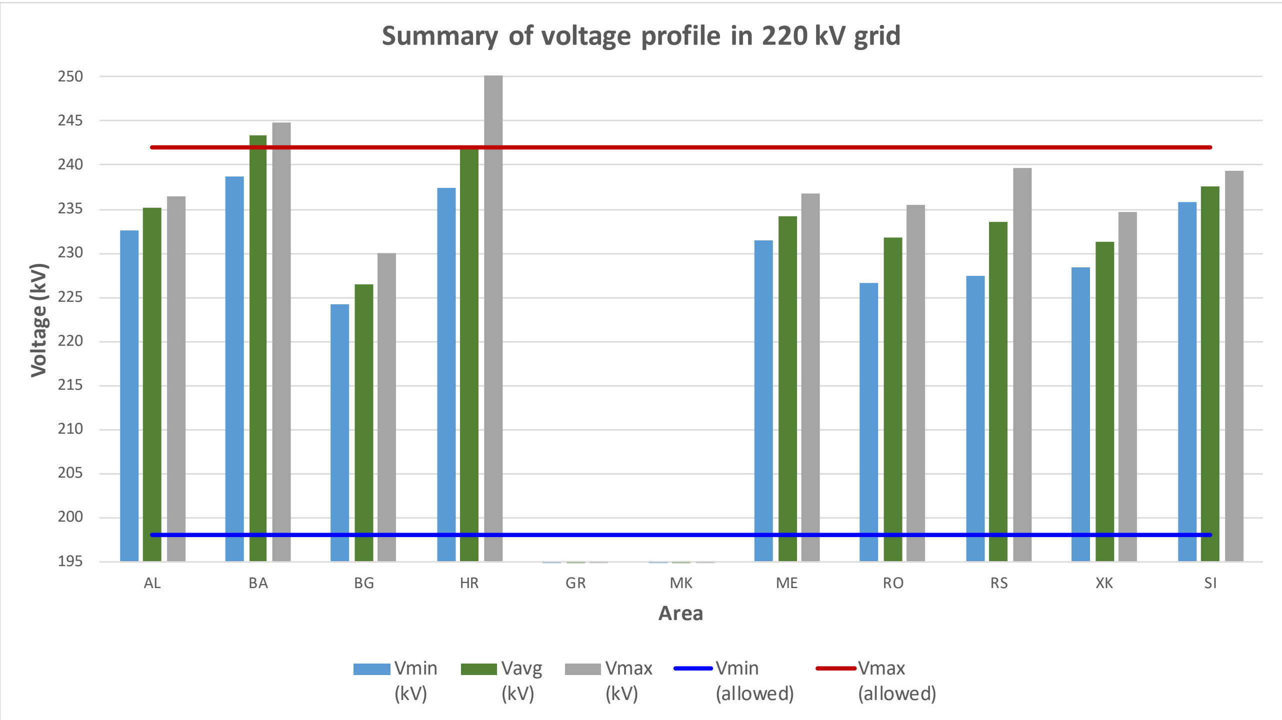


Figure 13: Summary of voltage profile in 220 kV grid – minimum load 2030, referent RES

It is clear that **voltages in the 400 kV grid are very high**. **Except for Romania, 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. However, this is not a critical issue for this kind of planning analysis. The TSOs can handle this problem on an operational level.

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, referent RES, in Figure 14.

Figure 14: Aggregated border exchanges – minimum load 2030, referent RES

We show the aggregated border exchanges using arrows. 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/countr,y there is the TSO balance, which represents the total import/export as the sum of all aggregated border power flows from the corresponding TSOs.

The initial results from the (N-1) contingencies analysis shows that there are no outages that would cause overloads in the HV grid.

3.2.4. Minimum load regime – high RES

We summarize the SEE area totals, as reported from PSS®E, for minimum load 2030 regime in the high RES case, in Table 21. 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 21: Summaries of all areas in regional model – minimum load 2030, high RES

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	703.3	0.0	0.0	560.7	0.0	0.0	5.3	0.0	7.3	130.0	130.0	130.0
AL	-125.6	0.0	0.0	158.5	548.7	0.0	32.4	737.9	83.2	-210.6	-210.6	
13	1545.1	0.0	0.0	1105.0	0.0	0.0	17.2	0.0	23.0	400.0	400.0	400.0
BA	-202.0	0.0	0.0	232.3	0.0	0.0	175.3	1133.9	283.5	240.9	240.9	
14	3237.0	0.0	0.0	3142.3	0.5	0.0	62.4	0.0	31.7	0.0	0.0	0.0
BG	589.9	0.0	0.0	1243.8	1301.7	0.0	181.6	2905.9	555.6	213.1	213.1	
16	1177.3	0.0	0.0	1405.0	0.0	0.0	5.3	0.0	42.0	-275.0	-275.0	-275.0
HR	-230.5	0.0	0.0	331.4	342.4	0.0	25.6	1763.6	363.0	470.8	470.8	
30	5806.8	0.0	0.0	5168.7	0.0	0.0	0.0	0.0	103.0	535.1	535.1	535.0
GR	-1492.3	0.0	0.0	2653.5	2091.8	0.0	21.9	8261.3	1930.3	71.5	71.5	
37	579.4	0.0	0.0	632.3	0.0	0.0	2.3	0.0	4.7	-60.0	-60.0	-60.0
MK	14.5	0.0	0.0	242.1	0.0	0.0	9.6	543.7	66.7	239.9	239.9	
38	694.5	0.0	0.0	410.0	0.0	0.0	4.3	0.0	19.1	261.0	261.0	261.0
ME	-40.8	0.0	0.0	138.6	0.0	0.0	28.9	473.5	199.2	66.0	66.0	
44	6192.2	0.0	0.0	5193.5	0.0	0.0	88.2	0.0	160.2	750.3	750.3	750.0
RO	-509.4	0.0	0.0	1677.1	2106.2	0.0	209.1	5609.9	1911.0	-802.9	-802.9	
46	3959.6	0.0	0.0	2663.5	0.0	0.0	31.5	0.0	64.8	1199.8	1199.8	1200.0
RS	-110.8	0.0	0.0	785.3	0.0	0.0	128.8	1950.2	878.7	46.6	46.6	
47	771.6	0.0	0.0	700.0	0.0	0.0	5.5	0.0	6.1	60.0	60.0	60.0
XK	-27.0	0.0	0.0	233.6	0.0	0.0	16.1	288.8	104.4	-92.3	-92.3	
49	1687.1	0.0	0.0	1587.9	0.0	0.0	8.3	0.0	24.8	66.0	66.0	66.0
SI	-412.2	0.0	0.0	272.7	0.0	0.0	53.8	742.7	375.5	-371.6	-371.6	

In comparison to the corresponding data from the national/TSO models, the losses (and therefore total generation) are slightly changed. This results from the influence of the regional model (especially the impact of neighboring TSOs), caused by changing voltage profile and loop flows.

We provide a summary of the voltage profile for the HV grid in Table 22. This table shows data for each area, and includes voltage levels for both the 400 kV as well as 220 kV nodes (if they exist). For each system and voltage level, we show the numbers of nodes in operation, along with the maximum, minimum and average voltage values.

Table 22: Summary of voltage profile for minimum load regime – high RES scenario

Area	400 kV nodes				220 kV nodes			
	Nodes	Vmin (kV)	Vavg (kV)	Vmax (kV)	Nodes	Vmin (kV)	Vavg (kV)	Vmax (kV)
AL	9	415,61	418,80	421,18	29	232,41	234,87	236,49
BA	13	422,00	424,88	426,95	26	238,69	243,11	244,58
BG	22	409,41	416,14	421,70	39	223,57	225,80	229,09
HR	10	426,18	428,96	431,41	22	236,84	241,56	263,31
GR	75	404,62	416,86	425,57	0			
MK	7	423,11	424,98	426,19	0			
ME	6	420,10	423,60	425,40	5	231,32	234,20	236,71
RO	44	395,15	399,66	408,85	68	222,22	229,00	235,30
RS	46	409,11	414,74	423,15	42	227,29	233,39	239,32
XK	5	420,62	422,00	423,27	11	228,43	231,37	235,13
SI	9	415,55	421,74	426,03	6	234,84	236,55	238,18

Below we show these data graphically. Figure 15 shows the voltage profile summary for the 400 kV grid, while Figure 16 shows the voltage profile summary for the 220 kV grid. For a better overview, both figures include lines that show the allowed operational maximum and minimum voltages.

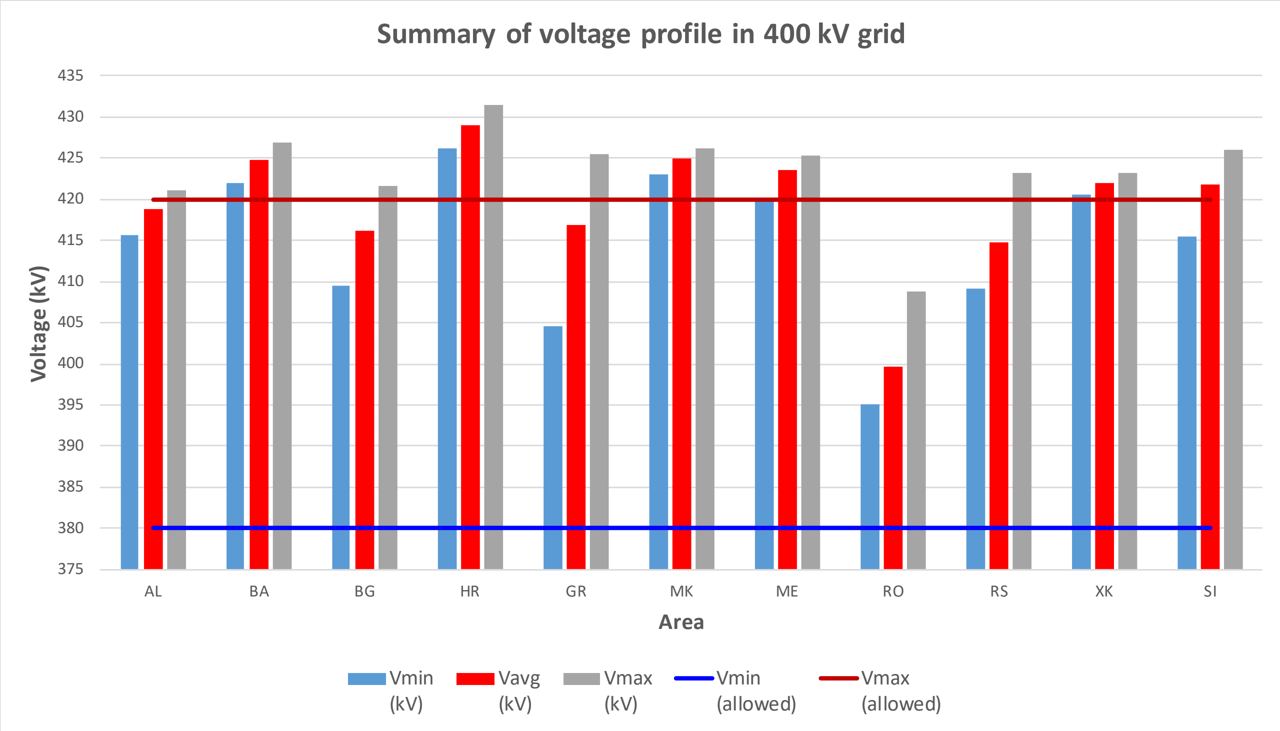


Figure 15: Summary of voltage profile in 400 kV grid – minimum load 2030, high RES

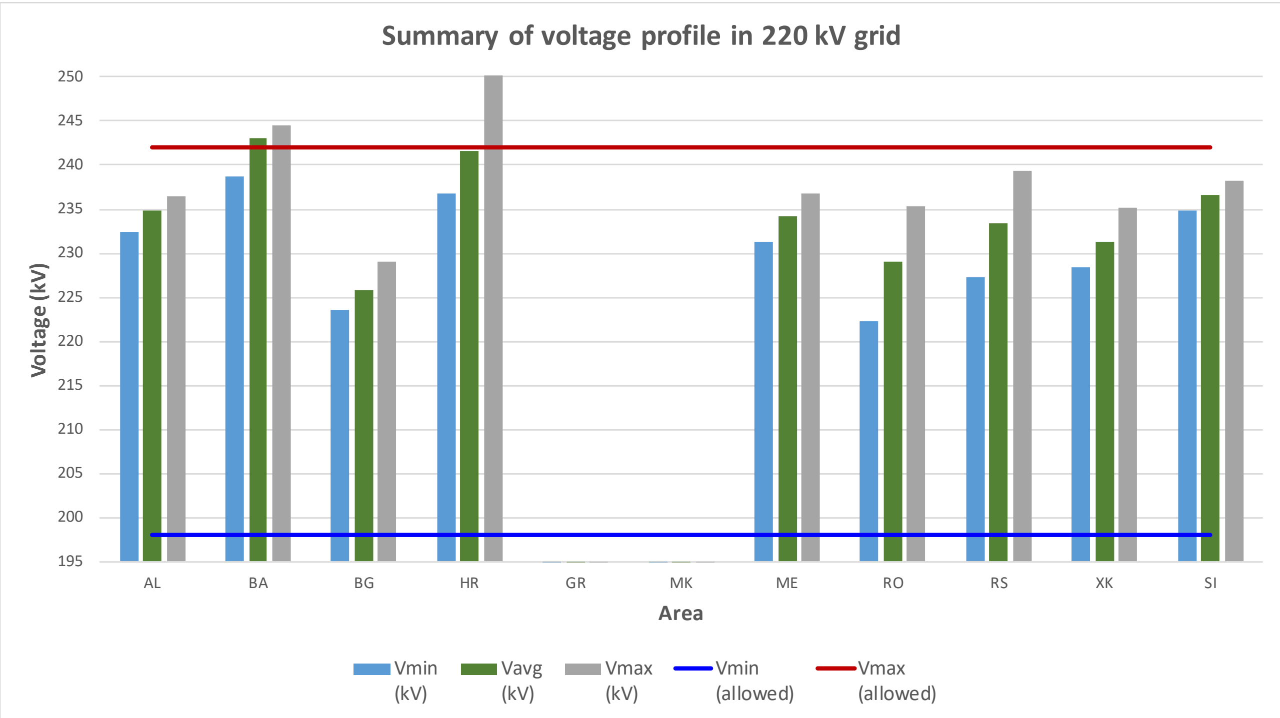


Figure 16: Summary of voltage profile in 220 kV grid – minimum load 2030, high RES

It is clear that **voltages in the 400 kV grid are very high. Except for Romania, all other systems have nodes with voltages above the allowed maximum value**. In six of the areas even average values are above the allowed maximum limit. As mentioned above, voltages slightly over maximum allowed limit are operational issues that TSOs can handle in their daily operation. It is not a critical part of this RES integration planning study.

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

There are no overloaded HV branches.

We show the aggregated border exchanges for the minimum load regime, high RES, in Figure 17.

Figure 17: Aggregated border exchanges – minimum load 2030, high RES

We show the aggregated border exchanges using in arrows. 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 represents the total import/export as the sum of all aggregated border power flows from the corresponding TSOs.

We show the initial results from (N-1) contingencies in Table 23, based on PSS®E analysis.

Table 23: Results from contingency (N-1) assessment– minimum load 2030, high RES

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING     FLOW       %
 448037 RGADAL1     400.00 448039*RROSIO1     400.00 1  SINGLE 448008-448009(1)           1277.8     159.5    102.0
 448067*RMINTI2A    220.00 448068 RMINTI2B    220.00 1  SINGLE 448008-448009(1)            333.4     295.1    110.9


 <----- CONTINGENCY LABEL ------><----- POST-CONTINGENCY SOLUTION ----->
                                <TERMINATION  STATE> FLOW# VOLT#  LOAD
 BASE CASE                       Met convergence to      0     0    0.0
 SINGLE 448008-448009(1)         Met convergence to      2     0    0.0

 CONTINGENCY LEGEND:
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 448008-448009(1)         : OPEN LINE FROM BUS 448008 [RARAD 1      400.00] TO BUS 448009 [RNADAB1      400.00] CKT 1
```

It can be seen that there is one outage, which causes an overload. There is an outage of the internal 400 kV line in Romania, Arad – Nadab, which shows an overload of around 2% of 400 kV internal line Gadalin – Rosiori, and an overload of around 10.9% of the 220 kV coupler in Mintia.

4. APPLIED METHODOLOGICAL APPROACH AND SCENARIOS

This Chapter discusses applied methodological approach and scenarios. This study methodology is based on the previous EMI activities and reports, as verified by the working group, with the scenarios designed to cover the primary uncertainties and combinations of the most important variables.

4.1. Methodological approach

We have divided our methodological approach into two types of simulations:

1. Market and
2. Network.

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 are 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 location of new plants, particularly RES, and the injection into the grid at those points
4. The development status and changes to the regional networks (down to the 110 kV level)
5. Topology and operational status of the network elements

These drivers are not fully independent. For example: if the CO_2 emission price is higher, then thermal power plants will produce less, which can lead to higher cross-border flows. Also, as RES levels increase, there may be needs to upgrade certain network elements, and there will be reductions in the dispatch of other generating units.

In this study the most important task was to analyze the impacts of the development of large-scale RES and natural gas generation on SEE's electricity market and network. Therefore, our work gave special attention to the impact of RES generation capacities under different operating circumstances, with alternative scenarios to assess changes to four influential drivers: electricity demand growth rate (hourly loads and annual consumption), hydro conditions, fuel prices (gas, coal) and CO_2 emission prices. For each market area, and for the SEE region as a whole, we modeled and analyzed two levels of RES integration:

- Referent RES generation integration;
- High RES generation integration.

Each TSO defines its referent level of RES integration in strategic documents, such as their transmission network development plans, or their national strategy of energy and climate plans (NCEP). The TSOs verify all RES projects through grid connection agreements, connection consents, connection requests, and in other formal ways. We define the high-RES integration scenario as including additional RES projects in each country that are under development or under evaluation that the TSO has not yet formally approved or registered.

Clearly, there are different practices and experiences in the treatment of RES projects in each country/TSO. RES integration is a dynamic process worldwide, and thus a subject of uncertainty with regard to the projects' location, stage of development, size and total installed capacity, especially over a 10-year future timeframe as we are analyzing in this EMI study. During this ToR development and data collection period alone, there have been updates in RES projects' status.

To minimize uncertainties in this study, we consistently defined the RES integration range between the referent RES and high-RES cases for each country through clarification and approval with all WG members (TSOs and market operators). Moreover, input data, methodology approach and scenarios have been presented to the WG members in our Interim Report that was reviewed and approved by them. This consistent approach - with input data submitted and verified by all SEE TSOs and MOs - is the most reliable path to this kind of analyses in the region.

Finally, the EMI TSOs and MOs will be able to conduct their own country-specific analyses, both for internal planning and for regulatory and policy purposes, using the same model framework, once we complete the EMI analysis later this year, and we train the EMI members in how to do so.

Based on verified input data and market and network models developed in Antares and PSS/E, we conducted this forecast analysis focused on the impact of RES integration for the year 2030.

We ran the market simulations on an hourly basis, providing market simulation results for all 8760 hours. The market assessment produced four main outputs for the year 2030:

1. Impact on market prices: wholesale day-ahead market prices for both the region as a whole, and on the country level.
2. Impact on the generation mix: changes in the mix by country and for the region.
3. Impact on carbon emissions: changes in thermal generation and total carbon emissions
4. Impact on electricity imports and exports: level of imports and exports on a country and a regional level

After we completed the market simulations, we selected characteristic market results and transferred them to the network model. From the 8760 hours of market simulation results, we selected the most indicative snapshots from the network operation perspective (with regard to network element loading, voltage profiles, and system security) and transferred them to the network simulation software (PSS/E). We selected characteristic market results based on the scenarios as described in subchapter 4.3 below. In the final step, the network assessment produced four main outputs:

1. Load flows in the SEE transmission network;
2. Voltage profiles on all transmission network nodes;
3. Transmission network losses for each country, and on the regional level;
4. Security analyses (N-1) and the detection of network bottlenecks, at 110 kV and above.

4.2. Different operating circumstances

In consultation with USEA and the EMI WG participants, we defined different operational conditions, in concert with the above mentioned methodology, to create specific scenarios described in this subchapter. These scenarios test the key elements of uncertainty, including the level of RES integration; electricity demand growth; hydrology, and fuel and carbon prices.

These are large mathematical optimizations, with several thousand elements, requiring hourly resolution. We ca refully selected the scenarios, to ensure we can perform the required analyses, while still providing the EMI members with meaningful results, and a clear evaluation of benefits. This is a common approach used in electricity market and network analyses worldwide.

In all the analyzed scenarios with referent and high RES penetration, certain assumptions have been the same, including assumptions regarding: existing and planned conventional generation capacities in the region; detailed technical and economic inputs; and cross-border transmission capacities.

To assess the impact of changes in the most important assumptions, the Study included several additional scenarios. These scenarios are plausible but not overly numerous, since we want to focus more on whether the impacts and differences are meaningful than on the precise numbers. Moreover, all these analyses, final report and training must be completed by the end of 2020. To do so, the EMI has agreed to model and analyze twelve market scenarios, twenty network scenarios and two gas impact scenarios (one market and one network scenario), as described below.

4.2.1. Different scenarios of demand growth rate

As agreed at the EMI meetings, we analyzed different levels of demand growth. Many changes in electricity demand can take place over a decade. In the last decade, the global financial crisis greatly reduced regional electricity demand growth, especially in the 2009-2012 period. Now, we are witnessing the negative impact of the global COVID-19 pandemic crisis, with great uncertainty over the impact on regional electricity demand in 2030. In this light, we assessed two alternative scenarios regarding the demand growth rate:

- Referent (as initially expected) demand growth through 2030;
- Lower demand in 2030 (either given by the TSOs, or if not, half the referent growth rates).

The combination of high RES penetration and low demand could present a network challenge, as RES would supply a greater share of less demand. This is plausible, so we analyzed scenarios with both of these assumptions, with different levels of CO_2 emission price and hydrology.

4.2.2. Different scenarios of CO_2 emission price

The EU clean energy law package sets high targets for CO_2 emission reduction, and they promote an increase in the CO2 emission price. However, since the CO_2 emission market is rather volatile and unpredictable, the EMI agreed to investigate the impact of high RES penetration in scenarios with two levels (scenarios) of CO_2 emission price in 2030:

- Referent (expected) CO_2 emission tax of 27 EUR/t, based on the ENTSO-E Ten-year network development plan (TYNDP) 2020 – National trends scenario
- Alternative CO_2 emission tax of 53 EUR/t, based on the ENTSO-E TYNDP 2020 – Distributed Energy scenario

In the analysed scenarios, we applied these different CO_2 emission prices, corresponding fuel prices and annual average wholesale market prices for the external spot markets (i.e., Central Europe, Italy and Turkey).

4.2.3. Different hydro conditions

Hydro conditions can be critical for a number of EMI members, due to their high share of hydro generation, particularly for Albania. Thus, we have agreed to evaluate the impact of high RES penetration along with changes in hydro conditions, along with different levels of CO_2 emission price and different demand levels. Our hydro scenarios included the following:

- Average hydro conditions; and
- Dry hydro conditions.

The TSOs provide most inputs and assumptions on generation from HPPs in different hydro conditions for each country/market area. Appendix provides a summary of these data.

4.3. Electricity market and transmission network scenarios

Based on all the above-mentioned indicators, Figure 18 below provides an overview of all 12 electricity market scenarios, with scenario-specific assumptions regarding the levels of RES penetration under different demand growth levels, CO_2 emission prices and hydro conditions.

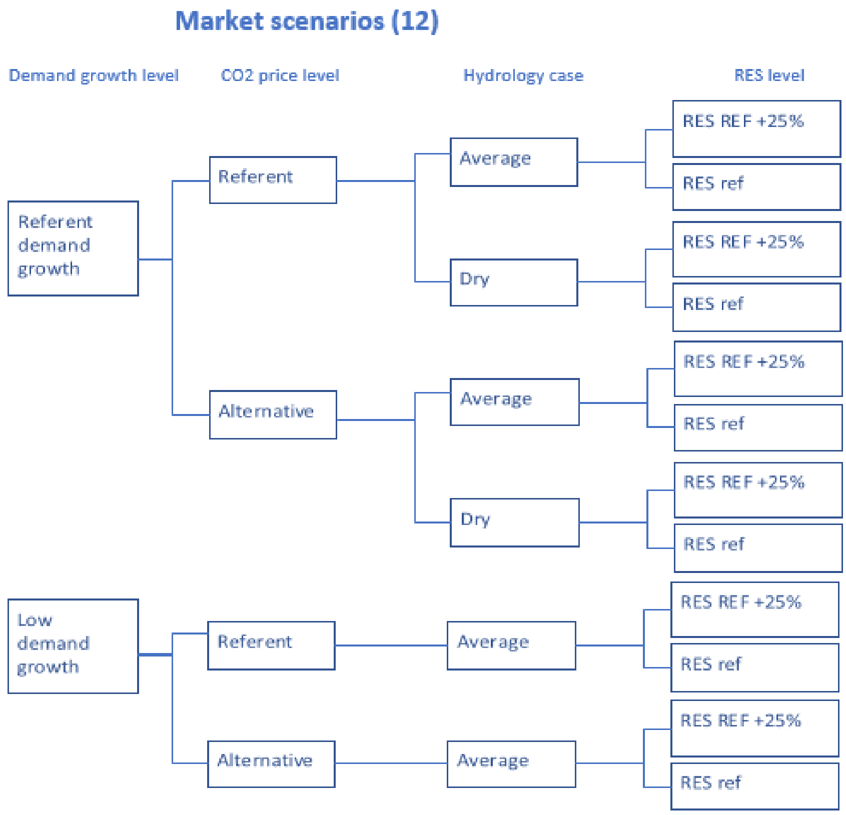


Figure 18: Set of scenarios with scenario-specific assumptions

Figure 19 below provides an overview of the 20 transmission network analysis scenarios, with scenario-specific assumptions regarding the levels of RES penetration under different demand growth levels, and alternative CO_2 emission prices. The number of scenarios is higher for the network analyses than for the market analyses since we needed a set of 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, 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.

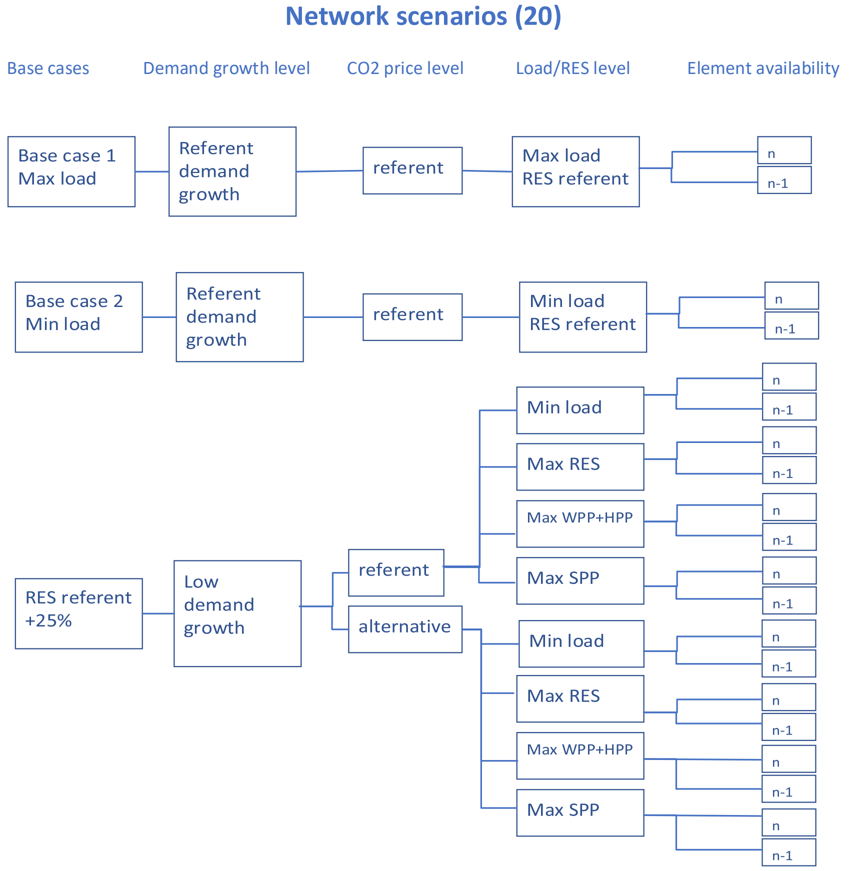


Figure 19: Set of network scenarios with scenario-specific assumptions for 2030

These scenarios provided the EMI participants with a wide range of network conditions based on the levels of demand growth, RES penetration, generation output and network availability. Since all these inputs are uncertain, this approach identified some, but not all potential bottlenecks in the network in 2030, regardless of their probability. Later, we will train the EMI members in tailoring this analysis to their systems, along with more detailed analysis of combined RES and gas development in the region. Two network scenarios assessed the impact of gas power plants.

In sum, this EMI study assessed 12 market scenarios and 20 network scenarios. Every scenario provided 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 (including the level and duration of cross-border congestion)
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, 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.

4.4. Assessment of natural gas system development on SEE electricity market and network operation

An additional part of this study relates to the impact of gas generation on the regional electricity market and network operation. Several large gas-fired power projects are currently under development in SEE. Natural gas may provide a transition to a cleaner environment, and help mitigate the intermittency of solar and wind. In addition, the ramp-rate characteristics of gas-fired plants can provide power system balancing and support larger-scale RES integration.

The objective of this study was not to analyze specific gas projects, but rather to evaluate their potential impact on the regional market and network operation in large-scale RES integration. Therefore, we evaluated just one market and two network scenarios using new natural gas power plants. The key assumptions related to operating conditions for these scenarios included:

- Referent level of demand growth
- New and existing gas-fired plants in the region, in line with the referent scenarios in USAID/USEA Natural Gas Working Group - Eastern Europe Natural Gas Partnership;
- Referent level of RES integration, as given above;
- Average hydro conditions;
- Referent level of fuel prices (gas, coal); and
- Referent level of CO_2 emission price.

Figure 20 shows the natural gas impact analysis scenarios, with scenario-specific assumptions for the RES integration level, demand growth level and CO_2 emission price.

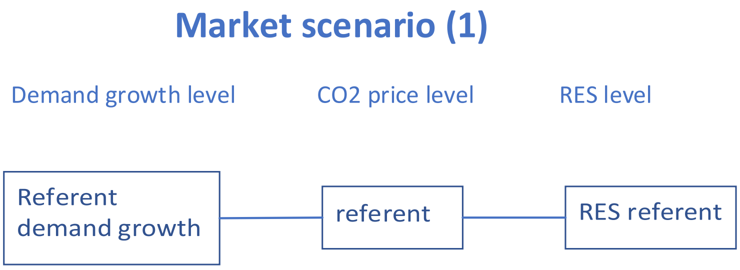


Figure 20: Electricity market scenario for natural gas impact

This gas scenario resulted in 8760 hourly snapshots. For the network analysis, we used just one market snapshot to represent the most critical network conditions. The market snapshot included the load, generation and exchange data for each country. To effectively combine the network and market analysis, we converted the hourly load and dispatch data from the Antares model into PSS/E format, and then executed the precise network simulation using the detailed AC network model.

This network analysis assessed the impacts of potential new gas-fired plants on transmission network operation.

For this network purpose, we needed just one base case: maximum system load, and we evaluated that scenario using five main criteria: 1) referent demand growth; 2) referent CO_2 emission price; 3) referent RES level; 4) regime that corresponds to maximum load hour and 5) network availability (all (n) elements available and n-1 elements available), as shown in Figure 21 below.

As usual in network analyses, we ran a contingency analysis for every single area, with: 1) all network elements available (n); and 2) one key element out of operation (n-1). The N-1 calculation assumes that every single transmission network element in the regional network has been switched off (one by one) and we detected power flow and voltage violations for every single case. It is highly unlikely that such multiple outages (n-2 or higher) would occur in different parts of the network at the same time. Therefore, we only ran the n-1 contingency analysis.

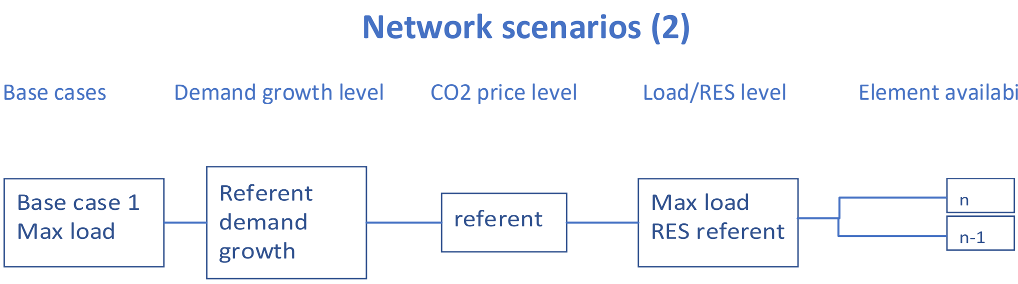


Figure 21: Transmission network scenario for natural gas impact

The Final Interim Report, based on the EMI members' feedback, confirmed all data and assumptions for the network and market modeling.

After we finalized the Interim Report, we developed the regional market model, merged the country network models into a common regional one, and used these regional tools for our analysis.

We will provide these models, data and tools to the EMI members at the end of our analysis and train them how to use them. This will enable EMI members to use these models and tools for analyses specific to their planning, regulatory and investment needs.

5. MARKET ANALYSES RESULTS

Presentation of the market analyses results is focused on relevant power system operation indicators and relevant impacts of the high RES capacities that can be expected in each market area, as well as at the regional level.

To be as clear as possible, we grouped the 12 market scenarios into three groups of four, focused on different assumptions related to demand development and CO_2 emission taxes:

1. **Group 1: Scenarios with referent (expected) demand development, and referent CO_2 emission tax (27 EUR/t)**
2. **Group 2: Scenarios with referent (expected) demand development, and high CO_2 emission tax (53 EUR/t)**
3. **Group 3: Scenarios with slower demand development, and both referent and high CO_2 emission taxes**

In the first two groups, we analysed alternatives with referent and high RES capacities in two hydro conditions (average and dry). In third group of scenarios, we analysed alternatives with referent and high RES capacities for two different levels of CO_2 emission tax, while assuming average hydro conditions for all scenarios.

Among the market operation indicators, for each scenario group we present the following indicators:

1. Generation mix which gives the overview of the system's structure in the sense of the generation from different technologies
2. RES generation: Sum of generation of wind and solar plants in two RES integration scenarios
3. Generation from fossil fuel plants: Sum of the generation from lignite, coal and gas units
4. CO_2 emissions in metric tons (Mt)
5. Balance of the market area: Sum of the exports and imports of the zone
6. Wholesale market prices

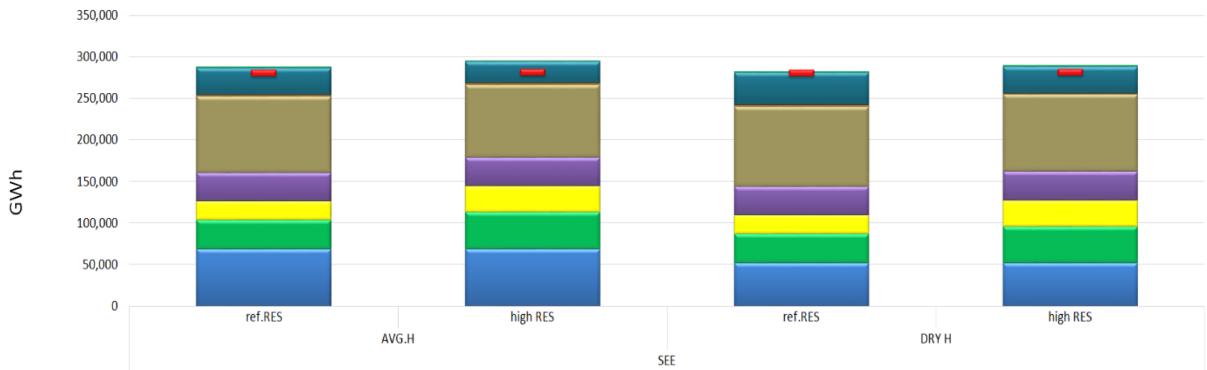
For each market area, we present this set of relevant indicators showing impact that different development and operating scenario can have on the market in the EMI region in 2030.

5.1. Group 1: Referent demand growth and referent CO2 scenarios

In the first group of four scenarios, we kept constant the level of referent demand and referent CO2 emission tax under these conditions::

1. Average hydrology and referent RES integration
2. Average hydrology and high RES integration
3. Dry hydrology and referent RES integration
4. Dry hydrology and high RES integration

Under these conditions, we present the projected (2030) generation mix for the whole EMI region in Figure 22, and the main regional indicators in Figure 23.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
Other	1,261	993	1,496	1,222
Gas	32,590	25,915	39,322	32,096
Coal	1,688	1,687	1,696	1,690
Lignite	91,856	87,677	95,977	92,528
Nuclear	34,497	34,496	34,497	34,496
Solar	22,513	31,455	22,513	31,455
Wind	35,213	43,872	35,213	43,872
Hydro	68,712	69,186	51,893	52,419
Consumption	281,018	281,661	281,093	281,806

Figure 22: Generation mix in EMI region in 2030 - ref. RES vs high RES, dry and average hydrology

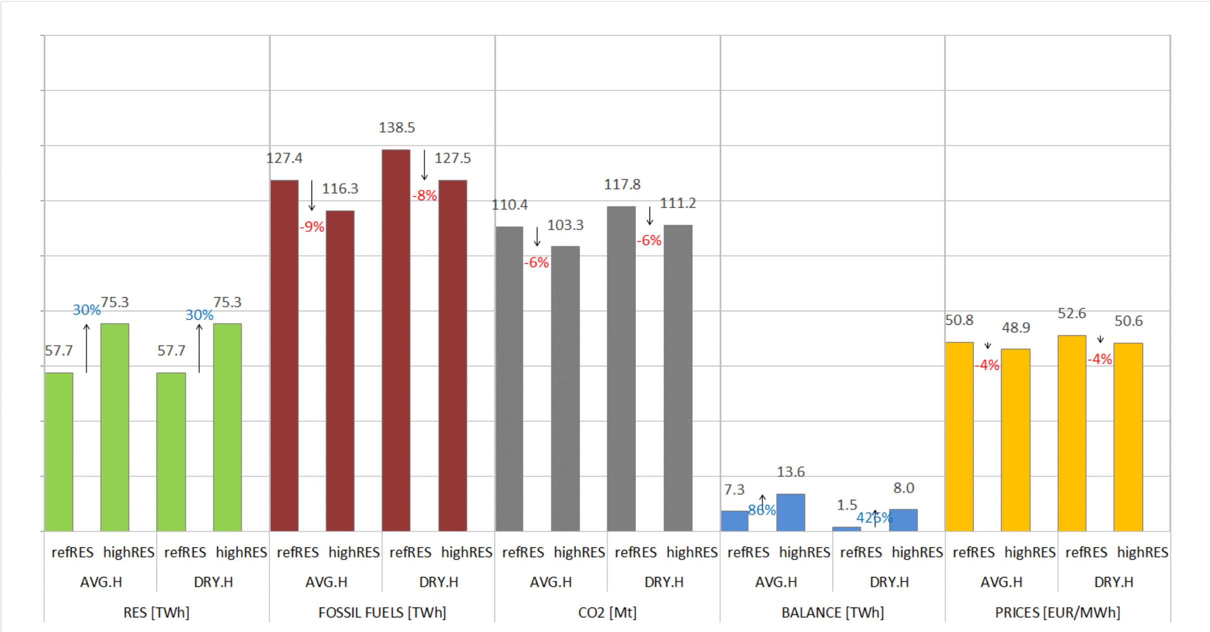


Figure 23: Main system operating indicators in EMI region in 2030 - ref. RES vs high RES, dry and average hydrology

In these scenarios, we conclude the following:

- **The main fuel in 2030 will still be lignite, meeting 31-34% of energy needs. (though as mentioned in Section 2.5 in discussing Table 10, lignite generation in 2030 could be lower due to retirements above current official figures).**
- Hydro plants supply between 18% and 25%, depending on hydrology, while RES generation (depending on the scenario) supplies between 21% and 27% of total demand. Separately considered, hydro and RES become the second main fuels in the EMI region in 2030, but considered together as "green" options, hydro and RES generation become the main sources, supplying 39% to 51% of total demand.
- Gas plants supply between 9% and 14% of demand, while nuclear technology is stable and covers 12% in all scenarios.
- **RES generation increases from 57.7 TWh (in ref. RES scenario) to 75.3 TWh in the high RES scenario, which is an increase of 30% (Figure 23).** These increases vary widely per market area (Figure 24), from 0.2 to 6 TWh (in the CGES and IPTO market areas), and from 19% to 278% (in the HOPS and ELES market areas).
- Generation from additional RES capacities of 17.6 TWh (ref.RES vs. high RES) supplies 6% of total demand of the EMI region in 2030. **Due to this increase in RES generation, fossil fuel generation falls: gas generation falls by 7 TWh, and lignite fired plants by 4 TWh, while export from the region increased by 6 TWh.**

  The reason for this high decrease in gas generation is that in one of the biggest market areas (IPTO) today, gas is the only fossil generation. In the IPTO region, a 6 TWh increase in RES generation provokes a decrease of 5 TWh in gas generation, which is most of the regional change. In all other market areas, the decrease of fossil generation due to increased RES generation is almost equally divided between lignite and gas (Figure 25).

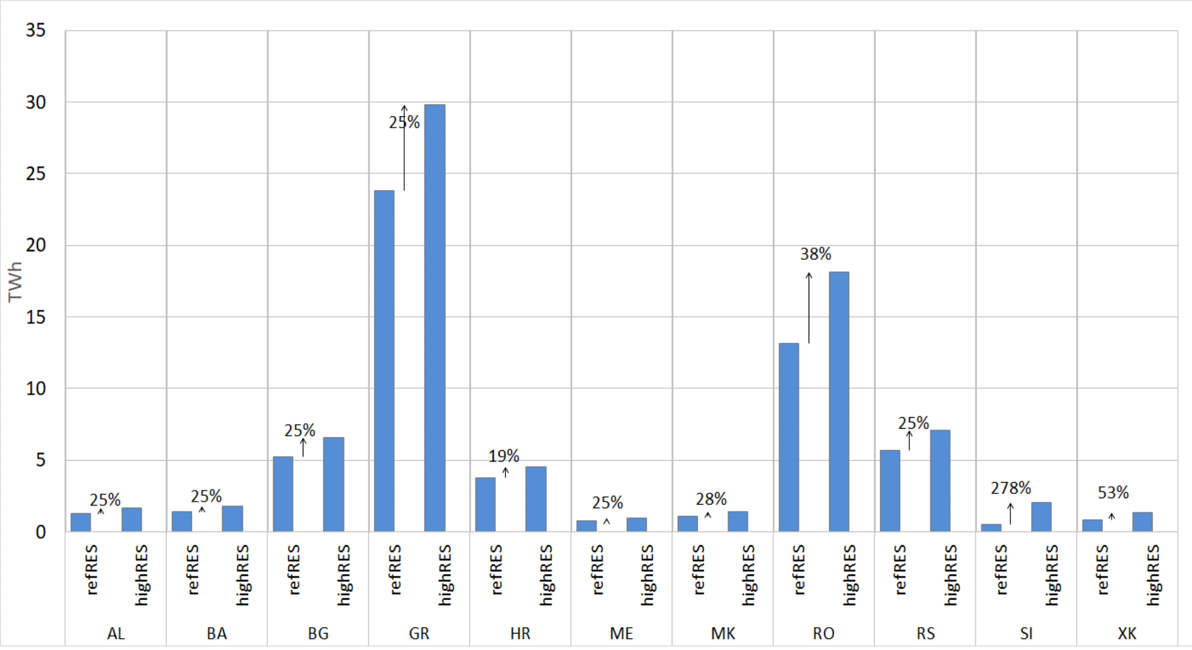


Figure 24: RES generation in 2030 - ref. RES vs high RES

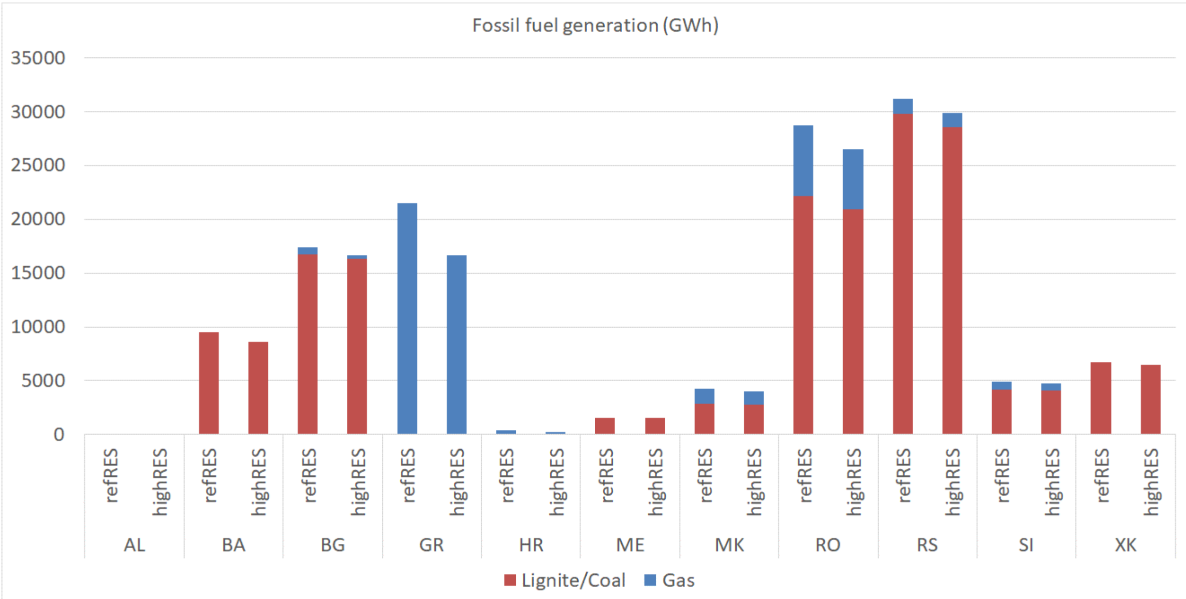


Figure 25: Fossil fuel powered plants generation in 2030 - ref. RES vs high RES, average hydrology

- **Following the decrease in fossil generation, CO_2 emissions fall with high RES integration by around 6%, or 7 Mt of CO_2 for the whole EMI region.**
- **The EMI region is a net exporter in 2030 in all scenarios, with exports between 1.5 TWh and 13.6 TWh, or 1% and 5% of total demand.**
- Higher RES generation provokes a decrease in TPP generation, but at the smaller level, and leads to an increase in net exports. The increase of regional exports is around 6.5 TWh, and is similar in both hydro conditions (Figure 23). Changes in the balance positions for all market zones under average hydro conditions (Figure 26) shows that in almost all countries, due to

additional RES generation, exports increase or imports fall. The only difference is in the NOSBIH market area, where lignite fired plants become less competitive, and there is a drop in exports.

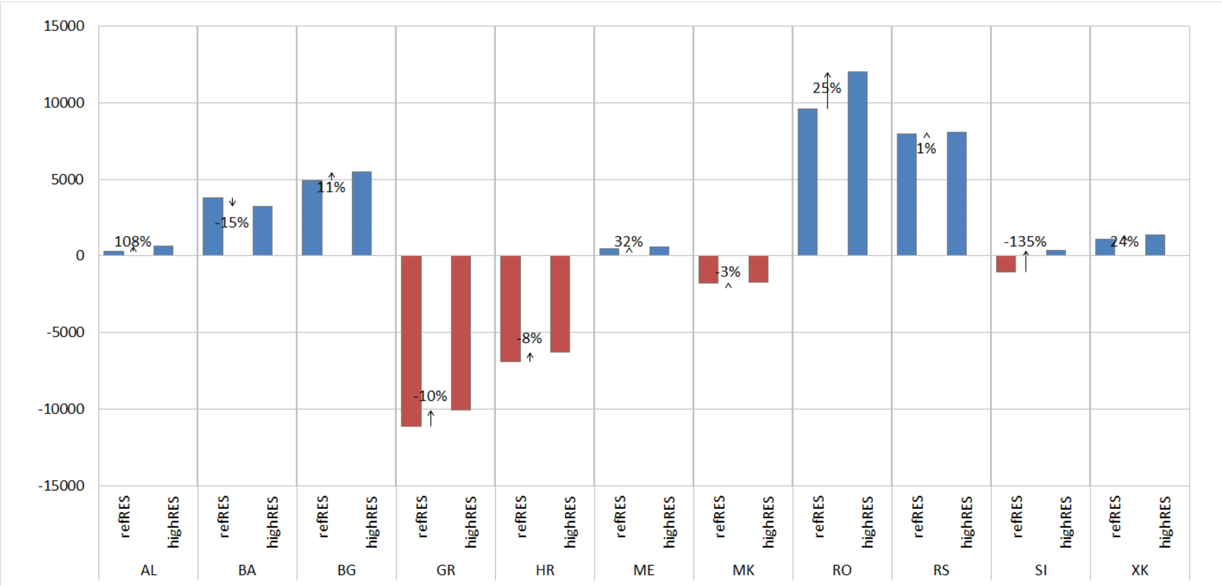


Figure 26: Balance positions per market areas in 2030 - ref. RES vs high RES, average hydrology

- **Average regional prices (Figure 23) are between 48.9 and 52.6 EUR/MWh in 2030, with the decrease under high RES integration of around 2 EUR/MWh or 4% in both hydro conditions.** By contrast, the same figure shows that prices in dry hydro conditions would be higher by around 1.7 EUR/MWh, or 3.5%.

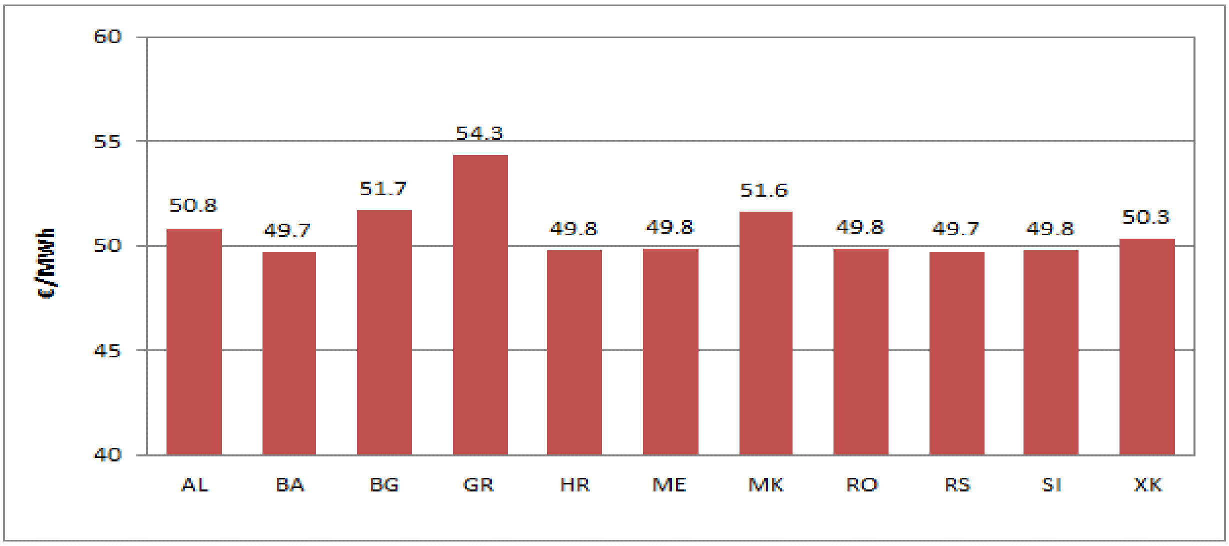


Figure 27: Prices in EMI region in 2030 - ref. RES, average hydrology

From Figure 27 we see that there are four price zones in the EMI region:

1) IPTO, a big importing market area, with the highest wholesale market prices

2) ESO EAD and MEPSO – exporting and transiting zones, with the second highest prices in the region
3) OST and KOSTT – almost balanced zones, between the centrally located and low priced zones and IPTO
4) The rest of the centrally located zones with lower prices

The same groups of price zones can be seen in all scenarios.

- The decrease of HPPs generation in dry hydro conditions provokes higher TPPs generation and lower exports. These changes leads to increased prices, but change is rather small – 1.7 EUR/MWh at the regional level (as can be seen in Figure 23).
- Available energy in the whole EMI region in dry hydro conditions is smaller, and the regional merit order curve is moved to the left. This enables higher generation from fossil fired plants in all market areas and increases marginal prices. In almost all market areas balance positions are changed in the same direction (net export is decreased or net import is increased), except in the IPTO and EMS market areas, where TPPs become more competitive (Figure 28) enabling lower imports (in IPTO) and higher exports (in the EMS market area).

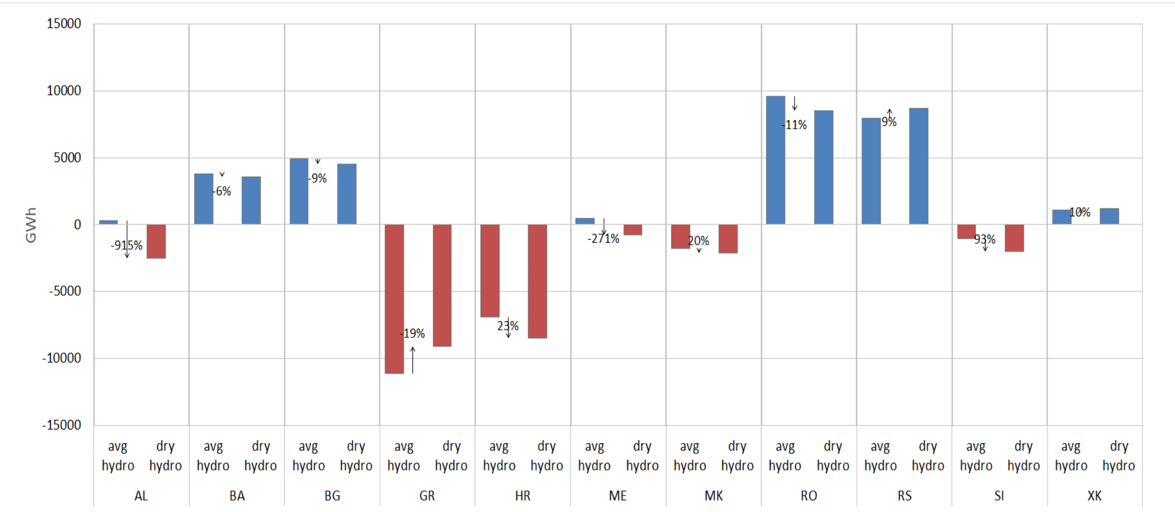
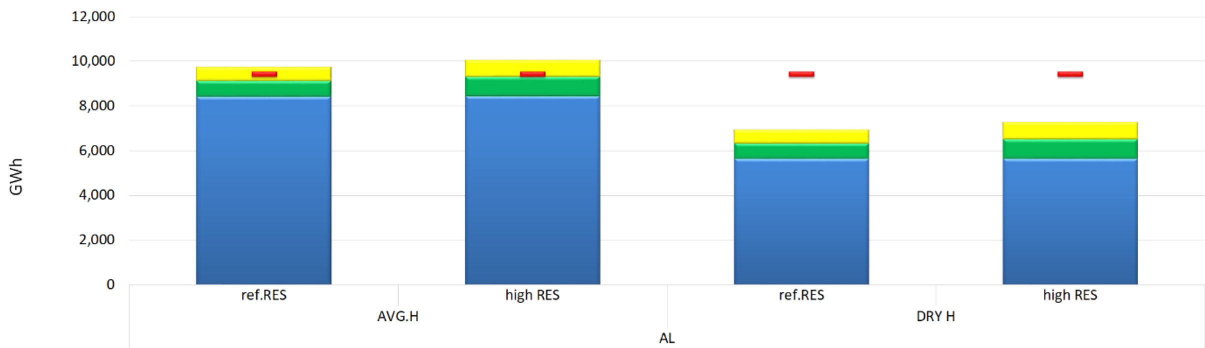


Figure 28: Balance positions per market areas in 2030 – average vs. dry hydrology

Below, we present detailed results for each market area under these four scenarios.

5.1.1. OST market area

To show the main results of the market analysis for the OST market area, we present the generation mix and a selected set of indicators in Figure 29 and Figure 30, respectively.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	606	758	606	758
Wind	703	879	703	879
Hydro	8,439	8,440	5,640	5,640
Consumption	9,442	9,442	9,442	9,442

Figure 29: Generation mix in the OST market area in 2030 - ref. RES vs high RES, dry and average hydrology

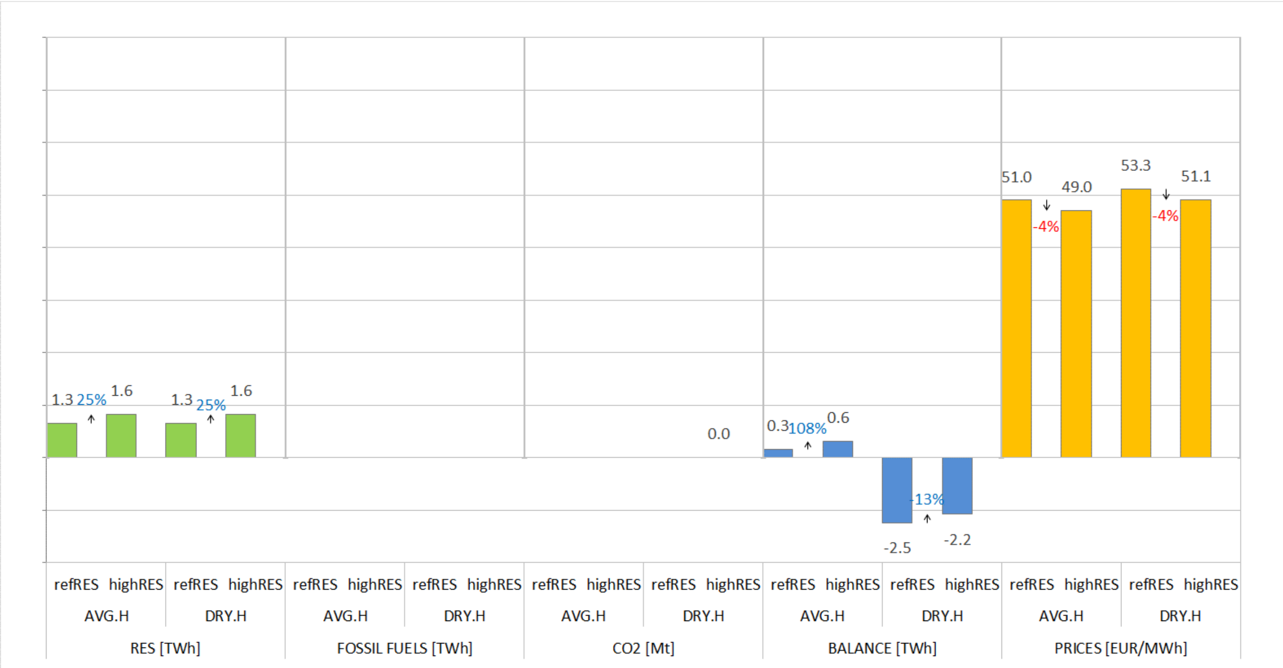


Figure 30: Main system operating indicators in the OST market area in 2030 - ref. RES vs high RES, dry and average hydrology

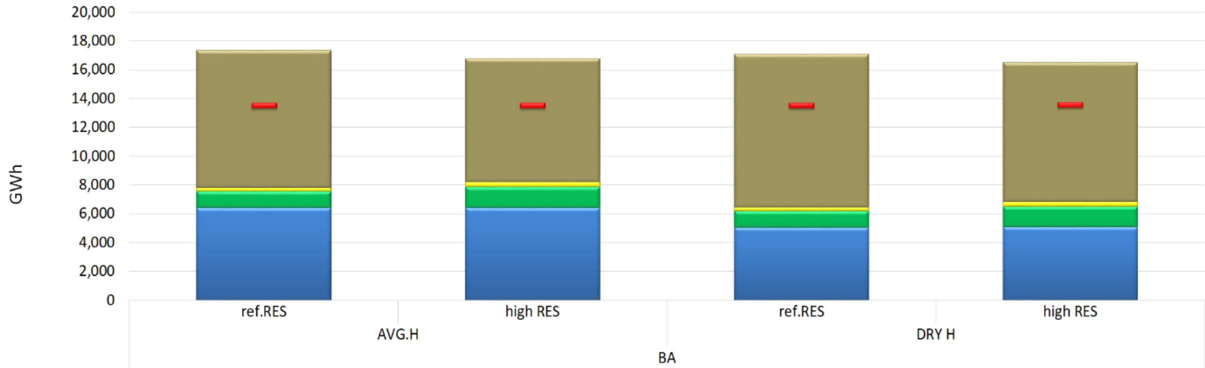
Considering the generation mix in Figure 29, in conjunction with the main system indicators in Figure 30, we draw the following conclusions about the operation of this market area in the high RES scenario in 2030, compared to the ref. RES in dry and average hydro conditions:

- RES generation increases 25%, from 1.3 TWh in the ref.RES scenario, to 1.6 TWh in the high RES scenario. This is lower than the average increase in the EMI region (30%).
- RES generation supplies between 14% and 17% of the area demand.
- Since the OST market area has high hydro generation, its operation strongly depends on hydro conditions. In average hydro conditions, the OST market area is balanced (with a small net export), but in dry hydro conditions, with hydro generation reduced by 2.8 TWh (33%), imports are high (2.2 to 2.5 TWh), reaching 26% of total demand.

- The impact of RES integration on prices is the same as on the regional level (-2 EUR/MWh). The impact of dry hydro conditions on prices is similar, but in the opposite direction (around a 2 EUR/MWh increase).

5.1.2. NOSBIH market area

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



	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	9,493	8,565	10,617	9,654
Nuclear	0	0	0	0
Solar	271	339	271	339
Wind	1,144	1,431	1,144	1,431
Hydro	6,425	6,440	5,063	5,085
Consumption	13,538	13,558	13,542	13,571

Figure 31: Generation mix in the NOSBIH market area in 2030 - ref. RES vs high RES, dry and average hydrology

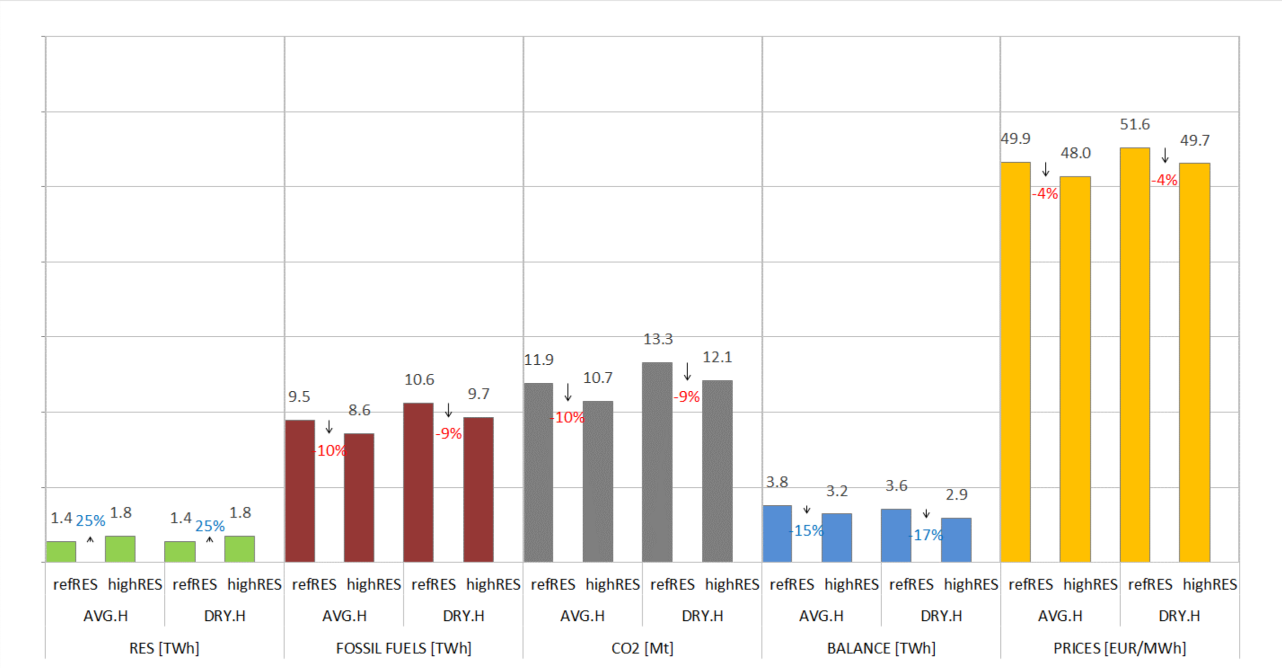


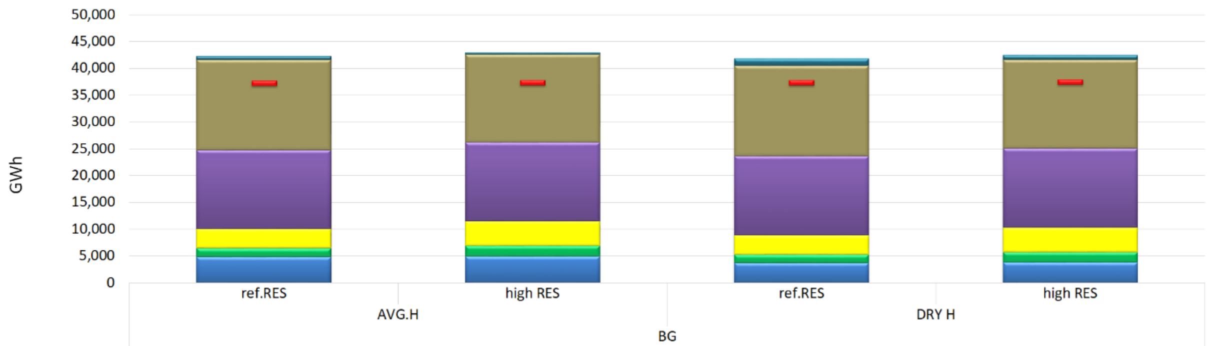
Figure 32: Main system operating indicators in the NOSBIH market area in 2030 - ref. RES vs high RES, dry and average hydrology

By analyzing these results, we conclude the following for the NOSBiH market area in 2030:

- RES generation (wind+solar) rises from 1.4 TWh to 1.7 TWh (+25%), supplying 10%-13% of the area demand.
- Higher RES generation leads to a 10% (-0.9 TWh) reduction of generation from lignite fired plants in both hydro conditions. This decrease in TPPs generation leads to a decrease of CO2 emission by the same 10%.
- With a small increase in RES generation (0.3 TWh) and a reduction in TPP generation (-0.9 TWh), NOSBIH's net exports decrease by around 0.6-0.7 TWh or 15% to 17% depending on the hydro conditions. The reason is that with higher RES generation in both the NOSBIH market area and the whole region, NOSBiH's lignite fired plants become less competitive.
- On the other hand, dry hydro moves the regional merit order curve to the left and prices rise, which is better for NOSBiH's lignite plants. Hydro generation in dry hydro conditions falls by 1.4 TWh (22%) compared to average hydrology, but net export fall only 0.2-0.3 TWh. This means that in dry conditions for the whole EMI region, the lignite plants in NOSBIH's market area become more competitive than in average hydro conditions.
- As a result, greater RES generation in both hydro conditions leads to about a 2 Euro, or 4% price decrease, the same as in the OST and other market areas. That is, higher RES generation moves the merit order curve to the right, placing cheaper power plants on the margin.
- Our simulations show that need for PS HPP to fill gaps due to RES intermittancy is very small, since the existing hydro plants and strong regional connections provide enough flexiblity for the projected level of RES generation.

5.1.3. ESO EAD market area

We present the main results of our market analysis for the ESO EAD market area, including generation mix and a selected set of indicators, in Figure 33 and Figure 34.



	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
Other	0	0	0	0
Gas	631	335	1,363	793
Coal	0	0	0	0
Lignite	16,775	16,334	16,824	16,608
Nuclear	14,693	14,693	14,693	14,693
Solar	3,678	4,598	3,678	4,598
Wind	1,570	1,962	1,570	1,962
Hydro	4,873	4,959	3,695	3,799
Consumption	37,277	37,392	37,315	37,454

Figure 33: Generation mix in the ESO EAD market area in 2030 - ref. RES vs high RES, dry and average hydrology

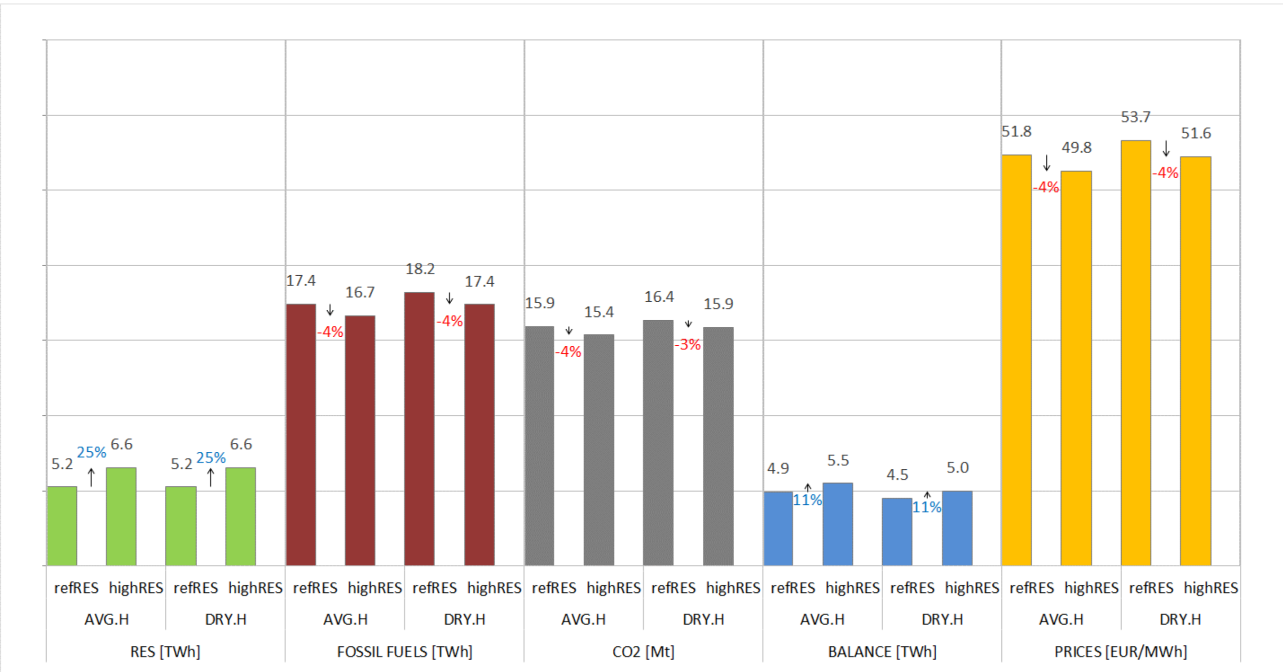


Figure 34: Main system operating indicators in the ESO EAD market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix presented above, in conjunction with the main system indicators in Figure 34, we draw the following conclusions about the operation of the ESO market area in the high RES scenario, compared to the ref. RES for dry and average hydrology:

- RES generation (wind+solar) rises from 5.2 TWh to 6.5 TWh (+25%) supplying 14% -18% of the areas demand.

- Higher RES generation leads to TPPs generation (only fossil fuels fired plants) reduction by about 4% (-0.7 TWh and -0.8 TWh) in both hydrolo conditions. This decrease in TPPs generation leads to a decrease of CO_2 emission by 3-4%.
- At the same time, the higher RES generation increases the export of the ESO EAD market area from 4.9 TWh to 5.5 TWh (+11%) in case of average hydrology. Exports are also increased in case of dry hydrology, for a similar amount, since the impact of hydro conditions is limited. The increase of exports is almost equal to the sum of the changes in RES and TPPs generation. It means that in case of increased RES generation, part of the ESO's thermal generation fleet becomes non-competitive. Then, one part of the increase in RES generation compensates a decrease of TPPs generation, while the other part of the RES generation increase leads to an increase in exports of electricity.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 4%.
- Higher RES capacities increase the need for flexibility and increases the utilization of PS HPPs, as we show in Table 24.

Table 24: PS HPPs generation in the ESO EAD market area

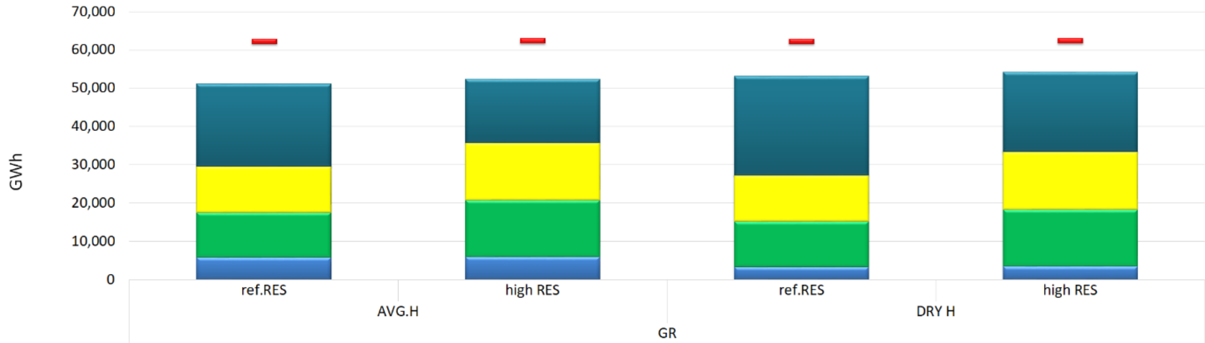
Generation from PS HPPs (GWh)	Average hydro conditions	Dry hydro conditions
Ref. RES	43.0	71.6
High RES	129.4	175.7
Difference	**86.4**	**104.1**

In general, the engagement of PS HPPs is low (<200 GWh) since existing HPPs and strong regional interconnections provide enough flexibility. However, generation from PS HPPs in the high RES scenario more than doubles in comparison with the referent RES scenario. This is mainly because greater RES generation raises the opportunities for pumping in hours with low prices, thus storing energy for utilization in hours with higher prices. Smaller HPPs generation (in the case of dry hydrology) increases the use of this kind of power plant.

- In dry hydro conditions, hydro generation falls by 25% (1.2 TWh), offset by an increase in TPPs generation (0.8 TWh) and a decrease in exports (0.4 TWh). The Bulgarian thermal fleet becomes more competitive in dry hydro conditions, which leads to higher TPPs generation and higher prices, in comparison with average hydrology.

5.1.4. IPTO market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the IPTO market area, in the following figures (Figure 35 and Figure 36).



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	0	0	0	0
Gas	21,515	16,666	25,947	20,846
Coal	0	0	0	0
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	12,093	15,076	12,093	15,076
Wind	11,742	14,761	11,742	14,761
Hydro	5,811	5,960	3,446	3,596
Consumption	62,311	62,524	62,309	62,522

Figure 35: Generation mix in the IPTO market area in 2030 - ref. RES vs high RES, dry and average hydrology

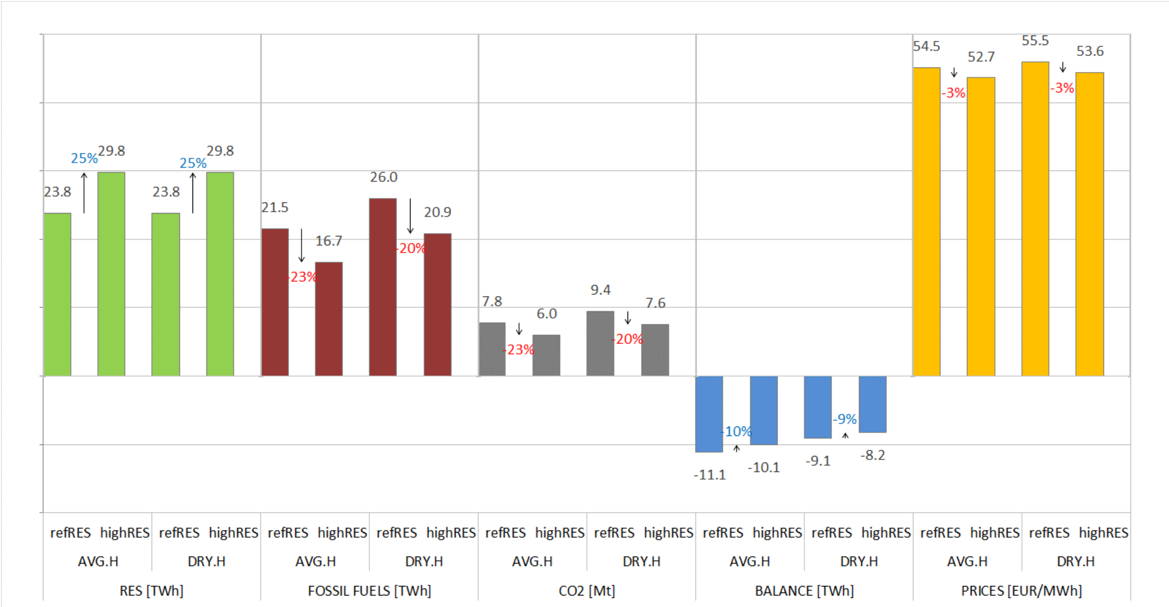


Figure 36: Main system operating indicators in the IPTO market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix and the main system indicators presented in the above figures, we drawn the following conclusions:

- Beside the Transelectrica market area, the IPTO market area is the biggest in the EMI region. So, changes due to higher RES integration in this area have a significant impact at the regional level.
- RES generation (wind+solar) rises from 23.8 TWh to 29.8 TWh (+25%). This increase in absolute value (6 TWh) is the highest in the region.
- This level of RES generation supplies between 38 and 48% of the area demand, which is the highest RES participation in the EMI region.
- Higher RES generation leads to a reduction in TPP generation by more than 20% (-4.8 TWh and -5.1 TWh) in both hydro conditions and this decrease is (again) the highest in the region.

This decrease is noted only in gas fired units and this leads to a decrease of CO2 emission by the same percentage.

- At the same time, the increase in RES generation and decrease in TPPs generation enables net electricity imports to the IPTO market area to fall by around 1.1 TWh or by 10%. Even so, imports into the IPTO market area remain the highest in the region, both in absolute terms (between -11.1 TWh and -8.2 TWh) as well as in relative terms (between 18% and 13% of area demand).
- The participation of HPPs in meeting demand in the IPTO market area is rather low (<10%) so even in dry conditions, when HPP generation decreases by about 40%, this has limited impact. Available energy in the whole EMI region in dry conditions is lower, and the regional merit order curve moves to the left. In this case, the gas units in the IPTO market area become more competitive, which increases gas generation and prices, and reduces net electricity imports.
- Greater RES generation in both hydrolo conditions leads to a decrease in prices by 3%. The impact of hydrology is smaller and in the opposite direction – prices increase by around 1 EUR/MWh under dry conditions.
- As in other market areas, our simulations show modest engagement of PS HPPs (Table 25).

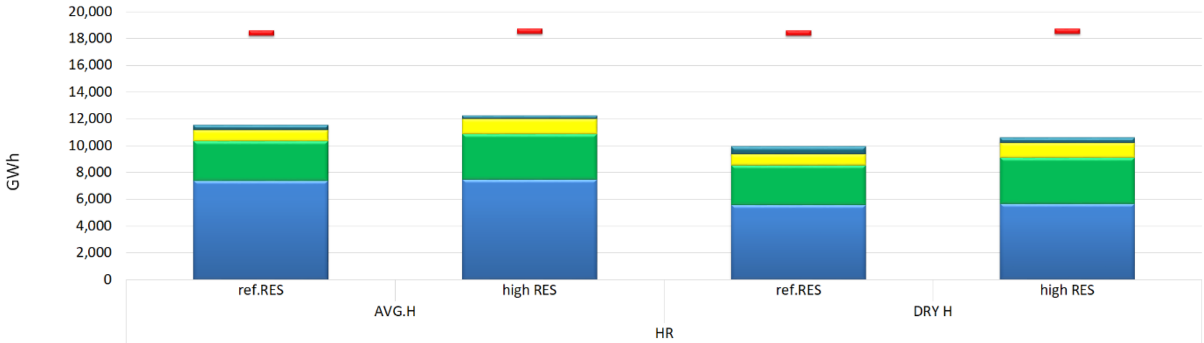
Table 25: PS HPPs generation in the IPTO market area

Generation from PS HPPs (GWh)	Average hydro conditions	Dry hydro conditions
Ref. RES	43	41.3
High RES	191.6	190.2
Difference	**148.6**	**148.9**

Generation from PS HPPs in the high RES scenario is several times higher compared to the generations of PS HPPs in the referent RES scenario, although it is still modest engagement. No impact of hydro conditions points again to negligible impact of hydro generation in the IPTO market area.

5.1.5. HOPS market area

To show the main results of the market analysis for the HOPS market area, we present the generation and a selected set of indicators, in Figure 37 and Figure 38, respectively.



	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
Other	0	0	0	0
Gas	368	246	575	389
Coal	5	5	10	8
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	840	1,120	840	1,120
Wind	2,960	3,415	2,960	3,415
Hydro	7,374	7,472	5,579	5,681
Consumption	18,432	18,563	18,436	18,572

Figure 37: Generation mix in the HOPS market area in 2030 - ref. RES vs high RES, dry and average hydrology

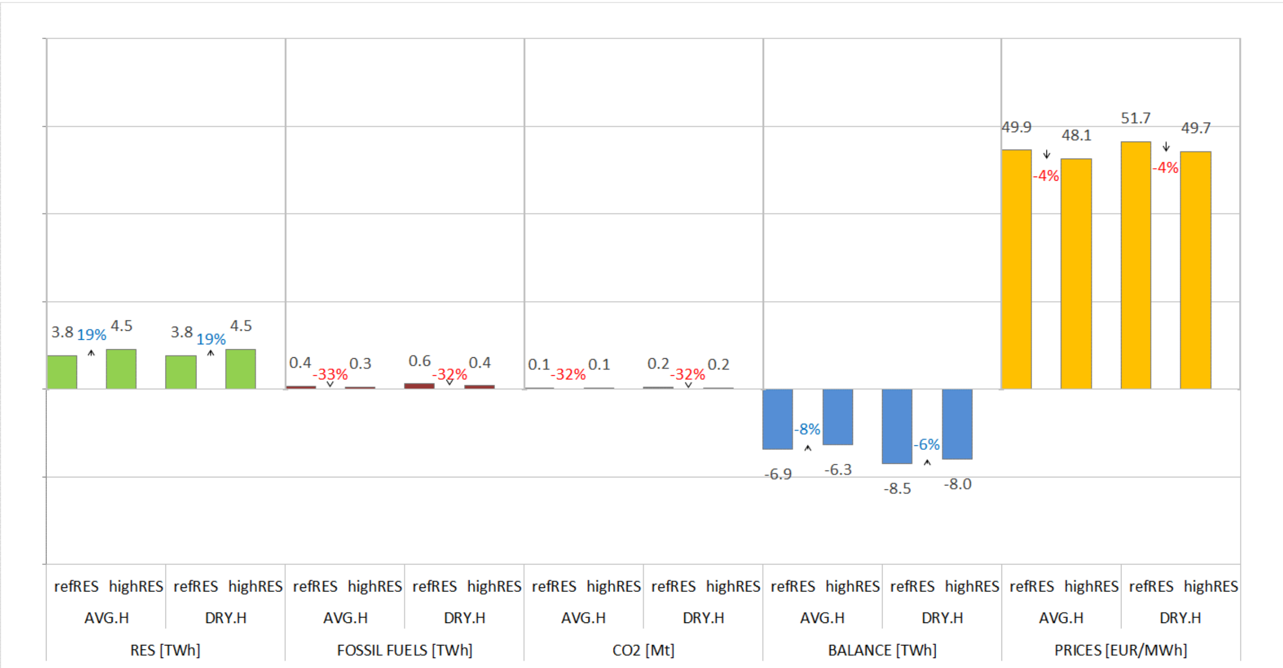


Figure 38: Main system operating indicators in the HOPS market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix in Figure 37, in conjunction with the main system indicators in Figure 38, we draw the following conclusions about the operation of this market area in the high RES scenario, in comparison with the ref. RES in dry and average hydro conditions:

- RES generation (wind+solar) rises from 3.8 TWh to 4.5 TWh (+19%), which is the lowest increase in percentages in the region. This level of RES generation supplies between 21% and 24% of the area demand, which is close to the regional average.
- In the HOPS market area total demand in 2030 is supplied by hydro and RES generation as well as the electricity imports. Generation from fossil fuel fired plants is very low, below 0.5

TWh and higher RES generation almost does not provoke changes in TPPs generation. This low level of TPPs generation is followed by low level of CO2 emission. In case of dry conditions, TPPs generation is somewhat higher, but still below 1 TWh.

- The net imports in the HOPS market area are between 6.3 and 6.9 TWh (34% and 37% of the area demand) in case of average hydrology and increases with decrease in generation from HPPs in case of dry hydrology, reaching 46% of the total demand.
- Higher RES integration decreases the net imports in all hydro conditions by 6%-8%.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 4%.
- Similar as in other market areas, our simulations show that the engagement of PS HPPs is small (Table 26).

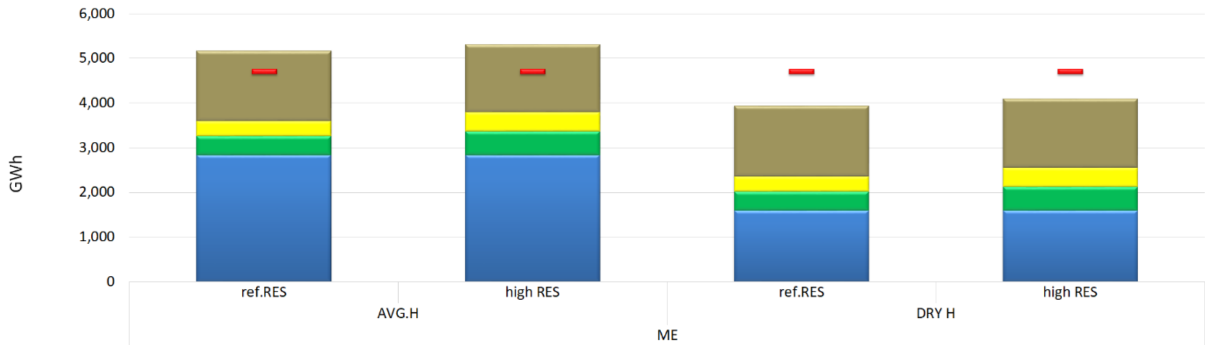
Table 26: PS HPPs generation in the HOPS market area

Generation from PS HPPs (GWh)	Average hydro conditions	Dry hydro conditions
Ref. RES	183	185.3
High RES	280.6	286.1
Difference	**97.6**	**100.8**

Small generation from PS HPPs points to the fact that other HPPs and good regional interconnections provide enough flexibility.

5.1.6. CGES market area

To show the main results of the market analysis for the CGES market area, we present the generation mix and a selected set of indicators, in Figure 39 and Figure 40, respectively.



Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	1,557	1,510	1,567	1,544
Nuclear	0	0	0	0
Solar	341	426	341	426
Wind	423	529	423	529
Hydro	2,844	2,844	1,600	1,600
Consumption	4,710	4,710	4,710	4,710

Figure 39: Generation mix in the CGES market area in 2030 - ref. RES vs high RES, dry and average hydrology

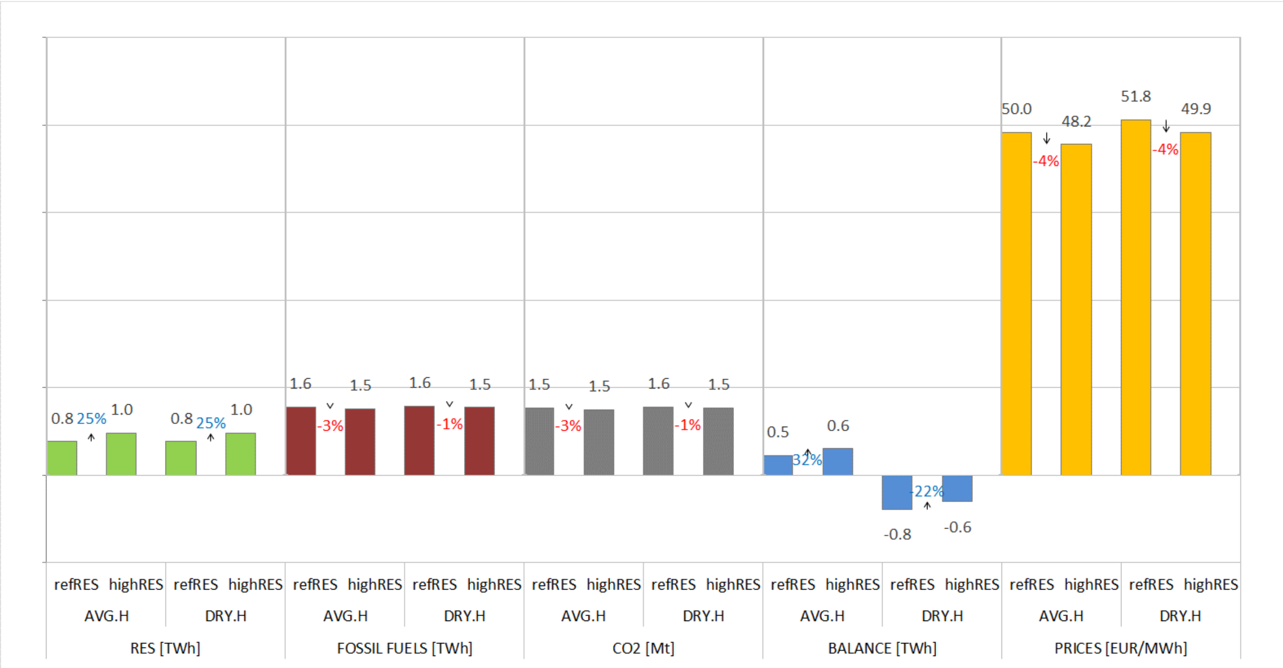


Figure 40: Main system operating indicators in the CGES market area in 2030 - ref. RES vs high RES, dry and average hydrology

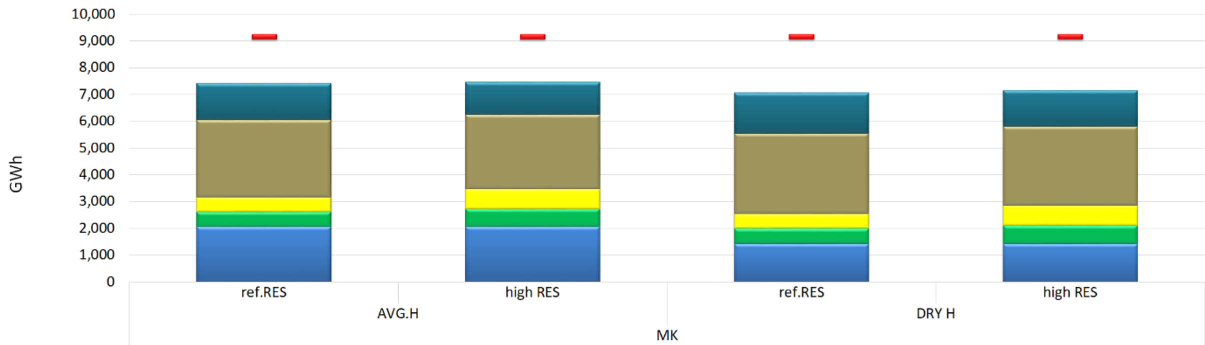
Considering the generation mix and main system indicators in the figures above, we draw the following conclusions:

- The CGES market area is the smallest, almost balanced market area in the EMI region
- RES generation (wind+solar) rises from 0.8 TWh to 1 TWh (+25%) and this level of RES generation supplies between 16% and 20% of the area demand.
- Small changes in RES generation leads to small changes in TPPs generation – 0.1 TWh in both hydro conditions and small changes in CO2 emissions.
- With higher RES generation, the CGES market area increases its net exports or decreases its net imports, depending on the hydrology.

- In dry hydro conditions, generation from HPPs decreases by 1.2 TWh (44%) and balance position changes by the same level, moving from the net export of 0.5 TWh to net import of 0.8 TWh, without changes in TPPs generation.

5.1.7. MEPSO market area

To show the main results of the market analysis for the MEPSO market area, we present the , generation mix and a selected set of indicators in Figure 41 and Figure 42, respectively.



	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
Other	0	0	0	0
Gas	1,356	1,201	1,502	1,346
Coal	0	0	0	0
Lignite	2,889	2,778	3,005	2,942
Nuclear	0	0	0	0
Solar	549	749	549	749
Wind	560	670	560	670
Hydro	2,058	2,058	1,440	1,440
Consumption	9,170	9,170	9,170	9,170

Figure 41: Generation mix in the MEPSO market area in 2030 - ref. RES vs high RES, dry and average hydrology

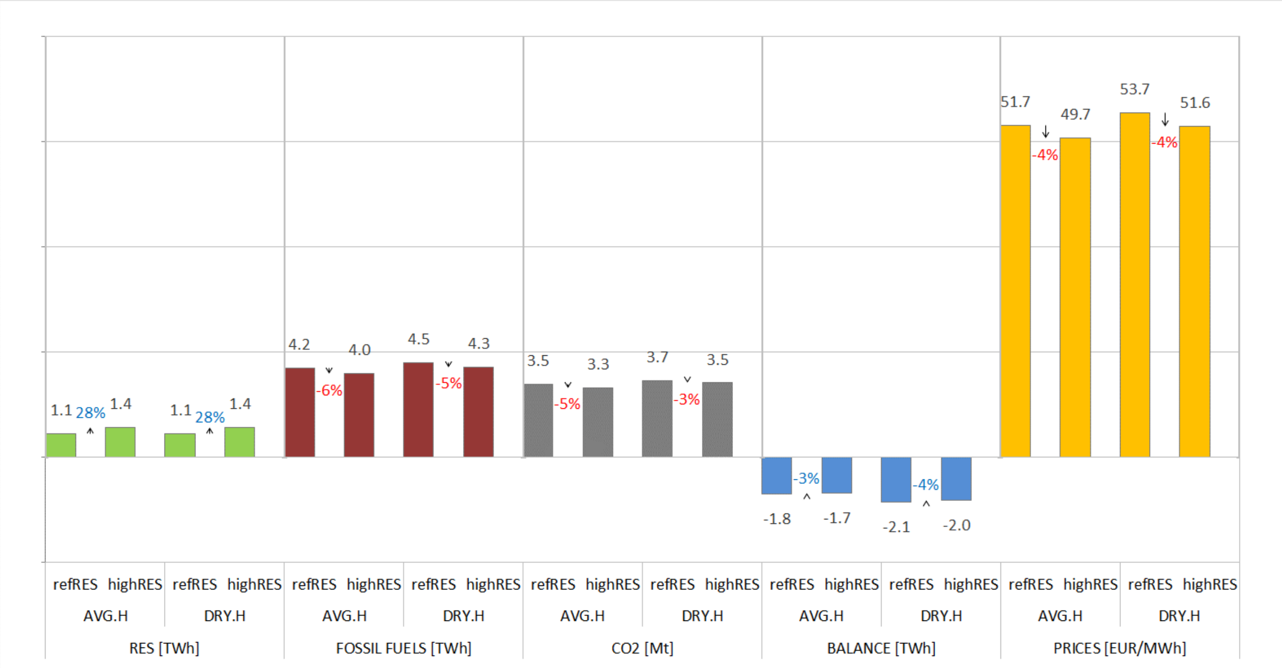


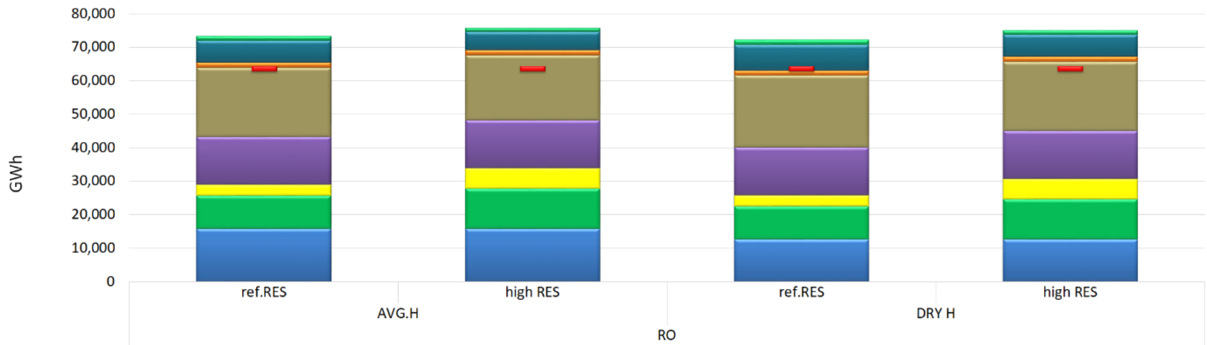
Figure 42: Main system operating indicators in the MEPSO market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix in Figure 41, in conjunction with the main system indicators in Figure 42, we draw the following conclusions about the operation of this market area in the high RES scenario, in comparison with the ref. RES scenario in case of both, dry and average hydro conditions:

- RES generation (wind+solar) rises from 1.1 TWh to 1.4 TWh (+28%), supplying between 12% and 15% of area demand (which is below the regional average).
- Higher RES generation leads to TPPs generation reduction by 0.25 TWh (-6%) approximately, in both hydro conditions and decrease of imports (-0.1 TWh).
- Decrease in fossil fuel fired plants generation decreases the CO2 emission by 5% and 3% in average and dry hydro conditions, respectively.
- Net imports slightly decrease with the higher RES generation, but in all scenarios the MEPSO market area is a net importer of electricity.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 4%.
- In dry hydro conditions, hydro generation is reduced by 30% (0.6 TWh) which is compensated by increase in TPPs generation (0.3 TWh) and increase in imports (0.3 TWh). Thermal fleet in the MEPSO market area becomes more competitive in dry hydro conditions which leads to higher TPPs generation and higher prices (+2 EUR/MWh) compared to the average hydrology.

5.1.8. Transelectrica market area

To show the main results of the market analysis for the Transelectrica market area, we present the generation mix and a selected set of indicators in Figure 43 and Figure 44, respectively.



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	1,261	993	1,496	1,223
Gas	6,600	5,524	7,658	6,626
Coal	1,508	1,508	1,509	1,508
Lignite	20,656	19,444	21,452	20,686
Nuclear	14,245	14,245	14,245	14,245
Solar	3,360	6,216	3,360	6,216
Wind	9,787	11,885	9,787	11,885
Hydro	15,889	15,889	12,710	12,710
Consumption	63,717	63,717	63,717	63,717

Figure 43: Generation mix in the Transelectrica market area in 2030 - ref. RES vs high RES, dry and average hydrology

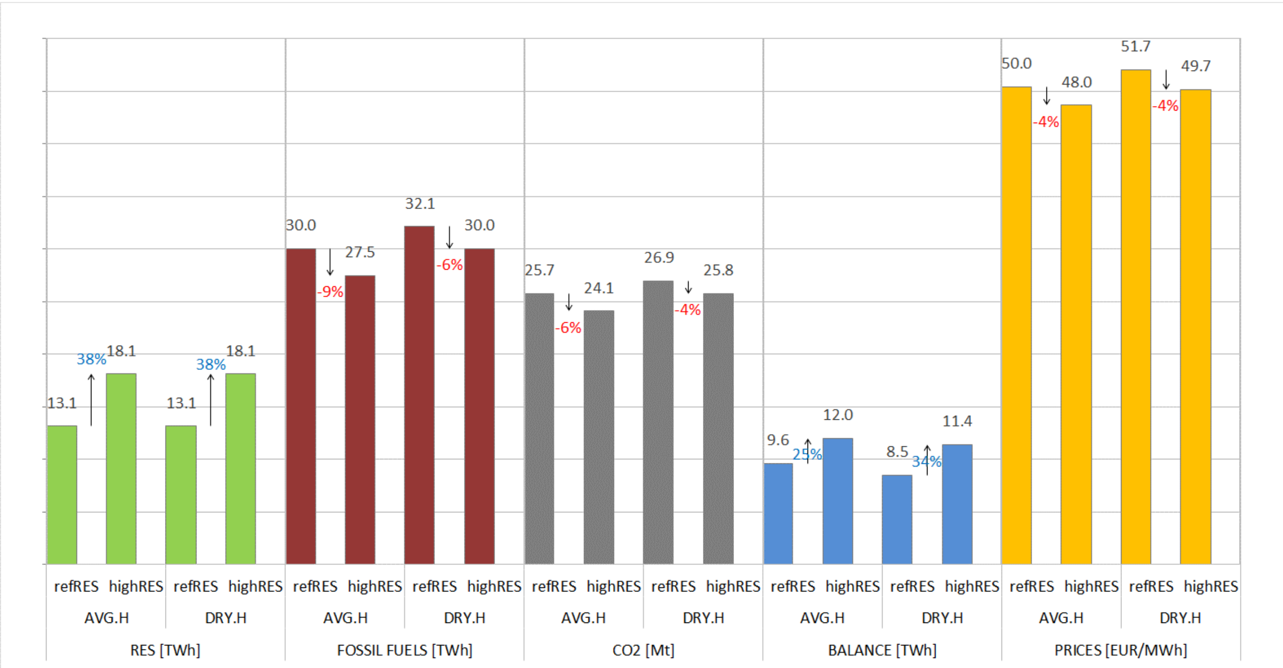


Figure 44: Main system operating indicators in the Transelectrica market area in 2030 - ref. RES vs high RES, dry and average hydrology

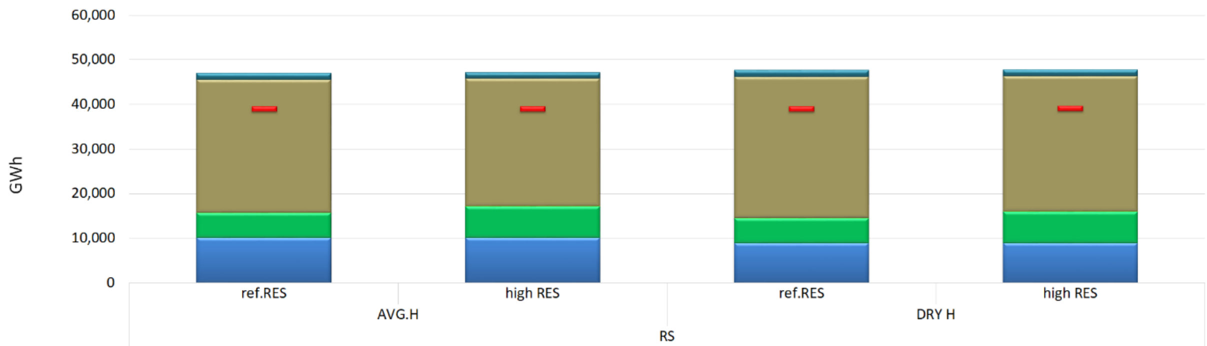
We concluded the following, by jointly analyzing these results:

- RES generation increases from 13 TWh in the ref.RES scenario to 18 TWh in the high RES scenario, which is the increase of 38%. This increase puts Transelectrica market area in the group of zones with the highest RES increase (ELES, KOSTT and Transelectrica with 270%, 53% and 38%, respectively).

- RES participation in supplying the area demand in the Transelectrica market area is at the regional average, between 21% and 28%.
- At the same time, generation of fossil fuels fired TPPs falls from 30.0 TWh to 27.5 TWh (-9%) as well as from 32.1 TWh to 30.0 TWh (-6%) for average and dry hydrology respectively. This leads to a decrease in CO2 emission by 6% and 4%, since total decrease in TPPs generation is almost equally shared between the gas and lignite fired TPPs.
- In dry hydro conditions, TPPs generation increases to compensate the reduction in HPPs generation. In dry hydro conditions in the whole EMI region, regional merit order curve is moved to the left providing space for generation of more expensive units and TPPs in the Transelectrica market area becomes more competitive. This is also the reason for smaller decrease in TPPs generation with additional RES generation expected in the high RES scenario (-6%).
- With higher RES generation, the net exports of the Transelectrica market area rise by 2.4 TWh (25%) in average hydro conditions. In dry hydro conditions, this increase is even higher and exports increase by 2.9 TWh or 34%.
- Greater RES generation in both hydro conditions leads to a decrease in prices by 4%. With increased RES generation cheaper power plants are on the margin and the prices decrease.
- In case of dry hydrology, hydro generation is reduced by 20% (3.2 TWh) which is compensated by increase in TPPs generation (2.1 TWh) and decrease in exports (1.1 TWh). At the same time, prices in dry hydro conditions are higher by 1.7 EUR/MWh

5.1.9. EMS market area

To show the main results of the market analysis for the EMS market area, we present the , generation mix and a selected set of indicators in Figure 45 and Figure 46 , respectively.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
Other	0	0	0	0
Gas	1,420	1,284	1,537	1,400
Coal	0	0	0	0
Lignite	29,778	28,590	31,594	30,334
Nuclear	0	0	0	0
Solar	41	51	41	51
Wind	5,639	7,048	5,639	7,048
Hydro	10,095	10,140	8,917	8,973
Consumption	39,012	39,072	39,030	39,103

Figure 45: Generation mix in the EMS market area in 2030 - ref. RES vs high RES, dry and average hydrology

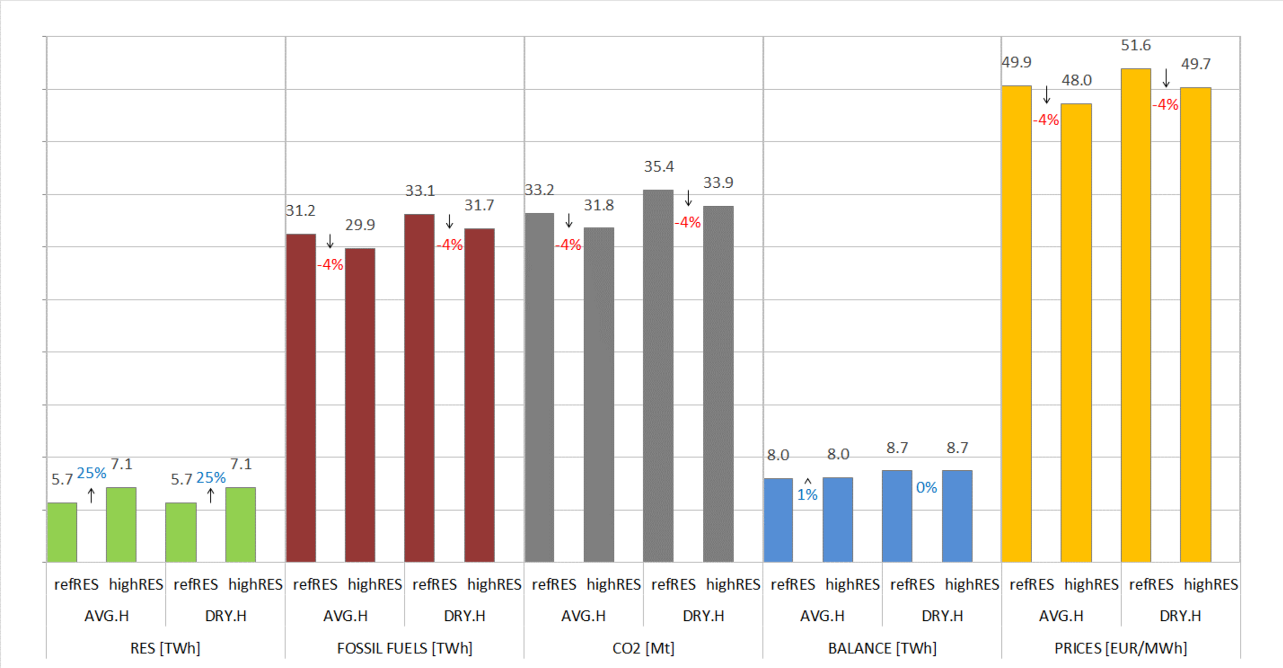


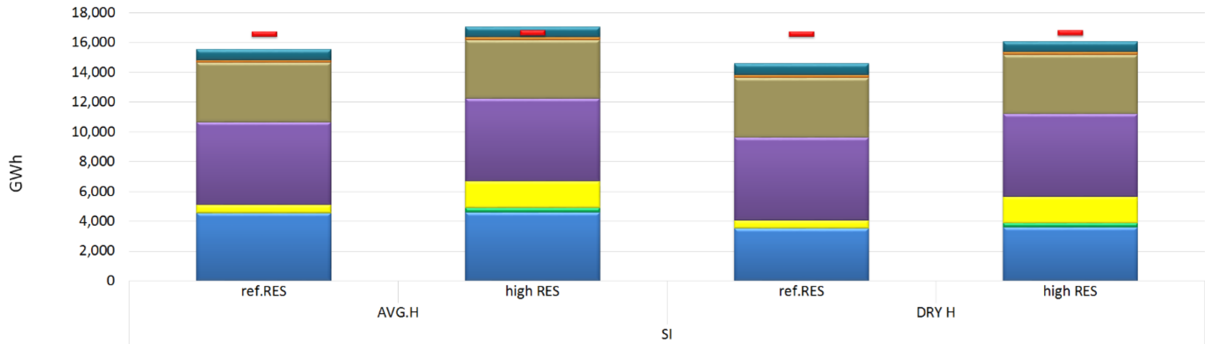
Figure 46: Main system operating indicators in the EMS market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix in Figure 45, in conjunction with the main system indicators in Figure 46, we draw the following conclusions about the operation of the EMS market area in the high RES scenario in comparison with the ref. RES, for both dry and average hydrology:

- RES generation (wind+solar) rises from 5.7 TWh to 7.1 TWh (+25%) supplying between 15% and 18% of the area demand. This participation is lower than the regional average (21%-27%).
- Increased installed capacities in renewable energy sources, as well as corresponding generation of electricity leads to the reduction in TPPs generation, almost completely realized as decrease in lignite fired plants generation (-4%). With this decrease in TPPs generation, CO2 emissions decrease by the same percentage.
- At the same time, the exports of the EMS market area are practically the same. The increase in RES generation pushes generation from TPPs by the same value and exports of electricity remain the same in both hydro conditions, dry and average.
- More critical operating conditions, such as dry hydrology, put thermal fleet in the EMS market area in more competitive position and enable higher thermal generation and higher exports. The HPPs generation in dry hydrolo conditions is lower by 1.2 TWh, but TPPs increase their generation by 1.9 TWh and net exports from the EMS market area increase by 0.7 TWh.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 4%, due to shifting of the regional merit order curve to the right and pushing out of the most expensive units.
- Our simulations show that the engagement of the PS HPP is very small, since existing hydropower plants and strong regional connections enable enough flexibility for the given level of the RES generation.

5.1.10. ELES market area

To show the main results of the market analysis for the ELES market area, we present the , generation mix and a selected set of indicators in Figure 47 and Figure 48, respectively.



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	0	0	0	0
Gas	701	661	741	698
Coal	175	175	176	175
Lignite	4,003	3,941	4,015	3,964
Nuclear	5,558	5,558	5,558	5,558
Solar	531	1,780	531	1,780
Wind	20	301	20	301
Hydro	4,552	4,614	3,533	3,602
Consumption	16,582	16,664	16,589	16,682

Figure 47: Generation mix in the ELES market area in 2030 - ref. RES vs high RES, dry and average hydrology

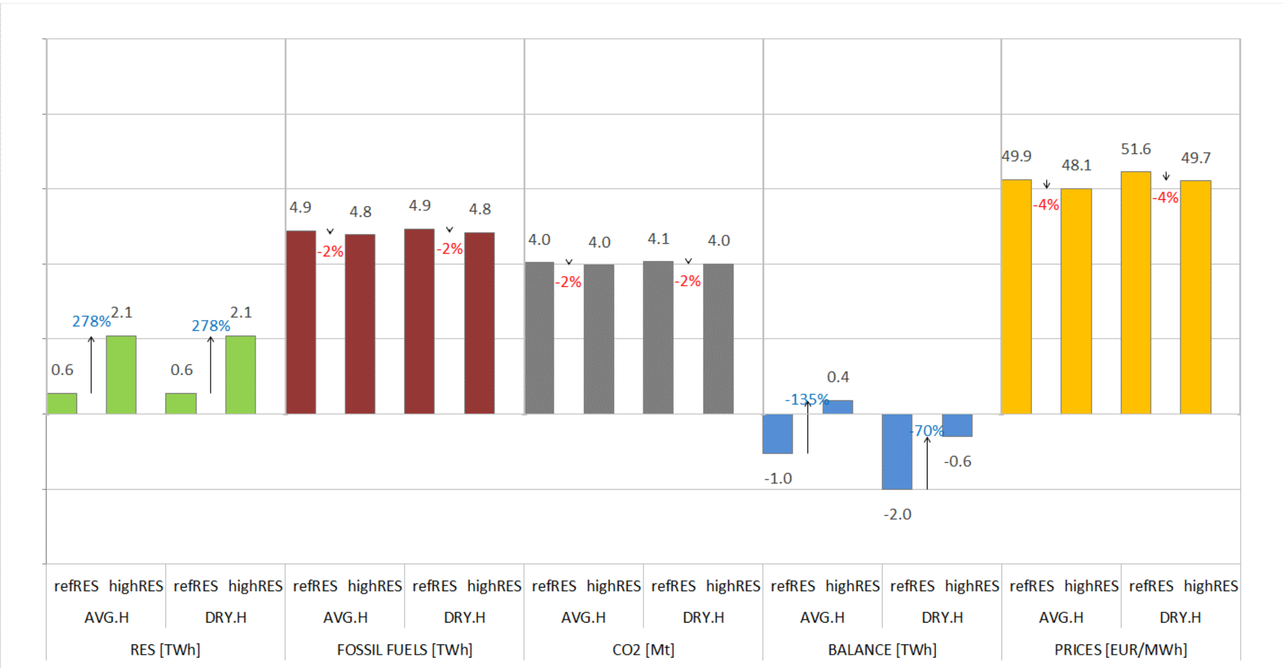


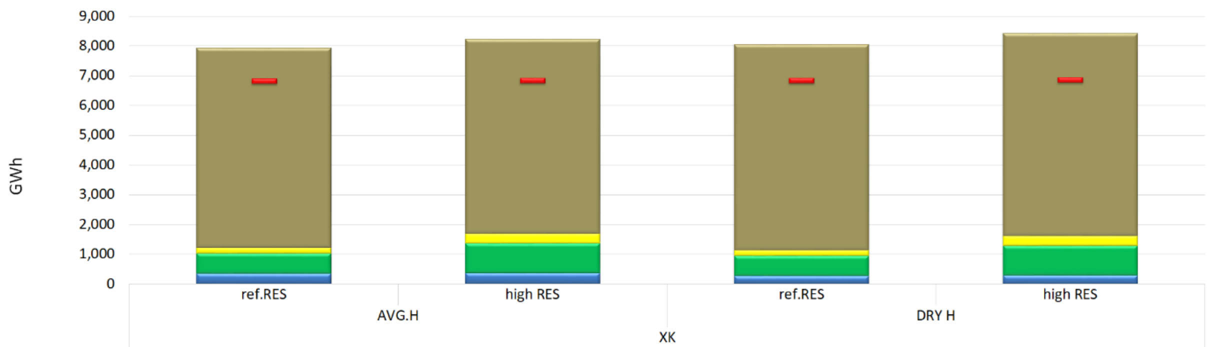
Figure 48: Main system operating indicators in in the ELES market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix and main system indicators presented in the figures above, we draw the following conclusions:

- RES generation (wind+solar) rises from 0.6 TWh to 2.1 TWh (+278%). We would like to emphasize that this is the largest relative increase of RES in the whole SEE region. RES in the ELES market area supplies between 3% and 12% of the area demand, which is far from the regional average (21%-27%).
- Generation from fossil fuels fired plants remains stable in the referent and high RES scenarios and only the reduction by 0.1 TWh (2%) is expected in case of the high RES scenario, while the remaining part of increased RES generation (1.5 TWh) reduces the imports and converts the ELES market area from a typical electricity importer to net electricity exporter in case of average hydrology. Similar decrease in imports happens also in the case of dry hydrology, but with reduced HPPs generation. Our simulations show that the ELES market area remains as net importer in both scenarios: the referent and high RES.
- Higher RES generation leads to decrease of CO_2 emissions by 2% for both, average and dry hydrology.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 4%. Namely, with increase in RES generation the cheaper power plants are on the margine.
- Our simulations show that engagement of PS HPP is very small, since existing hydropower plants and strong regional connections enable enough flexibility for the given level of RES generation.

5.1.11. KOSTT market area

To show the main results of the market analysis for the KOSTT market area, we present the generation mix and a selected set of indicators in Figure 49 and Figure 50 , respectively.



	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	6,706	6,511	6,899	6,791
Nuclear	0	0	0	0
Solar	205	341	205	341
Wind	666	990	666	990
Hydro	356	374	275	299
Consumption	6,830	6,854	6,838	6,869

Figure 49: Generation mix in the KOSTT market area in 2030 - ref. RES vs high RES, dry and average hydrology

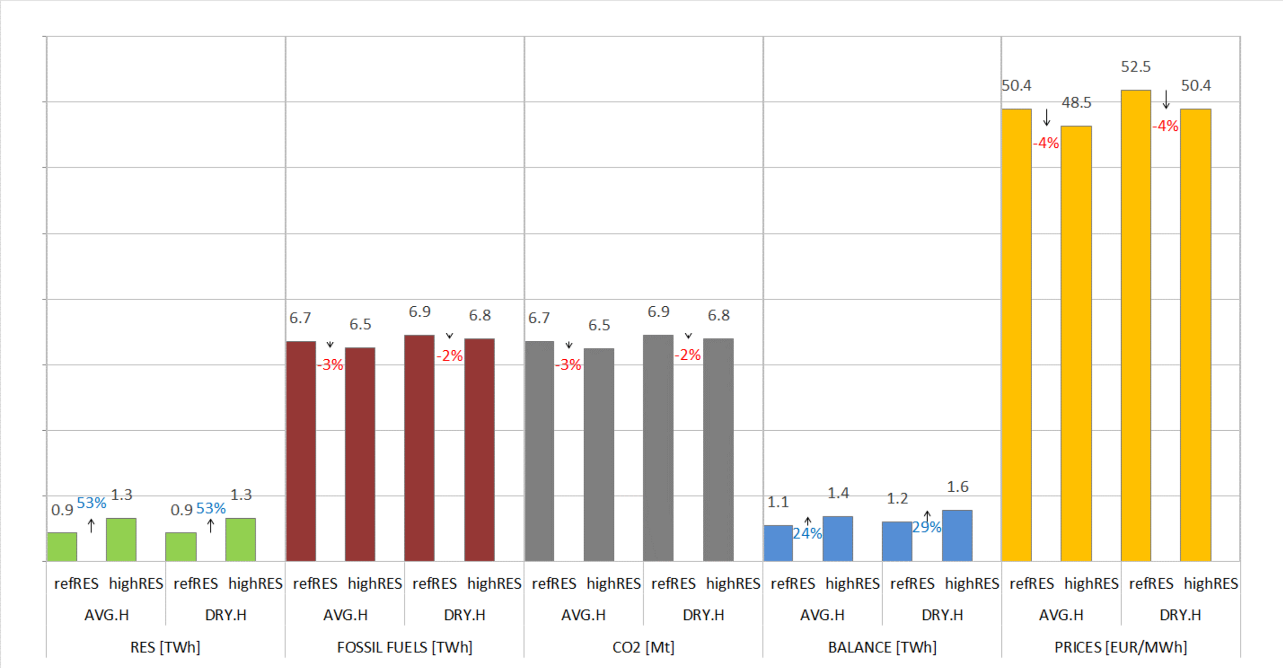


Figure 50: Main system operating indicators in the KOSTT market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix in Figure 49, in conjunction with the main system indicators in Figure 50, we draw the following conclusions about the operation of the KOSTT market zone in the high RES scenario, in comparison with ref. RES, for dry and average hydrology:

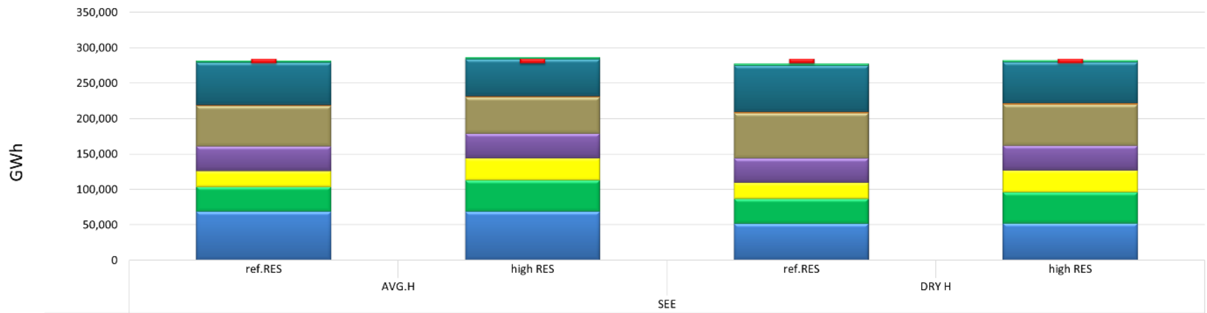
- RES generation (wind+solar) rises from 0.9 TWh to 1.3 TWh (+53%), supplying between 13% and 20% of the area demand.
- Higher RES generation leads to fossil fuels fired TPPs generation reduction of about 0.1-0.2 TWh (2-3%) and decrease in CO2 emission is proportional.
- The KOSTT market area is expected to be net exporter of electricity, as we present in the Figure 50. , where exports increase from 1.1 TWh to 1.4 TWh (+24%) in case of average hydrology and 1.2 TWh to 1.6 TWh (+29%) in case of dry hydrology. Similar as in other market areas, the reduction in TPPs generation is lower than increase in the RES generation and area exports more in the high RES scenario.
- In dry hydro conditions, thermal power plants in the KOSTT market area produce more, partially compensating decrease in HPPs and increasing the exports of electricity.
- As a result, greater RES generation for both hydro conditions leads to a decrease in prices by 4%. This is consequence of merit order curve shifting to the right, caused by zero price renewable sources, thus cheaper power plants are on the margin.
- Our ssimulations show that the engagement of PS HPP is very small, since existing hydropower plants and strong regional connections enable enough flexibility for the given level of RES generation.

5.2. Group 2: Referent demand growth and high CO_2 scenarios

Similar to the results in Chapter 5.1, in this second group of scenarios, we have kept referent demand development and alternative (high) CO_2 emission tax constant in four analyzed scenarios, as follows:

1. Average hydrology and referent level of RES integration
2. Average hydrology and high level of RES integration
3. Dry hydrology and referent level of RES integration
4. Dry hydrology and high level of RES integration

We present the generation mix for the whole EMI region in Figure 51, and the main regional indicators in Figure 52.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
Other	2,662	2,631	2,665	2,639
Gas	59,663	51,891	65,380	57,877
Coal	1,685	1,685	1,686	1,685
Lignite	56,877	51,417	63,735	58,312
Nuclear	34,497	34,497	34,497	34,497
Solar	22,513	31,455	22,513	31,455
Wind	35,213	43,872	35,213	43,872
Hydro	68,468	68,744	51,605	51,890
Consumption	280,689	281,061	280,705	281,090

Figure 51: Generation mix in EMI region in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

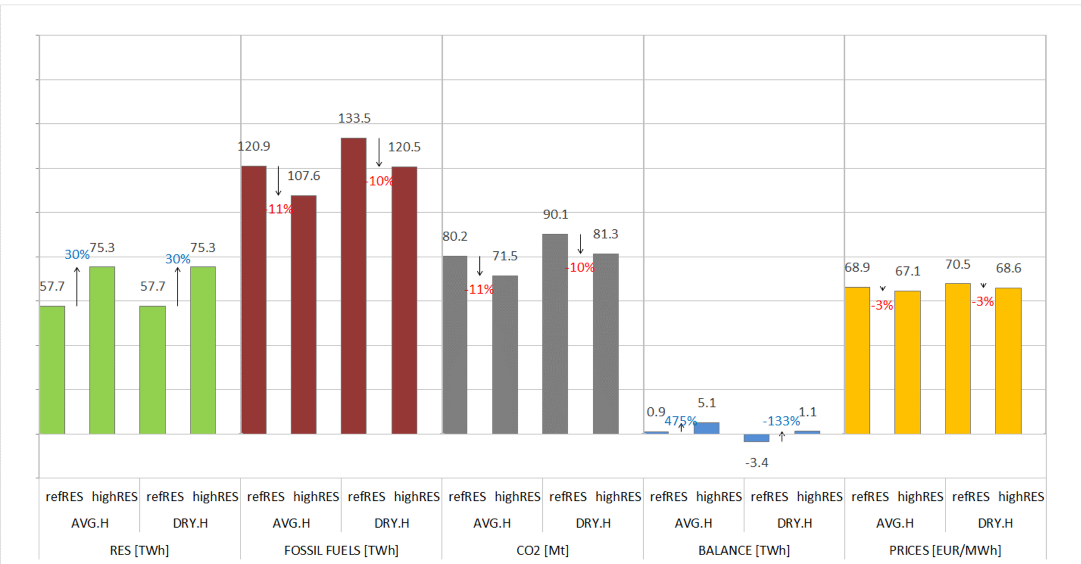


Figure 52: Main system operating indicators in EMI region in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

From these results, we draw the following conclusions:

- **In the case of a high CO2 tax in 2030, the main technology is hydro under average hydro conditions (it supplies approx. 24% of the load), while in dry hydro conditions, lignite and gas supply almost the same share: between 18% and 23%.** The higher level of CO_2 emission tax changes the position of the lignite and gas fired plants in the merit order curve and decreases the competitiveness of the lignite plants, which lowers their generation by ~30TWh (or 50%). At the same time, gas generation rises.
- Hydro plants supply 18% to 24%, depending on the hydrology, while RES generation (depending on the scenario) supplies 21% to 27% of total demand. It fact, hydro and RES technologies, the "green" technologies, together become the main technologies in the EMI region in 2030, supplying 39% to 51% of total demand. This is the same with the referent CO_2 tax, since a change in CO_2 emission tax only affects generation from fossil fuel plants.
- It is the same with the referent CO_2 tax, in which RES generation increases from 57.7 TWh (in ref. RES scenario) to 75.3 TWh in the high RES scenario, an increase of 30% (Figure 52). The increase per market area (Figure 53) is between 0.2 and 6 TWh (in the CGES and IPTO market areas), or between 19% and 278% (in the HOPS and ELES market areas).

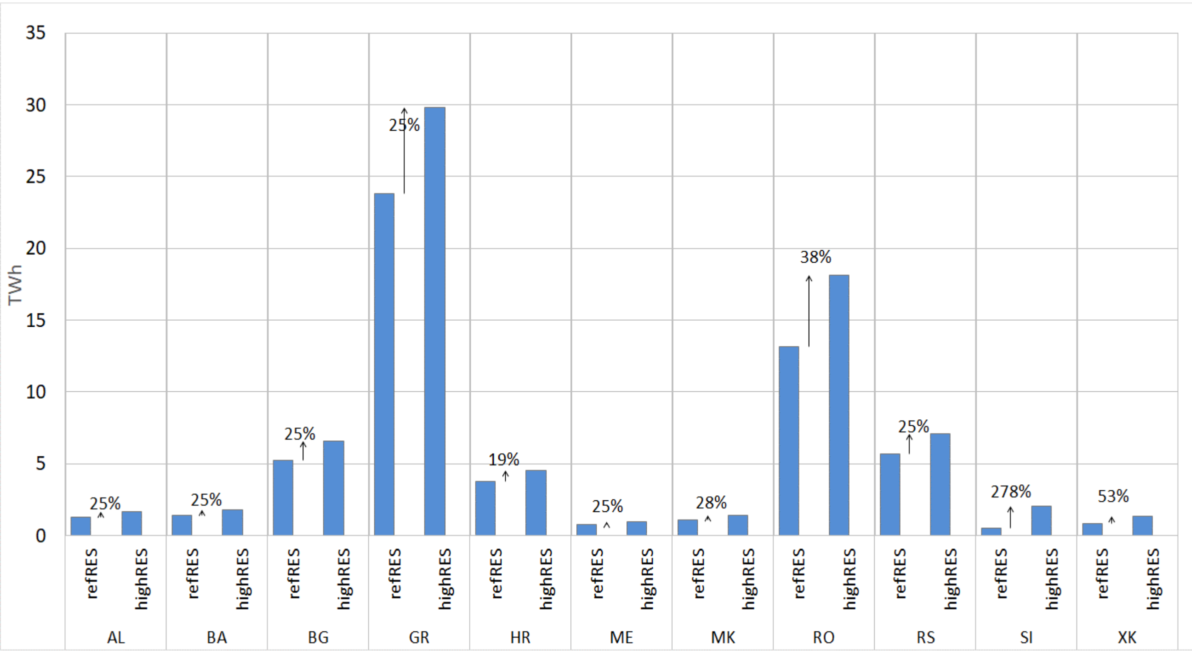


Figure 53: RES generation in 2030 - ref. RES vs high RES

- **Generation from the additional RES of 17.6 TWh (referent RES vs. high RES) supplies 6% of total demand in the EMI region in 2030. Due to this increase, fossil generation falls: gas generation decreases by 8 TWh, and lignite generation by 5 TWh, while exports from the region rise by 4 TWh.**

Since the share of gas and lignite plants is similar, the increase in RES generation has a similar impact on both. However, the somewhat higher drop in gas generation is because one of the biggest market areas (IPTO) in 2030 has only gas fired units. In all other market areas, the decrease of fossil generation due to increased RES is almost equally divided between lignite and gas technologies (Figure 54).

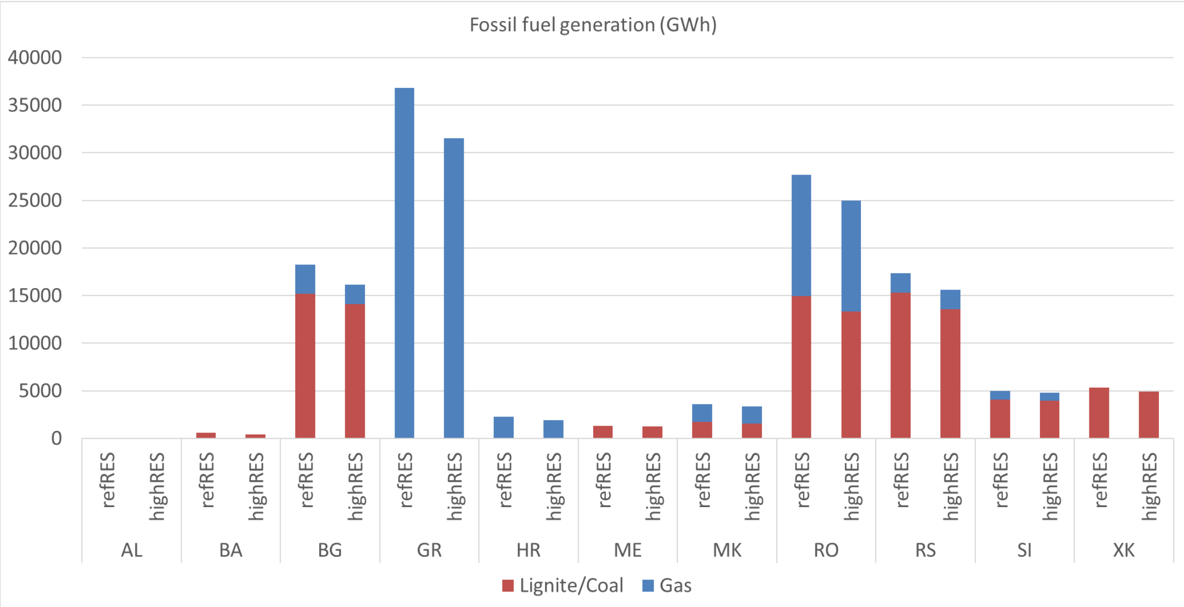


Figure 54: Fossil fuel powered plants generation in 2030 - ref. RES vs high RES, average hydrology – Alternative CO_2 emission tax

- **Following the decrease in fossil generation, CO_2 emission falls with high RES integration by around 11%, or 9 Mt of CO_2, for the whole EMI region.**
- **The EMI region has net exports between 0.9 TWh and 5.1 TWh, or 0.3% and 2% of total demand in all scenarios, except in the scenario with dry hydro and referent RES integration. In that scenario, the EMI region is a net importer of 3 TWh, or approximately 1% of total demand.**
- Higher RES provokes a decrease of TPP generation, but at a smaller level, and this leads to a rise in regional net exports, by around 4.2 TWh in both hydroconditions. The rise in net export in the high RES scenario is lower than with the referent CO_2 tax, since the regional competitiveness of fossil plants is lower, and the decrease in their generation is larger.
- The change in balance positions for all market zones in average hydro conditions (Figure 55) shows that in almost all areas, additional RES generation will increase exports or decrease imports. The only exception is in the ESO EAD and EMS areas, where fossil (gas+lignite) plants become less competitive, leading to lower exports and higher imports, respectively.

  Also, with a higher CO_2 tax, lignite plants in the KOSTT, NOSBIH and EMS market areas become less competitive and these areas become net importers. At the same time, gas fired plants in the IPTO market area become competitive and this area becomes a net exporter. This leads to substantially different energy flows in the region, with reduced congestion and greater price equalization.

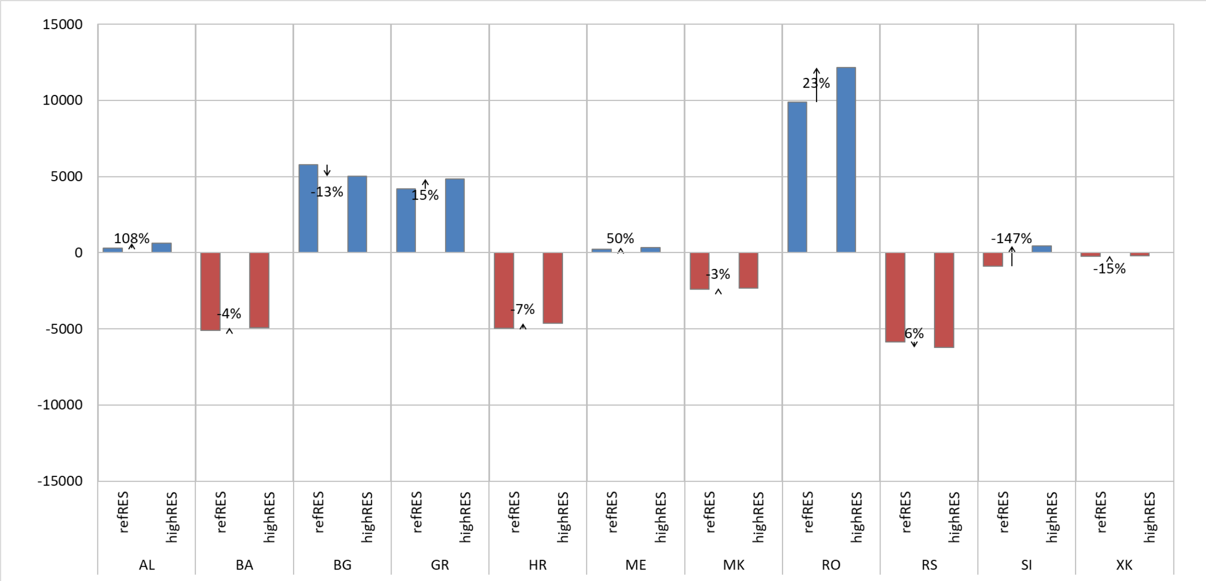


Figure 55: Balance positions per market areas in 2030 - ref. RES vs high RES, average hydrology – Alternative CO_2 emission tax

- **Average regional prices (Figure 52) are between 67.1 and 70.5 EUR/MWh with decrease due to high RES integration of around 2 EUR/MWh or 2.7% in both hydro conditions.** The same figure shows that prices in dry hydro conditions would be around 1.5 EUR/MWh, or 2.3% higher.

Figure 56: Prices in EMI region in 2030 - ref. RES, average hydrology – Alternative CO_2 emission tax

From Figure 56 we see that electricity prices are evenly distributed across the EMI region, without significant deviations from the average price on a regional level.

- The decrease of HPP generation in dry hydro conditions provokes higher TPP generation that partially compensates the reduced HPP generation, while the other part is compensated in lower regional exports. These changes lead to increased prices, but the change is rather small – 1.5 EUR/MWh at the regional level.

- Available energy in the whole EMI region in dry hydro conditions is smaller, and the regional merit order curve moves to the left. This enables higher generation from fossil plants in all market areas, and increases marginal prices. This move of the merit order curve has different impacts on the balance in different countries. In most market areas, the balance positions change in the same direction (net exports fall, or net imports rise), but in some (like ESO EAD, IPTO, EMS and KOSTT), where TPPs become more competitive, imports decrease (in EMS market area), exports increase (in ESO EAD and IPTO market areas) or there is a change from net importer to net exporter (KOSTT market area), as depicted in Figure 57.

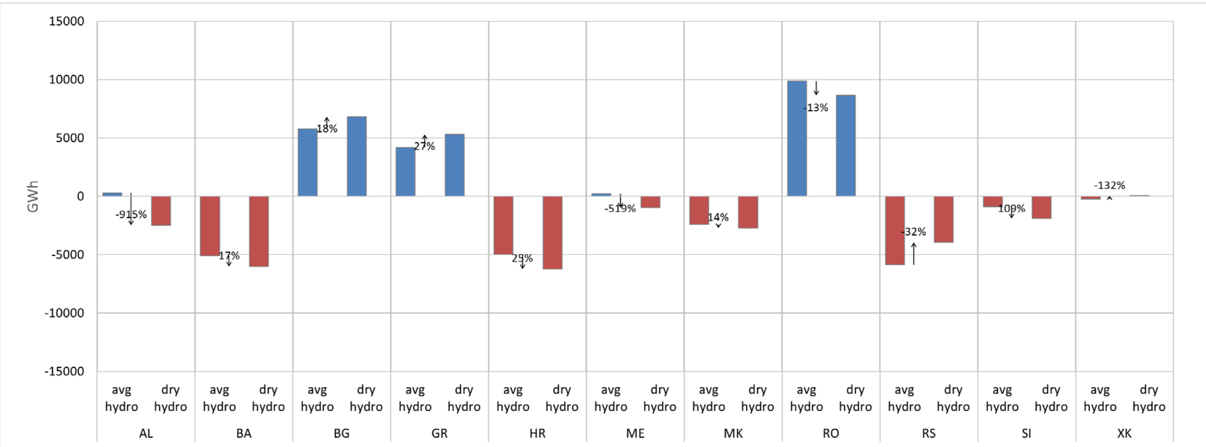
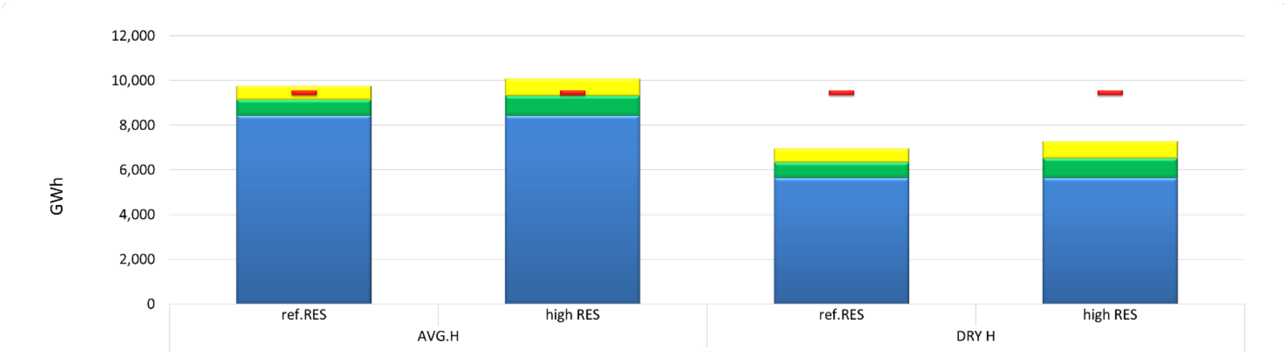


Figure 57: Balance positions per market areas in 2030 – average vs. dry hydrology , ref. RES – Alternative CO2 emission tax

In the following chapters, we present a detailed overview of the results in each market area.

5.2.1. OST market area

We present the generation mix and selected indicators, as the main results for the OST market area, in Figure 58 and Figure 59, respectively.



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	606	758	606	758
Wind	703	879	703	879
Hydro	8,439	8,440	5,640	5,640
Consumption	9,442	9,442	9,442	9,442

Figure 58: Generation mix in OST market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

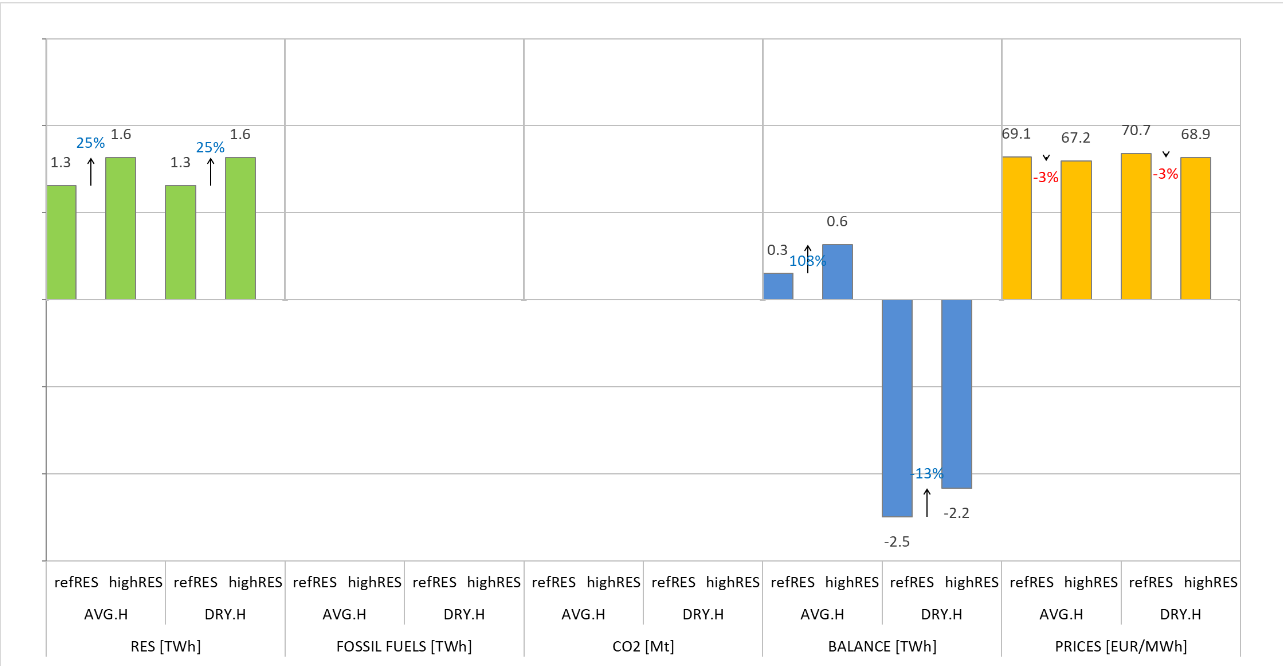


Figure 59: Main system operating indicators in OST market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix in Figure 58, along with the main system indicators in Figure 59, we draw the following conclusions about the operation of this market area in the high RES scenario, in comparison with referent RES, in dry and average hydro conditions:

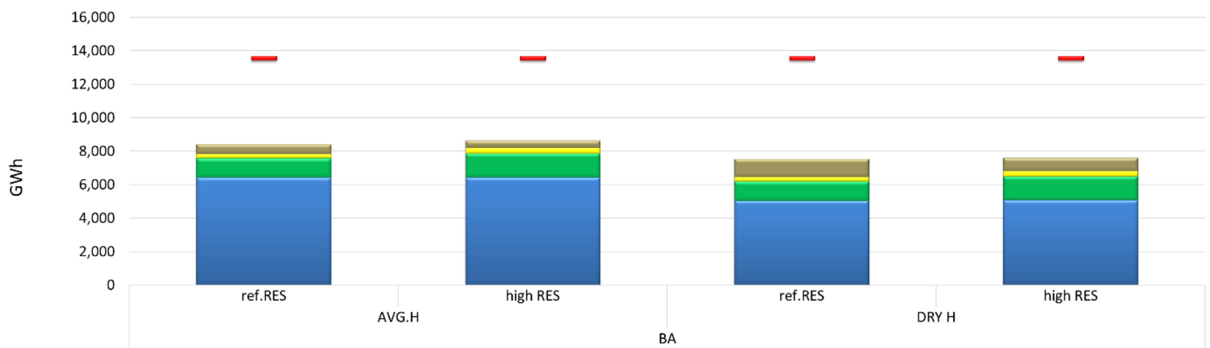
- RES generation rises from 1.3 TWh in the referent RES scenario, to 1.6 TWh in the high RES scenario, a rise of 25%. This increase is lower than the average in the EMI region (30%).
- RES generation supplies between 14% and 17% of the area demand.
- Since the OST market area has high hydro generation, its operation strongly depends on hydro conditions. In average hydro conditions, the OST market area is balanced (with small

net exports), but in dry hydro conditions, with hydro generation reduced by 2.8 TWh (33%), imports are high (2.5 TWh), reaching 26% of total area demand.

- The impact of RES integration on prices is the same as on the regional level (-2 EUR/MWh). The impact of hydro conditions on prices is on the same level, but in the opposite direction (an increase of around 2 EUR/MWh in dry hydro conditions).

5.2.2. NOSBIH market area

We present the generation mix and selected indicators as the main results for the NOSBIH market area in Figure 60 and Figure 61, respectively.



	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	575	430	1,055	752
Nuclear	0	0	0	0
Solar	271	339	271	339
Wind	1,144	1,431	1,144	1,431
Hydro	6,418	6,424	5,055	5,061
Consumption	13,529	13,537	13,530	13,539

Figure 60: Generation mix in NOSBIH market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

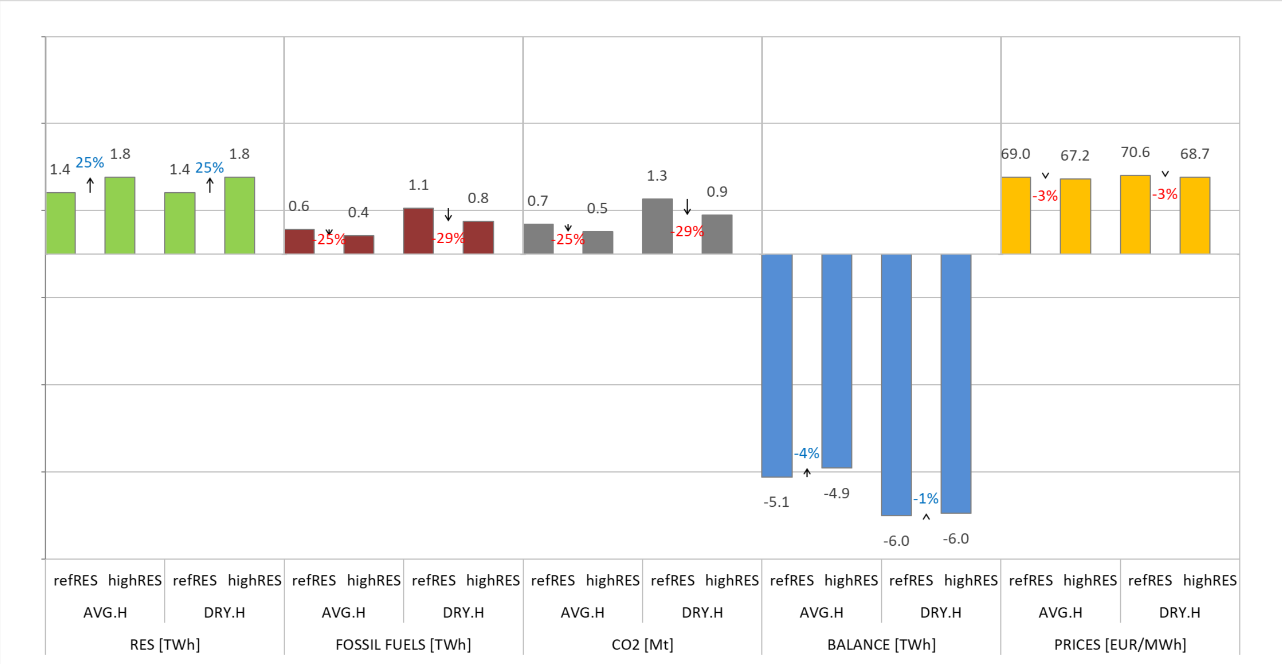


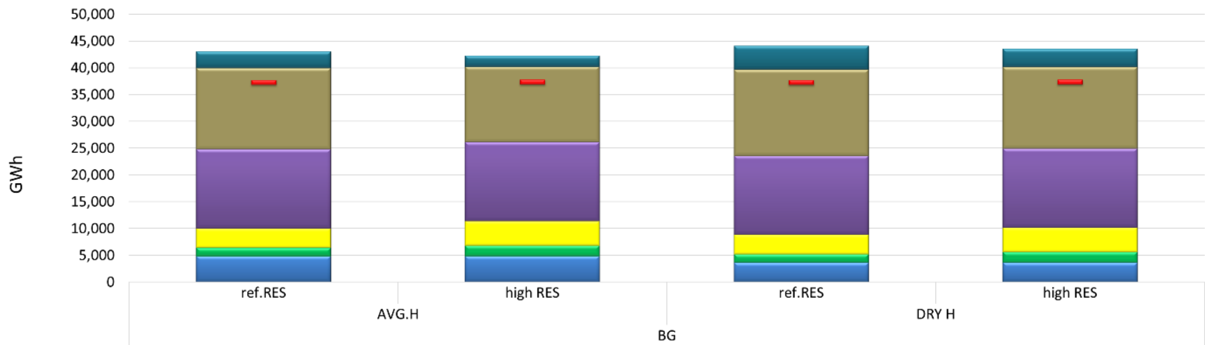
Figure 61: Main system operating indicators in NOSBIH market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

By jointly analyzing these results, we conclude the following:

- RES generation (wind+solar) rises from 1.4 TWh to 1.8 TWh (+25%), supplying 10%-13% of the area demand.
- Higher RES generation leads to a reduction of generation from lignite plants between 25% (-0.2 TWh) and 29% (-0.3 TWh) in average and dry hydro conditions, respectively. This decrease in TPP generation leads to a decrease of CO2 emissions by the same levels.
- With a small increase in RES generation (0.3 TWh) and a reduction in TPP generation (-0.2 to -0.3 TWh), the NOSBIH market area decreases net imports by 0.05-0.21 TWh, or 1% to 4%, depending on hydro conditions. The reason for this lies in the fact that, with higher RES generation in the NOSBIH market area and the whole EMI region makes the lignite plants from the NOSBIH area less competitive.
- On the other side, dry hydro conditions move the regional merit order curve to the left and prices rise, which provides a better position for lignite plants in the NOSBIH area. Hydro generation in dry hydro conditions falls by 1.4 TWh or 22% in comparison to average hydro, but net imports fall by only 0.05-0.21 TWh. This means that in dry hydro conditions for the whole EMI region, lignite plants in the NOSBIH market area become more competitive than in average hydro conditions.
- As a result, greater RES generation in both hydro conditions decrease prices by 3%. An increase in RES generation moves the merit order curve to the right, and cheaper power plants become marginal.
- Simulations shows that the engagement of PS HPP is very small, since existing hydro plants and strong regional connections provides enough flexibility for the given RES generation.

5.2.3. ESO EAD market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the ESO EAD market area in Figure 62 and Figure 63, respectively.



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	0	0	0	0
Gas	3,039	2,056	4,432	3,373
Coal	0	0	0	0
Lignite	15,189	14,115	16,055	15,249
Nuclear	14,693	14,693	14,693	14,693
Solar	3,678	4,598	3,678	4,598
Wind	1,570	1,962	1,570	1,962
Hydro	4,832	4,860	3,629	3,663
Consumption	37,223	37,260	37,227	37,273

Figure 62: Generation mix in ESO EAD market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

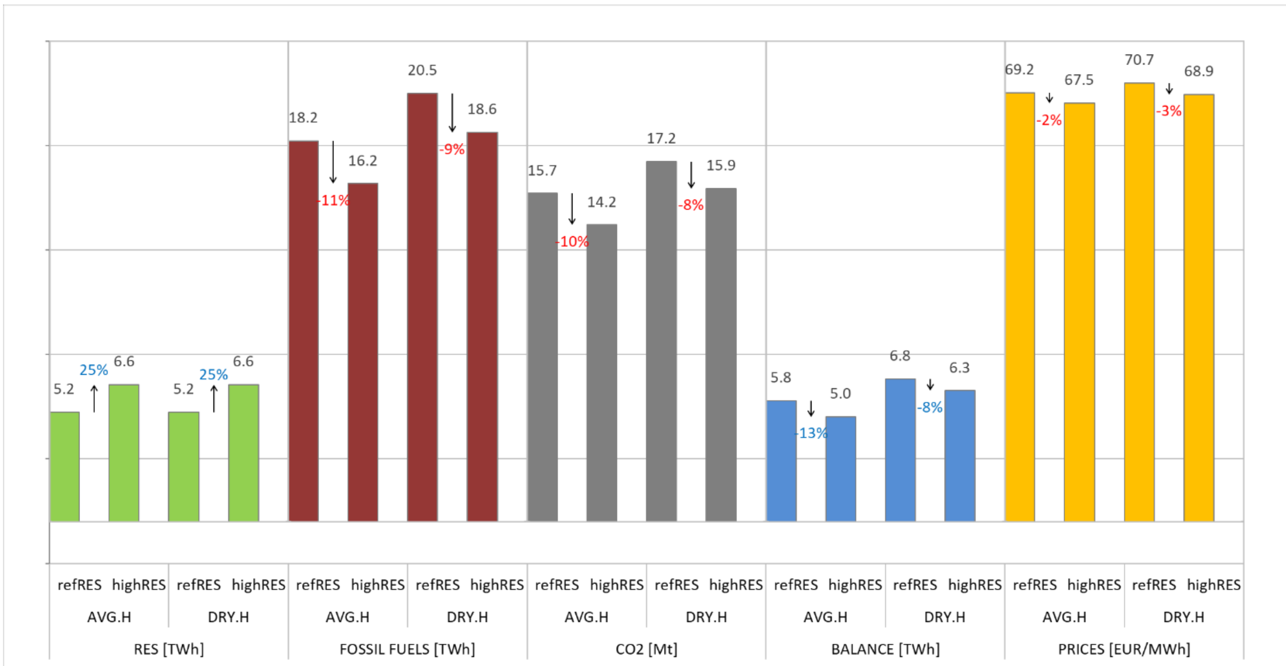


Figure 63: Main system operating indicators in ESO EAD market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 62, in conjunction with the main system indicators depicted in Figure 63, the following conclusions could be drawn about the operation of this market area in the high RES scenario, in comparison with ref. RES in dry and average hydro conditions:

- RES generation (wind+solar) rises from 5.2 TWh to 6.5 TWh (+25%) supplying 14% -18% of the areas demand.
- Higher RES generation leads to a TPPs generation (only fossil fuels fired plants) reduction for 9-11% (-1.9 TWh and -2.1 TWh), depending on hydro conditions. This decrease leads to a decrease of CO2 emissions by 8-10%.
- At the same time, higher RES generation decreases the export of the ESO EAD market area from 5.8 TWh to 5.0 TWh (-13%) in average hydro conditions. Export is also decreased in dry hydro conditions, for slightly less amount -0.56 TWh (8%). It should be noted that dry hydro conditions lead to the increase of generation from fossil fueled plants in order to compensate reduced generation from hydro power and to participate in increased export from market area.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 2-3%.
- Higher RES capacities increase the need for flexibility and increases the utilization of PS HPPs, as it can be seen in *Table 27*.

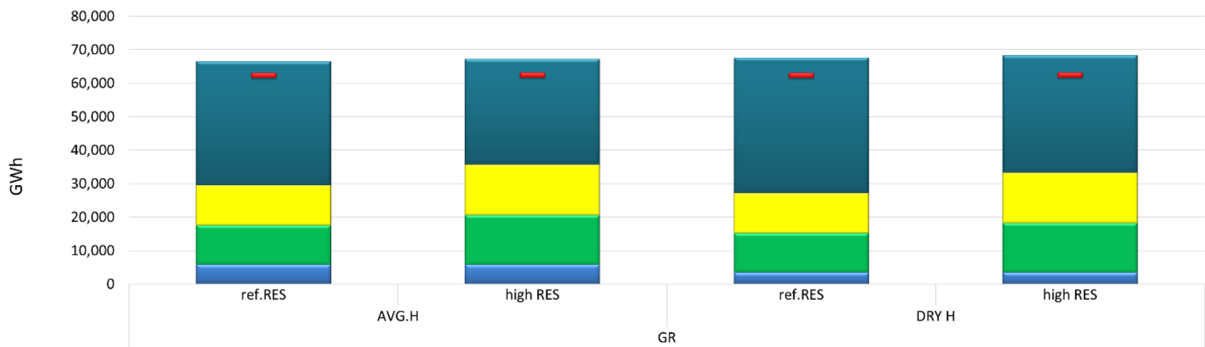
Table 27: PS HPPs generation in ESO EAD market area – Alternative CO_2 emission tax

Generation from PS HPPs (GWh)	Average hydro conditions	Dry hydro conditions
Ref. RES	2.7	5.3
High RES	31.6	39.8
Difference	**27.9**	**34.5**

In general, engagement of PSHPPs is very low (<50 GWh) due to the fact that existing HPPs and strong regional interconnections provide enough flexibility. However, generation from PS HPPs in the high RES scenario significantly larger in comparison with referent RES scenario. This is mainly because greater non-costly RES generation gives a higher possibility for pumping in hours with low prices and storing energy for utilization in hours with higher prices. Smaller HPPs generation (in dry hydro conditions) increases the engagement of this kind of power plants.

5.2.4. IPTO market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the IPTO market area, in Figure 64 and Figure 65, respectively.



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	0	0	0	0
Gas	36,838	31,528	40,324	34,970
Coal	0	0	0	0
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	12,093	15,076	12,093	15,076
Wind	11,742	14,761	11,742	14,761
Hydro	5,775	5,852	3,412	3,491
Consumption	62,260	62,369	62,260	62,372

Figure 64: Generation mix in IPTO market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

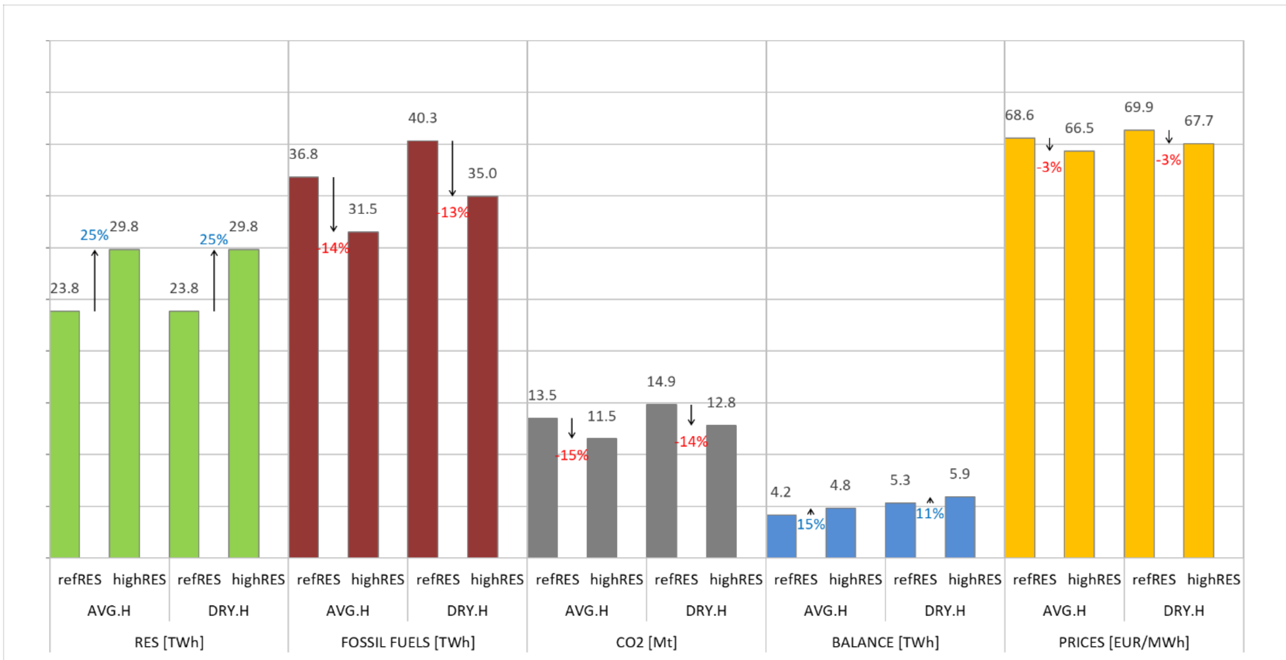


Figure 65: Main system operating indicators in IPTO market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix and the main system indicators presented in the above figures the following conclusions could be drawn:

- Beside the Transelectrica market area, the IPTO market area is the biggest in EMI region. Due to this fact, changes that are by higher RES integration reflected in this area operation have significant impact on the changes at the regional level.
- RES generation (wind+solar) rises from 23.8 TWh to 29.8 TWh (+25%). This increase in absolute values (6 TWh) is the highest in the region.
- This level of RES generation supplies between 38 and 48% of the area demand, which is the highest RES participation in the EMI region.

- Higher RES generation leads to TPPs generation reduction for about 14% (-5.3 TWh and -5.4 TWh) in both hydro conditions. Decrease is noted only in gas fired units and this leads to a decrease of CO_2 emissions for approx. the same percentages.
- Increase in RES generation leads to a TPPs generation decrease. However, RES generation increase is larger than decrease of TPPs generation which imposes larger net export of IPTO market area for around 0.6 TWh (11-15%, depending on hydro conditions).
- Participation of HPPs in supplying the demand in the IPTO market area is rather low (<10%) and, although in dry hydro conditions HPPs generation is decreased for around 40%, the impact of this is limited. Available energy in the whole EMI region in dry hydro conditions is smaller, and regional merit order curve is moved to the left, so that gas-fired units in the IPTO market area become more competitive. This increases the gas fired plants generation in dry hydro conditions, increases the prices but also increases the net export.
- Greater RES generation in both hydro conditions leads to a decrease in prices by 3%. Impact of hydro conditions is smaller and in the opposite direction – prices increase for around 1 EUR/MWh in dry hydro conditions.
- Similar as in other market areas, engagement of PS HPPs is not so big (*Table 28*).

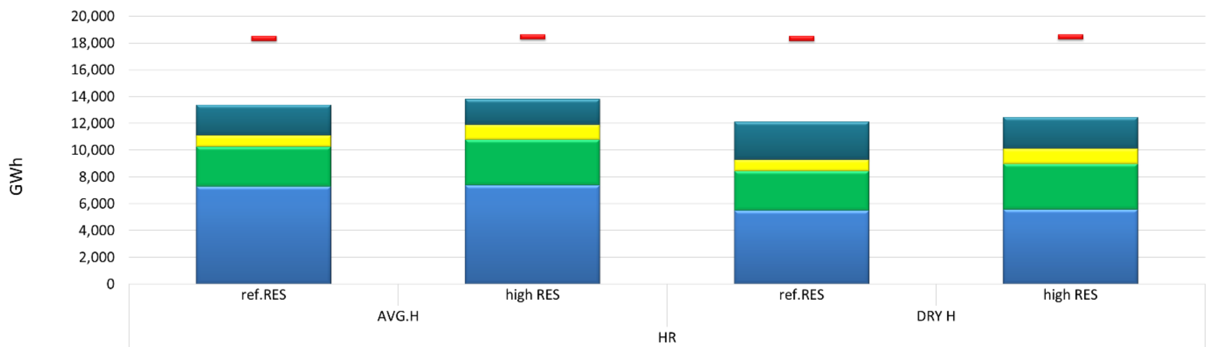
Table 28: PS HPPs generation in IPTO market area – Alternative CO_2 emission tax

Generation from PS HPPs (GWh)	Average hydro conditions	Dry hydro conditions
Ref. RES	7.1	7.2
High RES	83.7	85.4
Difference	**76.6**	**78.2**

Generation from PS HPPs in the high RES scenario is several times higher in comparison with referent RES scenario, although it is still modest engagement. No impact of hydro conditions points again to small impact of hydro generation in IPTO market area.

5.2.5. HOPS market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the HOPS market area, in Figure 66 and Figure 67, respectively.



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	0	0	0	0
Gas	2,271	1,891	2,804	2,348
Coal	2	2	3	3
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	840	1,120	840	1,120
Wind	2,960	3,415	2,960	3,415
Hydro	7,300	7,376	5,501	5,577
Consumption	18,334	18,434	18,332	18,433

Figure 66: Generation mix in HOPS market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

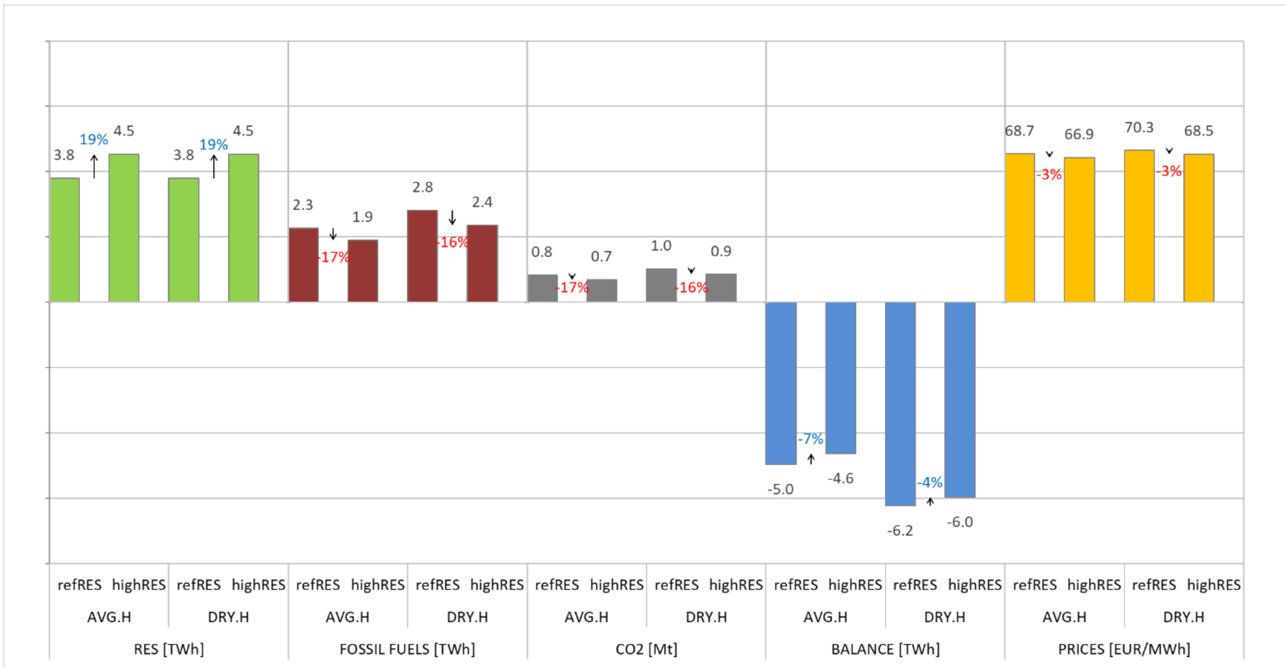


Figure 67: Main system operating indicators in HOPS market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 66, in conjunction with the main system indicators depicted in Figure 67, the following conclusions could be drawn about the operation of this market area in the high RES scenario, in comparison with ref. RES in dry and average hydro conditions:

- RES generation (wind+solar) rises from 3.8 TWh to 4.5 TWh (+19%), which is the lowest increase in percentages in the region. This level of RES generation supplies between 21% and 24% of area demand, which is close to regional average.

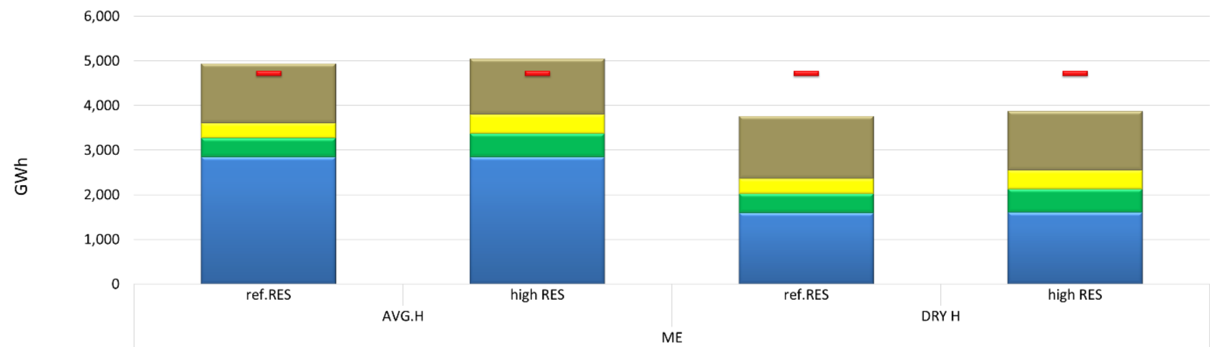
- In HOPS market area total demand in 2030 in average hydro conditions is mainly supplied by hydro and RES generation (60-64% depending on the level of RES integration). Generation from fossil fuel fired plants is on the level of 2.3 TWh and 1.9 TWh in the case of ref RES and high RES integration, respectively. Dry hydro conditions impose a increase in TPPs generation to a level of 2.8 TWh and 2.4 TWh in the case of ref RES and high RES integration, respectively. In both hydro conditions higher level of RES integration lead to a decrease of TPPs generation by 17%. In correlation to that, emissions of CO_2 have the same trend regarding hydro conditions and level of RES integration.
- Net import in the HOPS market area is between 4.6 and 5.0 TWh (25% and 27% of the area demand) in average hydro conditions and increases with decrease in generation from HPPs in dry hydro condition, reaching 33% of total demand.
- Higher RES integration decreases the net import in all hydro conditions for 4%-7%.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 3%.
- In comparison to other market areas, engagement of PS HPPs in the HOPS market is the highest in the region (Table 29).

Table 29: PS HPPs generation in HOPS market area – Alternative CO_2 emission tax

Generation from PS HPPs (GWh)	Average hydro conditions	Dry hydro conditions
Ref. RES	110.3	108.7
High RES	185.2	184.5
Difference	**74.9**	**75.8**

5.2.6. CGES market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the CGES market area, in Figure 68 in and Figure 69, respectively.



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	1,329	1,251	1,395	1,315
Nuclear	0	0	0	0
Solar	341	426	341	426
Wind	423	529	423	529
Hydro	2,844	2,844	1,600	1,600
Consumption	4,710	4,710	4,710	4,710

Figure 68: Generation mix in CGES market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

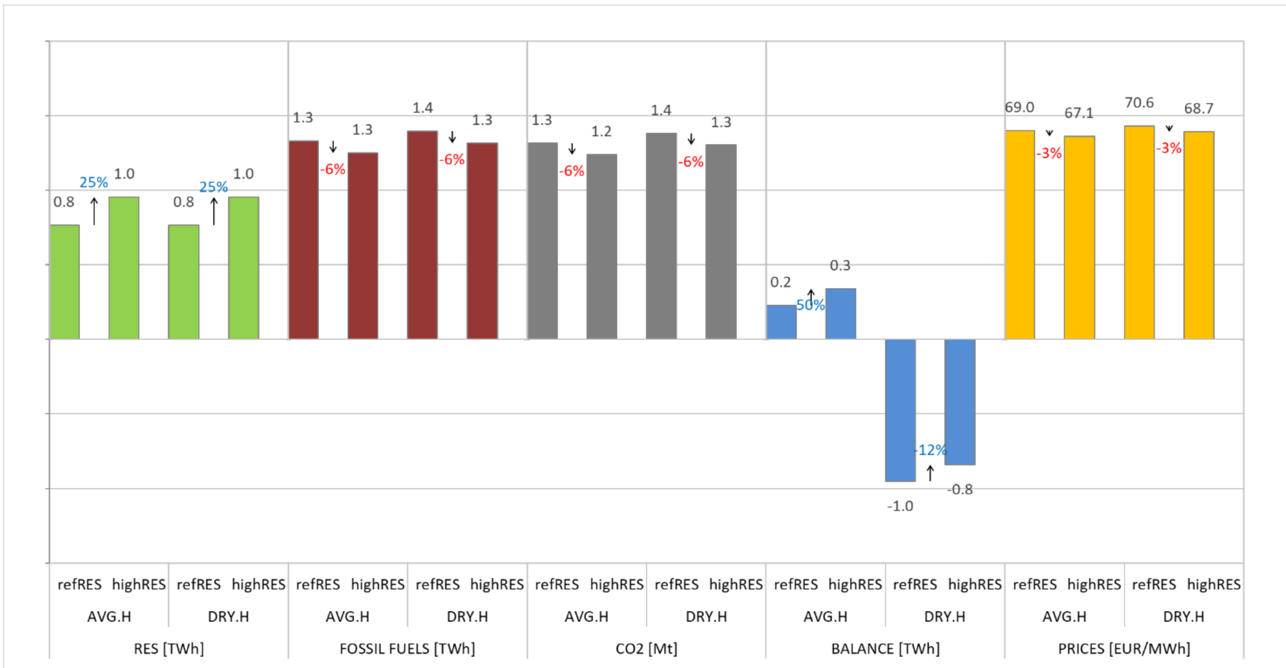


Figure 69: Main system operating indicators in CGES market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

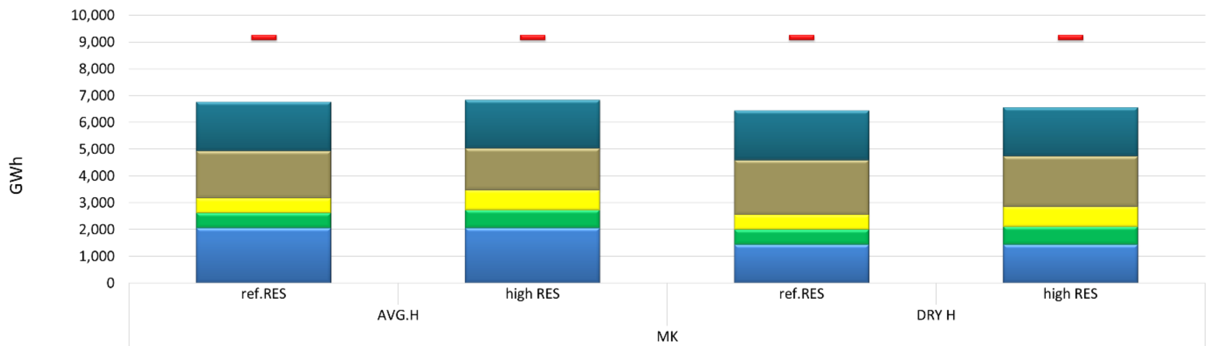
Considering the generation mix and main system indicators presented in the figures above the following conclusions could be drawn:

- the CGES market area is the smallest, almost balanced market area in the EMI region.
- RES generation (wind+solar) rises from 0.8 TWh to 1 TWh (+25%) and this level of RES generation supplies between 16% and 20% of area demand.
- Small changes in RES generation leads to small changes in TPPs generation – 0.1 TWh in both hydro conditions and small changes in CO_2 emissions.

- With higher RES generation, the CGES market area increases its net export or decreases its net import, depending on the hydro conditions.
- In dry hydro conditions, generation from HPPs is decreased by 1.2 TWh (44%) and balance position is changed at the same level, moving from net export of 0.2 TWh to net import of 1 TWh, without significant changes in TPPs generation.

5.2.7. MEPSO market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the MEPSO market area, in Figure 70 and Figure 71, respectively.



	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
Other	0	0	0	0
Gas	1,841	1,810	1,841	1,817
Coal	0	0	0	0
Lignite	1,755	1,543	2,046	1,877
Nuclear	0	0	0	0
Solar	549	749	549	749
Wind	560	670	560	670
Hydro	2,058	2,058	1,440	1,440
Consumption	9,170	9,170	9,170	9,170

Figure 70: Generation mix in MEPSO market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

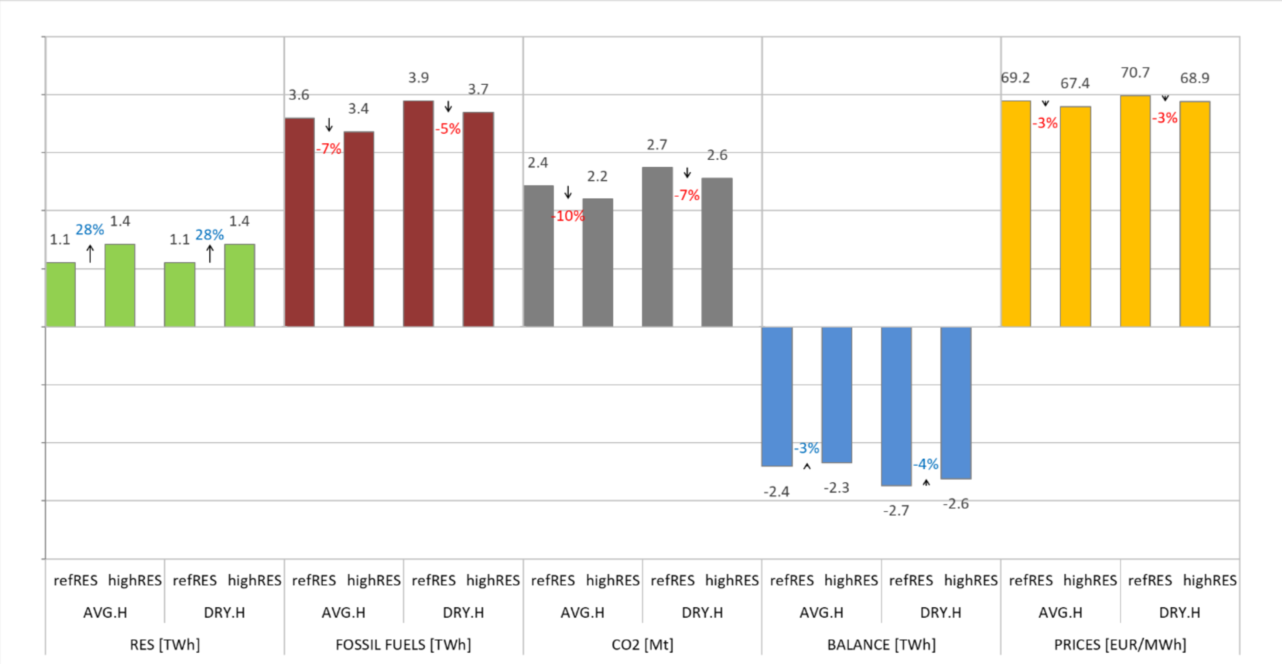


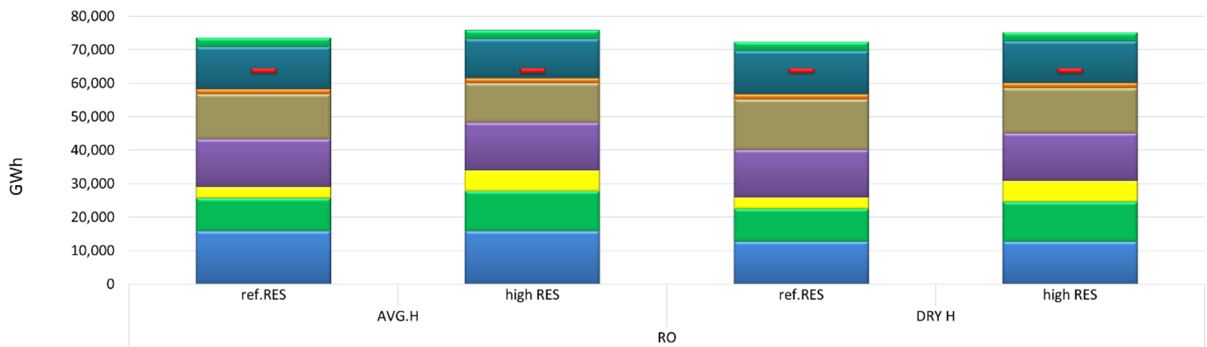
Figure 71: Main system operating indicators in MEPSO market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 70, in conjunction with the main system indicators depicted in Figure 71, the following conclusions could be drawn about the operation of this market area in the high RES scenario, in comparison with ref. RES in dry and average hydro conditions:

- RES generation (wind+solar) rises from 1.1 TWh to 1.4 TWh (+28%) supplying between 12% and 15% of area demand (below than the regional average).
- Higher RES generation leads to TPPs generation reduction by 0.24 TWh (-7%) in average hydro conditions and 0.19 TWh (-5%) in dry hydro conditions. It can be noted that higher level of RES generation provokes decrease of import (-0.1 TWh), in both hydro conditions.
- Decrease in fossil fuel fired plants generation decreases the CO_2 emissions by 10% and 7 % in average and dry hydro conditions, respectively.
- Net import slightly decrease with higher RES generation, but in all scenarios the MEPSO market area is a net importer.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 3%.
- In dry hydro conditions, hydro generation falls by 30% (0.6 TWh) which is compensated by increase in TPPs generation (0.3 TWh) and increase in import (0.3 TWh). Thermal fleet in MEPSO market area becomes more competitive in dry hydro conditions which leads to higher TPPs generation and higher prices (+1.5 EUR/MWh) in comparison with average hydrology.

5.2.8. Transelectrica market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the Transelectrica market area, in Figure 72 and Figure 73, respectively.



	ref.RES AVG.H	high RES AVG.H	ref.RES DRY H	high RES DRY H
Other	2,662	2,631	2,665	2,639
Gas	12,692	11,703	12,942	12,407
Coal	1,508	1,508	1,508	1,508
Lignite	13,459	11,796	15,144	13,578
Nuclear	14,245	14,245	14,245	14,245
Solar	3,360	6,216	3,360	6,216
Wind	9,787	11,885	9,787	11,885
Hydro	15,889	15,889	12,710	12,710
Consumption	63,717	63,717	63,717	63,717

Figure 72: Generation mix in Transelectrica market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

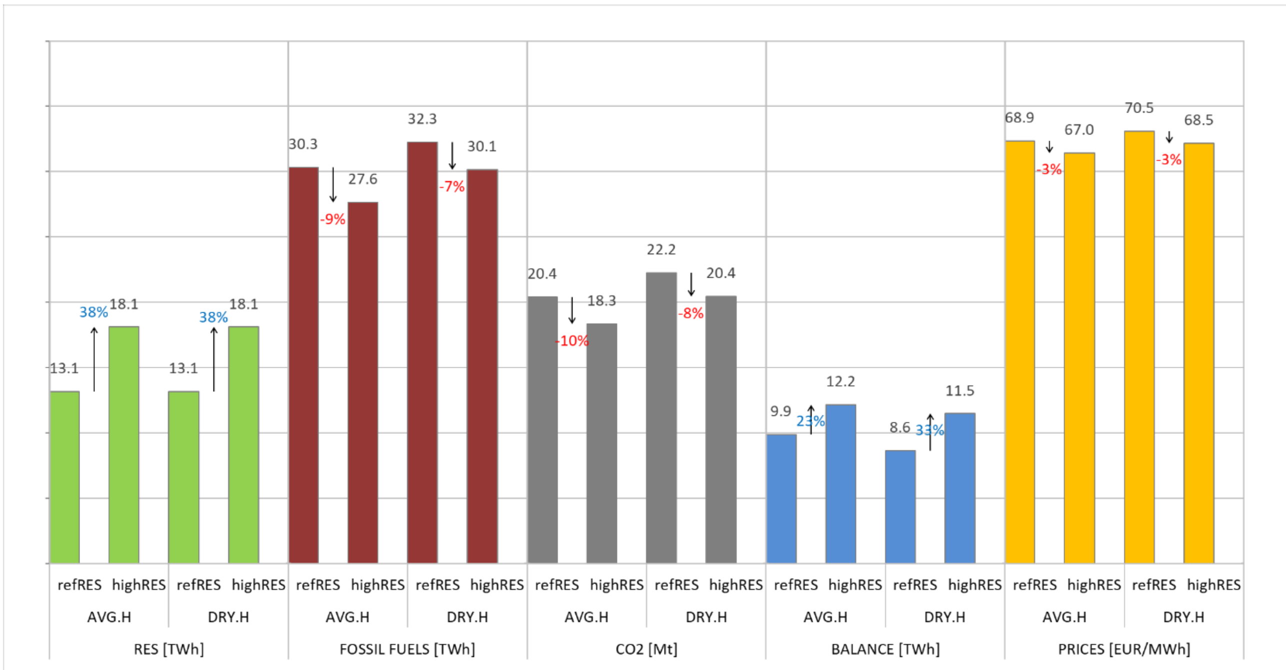


Figure 73: Main system operating indicators in Transelectrica market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

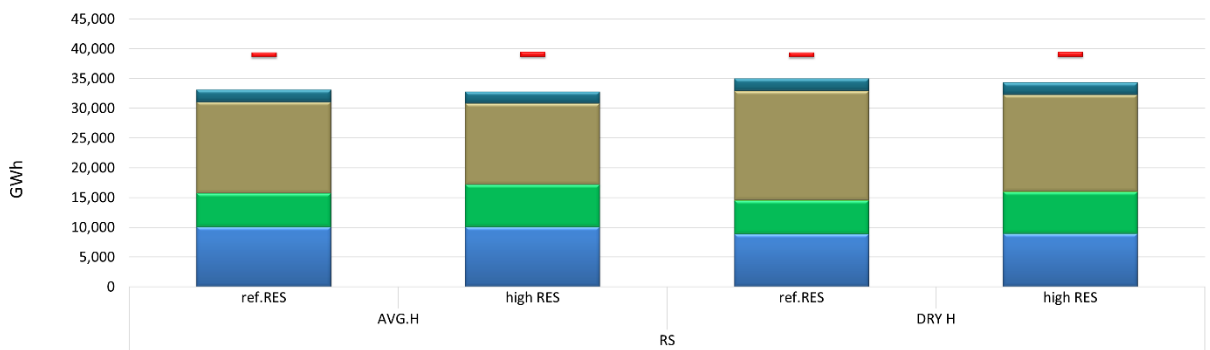
By jointly analyzing these results, the following can be concluded:

- RES generation is increased from 13 TWh in ref.RES scenario to 18 TWh in high RES scenario which is the increase of 38%. This increase puts the Transelectrica market area in the group of zones with the highest RES increase (ELES, KOSTT and Transelectrica with 270%, 53% and 38%, respectively).

- RES participation in supplying the area demand in the Transelectrica market area is at the regional average, between 21% and 28%.
- At the same time, generation of fossil fuels fired TPPs fall from 30.3 TWh to 27.6 TWh (-9%) as well as from 32.3 TWh to 30.1 TWh (-7%) for average and dry hydrology respectively. This leads to a decrease in CO2 emissions by 10% and 8%.
- In dry hydro conditions, TPPs generation is increased to compensate reduction in HPPs generation. In dry hydro conditions in the whole EMI region, regional merit order curve is moved to the left providing space for generation of more expensive units and TPPs in the Transelectrica market area become more competitive. This is also the reason for relatively smaller decrease in TPPs generation with additional RES generation expected in high RES scenario (-10%).
- With higher RES generation, the net export of the Transelectrica market area rises by 2.3 TWh (23%) in average hydro conditions. In dry hydro conditions, this increase is even higher and export increases by 2.8 TWh or 33%.
- Greater RES generation in both hydro conditions leads to a decrease in prices for 3%. With increased RES generation cheaper power plants become marginal and prices decrease.
- In dry hydro conditions, hydro generation falls by 20% (3.2 TWh) which is compensated by increase in TPPs generation (2 TWh) and decrease in export (1.2 TWh). At the same time, prices in dry hydro conditions are higher by 1.6 EUR/MWh

5.2.9. EMS market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the EMS market area in Figure 74 and Figure 75, respectively.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
Other	0	0	0	0
Gas	2,041	2,011	2,077	2,031
Coal	0	0	0	0
Lignite	15,318	13,584	18,372	16,273
Nuclear	0	0	0	0
Solar	41	51	41	51
Wind	5,639	7,048	5,639	7,048
Hydro	10,054	10,090	8,866	8,901
Consumption	38,958	39,006	38,961	39,008

Figure 74: Generation mix in EMS market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

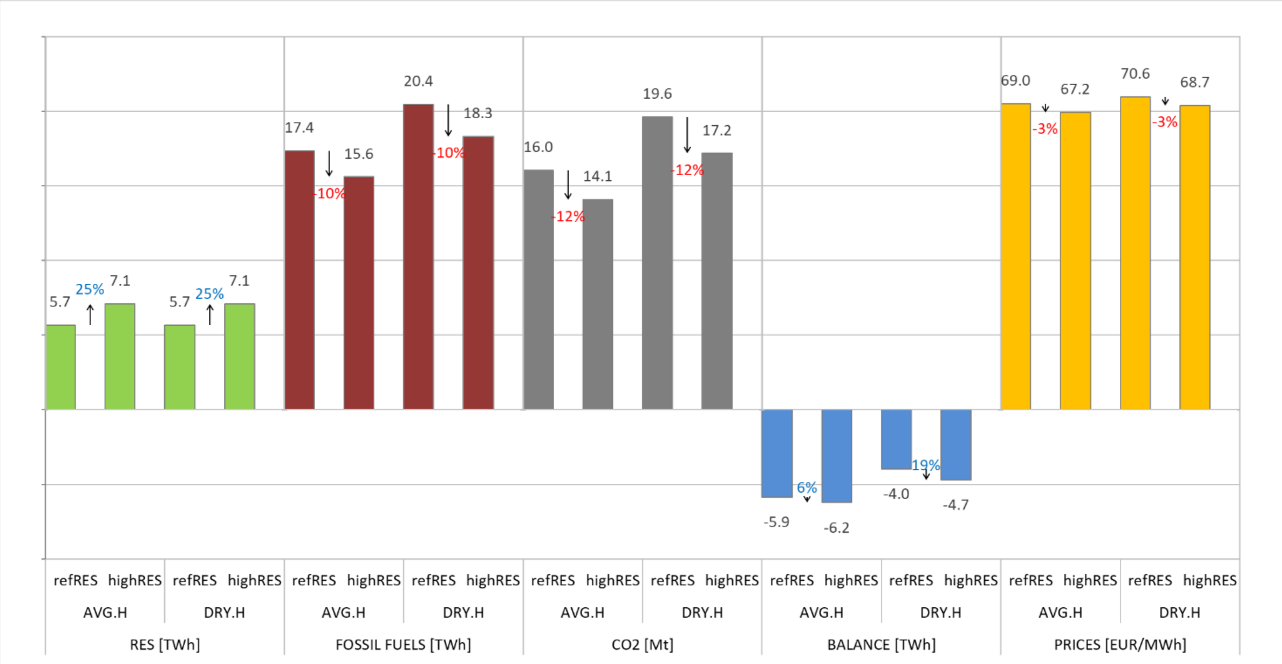


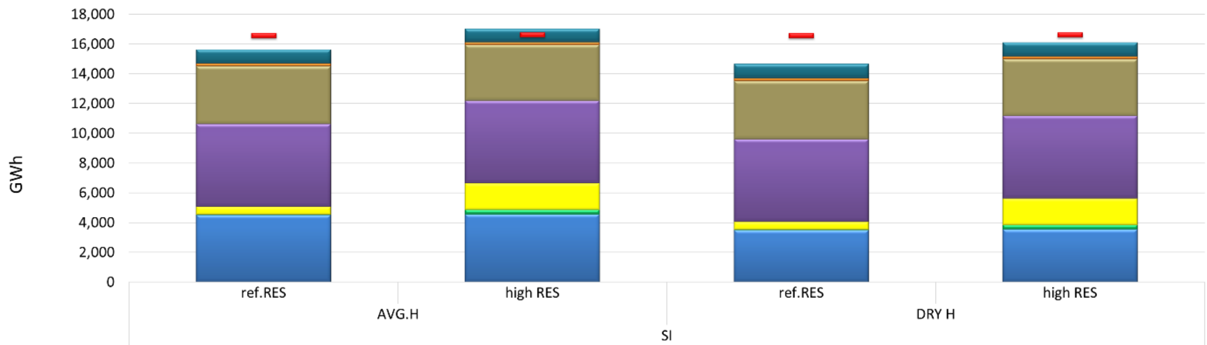
Figure 75: Main system operating indicators in EMS market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix in Figure 74, in conjunction with the main system indicators in Figure 75, we draw the following conclusions about the operation of this market area in the high RES scenario, in comparison with referent RES under dry and average hydro conditions:

- RES generation (wind+solar) rises from 5.7 TWh to 7.1 TWh (+25%) supplying between 15% and 18% of the area demand. This participation is lower than the regional average (21%-27%).
- Increased installed capacities in renewable energy sources, as well as corresponding generation of electricity leads to the reduction in TPPs generation, almost completely realized as decrease in lignite fired plants generation (-10%). With this decrease in TPPs generation, CO2 emissions decreases for 12%.
- At the same time, increased generation from RES implicates an increase in the import of the EMS market area by 0.3 TWh (6%) and 0.7 TWh (19%) in the case of average and dry hydro conditions, respectively.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 3%, due to shifting of regional merit order curve to the right and pushing out of the most expensive units.
- Simulations shows that engagement of PS HPP is very small, since existing hydropower plants and strong regional connections provide enough flexibility for the given level of RES generation.

5.2.10. ELES market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the ELES market area in Figure 76 and Figure 77, respectively.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
Other	0	0	0	0
Gas	940	891	960	931
Coal	175	175	175	175
Lignite	3,886	3,753	3,908	3,814
Nuclear	5,558	5,558	5,558	5,558
Solar	531	1,780	531	1,780
Wind	20	301	20	301
Hydro	4,516	4,556	3,497	3,539
Consumption	16,534	16,587	16,542	16,598

Figure 76: Generation mix in ELES market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

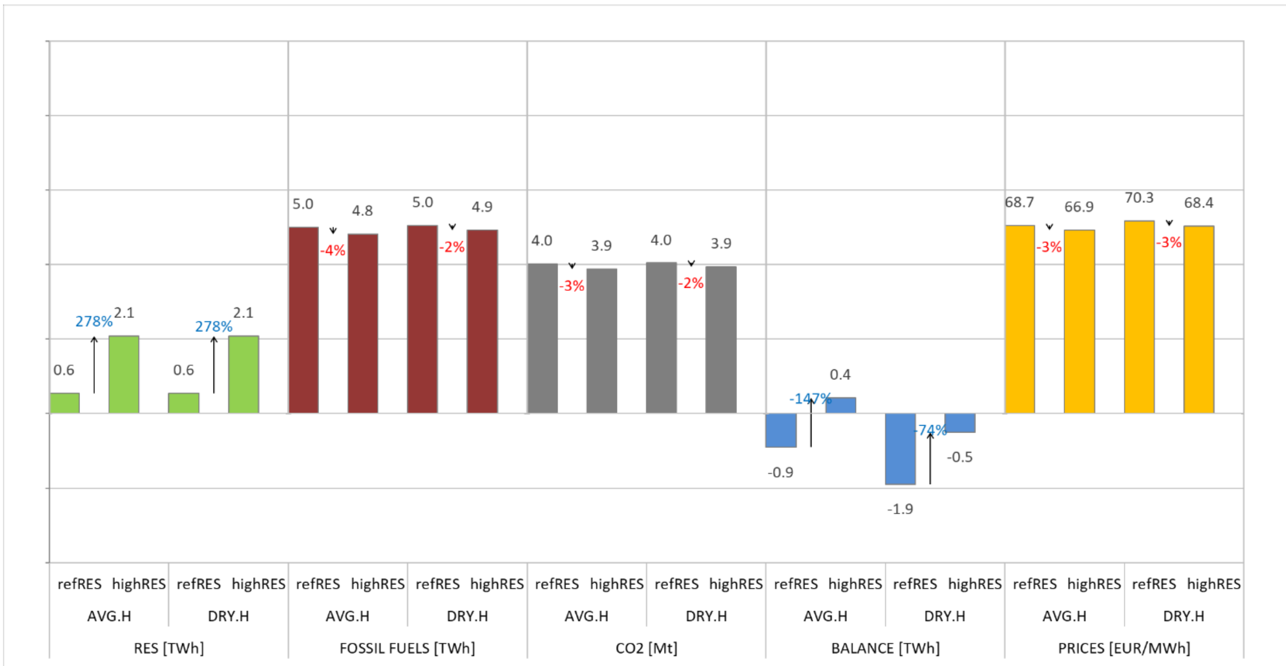


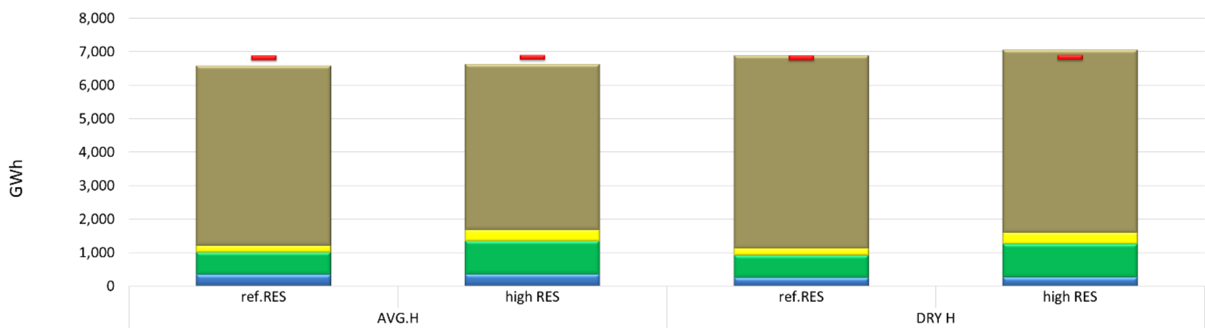
Figure 77: Main system operating indicators in in ELES market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix and main system indicators presented in the figures above the following conclusions could be drawn:

- RES generation (wind+solar) rises from 0.6 TWh to 2.1 TWh (+278%). It should be emphasized that this is the largest relative increase of RES in the whole SEE region. RES in the ELES market area supplies between 3% and 12% of the area demand which is far from the regional average (21%-27%).
- Generation from fossil fuels fired plants remain stable between referent and high RES scenarios and only the reduction of 0.2 TWh (4%) is expected in case of high RES scenario, while the remaining part of increased RES generation (1.5 TWh) reduces the import and converts this market area from typical electricity importer to net exporter in case of average hydrology. Similar decrease in import happens also in dry hydro conditions, but with reduced HPPs generation, the ELES market area remains as net importer in both scenarios: referent and high RES.
- Higher RES generation leads to decrease of CO2 emissions by 3% and 2% for average and dry hydro conditions, respectively.
- As a result, greater RES generation in both hydro conditions leads to a decrease in prices by 3%. Namely, with increase in RES generation cheaper power plants become marginal.
- Simulations shows that engagement of PS HPP is very small, since existing hydropower plants and strong regional connections provide enough flexibility for the given level of RES generation.

5.2.11. KOSTT market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the KOSTT market area in Figure 78 and Figure 79, respectively.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	5,366	4,945	5,760	5,454
Nuclear	0	0	0	0
Solar	205	341	205	341
Wind	666	990	666	990
Hydro	343	354	257	269
Consumption	6,812	6,828	6,813	6,829

Figure 78: Generation mix in KOSTT market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

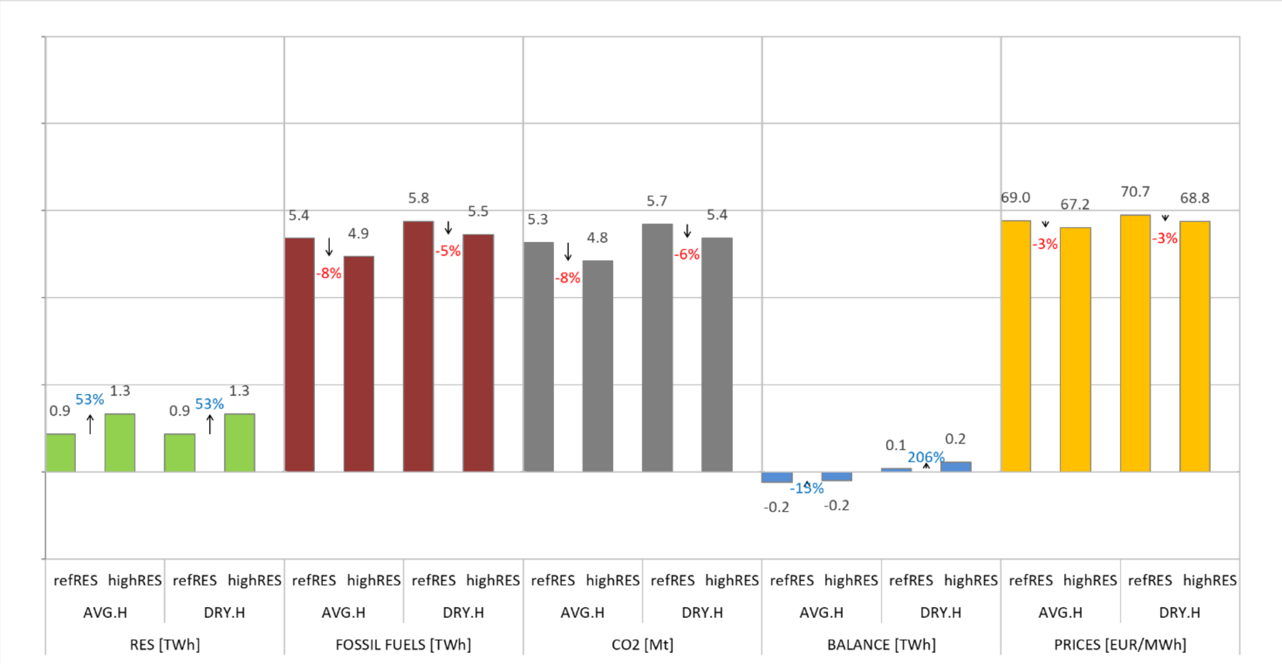


Figure 79: Main system operating indicators in KOSTT market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 78, in conjunction with the main system indicators depicted in Figure 79, the following conclusions could be drawn about the operation of this market zone in the high RES scenario, in comparison with ref. RES in dry and average hydro conditions:

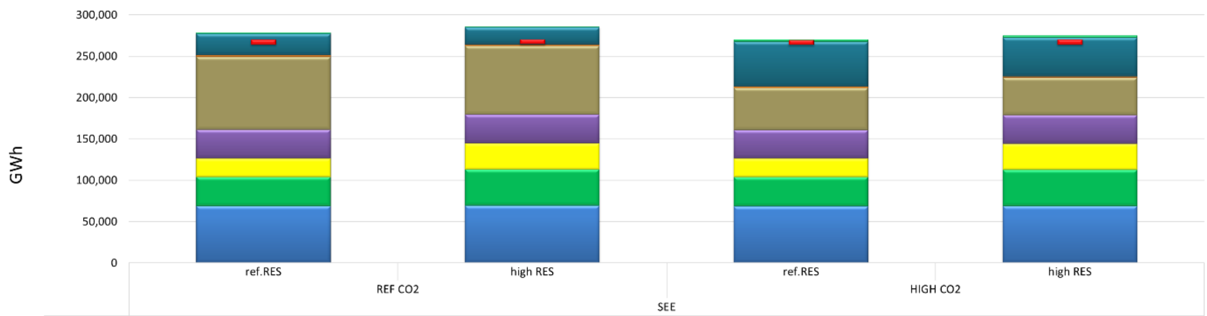
- RES generation (wind+solar) rises from 0.9 TWh to 1.3 TWh (+53%) supplying between 13% and 20% of area demand.
- Higher RES generation leads to fossil fuels fired TPPs generation reduction of about 0.3-0.5 TWh (5-8%), depending on hydro conditions, and decrease in CO_2 emissions is proportional.
- the KOSTT market area is almost balanced in this group of scenarios. In the case of the average hydro conditions this market area imports about 0.2 TWh and 0.23 TWh in increased and referent level of RES generation, respectively. In dry hydro conditions TPPs are competitive enough to compensate reduction from hydro generation and to convert the KOSTT market area to net exporter with export for about 0.1 TWh and 0.2 TWh, depending on level of RES integration.
- As a result, greater RES generation for both hydro conditions leads to a decrease in prices by 3%. This is consequence of merit order curve shifting to the right, caused by zero price renewable sources, thus cheaper power plants become marginal.
- Simulations shows that engagement of PS HPP is very small, since existing hydropower plants and strong regional connections provide enough flexibility for the given level of RES generation.

5.3. Group 3: Low demand growth, referent and high CO_2 scenarios

Finally, in the third group of scenarios, low demand development and average hydro conditions have been set and kept constant in the following four analyzed scenarios:

1. Referent CO_2 emission tax and referent level of RES integration
2. Referent CO_2 emission tax and high level of RES integration
3. Alternative (higher) CO_2 emission tax and referent level of RES integration
4. Alternative (higher) CO_2 emission tax and high level of RES integration

This group of scenarios combines to some extent conditions from the previous two groups of scenarios. In these scenarios, we focus on the impact of different levels of CO_2 emission tax, together with both levels of RES integration. We present the generation mix for the whole EMI region in Figure 80, and provide the main indicators in Figure 81.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	1,019	702	2,655	2,609
Gas	26,261	20,670	54,246	46,654
Coal	1,687	1,686	1,684	1,683
Lignite	88,261	83,410	50,774	45,267
Nuclear	34,497	34,495	34,497	34,497
Solar	22,513	31,455	22,513	31,455
Wind	35,213	43,872	35,213	43,872
Hydro	68,784	69,310	68,496	68,832
Consumption	266,503	267,220	266,113	266,567

Figure 80: Generation mix in EMI region in 2030 - ref. RES vs high RES, ref. and high CO_2 emission tax

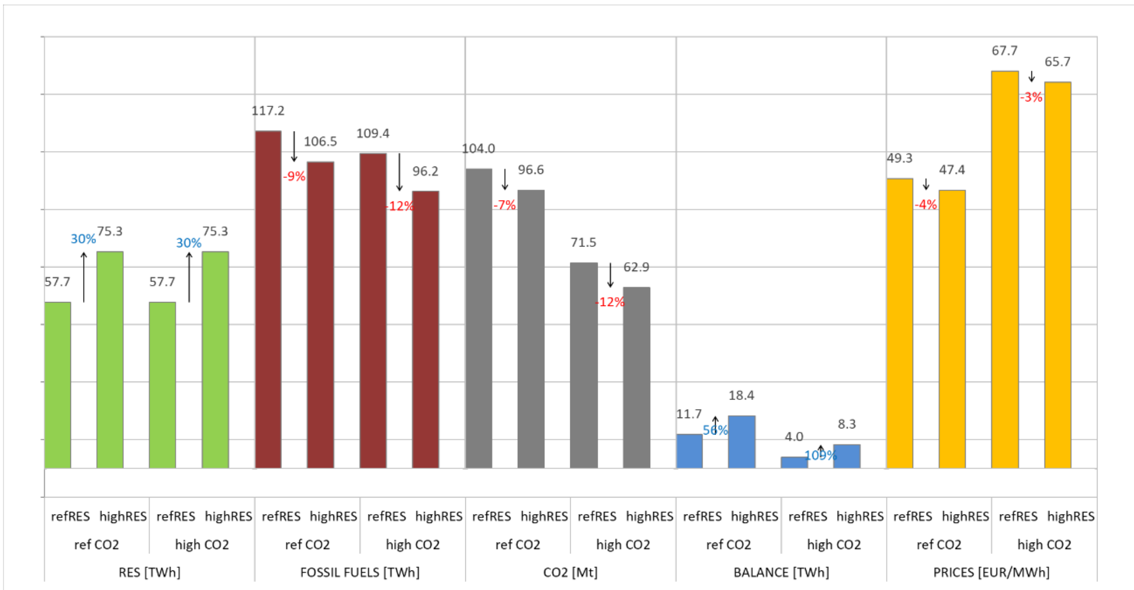


Figure 81: Main system operating indicators in EMI region in 2030 - ref. RES vs high RES, ref. and high CO_2 emission tax

These figures lead to the following conclusions:

- **In the case of slower demand growth, the main technology in 2030 with the ref. CO_2 emission tax is lignite, and it supplies about 33% of the load, followed by HPPs at 26%.** RES participates with 22-28%, while gas TPPs supply 8-10% of the load, depending on the level of RES integration.
- **In the case of high CO_2 emission tax scenarios, hydro generation is the dominant source of power supply (26%), followed by wind and solar (22%-28%, depending on the level of RES integration).** The share of lignite falls to 17-19%, while the share of gas TPPs rises to 18-20% of the load, also based on the RES integration level.

  This change in the main technology that supplies the load in the EMI region in 2030 is fully in line with changes previously described for the referent load cases.
- Hydro and RES technologies, the "green" technologies, become the main technologies in EMI region in 2030, supplying 47% to 54% of total demand.
- As with the previous scenarios, RES generation increases from 57.7 TWh (in ref. RES scenario) to 75.3 TWh in the high RES scenario, an increase of 30% (Figure 81). Increase for each market area (Figure 82) is between 0.2 and 6 TWh (in the CGES and IPTO market areas), and between 19% and 278% (in the HOPS and ELES market areas).

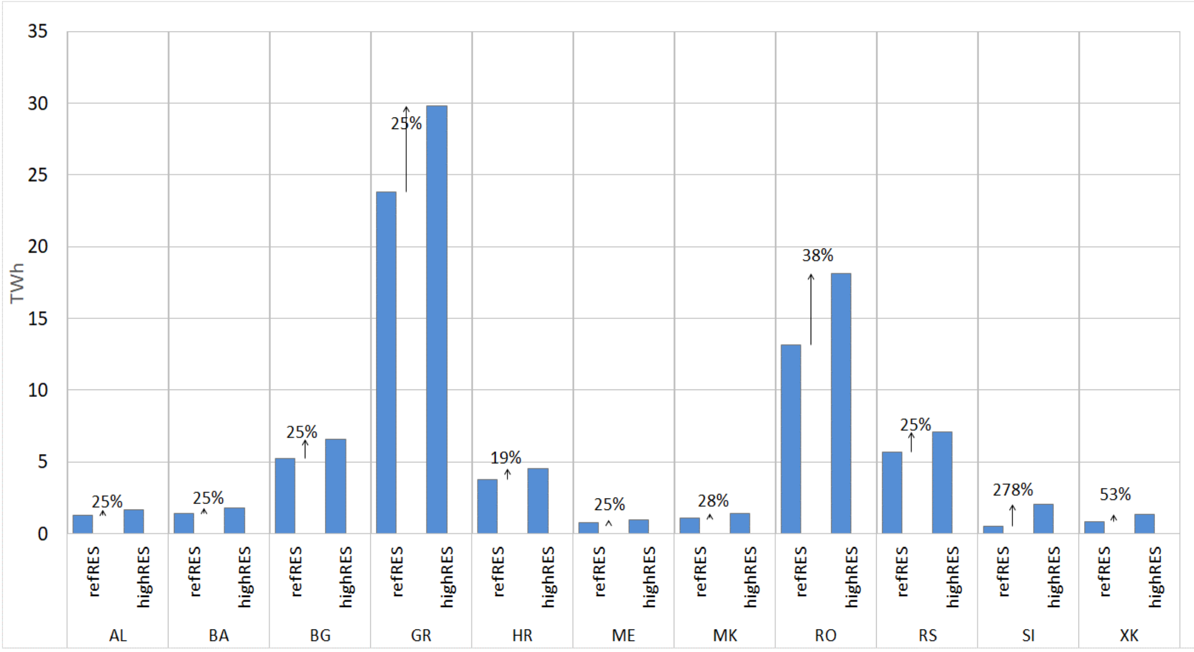


Figure 82: RES generation in 2030 - ref. RES vs high RES

- **The higher level of CO_2 emission tax will reduce total TPPs generation, and the main source of that reduction is lignite plants which have greater CO_2 emissions. Compared to Ref. CO_2 scenarios, the lignite generation falls by 37-38 TWh (-42% to -46%), depending on the level of RES integration.** Since hydro and RES generation are stable, gas generation increases to compensate. Gas TPPs have lower CO_2 emissions, and their marginal price is lower than lignite with the high CO2 tax. This leads to an increase in gas generation by 28 TWh (+106%) and 26 TWh (+126%) in the ref. RES and high RES generation cases. On net, the high CO2 price decreases fossil generation by 8 TWh (-6.7%) to 10 TWh (-9.6%), depending on the level of RES generation, and **CO_2 emissions decrease by 33 Mt (-31 %) to 34 Mt (-35%).**
- Increase in the CO_2 emission tax would decrease fossil generation, with a significant change in the mix between lignite and gas. Due to lower marginal price of electricity generation, gas fired plants generation increases with higher level of CO_2 emission tax on the regional level. This increase is mainly from a significant increase in gas generation in the two biggest market areas - IPTO and Transelectrica. In the IPTO market area, only gas plants remain in 2030, which increase by 16 TWh, or 96%. In the Transelectrica market area, gas generation rises even more in relative terms, 121%, or around 7 TWh. In Transelectrica, total fossil generation falls by 1.3 TWh, since lignite falls by 40%. **The sharpest drop in TPPs generation is in the NOSBiH market area, where lignite falls by 8.2 TWh or over 96%. In all other areas, we show the decrease in lignite and increase in gas TPPs in Figure 83.**

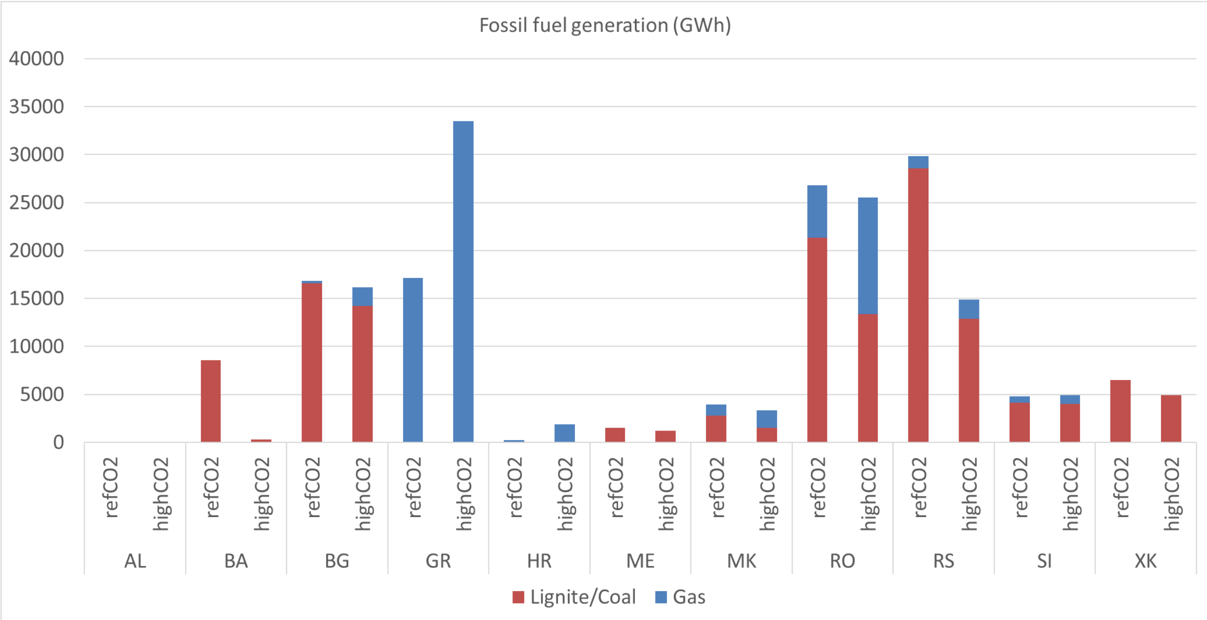


Figure 83: Fossil fuel powered plants generation in 2030 - ref. CO2 vs high CO2, referent RES integration

- **The EMI region is a net exporter in 2030, sending 4 TWh to 18.4 TWh, or 1.5% to 6.9%, of total demand in all scenarios outside the region.** A high CO_2 emission tax reduces net exports by 8-10 TWh, but still, due to slower demand growth, the EMI region remains a net exporter.
- **Figure 84 shows that in almost all countries where lignite plants have a significant share, exports fall, or the zone becomes a net importer (KOSTT, NOSBiH and EMS areas), due to an increased CO_2 emission tax. Where gas plants have bigger share, exports increase (Transelectrica area) or imports decrease (HOPS area). The IPTO area, due to significant gas generation, becomes a net exporter.**

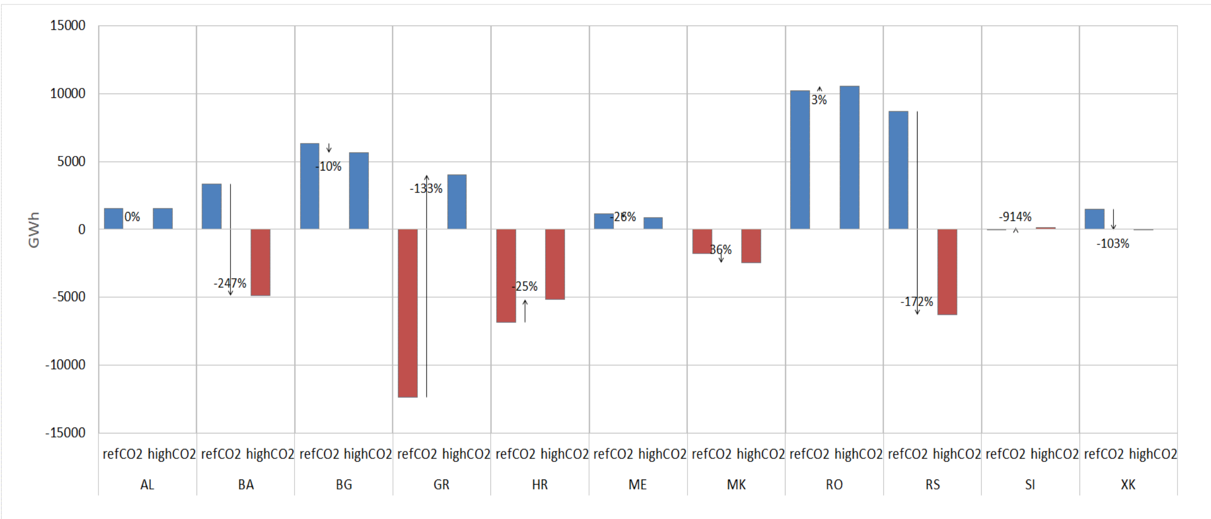


Figure 84: Balance positions per market areas in 2030 - ref. CO2 vs high CO2, referent RES integration

- **Average regional wholesale market prices (Figure 81) range from 47.4 to 67.7 EUR/MWh, and high RES integration reduces prices by around 2 EUR/MWh or 3-**

4% in both levels of CO_2 emission tax. Wholesale prices in the case of a high CO_2 emission tax would be around 18 EUR/MWh or 38% higher.

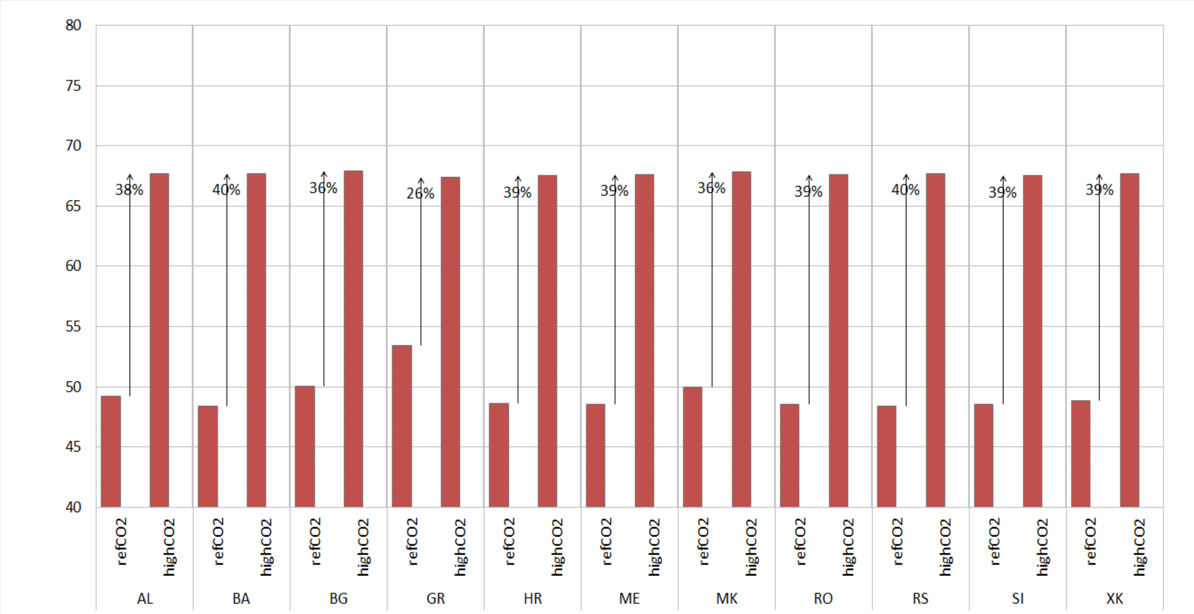
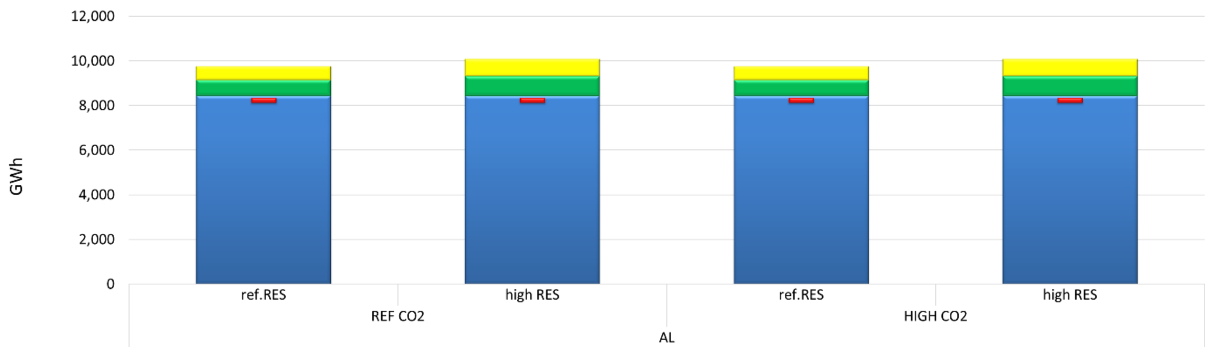


Figure 85: Wholesale Prices in the EMI region in 2030 - ref. CO2 vs high CO2, referent RES integration

From Figure 85 we see that wholesale electricity prices are evenly distributed across the EMI region without significant deviations, especially with a high CO_2 tax. In the ref. CO_2 tax level, the highest price is in the IPTO area, a large importer. In all other areas, a high CO_2 tax increases prices by 36-40%, compared to the ref. CO_2 price level.

5.3.1. OST market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the OST market area, in Figure 86 and Figure 87, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	606	758	606	758
Wind	703	879	703	879
Hydro	8,439	8,440	8,439	8,440
Consumption	8,227	8,227	8,227	8,227

Figure 86: Generation mix in OST market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

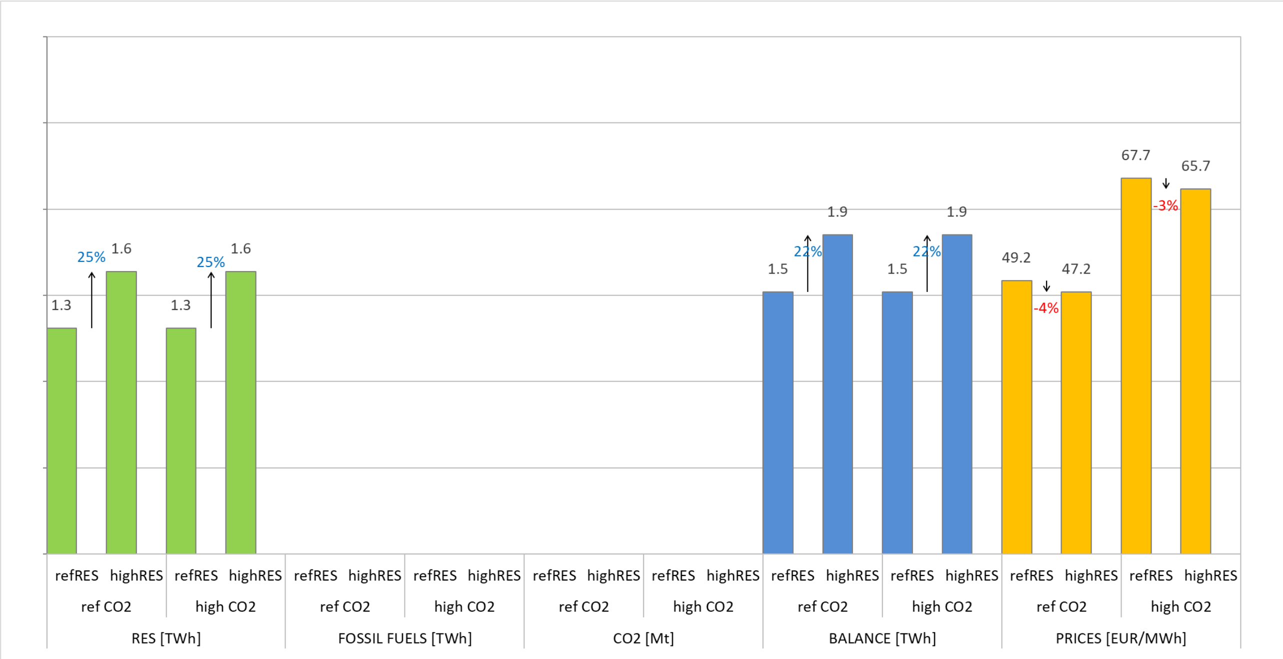


Figure 87: Main system operating indicators in OST market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

Considering the generation mix presented in Figure 86, in conjunction with the main system indicators depicted in Figure 87, the following conclusions could be drawn about the operation of this market area:

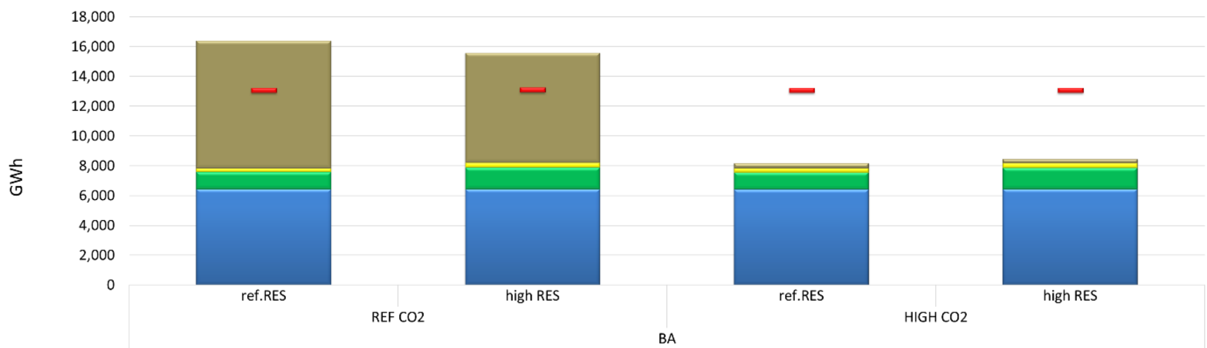
- RES generation is increased from 1.3 TWh in ref. RES scenario to 1.6 TWh in high RES scenario which is the increase of 25%. This increase is lower than the average increase in the EMI region (30%).
- RES generation supply between 16% and 20% of the area demand.
- Having in mind that the OST market area is characterized with high hydro generation, its operation strongly depends on hydro conditions, thus CO_2 emission price tax have limited

impact on operation indicators of this market area. In both level of CO_2 emission tax OST market area is net exporter, with net export of 1.5 to 1.9 TWh.

- Impact of RES integration on prices has negative correlation (-2 EUR/MWh), while high CO_2 emission price implicates an increase of wholesale market price by 18 EUR/MWh.

5.3.2. NOSBIH market area

We present the generation mix and a selected set of indicators as the main results of market analysis for the NOSBIH market area, in Figure 88 and Figure 89, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	8,542	7,346	325	238
Nuclear	0	0	0	0
Solar	271	339	271	339
Wind	1,144	1,431	1,144	1,431
Hydro	6,425	6,442	6,419	6,428
Consumption	13,050	13,073	13,041	13,054

Figure 88: Generation mix in NOSBIH market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

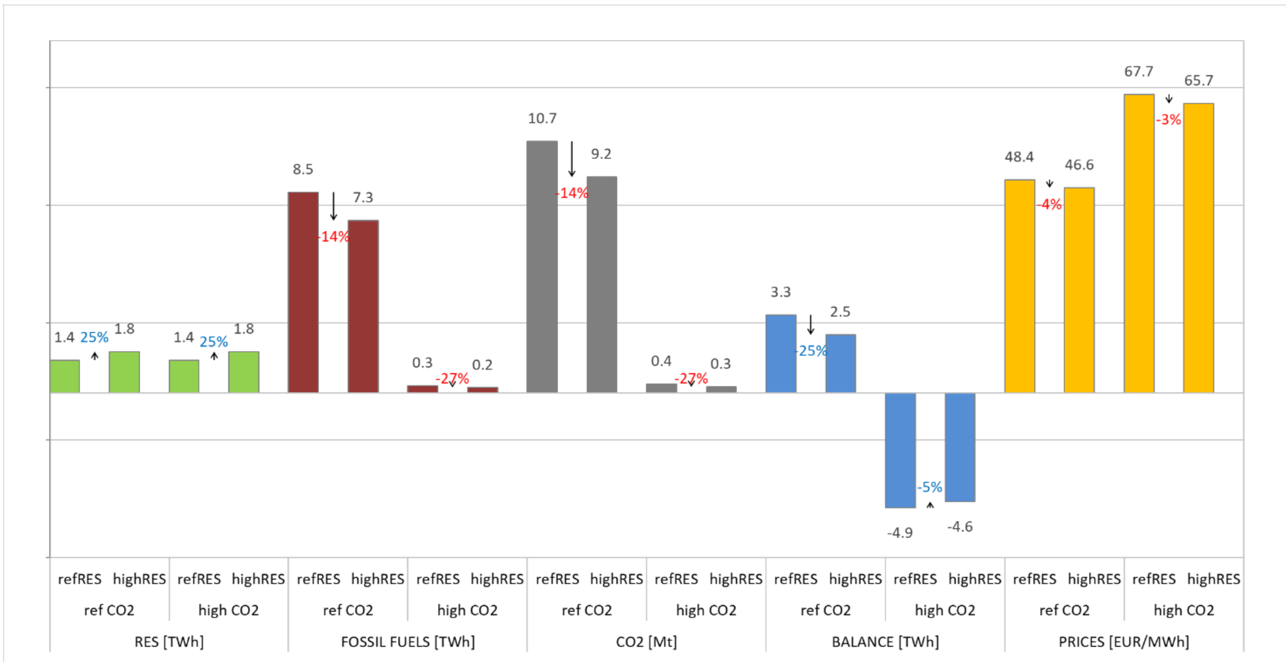


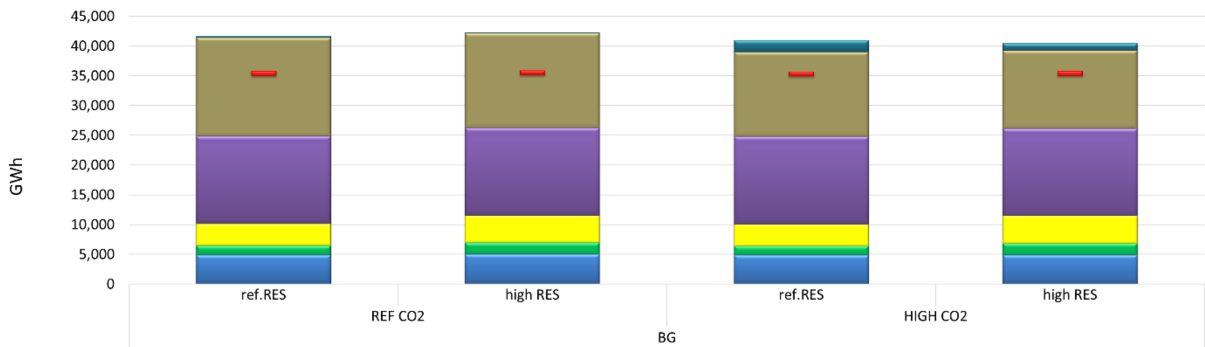
Figure 89: Main system operating indicators in NOSBIH market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

By jointly analyzing these results, we conclude the following:

- RES generation (wind+solar) rises from 1.4 TWh to 1.8 TWh (+25%), supplying 11%-14% of the area demand.
- Higher CO_2 emission tax leads a 95% drop in generation from lignite plants, which is a fall of 7-8 TWh, depending on the level of RES generation. This decrease in TPPs generation leads to a decrease in CO_2 emissions of the same level.
- Higher RES generation also leads to reduction of generation from lignite of 14% (-1.2 TWh) to 27% (-0.1 TWh) in the ref. CO_2 and high CO_2 price cases, respectively. This decrease in TPPs generation leads to a decrease of CO2 emissions of the same level.
- With a small increase in RES generation (0.3 TWh) and a reduction in TPP generation (-1.2 TWh), net exports from the NOSBIH market area decrease by around 0.8 TWh or 25% in case of Ref. CO_2 price level. However, with a high CO_2 price, this situation reverses, and the NOSBIH market area imports 4.9 TWh and 4.6 TWh in the Ref. RES and High RES generation cases, respectively. The reason is that with high CO_2 prices, lignite plants in the NOSBIH area become less competitive.
- A higher CO2 emission tax would increase wholesale market price by 40% in this market area. In addition, greater generation from RES would decrease market prices by about 2 EUR/MWh or 3-4%.
- Our simulations shows that PS HPP use is very low, since existing hydro plants and strong regional connections provide enough flexibility for the given level of RES generation.

5.3.3. ESO EAD market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the ESO EAD market area, in Figure 90 and Figure 91, respectively.



	REF CO2 ref.RES	REF CO2 high RES	HIGH CO2 ref.RES	HIGH CO2 high RES
Other	0	0	0	0
Gas	241	92	1,933	1,194
Coal	0	0	0	0
Lignite	16,585	15,958	14,232	13,099
Nuclear	14,693	14,692	14,693	14,693
Solar	3,678	4,598	3,678	4,598
Wind	1,570	1,962	1,570	1,962
Hydro	4,882	4,967	4,836	4,879
Consumption	35,336	35,450	35,274	35,331

Figure 90: Generation mix in ESO EAD market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

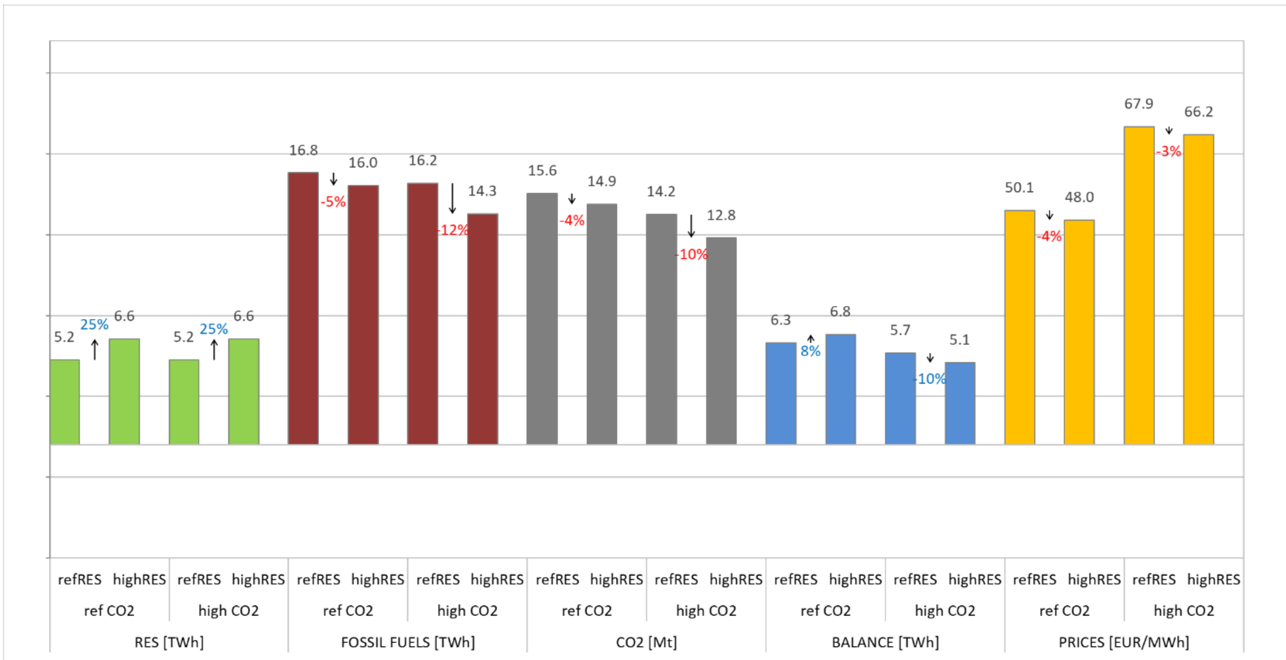


Figure 91: Main system operating indicators in ESO EAD market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

Considering the generation mix presented in Figure 90, in conjunction with the main system indicators depicted in Figure 91, the following conclusions could be drawn about the operation of this market area:

- RES generation (wind+solar) rises from 5.2 TWh to 6.5 TWh (+25%) supplying 15% -19% of the areas demand.
- Increase of CO_2 price level provokes reduction in lignite fired plants by 2.4 TWh (14%) and 2.7 TWh (18%) in Ref. RES and High RES generation, respectively. At the same time, gas powered plants increased generation between 1.7 TWh (700 %) and 1.1 TWh (1200%) in Ref RES and High RES generation, respectively.

- High level of CO_2 price implicates decrease in CO_2 emissions by 1.3 Mt (8%) and 2.1 Mt (14%), depending on the level of RES generation, due to reduction in generation from lignite TPPs and by increase in generation from gas technologies.
- Higher RES generation leads to a reduction of CO_2 emissions between 4 to 10%.
- Higher RES generation leads to TPPs generation (only fossil fuels fired plants) reduction by 5-12% (-0.8 TWh and -1.9 TWh), depending on CO_2 price level.
- In general, high level of CO_2 price leads to a decrease of net export by about 10 % (0.6 TWh) to 25% (1.7 TWh), depending on RES generation. However, in case of Ref. CO_2 price increase in RES generation provokes increase in export from this market area by 0.5 TWh (8%), while in the case of high CO_2 price level, increase in RES generation leads to a reduction of export by 0.6 TWh (10%).
- As a result, higher level of CO_2 prices provokes increase in wholesale market price by about 36%, while RES generation in both levels of CO_2 prices leads to a decrease in prices by 3-4%.
- Higher RES capacities increase the need for flexibility and increases the utilization of PS HPPs, as it can be seen in Table 30.

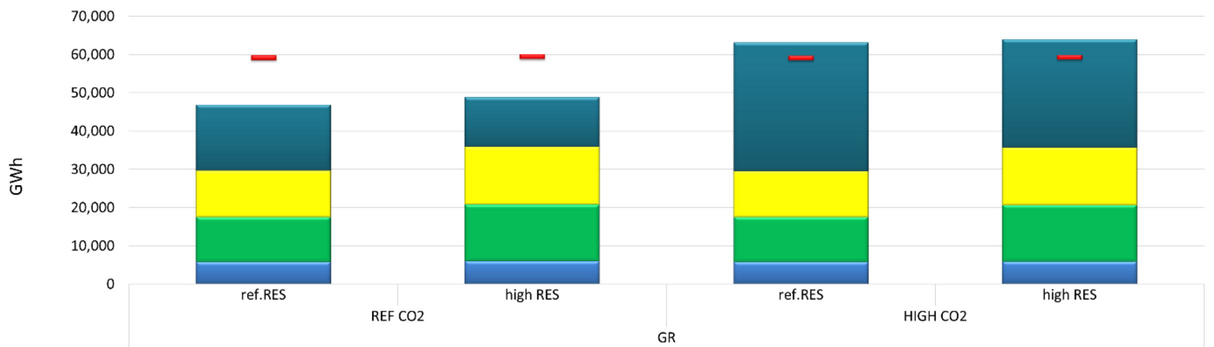
Table 30: PS HPPs generation in ESO EAD market area – Low demand growth

Generation from PS HPPs (GWh)	Referent CO2 emission tax	High CO2 emission tax
Ref. RES	52.3	5.8
High RES	137.5	48.8
Difference	**85.1**	**43.0**

In general, engagement of PSHPPs is very low (<150 GWh) due to the fact that existing HPPs and strong regional interconnections provide enough flexibility. However, generation from PS HPPs in the high RES scenario significantly larger in comparison with referent RES scenario. This is mainly because greater non-costly RES generation gives a higher possibility for pumping in hours with low prices and storing energy for utilization in hours with higher prices.

5.3.4. IPTO market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the IPTO market area, in Figure 92 and Figure 93, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	0	0	0	0
Gas	17,113	12,956	33,481	28,213
Coal	0	0	0	0
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	12,093	15,076	12,093	15,076
Wind	11,742	14,761	11,742	14,761
Hydro	5,835	6,035	5,779	5,880
Consumption	59,135	59,419	59,054	59,198

Figure 92: Generation mix in IPTO market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

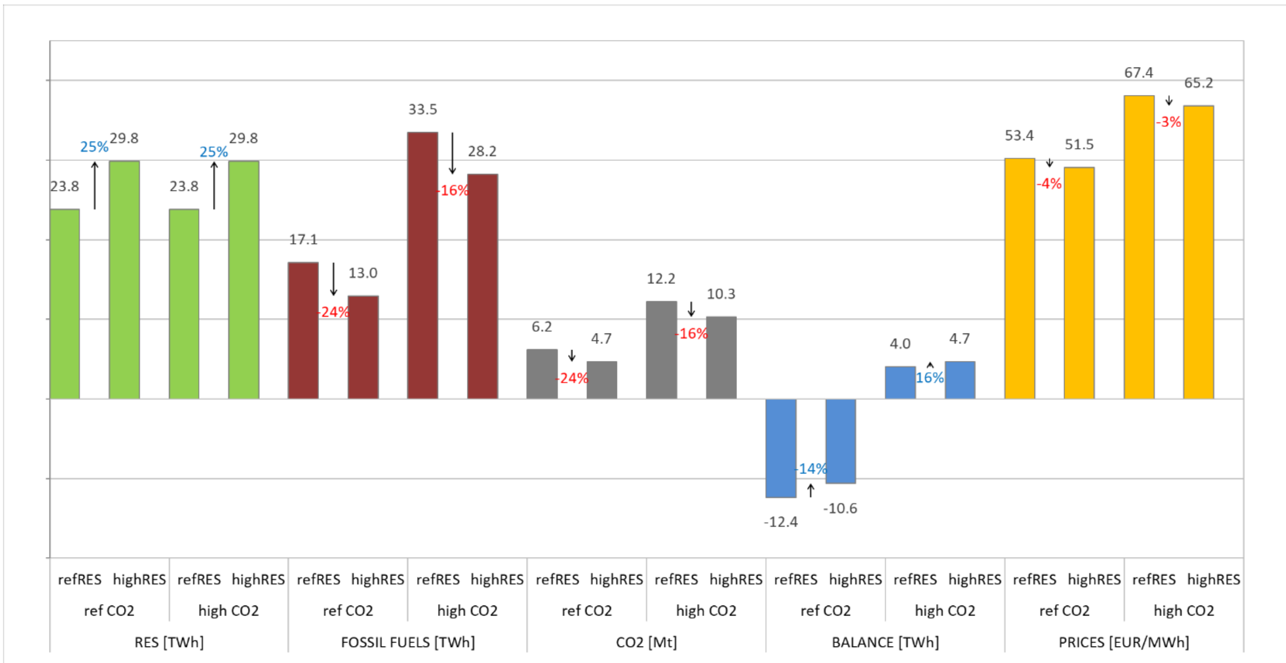


Figure 93: Main system operating indicators in IPTO market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

Considering the generation mix and the main system indicators presented in the above figures the following conclusions could be drawn:

- Beside Transelectrica market area, the IPTO market area is the biggest in EMI region. Due to this fact, changes that are induced by higher CO_2 emission tax in this area operation have significant impact on the changes at the regional level.
- Higher level of CO_2 emission price leads to a significant change in gas fired plants generation, CO_2 emissions as well as in export and import in the IPTO market area.
- This market area has significant generation capacities in gas technology and taking into account that higher level of CO_2 emission tax puts lignite powered plants into less favorable position, generation from gas TPPs increases by 16 TWh (+99%) and 15 TWh (+120%) for

Ref. RES and High RES generation, respectively. This increase, in absolute terms, is the greatest increase in the EMI region. This increase in gas generation is in a correlation with a CO_2 emissions increase for the same pecetanges.

- As in the previous groups of scenarios, RES generation (wind+solar) rise from 23.8 TWh to 29.8 TWh (+25%). This increase in absolute values (6 TWh) is the highest in the region.
- This level of RES generation supplies between 40 and 50% of the area demand, which is the highest RES participation in the EMI region.
- For Ref. CO_2 emission price this market area is a net importer and depending on the level of RES generation it imports 10.6 TWh to 12.4 TWh.
- Due to the increases in CO_2 emission price and TPPs generation, the IPTO market area becomes net exporter of 4 to 4.7 TWh.
- Higher RES generation decreases net import by 1.8 TWh and increases net export by 0.7 TWh in Ref. CO_2 and High CO_2 price level. respectively.
- Higher CO_2 price level implicates an increase of wholesale market price by 26%, which is the lowest increase in market price in the EMI region.
- Greater RES generation leads to a decrease in prices by 3-4%, depending on the level of CO_2 emission price.
- Similar as in other market areas, engagement of PS HPPs is not so big (Table 31).

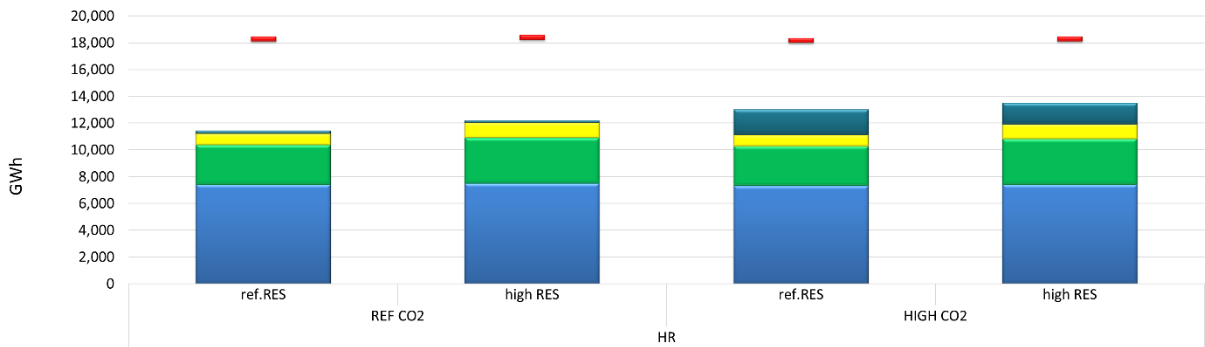
Table 31: PS HPPs generation in IPTO market area – Low demand growth

Generation from PS HPPs (GWh)	Referent CO2 emission tax	High CO2 emission tax
Ref. RES	67.2	11.0
High RES	266.4	111.3
Difference	**199.1**	**100.3**

Generation from PS HPPs in the high RES scenario is several times higher in comparison with referent RES scenario. No impact of CO_2 emission tax level points again to small impact of hydro generation in IPTO market area.

5.3.5. HOPS market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the HOPS market area, in Figure 94 and Figure 95, respectively.



	REF CO2 ref.RES	REF CO2 high RES	HIGH CO2 ref.RES	HIGH CO2 high RES
Other	0	0	0	0
Gas	234	168	1,904	1,576
Coal	4	4	2	1
Lignite	0	0	0	0
Nuclear	0	0	0	0
Solar	840	1,120	840	1,120
Wind	2,960	3,415	2,960	3,415
Hydro	7,398	7,492	7,311	7,391
Consumption	18,269	18,393	18,152	18,258

Figure 94: Generation mix in HOPS market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

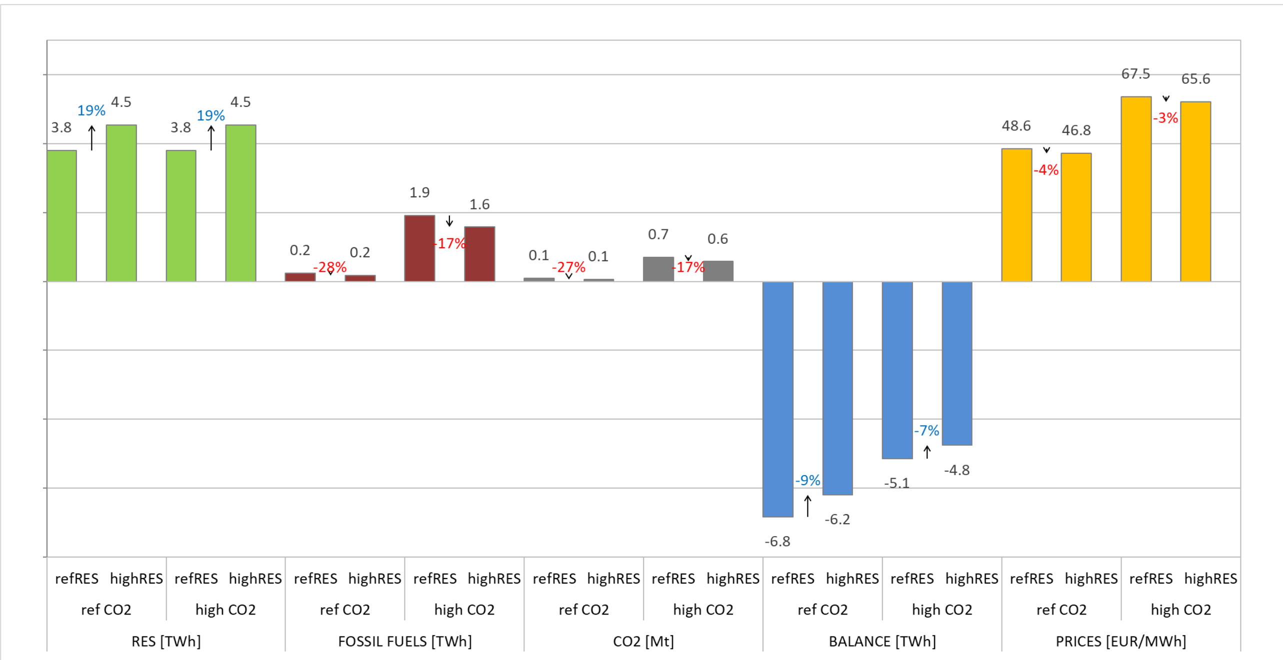


Figure 95: Main system operating indicators in HOPS market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

Considering the generation mix presented in Figure 94, in conjunction with the main system indicators depicted in Figure 95, the following conclusions could be drawn about the operation of this market area:

- In the case of Ref. CO_2 emission tax, generation from gas TPPs is neglectable, while increase in CO_2 emission tax provokes increase in gas TPPs generation by 1.7 TWh (+714%) and 1.4 TWh (+836%) for Ref. RES and high RES generation, respectively.
- Increases in CO_2 emissions are of the same correlation and of the same percentages.

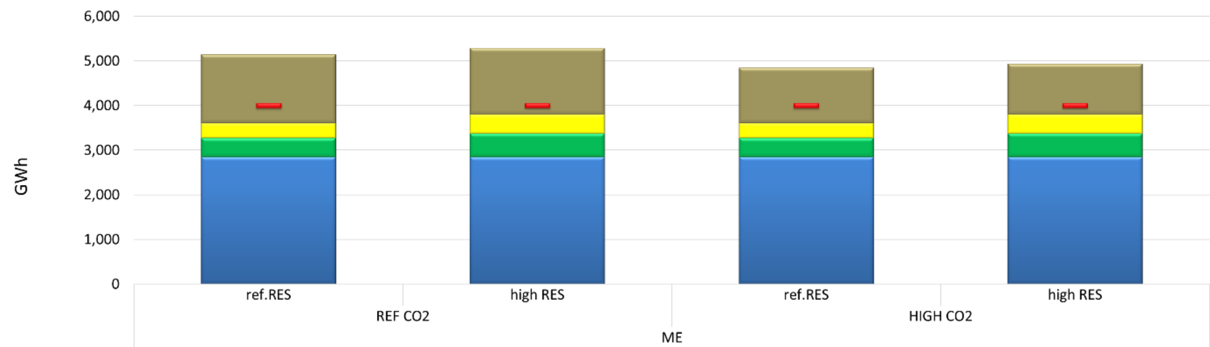
- RES generation (wind+solar) rises from 3.8 TWh to 4.5 TWh (+19%), which is the lowest increase in percentages in the region. This level of RES generation supplies between 21% and 25% of area demand, which is close to regional average.
- In the HOPS market area total demand in 2030 is mainly supplied by hydro and RES generation (61-65% depending on the level of RES integration).
- Net import in the HOPS market area is between 4.8 and 6.8 TWh (26% and 37% of the area demand), depending on the level of CO_2 emission price and REG generation. Higher CO_2 emission price provokes increase in gas TPPs generation which leads to the decrease in net import by about 1.7 and 1.4 TWh in Ref RES and high RES generation, respectively.
- Higher RES integration decreases the net import by 7%-9%.
- In the case of high CO_2 emission price wholesale market price in this area increases by 39% (19 EUR/MWh) reaching the level of 65.6 – 67.5 EUR/MWh.
- Higher RES generation leads to a decrease in prices by 3 to 4%, depending on the level of CO_2 emission tax.
- In comparison to other market areas, engagement of PS HPPs in the HOPS market is the highest in the region (Table 32).

Table 32: PS HPPs generation in HOPS market area – Low demand growth

Generation from PS HPPs (GWh)	Referent CO2 emission tax	High CO2 emission tax
Ref. RES	208.7	120.9
High RES	301.9	200.6
Difference	**93.1**	**79.7**

5.3.6. CGES market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the CGES market area, Figure 68 in and Figure 69, respectively.



	REF CO2 ref.RES	REF CO2 high RES	HIGH CO2 ref.RES	HIGH CO2 high RES
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	1,533	1,480	1,234	1,131
Nuclear	0	0	0	0
Solar	341	426	341	426
Wind	423	529	423	529
Hydro	2,844	2,844	2,844	2,844
Consumption	3,997	3,997	3,997	3,997

Figure 96: Generation mix in CGES market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

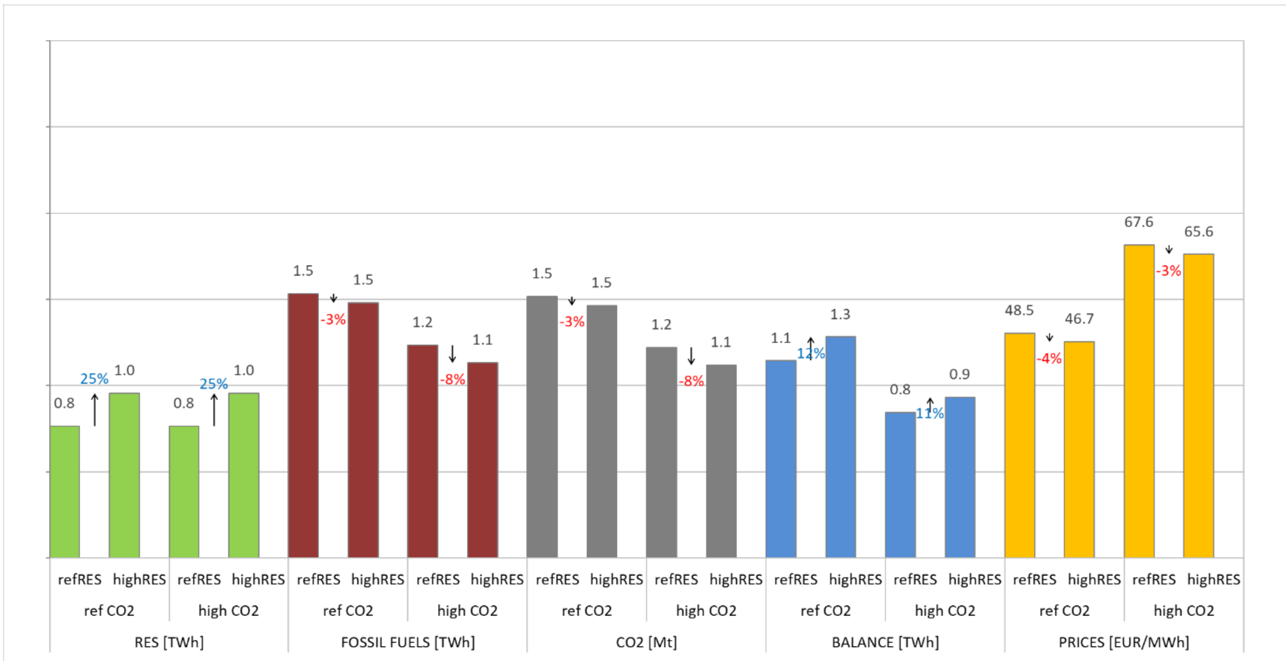


Figure 97: Main system operating indicators in CGES market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

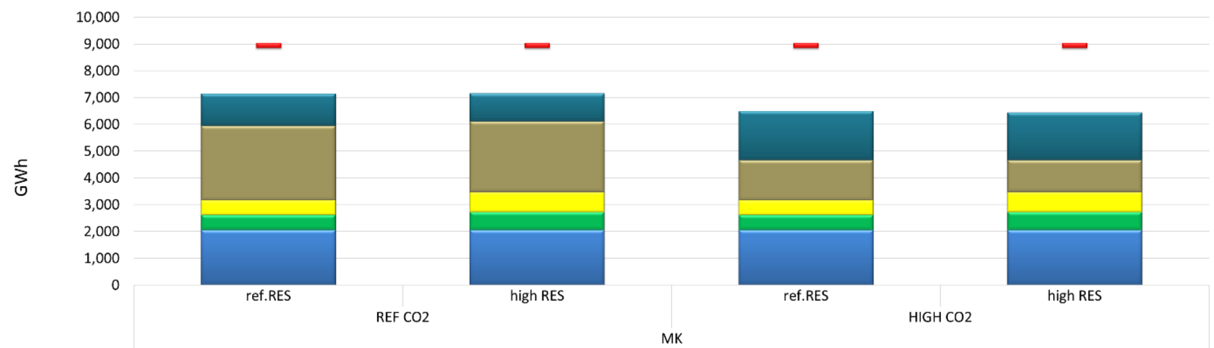
Considering the generation mix and main system indicators presented in the figures above the following conclusions could be drawn:

- the CGES market area is the smallest market area in the EMI region.
- High level of CO_2 emission tax reduced generation from lignite TPPs between 0.3 TWh (20%) and 0.35 TWh (24%) for Ref. RES and high RES generation, respectively. Changes in CO_2 emissions are of the same correlation and of the same percentages.
- As in the previous groups of scenarios, RES generation (wind+solar) rise from 0.8 TWh to 1 TWh (+25%) and this level of RES generation supplies between 19% and 24% of area demand.

- Relatively small changes in RES generation leads to small changes in TPPs generation – 0.1 TWh.
- Higher level of CO_2 emission tax leads to a decrease in net export by -0.3 to -0.35 TWh, depending on RES generation.
- In general, with higher RES generation, the CGES market area increases its net export.
- Wholesale market prices rise with higher level of CO_2 emission tax by about 39% which is the consequence of operating costs increase not only in CGES market area but across the region. On the other side, increase in RES generation provokes decrease of prices for only 3-4%.

5.3.7. MEPSO market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the MEPSO market area, in Figure 98 and Figure 99, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	0	0	0	0
Gas	1,207	1,040	1,832	1,780
Coal	0	0	0	0
Lignite	2,770	2,639	1,492	1,186
Nuclear	0	0	0	0
Solar	549	749	549	749
Wind	560	670	560	670
Hydro	2,058	2,058	2,058	2,058
Consumption	8,933	8,933	8,933	8,933

Figure 98: Generation mix in MEPSO market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

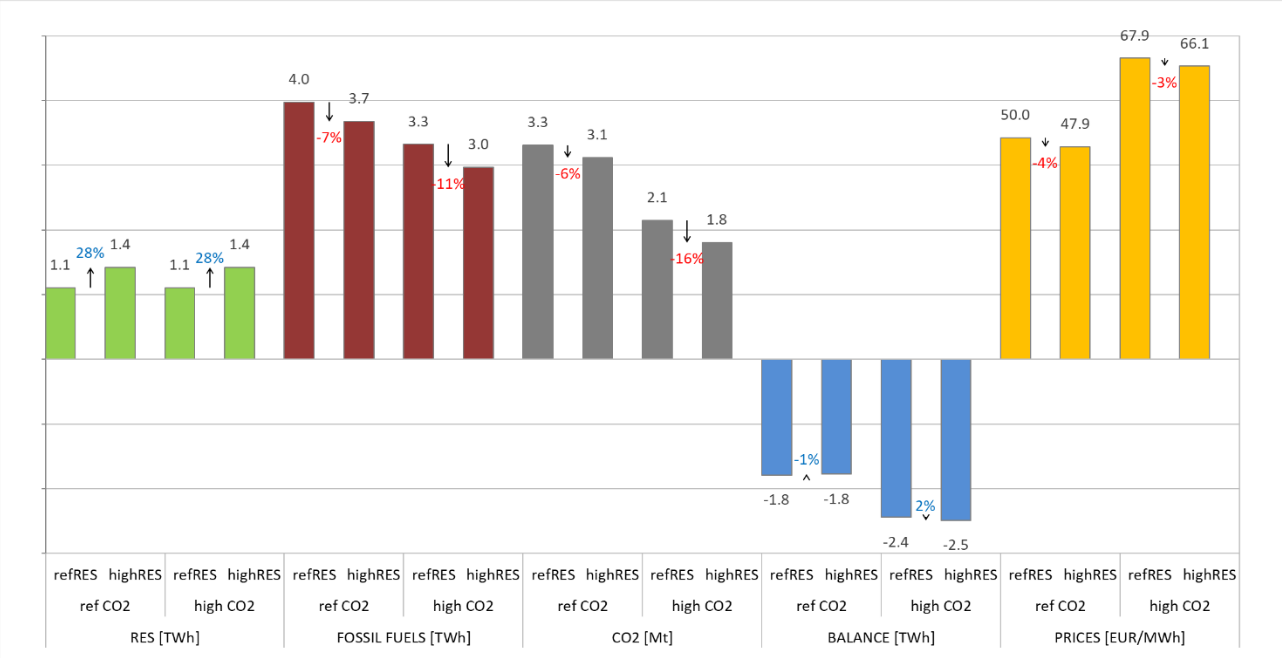


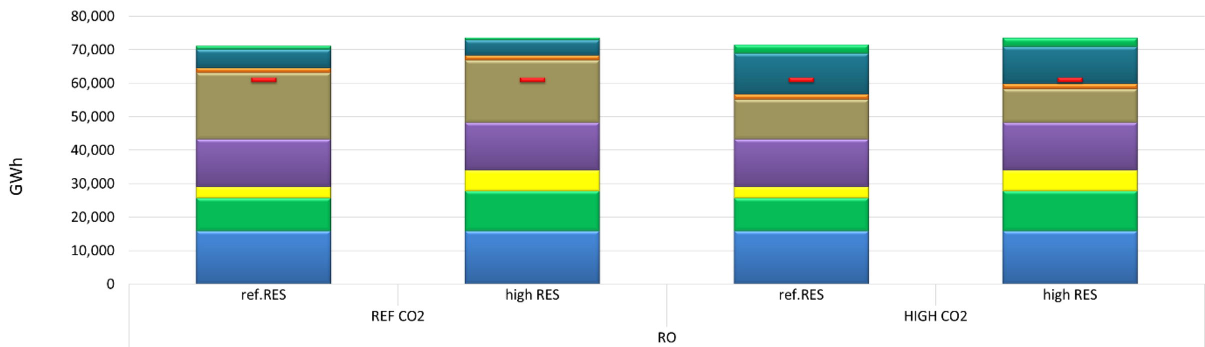
Figure 99: Main system operating indicators in MEPSO market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

Considering the generation mix presented in Figure 98, in conjunction with the main system indicators depicted in Figure 99, the following conclusions could be drawn about the operation of this market area:

- High level of CO_2 emission tax leads to a decrease in lignite TPPs generation by 1.3 TWh (-46%) and 1.5 TWh (-55%) for Ref. RES and high RES generation cases, respectively.
- At the same time, gas fueled power plants increase generation between 0.63 TWh (+52%) and 0.74 TWh (71%) for Ref. RES and high RES generation cases, respectively.
- Changes in generation mix provokes decrease in CO_2 emissions. Higher level of CO_2 prices imposes decrease of emission by 1.2 to 1.3 Mt.
- RES generation (wind+solar) rise from 1.1 TWh to 1.4 TWh (+28%) supplying between 12% and 16% of area demand (below than the regional average).
- Impact of RES generation on net import is neglectable for both levels of CO_2 emission tax.
- High level of CO_2 emission tax provokes increase in net import by about 0.7 TWh.
- Regarding wholesale market price, high CO_2 emission tax implicates increase in price by 36% to a level of 66.1 – 67.9 EUR/MWh. In addition, greater RES generation leads to a decrease in prices by 3-4%.

5.3.8. Transelectrica market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the Transelectrica market area, in Figure 100 and Figure 101, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	1,019	702	2,655	2,609
Gas	5,496	4,626	12,156	11,041
Coal	1,508	1,508	1,508	1,508
Lignite	19,804	18,548	11,862	10,076
Nuclear	14,245	14,245	14,245	14,245
Solar	3,360	6,216	3,360	6,216
Wind	9,787	11,885	9,787	11,885
Hydro	15,889	15,889	15,889	15,889
Consumption	60,908	60,908	60,908	60,908

Figure 100: Generation mix in Transelectrica market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

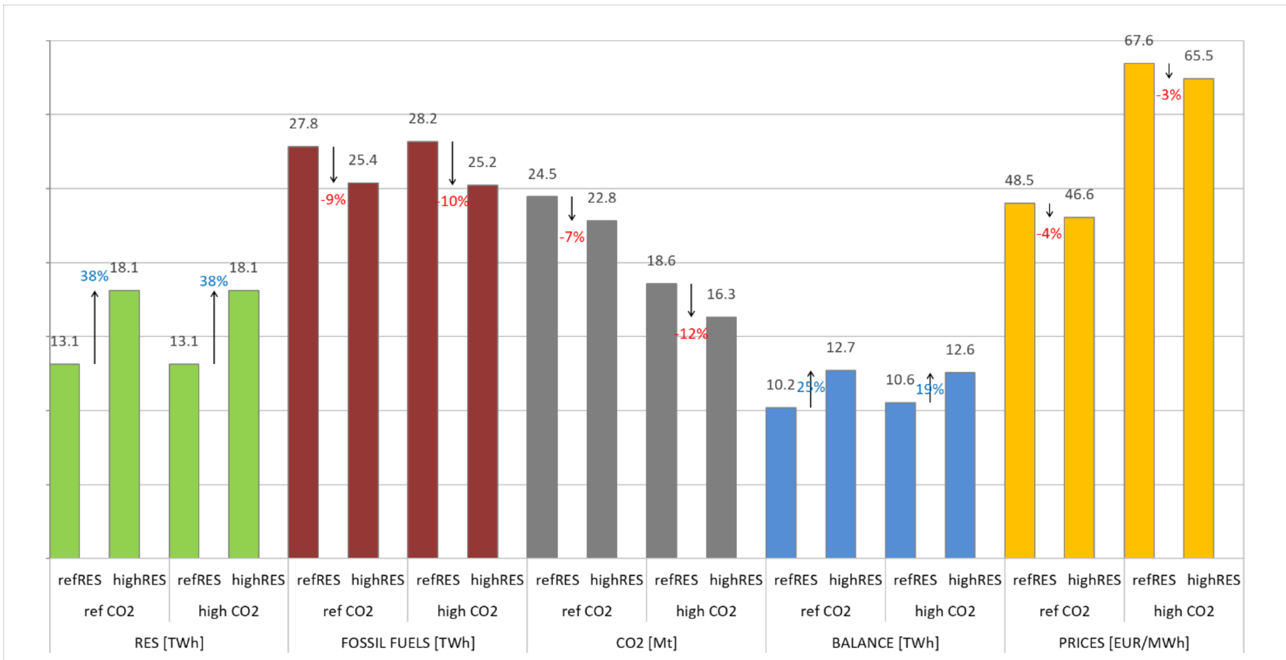


Figure 101: Main system operating indicators in Transelectrica market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

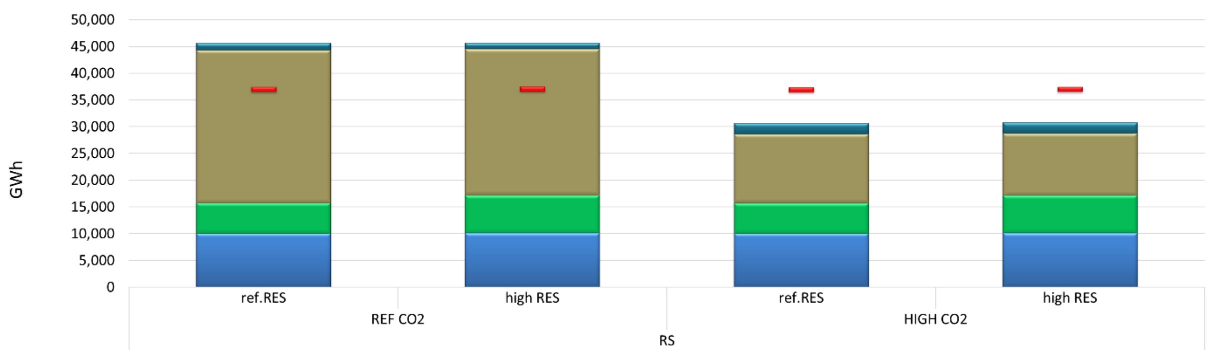
By jointly analyzing these results, the following can be concluded:

- Increase in CO_2 emission tax in the Transelectrica market area provokes decrease in lignite technology generation between 7.9 TWh (-40%) and 8.4 (-46%) for Ref. RES and High RES generation, respectively. At the same time, gas TPPs, due to lower marginal cost of generation, become more competitive on the market and increase generation between 6.6 TWh (+121%) and 6.4 TWh (139%) for Ref. RES and High RES generation, respectively.

- CO_2 emissions fall by about 5.9 to 6.5 Mt due to increase in CO_2 emissions tax.
- As in previous groups od scenarios, RES generation is increased from 13 TWh in ref.RES scenario to 18 TWh in high RES scenario which is the increase of 38%. This increase puts the Transelectrica market area in the group of zones with the highest RES increase.
- RES participation in supplying the area demand in the Transelectrica market area is at the regional average, between 22% and 30%.
- Increase in RES generation provokes decrease in CO_2 emissions by 1.6 Mt (-7%) and 2.3 Mt (-12%), depending on the level of CO_2 emission tax.
- Increase in CO_2 emission tax does not have significant impact on the net balance of this market area and it stays on the same level.
- With higher RES generation, the net export of the Transelectrica market area rises by 2.5 TWh (25%) in Ref. CO_2 emission tax. In case of high CO_2 emission tax, this increase is lower and amounts to 2 TWh or 19%.
- In the case of high CO_2 emission tax, wholesale market price in this area increases by 39% (19 EUR/MWh) reaching the level of 65.5 – 67.6 EUR/MWh.
- Higher RES generation leads to a decrease in prices by 3 to 4%, depending on the level of CO_2 emission tax.

5.3.9. EMS market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the EMS market area, in Figure 102 and Figure 103, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	0	0	0	0
Gas	1,305	1,158	2,030	1,986
Coal	0	0	0	0
Lignite	28,560	27,264	12,858	11,564
Nuclear	0	0	0	0
Solar	41	51	41	51
Wind	5,639	7,048	5,639	7,048
Hydro	10,090	10,138	10,058	10,101
Consumption	36,935	36,999	36,892	36,949

Figure 102: Generation mix in EMS market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

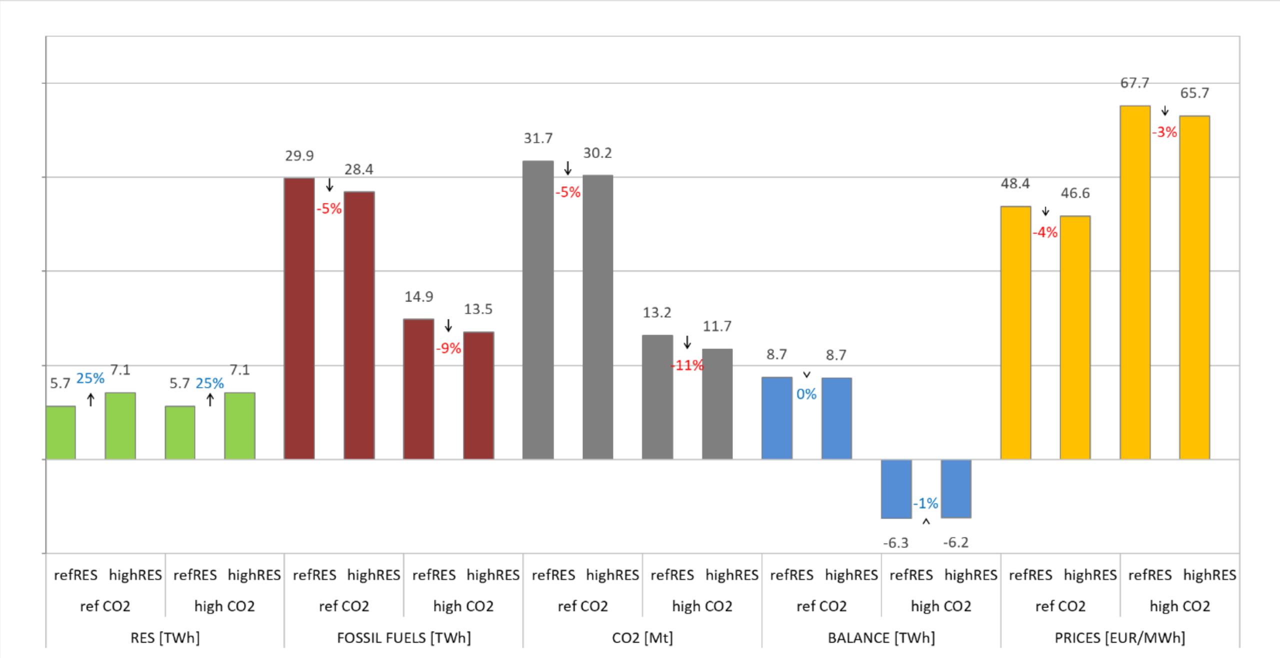


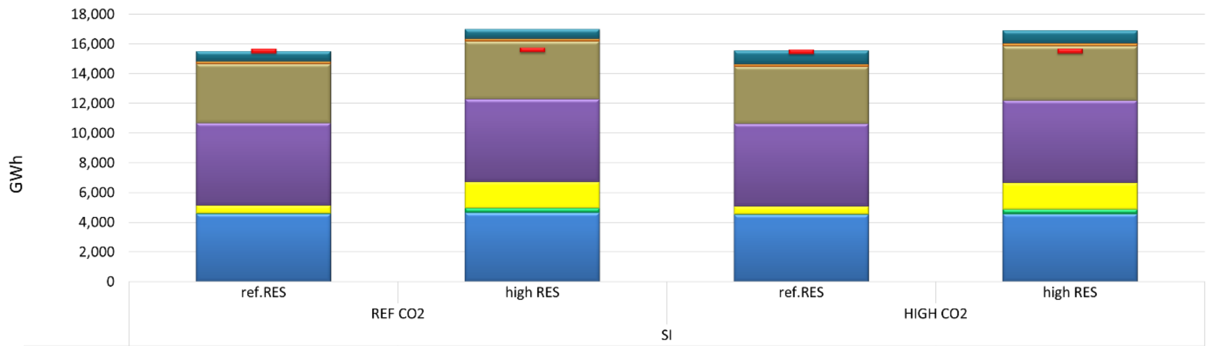
Figure 103: Main system operating indicators in EMS market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

Considering the generation mix presented in Figure 102, in conjunction with the main system indicators depicted in Figure 103, the following conclusions could be drawn about the operation of this market area:

- In Ref. CO_2 emission tax lignite TPPs generation supply 74-75% of total area demand, while gas powered plants participate with 3-3.5%, depending on the level of RES generation.
- Increase in CO_2 emission tax implicates strong decrease in generation from lignite technology by -15.7 TWh (-55%) for Ref. RES generation or -58% for High RES generation. At the same time generation from gas TPPs increased by 0.7 TWh (+56%) and 0.8 TWh (+71%) for Ref. RES and High RES generation, respectively.
- As already stated, RES generation (wind+solar) rise from 5.7 TWh to 7.1 TWh (+25%) supplying between 15% and 19% of the area demand. This participation is lower than the regional average (22%-28%). Consequently, gas and lignite TPPs supply around 5.4-5.5% and 31-35% of total area demand for REF. RES and High RES generation, respectively.
- In case of High CO_2 emission tax total CO_2 emissions fall by 18.5 Mt (-58%) and 18.4 Mt (-61%), depending on the level of RES generation.
- This market area in 2030 exports around 8.7 TWh, in case of Ref. CO_2 emission tax. However, due to sharp decline in TPPs generation for High CO_2 emission tax, EMS market area become net importer. Total import is on the level of 6.3 TWh or 17% of total area demand. High RES generation does not have significant impact on change in export/import.
- High CO_2 emission tax provokes increase in wholesale market price by around 19 EUR/MWh (+40%). On the other hand, increase in RES generation implicates a decrease in market price by 3-4%.
- Simulations shows that engagement of PS HPP is very small, since existing hydropower plants and strong regional connections provide enough flexibility for the given level of RES generation.

5.3.10. ELES market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the ELES market area, in Figure 104 and Figure 105, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	0	0	0	0
Gas	666	630	910	864
Coal	175	175	175	175
Lignite	3,981	3,909	3,838	3,640
Nuclear	5,558	5,558	5,558	5,558
Solar	531	1,780	531	1,780
Wind	20	301	20	301
Hydro	4,568	4,629	4,520	4,564
Consumption	15,512	15,593	15,447	15,507

Figure 104: Generation mix in ELES market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

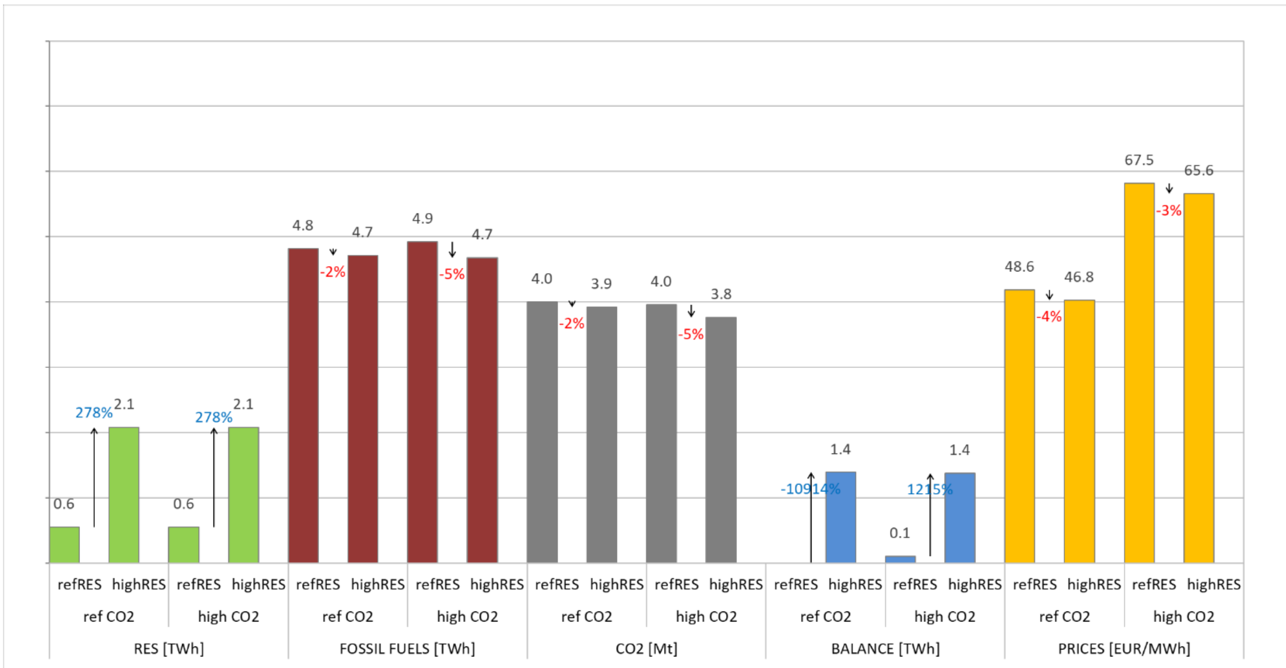


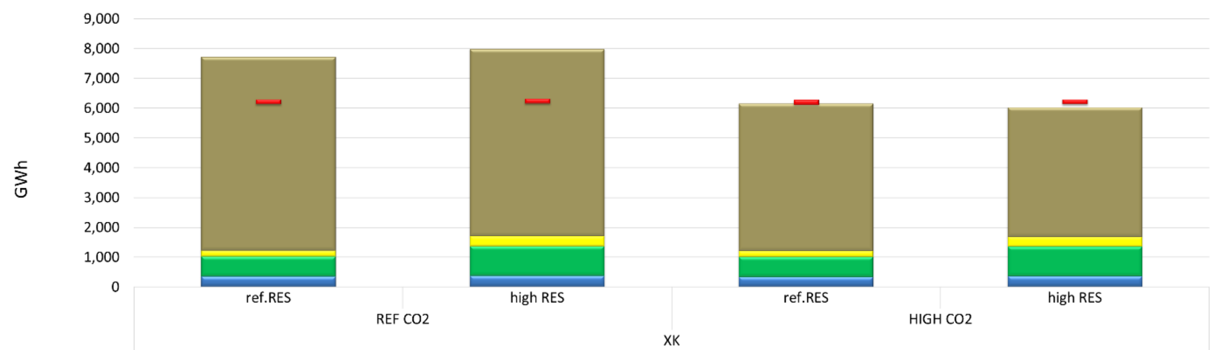
Figure 105: Main system operating indicators in in ELES market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

Considering the generation mix and main system indicators presented in the figures above the following conclusions could be drawn:

- In this market area the increase in CO_2 emission tax almost have no impact on generation mix, CO_2 emissions and net balance.
- Generation from lignite powered plants reduces by 0.1 to 0.3 TWh (-4 – -7%), depending on the RES generation, while gas powered plants increase generation by 0.2 TWh (+37%) for both levels of RES generation. This offset in generation mix does not change total CO_2 emissions. Emission are affected only by an increase in RES generation (0.1-0.2 Mt).
- As already stated, RES generation (wind+solar) rise from 0.6 TWh to 2.1 TWh (+278%). It should be emphasized that this is the largest relative increase of RES in the whole SEE region. RES in the ELES market area supplies between 4% and 13% of the area demand which is far from the regional average (22%-28%).
- This market area is almost completely balanced, especially for Ref. RES generation and both levels of CO_2 emission tax. Increase in RES generation makes this market area a net electricity exporter at a level of 1.4 TWh, or 9% of total area load.
- Higher CO_2 emission tax leads to an increase in prices by 19 EUR/MWh. On the other hand, increase in RES generation implicates a decrease in market price by 3-4%.
- Simulations shows that engagement of PS HPP is very small, since existing hydropower plants and strong regional connections provide enough flexibility for the given level of RES generation.

5.3.11. KOSTT market area

We present the generation mix and selected set of indicators, as the main results of market analysis for the KOSTT market area, in Figure 106 and Figure 107, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
Other	0	0	0	0
Gas	0	0	0	0
Coal	0	0	0	0
Lignite	6,486	6,266	4,933	4,334
Nuclear	0	0	0	0
Solar	205	341	205	341
Wind	666	990	666	990
Hydro	355	375	344	358
Consumption	6,202	6,230	6,188	6,207

Figure 106: Generation mix in KOSTT market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

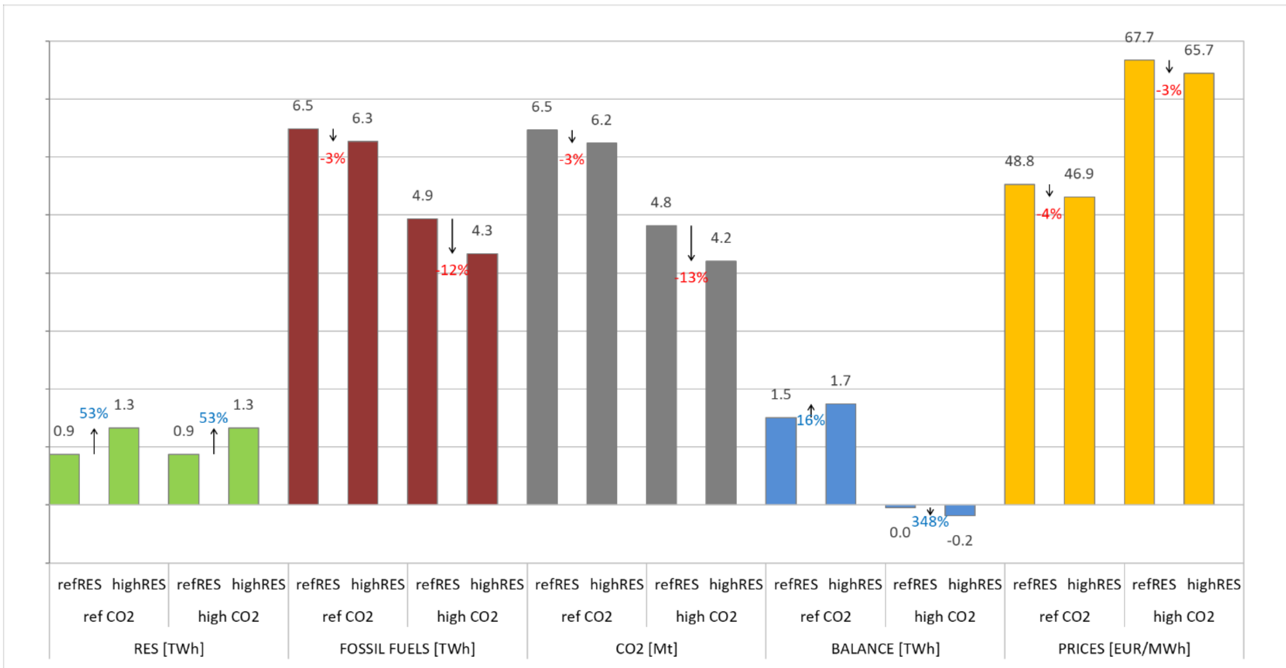


Figure 107: Main system operating indicators in KOSTT market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

Considering the generation mix presented in Figure 106, in conjunction with the main system indicators depicted in Figure 107, the following conclusions could be drawn about the operation of this market zone:

- In the KOSTT market area lignite has dominant role in generation mix. In Ref. CO_2 emission tax scenarios, generation from lignite is greater than total area demand. However, by an increase in CO_2 emission tax generation from lignite TPPS falls by 1.6 TWh (-24%) to 1.9 TWh (-31%), depending on the level of RES generation. This decrease in lignite TPPs generation provokes a proportional decrease in CO_2 emissions, as well. Emissions fall by 1.6 Mt (-26%) and 2 Mt (-33%), depending on the level of RES generation.
- RES generation (wind+solar) rises from 0.9 TWh to 1.3 TWh (+53%) supplying between 14% and 21% of area demand.
- the KOSTT market area is net electricity exporter in 2030 for Ref. CO_2 emission tax. The increase in RES generation additionally increase export from 1.5 TWh to 1.7 TWh, or by 16%. However, decrease in TPPs generation, provoked by the increase in CO2 emission tax, makes this market area almost completely balanced (with small net import of 0.7% to 3% of total area demand, depending on RES generation).
- As in all other market areas, the increase in CO_2 emission tax implicates an increase in wholesale market price by about 39%, in relative terms, or 18 EUR/MWh in absolute terms.
- High level of RES generation decreases price by approx. 2 EUR/MWh.
- Simulations shows that engagement of PS HPP is very small, since existing hydropower plants and strong regional connections provide enough flexibility for the given level of RES generation.

5.4. Concluding remarks on the impact of different level of RES on market operation in SEE

The results of the 3 groups of scenarios above provide the basis for this section's overall assessment of different levels of RES on market operation in SEE. In general we derive the following conclusions:

- **In 2030, in the EMI region, RES generation increases from 57.7 TWh (in ref. RES scenario) to 75.3 TWh in the high RES scenario, an increase of 30%, and a tripling or quadrupling of the level of RES generation at present. The increase per market areas (Figure 108) is between 0.2 and 6 TWh (in the CGES and IPTO market areas) or between 19% and 278% (in the HOPS and ELES market areas).**

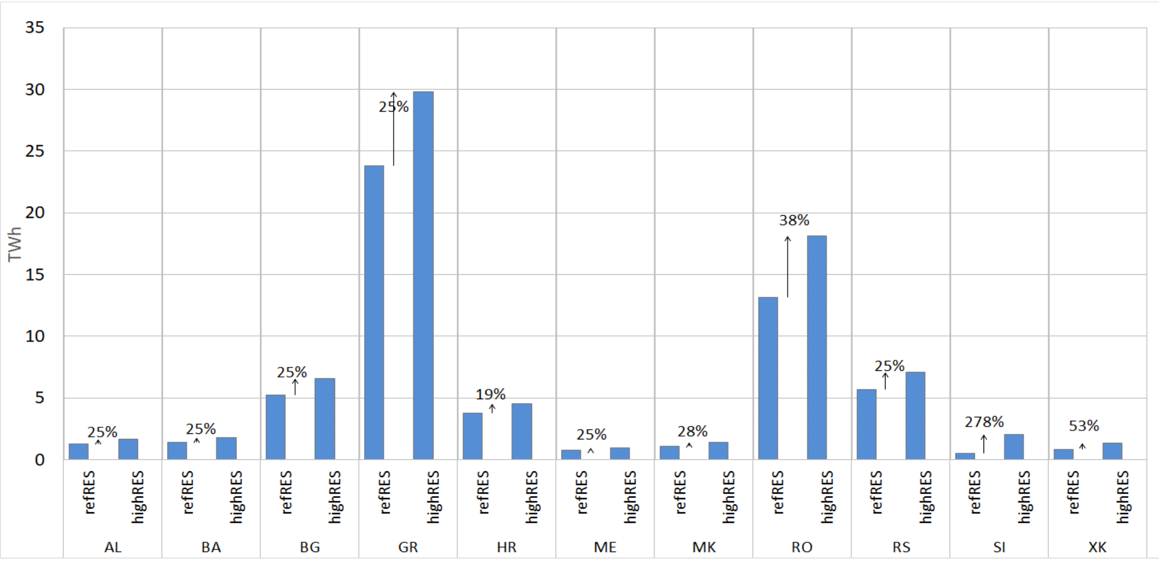


Figure 108: RES generation in 2030 - ref. RES vs high RES

- **This change in RES generation provokes a 10% decrease in lignite and gas generation. In all scenarios, this decrease is smaller than increase in RES generation. Also, with higher RES generation, the region can increase its exports.**

- In 2030, a key driver of the main generation technology is the level of CO_2 emission tax. An increase in this tax will have a major impact on lignite and coal fired plants. With higher CO_2 tax, generation from lignite in some cases becomes more expensive than generation from gas, and as a result, these two technologies change their position in the regional merit order curve. That is, the share of these technologies in the generation mix is significantly different in the scenarios with referent and high CO_2 tax (Figure 109).

  With the referent CO_2 tax (27 EUR/tCO2), lignite is the main technology, while with the higher CO_2 tax (almost doubled, 53 EUR/t CO_2), the shares of lignite and gas plants are almost the same. When generation from lignite plants falls, hydro generation dominates, at least in average hydro conditions. In dry hydro conditions, lignite remain the main technology, even with a high CO_2 tax.

- In all scenarios, higher RES generation provokes a bigger decrease in gas generation than in lignite generation. The decrease in capacity factors (equivalent operating hours with installed capacity divided by 8,760 hours) for lignite plants is 2-3% and for gas plants it is 4-5%.

The capacity factors of lignite and gas generation changes much more with changes in the CO_2 tax than with increased RES. Lignite plants' capacity factor decreases from 60-70% with the referent CO_2 tax to 35-50% with the high tax. At gas plants, the change is the opposite: the capacity factor increases from 16-30% in the referent CO_2 tax case to 36-50% in the high tax case.

As also mentioned in Section 5.1 with regard to Table 10, this change in capacity factors could well lead to higher retirements of lignite plants by 2030 than reported in the generation plans submitted for evaluation in this report, with the need for other generation or imports to make up for this reduction.

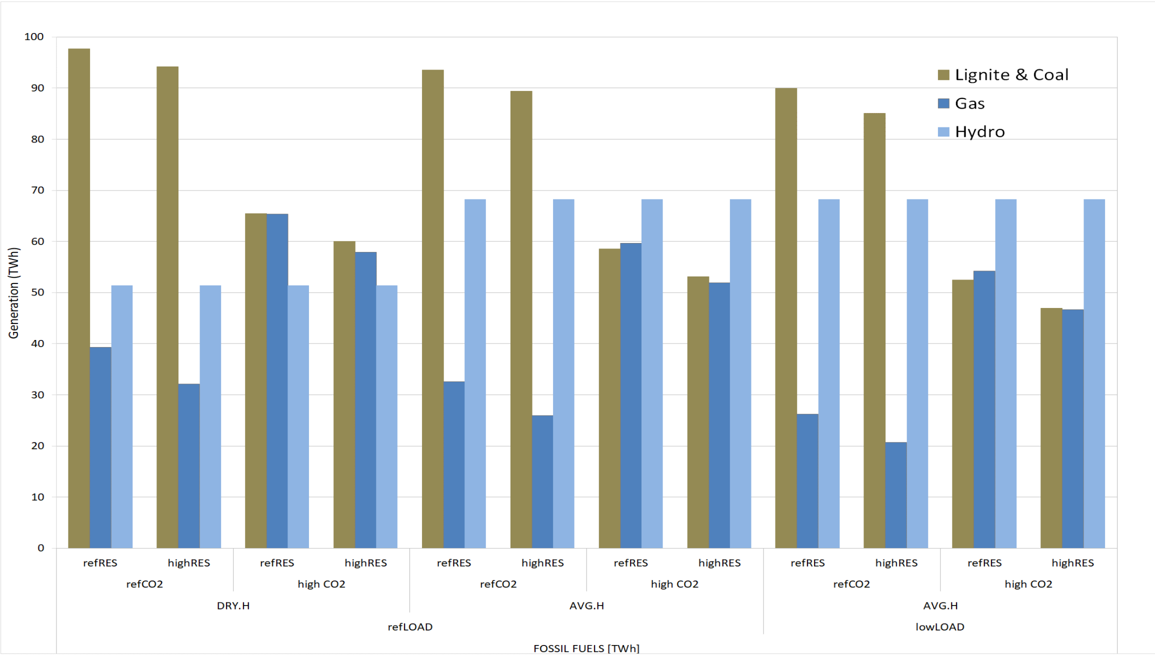


Figure 109: Fossil fuels and hydro generation in all scenarios in 2030

- RES generation (depending on the scenario) supplies between 21% and 27% of total demand (or 28% in case of slower demand growth). Separately considered, hydro and RES technologies present the second main technologies in the EMI region in 2030, and when **considered "green" technologies, hydro and RES generation become the main sources, and supplies 39% to 51% of total demand, or in case of slower demand growth, 54% of total demand.**
- As presented in Figure 110, the highest fossil plant generation is expected in the case of referent demand, referent CO_2 emission tax and dry hydrology, and it falls in the cases of higher CO_2 tax, more hydro generation (in average hydrology) and reduced regional demand.

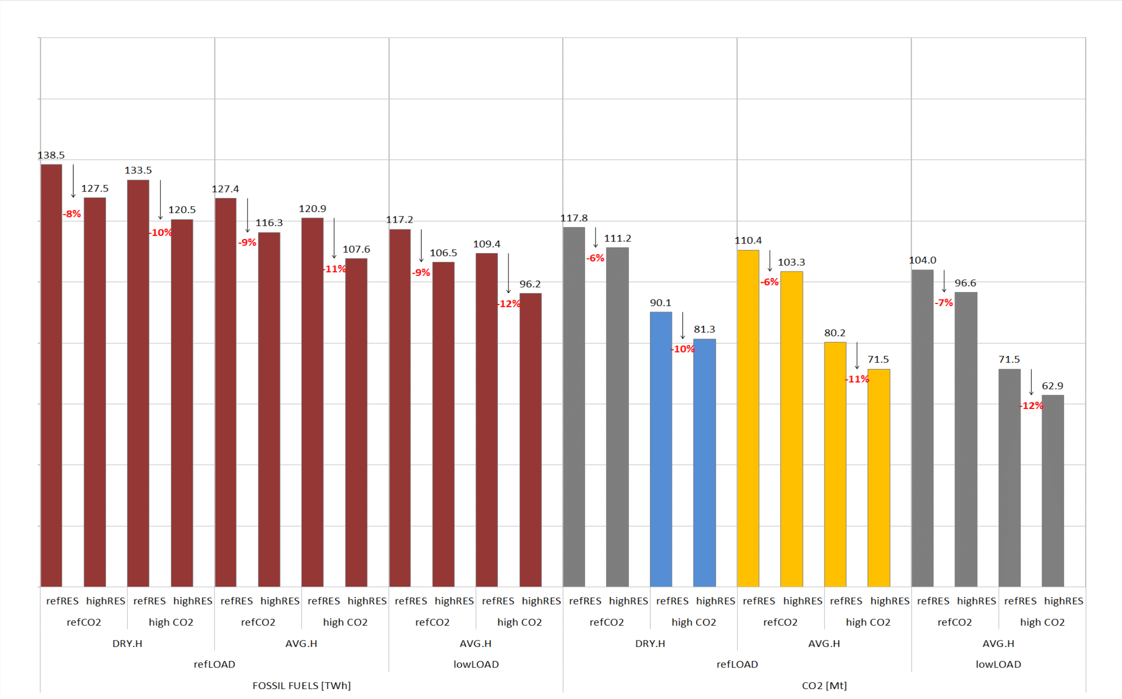


Figure 110: Fossil fuel powered plants generation in 2030 – all scenarios

- Generation from additional RES capacities of 17.6 TWh (ref.RES vs. high RES) supplies 6% of total demand of the EMI region in 2030 (or 7% in case of slower demand growth). This is lower than the RES share of installed capacity, due to the low capacity factor of wind and solar. Still, due to this RES increase, fossil generation and CO_2 emissions fall (Figure 110).
- **Higher RES generation provokes a decrease in both lignite and gas fired plants generation in almost the same volume (Figure 109). The reason is that in IPTO, one of the biggest market areas, in 2030 only gas units exist. In all other market areas, the decrease of fossil generation, due to increased generation from RES, is almost equally divided between lignite and gas technologies.**
- The EMI region has different net positions in different scenarios, as presented in Figure 111. **In the case of high CO_2 tax, dry hydrology and referent level of RES generation, the EMI region is a net importer of 3.4 TWh (1% of total demand), while in case referent CO_2 tax, average hydrology and lower demand, net export from the EMI region can reach 18.4 TWh or 6.9% of total demand.**

  Higher CO_2 tax reduces the comptetitivness of the TPPs in the region and reduces their generation which has the highest impact on regional net position. Higher RES and hydro generation enables export outside of the region, but with a smaller impact in comparison to the impact of the CO_2 tax.

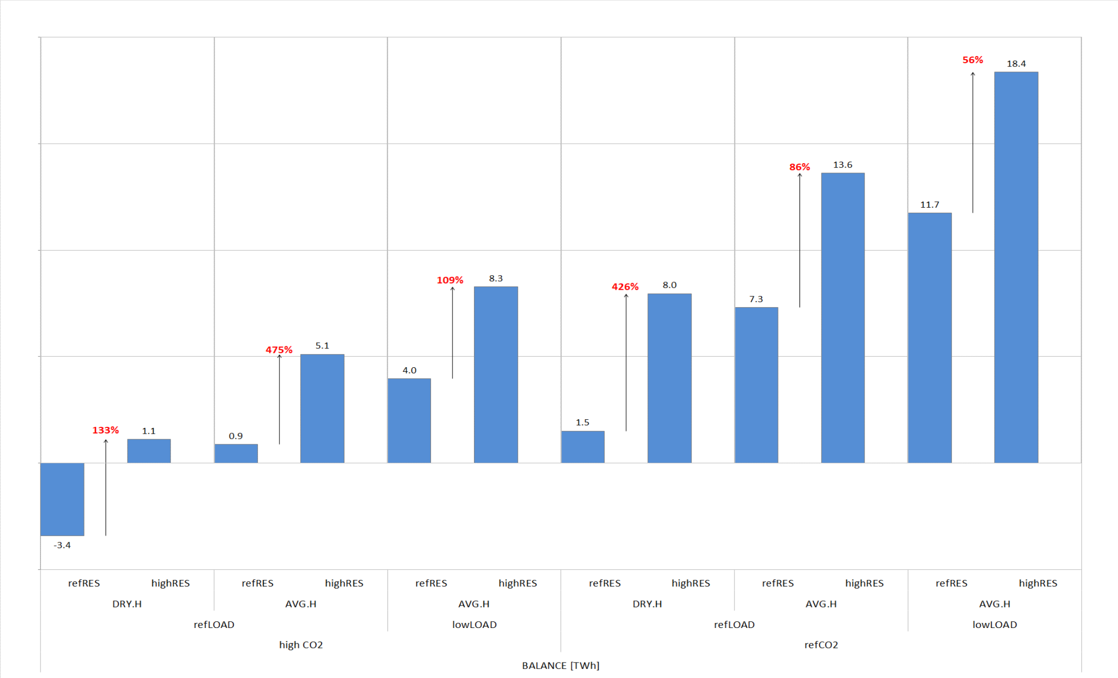


Figure 111: Balance positions of the EMI region in 2030 – all scenarios

In almost all zones where lignite plants have a significant share of the generation mix, exports fall, or the zone even becomes a net importer (NOSBiH, EMS, KOSTT markets areas) due to an increase in the CO_2 tax (Figure 112). In market areas where gas plants are a significant part of the generation mix, exports increase (Transelectrica market area) or imports decrease (HOPS market area). The IPTO market area, due to significant generation from gas, becomes a net exporter in the case of a high CO_2 tax.

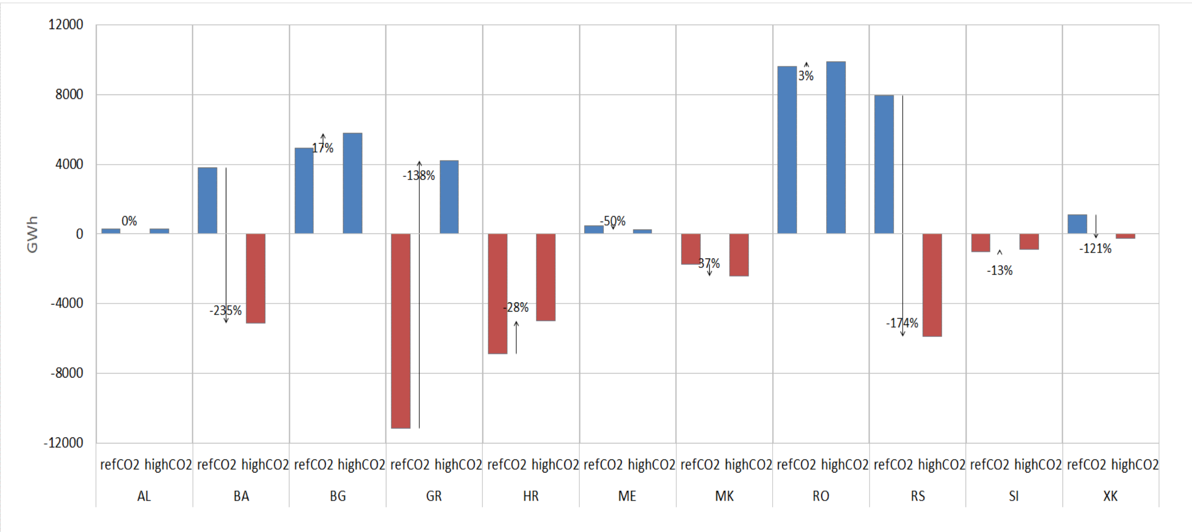


Figure 112: Balance positions per market areas in 2030 - ref. CO2 vs high CO2, referent RES integration

- **Average regional prices (Figure 113) range from 47.4 to 70.5 EUR/MWh.** High RES integration reduces prices by around 2 EUR/MWh or 4% in all scenarios. The main driver for

higher prices is the value of the CO_2 tax: the increase from 27 EUR/tCO2 to 53EUR/tCO_2 would raise wholesale market prices in the EMI region in 2030 by around 18 EUR/MWh, or around 35%.

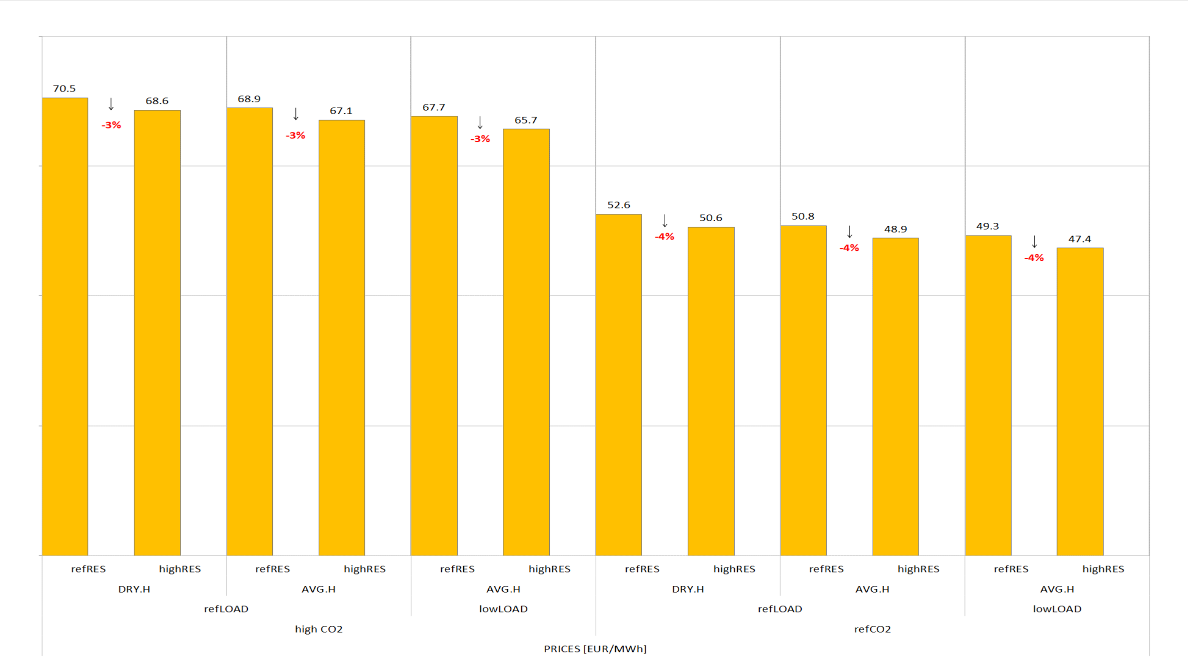


Figure 113: Prices in EMI region in 2030 - ref. RES, average hydrology

The impact of hydrology and demand level on wholesale market prices in the region is rather modest: 2 EUR/MWh in the case of hydrology, and 1.3 EUR/MWh in the case of demand.

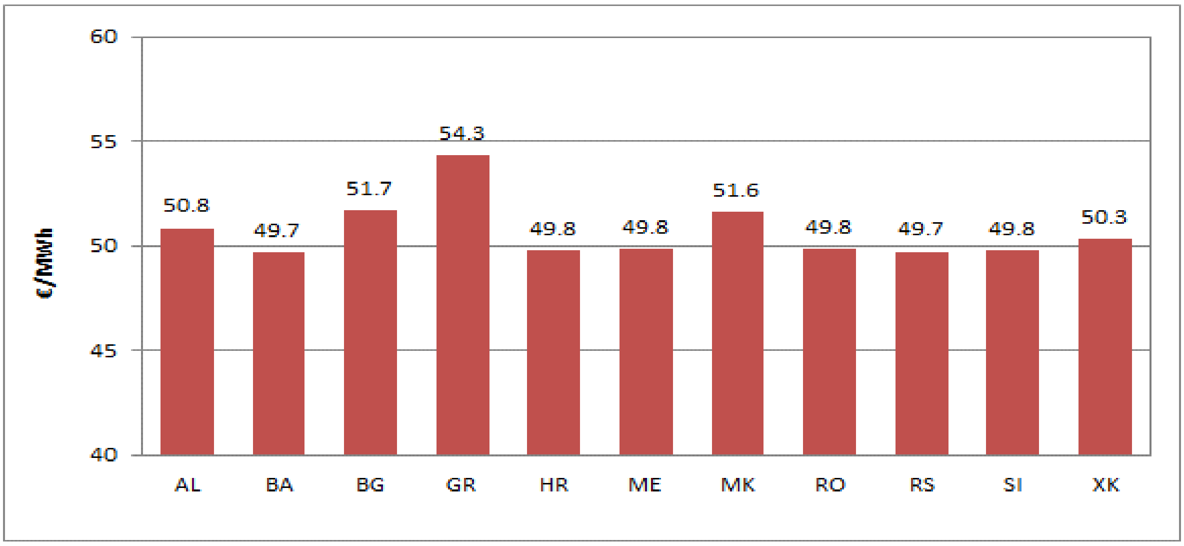


Figure 114: Prices in EMI region in 2030 – ref CO2 & ref. RES, average hydrology

In the referent CO_2 tax case, there are four price zones in the EMI region regardless of hydrology, demand growth or level of RES (Figure 114):

1) IPTO, a large importing market area with the highest wholesale market prices
2) ESO EAD and MEPSO – exporting and transiting zones, and the second highest regional prices
3) OST and KOSTT – almost balanced zones between the central zones and IPTO

4) All other zones

With the high CO_2 tax, the zones' balance positions change, and practically all zones become one price zone, without congestion between them (Figure 115).

Figure 115: Prices in EMI region in 2030 - ref. RES, average hydrology – Alternative CO_2 emission tax

Further, conventional units (mainly hydro and PSPs) as well as good interconnections between the EMI market zones (and exports) provides enough flexibility to cope with hourly variablility in RES generation. The fact that there are no spillages or curtailments in wind, solar or hydro generation in our scenarios confirms this.

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.

5.5. Additional market assessment of natural gas system development

In addition to market simulations of RES scenarios, we assessed a number of new gas plants.

According to the conclusions of the USAID/USEA Natural Gas Working Group - Eastern Europe Natural Gas Partnership (EE-NGP), the EMI countries will add 1,155 MW of gas

generation to the current fleet by 2030. This added gas capacity would lead to an increase of 3.2% in all TPP capacity in the region, and increase gas-based TTPs by 7.4%.

The additional gas generation capacity would come from five potential new projects in the EMI region till 2030, as reported by the national natural gas TSOs:

- **OST market area: TPP Kucove – 200 MW**
- **NOSBIH market area: TPP Zenica – 385 MW**
- **CGES market area: TPP Podgorica – 100 MW**
- **MEPSO market area: a) TPP TE-TO 2 – 220 MW, and b) TPP Negotino – 250 MW**

We note that the two gas-fired power plants in N. Macedonia, TPP Negotino (250 MW) and TPP TE-TO 2 (220 MW), were not mentioned in the National Energy Development Strategy nor in MEPSO's network development plan. However, as agreed at the outset of this project, we included these new gas plants based on the ongoing USAID-USEA EE-NGP regional gas project, to determine the potential impacts of such generation, when combined with large-scale RES integration.

In addition to the market analysis, we included these TPPs in the PSS/E network model provided by MEPSO. In specific, we injected the output of the gas TPP Negotino (250 MW) plant into the existing Dubrovno node, in order to avoid overloads in the local network. We assigned the remaining gas TPP production to the northern part of the transmission network (grid).

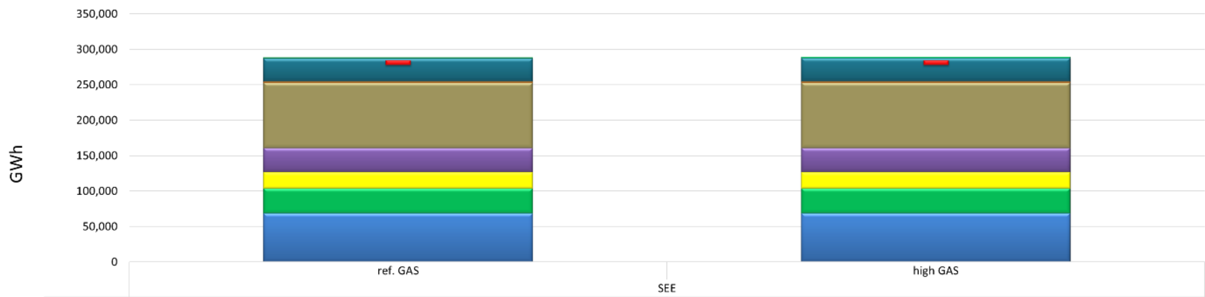
We provide the results of our corresponding market analyses with these added plants below. We analyze the impact of the additional gas generation capacities compared to the referent scenario without additional gas TPPs.

The scenario with additional gas generation units is "High GAS" scenario, while the referent scenario is "Ref GAS". The Ref GAS scenario is based on the following assumptions:

- Referent level of demand growth;
- Referent level of RES integration;
- Average hydro conditions;
- Referent level of fuel prices (gas, coal); and
- Referent level of CO_2 emission price.

The Ref GAS scenario is the same as the first scenario in the first group presented in chapter 5.1.

We show the generation mix for the whole EMI region in Figure 116, and the main indicators in Figure 117, with this additional gas-fired generation capacity.



	ref. GAS	high GAS
Other	1,261	1,264
Gas	32,590	33,322
Coal	1,688	1,687
Lignite	91,856	91,808
Nuclear	34,497	34,497
Solar	22,513	22,513
Wind	35,213	35,213
Hydro	68,712	68,685
Consumption	281,018	280,982

Figure 116: Generation mix in EMI region in 2030 - ref. GAS vs high GAS

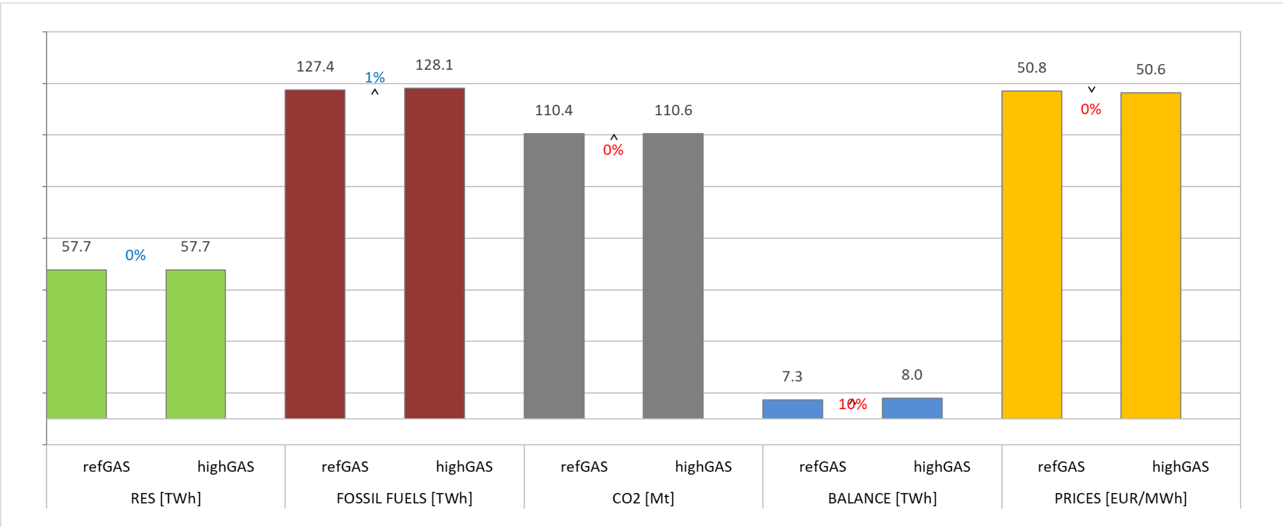


Figure 117: Main system operating indicators in EMI region in 2030 - ref. GAS vs high GAS

We draw the following conclusions from this market analysis:

- **The generation mix in the high GAS scenario is not significantly changed compared to the ref GAS (baseline) scenario. This is in part since we assumed the amount of gas generation added was modest compared to the region as a whole.**
- The main technology in 2030 is still lignite, supplying more than 33% of the load, followed by HPPs at 24%, and RES at 21%, for both levels of gas TPPs installed capacities. Gas generation does not significantly change with additional gas TPPs in the region. **In the high GAS scenario, gas generation on the regional level slightly increases, by 0.7 TWh or just 2.5% of total generation from gas-fired TPPs, and by 0.3% of regional load. The new 1,155 MW in gas TPPs also increases total regional generation by 0.7 TWh, while the gas plants' electricity output is 2.2 TWh.**

- Despite the additional gas capacity (1,155 MW), regional gas generation would not change significantly, because generation from existing, old gas TPPs will decrease due to its higher marginal generation costs. **In other words, new gas generation will mainly replace existing regional gas generation. This happens mainly in the market areas of IPTO (-1.2 TWh or -6% of existing gas generation), Transelectrica (-0.3 TWh or -4% of existing gas generation) and ESO EAD (-0.2 TWh or -27% of existing gas generation)**, as shown in Figure 118.

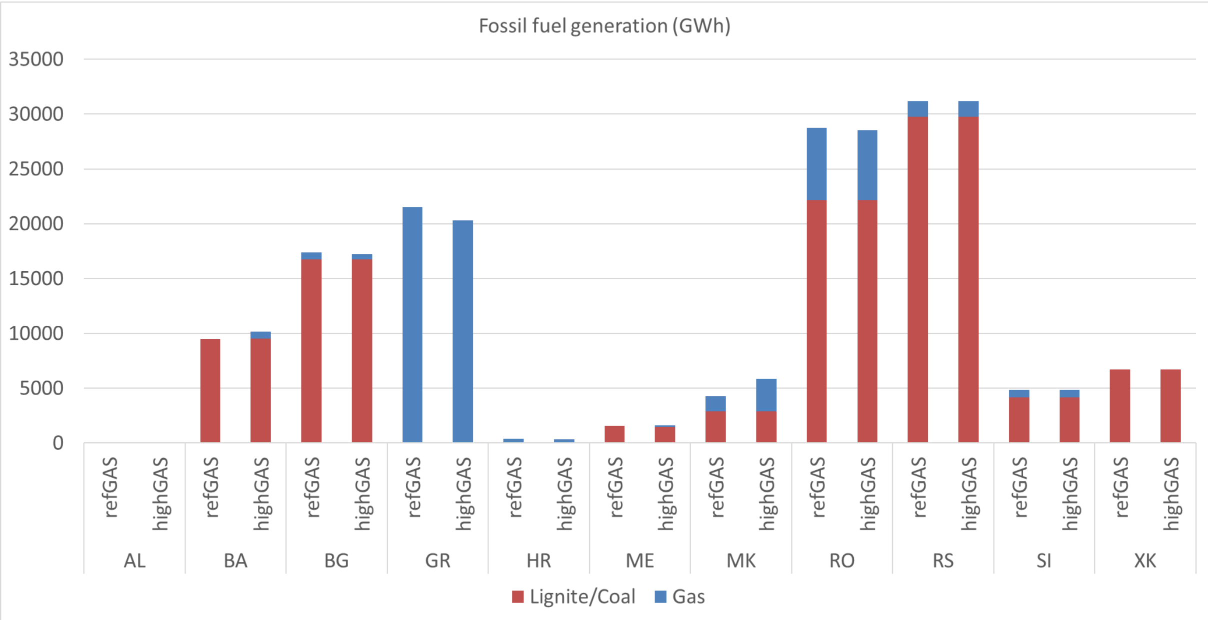


Figure 118: Fossil fuel powered plants generation in 2030 - ref. GAS vs high GAS

- **New gas TPPs will increase total gas generation in a number of market areas, by 2.9 TWh in total** (e.g., NOSBIH, MEPSO and CGES), but not in OST's market area. In the NOSBIH, MEPSO and CGES market areas, gas generation increases by 0.6 TWh, 1.6 TWh and 0.7 TWh, respectively. In OST's market area, despite new gas generation capacity, hydro is still dominant, and gas TPPs are not competitive or active on the market in this scenario.
- **With new gas in the region, the use of existing pumped storage falls.** This affects total regional consumption and the electricity balance (exports) of the region.
- The EMI region is a net exporter in 2030, and additional gas generation will slightly increase those exports. Compared to referent case, exports grows from 7.3 TWh to 8 TWh, or from 2.6% to 2.8% of total demand. In the **High GAS scenario, the EMI region increases its net exports by approximately 10% (Figure 117).**
- **In these gas scenarios, hydro and RES technologies (the "green" technologies) will become the main power generation technologies in EMI region in 2030, and will supply 45% of total demand.**
- Changes in the balance positions for all market zones correlate with the increase or decrease in gas generation, as shown in Figure 119.

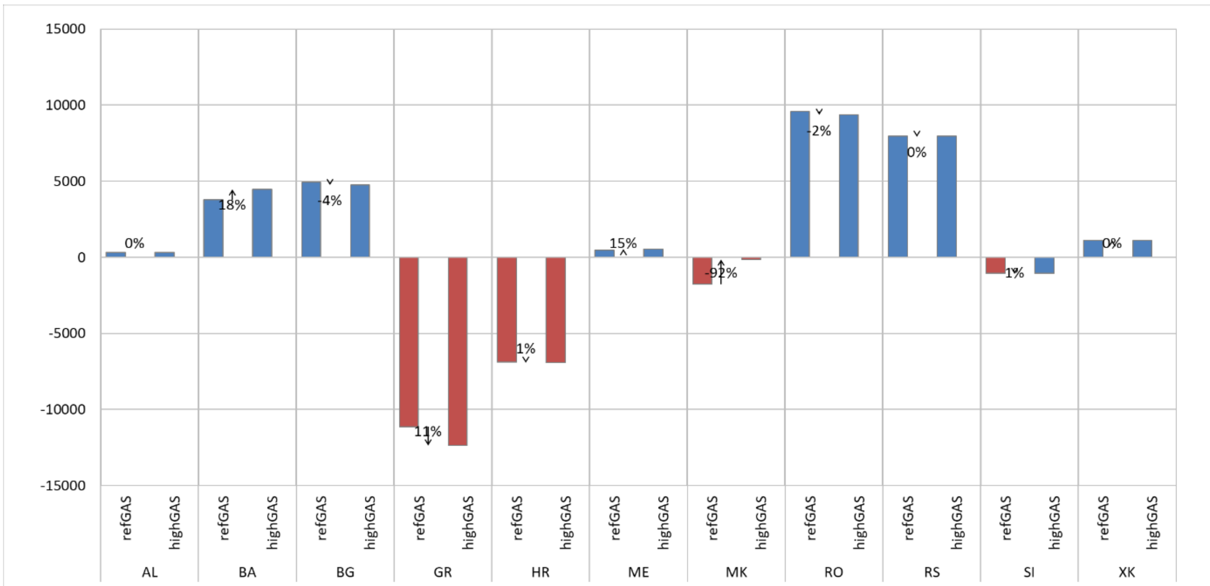


Figure 119: Balance positions per market areas in 2030 - ref. GAS vs high GAS

- In the gas scenarios, average regional prices (Figure 120) fall slightly, by 0.2 EUR/MWh, as shown in the following figure. The greatest change in the wholesale market price would be in the MEPSO market area, where the price decline would be 0.5 EUR/MWh.

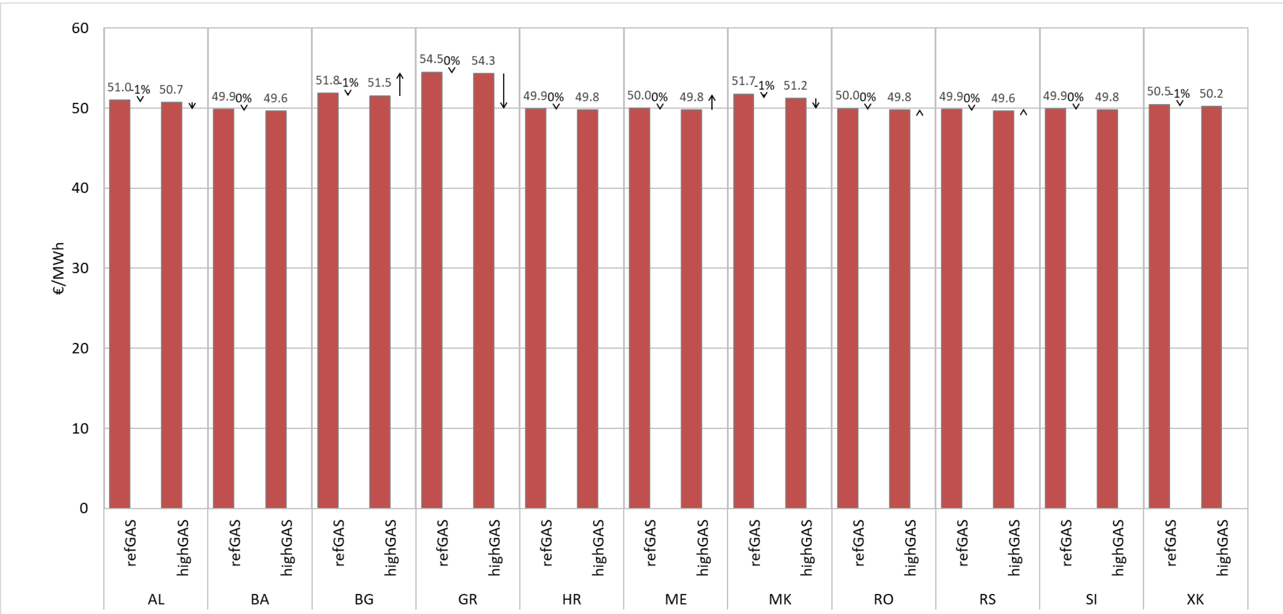


Figure 120: Prices in EMI region in 2030 - ref. GAS vs high GAS

- **From this scenario, we conclude that this level of additional gas generation capacities does not change the regional generation mix significantly.** Total generation from gas TPPs rises slightly (0.7 TWh) compared to the referent case without new gas TPPs. **Additional gas generation capacity mostly displaces older and less competitive TPPs, while at the same time providing flexibility to the power system**

to utilize RES and hydro resources in a technically and economically more efficient way. Further proof is that with new gas capacities, EMI net exports rise 10%.

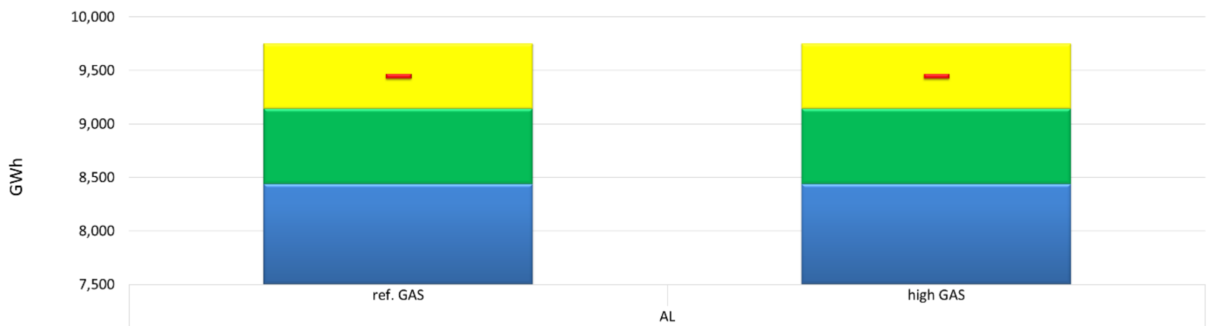
- In the case of different CO_2 emission taxes and different levels of wholesale electricity prices on the neighboring electricity markets, we expect a different generation mix.

- **The most important role of new gas TPPs in the region will be in their flexibility to accommodate expected high RES integration in the near future. More gas generation could well reduce generation from existing TPPs.**

Importantly, this analysis shows that it is valuable for EMI members to continue to evaluate gas generation options in their TYNDPs and other plans, as even the modest gas additions evaluated in this Report shows that their effects can be quite beneficial. As the gas pipeline and LNG options in the region grow, this factor will become even more important.

These conclusions are from the regional perspective. We provide individual EMI market area perspectives and values in the following subchapters. Since we draw similar conclusions from the regional and individual perspectives, we have not repeated the conclusions below, and just provided the relevant graphs.

5.5.1. OST market area



	ref. GAS	high GAS
Other	0	0
Gas	0	0
Coal	0	0
Lignite	0	0
Nuclear	0	0
Solar	606	606
Wind	703	703
Hydro	8,439	8,439
Consumption	9,442	9,442

Figure 121: Generation mix in OST market area in 2030 - ref. GAS vs high GAS

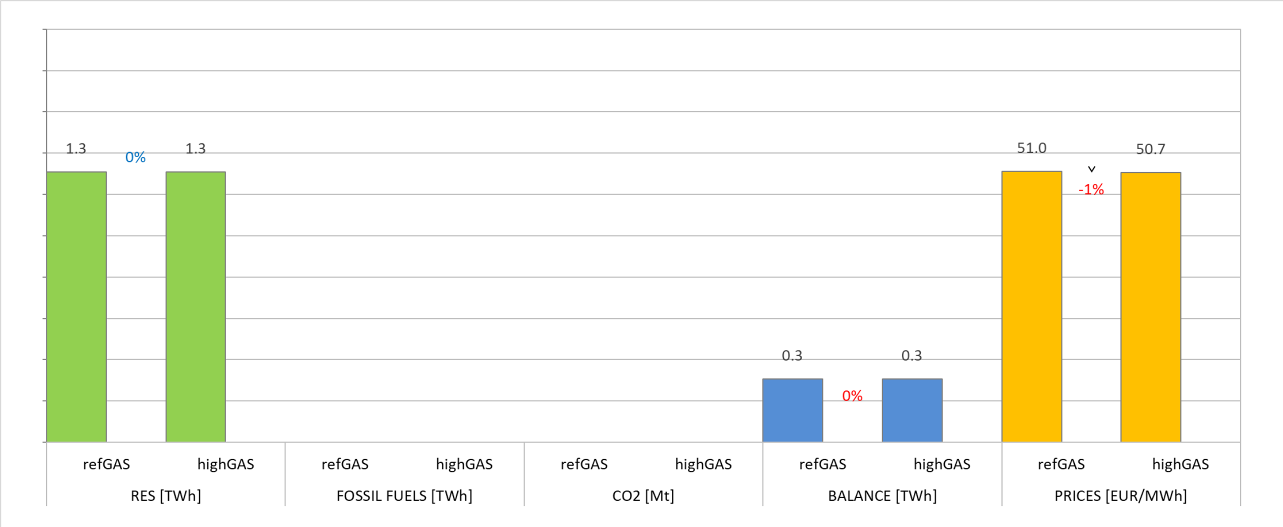
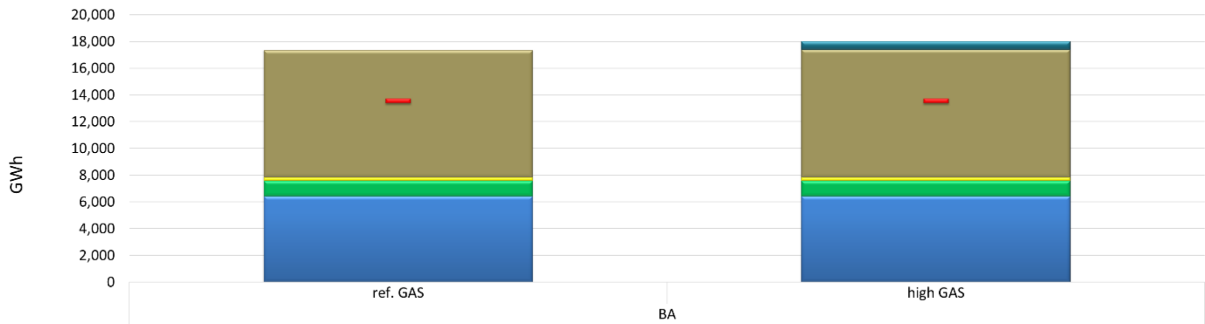


Figure 122: Main system operating indicators in OST market area in 2030 - ref. GAS vs high GAS

5.5.2. NOSBIH market area



	ref. GAS	high GAS
Other	0	0
Gas	0	623
Coal	0	0
Lignite	9,493	9,544
Nuclear	0	0
Solar	271	271
Wind	1,144	1,144
Hydro	6,425	6,424
Consumption	13,538	13,537

Figure 123: Generation mix in NOSBIH market area in 2030 - ref. GAS vs high GAS

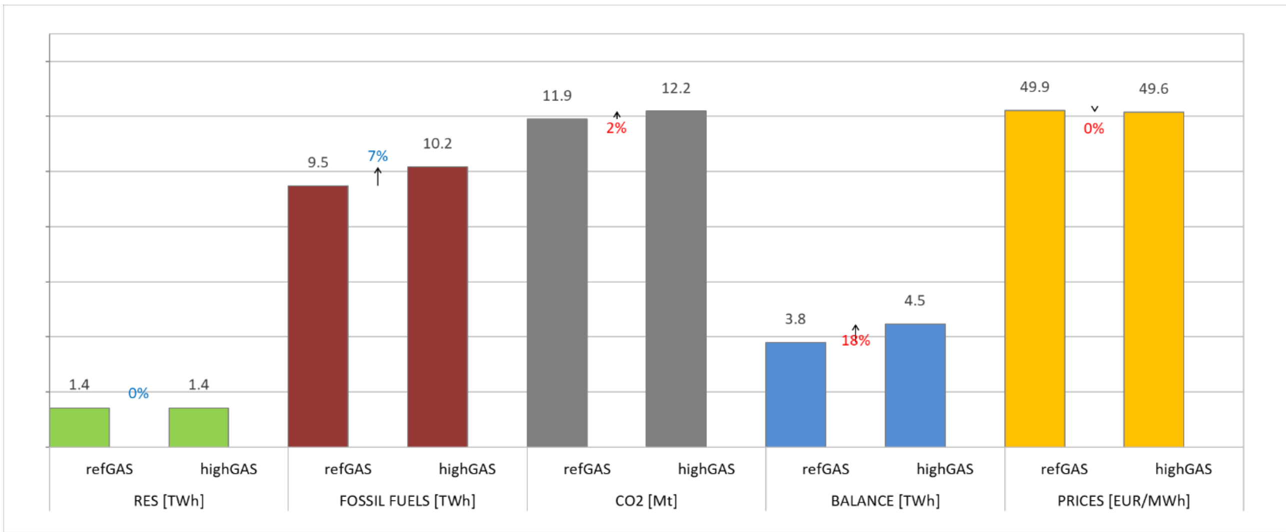
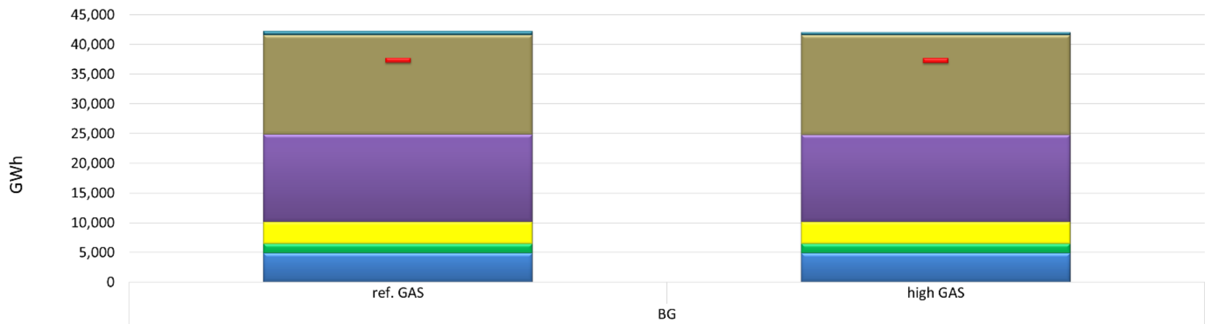


Figure 124: Main system operating indicators in NOSBIH market area in 2030 - ref. GAS vs high GAS

5.5.3. ESO EAD market area



	ref. GAS	high GAS
Other	0	0
Gas	631	461
Coal	0	0
Lignite	16,775	16,769
Nuclear	14,693	14,693
Solar	3,678	3,678
Wind	1,570	1,570
Hydro	4,873	4,866
Consumption	37,277	37,268

Figure 125: Generation mix in ESO EAD market area in 2030 - ref. GAS vs high GAS

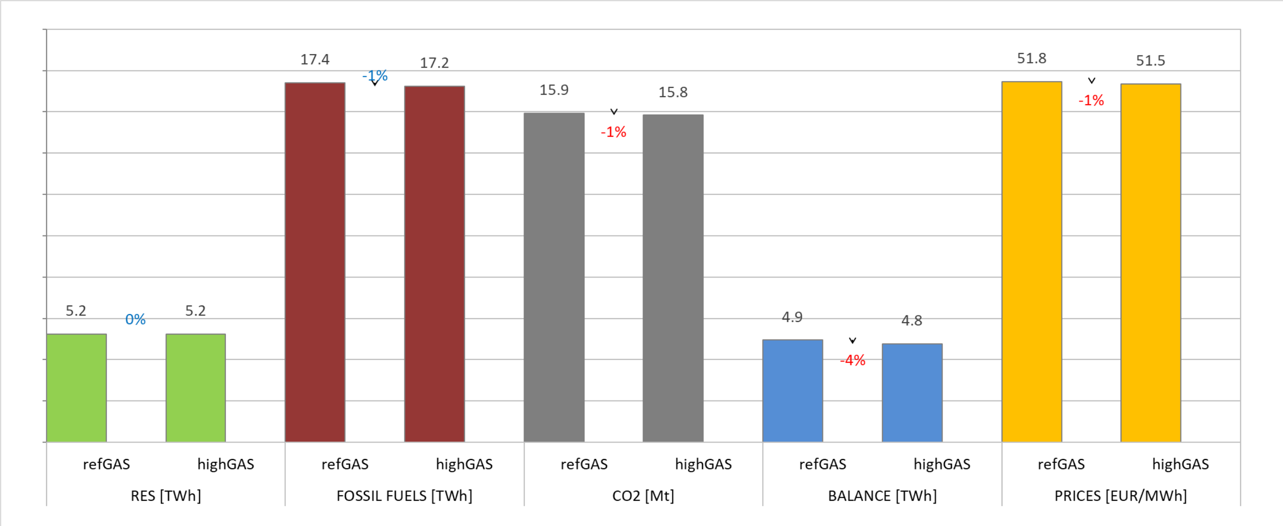
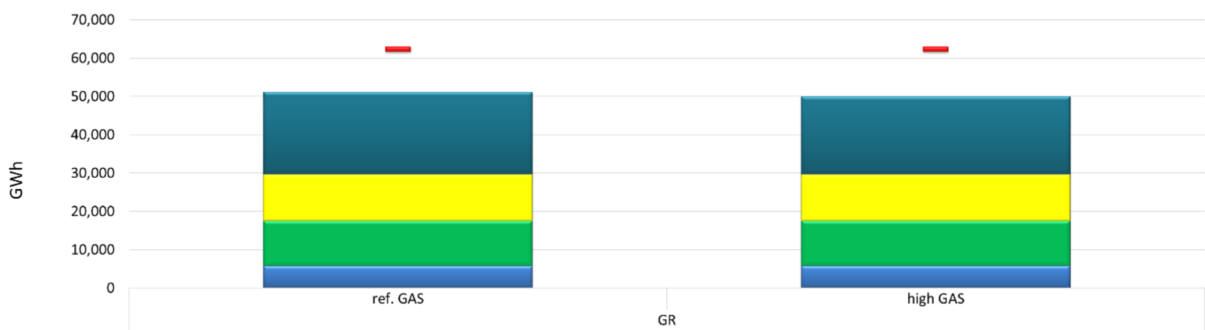


Figure 126: Main system operating indicators in ESO EAD market area in 2030 - ref. GAS vs high GAS

5.5.4. IPTO market area



	ref. GAS	high GAS
Other	0	0
Gas	21,515	20,305
Coal	0	0
Lignite	0	0
Nuclear	0	0
Solar	12,093	12,093
Wind	11,742	11,742
Hydro	5,811	5,811
Consumption	62,311	62,311

Figure 127: Generation mix in IPTO market area in 2030 - ref. GAS vs high GAS

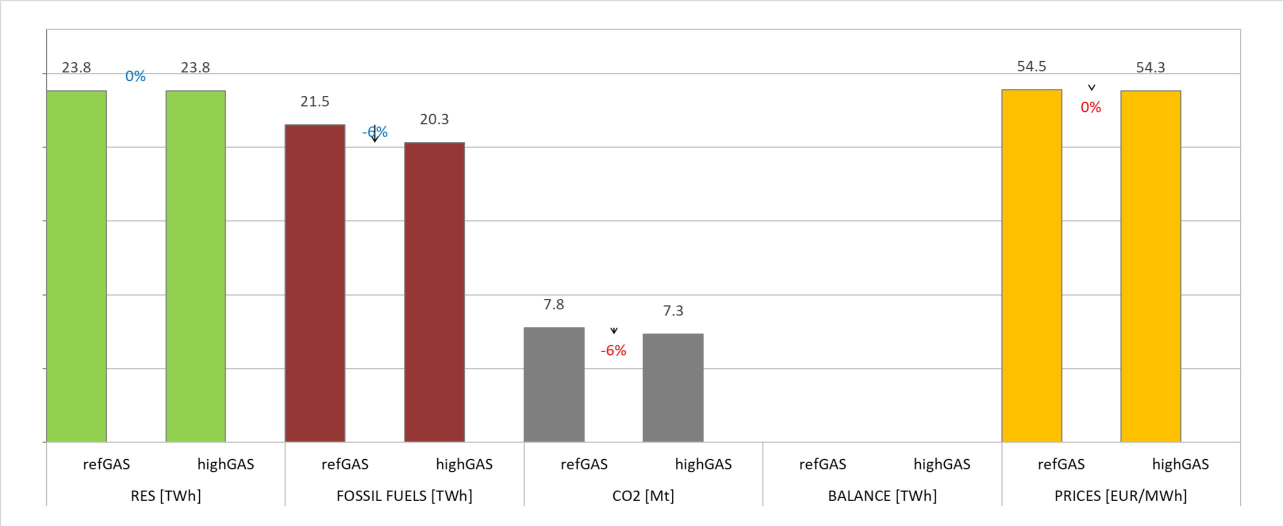
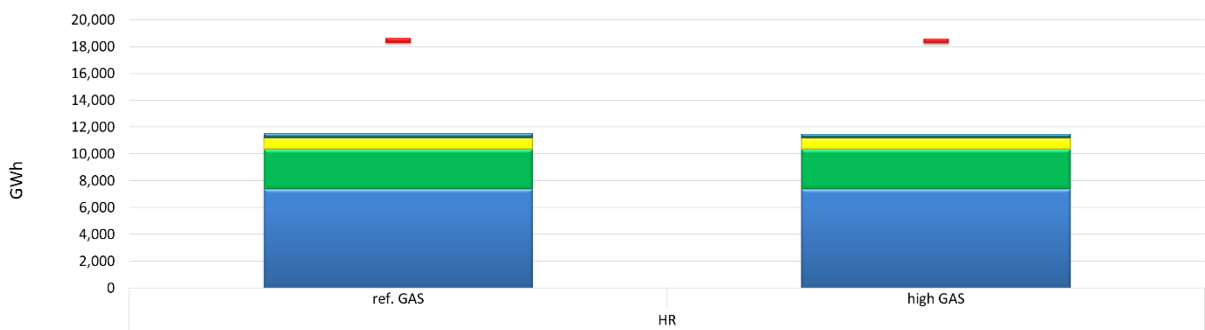


Figure 128: Main system operating indicators in IPTO market area in 2030 - ref. GAS vs high GAS

5.5.5. HOPS market area



	ref. GAS	high GAS
Other	0	0
Gas	368	320
Coal	5	5
Lignite	0	0
Nuclear	0	0
Solar	840	840
Wind	2,960	2,960
Hydro	7,373	7,367
Consumption	18,431	18,423

Figure 129: Generation mix in HOPS market area in 2030 - ref. GAS vs high GAS

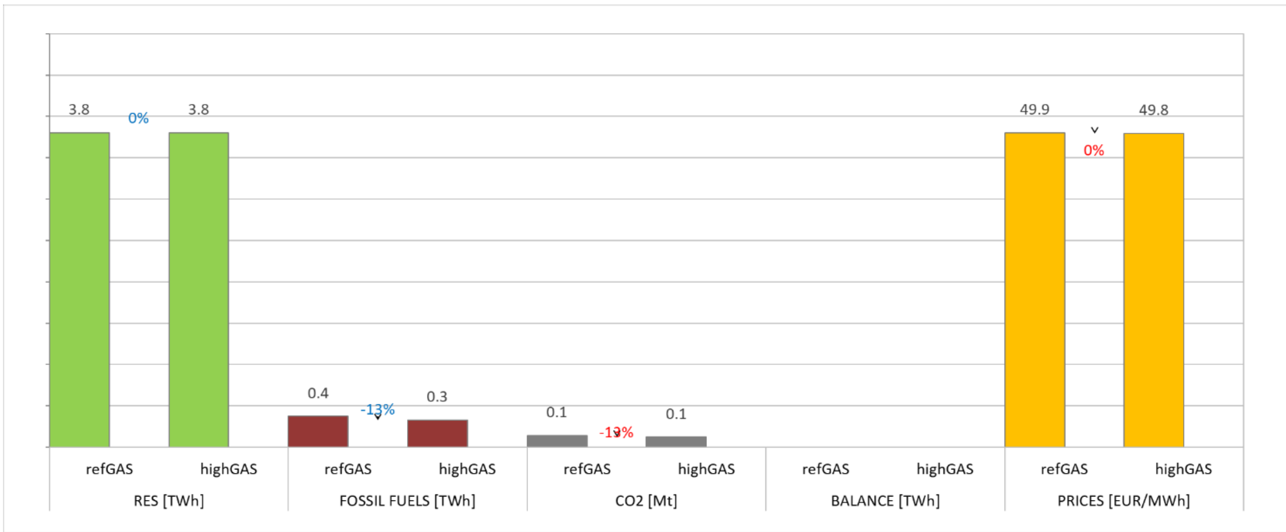
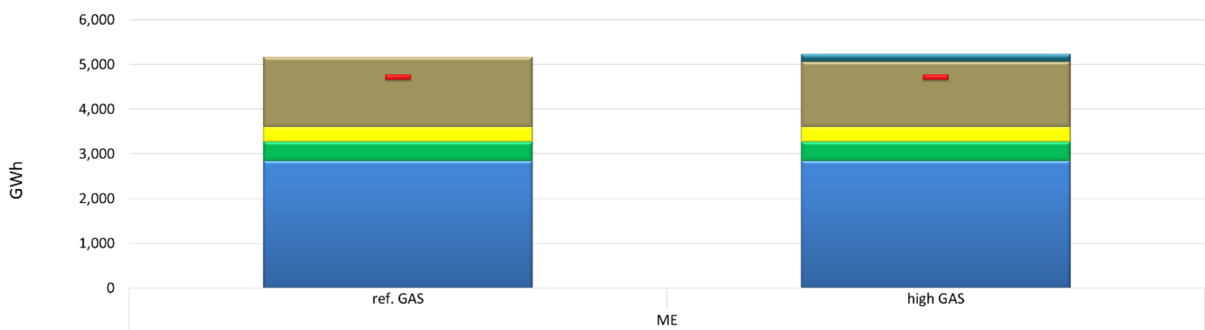


Figure 130: Main system operating indicators in HOPS market area in 2030 - ref. GAS vs high GAS

5.5.6. CGES market area



	ref. GAS	high GAS
Other	0	0
Gas	0	171
Coal	0	0
Lignite	1,557	1,456
Nuclear	0	0
Solar	341	341
Wind	423	423
Hydro	2,844	2,844
Consumption	4,710	4,710

Figure 131: Generation mix CGES market area in 2030 - ref. GAS vs high GAS

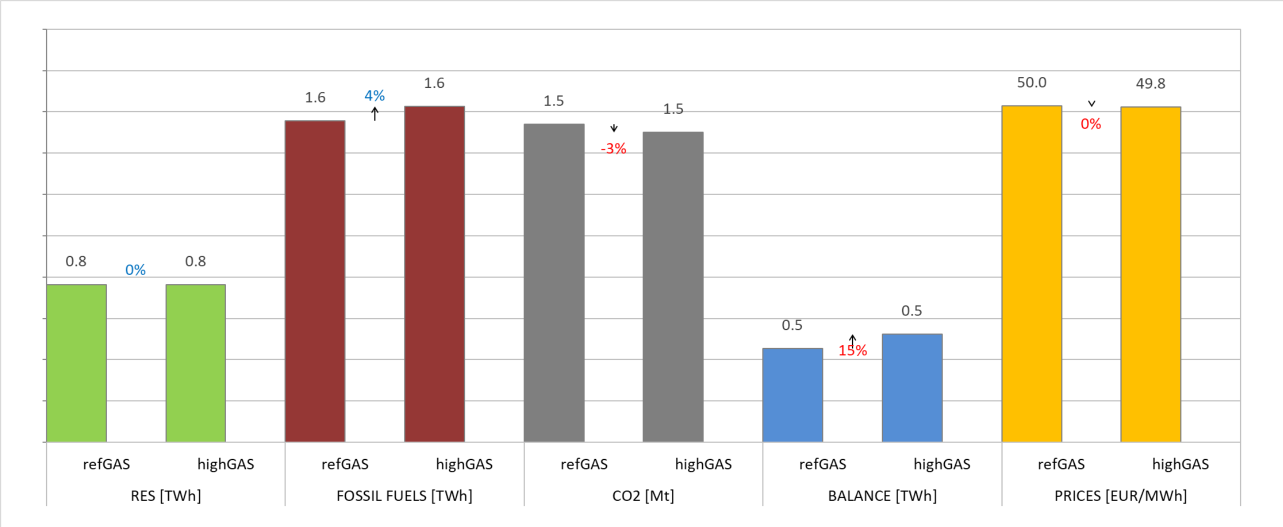
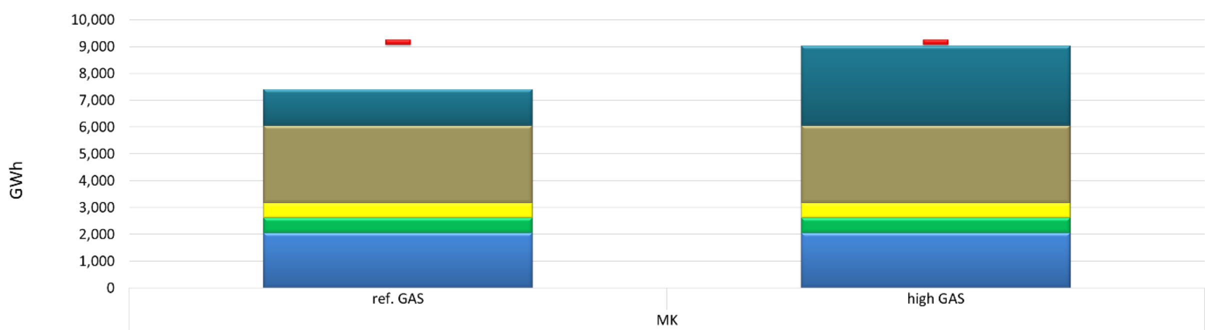


Figure 132: Main system operating indicators in CGES market area in 2030 - ref. GAS vs high GAS

5.5.7. MEPSO market area



	ref. GAS	high GAS
Other	0	0
Gas	1,356	2,974
Coal	0	0
Lignite	2,889	2,889
Nuclear	0	0
Solar	549	549
Wind	560	560
Hydro	2,058	2,058
Consumption	9,170	9,170

Figure 133: Generation mix MEPSO market area in 2030 - ref. GAS vs high GAS

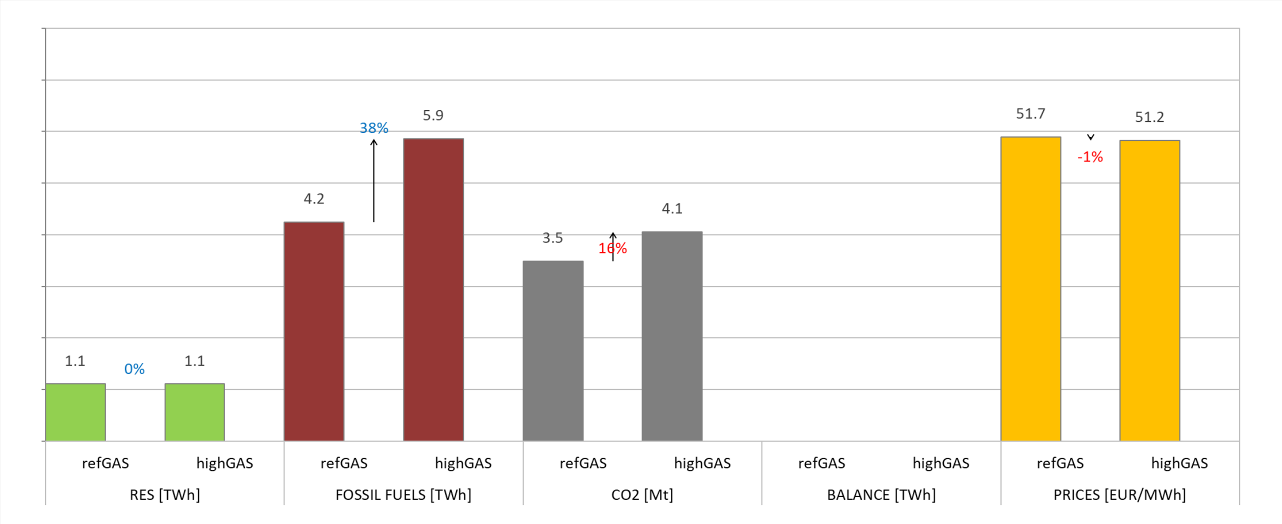
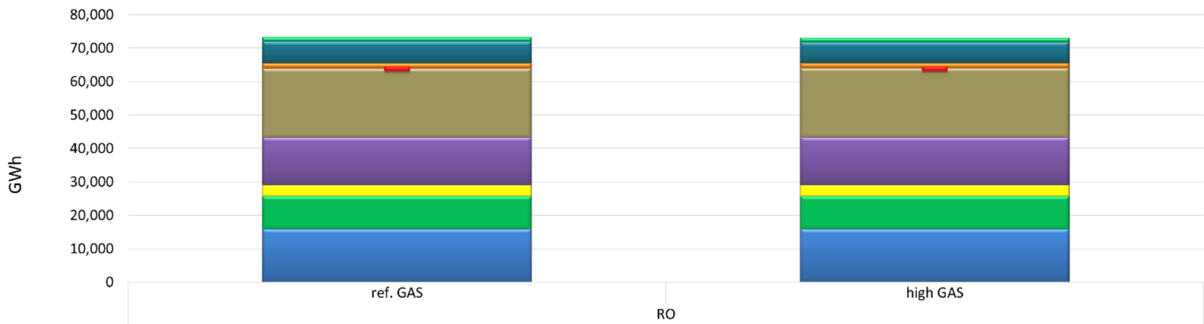


Figure 134: Main system operating indicators in MEPSO market area in 2030 - ref. GAS vs high GAS

5.5.8. Transelectrica market area



	ref. GAS	high GAS
Other	1,261	1,264
Gas	6,599	6,353
Coal	1,508	1,508
Lignite	20,655	20,670
Nuclear	14,245	14,245
Solar	3,360	3,360
Wind	9,787	9,787
Hydro	15,889	15,889
Consumption	63,717	63,717

Figure 135: Generation mix Transelectrica market area in 2030 - ref. GAS vs high GAS

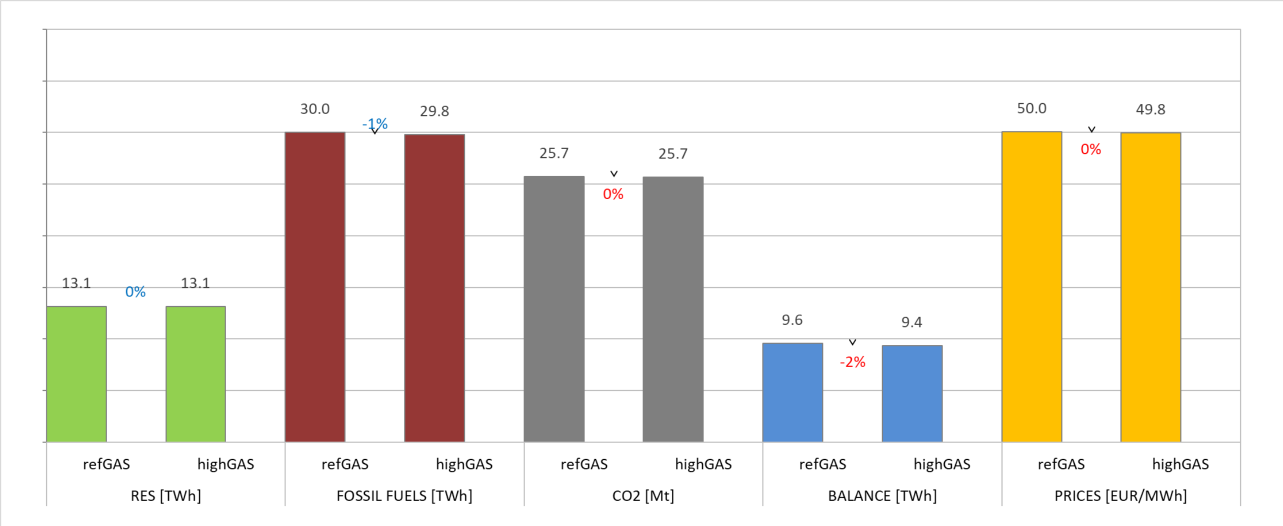
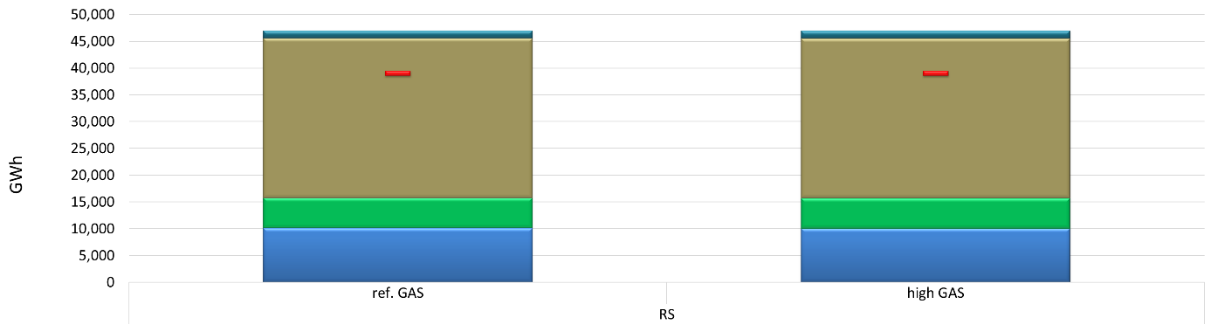


Figure 136: Main system operating indicators in Transelectrica market area in 2030 - ref. GAS vs high GAS

5.5.9. EMS market area



	ref. GAS	high GAS
Other	0	0
Gas	1,420	1,421
Coal	0	0
Lignite	29,778	29,771
Nuclear	0	0
Solar	41	41
Wind	5,639	5,639
Hydro	10,095	10,086
Consumption	39,012	39,000

Figure 137: Generation mix EMS market area in 2030 - ref. GAS vs high GAS

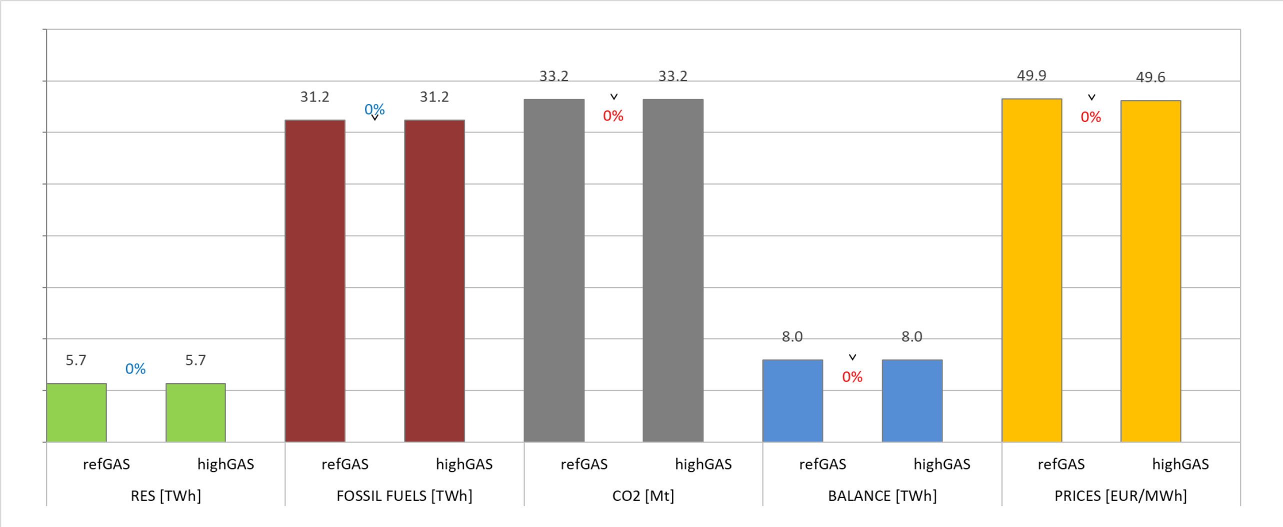
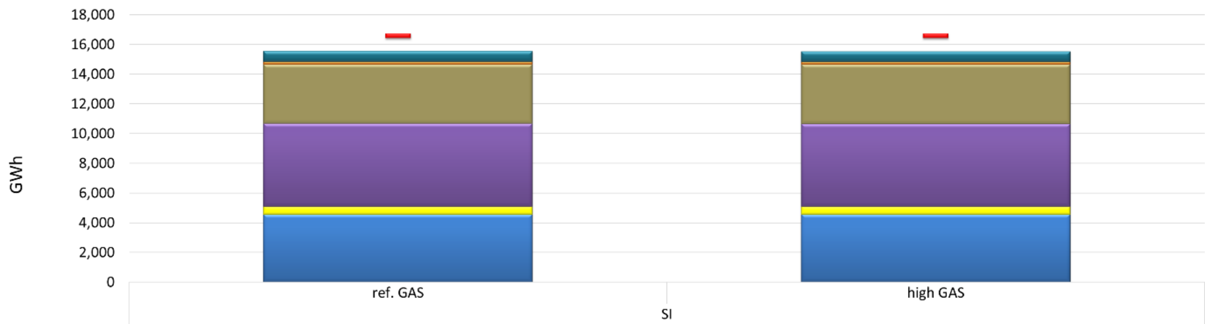


Figure 138: Main system operating indicators in EMS market area in 2030 - ref. GAS vs high GAS

5.5.10. ELES market area



	ref. GAS	high GAS
Other	0	0
Gas	700	694
Coal	175	175
Lignite	4,004	4,003
Nuclear	5,558	5,558
Solar	531	531
Wind	20	20
Hydro	4,551	4,550
Consumption	16,580	16,579

Figure 139: Generation mix ELES market area in 2030 - ref. GAS vs high GAS

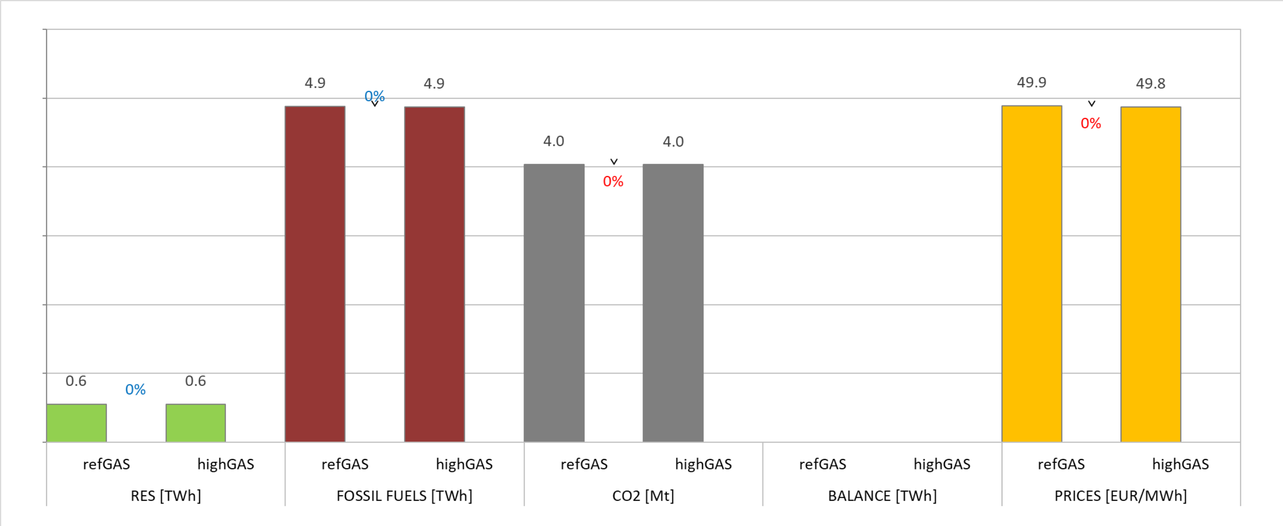
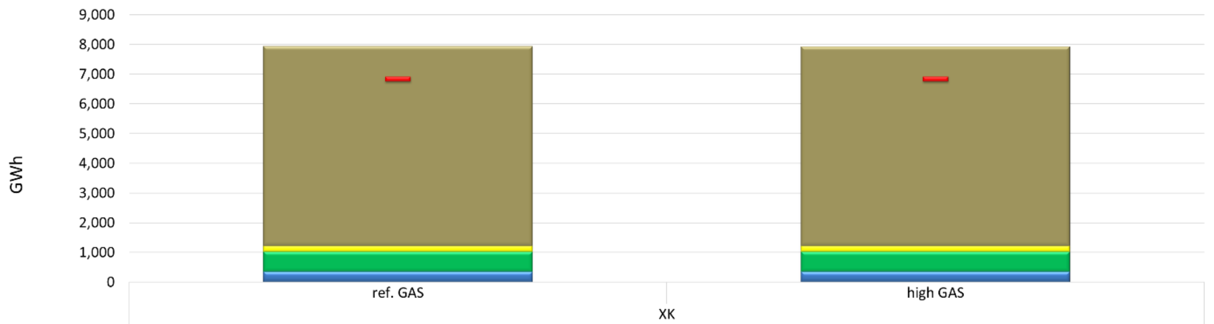


Figure 140: Main system operating indicators in ELES market area in 2030 - ref. GAS vs high GAS

5.5.11. KOSTT market area



	ref. GAS	high GAS
Other	0	0
Gas	0	0
Coal	0	0
Lignite	6,706	6,707
Nuclear	0	0
Solar	205	205
Wind	666	666
Hydro	356	352
Consumption	6,830	6,825

Figure 141: Generation mix KOSTT market area in 2030 - ref. GAS vs high GAS

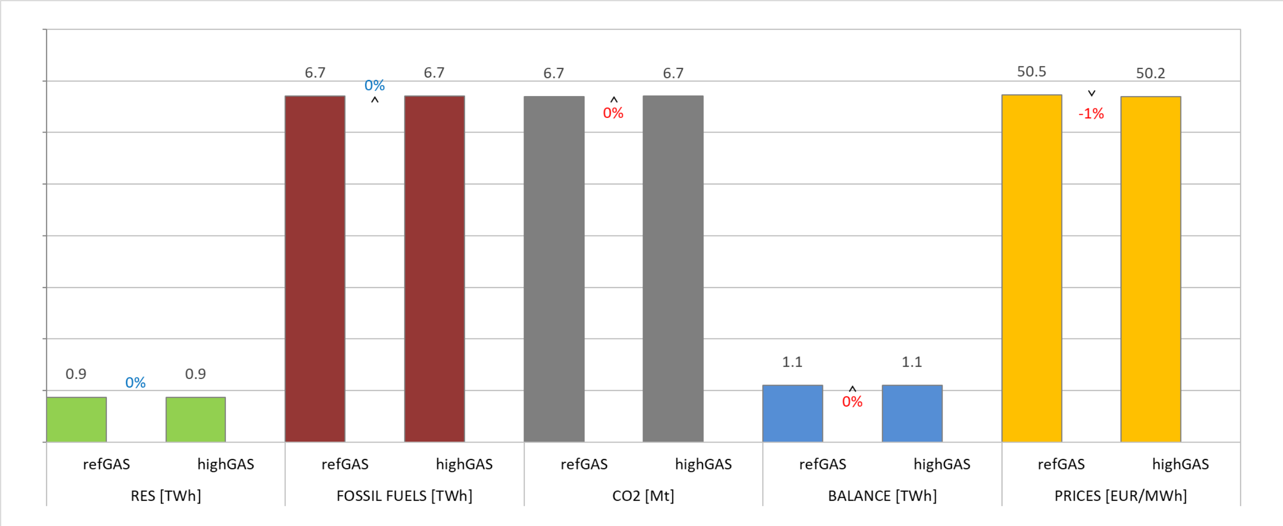


Figure 142: Main system operating indicators in KOSTT market area in 2030 - ref. GAS vs high GAS

6. NETWORK ANALYSES RESULTS

This Chapter provides the results of detailed regional power network analyse. It is focused on the impact of high RES integration on the main power network operation indicators such as:

1. Load flows
2. Voltage profiles on transmission network nodes
3. Transmission network losses for each country and on the regional level
4. Security analyses (N-1) and the detection of network bottlenecks at 110 kV and above

The biggest challenge of these network analyses was the transfer of the market results from the Antares software into the PSS/E network simulator. For this exercise we had to develop and test numerous procedures and scripts, since these two models are not directly linked and compatible. It was quite a challenging and time consuming task.

With considerable effort, we managed to create 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**

We then adapted this model and analyzed 11 scenarios (10 regular scenarios and an additional natural gas scenario). We ran each scenario in two variants:

- with all n elements available
- with n-1 element available (contingency analysis)

The other challenge in this section was to select the most appropriate format for the presentation of numerous outputs of the PSS/E network analyses. There are hundreds of pages of PSS/E outputs for selected network scenarios. Without presenting all the details, we worked to share the important results. Below, we present the network results for each scenario in the following way:

1. Each area (country) summary list, with total generation, consumption and losses;
2. Geographic map, with cross-border exhanges (MW) and directions between the countries
3. Heavily loaded branches (>80%) on the 400 kV and 220 kV levels
4. Voltage profiles on the 400 kV and 220 kV levels

5. Critical network outages and consequent overloadings (n-1 analysis)

Finally, to recap the network analyses, we provide this regional overview for all combined scenarios:

1. Total regional network losses, with individual country contributions
2. All heavily loaded branches (>80%) on the 400 kV and 220 kV levels
3. Summarized table and figure, with all n-1 analytic results

In addition, we provide the main recap on the country level. The final recapitulation and comparison between the different network scenarios gives a clear overview of the impact of high RES on transmission network operation, both on the regional and the individual country levels.

6.1. Scenario 1: Base case, referent demand growth, maximum load, referent CO2 and referent RES

We first provide the summary report, with data for each selected area. We present the area summary for the first network scenario 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	TO TIES + LOADS	DESIRED NET INT
10	2226.6	0.0	0.0	1655.7	0.0	0.0	5.7	0.0	51.2	514.0	514.0	514.0
AL	300.6	0.0	0.0	447.7	-52.8	0.0	34.0	691.7	556.3	7.1	7.1	
13	3036.9	0.0	0.0	2041.0	0.0	0.0	14.9	0.0	88.9	892.1	892.1	892.0
BA	734.5	0.0	0.0	402.0	0.0	0.0	151.9	1050.9	860.9	370.7	370.7	
14	6032.0	0.0	0.0	5785.7	0.0	0.0	58.9	0.0	169.4	18.0	18.0	18.0
BG	2056.6	0.0	0.0	2204.2	82.6	0.0	158.1	2801.9	2146.4	267.2	267.2	
16	3207.0	0.0	0.0	2630.0	0.0	0.0	4.6	0.0	157.1	415.3	415.3	415.0
HR	-144.3	0.0	0.0	620.5	106.5	0.0	22.3	1550.7	1382.4	-725.2	-725.2	
30	8611.6	0.0	0.0	9282.0	0.0	0.0	0.0	0.0	235.6	-906.0	-906.0	-906.0
GR	937.9	0.0	0.0	4535.0	1739.6	0.0	23.2	7722.7	2375.2	-12.4	-12.4	
37	1164.8	0.0	0.0	1391.0	0.0	0.0	2.1	0.0	22.7	-251.0	-251.0	-251.0
MK	230.8	0.0	0.0	482.5	0.0	0.0	8.5	495.4	268.9	-33.7	-33.7	
38	1419.4	0.0	0.0	704.0	0.0	0.0	4.5	0.0	30.9	680.0	680.0	680.0
ME	216.2	0.0	0.0	240.8	0.0	0.0	30.9	452.5	364.9	32.3	32.3	
44	14368.2	0.0	0.0	9444.0	0.0	0.0	111.8	0.0	350.3	4462.1	4462.1	4462.0
RO	147.3	0.0	0.0	2070.5	601.4	0.0	377.6	6187.7	3734.2	-448.8	-448.8	
46	8981.1	0.0	0.0	5811.0	0.0	0.0	31.4	0.0	166.6	2972.1	2972.1	2972.0
RS	1496.5	0.0	0.0	1229.3	0.0	0.0	184.2	1863.9	2191.4	-244.5	-244.5	
47	1228.1	0.0	0.0	1163.0	0.0	0.0	5.0	0.0	18.1	42.0	42.0	42.0
XK	279.1	0.0	0.0	385.8	0.0	0.0	14.8	269.5	262.1	-114.2	-114.2	
49	2156.4	0.0	0.0	2229.0	0.0	0.0	7.6	0.0	40.8	-121.0	-121.0	-121.0
SI	178.7	0.0	0.0	354.4	0.0	0.0	49.4	678.9	551.1	-97.3	-97.3	
COLUMN	52432.3	0.0	0.0	42136.4	0.0	0.0	246.5	0.0	1331.8	8717.6	8717.6	8717.0
TOTALS	6433.8	0.0	0.0	12972.6	2477.3	0.0	1054.8	23765.8	14693.8	-998.9	-998.9	

Figure 143: Area summary report in scenario 1

This regime refers to January, 16th at 6 pm (peak consumption).

In this scenario, the total regional load is 42,136 MW, while total generation is 52,432 MW. Clearly, the largest net exporters in the region in scenario 1 are Romania (4,462 MW) and Serbia (2,972 MW), while the largest importer is Greece (-906 MW). In total, in scenario 1, the EMI region has a surplus of 8,717 MW.

The following figure shows the cross-border power exchange map for scenario 1 with maximum load, referent CO_2 and referent RES. 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.

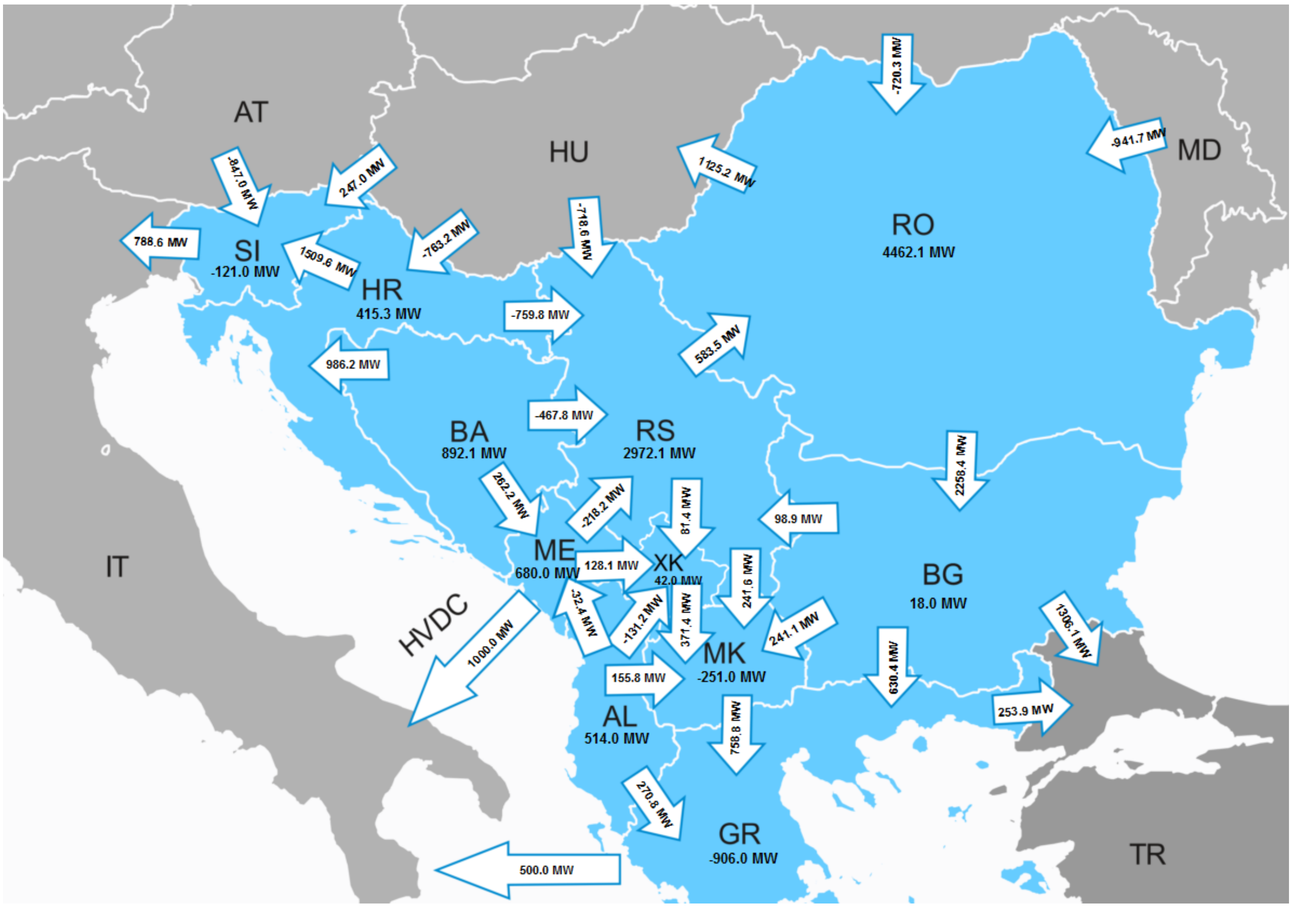


Figure 144: Cross-border exhanges (MW) and directions between the countries in scenario 1: Base case, maximum load, referent CO_2 and referent RES

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 the 400 kV network are within limits in all countries in this scenario.

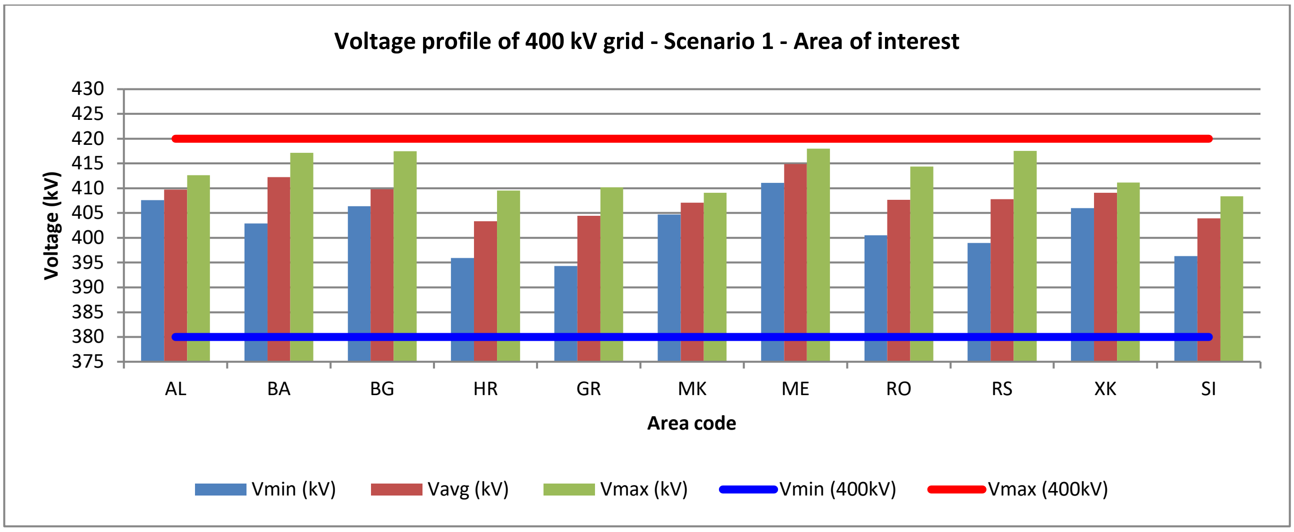


Figure 145: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 1 (base case, maximum load, referent CO_2 and referent RES)

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.

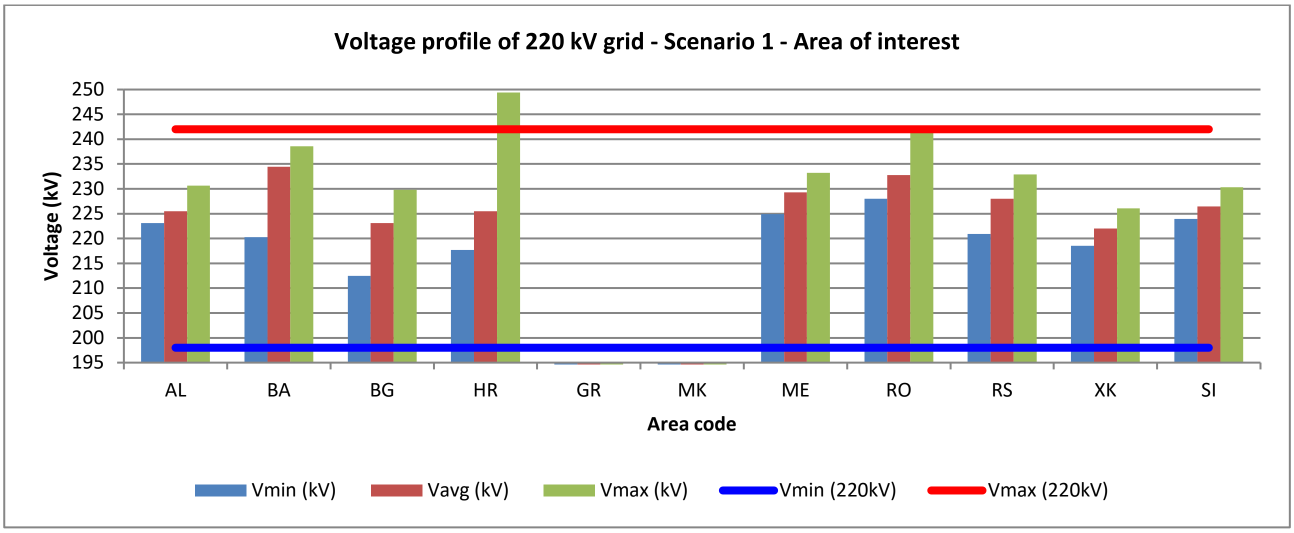


Figure 146: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 1 (base case, maximum load, referent CO_2 and referent RES)

The 400 kV and 220 kV elements that are loaded more than 80% are as follows:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	720.25	-131.78	732.21	692.80	103.28
448065	[RHAJD 2 220.00]	448914	[RR.MAR2 220.00]	-348.93	47.76	352.18	417.70	80.63

Figure 147: List of 400 and 220 kV elements loaded more than 80% in scenario 1

In scenario 1 there are just 2 elements in the region with loading above 80%, both in Romania: the interconnection to Ukraine (103%) and an internal 220 kV line (80%). It is important to note that tie-line capacity on 400 kV line Rosiori (RO) – Mukacevo (UA) is set by the Ukrainian TSO. However, this limit is quite low compared to standard typical values for 400 kV lines and it appears to be imposed by the current transformer capacity limit. Therefore, this limitation should not be considered as a serious limiting factor on the cross-border exchange.

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

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING    FLOW      %
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BASE CASE                        692.8    732.2    103.3
 133240*WTTUZL2      220.00 133250 WTUZL42     220.00 2  SINGLE 133240-133250(1)          301.0    349.7    108.8
 133240*WTTUZL2      220.00 133250 WTUZL42     220.00 1  SINGLE 133240-133250(2)          301.0    347.0    108.0
 141045 VMAIZ11      400.00 141060*VMAIZ51     400.00 1  SINGLE 141045-141065(1)          519.0    613.1    113.7
 142060*VDOBRU2      220.00 142250 VVARNA2     220.00 1  SINGLE 142085-142250(1)          360.0    375.2    103.2
 162040*HMELIN21     220.00 161035 HMELIN11    400.00 2  SINGLE 161021-162005(1)          150.0    151.8    102.4
 162040*HMELIN21     220.00 161035 HMELIN11    400.00 2  SINGLE 161035-161055(1)          150.0    155.3    105.9
 161035*HMELIN11     400.00 162040 HMELIN21    220.00 2  SINGLE 161035-161055(1)          150.0    152.9    100.6
 162040*HMELIN21     220.00 161035 HMELIN11    400.00 2  SINGLE 161035-162040-166282(1)   150.0    192.0    129.1
 161035*HMELIN11     400.00 162040 HMELIN21    220.00 2  SINGLE 161035-162040-166282(1)   150.0    186.4    122.7
 162040*HMELIN21     220.00 161035 HMELIN11    400.00 2  SINGLE 162020-162040(1)          150.0    168.3    113.3
 161035*HMELIN11     400.00 162040 HMELIN21    220.00 2  SINGLE 162020-162040(1)          150.0    165.7    107.8
 490038*DIVACA400    400.00 490123 PST_DIV     400.00 2  SINGLE 490038-490123(1)          600.0    619.0    104.3
 490038*DIVACA400    400.00 490123 PST_DIV     400.00 1  SINGLE 490038-490123(2)          600.0    619.0    104.3
  14124*XVA_MG11     400.00 141115 VVARNA1     400.00 1  BUS 14121                        900.0   1054.9    117.3
  14121*XDO_MG11     400.00 141035 VDOBRU1     400.00 1  BUS 14124                        850.0    997.0    117.2
  14141*XMI_HA11     380.00 141055 VMAIZ31     400.00 1  BUS 14142                       1200.0   1231.4    101.5
 162040*HMELIN21     220.00 161035 HMELIN11    400.00 2  BUS 16131                        150.0    271.2    184.0
 161035*HMELIN11     400.00 162040 HMELIN21    220.00 2  BUS 16131                        150.0    265.7    175.1
  32201 XPA_DI21     220.00 490018*DIVACA220   220.00 1  BUS 32101                        365.8    600.2    163.0
 162040*HMELIN21     220.00 161035 HMELIN11    400.00 2  BUS 32101                        150.0    205.3    138.4
 161035*HMELIN11     400.00 162040 HMELIN21    220.00 2  BUS 32101                        150.0    200.5    131.6

 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 133240-133250(1)          Met convergence to     1     0    0.0
 SINGLE 133240-133250(2)          Met convergence to     1     0    0.0
 SINGLE 141045-141065(1)          Met convergence to     1     0   38.0
 SINGLE 142085-142250(1)          Met convergence to     1     0    0.0
 SINGLE 161021-162005(1)          Met convergence to     1     0    0.0
 SINGLE 161035-161055(1)          Met convergence to     2     0    0.0
 SINGLE 161035-162040-166282(1)   Met convergence to     2     0    0.0
 SINGLE 162020-162040(1)          Met convergence to     2     0    0.0
 SINGLE 490038-490123(1)          Met convergence to     1     0    0.0
 SINGLE 490038-490123(2)          Met convergence to     1     0    0.0
 BUS 14121                        Met convergence to     1     0    0.0
 BUS 14124                        Met convergence to     1     0    0.0
 BUS 14142                        Met convergence to     1     0    0.0
 BUS 16131                        Met convergence to     2     0    0.0
 BUS 32101                        Met convergence to     3     0    0.0

CONTINGENCY LEGEND: (selected 16 contingecies appeared above from list of total 792 analyzed contingencies)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 133240-133250(1)         : OPEN LINE FROM BUS 133240 [WTTUZL2     220.00] TO BUS 133250 [WTUZL42     220.00] CKT 1
 SINGLE 133240-133250(2)         : OPEN LINE FROM BUS 133240 [WTTUZL2     220.00] TO BUS 133250 [WTUZL42     220.00] CKT 2
 SINGLE 141045-141065(1)         : OPEN LINE FROM BUS 141045 [VMAIZ11     400.00] TO BUS 141065 [VMAIZ61     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 161021-162005(1)         : OPEN LINE FROM BUS 161021 [HVEKRP21    220.00] TO BUS 162005 [HBRINJ21    220.00] CKT 1
 SINGLE 161035-161055(1)         : OPEN LINE FROM BUS 161035 [HMELIN11    400.00] TO BUS 161055 [HTUMBR11    400.00] CKT 1
 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 162020-162040(1)         : OPEN LINE FROM BUS 162020 [HESENJ22    220.00] TO BUS 162040 [HMELIN21    220.00] CKT 1
 SINGLE 490038-490123(1)         : OPEN LINE FROM BUS 490038 [DIVACA400   400.00] TO BUS 490123 [PST_DIV     400.00] CKT 1
 SINGLE 490038-490123(2)         : OPEN LINE FROM BUS 490038 [DIVACA400   400.00] TO BUS 490123 [PST_DIV     400.00] CKT 2
 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    380.00] TO BUS 141055 [VMAIZ31     400.00] CKT 1
                                   OPEN LINE FROM BUS 14142 [XMI_HA12    380.00] 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 490038 [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 490123 [PST_DIV     400.00] CKT 1
```

Figure 148: Contingency (n-1) analysis report for scenario 1

In the base case (scenario 1) there are 16 contingency events. There are five cases with overloadings higher than 130% (given above in red). In the base case, with all elements available, the interconnection line Rosiori (Ro) – Mukacevo (UA) 400 kV is slightly overloaded (103%), as mentioned above. Since there is an overload in the base case, this element is not shown as an overloaded element in all the other outages.

It is important to explain the overloading on branch VMAIZ11-VMAIZ51 in Bulgaria that appears in a few scenarios. Two generator units are connected to the same bus via overhead lines (OHTL). One of these units is the Bulgarian swing generator. In case of an outage of the OHTL radially connected to the generator, our model shows an overload on the OHTL connecting the swing bus. Therefore, this overload does not represent an operational issue. However, in accordance with our agreed principle, and to be consistent, we have kept it in the report, with this explanation note.

6.2. Scenario 2: Base case, referent demand growth, minimum load, referent CO2 and referent RES

The area summary for the second network scenario is 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	633.1	0.0	0.0	596.0	0.0	0.0	5.3	0.0	30.9	1.0	1.0	1.0
AL	-59.2	0.0	0.0	168.5	548.7	0.0	32.2	738.9	257.3	-327.0	-327.0	
13	732.7	0.0	0.0	970.0	0.0	0.0	15.0	0.0	22.6	-275.0	-275.0	-275.0
BA	-206.5	0.0	0.0	184.1	0.0	0.0	153.5	1159.3	196.7	418.6	418.6	
14	4024.9	0.0	0.0	2725.7	0.5	0.0	61.1	0.0	91.5	1146.0	1146.0	1146.0
BG	1102.6	0.0	0.0	1038.8	1316.9	0.0	164.8	2939.7	1241.5	280.2	280.2	
16	1043.1	0.0	0.0	1243.0	0.0	0.0	5.3	0.0	40.8	-246.0	-246.0	-246.0
HR	-314.8	0.0	0.0	293.2	248.5	0.0	25.6	1772.1	317.5	572.5	572.5	
30	2649.9	0.0	0.0	4837.0	0.0	0.0	0.0	0.0	103.0	-2290.0	-2290.0	-2290.0
GR	-1587.5	0.0	0.0	2499.4	2177.0	0.0	23.8	8434.2	1596.8	549.6	549.6	
37	77.0	0.0	0.0	672.0	0.0	0.0	2.3	0.0	11.6	-609.0	-609.0	-609.0
MK	-25.2	0.0	0.0	245.9	0.0	0.0	9.4	538.1	123.6	134.0	134.0	
38	304.9	0.0	0.0	343.0	0.0	0.0	4.8	0.0	27.1	-70.0	-70.0	-70.0
ME	-42.3	0.0	0.0	121.3	0.0	0.0	34.0	484.5	239.6	47.3	47.3	
44	6924.8	0.0	0.0	5465.0	0.0	0.0	111.3	0.0	140.2	1208.3	1208.3	1208.0
RO	-853.4	0.0	0.0	1761.1	2179.9	0.0	376.3	6179.5	1521.5	-512.7	-512.7	
46	2385.1	0.0	0.0	2784.5	0.0	0.0	30.2	0.0	57.5	-487.0	-487.0	-487.0
RS	-336.2	0.0	0.0	810.9	0.0	0.0	118.1	1964.3	667.8	31.4	31.4	
47	275.0	0.0	0.0	402.0	0.0	0.0	5.5	0.0	9.5	-142.0	-142.0	-142.0
XK	-35.7	0.0	0.0	135.7	0.0	0.0	16.2	289.7	110.6	-8.3	-8.3	
49	1905.8	0.0	0.0	1492.0	0.0	0.0	8.2	0.0	18.6	387.0	387.0	387.0
SI	-433.2	0.0	0.0	256.2	-171.6	0.0	52.7	726.5	272.5	-116.5	-116.5	
COLUMN	20956.2	0.0	0.0	21530.2	0.5	0.0	248.9	0.0	553.3	-1376.8	-1376.8	-1377.0
TOTALS	-2791.4	0.0	0.0	7515.2	6299.4	0.0	1006.6	25227.0	6545.5	1069.0	1069.0	

Figure 149: Area summary report in scenario 2

This regime refers to May 6th, at 4 am (minimum load).

With the minimum load (scenario 2), the total regional load is significantly lower, at 21,530 MW (51% of the max load in scenario 1 with 42,136 MW), while total generation is 20,956 MW (compared to max load regime with 52,432 MW). The difference between total generation and the load is consumed by the network losses. The largest net exporters in the region in scenario 2 are Romania again (1,208 MW) and Bulgaria (1,146 MW), while the largest importer is again Greece (-2,290 MW). In total, the region has a deficit of -1,377 MW.

The following Figure shows the cross-border power exchange map. The HVDC submarine cables to Italy in this scenario now transfer power in the opposite direction in comparison with scenario 1 – from Italy to SEE (the arrow is still pointing to Italy, but the value is negative). Tthe East side of SEE, exports to Turkey remains the same, around 1,500 MW.

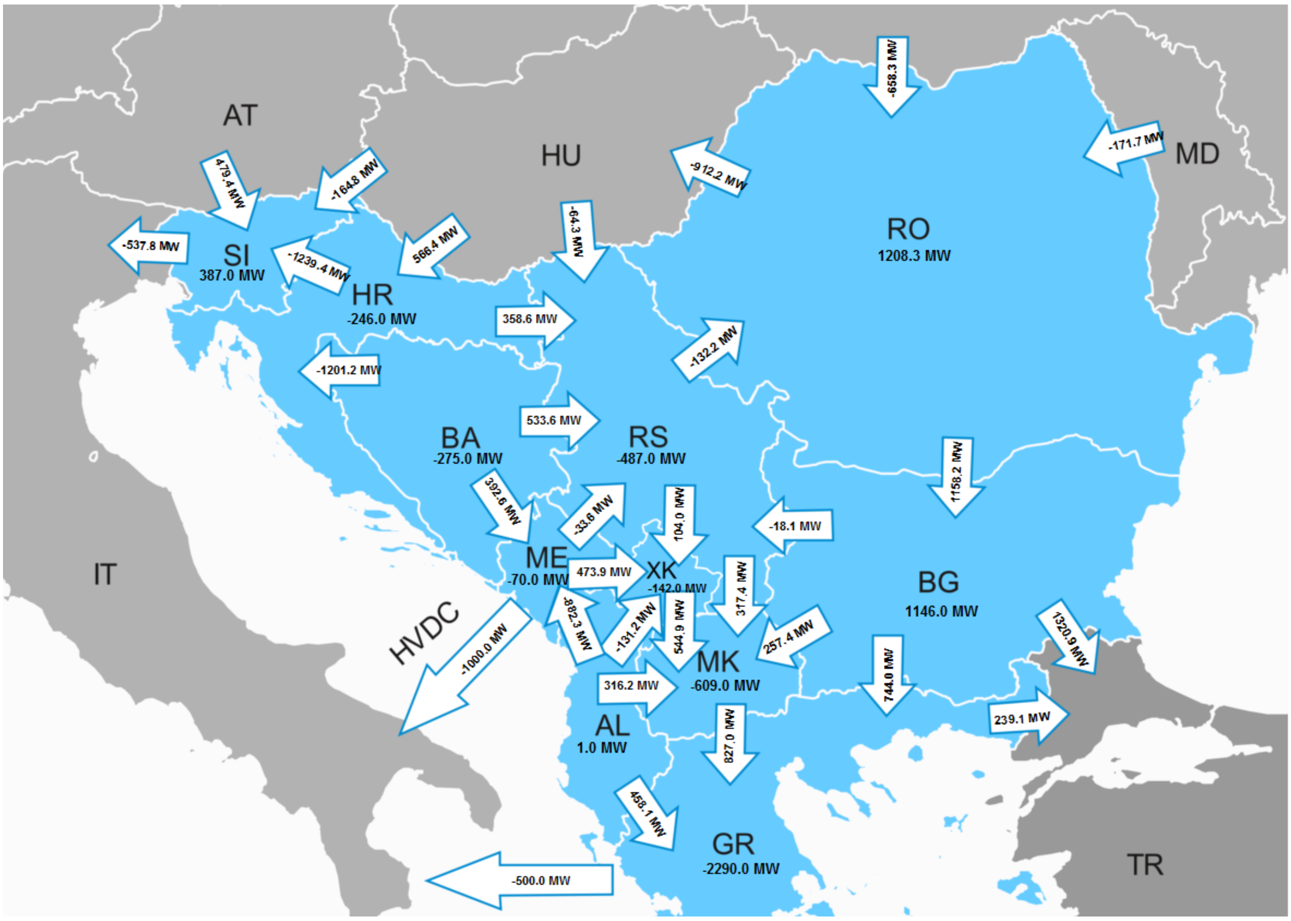


Figure 150: Cross-border exhanges (MW) and directions between the countries in scenario 1: Base case, minimum load, referent CO_2 and referent RES

The following two figures show the 400 kV and 220 kV voltage profiles in each country with maximum, minimum and average values in each country.

As expected, in the minimum load regime, the 400 kV and 220 kV voltages in the region are higher than in scenario 1, and in some countries even above the limits, especially in 400 kV network.

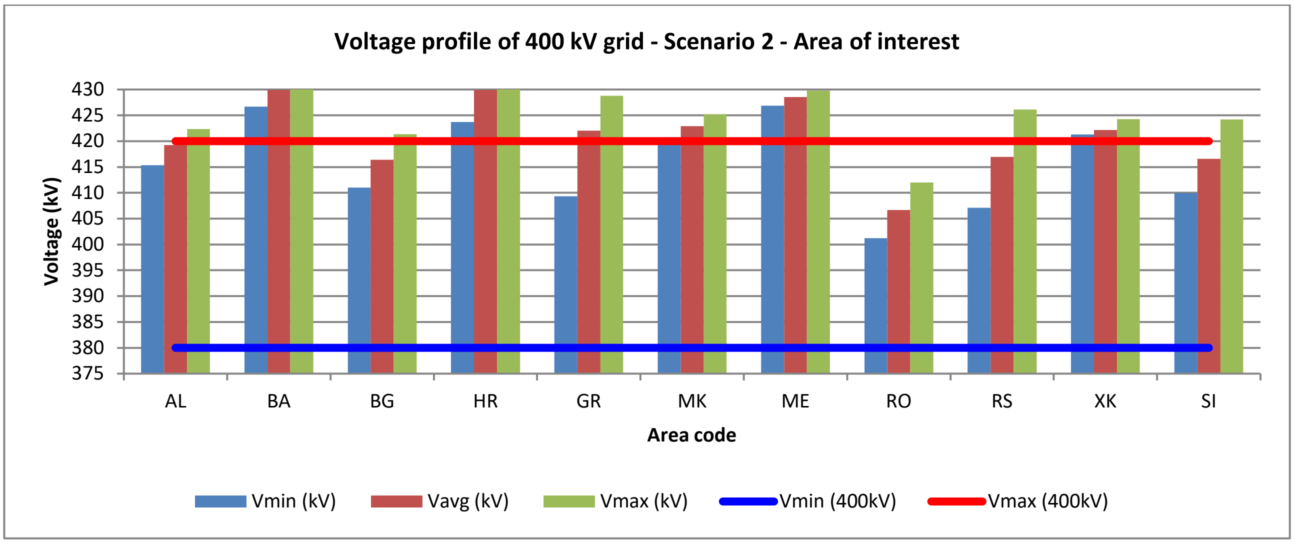


Figure 151: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 2 (base case, minimum load, referent CO_2 and referent RES)

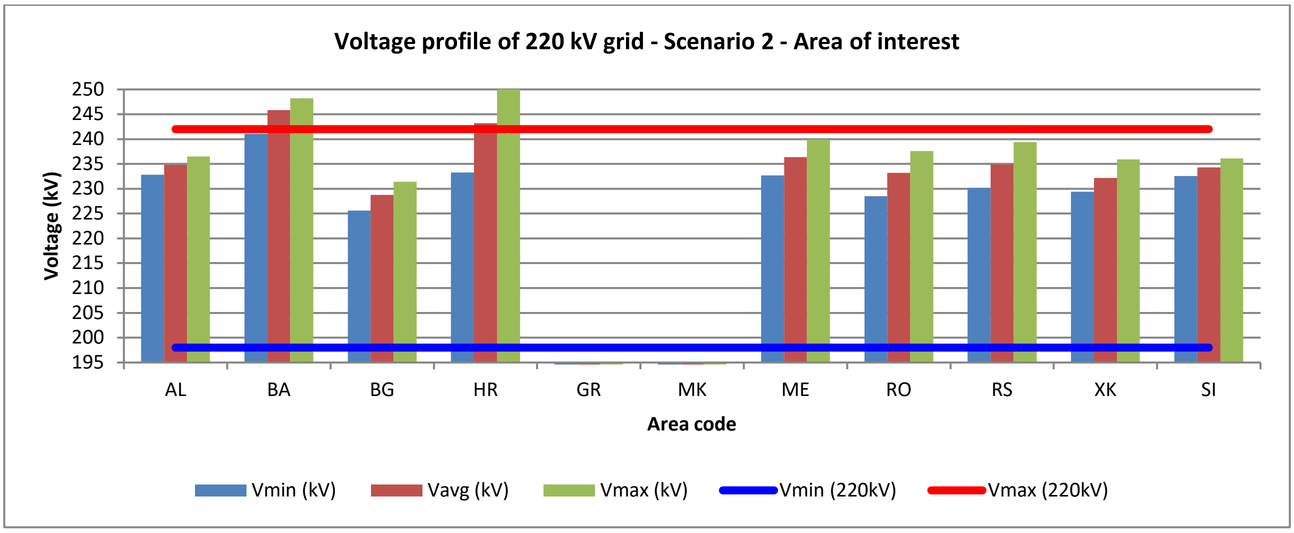


Figure 152: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 2 (base case, minimum load, referent CO_2 and referent RES)

List of 400 and 220 kV elements that are loaded more than 80% is given as follows:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	658.31	-147.78	674.70	692.80	95.44
32201	[XPA_DI21 220.00]	490018	[DIVACA220 220.00]	322.75	-97.55	337.17	365.81	86.22
38030	[XVI_LA1M 400.00]	381030	[OLASTV11 400.00]	1000.00	-50.00	1001.25	1108.50	84.18

Figure 153: List of 400 kV and 220 kV elements loaded more than 80% in scenario 2

In this scenario there are just three heavily loaded elements (all interconnections), but none is overloaded, not even the 400 kV Rosiori – Mukacevo that was slightly above the limit in scenario 1.

Finally, we provide the contingency N-1 analysis results for this scenarios as follows:

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>   RATING     FLOW       %
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  SINGLE 448014-448950(1)            692.8     726.0     103.2
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  SINGLE 448024-448025(1)            692.8     705.3     100.0
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  SINGLE 448025-448950(1)            692.8     709.7     100.7
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BUS 4421                           692.8     745.8     106.0
  10210*XKO_PO21     220.00 102015 AKOPLI2    220.00 1  BUS 10110                          274.4     365.3     127.2
  10210 XKO_PO21     220.00 382030*0PODG121   220.00 1  BUS 10110                          274.4     367.7     127.3
 102010 AVDEJA2      220.00 102015*AKOPLI2    220.00 1  BUS 10110                          278.2     358.8     123.6
  14141*XMI_HA11     380.00 141055 VMAIZ31    400.00 1  BUS 14142                         1200.0    1243.1     102.5
  32201*XPA_DI21     220.00 490018 DIVACA220  220.00 1  BUS 32101                          365.8     503.9     128.2
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BUS 44121                          692.8     729.9     103.6

 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   100    0.0
 SINGLE 448014-448950(1)         Met convergence to     1     0    0.0
 SINGLE 448024-448025(1)         Met convergence to     1     0    0.0
 SINGLE 448025-448950(1)         Met convergence to     1     0    0.0
 BUS 4421                        Met convergence to     1     0    0.0
 BUS 10110                       Met convergence to     3     0    0.0
 BUS 14142                       Met convergence to     1     0    0.0
 BUS 32101                       Met convergence to     1    10    0.0
 BUS 44121                       Met convergence to     1     0    0.0

CONTINGENCY LEGEND: (selected 8 contingecies appeared above from list of total 790 analyzed contingencies)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 448014-448950(1)         : OPEN LINE FROM BUS 448014 [RSUCEA1     400.00] TO BUS 448950 [RROMAN1     400.00] CKT 1
 SINGLE 448024-448025(1)         : OPEN LINE FROM BUS 448024 [RGUTIN1     400.00] TO BUS 448025 [RBACAU1     400.00] CKT 1
 SINGLE 448025-448950(1)         : OPEN LINE FROM BUS 448025 [RBACAU1     400.00] TO BUS 448950 [RROMAN1     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 14142                       : OPEN LINE FROM BUS 14142 [XMI_HA12    380.00] TO BUS 141055 [VMAIZ31     400.00] CKT 1
                                   OPEN LINE FROM BUS 14142 [XMI_HA12    380.00] TO BUS 540004 [4HAMITABAT  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 490123 [PST_DIV     400.00] CKT 1
 BUS 44121                       : OPEN LINE FROM BUS 44121 [XVK_IS11; OV400.00] TO BUS 448020 [RISACC1     400.00] CKT 1
                                   OPEN LINE FROM BUS 44121 [XVK_IS11; OV400.00] TO BUS 636049 [5VULKADC1   400.00] CKT 1
```

Figure 154: Contingency (n-1) analysis report for scenario 2

In scenario 2, with minimum system load, there are eight contingency events that provoke overloading or voltage out of limits (two cases are at the level of 100%). Among them there are no severe overloadings (higher than 130%).

6.3. Scenario 3: High RES, low demand growth, referent CO2 and minimum load

We provide the area summary for the third network scenario (high RES, low demand growth, referent CO_2 and minimum load) 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	513.2	0.0	0.0	512.0	0.0	0.0	7.8	0.0	27.4	-34.0	-34.0	-34.0
AL	-26.9	0.0	0.0	138.4	-76.9	0.0	46.4	931.1	220.4	575.9	575.9	
13	759.7	0.0	0.0	929.0	0.0	0.0	16.1	0.0	19.5	-205.0	-205.0	-205.0
BA	-299.7	0.0	0.0	176.8	0.0	0.0	164.4	1243.1	170.0	432.2	432.2	
14	4060.1	0.0	0.0	2583.7	0.6	0.0	67.4	0.0	80.4	1328.0	1328.0	1328.0
BG	1195.1	0.0	0.0	1032.8	1441.7	0.0	178.6	3192.1	1111.8	622.3	622.3	
16	1137.2	0.0	0.0	1230.0	0.0	0.0	5.5	0.0	36.7	-135.0	-135.0	-135.0
HR	-347.4	0.0	0.0	290.1	239.4	0.0	26.4	1839.3	283.0	652.9	652.9	
30	2416.8	0.0	0.0	4601.0	0.0	0.0	0.0	0.0	105.8	-2290.0	-2290.0	-2290.0
GR	-2543.0	0.0	0.0	2396.0	2332.5	0.0	25.6	9148.8	1698.2	153.5	153.5	
37	77.6	0.0	0.0	657.0	0.0	0.0	2.7	0.0	9.8	-592.0	-592.0	-592.0
MK	-29.3	0.0	0.0	240.5	0.0	0.0	11.1	628.8	103.5	244.3	244.3	
38	334.5	0.0	0.0	290.0	0.0	0.0	5.5	0.0	25.9	13.0	13.0	13.0
ME	-156.2	0.0	0.0	103.3	0.0	0.0	38.9	556.9	222.2	36.4	36.4	
44	6259.0	0.0	0.0	5224.0	0.0	0.0	115.1	0.0	136.8	783.2	783.2	783.0
RO	-1188.3	0.0	0.0	1686.5	2258.9	0.0	388.7	6404.0	1538.6	-657.1	-657.1	
46	2672.8	0.0	0.0	2638.5	0.0	0.0	32.2	0.0	60.1	-58.0	-58.0	-58.0
RS	-775.1	0.0	0.0	771.0	0.0	0.0	126.4	2101.5	682.5	-253.4	-253.4	
47	392.0	0.0	0.0	365.0	0.0	0.0	6.7	0.0	12.3	8.0	8.0	8.0
XK	-57.1	0.0	0.0	123.5	0.0	0.0	19.6	346.8	119.1	27.4	27.4	
49	1597.2	0.0	0.0	1394.0	0.0	0.0	8.2	0.0	14.9	180.0	180.0	180.0
SI	-433.2	0.0	0.0	239.4	0.0	0.0	53.3	734.1	203.2	-195.0	-195.0	
COLUMN	20220.0	0.0	0.0	20424.2	0.6	0.0	267.4	0.0	529.7	-1001.8	-1001.8	-1002.0
TOTALS	-4661.1	0.0	0.0	7198.5	6195.6	0.0	1079.4	27126.3	6352.5	1639.4	1639.4	

Figure 155: Area summary report in scenario 3

This regime refers to May 6th, 4am (minimum load).

With the minimum load in scenario 3, the total regional load is 20,424 MW, while total generation is 20,220 MW. In total, the region has a deficit of -1002 MW. The largest net exporters in the region in scenario 2 are again Bulgaria (1,328 MW) and Romania (783 MW) and, while the largest importer is again Greece (-2,290 MW).

The next Figure shows the cross-border power exchange map. Power system exchanges are similar to the previous scenario. Higher RES generation does not change major energy flows in the region.

The following Figure shows the cross-border power exchange map for the high RES, low demand growth, referent CO_2 and minimum load scenario.

Figure 156: Cross-border exhanges (MW) and directions between the countries in scenario 3: high RES, low demand growth, referent CO_2 and minimum load

The following two figures show the 400 kV and 220 kV voltage profiles in each country with maximum, minimum and average values in each country. As expected, with the minimum load regime and low demand growth, in most countries in the region, the 400 kV voltages are higher than in the previous scenario, in most cases even slightly above the upper limit.

This is the expected situation, since this scenario represents a case with minimum load and lower demand growth. In such a case, the expected minimum load is lower than expected, so most of lines have very low loading, and thus they generate reactive power from chargings.

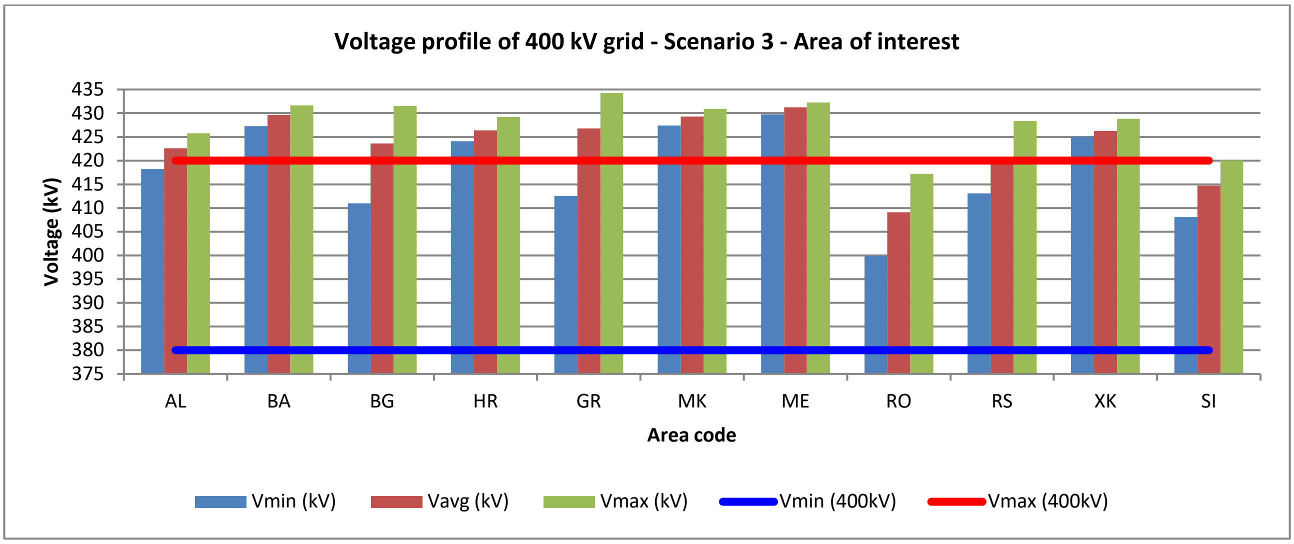


Figure 157: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 3: high RES, low demand growth, referent CO_2 and minimum load

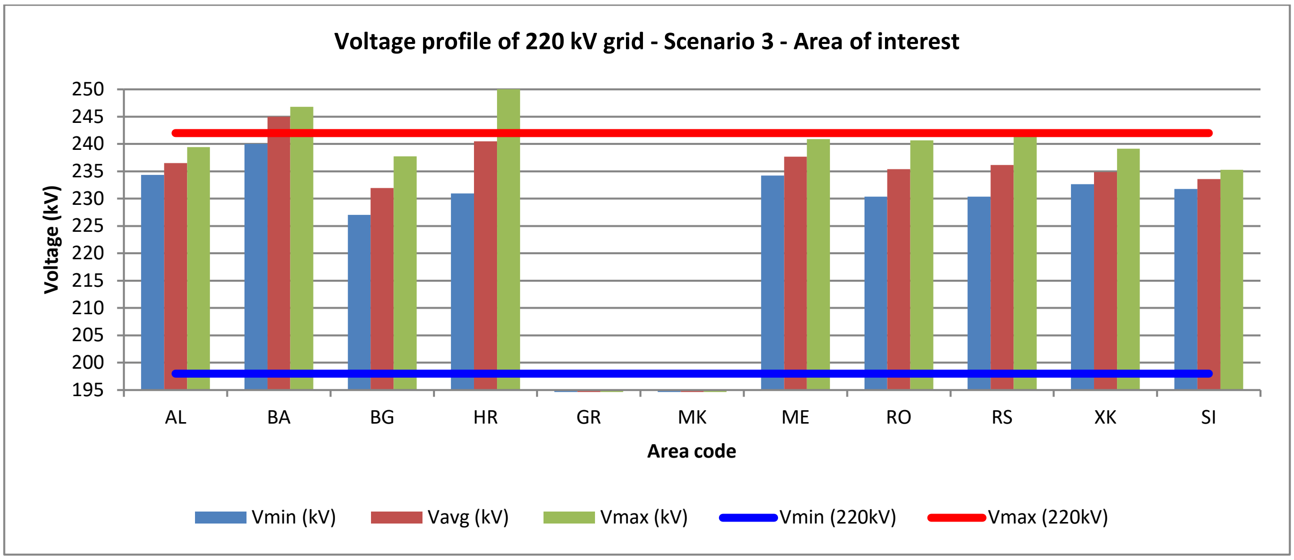


Figure 158: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 3: high RES, low demand growth, referent CO_2 and minimum load

Below is the list of 400 kV and 220 kV elements that are loaded over 80% in this case:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	631.92	-97.80	639.44	692.80	89.38

Figure 159: List of 400 kV and 220 kV elements loaded more than 80% in scenario 3

In scenario 3, there is just one element in the region with the loading above 80%: the interconnection from Mukacevo (UA) to Rosiori (RO) (89%).

Finally, the results of our contingency N-1 analysis for this scenario is as follows.

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING    FLOW      %
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BUS 4421                          692.8     736.6    103.5
  10210*XKO_PO21     220.00 102015 AKOPLI2     220.00 1  BUS 10110                         274.4     412.1    132.5
  10210 XKO_PO21     220.00 382030*0PODG121    220.00 1  BUS 10110                         274.4     408.8    132.8
 102010 AVDEJA2      220.00 102015*AKOPLI2     220.00 1  BUS 10110                         278.2     410.5    128.9
  14141*XMI_HA11     380.00 141055 VMAIZ31     400.00 1  BUS 14142                        1200.0    1244.9    102.6

 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   280    0.0
 BUS 4421                        Met convergence to     1     0    0.0
 BUS 10110                       Met convergence to     3     0    0.0
 BUS 14142                       Met convergence to     1     2    0.0

CONTINGENCY LEGEND: (selected 3 contingecies appeared above from list of total 788 analyzed contingencies)
 <----- CONTINGENCY LABEL ------>  EVENTS
 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 14142                       : OPEN LINE FROM BUS 14142 [XMI_HA12    380.00] TO BUS 141055 [VMAIZ31     400.00] CKT 1
                                   OPEN LINE FROM BUS 14142 [XMI_HA12    380.00] TO BUS 540004 [4HAMITABAT  400.00] CKT 1
```

Figure 160: Contingency (n-1) analysis report for scenario 3

In scenario 3 there are three contingency events. There are two cases with overloadings higher than 130% (given above in red). In the base case, with all elements available, the interconnection line from Rosiori (Ro) to Mukacevo (UA) 400 kV is slightly overloaded (103%), as mentioned above.

6.4. Scenario 4: High RES, low demand growth, referent CO2 and maximum RES

We provide the area summary for the fourth network scenario (high RES integration level, low demand growth, referent CO_2 and maximum RES generation output) below:

	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	956.2	0.0	0.0	1261.0	0.0	0.0	5.5	0.0	35.7	-346.0	-346.0	-346.0
AL	12.8	0.0	0.0	340.9	-51.3	0.0	32.7	663.8	315.7	38.5	38.5	
13	1234.3	0.0	0.0	1823.0	0.0	0.0	12.8	0.0	54.5	-656.0	-656.0	-656.0
BA	369.5	0.0	0.0	335.0	0.0	0.0	130.9	1004.2	508.7	399.2	399.2	
14	5496.3	0.0	0.0	5681.7	0.5	0.0	58.5	0.0	164.6	-409.0	-409.0	-409.0
BG	2968.4	0.0	0.0	2177.2	446.3	0.0	166.4	2764.1	2028.5	914.0	914.0	
16	1837.3	0.0	0.0	2195.0	0.0	0.0	4.6	0.0	118.7	-481.0	-481.0	-481.0
HR	-157.1	0.0	0.0	517.8	105.2	0.0	22.6	1562.8	948.2	-188.2	-188.2	
30	11899.7	0.0	0.0	8153.7	0.0	0.0	0.0	0.0	436.0	3310.0	3310.0	3310.0
GR	971.2	0.0	0.0	4022.4	1768.1	0.0	22.0	7768.6	3276.1	-348.8	-348.8	
37	724.5	0.0	0.0	1231.0	0.0	0.0	2.0	0.0	25.5	-534.0	-534.0	-534.0
MK	142.8	0.0	0.0	428.7	0.0	0.0	8.2	476.4	257.6	-75.3	-75.3	
38	593.4	0.0	0.0	525.0	0.0	0.0	4.5	0.0	27.9	36.0	36.0	36.0
ME	119.1	0.0	0.0	180.9	0.0	0.0	31.9	427.2	205.1	128.4	128.4	
44	12530.3	0.0	0.0	7577.0	0.0	0.0	98.6	0.0	279.5	4575.2	4575.2	4575.0
RO	236.2	0.0	0.0	2414.7	1945.6	0.0	331.3	5426.0	2705.9	-1735.4	-1735.4	
46	2055.3	0.0	0.0	4934.1	0.0	0.0	27.1	0.0	118.1	-3023.9	-3023.9	-3024.0
RS	785.9	0.0	0.0	1031.2	0.0	0.0	146.1	1759.5	1437.1	-69.0	-69.0	
47	546.6	0.0	0.0	943.0	0.0	0.0	4.8	0.0	15.7	-417.0	-417.0	-417.0
XK	369.9	0.0	0.0	313.5	0.0	0.0	14.4	259.4	204.6	96.9	96.9	
49	2222.8	0.0	0.0	1744.0	0.0	0.0	7.7	0.0	35.1	436.0	436.0	436.0
SI	-205.3	0.0	0.0	299.5	-157.2	0.0	49.8	686.1	460.4	-171.7	-171.7	
COLUMN	40096.7	0.0	0.0	36068.5	0.5	0.0	226.1	0.0	1311.3	2490.2	2490.2	2490.0
TOTALS	5613.4	0.0	0.0	12061.9	4056.8	0.0	956.2	22798.1	12348.0	-1011.3	-1011.3	

Figure 161: Area summary report in scenario 4

High RES refers to the level of RES integration, while maximum RES refers to the selected hour in this scenario with maximum RES generation output. This regime refers to March 24th, at 11am.

In this scenario, the regional load is 36,068 MW, and generation is 40,096 MW. The largest net exporters in scenario 4 are Romania (4,575 MW) and Greece (3,310 MW), while the largest importer is Serbia (-3,024 MW). In sum, in scenario 4, the EMI region has a surplus of 2,490 MW.

So, in this scenario, the EMI region is exporting, but the usual exporter Bulgaria is importing, and the usual importer Greece is exporting. While not the norm, this is expected in this case, given the different levels of RES share in these areas (bigger share of RES in GR than in BG), and the fact that this regime refers to the hours around noon, when the load is still low.

The following Figure shows the cross-border power exchange map for the high RES, low demand growth, referent CO_2 and maximum RES scenario.

Figure 162: Cross-border exhanges (MW) and directions between the countries in scenario 4: high RES, low demand growth, referent CO_2 and maximum RES

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

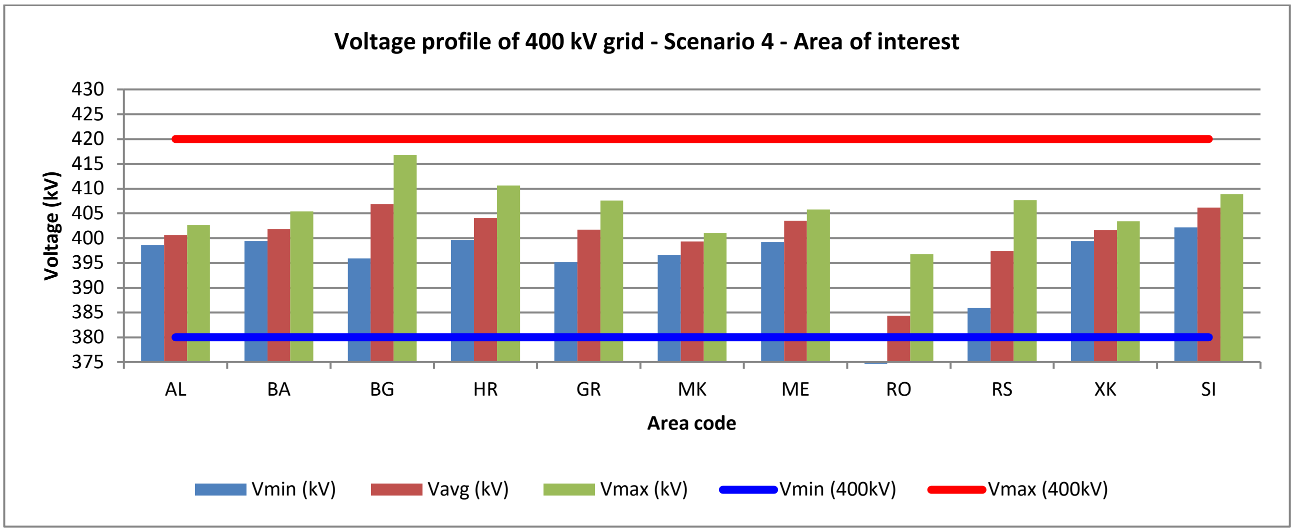


Figure 163: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 4: high RES, low demand growth, referent CO_2 and maximum RES

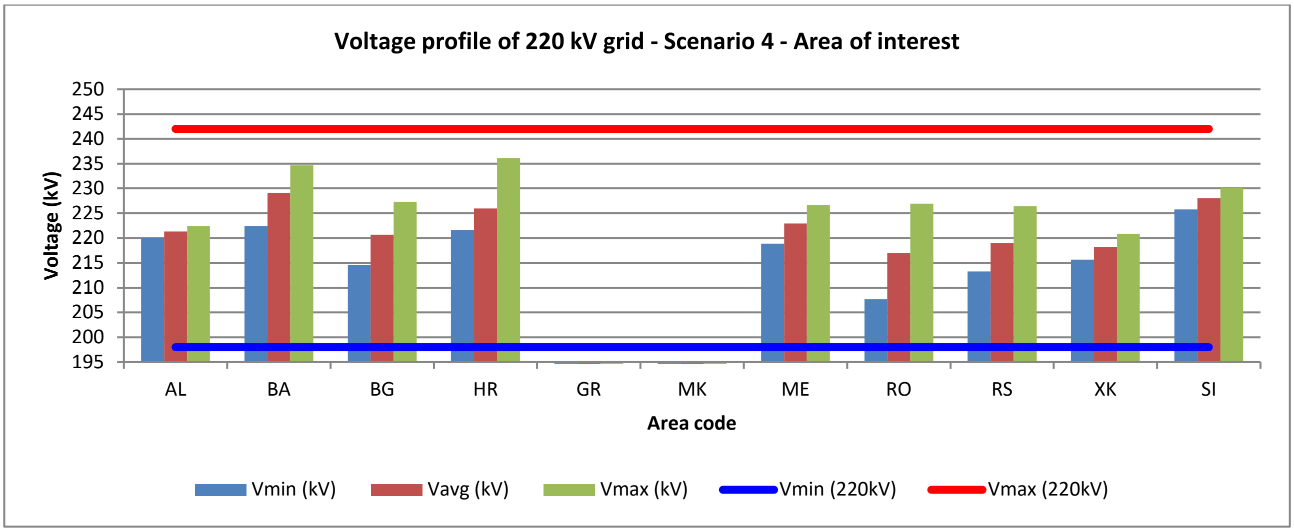


Figure 164: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 4: high RES, low demand growth, referent CO_2 and maximum RES

Below is the list of 400 kV and 220 kV elements that are loaded more than 80% in this scenario:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	711.94	-285.68	767.12	692.80	112.46
44101	[XPF_DJ11 400.00]	460015	[JHDJE111 400.00]	977.75	-91.76	982.05	1247.10	80.57

Figure 165: List of 400 and 220 kV elements loaded more than 80% in scenario 4

In scenario 4 there are just two elements in the region with a loading above 80%, and both are Romanian interconnections: to Ukraine (112%) and to Serbia (80%).

Finally, we provide the contingency N-1 analysis results for this scenarios as follows.

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING     FLOW       %

  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BASE CASE                          692.8     767.1    112.5

 161025*HKONJS11    400.00 162030 HKONJS21    220.00 2  SINGLE 161025-162030-166283(1)     400.0     407.7    101.9

 161025*HKONJS11    400.00 162030 HKONJS21    220.00 1  SINGLE 161025-162030-166290(2)     400.0     407.7    101.9

  14124*XVA_MG11    400.00 141115 VVARNA1     400.00 1  BUS 14121                          900.0     997.2    114.7

  14121*XDO_MG11    400.00 141035 VDOBRU1     400.00 1  BUS 14124                          850.0     941.6    114.4

  32201 XPA_DI21    220.00 490018*DIVACA220   220.00 1  BUS 32101                          365.8     495.1    131.2


 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     1     9    0.0

 SINGLE 161025-162030-166283(1)  Met convergence to     1     0    0.0

 SINGLE 161025-162030-166290(2)  Met convergence to     1     0    0.0

 BUS 14121                       Met convergence to     1     4    0.0

 BUS 14124                       Met convergence to     1     5    0.0

 BUS 32101                       Met convergence to     1     0    0.0


CONTINGENCY LEGEND: (selected 5 contingecies appeared above from list of total 793 analyzed contingencies)

 <----- CONTINGENCY LABEL ------>  EVENTS

 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

 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 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 490123 [PST_DIV     400.00] CKT 1
```

Figure 166: Contingency (n-1) analysis report for scenario 4

In scenario 4 there are five contingency events. However, there is just one case with overloading higher than 130% (interconnection between Slovenia and Italy, given above in red). In the base case with all elements available, the interconnection line from Rosiori (Ro) to Mukacevo (UA) 400 kV is slightly overloaded (112%), as mentioned above. Again, since there is an overload in the base case, this element is not shown as overloaded element in all other outages.

6.5. Scenario 5: High RES, low demand growth, referent CO2 and maximum WPP and HPP

We provide the area summary for the fifth network scenario (high RES, low demand growth, referent CO_2 and maximum WPP and HPP) below:

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	2725.0	0.0	0.0	1355.0	0.0	0.0	5.6	0.0	51.4	1313.0	1313.0	1313.0
AL	390.4	0.0	0.0	383.1	501.1	0.0	33.3	669.7	592.5	-450.0	-450.0	
13	1948.2	0.0	0.0	1931.0	0.0	0.0	12.5	0.0	134.7	-130.0	-130.0	-130.0
BA	554.2	0.0	0.0	354.1	0.0	0.0	127.6	984.1	989.3	67.4	67.4	
14	6296.3	0.0	0.0	6018.6	0.5	0.0	58.6	0.0	168.5	50.0	50.0	50.0
BG	2405.6	0.0	0.0	2288.8	449.1	0.0	166.0	2763.1	2111.2	153.6	153.6	
16	4286.2	0.0	0.0	2640.0	0.0	0.0	4.3	0.0	242.0	1400.0	1400.0	1400.0
HR	496.6	0.0	0.0	622.8	101.0	0.0	20.7	1449.5	1995.2	-793.7	-793.7	
30	7548.4	0.0	0.0	8621.0	0.0	0.0	0.0	0.0	217.4	-1290.0	-1290.0	-1290.0
GR	451.0	0.0	0.0	4238.7	1799.7	0.0	23.5	7924.3	2104.7	208.8	208.8	
37	1490.0	0.0	0.0	1363.0	0.0	0.0	2.1	0.0	24.9	100.0	100.0	100.0
MK	268.9	0.0	0.0	478.7	0.0	0.0	8.5	495.7	274.0	3.3	3.3	
38	1543.3	0.0	0.0	580.0	0.0	0.0	4.8	0.0	30.6	928.0	928.0	928.0
ME	279.3	0.0	0.0	199.3	0.0	0.0	33.4	445.9	343.7	148.9	148.9	
44	11971.2	0.0	0.0	8767.0	0.0	0.0	112.7	0.0	266.4	2825.0	2825.0	2825.0
RO	-318.0	0.0	0.0	1937.5	1467.2	0.0	379.8	6263.5	2860.2	-699.2	-699.2	
46	6038.2	0.0	0.0	5731.0	0.0	0.0	31.8	0.0	101.4	174.0	174.0	176.0
RS	1103.5	0.0	0.0	1216.0	0.0	0.0	185.9	1881.5	1319.2	263.9	263.9	
47	1105.4	0.0	0.0	1061.0	0.0	0.0	5.0	0.0	20.4	19.0	19.0	19.0
XK	293.1	0.0	0.0	352.3	0.0	0.0	14.9	268.7	249.8	-55.2	-55.2	
49	1967.7	0.0	0.0	2000.0	0.0	0.0	7.1	0.0	40.6	-80.0	-80.0	-80.0
SI	317.4	0.0	0.0	343.5	0.0	0.0	46.1	634.6	564.3	-1.9	-1.9	
COLUMN	46919.9	0.0	0.0	40067.7	0.5	0.0	244.5	0.0	1298.3	5309.0	5309.0	5311.0
TOTALS	6242.0	0.0	0.0	12414.8	4318.2	0.0	1039.7	23780.6	13404.0	-1154.1	-1154.1	

Figure 167: Area summary report in scenario 5

This regime refers to March 22th, at 7:00 pm.

In this scenario, the region is exporting, and the situation around exporters and importers is as expected, since this regime refers to the evening hour, when SPP generation is low, and the system load is close to its peak.

The following Figure shows the cross-border power exchange map for high RES, low demand growth, referent CO_2 and maximum WPP and HPP scenario.

Figure 168: Cross-border exhanges (MW) and directions between the countries in scenario 5: high RES, low demand growth, referent CO_2 and maximum WPP and HPP

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

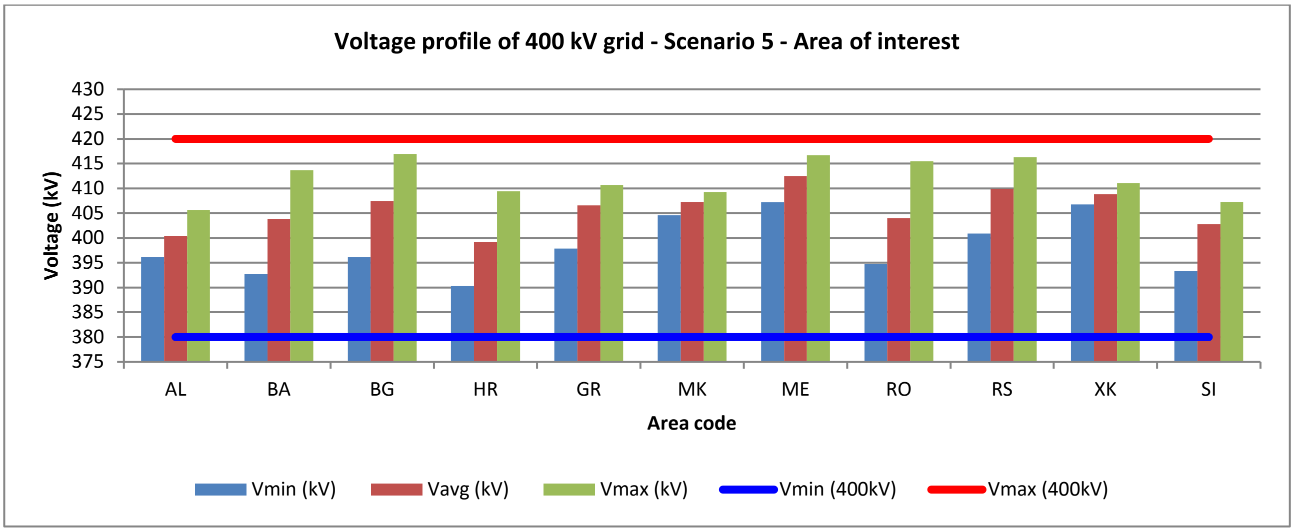


Figure 169: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 5: high RES, low demand growth, referent CO_2 and maximum RES

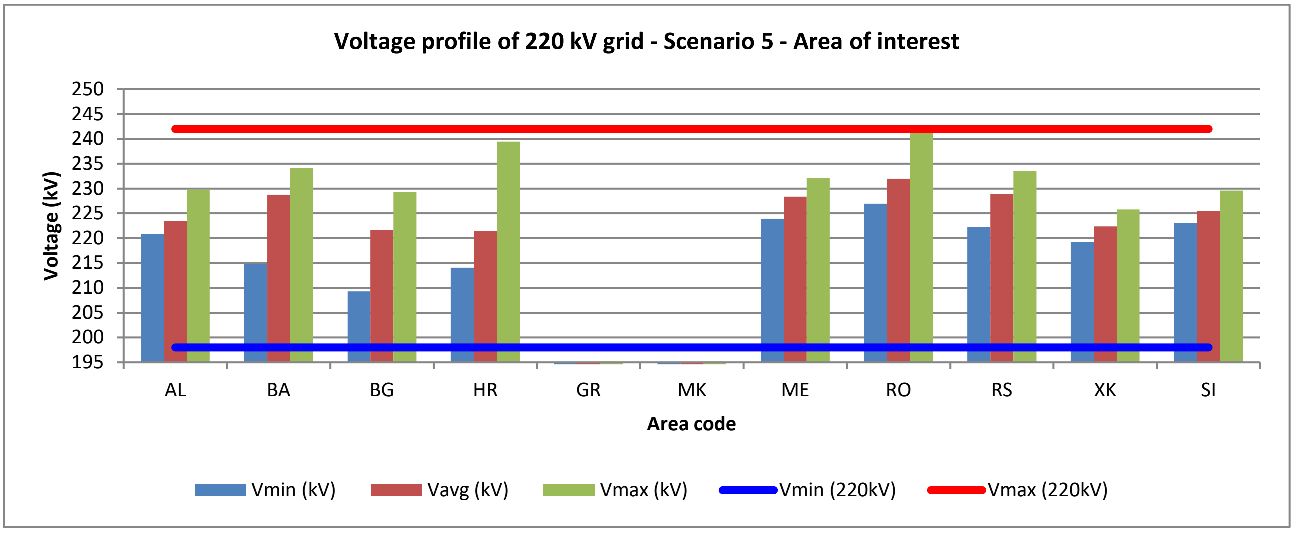


Figure 170: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 5: high RES, low demand growth, referent CO_2 and maximum WPP and HPP

Here is the list of 400 kV and 220 kV elements that are loaded more than 80%:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	MW	MVAR	MVA	RATING	%I
14124	[XVA_MG11 400.00]	141115	[VVARNA1 400.00]	758.60	-52.08	760.38	900.00	85.57
133220	[WRPJAB2 220.00]	133225	[WRPKAK2 220.00]	264.77	0.51	264.77	301.00	83.59
142060	[VDOBRU2 220.00]	142250	[VVARNA2 220.00]	-294.17	43.34	297.35	360.00	83.48
448065	[RHAJD 2 220.00]	448914	[RR.MAR2 220.00]	-348.93	48.99	352.35	417.70	80.61

Figure 171: List of 400 kV and 220 kV elements loaded more than 80% in scenario 5

In scenario 5 there are four elements in the region with the loading above 80%, but none over 86%.

Finally, we provide the contingency N-1 analysis results for this scenario on the following page.

In scenario 5 there are three contingency events. There are five cases with overloadings above 130% (given above in red). In the base case, with all elements available, there are no overloadings in the network.

```
<---------------- MONITORED BRANCH ----------------> <----- CONTINGENCY LABEL ------>  RATING     FLOW      %
 102010 AVDEJA2     220.00 102012*AVDJRI2     220.00 1  SINGLE 102005-102012(1)          325.4    360.8    109.2
 133220*WRPJAB2     220.00 133225 WRPKAK2     220.00 1  SINGLE 133105-137100(1)          301.0    318.2    100.9
 133220*WRPJAB2     220.00 133225 WRPKAK2     220.00 1  SINGLE 133215-133225(1)          301.0    322.7    102.2
 133220*WRPJAB2     220.00 133225 WRPKAK2     220.00 1  SINGLE 133220-137215(1)          301.0    334.3    105.0
 141045 VMAIZ11     400.00 141060*VMAIZ51     400.00 1  SINGLE 141045-141065(1)          519.0    604.8    112.3
 142060 VDOBRU2     220.00 142250*VVARNA2     220.00 1  SINGLE 142085-142250(1)          360.0    408.0    114.4
 161000*HLIKA 11    400.00 161035 HMELIN11    400.00 2  SINGLE 161000-161035(1)         1330.0   1298.9    100.5
 161000*HLIKA 11    400.00 161035 HMELIN11    400.00 1  SINGLE 161000-161035(2)         1330.0   1298.9    100.5
 161001 HLIKA 22    220.00 162021*HESENJ23    220.00 2  SINGLE 161001-162021(1)          300.0    371.8    125.7
 161001 HLIKA 22    220.00 162021*HESENJ23    220.00 1  SINGLE 161001-162021(2)          300.0    371.8    125.7
 161025*HKONJS11    400.00 162030 HKONJS21    220.00 2  SINGLE 161025-162030-166283(1)   400.0    484.7    121.9
 162030*HKONJS21    220.00 161025 HKONJS11    400.00 2  SINGLE 161025-162030-166283(1)   400.0    470.3    116.1
 161025*HKONJS11    400.00 162030 HKONJS21    220.00 1  SINGLE 161025-162030-166290(2)   400.0    484.7    121.9
 162030*HKONJS21    220.00 3WNDTR KONJSKO AT1  WND 2 1  SINGLE 161025-162030-166290(2)   400.0    470.3    116.1
 162040*HMELIN21    220.00 161035 HMELIN11    400.00 2  SINGLE 161035-162040-166282(1)   150.0    157.5    107.3
 161035*HMELIN11    400.00 162040 HMELIN21    220.00 2  SINGLE 161035-162040-166282(1)   150.0    152.0    102.0
 162040*HMELIN21    220.00 161035 HMELIN11    400.00 2  SINGLE 162020-162040(1)          150.0    158.8    108.6
 161035*HMELIN11    400.00 162040 HMELIN21    220.00 2  SINGLE 162020-162040(1)          150.0    156.0    103.3
 490038*DIVACA400   400.00 490123 PST_DIV     400.00 2  SINGLE 490038-490123(1)          600.0    617.5    105.0
 490038*DIVACA400   400.00 490123 PST_DIV     400.00 1  SINGLE 490038-490123(2)          600.0    617.5    105.0
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BUS 4421                         692.8    726.7    103.6
  14124*XVA_MG11    400.00 141115 VVARNA1     400.00 1  BUS 14121                        900.0   1174.2    133.9
  14121*XDO_MG11    400.00 141035 VDOBRU1     400.00 1  BUS 14124                        850.0   1106.4    133.7
  14141 XMI_HA11    380.00 141055*VMAIZ31     400.00 1  BUS 14142                       1200.0   1257.5    102.3
  16231 XPE_DI21    220.00 162050*HPEHLI21    220.00 1  BUS 16131                        365.8    366.1    101.9
  16231*XPE_DI21    220.00 490018 DIVACA220   220.00 1  BUS 16131                        365.8    367.7    101.7
 162040*HMELIN21    220.00 161035 HMELIN11    400.00 2  BUS 16131                        150.0    248.1    172.2
 161035*HMELIN11    400.00 162040 HMELIN21    220.00 2  BUS 16131                        150.0    242.7    163.9
  16231 XPE_DI21    220.00 162050*HPEHLI21    220.00 1  BUS 32101                        365.8    372.0    102.9
  16231*XPE_DI21    220.00 490018 DIVACA220   220.00 1  BUS 32101                        365.8    371.8    102.7
  32201 XPA_DI21    220.00 490018*DIVACA220   220.00 1  BUS 32101                        365.8    603.4    165.4
 162040*HMELIN21    220.00 161035 HMELIN11    400.00 2  BUS 32101                        150.0    178.5    122.3
 161035*HMELIN11    400.00 162040 HMELIN21    220.00 2  BUS 32101                        150.0    173.6    116.3
 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     0     0    0.0
 SINGLE 102005-102012(1)         Met convergence to     1     0    0.0
 SINGLE 133105-137100(1)         Met convergence to     1     0    0.0
 SINGLE 133215-133225(1)         Met convergence to     1     0    0.0
 SINGLE 133220-137215(1)         Met convergence to     1     0    0.0
 SINGLE 141045-141065(1)         Met convergence to     1     0   38.0
 SINGLE 142085-142250(1)         Met convergence to     1     0    0.0
 SINGLE 161000-161035(1)         Met convergence to     1     0    0.0
 SINGLE 161000-161035(2)         Met convergence to     1     0    0.0
 SINGLE 161001-162021(1)         Met convergence to     1     0    0.0
 SINGLE 161001-162021(2)         Met convergence to     1     0    0.0
 SINGLE 161025-162030-166283(1)  Met convergence to     2     0    0.0
 SINGLE 161025-162030-166290(2)  Met convergence to     2     0    0.0
 SINGLE 161035-162040-166282(1)  Met convergence to     2     0    0.0
 SINGLE 162020-162040(1)         Met convergence to     2     0    0.0
 SINGLE 490038-490123(1)         Met convergence to     1     0    0.0
 SINGLE 490038-490123(2)         Met convergence to     1     0    0.0
 BUS 4421                        Met convergence to     1     0    0.0
 BUS 14121                       Met convergence to     1     0    0.0
 BUS 14124                       Met convergence to     1     0    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

CONTINGENCY LEGEND: (selected 22 contingecies appeared above from list of total 792 analyzed contingencies)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 102005-102012(1)         : OPEN LINE FROM BUS 102005 [AKOMAN2     220.00] TO BUS 102012 [AVDJRI2     220.00] CKT 1
 SINGLE 133105-137100(1)         : OPEN LINE FROM BUS 133105 [WSAR101     400.00] TO BUS 137100 [WMOST41     400.00] CKT 1
 SINGLE 133215-133225(1)         : OPEN LINE FROM BUS 133215 [WHSALA2     220.00] TO BUS 133225 [WRPKAK2     220.00] CKT 1
 SINGLE 133220-137215(1)         : OPEN LINE FROM BUS 133220 [WRPJAB2     220.00] TO BUS 137215 [WJAJC22     220.00] CKT 1
 SINGLE 141045-141065(1)         : OPEN LINE FROM BUS 141045 [VMAIZ11     400.00] TO BUS 141065 [VMAIZ61     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 161000-161035(1)         : OPEN LINE FROM BUS 161000 [HLIKA 11    400.00] TO BUS 161035 [HMELIN11    400.00] CKT 1
 SINGLE 161000-161035(2)         : OPEN LINE FROM BUS 161000 [HLIKA 11    400.00] TO BUS 161035 [HMELIN11    400.00] CKT 2
 SINGLE 161001-162021(1)         : OPEN LINE FROM BUS 161001 [HLIKA 22    220.00] TO BUS 162021 [HESENJ23    220.00] CKT 1
 SINGLE 161001-162021(2)         : OPEN LINE FROM BUS 161001 [HLIKA 22    220.00] TO BUS 162021 [HESENJ23    220.00] CKT 2
 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 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 162020-162040(1)         : OPEN LINE FROM BUS 162020 [HESENJ22    220.00] TO BUS 162040 [HMELIN21    220.00] CKT 1
 SINGLE 490038-490123(1)         : OPEN LINE FROM BUS 490038 [DIVACA400   400.00] TO BUS 490123 [PST_DIV     400.00] CKT 1
 SINGLE 490038-490123(2)         : OPEN LINE FROM BUS 490038 [DIVACA400   400.00] TO BUS 490123 [PST_DIV     400.00] CKT 2
 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 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    380.00] TO BUS 141055 [VMAIZ31    400.00] CKT 1
                                   OPEN LINE FROM BUS 14142 [XMI_HA12    380.00] 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 490038 [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 490123 [PST_DIV    400.00] CKT 1
```

Figure 172: Contingency (n-1) analysis report for scenario 5

6.6. Scenario 6: High RES, low demand growth, referent CO2 and maximum SPP

We provide the area summary for the sixth network scenario (high RES, low demand growth, referent CO_2 and maximum SPP) below:

FROM X-- AREA --X	------AT AREA BUSES------- GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	-NET INTERCHANGE- TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	894.1	0.0	0.0	915.0	0.0	0.0	5.7	0.0	21.4	-48.0	-48.0	-48.0
AL	-75.4	0.0	0.0	247.4	590.3	0.0	34.0	691.3	193.6	-449.5	-449.5	
13	712.7	0.0	0.0	1458.0	0.0	0.0	13.9	0.0	27.9	-787.0	-787.0	-787.0
BA	52.1	0.0	0.0	270.4	0.0	0.0	141.5	1074.3	289.9	424.6	424.6	
14	5601.7	0.0	0.0	4040.7	0.0	0.0	64.6	0.0	69.3	1427.0	1427.0	1427.0
BG	1127.2	0.0	0.0	1570.5	94.5	0.0	182.5	3061.5	1078.3	1262.9	1262.9	
16	1337.7	0.0	0.0	2003.0	0.0	0.0	4.9	0.0	70.8	-741.0	-741.0	-741.0
HR	-276.8	0.0	0.0	472.5	108.9	0.0	23.8	1650.6	581.7	187.0	187.0	
30	8832.2	0.0	0.0	6488.7	0.0	0.0	0.0	0.0	163.4	2180.0	2180.0	2180.0
GR	-779.2	0.0	0.0	3268.5	1999.6	0.0	24.6	8498.3	2279.2	147.2	147.2	
37	621.4	0.0	0.0	952.0	0.0	0.0	2.2	0.0	11.1	-344.0	-344.0	-344.0
MK	9.1	0.0	0.0	334.9	0.0	0.0	9.2	528.7	120.6	73.2	73.2	
38	200.9	0.0	0.0	389.0	0.0	0.0	4.6	0.0	19.3	-212.0	-212.0	-212.0
ME	-38.6	0.0	0.0	129.7	0.0	0.0	31.8	453.9	139.7	114.0	114.0	
44	9249.3	0.0	0.0	6995.0	0.0	0.0	103.7	0.0	186.5	1964.1	1964.1	1964.0
RO	-1023.3	0.0	0.0	2234.6	2038.5	0.0	348.4	5695.6	1627.2	-1576.5	-1576.5	
46	1586.5	0.0	0.0	4267.1	0.0	0.0	28.8	0.0	74.6	-2784.0	-2784.0	-2784.0
RS	333.2	0.0	0.0	925.6	0.0	0.0	154.9	1865.5	925.3	192.9	192.9	
47	662.5	0.0	0.0	722.0	0.0	0.0	5.2	0.0	7.3	-72.0	-72.0	-72.0
XK	63.8	0.0	0.0	240.9	0.0	0.0	15.4	277.3	99.7	-14.8	-14.8	
49	2525.4	0.0	0.0	1959.0	0.0	0.0	7.7	0.0	44.6	514.0	514.0	514.0
SI	-258.3	0.0	0.0	336.4	-160.4	0.0	50.0	689.9	573.2	-367.7	-367.7	
COLUMN	32224.3	0.0	0.0	30189.5	0.0	0.0	241.4	0.0	696.2	1097.1	1097.1	1097.0
TOTALS	-866.2	0.0	0.0	10031.4	4671.4	0.0	1016.1	24486.8	7908.5	-6.7	-6.7	

Figure 173: Area summary report in scenario 6

This regime refers to April 23rd, at 12:00 pm.

In this scenario, the total regional load is 30,189 MW, while total generation is 32,224 MW. The largest net exporters in the region in scenario 6 are again: Romania (1,964 MW), Greece (2,180 MW) and Bulgaria (1,427 MW), while the largest importer is Serbia (-2,784 MW). In total, in scenario 6, the EMI region has a surplus of just 1,097 MW.

This scenario refer to hours around noon, when the region is exporting, similar to scenario 4.

The following Figure shows the cross-border power exchange map for high RES, low demand growth, referent CO_2 and maximum SPP scenario.

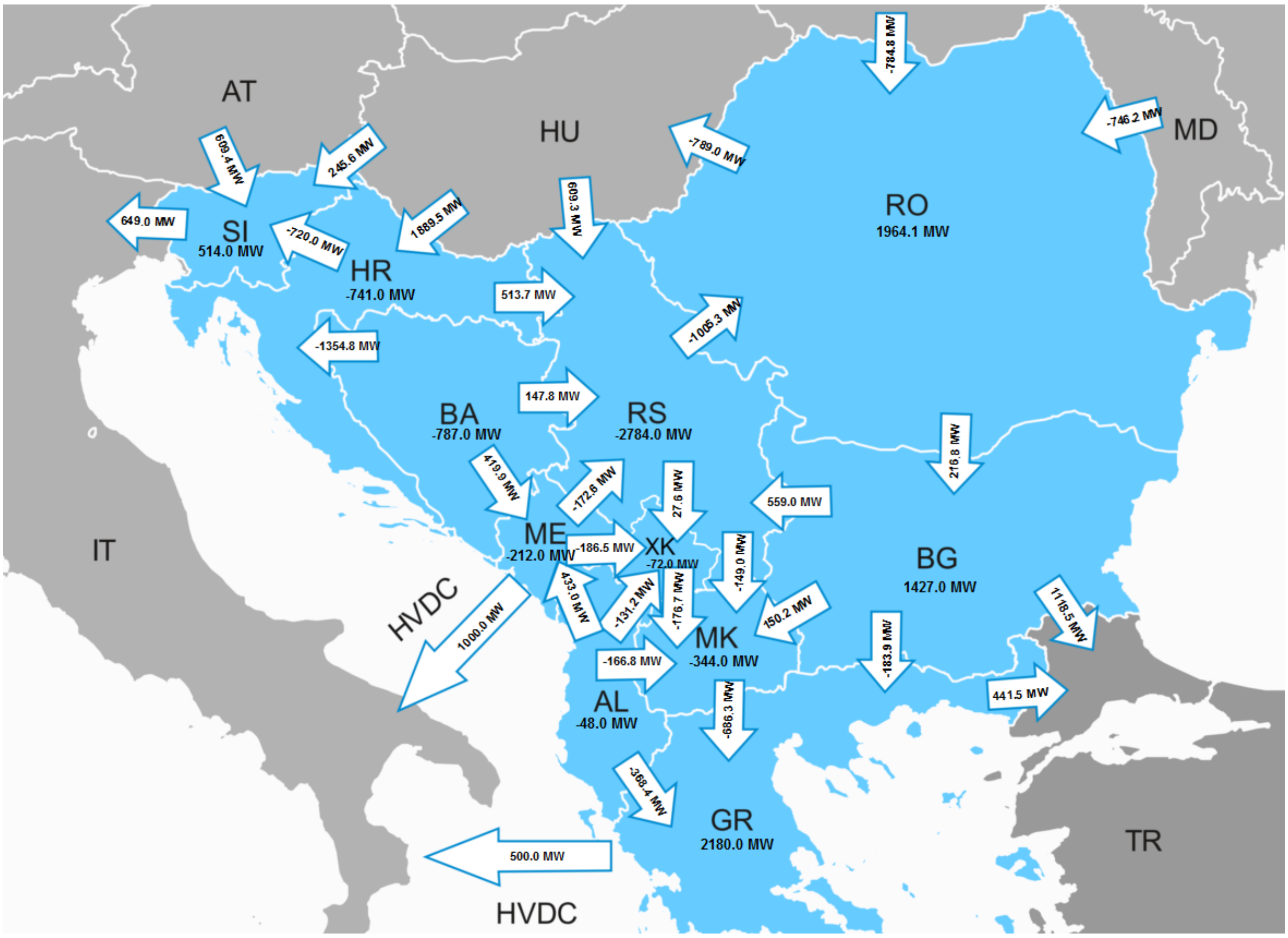


Figure 174: Cross-border exhanges (MW) and directions between the countries in scenario 6: high RES, low demand growth, referent CO_2 and maximum SPP

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 the region are within limits, except a few cases in the 400 kV netwotk in Bulgaria, and the 220 kV in Croatia with voltages slightly above the limit.

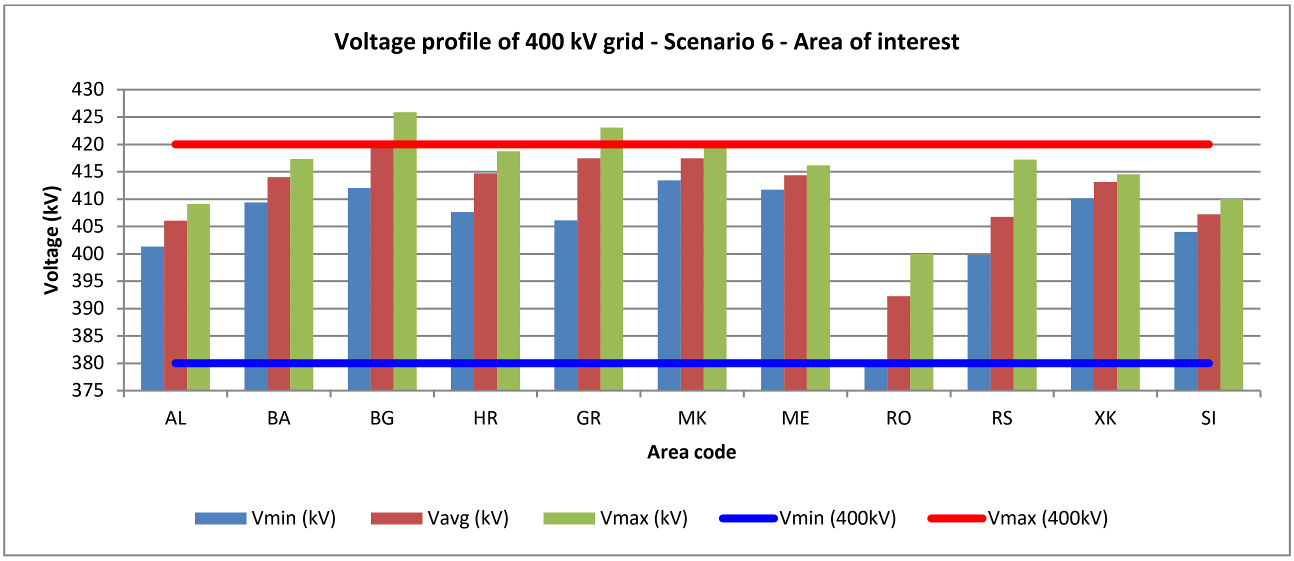


Figure 175: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 6: high RES, low demand growth, referent CO_2 and maximum SPP

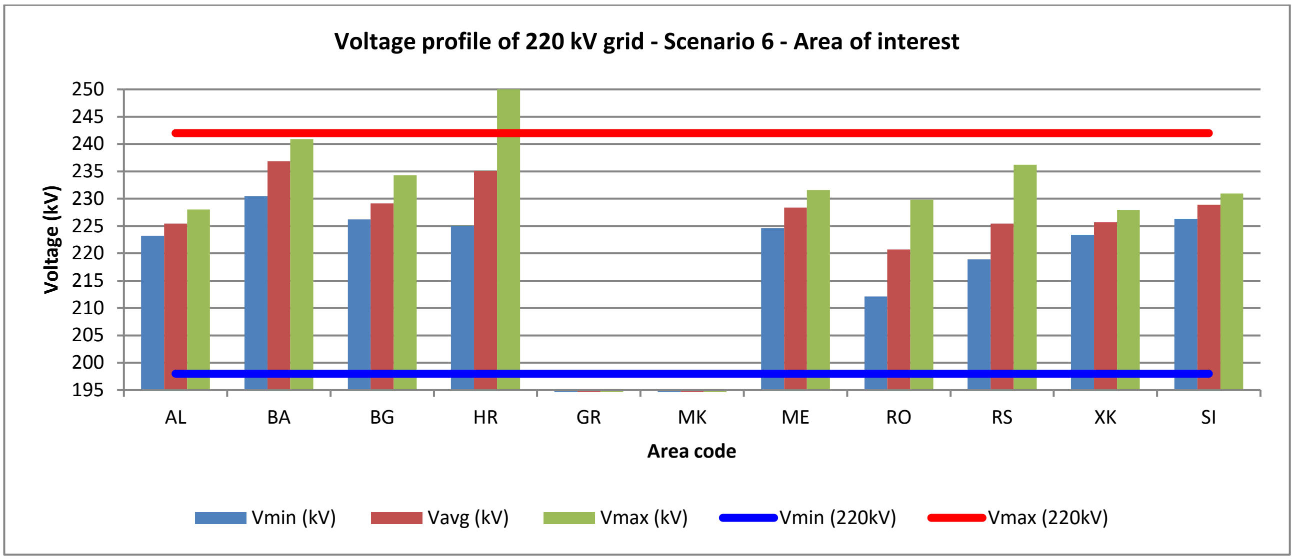


Figure 176: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 6: high RES, low demand growth, referent CO_2 and maximum SPP

The list of 400 kV and 220 kV elements that are loaded more than 80% is as follows:

FRMBUS	FROMBUSEXNAME	TOBUS	TOBUSEXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	784.87	-277.41	832.46	692.80	121.93

Figure 177: List of 400 kV and 220 kV elements loaded more than 80% in scenario 6

In scenario 6 there is just 1 element in the region with a loading above 80% and that is, as usual, the Romanian 400 kV interconnection to Ukraine (122%).

Finally, we provide the contingency N-1 analysis results for this scenario below.

```
<---------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING     FLOW       %

 44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BASE CASE                        692.8    832.5    121.9

 32201 XPA_DI21    220.00 490018*DIVACA220   220.00 1  BUS 32101                        365.8    490.7    128.2


 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     1    63    0.0

 BUS 32101                       Met convergence to     1     0    0.0


CONTINGENCY LEGEND: (selected 1 contingecies appeared above from list of total 791 analyzed contingencies)

 <----- CONTINGENCY LABEL ------>  EVENTS

 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 490123 [PST_DIV     400.00] CKT 1
```

Figure 178: Contingency (n-1) analysis report for scenario 6

In scenario 6 there is just 1 contingency event. There are no cases with overloadings higher than 130%. In the base case, with all elements available, the interconnection line Rosiori (Ro) – Mukacevo (UA) 400 kV is overloaded (122%), as mentioned above. Since there is an overload in the base case, this element is not shown as an overloaded element in all other outages.

6.7. Scenario 7: High RES, low demand growth, alternative CO2 and minimum load

We provide the area summary for the seventh network scenario (high RES, low demand growth, alternative CO_2 and mimimum load) below:

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	788.4	0.0	0.0	519.0	0.0	0.0	6.2	0.0	37.1	226.0	226.0	226.0
AL	-147.1	0.0	0.0	146.7	560.2	0.0	37.2	750.6	318.9	-459.6	-459.6	
13	767.2	0.0	0.0	932.0	0.0	0.0	15.0	0.0	25.2	-205.0	-205.0	-205.0
BA	-214.8	0.0	0.0	177.4	0.0	0.0	153.0	1156.2	212.5	398.5	398.5	
14	2686.5	0.0	0.0	2354.5	0.6	0.0	63.1	0.0	103.3	165.0	165.0	165.0
BG	1435.5	0.0	0.0	862.6	1387.8	0.0	161.3	3078.7	1215.5	886.9	886.9	
16	1142.6	0.0	0.0	1230.0	0.0	0.0	5.3	0.0	42.3	-135.0	-135.0	-135.0
HR	-342.3	0.0	0.0	290.1	226.3	0.0	25.4	1758.5	334.4	540.0	540.0	
30	2423.7	0.0	0.0	4613.0	0.0	0.0	0.0	0.0	100.8	-2290.0	-2290.0	-2290.0
GR	-1806.4	0.0	0.0	2400.9	2265.7	0.0	24.8	8818.3	1633.0	687.5	687.5	
37	658.1	0.0	0.0	649.0	0.0	0.0	2.4	0.0	21.7	-15.0	-15.0	-15.0
MK	-89.4	0.0	0.0	237.7	0.0	0.0	9.7	557.4	223.1	-2.5	-2.5	
38	162.3	0.0	0.0	274.0	0.0	0.0	4.7	0.0	25.5	-142.0	-142.0	-142.0
ME	-71.1	0.0	0.0	92.3	0.0	0.0	32.8	489.4	215.8	77.3	77.3	
44	6621.9	0.0	0.0	5224.0	0.0	0.0	110.2	0.0	154.6	1133.2	1133.2	1133.0
RO	-1080.7	0.0	0.0	1686.5	2163.4	0.0	371.8	6116.2	1704.3	-890.6	-890.6	
46	2334.9	0.0	0.0	2631.0	0.0	0.0	30.4	0.0	60.4	-387.0	-387.0	-387.0
RS	-399.0	0.0	0.0	766.8	0.0	0.0	120.4	1979.2	656.6	36.5	36.5	
47	388.9	0.0	0.0	365.0	0.0	0.0	5.6	0.0	10.3	8.0	8.0	8.0
XK	-57.1	0.0	0.0	123.5	0.0	0.0	16.5	296.4	114.6	-15.3	-15.3	
49	1597.7	0.0	0.0	1394.0	0.0	0.0	8.1	0.0	15.6	180.0	180.0	180.0
SI	-433.2	0.0	0.0	239.4	0.0	0.0	52.3	721.4	210.0	-213.6	-213.6	
COLUMN	19572.3	0.0	0.0	20185.5	0.6	0.0	251.0	0.0	597.0	-1461.8	-1461.8	-1462.0
TOTALS	-3205.7	0.0	0.0	7023.9	6603.3	0.0	1005.2	25722.3	6838.9	1045.3	1045.3	

Figure 179: Area summary report in scenario 7

This regime refers to May 6th, at 4:00 am.

In this scenario, the total regional load is very low, just 20,185 MW, while total generation is 19,572 MW. Large portion of RES is out of operation in this snapshot, partly due to early morning time and low insolation, and the EMI region has a deficit of 1,462 MW. The only significant net export in the region in scenario 7 is found in Romania (1,133 MW), while the largest importer is Greece (-2,290 MW).

The following Figure shows the cross-border power exchange map for high RES, low demand growth, alternative CO_2 and mimimum load scenario.

After that, the next two figures show the 400 kV and 220 kV voltage profiles with maximum, minimum and average values in each country. Again, due to minimum load and low demand growth, the region is facing high 400 kV voltage profiles in all countries, except Romania and Slovenia. In the 220 kV network, the voltages are mainly within given limits.

Figure 180: Cross-border exhanges (MW) and directions between the countries in scenario 7: high RES, low demand growth, alternative CO_2 and mimimum load

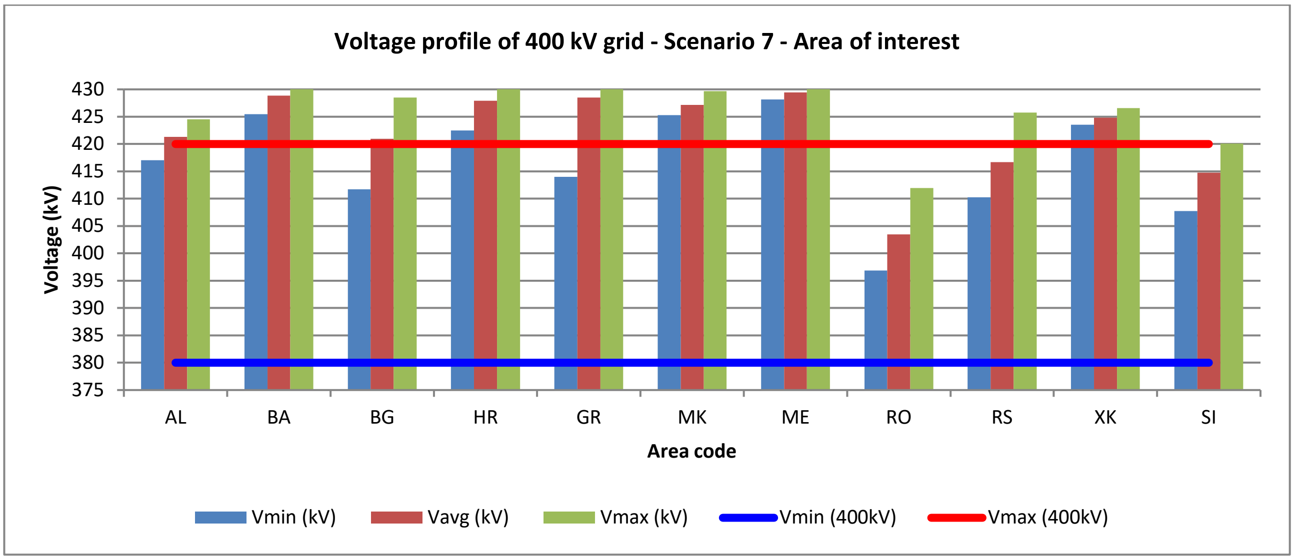


Figure 181: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 7: high RES, low demand growth, alternative CO_2 and mimimum load

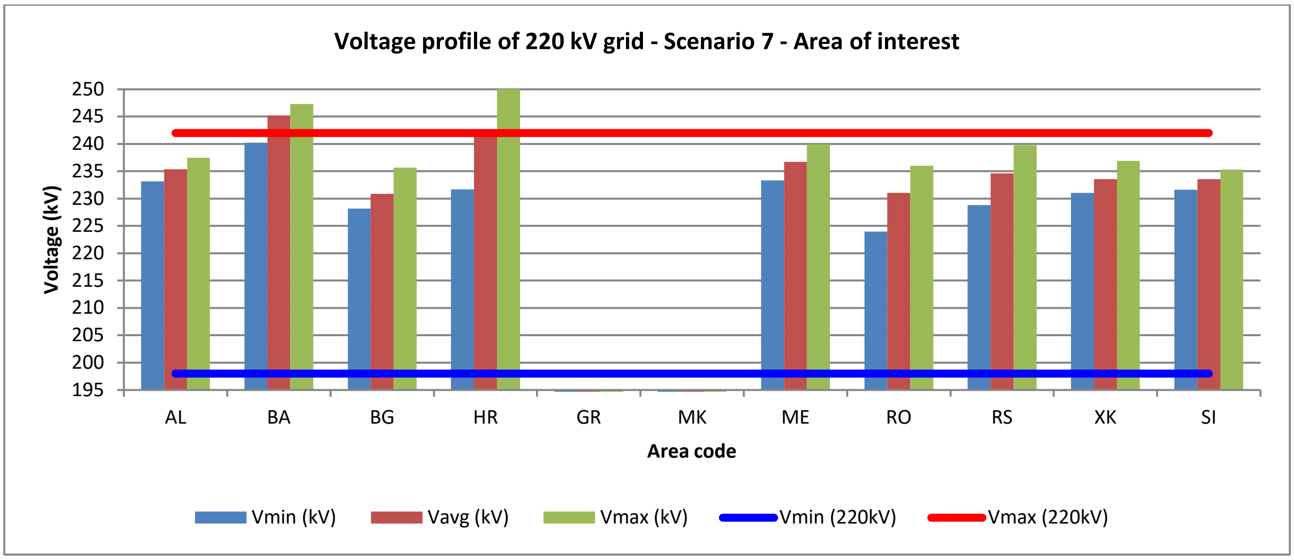


Figure 182: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 7: high RES, low demand growth, alternative CO_2 and mimimum load

The list of 400 kV and 220 kV elements that are loaded more than 80% is as follows:

FRM BUS	FROM BUS EXNAME	TO BUS	TO BUS EXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	835.72	-194.84	858.13	692.80	123.12
32201	[XPA_DI21 220.00]	490018	[DIVACA220 220.00]	319.75	-84.02	330.61	365.81	84.87
38030	[XVI_LA1M 400.00]	381030	[OLASTV11 400.00]	1000.00	-50.00	1001.25	1108.50	83.82

Figure 183: List of 400 and 220 kV elements loaded more than 80% in scenario 7

In scenario 7, there are just three elements in the region with the loading above 80%, including the Romanian 400 kV interconnection to Ukraine Rosiori - Mukacevo at 123%. Finally, we provide the contingency N-1 analysis results for this scenario:

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>   RATING     FLOW       %
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BASE CASE                         692.8     858.1    123.1
  10210*XKO_PO21    220.00 102015 AKOPLI2     220.00 1  BUS 10110                         274.4     329.1    113.7
  10210 XKO_PO21    220.00 382030*0PODG121    220.00 1  BUS 10110                         274.4     330.9    113.8
 102010 AVDEJA2     220.00 102015*AKOPLI2     220.00 1  BUS 10110                         278.2     323.4    110.5
  14124*XVA_MG11    400.00 141115 VVARNA1     400.00 1  BUS 14121                         900.0     987.8    109.0
  14121*XDO_MG11    400.00 141035 VDOBRU1     400.00 1  BUS 14124                         850.0     933.5    108.7
  32201*XPA_DI21    220.00 490018 DIVACA220   220.00 1  BUS 32101                         365.8     491.9    126.0

 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   145    0.0
 BUS 10110                       Met convergence to     3     0    0.0
 BUS 14121                       Met convergence to     1     0    0.0
 BUS 14124                       Met convergence to     1     0    0.0
 BUS 32101                       Met convergence to     1     8    0.0

CONTINGENCY LEGEND: (selected 4 contingecies appeared above from list of total 789 analyzed contingencies)
 <----- 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 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 490123 [PST_DIV     400.00] CKT 1
```

Figure 184: Contingency (n-1) analysis report for scenario 7

In scenario 7 there are four contingency events. However, there are no cases with severe overloading (higher than 130%). In the base case, with all elements available, the interconnection line Rosiori (Ro) – Mukacevo (UA) 400 kV line is slightly overloaded (123%), as mentioned above. Again, since there is an overload in the base case, this element is not shown as an overloaded element in all other outages.

6.8. Scenario 8: High RES, low demand growth, alternative CO2 and maximum RES

We provide the area summary for the 8th network scenario (high RES, low demand growth, alternative CO_2 and maximum RES) below:

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	945.5	0.0	0.0	1261.0	0.0	0.0	5.3	0.0	25.2	-346.0	-346.0	-346.0
AL	146.6	0.0	0.0	340.9	533.9	0.0	31.3	631.4	231.5	-359.7	-359.7	
13	1487.8	0.0	0.0	1821.0	0.0	0.0	12.9	0.0	65.9	-412.0	-412.0	-412.0
BA	325.6	0.0	0.0	334.6	0.0	0.0	131.1	1006.5	551.5	314.9	314.9	
14	4798.7	0.0	0.0	5403.0	0.5	0.0	58.2	0.0	148.0	-811.0	-811.0	-811.0
BG	2231.2	0.0	0.0	1998.9	455.2	0.0	158.8	2793.4	1783.9	627.6	627.6	
16	1822.4	0.0	0.0	2195.0	0.0	0.0	4.6	0.0	105.7	-483.0	-483.0	-483.0
HR	-163.2	0.0	0.0	517.8	106.3	0.0	22.6	1567.4	835.3	-77.8	-77.8	
30	11570.0	0.0	0.0	7788.0	0.0	0.0	0.0	0.0	471.9	3310.1	3310.1	3310.0
GR	1273.5	0.0	0.0	3848.2	1717.3	0.0	22.8	7636.8	3570.9	-248.8	-248.8	
37	533.2	0.0	0.0	1211.0	0.0	0.0	2.0	0.0	19.2	-699.0	-699.0	-699.0
MK	62.7	0.0	0.0	416.3	0.0	0.0	8.1	469.6	194.4	-86.5	-86.5	
38	612.3	0.0	0.0	535.0	0.0	0.0	4.5	0.0	36.8	36.0	36.0	36.0
ME	128.4	0.0	0.0	184.2	0.0	0.0	31.8	427.2	278.7	60.8	60.8	
44	10981.0	0.0	0.0	7577.0	0.0	0.0	104.7	0.0	233.3	3066.0	3066.0	3066.0
RO	-1335.1	0.0	0.0	2414.7	0.0	0.0	348.8	5787.3	2260.4	-571.7	-571.7	
46	1599.9	0.0	0.0	4957.1	0.0	0.0	27.6	0.0	89.2	-3474.0	-3474.0	-3474.0
RS	425.3	0.0	0.0	1028.7	0.0	0.0	150.3	1797.3	1089.6	-46.0	-46.0	
47	546.0	0.0	0.0	943.0	0.0	0.0	4.8	0.0	15.1	-417.0	-417.0	-417.0
XK	384.5	0.0	0.0	313.5	0.0	0.0	14.3	256.9	195.4	118.2	118.2	
49	2750.6	0.0	0.0	1744.0	0.0	0.0	7.7	0.0	28.9	970.0	970.0	970.0
SI	-287.5	0.0	0.0	299.5	0.0	0.0	49.9	687.4	360.5	-310.0	-310.0	
COLUMN	37647.3	0.0	0.0	35435.1	0.5	0.0	232.3	0.0	1239.3	740.1	740.1	740.0
TOTALS	3191.9	0.0	0.0	11697.5	2812.9	0.0	969.9	23061.2	11352.1	-579.2	-579.2	

Figure 185: Area summary report in scenario 8

This regime refers to March 24th, 11:00 am.

In this scenario, the region is exporting, but just 740 MW. It is less than in scenario 4 (2,490 MW of export) which is a similar regime, with max WPP+SPP generation, but with different dispatch of the conventional units due to a different level of CO_2 tax. Here again, usual exporter Bulgaria is importing and usual importer Greece is exporting, as in scenario 4. This is expected, given the different levels of RES share in these areas (a larger share of RES in GR than in BG), and the fact that this regime refers to the hours around noon, when load is still low.

The following Figure shows the cross-border power exchange map for the high RES, low demand growth, alternative CO_2 and maximum RES scenario.

Figure: Cross-border exhanges (MW) and directions between the countries in scenario: high RES, low demand growth, alternative CO_2 and maximum RES

The following two figures show the 400 kV and 220 kV voltage profiles with maximum, minimum and average values in each country. From the voltage profile perspective, this scenarios is ideal – there are no voltage problems, and no voltages out of limits.

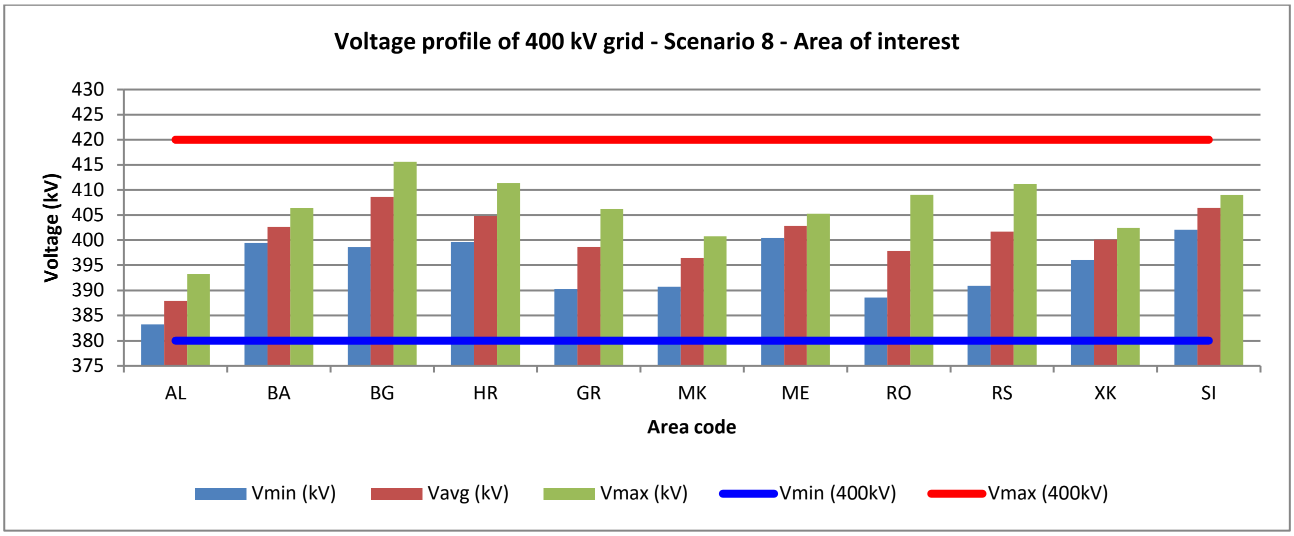


Figure 186: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 8: high RES, low demand growth, alternative CO_2 and maximum RES

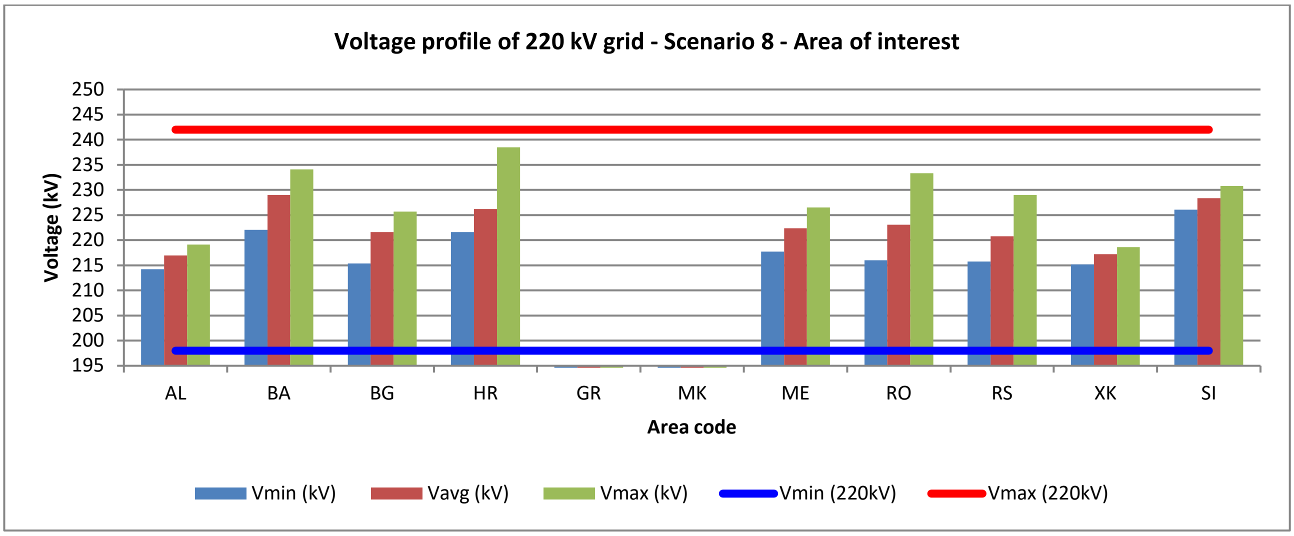


Figure 187: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 8: high RES, low demand growth, alternative CO_2 and maximum RES

List of 400 and 220 kV elements that are loaded more than 80% is given as follows:

FRMBUS	FROMBUSEXNAME	TOBUS	TOBUSEXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	599.99	-165.51	622.40	692.80	88.38

Figure 188: List of 400 kV and 220 kV elements loaded more than 80% in scenario 8

In scenario 8, there is just one element in the region with a loading above 80% and that is again the overhead line 400 kV Rosiori (RO) – Mukacevo (UA) (88%).

Finally, we provide the contingency N-1 analysis results for this scenario as follows.

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>   RATING     FLOW       %
 301274*GKPATR11     400.00 301279 GKPATC12    400.00 1  SINGLE 301274-301278(1)          717.1     705.6    100.7
 301274*GKPATR11     400.00 301278 GKPATC11    400.00 1  SINGLE 301274-301279(1)          717.1     773.8    110.0
 301274*GKPATR11     400.00 301279 GKPATC12    400.00 1  SINGLE 301278-301511(1)          717.1     705.4    100.6
 301274*GKPATR11     400.00 301278 GKPATC11    400.00 1  SINGLE 301279-301515(1)          717.1     772.9    109.9
 301274*GKPATR11     400.00 301278 GKPATC11    400.00 1  SINGLE 301505-301514(1)          717.1     767.6    108.7
 301274*GKPATR11     400.00 301279 GKPATC12    400.00 1  SINGLE 301511-301512(1)          717.1     704.5    100.3
 301274*GKPATR11     400.00 301278 GKPATC11    400.00 1  SINGLE 301514-301515(1)          717.1     770.7    109.4
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  SINGLE 448014-448950(1)          692.8     724.0    103.3
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BUS 4421                         692.8     819.7    117.7
  14124*XVA_MG11     400.00 141115 VVARNA1     400.00 1  BUS 14121                        900.0    1051.0    119.3
  14121*XDO_MG11     400.00 141035 VDOBRU1     400.00 1  BUS 14124                        850.0     990.8    119.0
  32201*XPA_DI21     220.00 490018 DIVACA220   220.00 1  BUS 32101                        365.8     416.1    109.5
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BUS 44121                        692.8     834.7    119.9
 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     0    0.0
 SINGLE 301274-301278(1)         Met convergence to     1     0    0.0
 SINGLE 301274-301279(1)         Met convergence to     1     0    0.0
 SINGLE 301278-301511(1)         Met convergence to     1     0    0.0
 SINGLE 301279-301515(1)         Met convergence to     1     0    0.0
 SINGLE 301505-301514(1)         Met convergence to     1     0    0.0
 SINGLE 301511-301512(1)         Met convergence to     1     0    0.0
 SINGLE 301514-301515(1)         Met convergence to     1     0    0.0
 SINGLE 448014-448950(1)         Met convergence to     1     0    0.0
 BUS 4421                        Met convergence to     1     0    0.0
 BUS 14121                       Met convergence to     1     0    0.0
 BUS 14124                       Met convergence to     1     0    0.0
 BUS 32101                       Met convergence to     1     0    0.0
 BUS 44121                       Met convergence to     1     0    0.0
CONTINGENCY LEGEND: (selected 13 contingecies appeared above from list of total 793 analyzed contingencies)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 301274-301278(1)        : OPEN LINE FROM BUS 301274 [GKPATR11    400.00] TO BUS 301278 [GKPATC11    400.00] CKT 1
 SINGLE 301274-301279(1)        : OPEN LINE FROM BUS 301274 [GKPATR11    400.00] TO BUS 301279 [GKPATC12    400.00] CKT 1
 SINGLE 301278-301511(1)        : OPEN LINE FROM BUS 301278 [GKPATC11    400.00] TO BUS 301511 [GKDISC11    400.00] CKT 1
 SINGLE 301279-301515(1)        : OPEN LINE FROM BUS 301279 [GKPATC12    400.00] TO BUS 301515 [GKACEC11    400.00] CKT 1
 SINGLE 301505-301514(1)        : OPEN LINE FROM BUS 301505 [GKACEL11    400.00] TO BUS 301514 [GKACET12    400.00] CKT 1
 SINGLE 301511-301512(1)        : OPEN LINE FROM BUS 301511 [GKDISC11    400.00] TO BUS 301512 [GKDIST12    400.00] CKT 1
 SINGLE 301514-301515(1)        : OPEN LINE FROM BUS 301514 [GKACET12    400.00] TO BUS 301515 [GKACEC11    400.00] CKT 1
 SINGLE 448014-448950(1)        : OPEN LINE FROM BUS 448014 [RSUCEA1     400.00] TO BUS 448950 [RROMAN1     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 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 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 490123 [PST_DIV     400.00] CKT 1
 BUS 44121                      : OPEN LINE FROM BUS 44121 [XVK_IS11; OV400.00] TO BUS 448020 [RISACC1     400.00] CKT 1
                                  OPEN LINE FROM BUS 44121 [XVK_IS11; OV400.00] TO BUS 636049 [5VULKADC1   400.00] CKT 1
```

Figure 189: Contingency (n-1) analysis report for scenario 8

In scenario 8, there are 13 contingency events. However, there are no cases with severe overloadings.

6.9. Scenario 9: High RES, low demand growth, alternative CO2 and maximum WPP and HPP

We provide the area summary for the 9th network scenario (high RES, low demand growth, alternative CO_2 and maximum WPP and HPP) below:

FROM X-- AREA --X	------AT AREA BUSES------- GENE-RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	-NET INTERCHANGE- TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	2926.9	0.0	0.0	1264.0	0.0	0.0	5.7	0.0	49.2	1608.0	1608.0	1608.0
AL	69.8	0.0	0.0	341.8	-53.5	0.0	34.1	692.7	594.6	-154.4	-154.4	
13	1768.7	0.0	0.0	1962.0	0.0	0.0	13.2	0.0	69.6	-276.0	-276.0	-276.0
BA	393.8	0.0	0.0	359.6	0.0	0.0	134.2	1029.8	647.9	281.8	281.8	
14	3225.3	0.0	0.0	4070.0	0.5	0.0	54.3	0.0	203.6	-1103.1	-1103.1	-1103.0
BG	1855.8	0.0	0.0	1484.5	421.3	0.0	145.8	2588.3	2204.0	188.5	188.5	
16	2614.3	0.0	0.0	2454.0	0.0	0.0	4.6	0.0	78.7	77.0	77.0	77.0
HR	-429.5	0.0	0.0	578.9	106.3	0.0	22.3	1553.0	696.4	-280.5	-280.5	
30	8315.9	0.0	0.0	7854.0	0.0	0.0	0.0	0.0	257.9	204.0	204.0	204.0
GR	313.7	0.0	0.0	3889.0	1801.7	0.0	23.4	7900.4	2303.2	196.9	196.9	
37	1300.6	0.0	0.0	1207.0	0.0	0.0	2.0	0.0	32.5	59.0	59.0	59.0
MK	-37.6	0.0	0.0	414.9	0.0	0.0	8.3	486.6	262.8	-237.0	-237.0	
38	1167.0	0.0	0.0	526.0	0.0	0.0	4.6	0.0	26.4	610.0	610.0	610.0
ME	152.2	0.0	0.0	175.6	0.0	0.0	32.2	450.7	291.5	103.6	103.6	
44	11898.8	0.0	0.0	8017.0	0.0	0.0	93.8	0.0	399.1	3389.0	3389.0	3389.0
RO	1501.6	0.0	0.0	1770.2	1075.0	0.0	272.6	5395.6	4750.1	-970.6	-970.6	
46	5096.5	0.0	0.0	5081.2	0.0	0.0	27.9	0.0	110.5	-123.1	-123.1	-107.0
RS	1041.0	0.0	0.0	1050.2	0.0	0.0	152.1	1822.2	1356.4	304.5	304.5	
47	881.3	0.0	0.0	864.0	0.0	0.0	5.0	0.0	18.3	-6.0	-6.0	-6.0
XK	231.8	0.0	0.0	287.6	0.0	0.0	14.8	270.6	192.3	7.7	7.7	
49	2610.5	0.0	0.0	1996.0	0.0	0.0	7.6	0.0	49.8	557.0	557.0	557.0
SI	236.8	0.0	0.0	317.4	-30.6	0.0	49.3	676.9	625.2	-47.6	-47.6	
COLUMN	41805.9	0.0	0.0	35295.2	0.5	0.0	218.7	0.0	1295.5	4996.0	4996.0	5012.0
TOTALS	5329.4	0.0	0.0	10669.4	3320.2	0.0	889.1	22866.9	13924.6	-607.1	-607.1	

Figure 190: Area summary report in scenario 9

This regime refers to March 20th, at 7:00 pm.

In this scenario the region is exporting, and the situation around exporters and importers is similar to other analyzed scenarios. The reason for this is that this regime refers to the evening hour (7pm), when generation from SPPs is small and load is close to its peak.

The following Figure shows the cross-border power exchange map for high RES, low demand growth, alternative CO_2 and maximum WPP and HPP scenario.

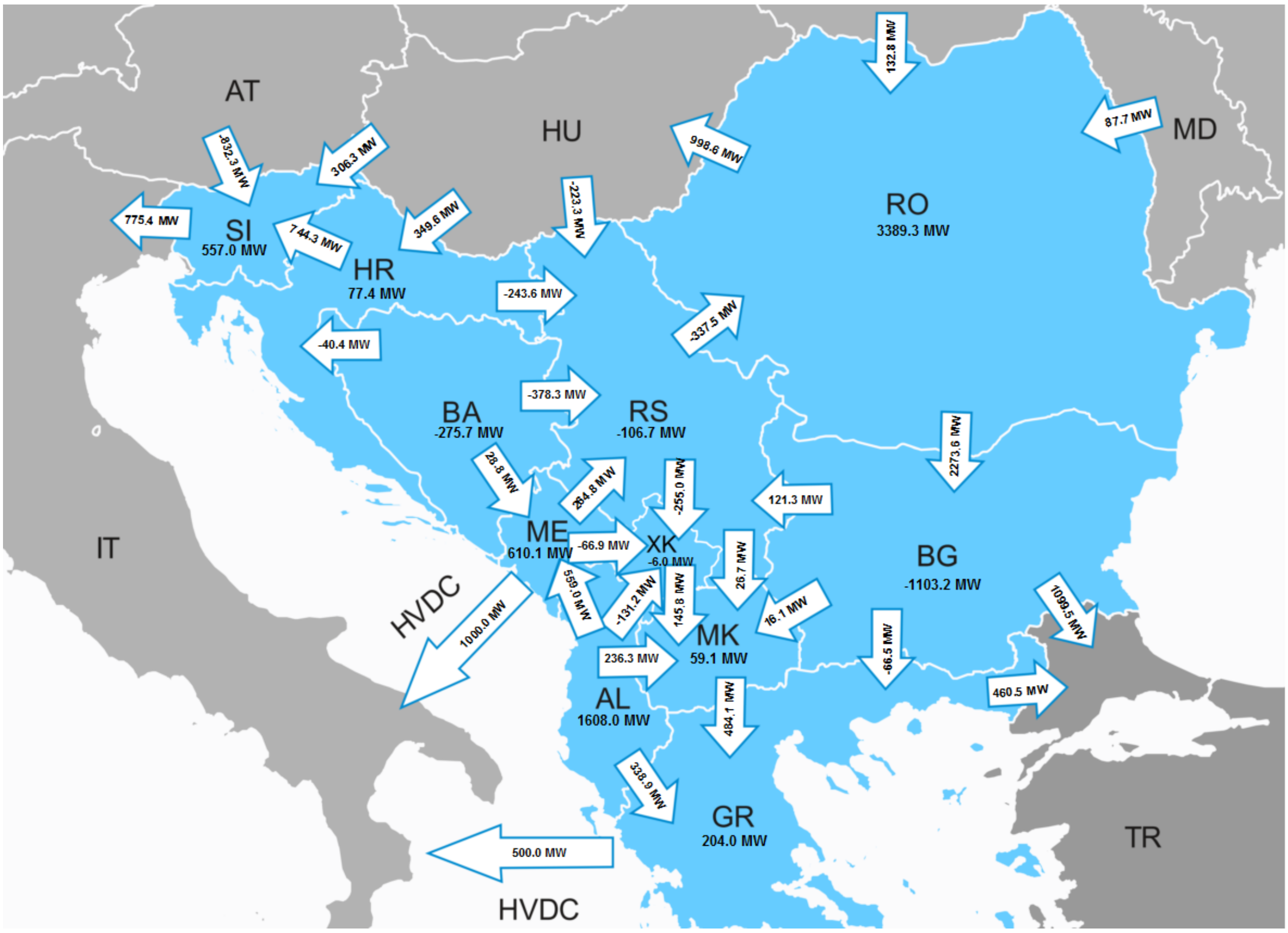


Figure 191: Cross-border exchanges (MW) and directions between the countries in scenario 9: high RES, low demand growth, alternative CO_2 and maximum WPP and HPP

The following two figures show the 400 kV and 220 kV voltage profiles with maximum, minimum and average values in each country. As in the previous scenario, there are no voltage profiles in the region out of limits, except the well known 220 kV case in Croatia (SS Plat).

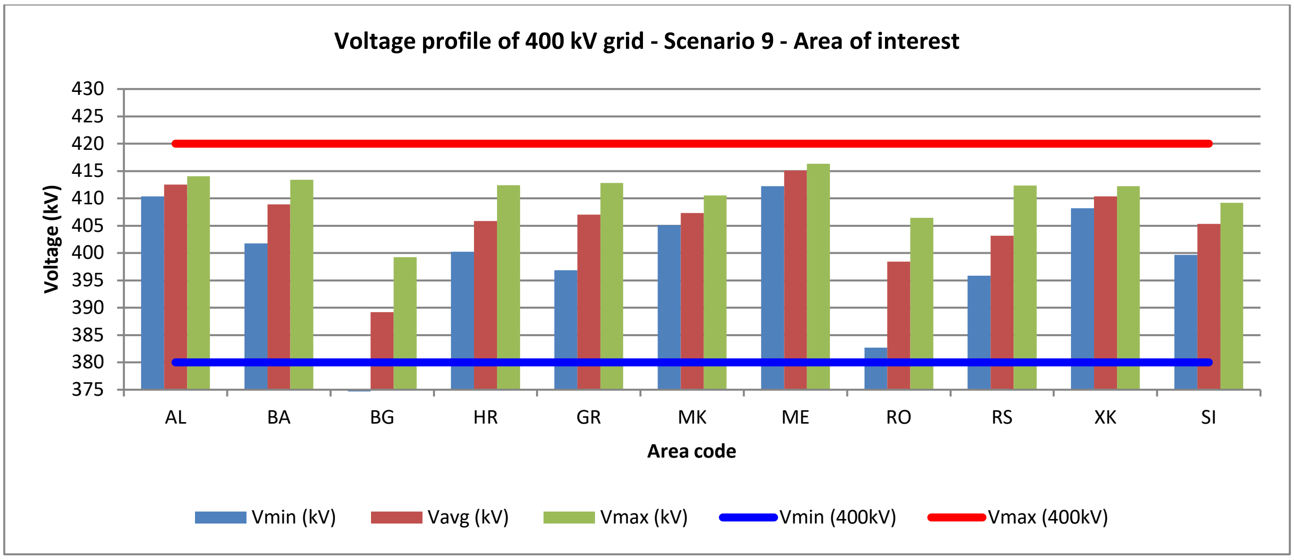


Figure 192: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 9: high RES, low demand growth, alternative CO_2 and maximum WPP and HPP

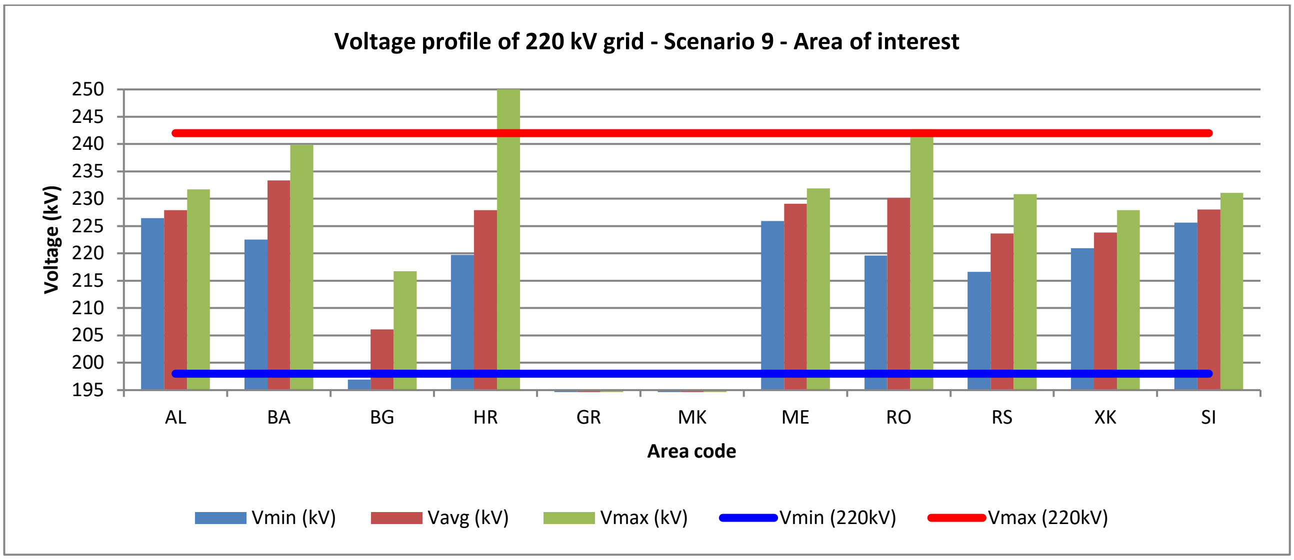


Figure 193: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 9: high RES, low demand growth, alternative CO_2 and maximum WPP and HPP

We provide the list of 400 kV and 220 kV elements loaded at more than 80% below:

FRMBUS	FROMBUSEXNAME	TOBUS	TOBUSEXNAME	MW	MVAR	MVA	RATING	%I
14124	[XVA_MG11 400.00]	141115	[VVARNA1 400.00]	1028.65	54.50	1030.09	900.00	121.43
14121	[XDO_MG11 400.00]	141035	[VDOBRU1 400.00]	871.34	28.87	871.82	850.00	108.78

Figure 194: List of 400 kV and 220 kV elements loaded more than 80% in scenario 9

In scenario 9 there are two elements in the region with the loading above 80%, both overloaded and both Bulgarian 400 kV interconnections.

Finally, we provide the contingency N-1 analysis results for this scenarios in the following table. **In scenario 9 there are 12 contingency events.** However, there are five cases with overloading higher than 130%. Moreover, in the base case, with all elements available, there are two Bulgarian interconnection lines overloaded. Since there are two overloaded elements in the base case, these elements are not shown in all other cases of outage.

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>   RATING    FLOW      %
  14121*XDO_MG11     400.00 141035 VDOBRU1      400.00 1  BASE CASE                        850.0     871.8    108.8
  14124*XVA_MG11     400.00 141115 VVARNA1      400.00 1  BASE CASE                        900.0    1030.1    121.4
 142060*VDOBRU2      220.00 142150 VO_KAR2T     220.00 1  SINGLE 141010-141115(1)          228.4     214.4    102.3
 161001 HLIKA 22     220.00 162021*HESENJ23     220.00 2  SINGLE 161001-162021(1)          300.0     380.0    126.7
 161001 HLIKA 22     220.00 162021*HESENJ23     220.00 1  SINGLE 161001-162021(2)          300.0     380.0    126.7
 448034*RSIBIU1      400.00 448366 RSIBIU22     220.00 1  SINGLE 448034-448100(1)          400.0     540.1    134.9
 448040*RLOTRU2      220.00 448366 RSIBIU22     220.00 1  SINGLE 448034-448100(1)          417.7     526.4    123.3
 448034*RSIBIU1      400.00 448100 RSIBIU21     220.00 1  SINGLE 448034-448366(1)          400.0     540.1    134.9
 448040*RLOTRU2      220.00 448100 RSIBIU21     220.00 1  SINGLE 448034-448366(1)          417.7     526.4    123.3
 448034*RSIBIU1      400.00 448366 RSIBIU22     220.00 1  SINGLE 448040-448100(1)          400.0     541.5    135.3
 448040*RLOTRU2      220.00 448366 RSIBIU22     220.00 1  SINGLE 448040-448100(1)          417.7     526.5    123.7
 448034*RSIBIU1      400.00 448100 RSIBIU21     220.00 1  SINGLE 448040-448366(1)          400.0     541.5    135.3
 448040*RLOTRU2      220.00 448100 RSIBIU21     220.00 1  SINGLE 448040-448366(1)          417.7     526.5    123.7
 490038*DIVACA400    400.00 490123 PST_DIV      400.00 2  SINGLE 490038-490123(1)          600.0     607.1    101.0
 490038*DIVACA400    400.00 490123 PST_DIV      400.00 1  SINGLE 490038-490123(2)          600.0     607.1    101.0
 162040*HMELIN21     220.00 161035 HMELIN11     400.00 2  BUS 16131                        150.0     179.8    119.5
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  BUS 16131                        150.0     176.4    113.7
  14141 XMI_HA11     380.00 141055*VMAIZ31      400.00 1  BUS 30121                       1200.0    1168.4    100.5
  32201 XPA_DI21     220.00 490018*DIVACA220    220.00 1  BUS 32101                        365.8     590.2    158.2
 162040*HMELIN21     220.00 161035 HMELIN11     400.00 2  BUS 32101                        150.0     160.9    106.6
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  BUS 32101                        150.0     157.3    101.3

 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      2     3    0.0
 SINGLE 141010-141115(1)         Met convergence to      1     0    0.0
 SINGLE 161001-162021(1)         Met convergence to      1     0    0.0
 SINGLE 161001-162021(2)         Met convergence to      1     0    0.0
 SINGLE 448034-448100(1)         Met convergence to      2     0    0.0
 SINGLE 448034-448366(1)         Met convergence to      2     0    0.0
 SINGLE 448040-448100(1)         Met convergence to      2     0    0.0
 SINGLE 448040-448366(1)         Met convergence to      2     0    0.0
 SINGLE 490038-490123(1)         Met convergence to      1     0    0.0
 SINGLE 490038-490123(2)         Met convergence to      1     0    0.0
 BUS 16131                       Met convergence to      2     0    0.0
 BUS 30121                       Met convergence to      1     0    0.0
 BUS 32101                       Met convergence to      3     0    0.0

CONTINGENCY LEGEND: (selected 12 contingecies appeared above from list of total 786 analyzed contingencies)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 141010-141115(1)         : OPEN LINE FROM BUS 141010 [VBURGA1      400.00] TO BUS 141115 [VVARNA1      400.00] CKT 1
 SINGLE 161001-162021(1)         : OPEN LINE FROM BUS 161001 [HLIKA 22     220.00] TO BUS 162021 [HESENJ23     220.00] CKT 1
 SINGLE 161001-162021(2)         : OPEN LINE FROM BUS 161001 [HLIKA 22     220.00] TO BUS 162021 [HESENJ23     220.00] CKT 2
 SINGLE 448034-448100(1)         : OPEN LINE FROM BUS 448034 [RSIBIU1      400.00] TO BUS 448100 [RSIBIU21     220.00] CKT 1
 SINGLE 448034-448366(1)         : OPEN LINE FROM BUS 448034 [RSIBIU1      400.00] TO BUS 448366 [RSIBIU22     220.00] CKT 1
 SINGLE 448040-448100(1)         : OPEN LINE FROM BUS 448040 [RLOTRU2      220.00] TO BUS 448100 [RSIBIU21     220.00] CKT 1
 SINGLE 448040-448366(1)         : OPEN LINE FROM BUS 448040 [RLOTRU2      220.00] TO BUS 448366 [RSIBIU22     220.00] CKT 1
 SINGLE 490038-490123(1)         : OPEN LINE FROM BUS 490038 [DIVACA400    400.00] TO BUS 490123 [PST_DIV      400.00] CKT 1
 SINGLE 490038-490123(2)         : OPEN LINE FROM BUS 490038 [DIVACA400    400.00] TO BUS 490123 [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 490038 [DIVACA400    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
 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 490123 [PST_DIV      400.00] CKT 1
```

Figure 195: Contingency (n-1) analysis report for scenario 9

6.10. Scenario 10: High RES, low demand growth, alternative CO2 and maximum SPP

We provide the area summary for the 10th network scenario (high RES, low demand growth, alternative CO_2 and maximum SPP) below:

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	890.6	0.0	0.0	915.0	0.0	0.0	5.9	0.0	17.8	-48.0	-48.0	-48.0
AL	-88.9	0.0	0.0	247.4	602.9	0.0	34.8	707.2	158.2	-425.1	-425.1	
13	718.6	0.0	0.0	1463.0	0.0	0.0	14.1	0.0	28.5	-787.0	-787.0	-787.0
BA	-11.7	0.0	0.0	271.3	0.0	0.0	143.9	1093.4	281.6	384.8	384.8	
14	4751.3	0.0	0.0	3917.6	0.0	0.0	66.8	0.0	63.9	703.0	703.0	703.0
BG	1141.2	0.0	0.0	1459.5	101.6	0.0	181.8	3198.9	905.2	1692.1	1692.1	
16	1333.9	0.0	0.0	2003.0	0.0	0.0	5.0	0.0	63.8	-738.0	-738.0	-738.0
HR	-291.3	0.0	0.0	472.5	110.0	0.0	24.3	1681.9	532.4	251.4	251.4	
30	9975.3	0.0	0.0	6481.0	0.0	0.0	0.0	0.0	184.3	3310.0	3310.0	3310.0
GR	-858.1	0.0	0.0	3265.8	2006.2	0.0	24.8	8540.3	2476.4	-90.9	-90.9	
37	439.2	0.0	0.0	932.0	0.0	0.0	2.3	0.0	13.9	-509.0	-509.0	-509.0
MK	-29.1	0.0	0.0	322.5	0.0	0.0	9.3	537.6	142.2	34.5	34.5	
38	195.1	0.0	0.0	379.0	0.0	0.0	4.8	0.0	23.3	-212.0	-212.0	-212.0
ME	-47.9	0.0	0.0	126.4	0.0	0.0	33.2	468.8	163.2	98.2	98.2	
44	8200.9	0.0	0.0	6995.0	0.0	0.0	107.9	0.0	177.0	921.1	921.1	921.0
RO	-1943.4	0.0	0.0	2232.4	999.8	0.0	359.9	5929.0	1542.4	-1148.8	-1148.8	
46	561.8	0.0	0.0	4205.1	0.0	0.0	29.0	0.0	71.7	-3744.0	-3744.0	-3744.0
RS	153.6	0.0	0.0	903.7	0.0	0.0	157.8	1906.7	788.8	210.0	210.0	
47	224.6	0.0	0.0	722.0	0.0	0.0	5.3	0.0	9.3	-512.0	-512.0	-512.0
XK	1.5	0.0	0.0	240.9	0.0	0.0	15.6	281.9	90.0	-63.1	-63.1	
49	2565.2	0.0	0.0	1959.0	0.0	0.0	7.9	0.0	32.3	566.0	566.0	566.0
SI	-204.1	0.0	0.0	311.5	-162.7	0.0	51.0	702.4	494.6	-196.1	-196.1	
COLUMN	29856.6	0.0	0.0	29971.6	0.0	0.0	249.0	0.0	685.8	-1049.9	-1049.9	-1050.0
TOTALS	-2178.1	0.0	0.0	9853.9	3657.8	0.0	1036.4	25048.0	7574.9	747.0	747.0	

Figure 196: Area summary report in scenario 10

This regime refers to April 23th, 12:00 pm. This scenario refer to hours around noon, and the region is exporting, similar to scenario 6.

The following Figure shows the cross-border power exchange map for the high RES, low demand growth, alternative CO_2 and maximum SPP scenario.

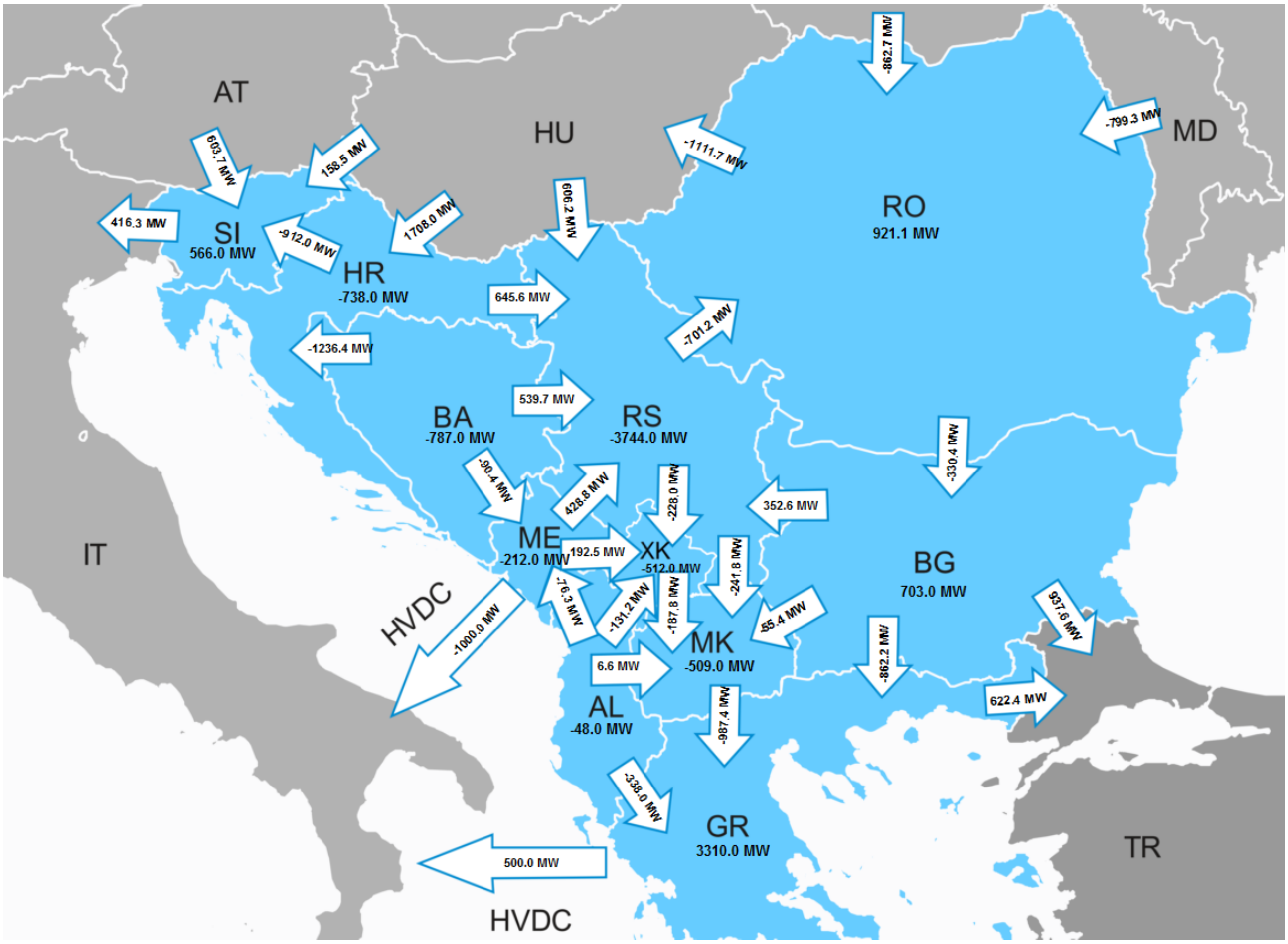


Figure 197: Cross-border exhanges (MW) and directions between the countries in scenario: high RES, low demand growth, alternative CO_2 and maximum SPP

The following two figures show 400 kV and 220 kV voltages with maximum, minimum and average values in each country. In the last scenario, the 400 kV voltage profiles are slightly above limits in Bulgaria and N.Macedonia. In 220 kV system, there are just a few light cases in Croatia and Bulgaria.

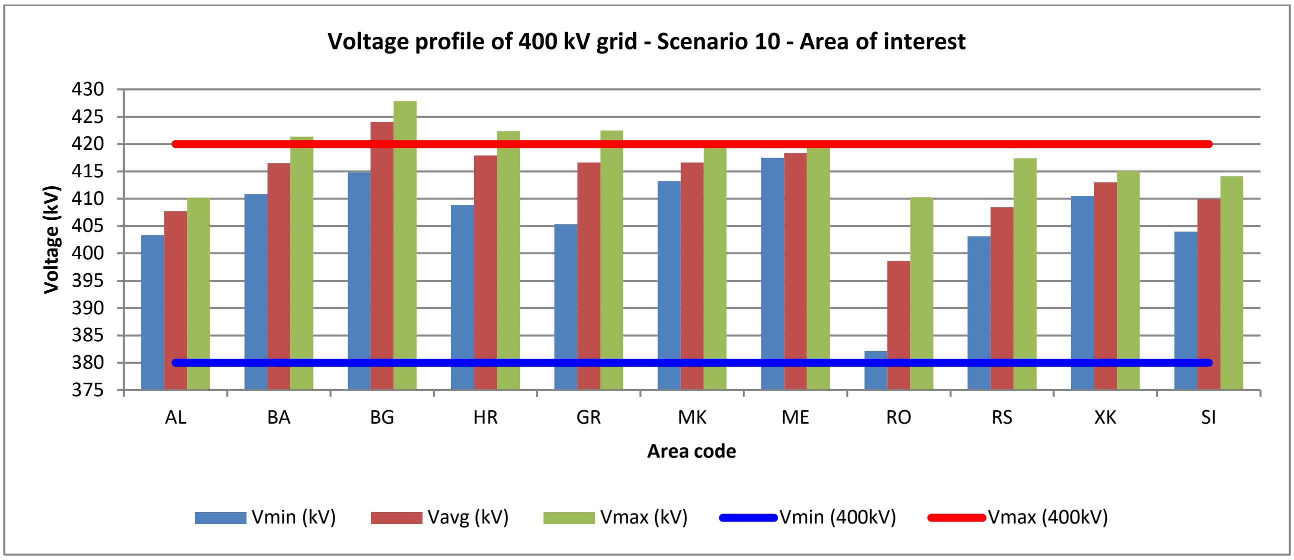


Figure 198: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 10: high RES, low demand growth, alternative CO_2 and maximum SPP

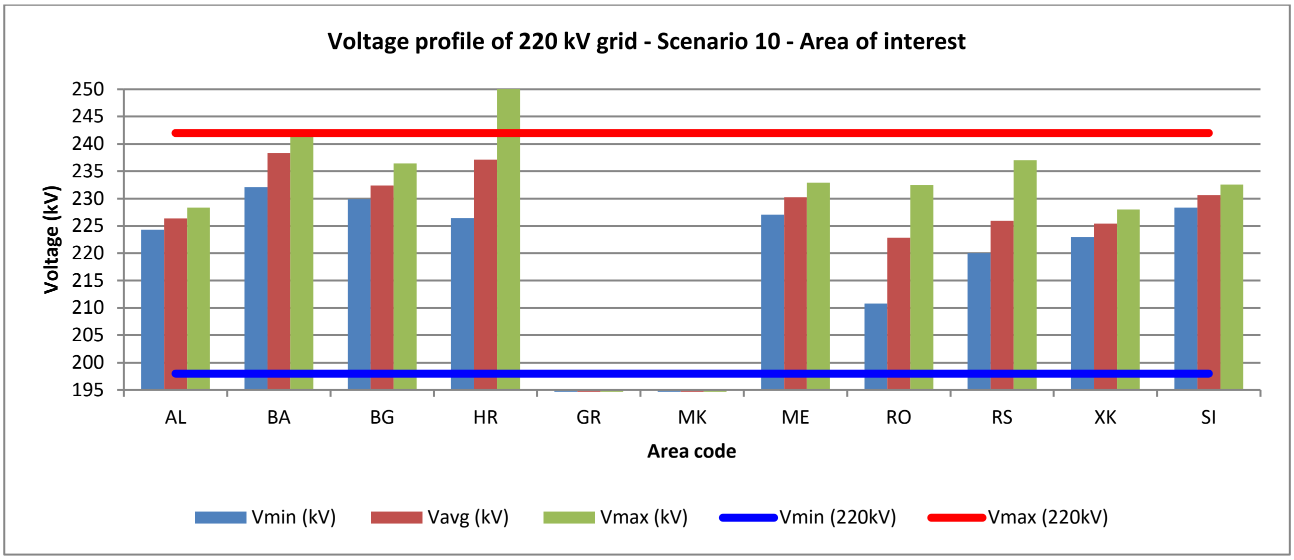


Figure 199: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 10: high RES, low demand growth, alternative CO_2 and maximum SPP

We provide the list of 400 and 220 kV elements that are loaded more than 80% as follows:

FRMBUS	FROMBUSEXNAME	TOBUS	TOBUSEXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	863.02	-285.84	909.13	692.80	133.73

Figure 200: List of 400 and 220 kV elements loaded more than 80% in scenario 10

In scenario 10, there is one well known element with the loading above 80% and that is the overloaded overhead line 400 kV Rosiori (RO) – Mukacevo (UA) (134%).

Finally, we provide the contingency N-1 analysis results for this scenario as follows.

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------> RATING    FLOW      %
  44111*XRO_MU11; OV400.00 600919 UMUKAC11    400.00 1  BASE CASE                       692.8    912.0    134.5
  44111 XRO_MU11; OV400.00 448039*RROSIO1     400.00 1  BUS 44121                      1277.8   1215.8    102.0

 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    55    0.0
 BUS 44121                       Met convergence to      1     5    0.0

CONTINGENCY LEGEND: (selected 1 contingecies appeared above from list of total 793 analyzed contingencies)
 <----- CONTINGENCY LABEL ------>  EVENTS
 BUS 44121                       : OPEN LINE FROM BUS 44121 [XVK_IS11; OV400.00] TO BUS 448020 [RISACC1     400.00] CKT 1
                                   OPEN LINE FROM BUS 44121 [XVK_IS11; OV400.00] TO BUS 636049 [5VULKADC1   400.00] CKT 1
```

Figure 201: Contingency (n-1) analysis report for scenario 10

In scenario 10, there is one contingency event. However, there is just one case with overloading higher than 130% (interconnection between Ukraine and Romania, given above in red), and it happens in the base case with all elements available. Since there is an overload in the base case, this element is not shown as overloaded element in all other cases of outage.

6.11. Scenario 11: Natural Gas, referent RES, referent demand growth, maximum load and referent CO2

For easier comparison we'll call this gas network scenario #11, as a follow up on the 10 scenarios in the previous chapter. We provide the area summary for the gas network scenario 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	2247.1	0.0	0.0	1810.0	0.0	0.0	5.6	0.0	61.6	370.0	370.0	370.0
AL	414.9	0.0	0.0	489.4	-51.3	0.0	33.1	678.0	646.2	-24.4	-24.4	
13	3754.2	0.0	0.0	2240.0	0.0	0.0	15.3	0.0	78.0	1421.0	1421.0	1421.0
BA	681.9	0.0	0.0	443.0	0.0	0.0	155.5	1055.3	830.3	308.4	308.4	
14	6042.8	0.0	0.0	6051.6	0.0	0.0	59.0	0.0	166.2	-234.0	-234.0	-234.0
BG	2399.8	0.0	0.0	2300.8	81.4	0.0	167.9	2792.1	2091.1	550.7	550.7	
16	2811.6	0.0	0.0	2984.0	0.0	0.0	4.6	0.0	106.0	-283.0	-283.0	-283.0
HR	-192.6	0.0	0.0	704.0	108.4	0.0	22.5	1567.6	917.4	-377.3	-377.3	
30	9345.5	0.0	0.0	10012.4	0.0	0.0	0.0	0.0	339.1	-1006.0	-1006.0	-1006.0
GR	1765.7	0.0	0.0	4840.7	1644.4	0.0	23.5	7504.0	2744.5	16.7	16.7	
37	1496.3	0.0	0.0	1166.0	0.0	0.0	2.1	0.0	23.2	305.0	305.0	305.0
MK	223.5	0.0	0.0	412.5	0.0	0.0	8.5	492.1	274.1	20.3	20.3	
38	1557.4	0.0	0.0	740.0	0.0	0.0	4.7	0.0	37.7	775.0	775.0	775.0
ME	250.7	0.0	0.0	252.8	0.0	0.0	33.3	446.4	421.9	-10.9	-10.9	
44	13356.6	0.0	0.0	9945.0	0.0	0.0	104.4	0.0	336.3	2970.9	2970.9	2971.0
RO	1146.5	0.0	0.0	2168.9	1389.2	0.0	363.6	5604.8	3745.0	-915.5	-915.5	
46	9422.6	0.0	0.0	7138.0	0.0	0.0	30.8	0.0	187.8	2066.0	2066.0	2066.0
RS	1812.0	0.0	0.0	1357.5	0.0	0.0	180.9	1838.4	2495.0	-383.0	-383.0	
47	1249.7	0.0	0.0	1273.0	0.0	0.0	4.9	0.0	21.8	-50.0	-50.0	-50.0
XK	386.7	0.0	0.0	422.0	0.0	0.0	14.5	264.7	312.0	-97.2	-97.2	
49	1827.5	0.0	0.0	2351.0	0.0	0.0	7.6	0.0	33.9	-565.0	-565.0	-565.0
SI	107.4	0.0	0.0	373.8	0.0	0.0	49.4	679.0	526.2	-163.0	-163.0	
COLUMN	53111.4	0.0	0.0	45711.0	0.0	0.0	239.0	0.0	1391.5	5769.9	5769.9	5770.0
TOTALS	8996.4	0.0	0.0	13765.4	3172.1	0.0	1052.7	22922.4	15003.8	-1075.2	-1075.2	

Figure 202: Area summary report in scenario 11

This regime refers to January 9th, at 5:00 pm.

In this scenario, the total regional load is 45,711 MW, while total generation is 53,111 MW. Similar to the other scenarios, the largest net exporters in the region are Romania (2,971 MW), Serbia (2,066 MW) and BiH (1,421 MW), while the largest importer is Greece (-1,006 MW). In total, in scenario 11, EMI region has a surplus of 5,770 MW.

The following Figure shows the cross-border power exchange map for the gas integration scenario.

Figure 203: Cross-border exhanges (MW) and directions between the countries in gas integration scenario

As in the following two figures, the 400 kV and 220 kV voltage profiles in the region in this scenario are within limits in all countries, with the exception of one 220 kV node in Croatia. In other words, the higher level of natural gas integration in the regional power system is not expected to have a negative impact on voltage profiles in the region.

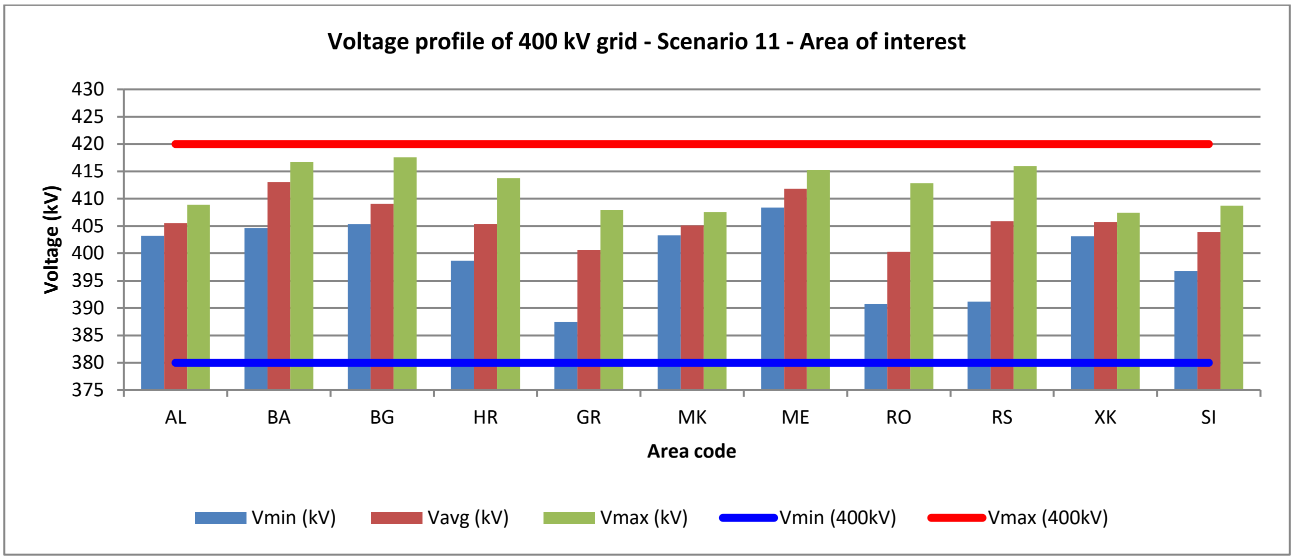


Figure 204: 400 kV voltage profiles (minimum, maximum and average) per country in the natural gas scenario

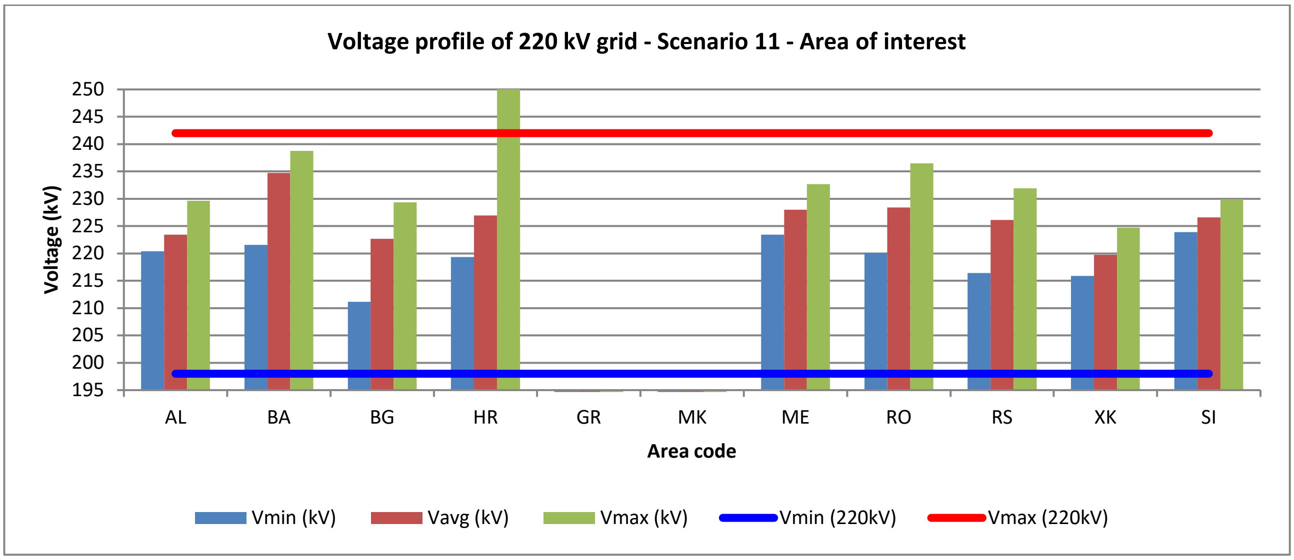


Figure 205: 220 kV voltage profiles (minimum, maximum and average) per country in the natural gas scenario

List of elements that are loaded more than 80% is given as follows:

FRMBUS	FROMBUSEXNAME	TOBUS	TOBUSEXNAME	MW	MVAR	MVA	RATING	%I
44111	[XRO_MU11; OV400.00]	600919	[UMUKAC11 400.00]	968.76	-254.88	1001.73	692.80	146.54

Figure 206: List of 400 and 220 kV elements loaded more than 80% in scenario 11

Similar to the other analyzed cases in scenario 11 there is one well known element with the loading above 80% and that is the overhead line 400 kV Rosiori (RO) – Mukacevo (UA) (146%).

Finally, we provide the contingency N-1 analysis results for this scenario as follows.

```
<----------------- MONITORED BRANCH -----------------> <----- CONTINGENCY LABEL ------>  RATING    FLOW      %
  44111*XRO_MU11; OV400.00 600919 UMUKAC11     400.00 1  BASE CASE                        692.8   1001.7    146.5
 162040*HMELIN21     220.00 161035 HMELIN11     400.00 2  BASE CASE                        150.0    151.6    101.4
 102010*AVDEJA2      220.00 102012 AVDJRI2      220.00 1  SINGLE 102005-102012(1)          325.4    357.2    107.8
 133240*WTTUZL2      220.00 133250 WTUZL42      220.00 2  SINGLE 133240-133250(1)          301.0    333.5    103.6
 133240*WTTUZL2      220.00 133250 WTUZL42      220.00 1  SINGLE 133240-133250(2)          301.0    331.0    102.9
 141045 VMAIZ11      400.00 141060*VMAIZ51      400.00 1  SINGLE 141045-141065(1)          519.0    592.8    109.8
 142060 VDOBRU2      220.00 142250*VVARNA2      220.00 1  SINGLE 142085-142250(1)          360.0    371.1    101.2
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  SINGLE 161021-162005(1)          150.0    170.5    110.6
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  SINGLE 161021-162030(1)          150.0    166.1    107.6
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  SINGLE 161035-161055(1)          150.0    153.4    100.3
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  SINGLE 161035-162040-166282(1)   150.0    227.7    149.2
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  SINGLE 162005-162020(1)          150.0    160.0    103.6
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  SINGLE 162020-162040(1)          150.0    190.1    123.1
 448034*RSIBIU1      400.00 448366 RSIBIU22     220.00 1  SINGLE 448034-448100(1)          400.0    534.1    136.1
 448040*RLOTRU2      220.00 448366 RSIBIU22     220.00 1  SINGLE 448034-448100(1)          417.7    528.2    124.3
 448034*RSIBIU1      400.00 448100 RSIBIU21     220.00 1  SINGLE 448034-448366(1)          400.0    534.1    136.1
 448040*RLOTRU2      220.00 448100 RSIBIU21     220.00 1  SINGLE 448034-448366(1)          417.7    528.2    124.3
 448034*RSIBIU1      400.00 448366 RSIBIU22     220.00 1  SINGLE 448040-448100(1)          400.0    535.3    136.5
 448040*RLOTRU2      220.00 448366 RSIBIU22     220.00 1  SINGLE 448040-448100(1)          417.7    528.2    124.7
 448034*RSIBIU1      400.00 448100 RSIBIU21     220.00 1  SINGLE 448040-448366(1)          400.0    535.3    136.5
 448040*RLOTRU2      220.00 448100 RSIBIU21     220.00 1  SINGLE 448040-448366(1)          417.7    528.2    124.7
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  SINGLE 490038-490123(1)          150.0    161.6    104.9
 490038*DIVACA400    400.00 490123 PST_DIV      400.00 2  SINGLE 490038-490123(1)          600.0    718.1    120.9
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  SINGLE 490038-490123(2)          150.0    161.6    104.9
 490038*DIVACA400    400.00 490123 PST_DIV      400.00 1  SINGLE 490038-490123(2)          600.0    718.1    120.9
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  BUS 16131                        150.0    280.0    182.4
  32201 XPA_DI21     220.00 490018*DIVACA220    220.00 1  BUS 32101                        365.8    727.2    198.9
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  BUS 32101                        150.0    243.6    159.4
 161035*HMELIN11     400.00 162040 HMELIN21     220.00 2  BUS 38030                        150.0    153.8    100.3
 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     2     0    0.0
 SINGLE 102005-102012(1)         Met convergence to     1     0    0.0
 SINGLE 133240-133250(1)         Met convergence to     1     0    0.0
 SINGLE 133240-133250(2)         Met convergence to     1     0    0.0
 SINGLE 141045-141065(1)         Met convergence to     1     0   38.0
 SINGLE 142085-142250(1)         Met convergence to     1     0    0.0
 SINGLE 161021-162005(1)         Met convergence to     1     0    0.0
 SINGLE 161021-162030(1)         Met convergence to     1     0    0.0
 SINGLE 161035-161055(1)         Met convergence to     1     0    0.0
 SINGLE 161035-162040-166282(1)  Met convergence to     1     0    0.0
 SINGLE 162005-162020(1)         Met convergence to     1     0    0.0
 SINGLE 162020-162040(1)         Met convergence to     1     0    0.0
 SINGLE 300117-300119-300120(T1) Iteration limit ex    --    --     --
 SINGLE 448034-448100(1)         Met convergence to     2     0    0.0
 SINGLE 448034-448366(1)         Met convergence to     2     0    0.0
 SINGLE 448040-448100(1)         Met convergence to     2     0    0.0
 SINGLE 448040-448366(1)         Met convergence to     2     0    0.0
 SINGLE 490038-490123(1)         Met convergence to     2     0    0.0
 SINGLE 490038-490123(2)         Met convergence to     2     0    0.0
 BUS 16131                       Met convergence to     1     0    0.0
 BUS 32101                       Met convergence to     2     0    0.0
 BUS 38030                       Met convergence to     1     0 1000.0
CONTINGENCY LEGEND: (selected 21 contingecies appeared above from list of total 787 analyzed contingencies)
 <----- CONTINGENCY LABEL ------>  EVENTS
 SINGLE 102005-102012(1)         : OPEN LINE FROM BUS 102005 [AKOMAN2    220.00] TO BUS 102012 [AVDJRI2     220.00] CKT 1
 SINGLE 133240-133250(1)         : OPEN LINE FROM BUS 133240 [WTTUZL2    220.00] TO BUS 133250 [WTUZL42     220.00] CKT 1
 SINGLE 133240-133250(2)         : OPEN LINE FROM BUS 133240 [WTTUZL2    220.00] TO BUS 133250 [WTUZL42     220.00] CKT 2
 SINGLE 141045-141065(1)         : OPEN LINE FROM BUS 141045 [VMAIZ11    400.00] TO BUS 141065 [VMAIZ61     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 161021-162005(1)         : OPEN LINE FROM BUS 161021 [HVEKRP21   220.00] TO BUS 162005 [HBRINJ21    220.00] CKT 1
 SINGLE 161021-162030(1)         : OPEN LINE FROM BUS 161021 [HVEKRP21   220.00] TO BUS 162030 [HKONJS21    220.00] CKT 1
 SINGLE 161035-161055(1)         : OPEN LINE FROM BUS 161035 [HMELIN11   400.00] TO BUS 161055 [HTUMBR11    400.00] CKT 1
 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 162005-162020(1)         : OPEN LINE FROM BUS 162005 [HBRINJ21   220.00] TO BUS 162020 [HESENJ22    220.00] CKT 1
 SINGLE 162020-162040(1)         : OPEN LINE FROM BUS 162020 [HESENJ22   220.00] TO BUS 162040 [HMELIN21    220.00] CKT 1
 SINGLE 448034-448100(1)         : OPEN LINE FROM BUS 448034 [RSIBIU1    400.00] TO BUS 448100 [RSIBIU21    220.00] CKT 1
 SINGLE 448034-448366(1)         : OPEN LINE FROM BUS 448034 [RSIBIU1    400.00] TO BUS 448366 [RSIBIU22    220.00] CKT 1
 SINGLE 448040-448100(1)         : OPEN LINE FROM BUS 448040 [RLOTRU2    220.00] TO BUS 448100 [RSIBIU21    220.00] CKT 1
 SINGLE 448040-448366(1)         : OPEN LINE FROM BUS 448040 [RLOTRU2    220.00] TO BUS 448366 [RSIBIU22    220.00] CKT 1
 SINGLE 490038-490123(1)         : OPEN LINE FROM BUS 490038 [DIVACA400  400.00] TO BUS 490123 [PST_DIV     400.00] CKT 1
 SINGLE 490038-490123(2)         : OPEN LINE FROM BUS 490038 [DIVACA400  400.00] TO BUS 490123 [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 490038 [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 490123 [PST_DIV    400.00] CKT 1
 BUS 38030                       : OPEN LINE FROM BUS 38030 [XVI_LA1M   400.00] TO BUS 381030 [OLASTV11   400.00] CKT 1
```

Figure 207: Contingency (n-1) analysis report for scenario 11

In scenario 11 there are 21 contingency events. There are eight cases with overloading higher than 130%, one in the base case with all elements available.

We would make the following conclusions from the network analysis in the high gas integration scenario:

1. **The integration of an additional 1,155 MW of gas-fired TPPs will have an impact on the regional transmission network, with 10 network bottlenecks, mainly in Albania, BiH, Croatia, Romania and Bulgaria.**
2. **The number of contingencies is comparable to number of bottlenecks detected in scenarios 1, 5 and 9, with maximum load and maximum WPP and HPP. We provide a full comparison of all scenarios in the following subchapter.**
3. **The integration of an additional 1,155 MW of gas-fired TPPs** is not expected to have a negative impact on the voltage profiles in the region.

6.12. Concluding remarks on the impact of different RES levels on SEE network operation

As mentioned above, in this subchapter we summarize the impact of different RES levels on the operation of the network in SEE, in these areas:

1. list of critical network elements (contingencies)
2. map of critical network elements (contingencies)
3. total network losses

The following table shows the list of critical elements in each analyzed scenario. **Altogether there are 73 contingency cases found in the 11 analyzed scenarios. All of the contingencies appear on 22 detected elements in the region that could be critical in the future due to large scale RES integration. Among them there are:**

- **8 critical tie lines (including one phase shift transformer on the Slovenian border to Italy),**
- **11 internal lines, and**
- **3 transformers**

The eight critical tie lines are found both in the 400 kV network (5 elements) and the 220 kV network (3 lines). These elements are located on the following borders:

- **Bulgaria – Romania (2 tie lines[5])**
- **Bulgaria – Turkey**
- **Romania – Ukraine[5]**
- **Slovenia – Italy (3 tie lines)**
- **Albania – Montenegro**

As mentioned before, the capacity of the 400 kV tie-line Rosiori (RO) – Mukacevo (UA) is set by the Ukrainian TSO, and it is quite low compared to standard values for 400 kV lines. Therefore, this limitation should not be considered a serious limiting factor on cross-border exchange.

The 11 critial internal lines are also found both in the 400 kV network (3 lines) and the 220 kV network (8 lines). These elements are located in these countries:

- **Albania (2 lines on 220 kV level)**

[5] This overloading is caused by different line ratings on both sides of the border. The reason behind this difference is in different settings of the current transformers. Therefore, this bottleneck can be easily released.

- **Greece (1 line on 400 kV level)**
- **Croatia (2 elements both double circuit lines, one on 400 kV, the other on 220 kV)**
- **Romania (1 line on 220 kV level)**
- **Bulgaria (3 lines, one on 400 kV[6] and 2 on 220 kV level) and**
- **Bosnia and Herzegovina (2 lines on 220 kV)**

Three transformers are critical in the region, with two in Croatia, and one in Romania[7].

Among the 22 critical elements there are six elements with severe overloadings (130% of rated current) in one or more scenarios. Three elements appear to be overloaded in the base cases (with all elements available).

The following figure shows the geographical dispersion of critical elements in the EMI region. It seems that **eight out of the 11 EMI TSOs can expect to face network bottlenecks in the high RES scenarios in 2030 (AL, BA, BG, HR, GR, ME, RO and SI). By comparison, our analysis also shows that in our scenarios, the TSOs of MK, RS and XK will not face any network bottlenecks with high RES integration.**

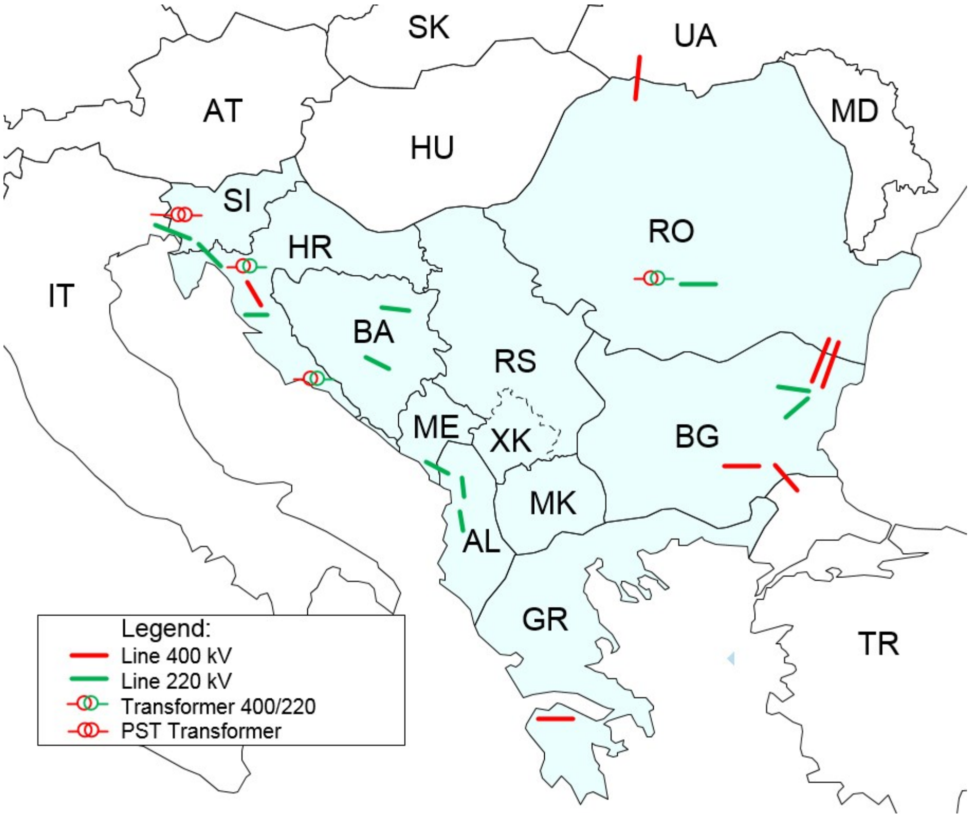


Figure 208: Geographical distribution of the critical transmission network elements in the region in all analyzed scenarios

[6] The 400 kV line overloading in Bulgaria is related to the swing bus node, as explained at the end of Chapter 6.1, and is not an operational issue.

[7] It seems than submitted input data on TS 400/220 kV Meline (HR) capacity is incorrect, so this should be double-checked.

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

Critical element			Area/Border	Scenario										
				Referent RES development		High RES development, low demand growth								Gas + Referent RES development
				Referent CO_2 price		Referent CO_2 price				Alternative CO2 price				Referent CO_2 price
Type	Voltage	Connected nodes		MAX Load 1	MIN Load 2	MIN Load 3	MAX RES 4	MAX WPP+HPP 5	MAX SPP 6	MIN Load 7	MAX RES 8	MAX WPP+HPP 9	MAX SPP 10	MAX Load 11
Tie-lines	400 kV	Dobrudzha - Medigidia Sud	BG-RO	117,2%			114,4%	**133,7%**		109,0%	119,0%	**109,1%**		
		Maritsa Iztok 3 - Hamitabat	BG-TR	101,5%	102,5%	103,1%		102,3%				102,1%		
		Rosiori - Mukachevo	RO-UA	**103,3%**	106,0%	104,7%	**112,5%**	103,6%	**122,2%**	**123,4%**	119,9%		**134,5%**	**146,5%**
		Varna - Medigidia Sud	BG-RO	117,3%			114,7%	**133,9%**		109,3%	119,3%	**121,8%**		
	400/400 kV	PST Divaca	IT-SI (in SI)	104,3%				105,0%				101,0%		120,9%
	220 kV	Koplik - Podgorica	AL-ME		127,3%	125,5%				114,5%				
		Divaca - Padriciano	SI-IT	**163,0%**	128,2%		**131,2%**	**165,4%**	128,2%	126,0%	109,5%	**158,2%**		**198,9%**
		Divaca - Pehlin	SI-IT					102,9%						
Internal lines	400 kV	Lika - Melina (circuit 1 and 2)	HR					100,5%						
		Maritsa Iztok 1 - Maritsa Iztok 5	BG	113,7%				112,3%						109,8%
		Patra - Patra C	GR								110,0%			
	220 kV	V.Dejes - Koplik	AL		123,6%	121,7%				111,1%				
		V.Dejes - Vdjri	AL					109,2%						107,8%
		Lika - Senj (circuit 1 and 2)	HR					125,7%				126,7%		
		Lotru - Sibiu (circuit 1 and 2)	RO									123,7%		124,3%
		Dobrudzha - Karnobat	BG									103,0%		
		Dobrudzha - Varna	BG	103,2%				114,4%						101,2%
		RP Jablanica - RP Kakanj	BA					105,0%						
		TPP Tuzla - Tuzla 4 (circuit 1 and 2)	BA	108,8%										103,6%
Transformers	400/220 kV	Konjsko	HR				101,9%	121,9%						
	400/220 kV	Melina	HR	**184,0%**				**172,2%**				119,5%		**182,4%**
	400/220 kV	Sibiu	RO									**135,3%**		**136,1%**

Legend: Overloading in Base case (N-0)

Bold - very high overload

The following figure shows the total number of contingencies in all scenarios in each country. It assumes a number of elements whose outage is causing overloadings in the network. For each scenario we show two bars. Bar A represents contingencies on internal lines, while bar B represents contingencies on interconnetion lines. In each bar, we separately label the number of contingencies in each country. **The highest number of outages in one scenario is eight, in scenario 5. Clearly, there are no scenarios with an extremely high number of contingencies which is good sign of network robustness.**

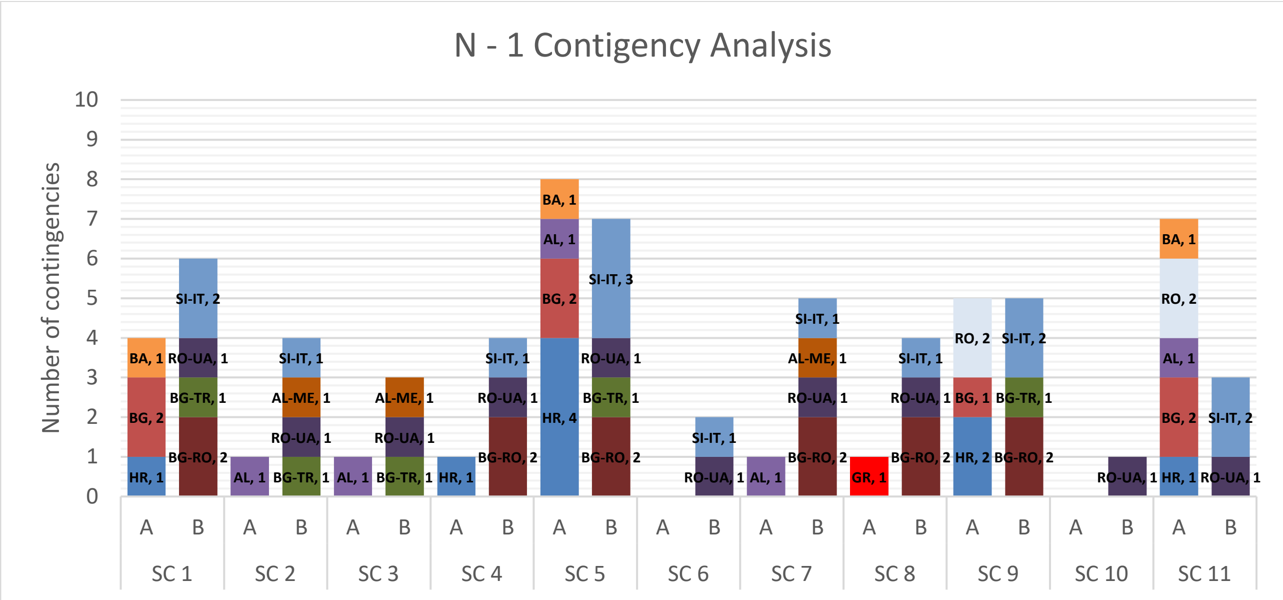


Figure 209: Total number of contingencies in all scenarios with each country contribution

Our network models are based on the TSOs' official 10-year network development plans (TYNDPs). This analysis incorporated significant changes in all power systems by 2030, including an additional 25% of RES capacities on top of RES capacities already included in these plans. **In sum, the total installed regional capacity will increase by 30%, or more than 24,000 MW, with modest TPP retirements.**

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 22 bottlenecks found in the region in all 11 scenarios, we conclude that while selected upgrades and de-bottlenecking make sense, the SEE regional network overall is quite robust for the future absorption and utilization of additional RES capacities.**

Similar to the contingency comparison, the following figure compares network losses for each scenario. Total network losses in the region are in the range of 500 – 1,400 MW. As expected, each country share is changing depending on the scenario.

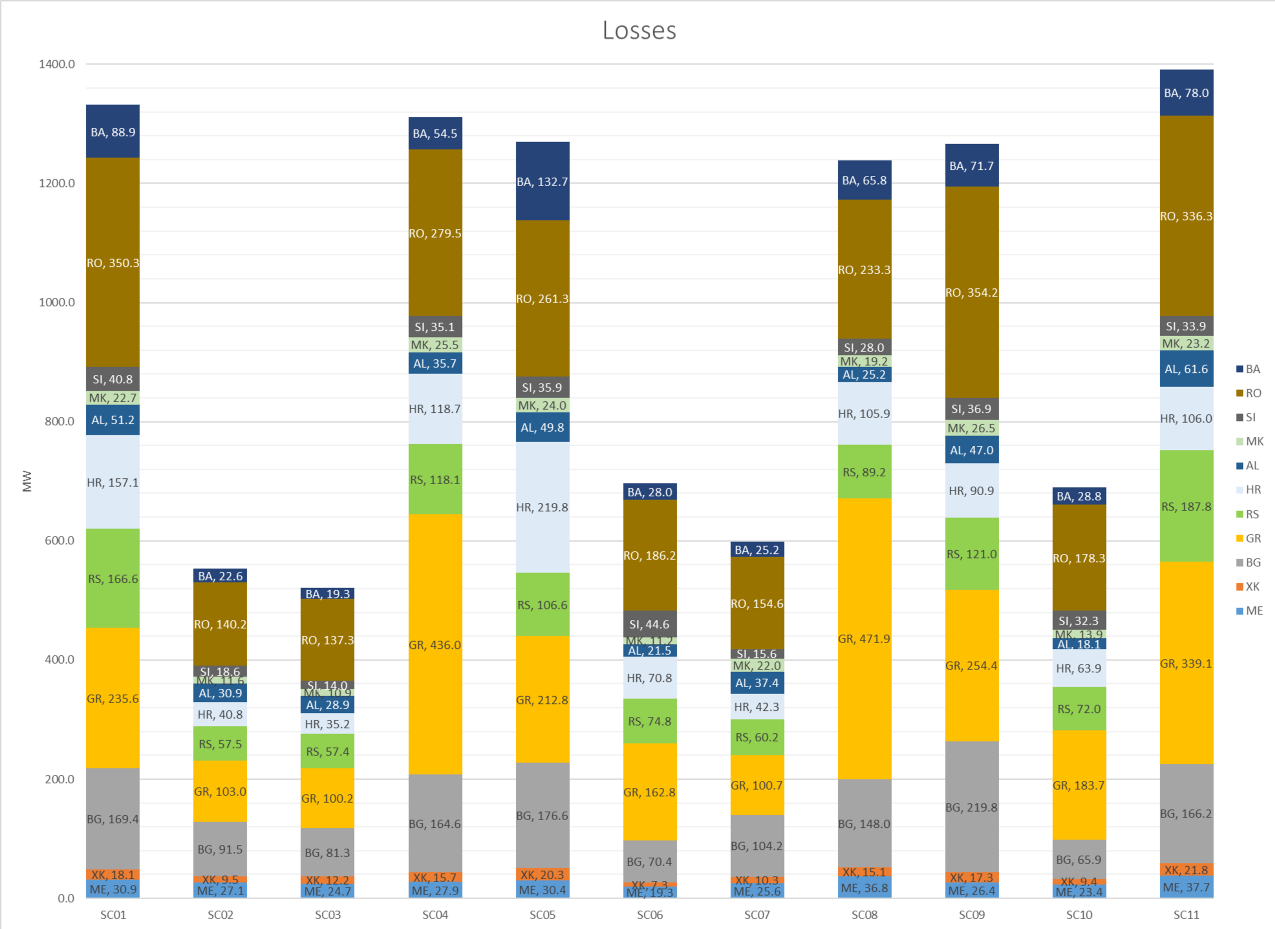


Figure 210: Total regional transmission network losses in all scenarios with each country contribution

Since EMI members are focused on the impact of RES integration 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 11 analyzed scenarios. In these figures, the first two scenarios are base cases, with minimum and maximum system load, and all other scenarios are with high RES penetration. Even though for more detailed loss analysis we would need to evaluate a yearly timeframe, these indicative figures allow us to follow the impact of RES integration 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, as well as its daily and seasonal curves.

The other two figures in each subchapter provide an overview of the voltage profiles in each area for all 11 analyzed cases.

6.12.1. OST (AL) network area

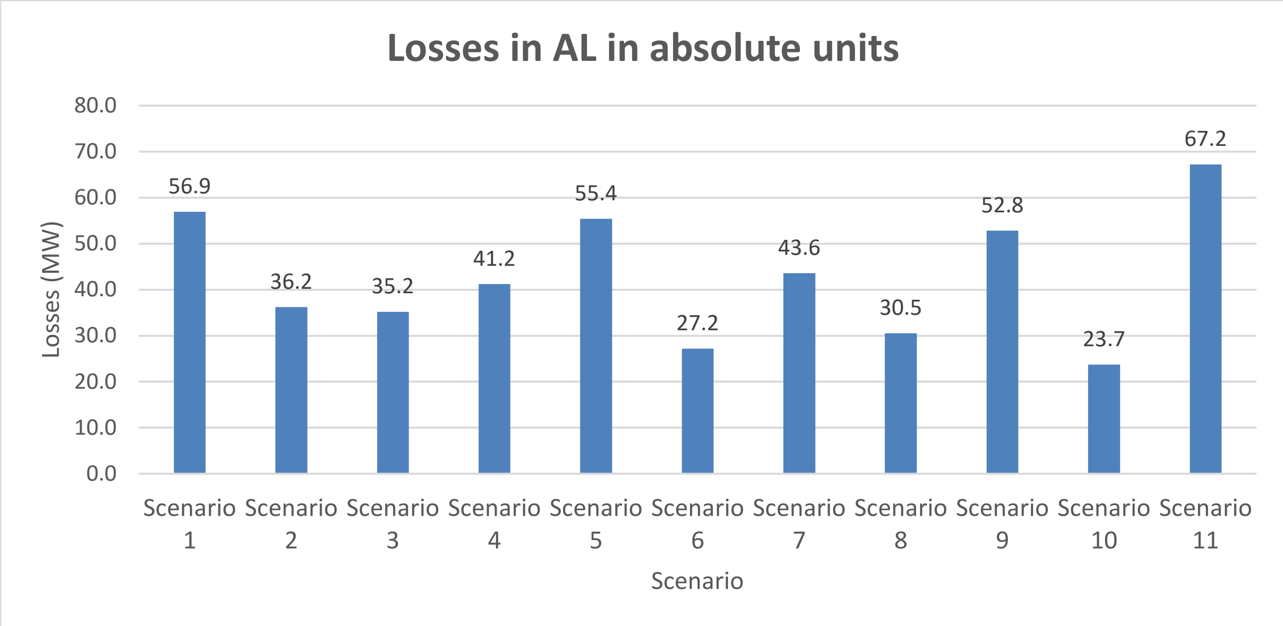


Figure 211: Transmission network losses in absolute value in the AL area in all analyzed scenarios

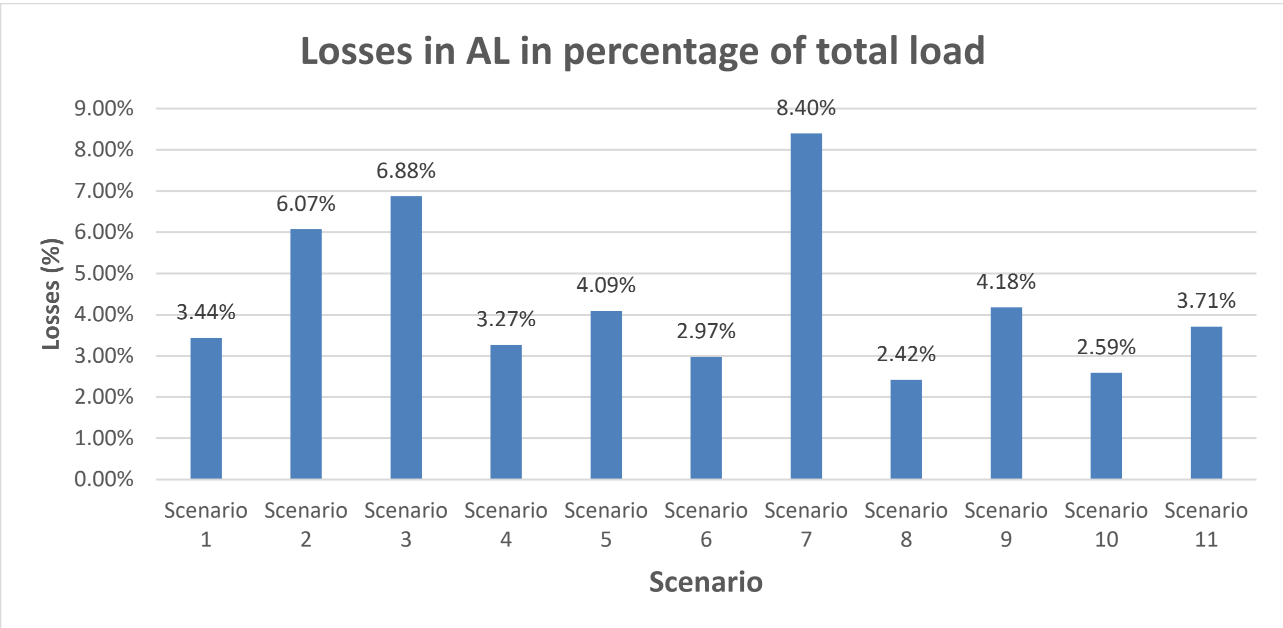


Figure 212: Transmission network losses in the AL area relative to system load in all analyzed scenarios

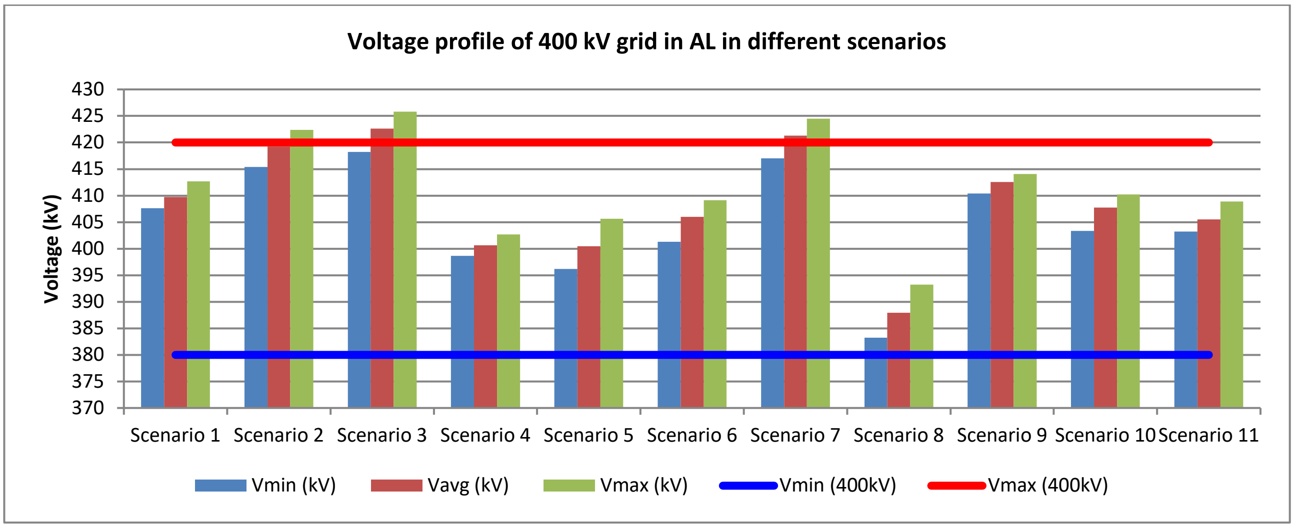


Figure 213: 400 kV voltage profiles (minimum, maximum and average) in the AL area in all analyzed scenarios

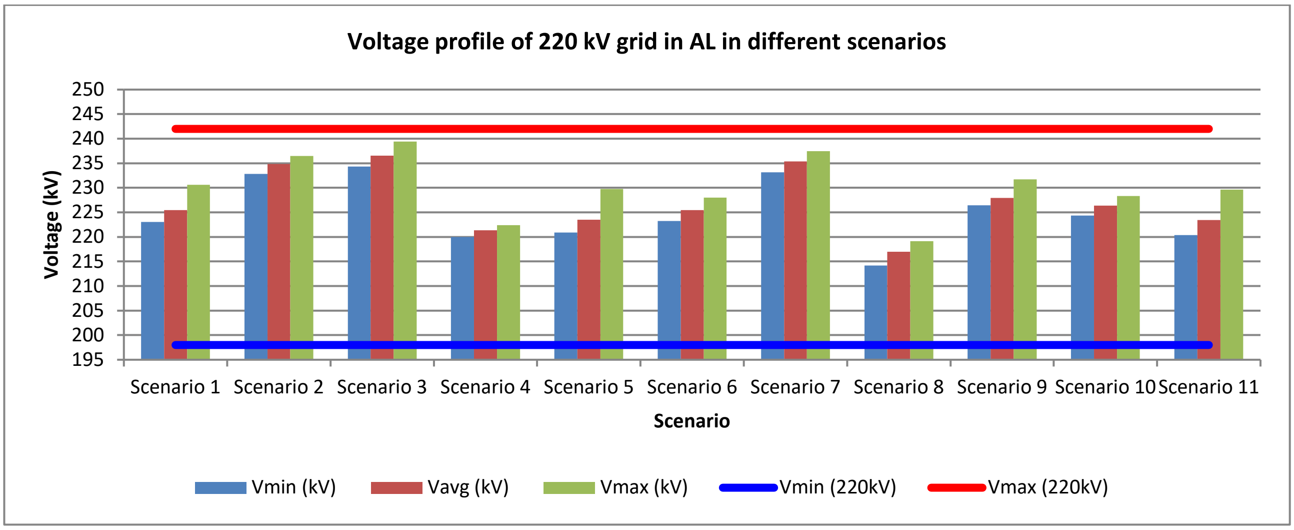


Figure 214: 220 kV voltage profiles (minimum, maximum and average) in the AL area in all analyzed scenarios

6.12.2. NOS BiH (BA) network area

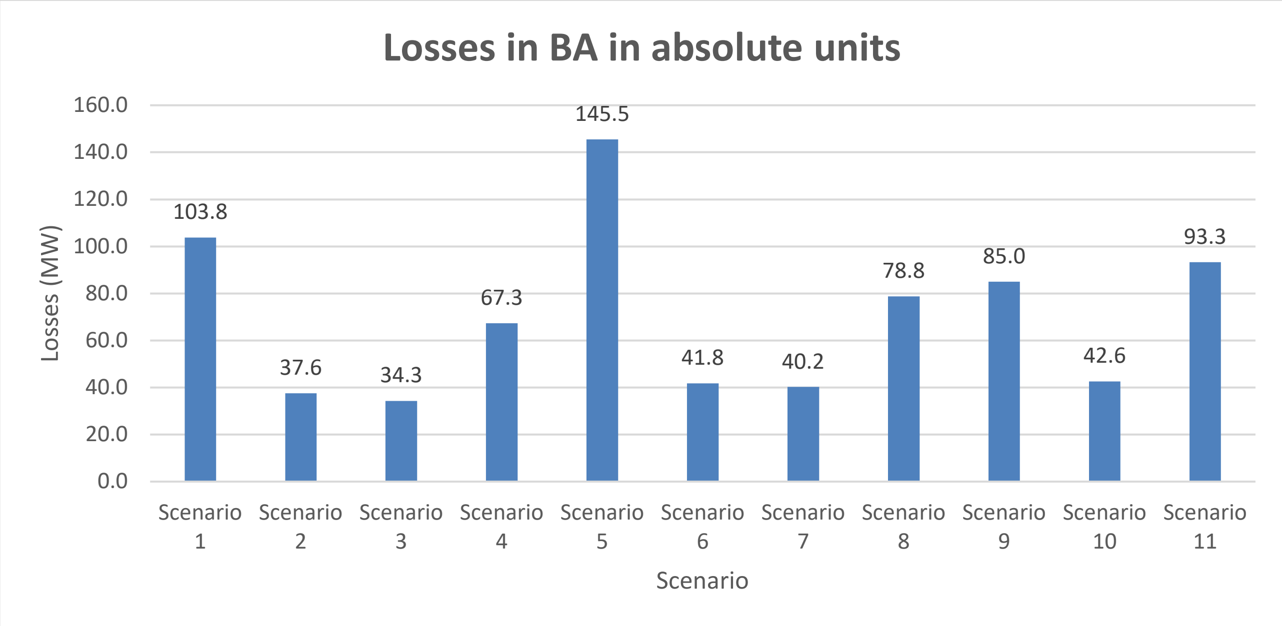


Figure 215: Transmission network losses in absolute value in the BiH area in all analyzed scenarios

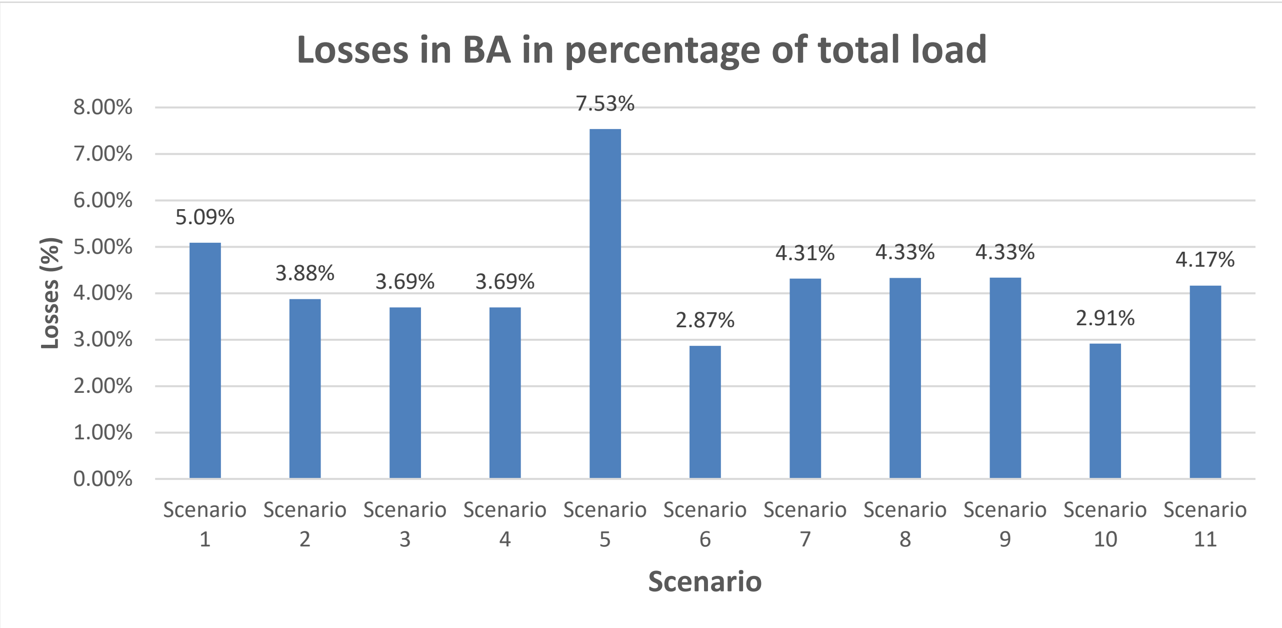


Figure 216: Transmission network losses in the BiH area relative to system load in all analyzed scenarios

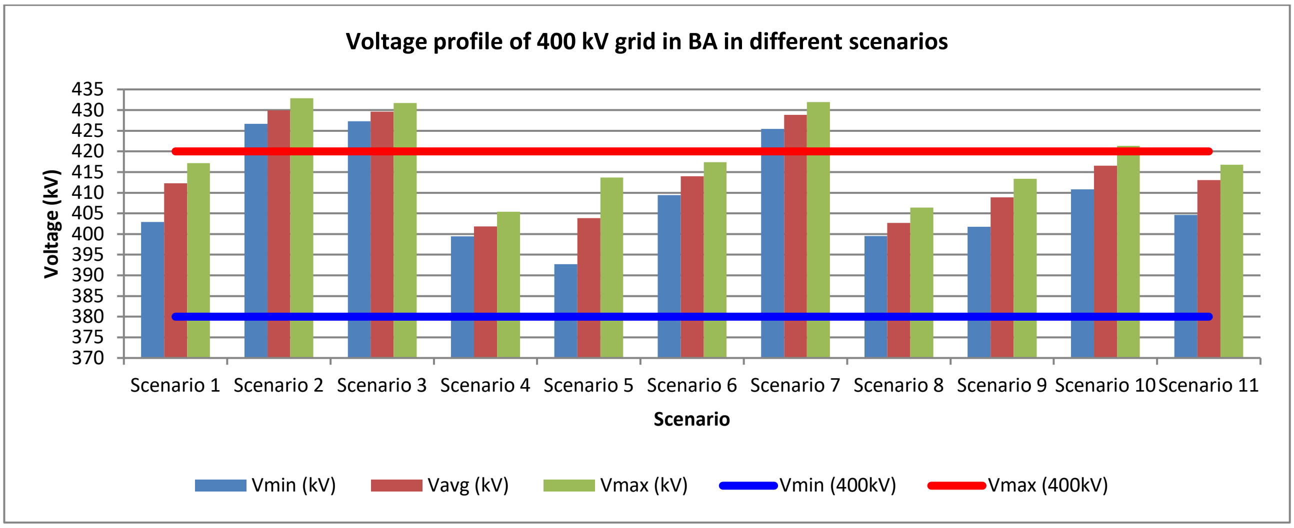


Figure 217: 400 kV voltage profiles (minimum, maximum and average) in the BiH area in all analyzed scenarios

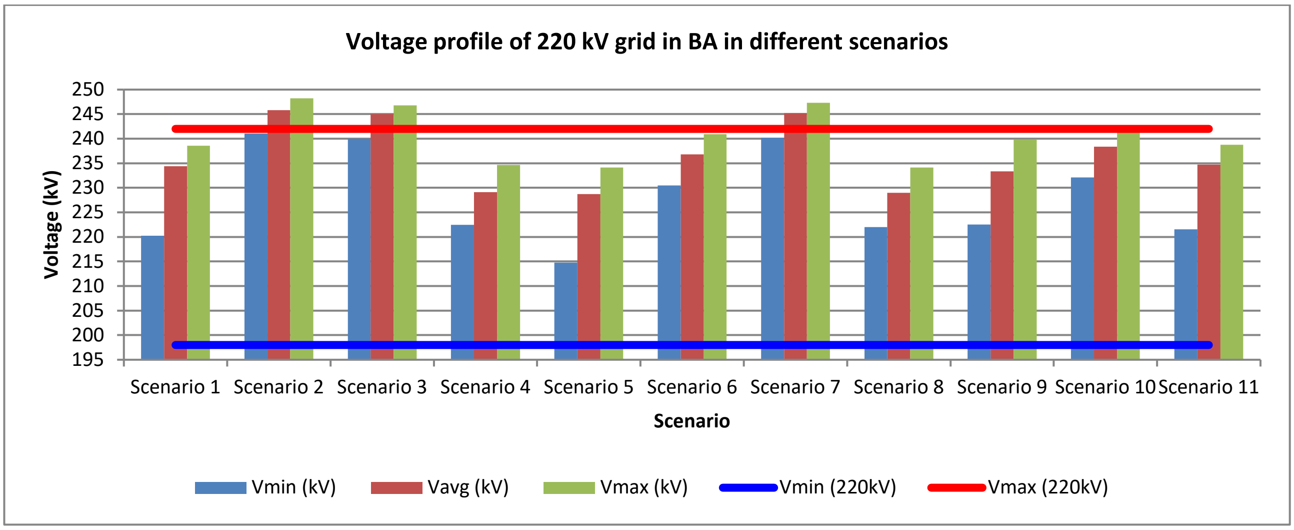


Figure 218: 220 kV voltage profiles (minimum, maximum and average) in the BiH area in all analyzed scenarios

6.12.3. ESO (BG) network area

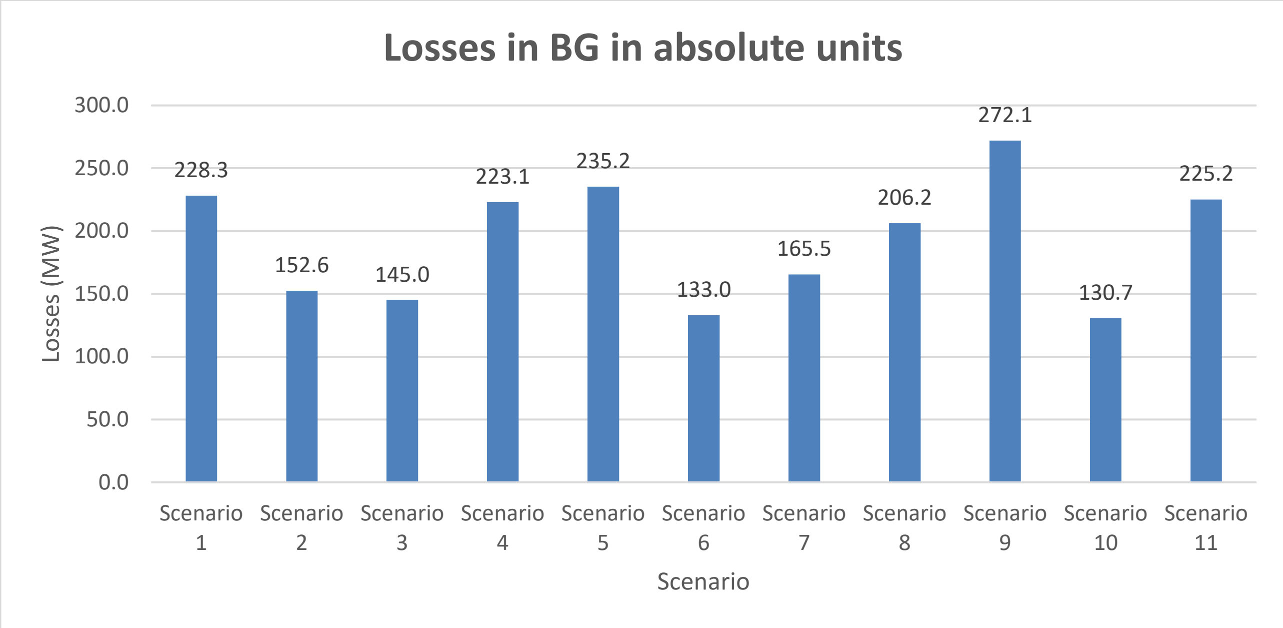


Figure 219: Transmission network losses in absolute value in the BG area in all analyzed scenarios

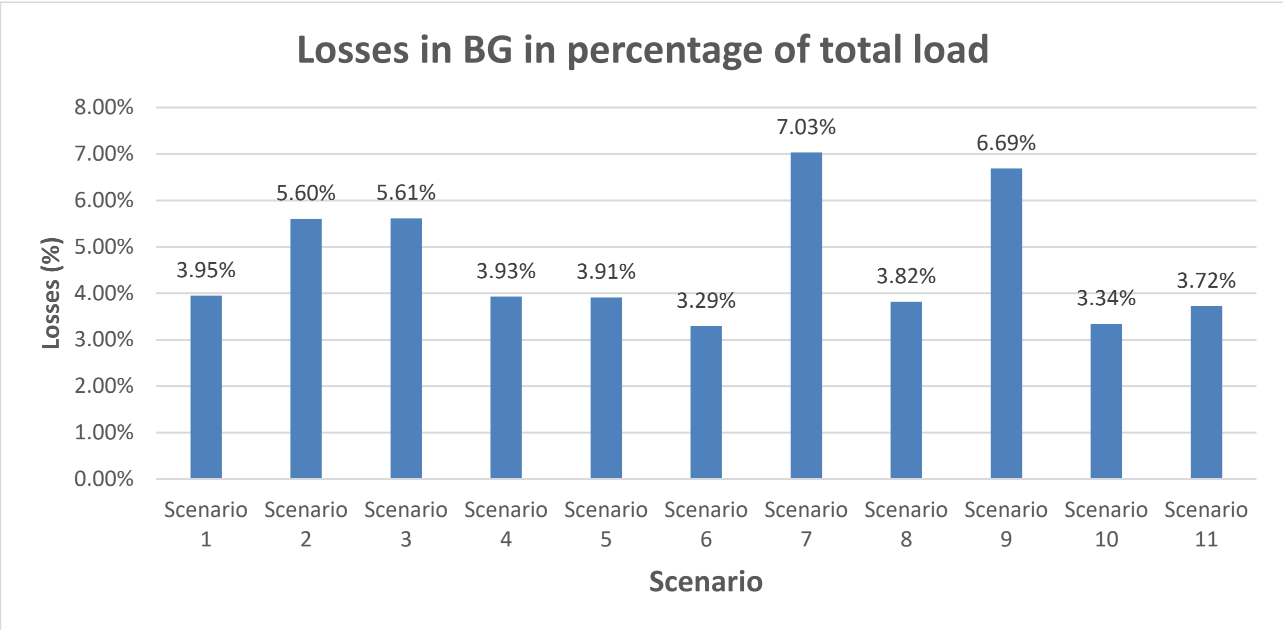


Figure 220: Transmission network losses in the BG area relative to system load in all analyzed scenarios

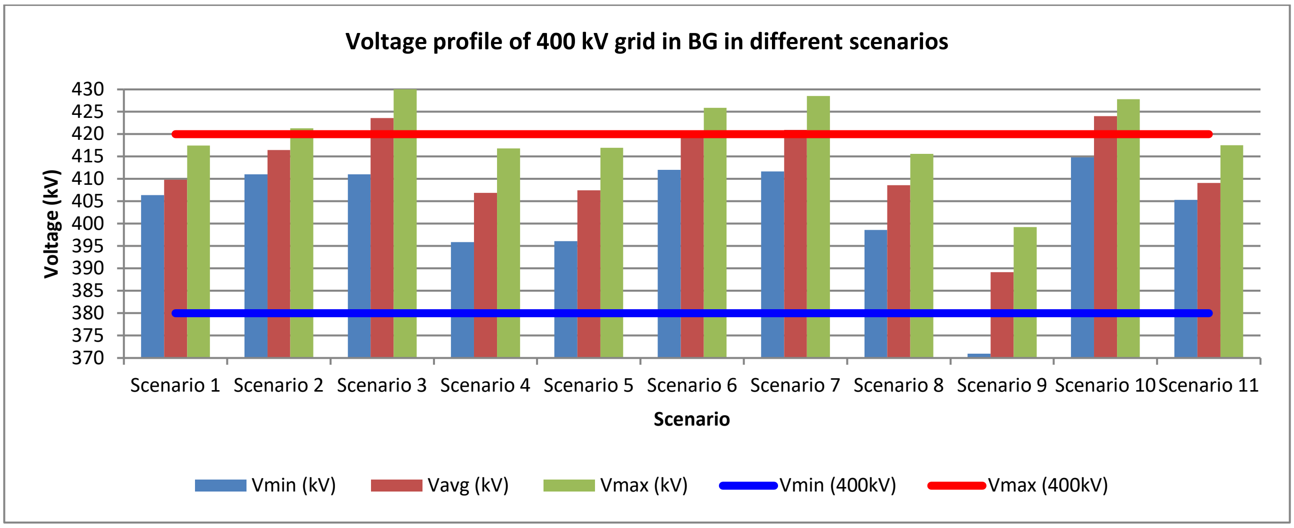


Figure 221: 400 kV voltage profiles (minimum, maximum and average) in the BG area in all analyzed scenarios

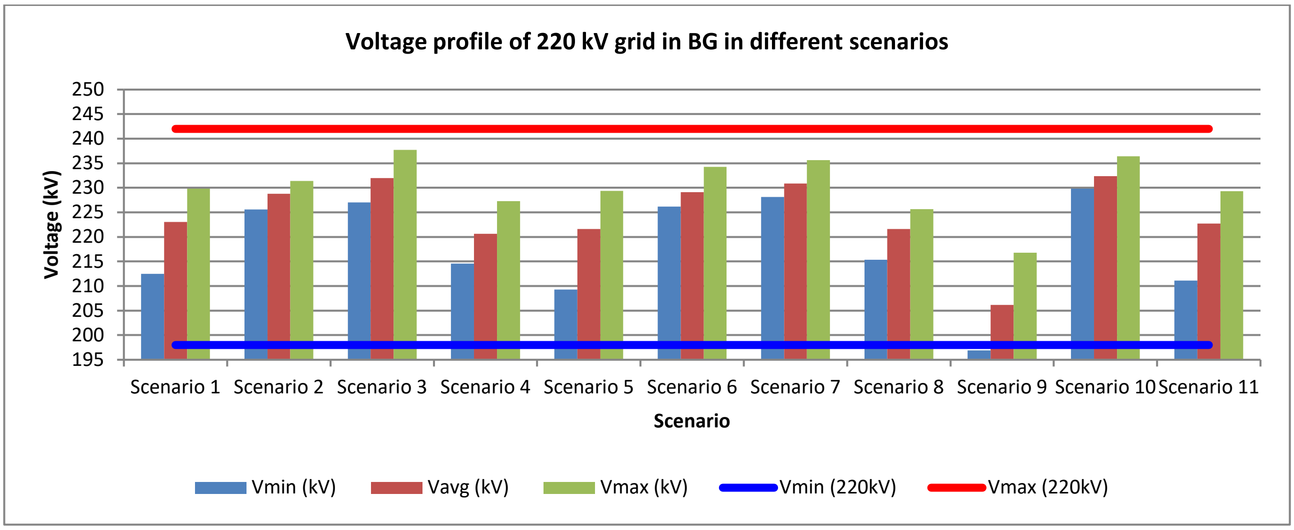


Figure 222: 220 kV voltage profiles (minimum, maximum and average) in the BG area in all analyzed scenarios

6.12.4. IPTO (GR) network area

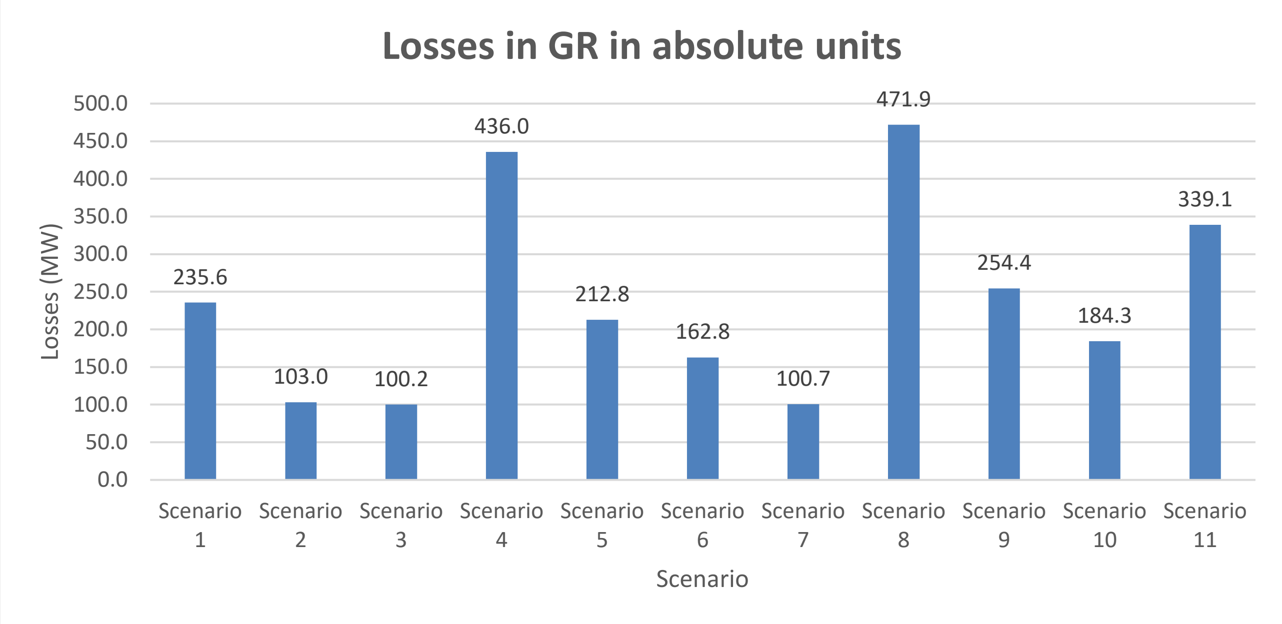


Figure 223: Transmission network losses in absolute value in the GR area in all analyzed scenarios

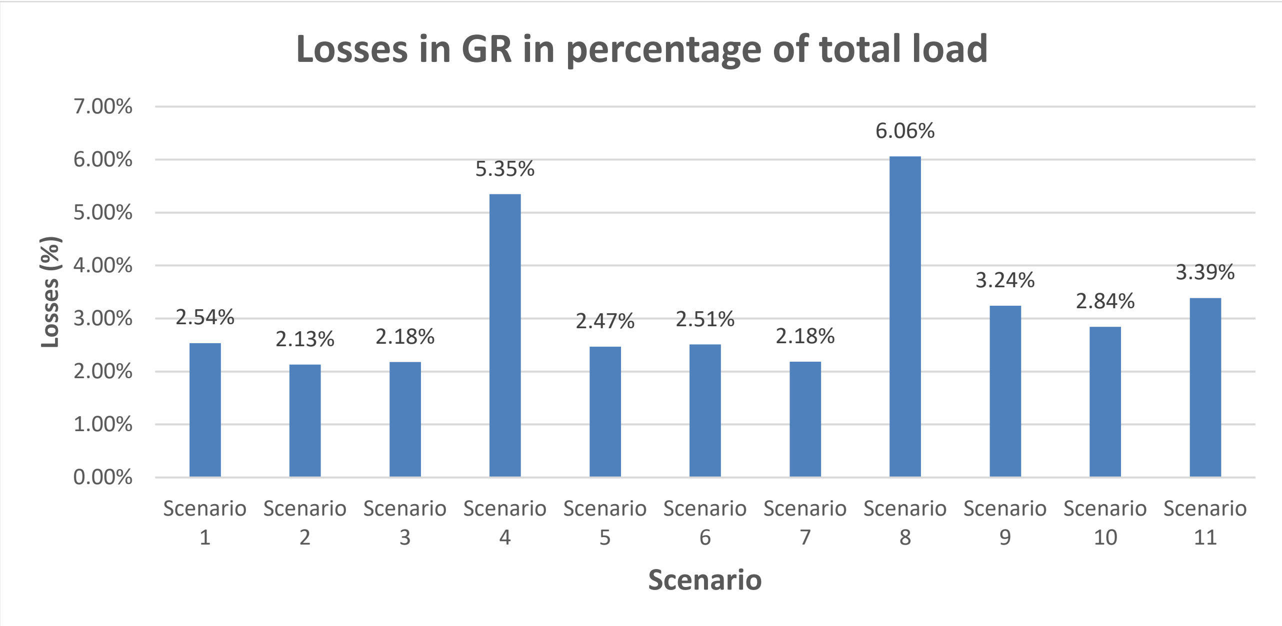


Figure 224: Transmission network losses in the GR area relative to system load in all analyzed scenarios

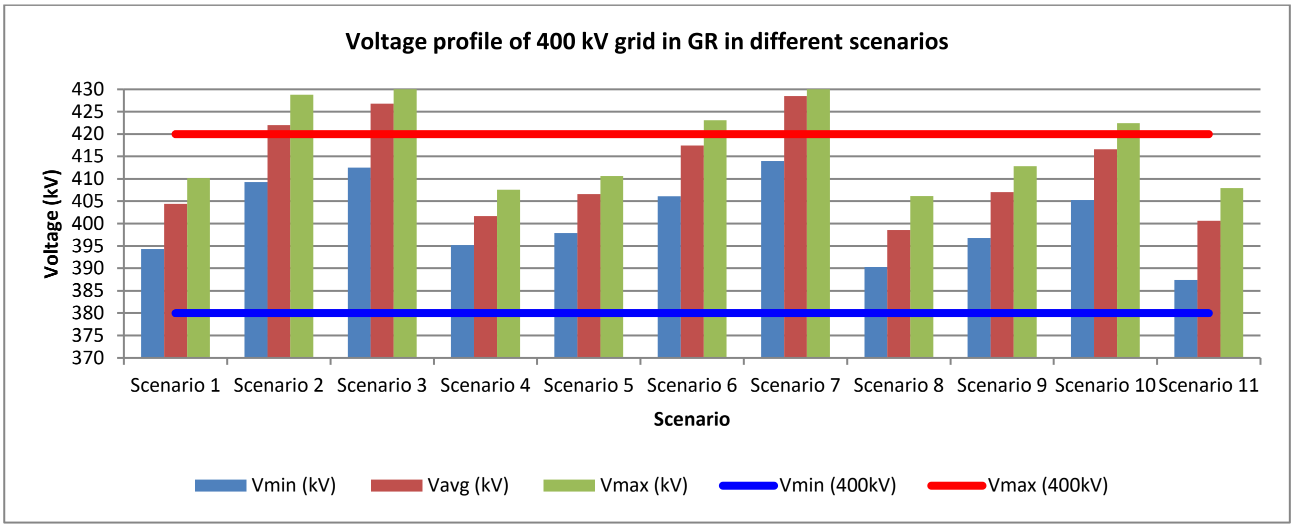


Figure 225: 400 kV voltage profiles (minimum, maximum and average) in the GR area in all analyzed scenarios

6.12.5. HOPS (HR) network area

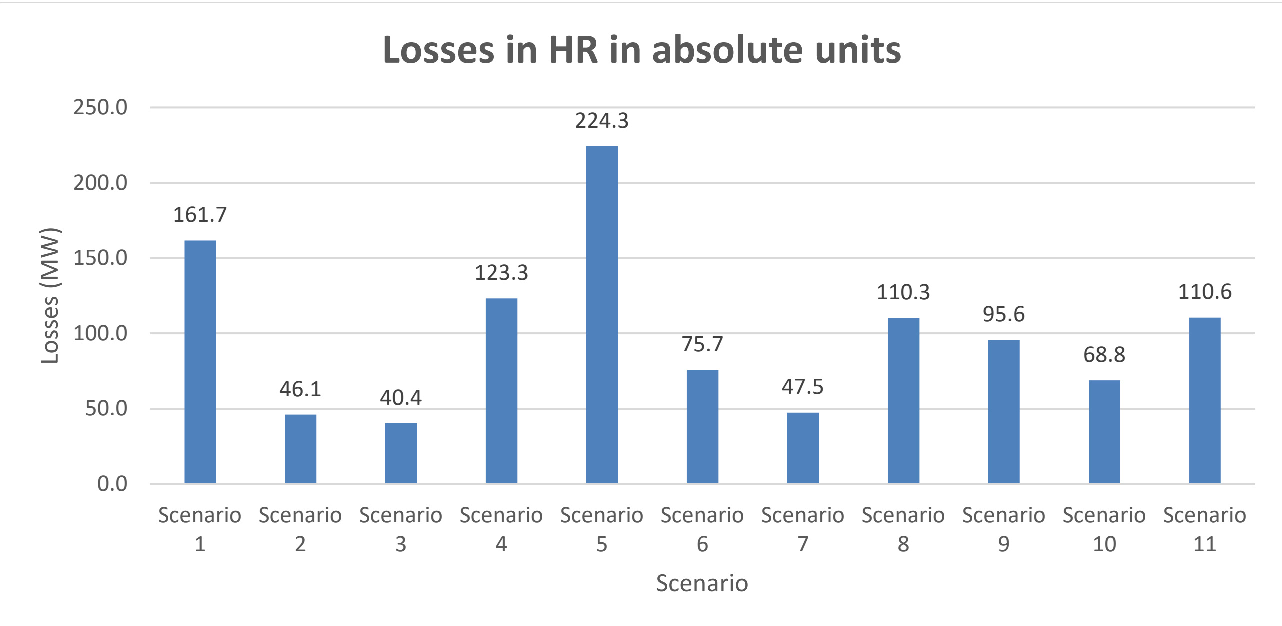


Figure 226: Transmission network losses in absolute value in the HR area in all analyzed scenarios

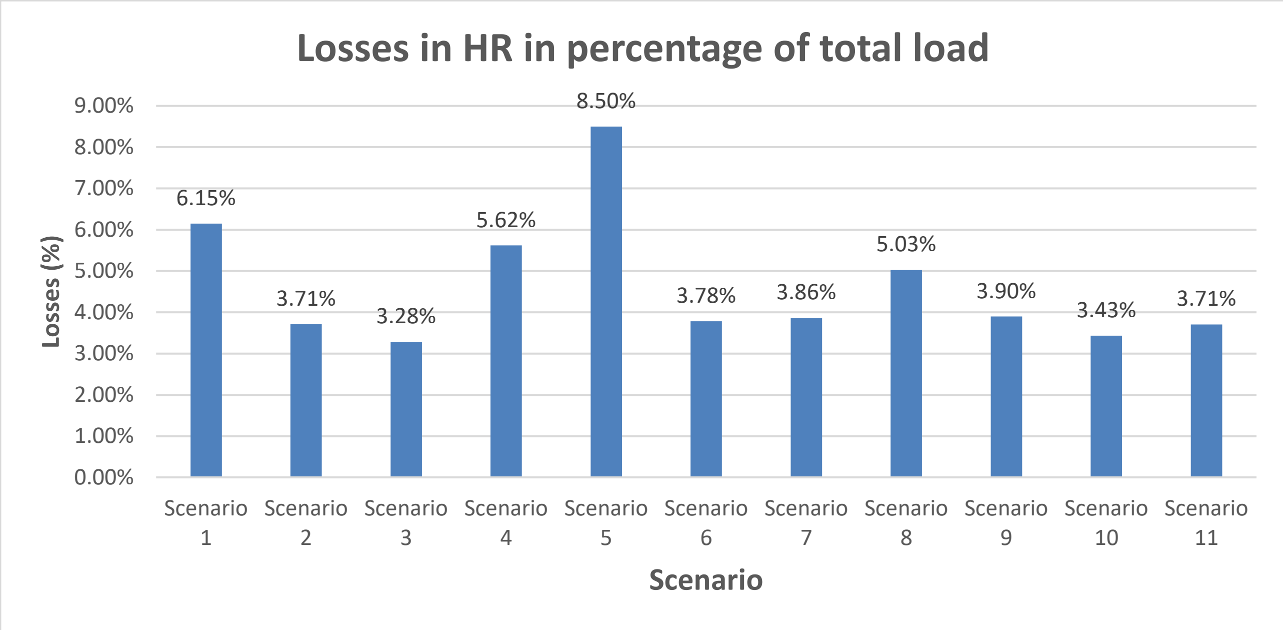


Figure 227: Transmission network losses in the HR area relative to system load in all analyzed scenarios

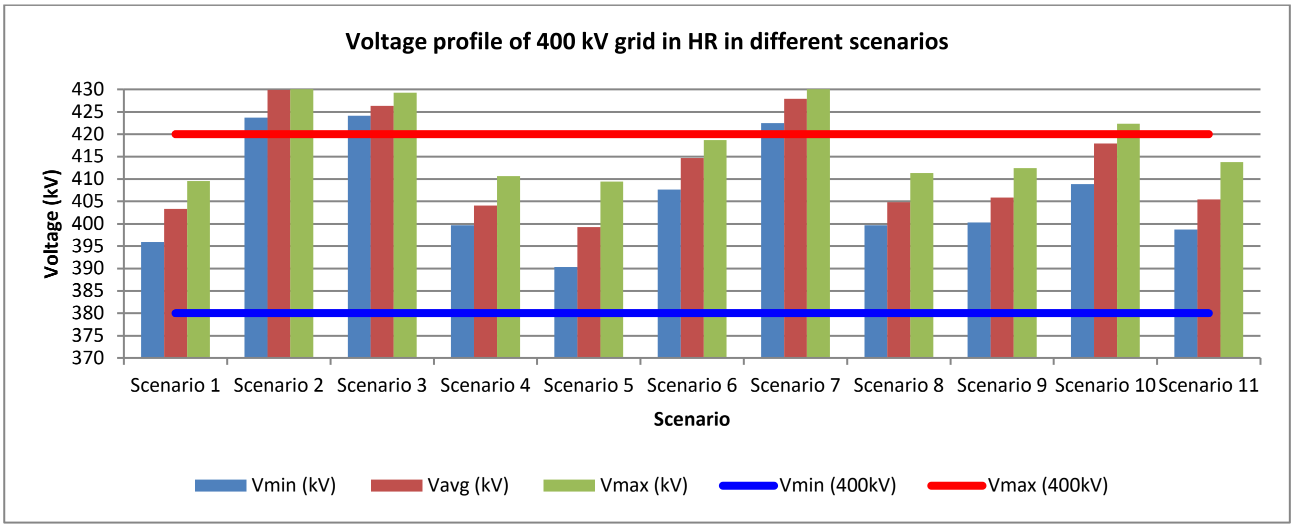


Figure 228: 400 kV voltage profiles (minimum, maximum and average) in the HR area in all analyzed scenarios

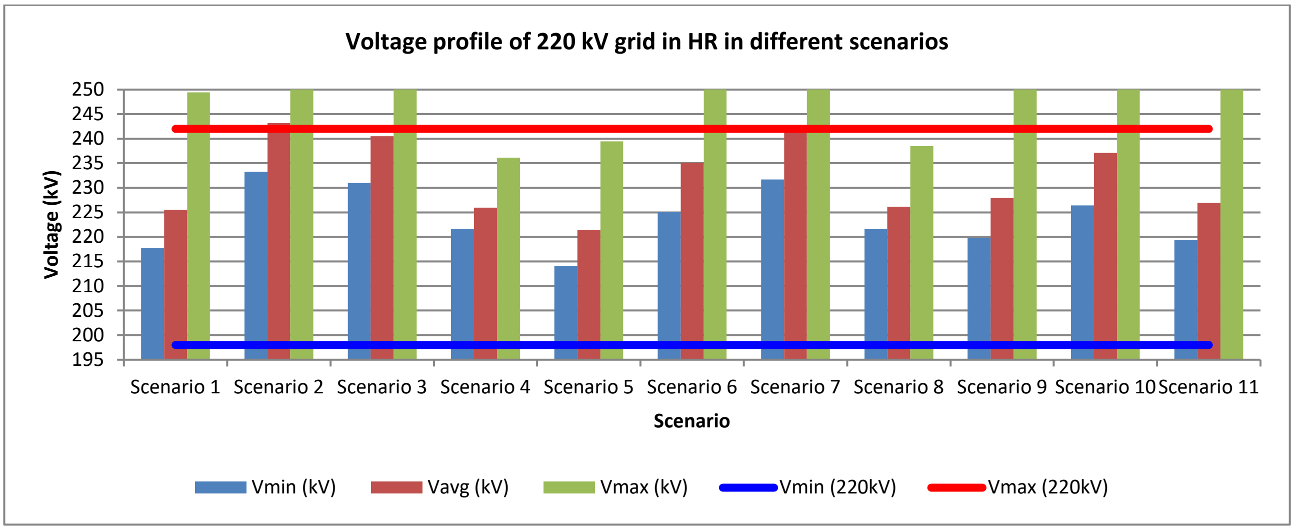


Figure 229: 220 kV voltage profiles (minimum, maximum and average) in the HR area in all analyzed scenarios

6.12.6. CGES (ME) network area

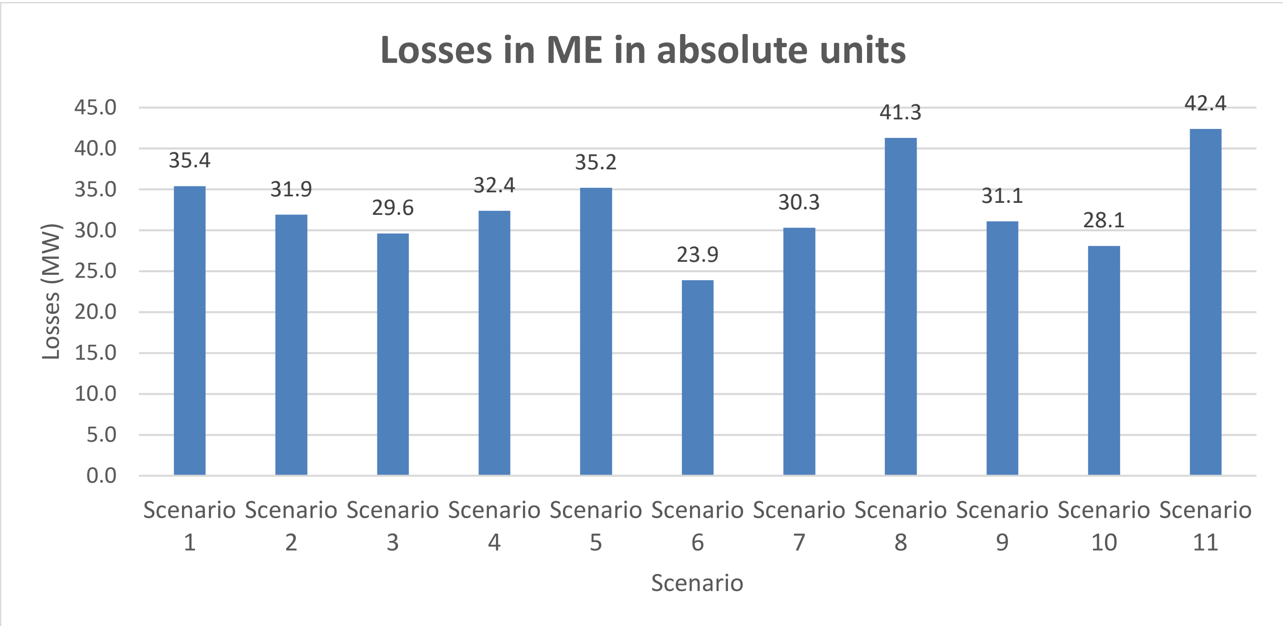


Figure 230: Transmission network losses in absolute value in the ME area in all analyzed scenarios

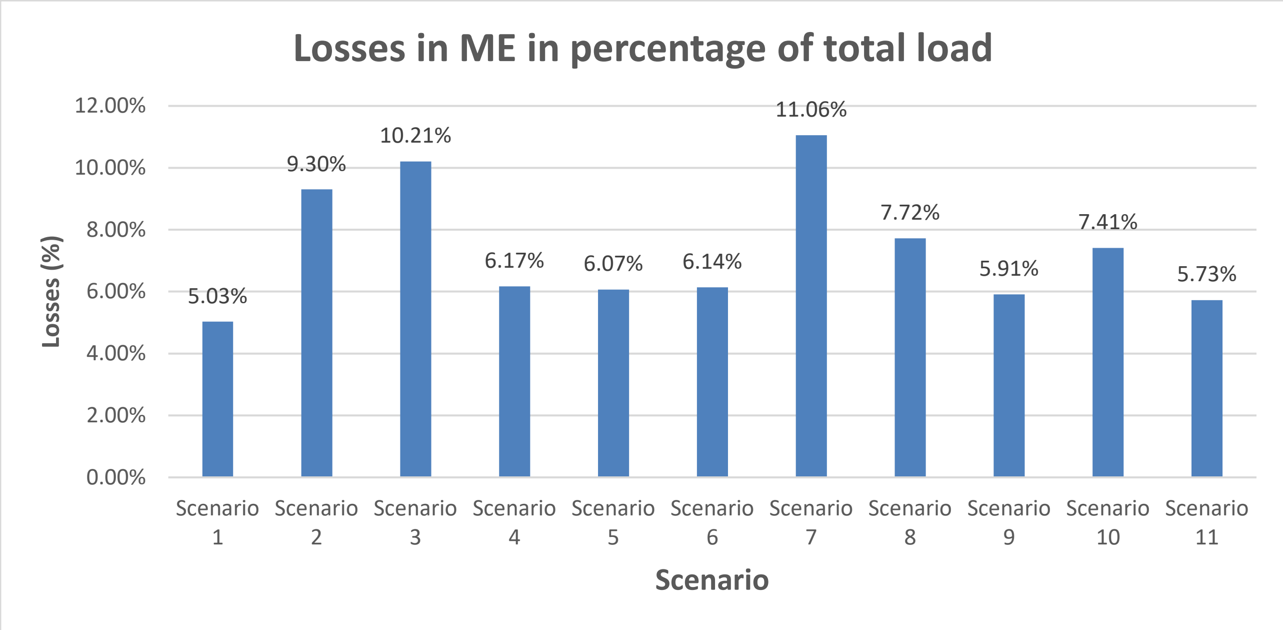


Figure 231: Transmission network losses in the ME area relative to system load in all analyzed scenarios

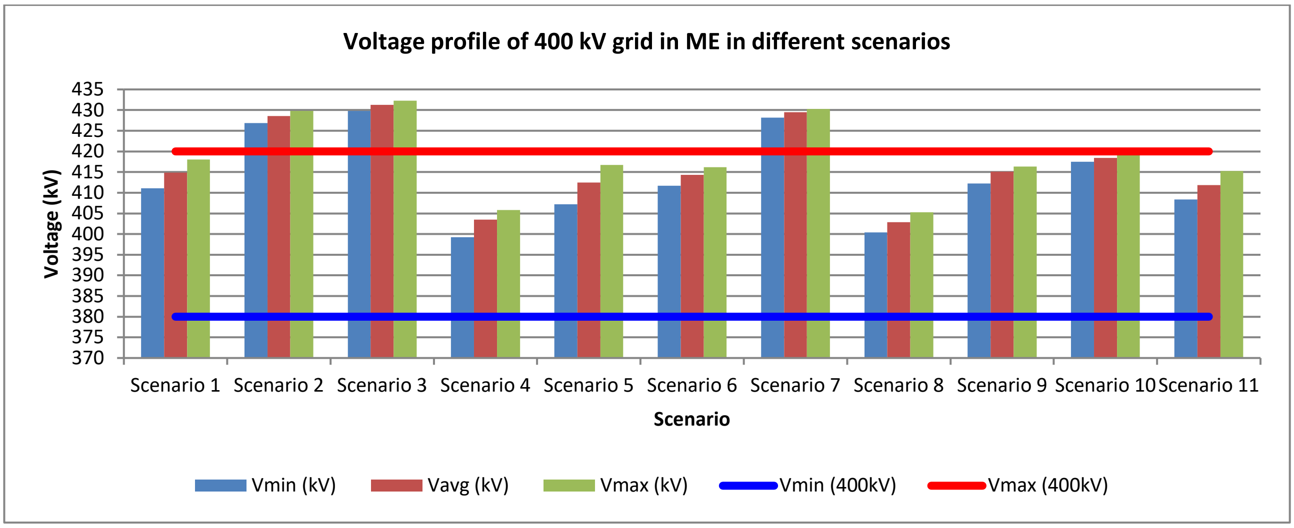


Figure 232: 400 kV voltage profiles (minimum, maximum and average) in the ME area in all analyzed scenarios

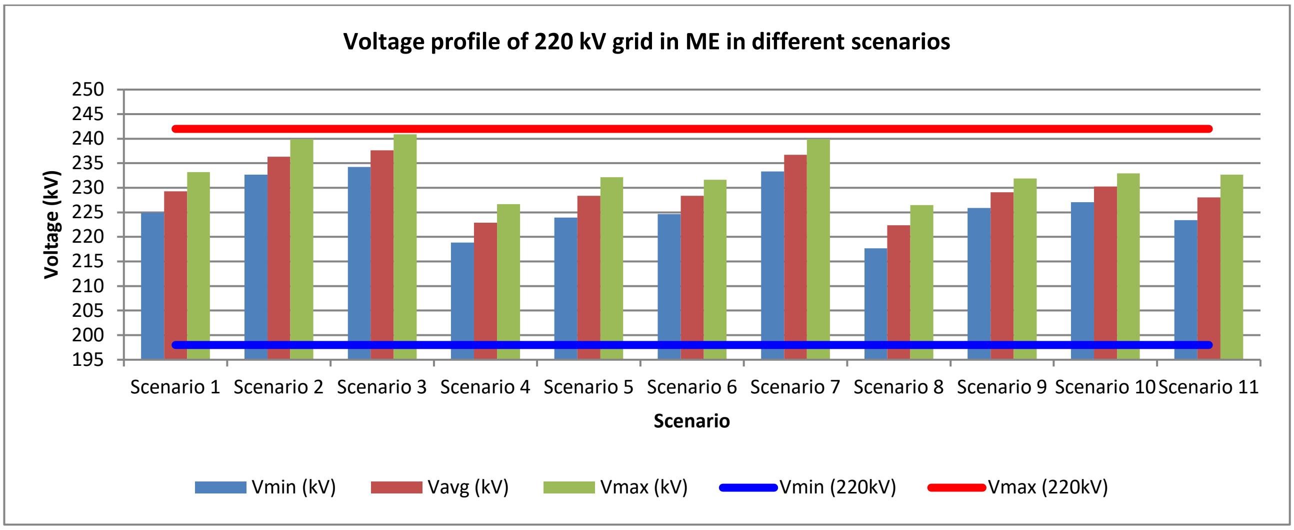


Figure 233: 220 kV voltage profiles (minimum, maximum and average) in the ME area in all analyzed scenarios

6.12.7. MEPSO (MK) network area

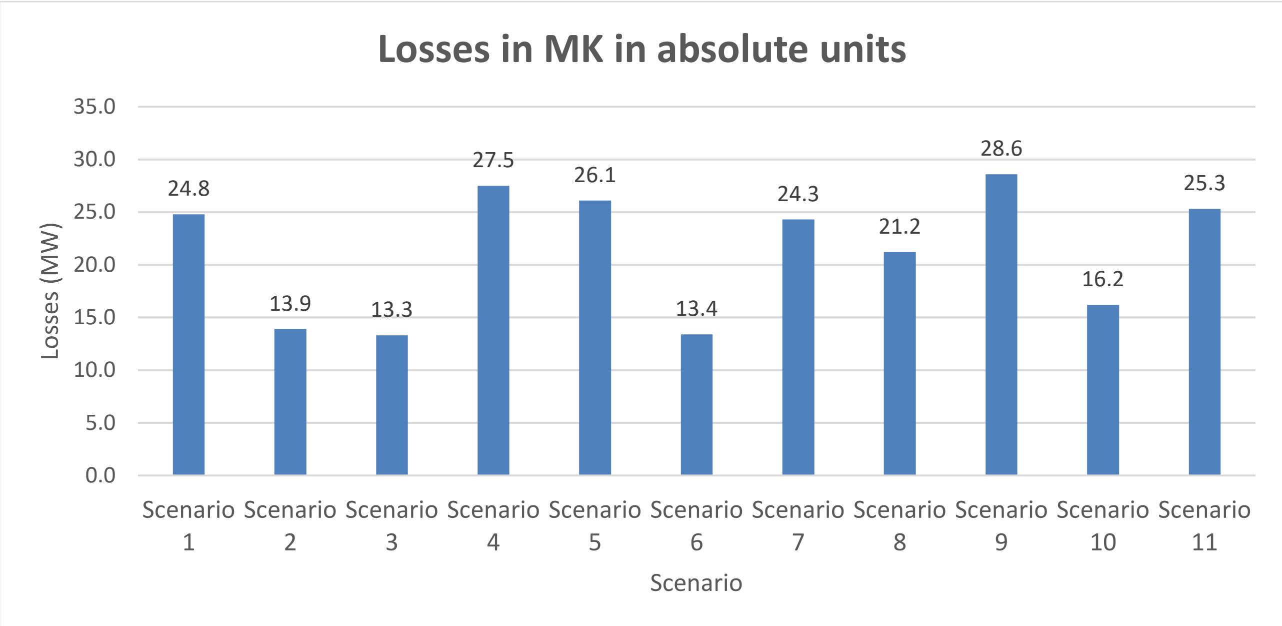


Figure 234: Transmission network losses in absolute value in the MK area in all analyzed scenarios

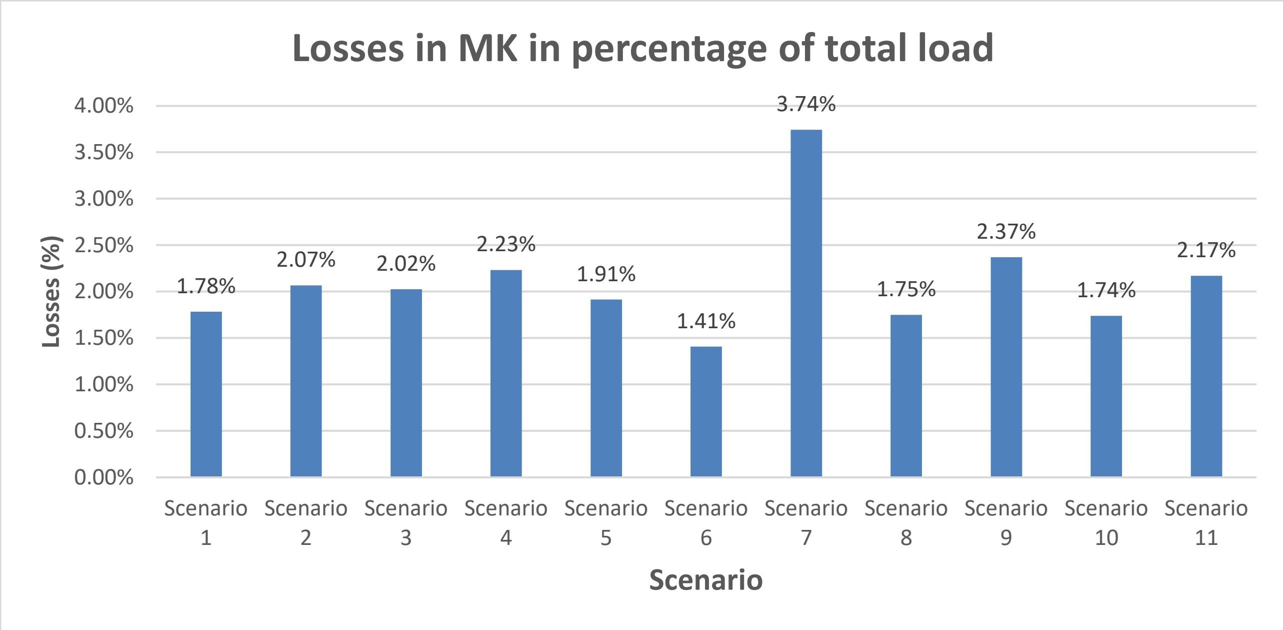


Figure 235: Transmission network losses in the MK area relative to system load in all analyzed scenarios

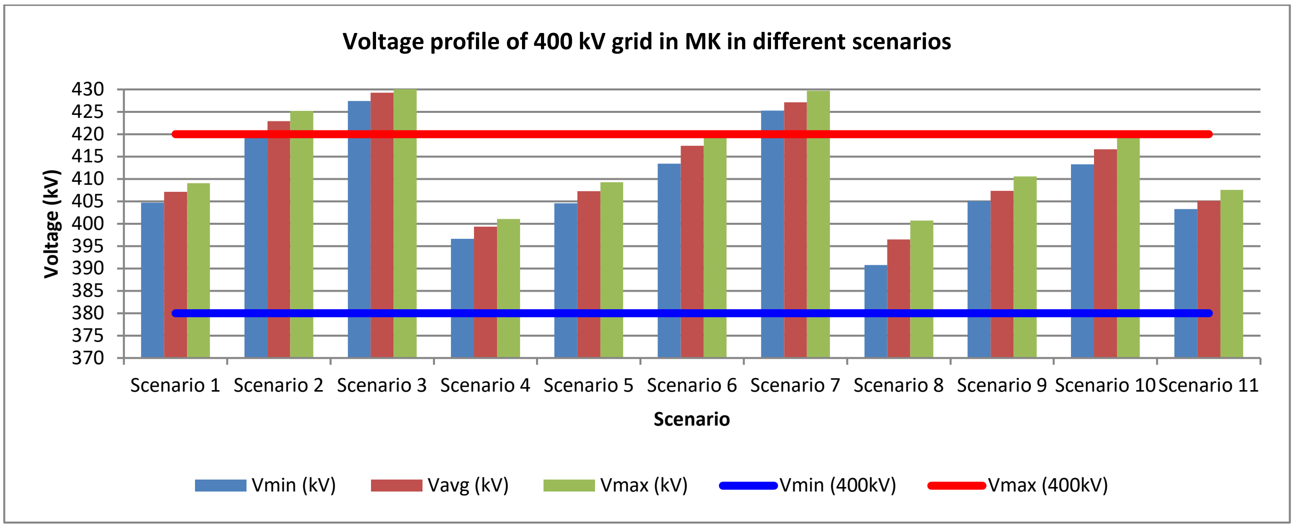


Figure 236: 400 kV voltage profiles (minimum, maximum and average) in the MK area in all analyzed scenarios

6.12.8. Transelectrica (RO) network area

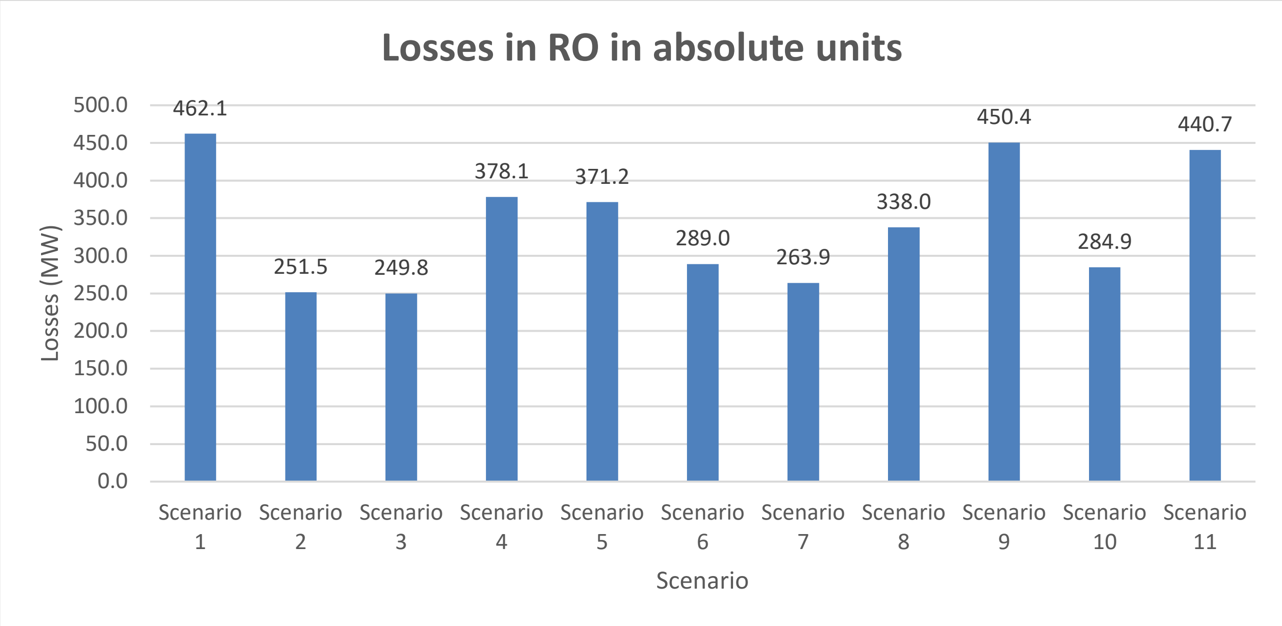


Figure 237: Transmission network losses in absolute value in the RO area in all analyzed scenarios

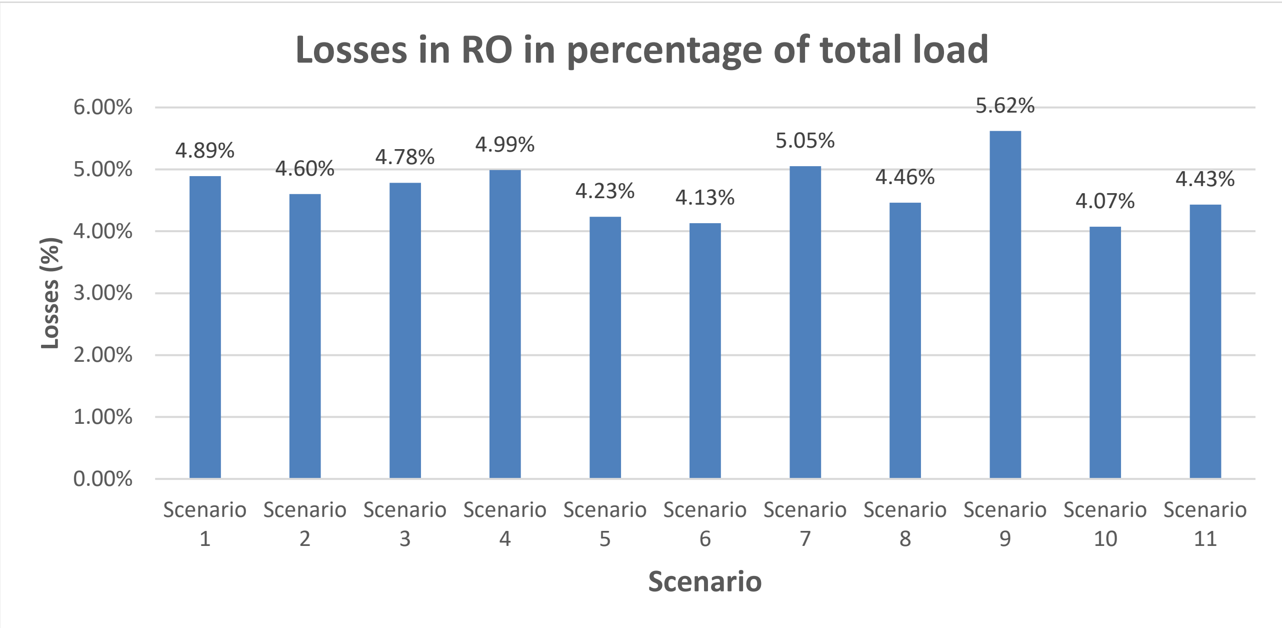


Figure 238: Transmission network losses in the RO area relative to system load in all analyzed scenarios

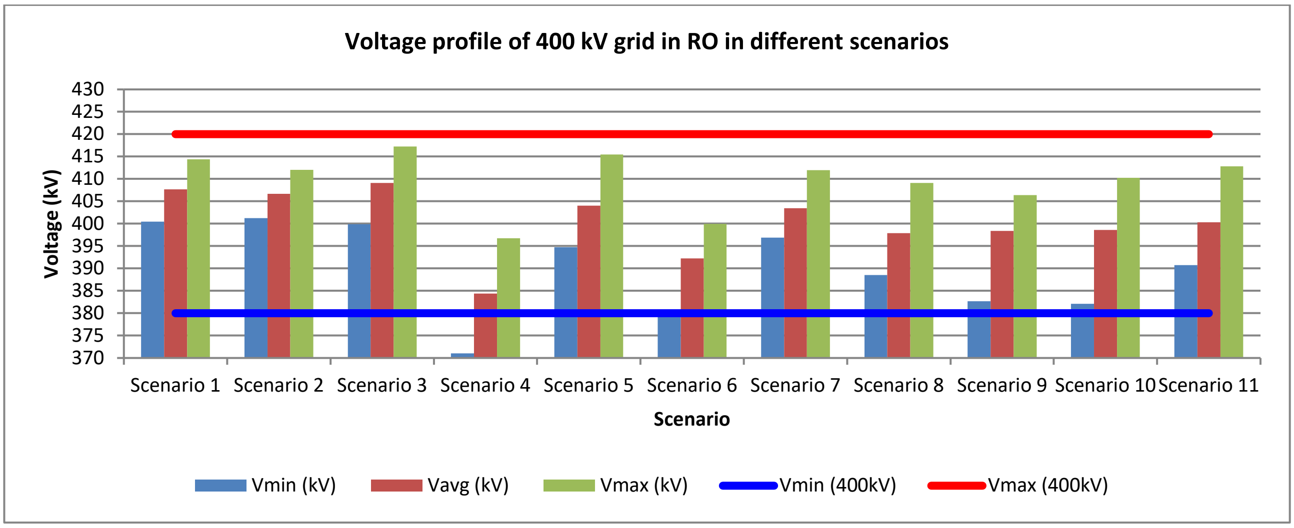


Figure 239: 400 kV voltage profiles (minimum, maximum and average) in the RO area in all analyzed scenarios

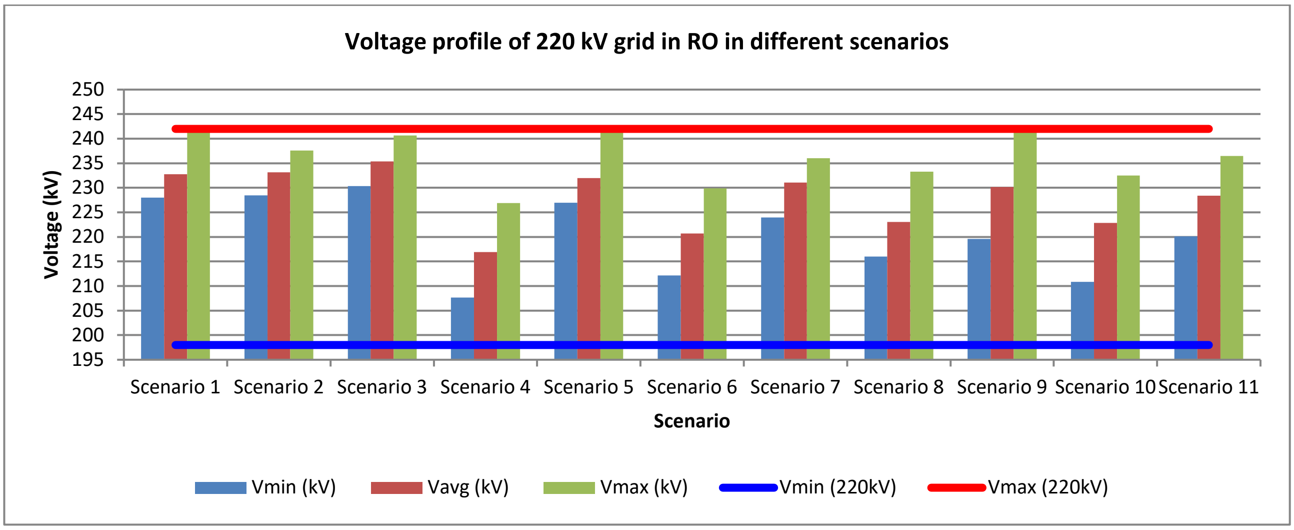


Figure 240: 220 kV voltage profiles (minimum, maximum and average) in the RO area in all analyzed scenarios

6.12.9. EMS (RS) network area

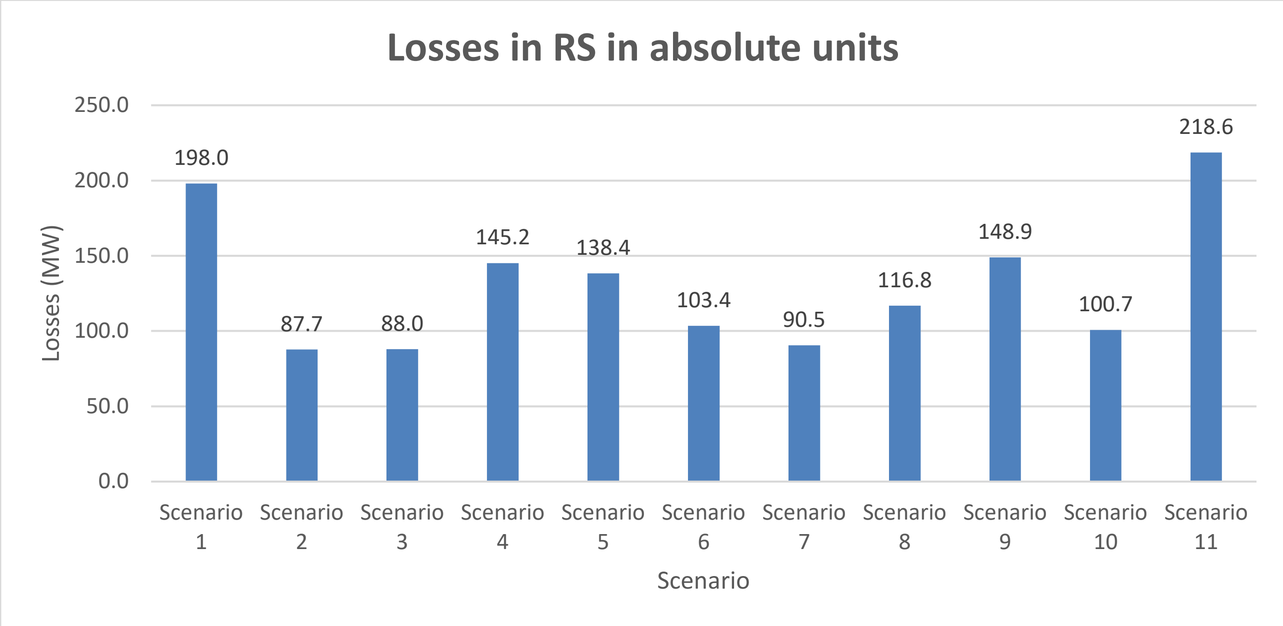


Figure 241: Transmission network losses in absolute value in the RS area in all analyzed scenarios

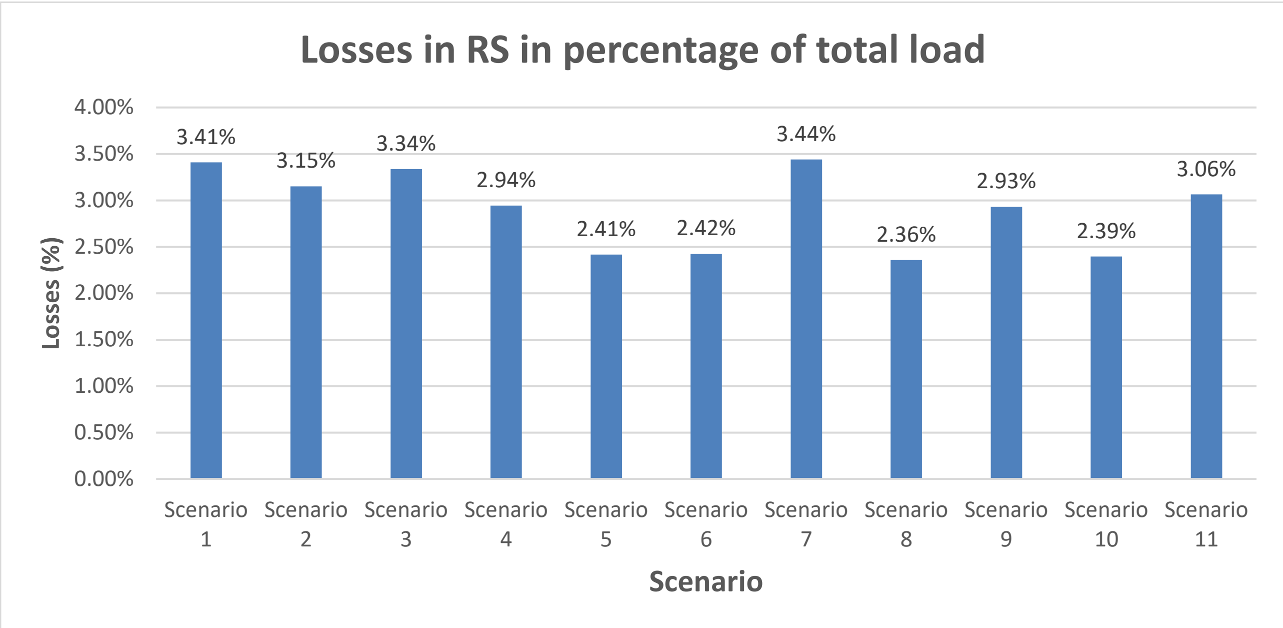


Figure 242: Transmission network losses in the RS area relative to system load in all analyzed scenarios

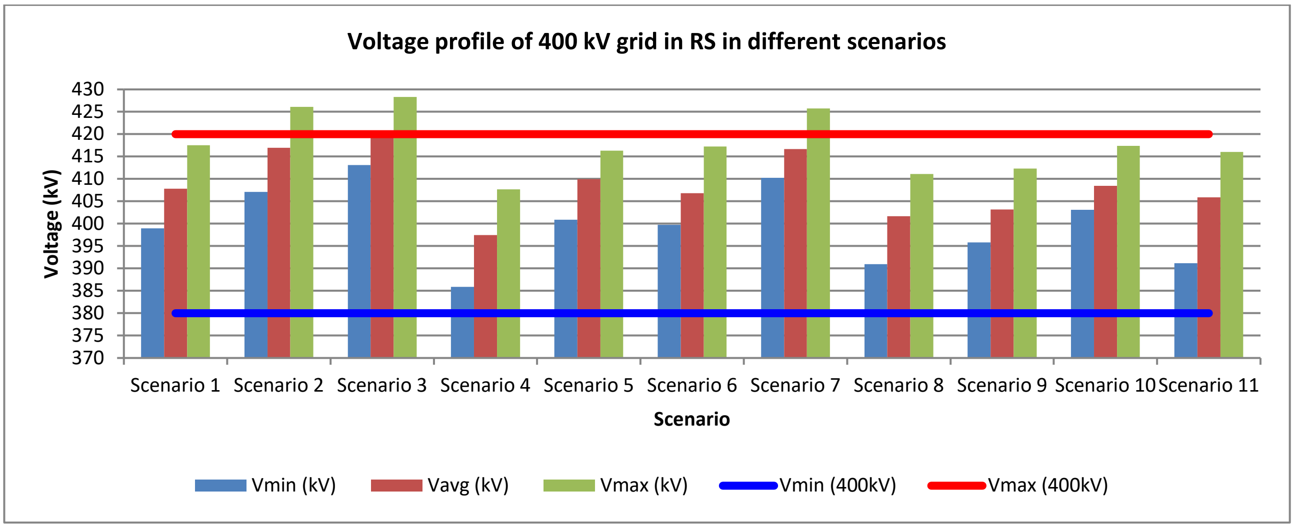


Figure 243: 400 kV voltage profiles (minimum, maximum and average) in the RS area in all analyzed scenarios

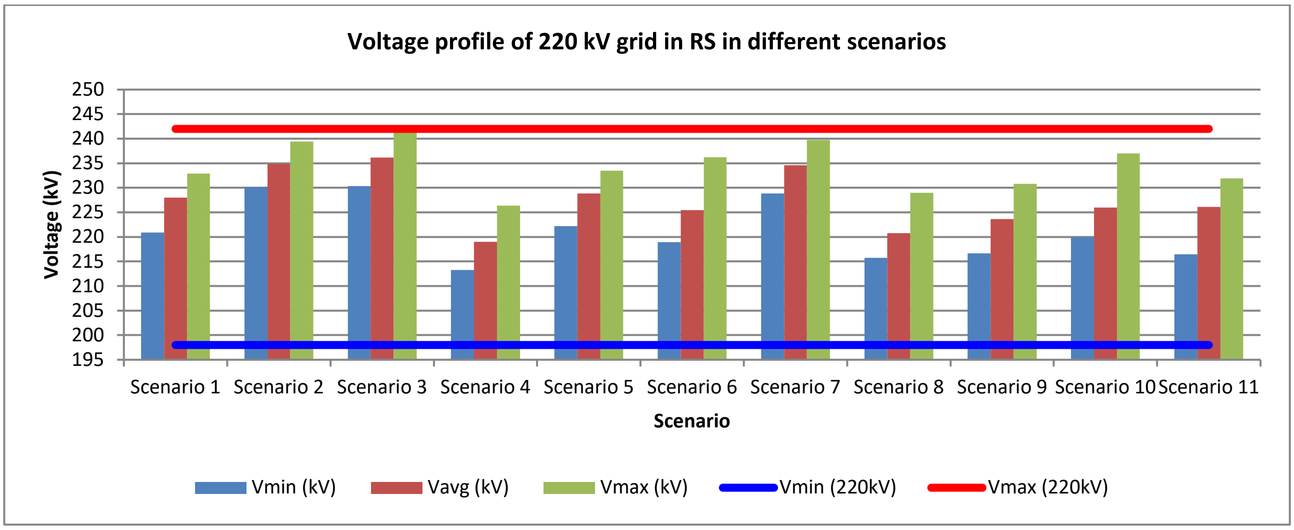


Figure 244: 220 kV voltage profiles (minimum, maximum and average) in the RS area in all analyzed scenarios

6.12.10. ELES (SI) network area

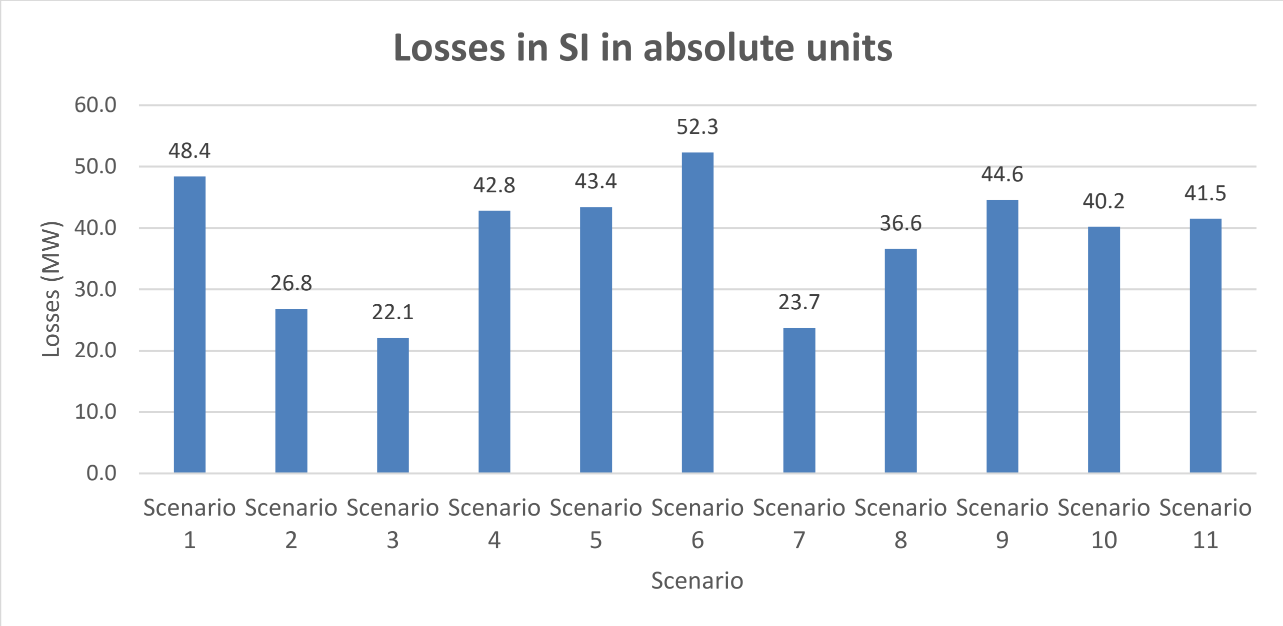


Figure 245: Transmission network losses in absolute value in the SI area in all analyzed scenarios

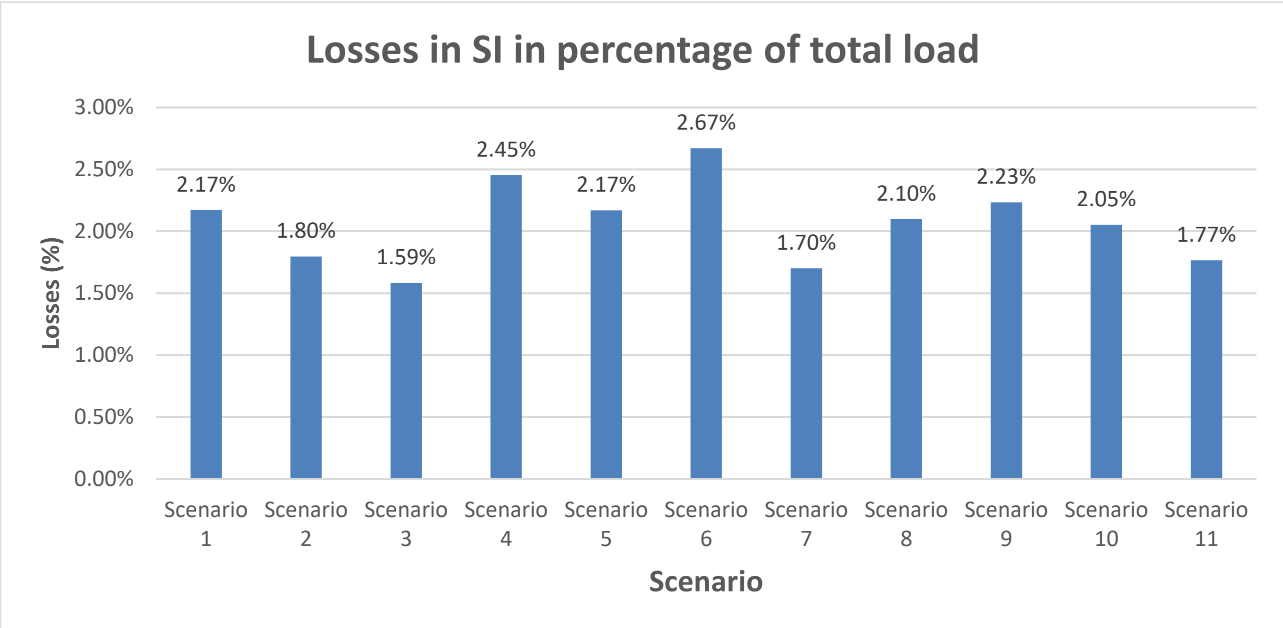


Figure 246: Transmission network losses in the SI area relative to system load in all analyzed scenarios

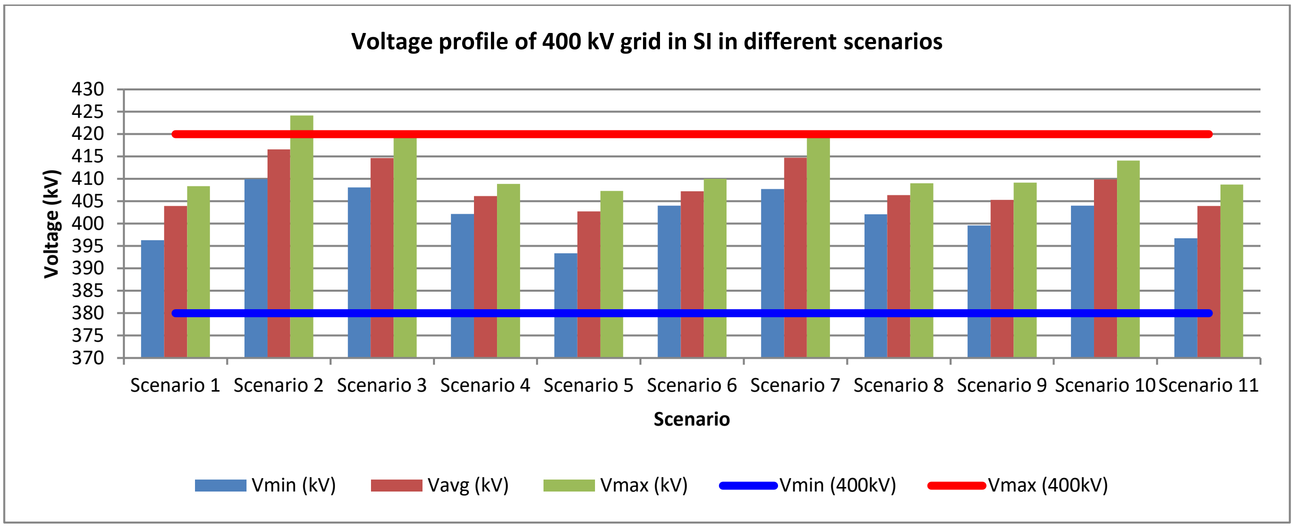


Figure 247: 400 kV voltage profiles (minimum, maximum and average) in the SI area in all analyzed scenarios

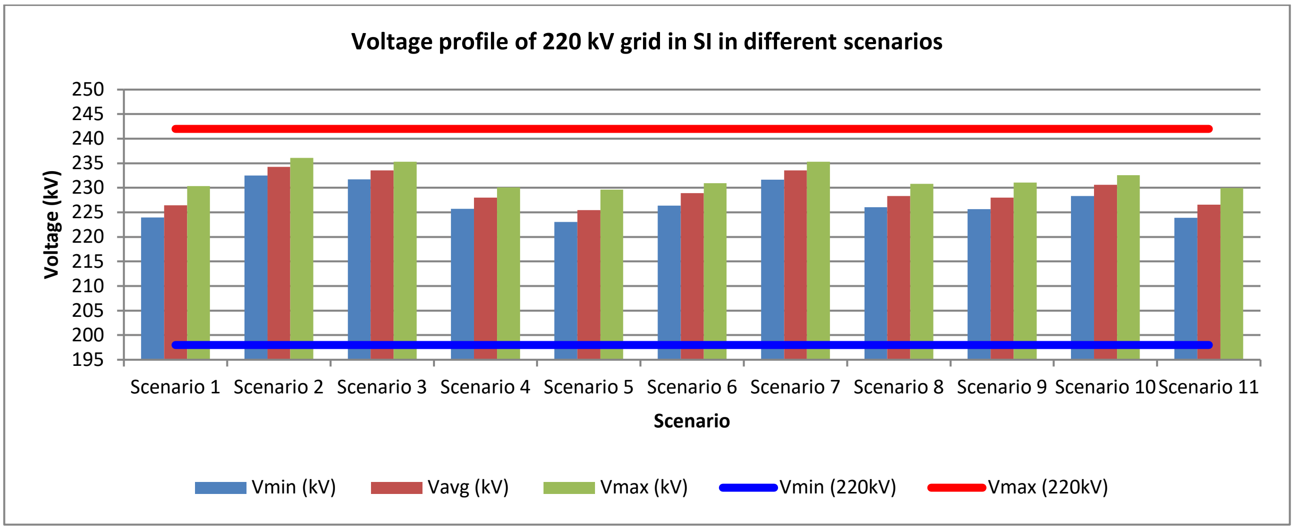


Figure 248: 220 kV voltage profiles (minimum, maximum and average) in the SI area in all analyzed scenarios

6.12.11. KOSTT (XK) network area

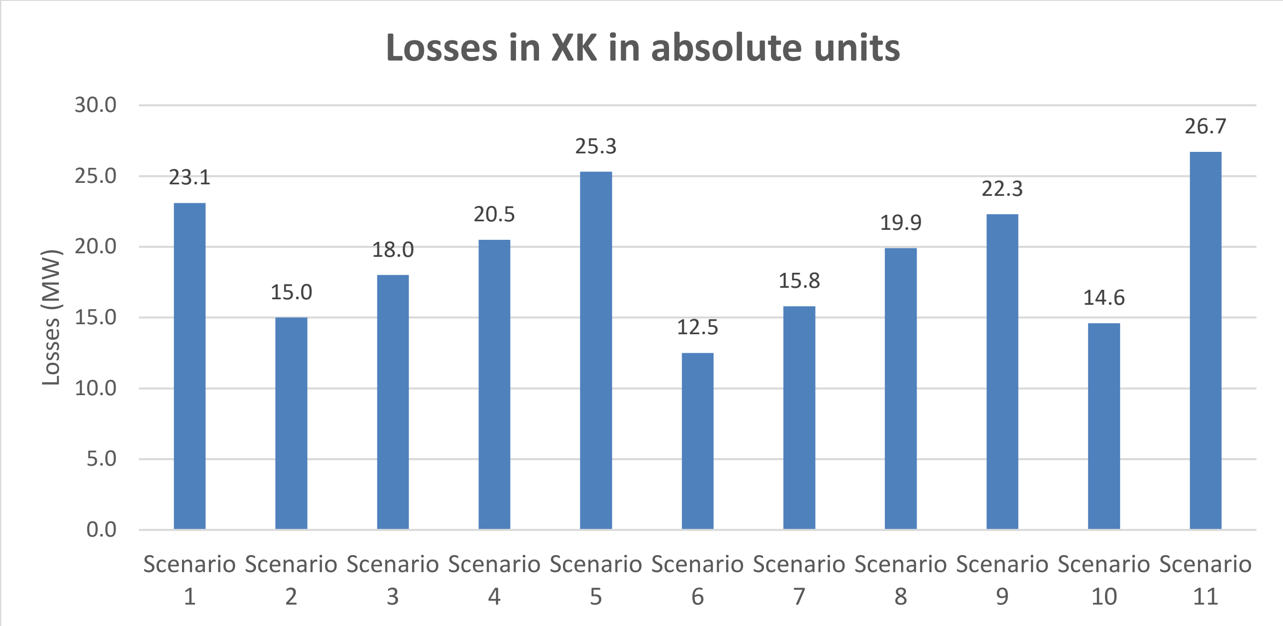


Figure 249: Transmission network losses in absolute value in the XK area in all analyzed scenarios

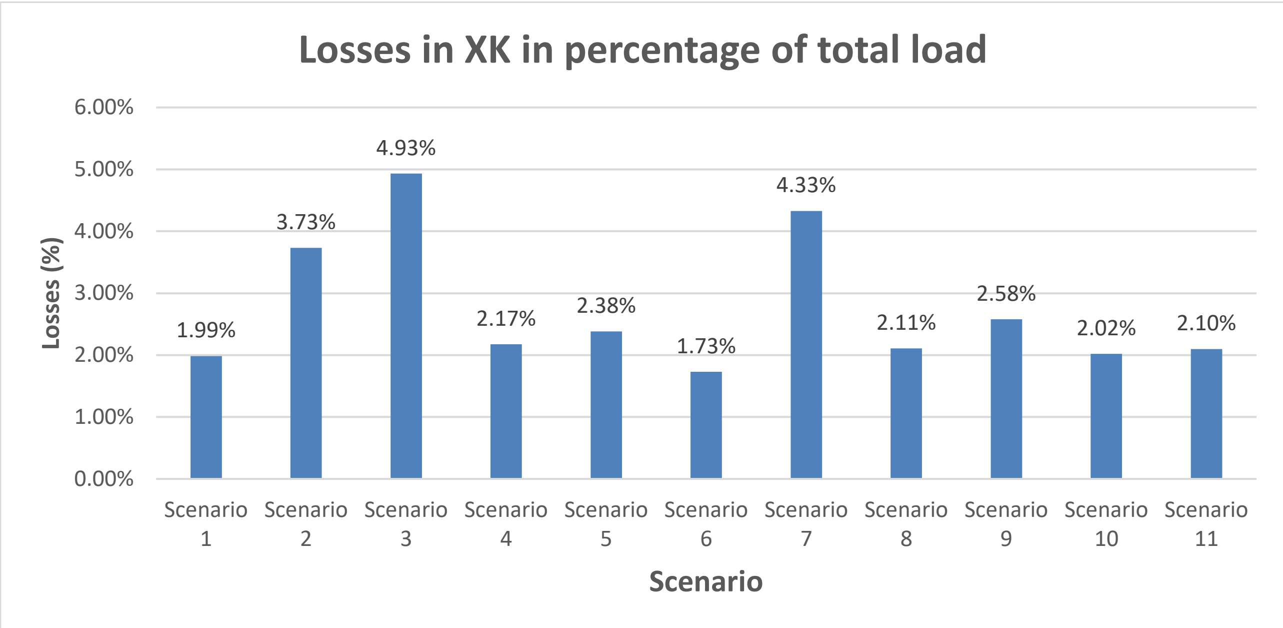


Figure 250: Transmission network losses in the XK area relative to system load in all analyzed scenarios

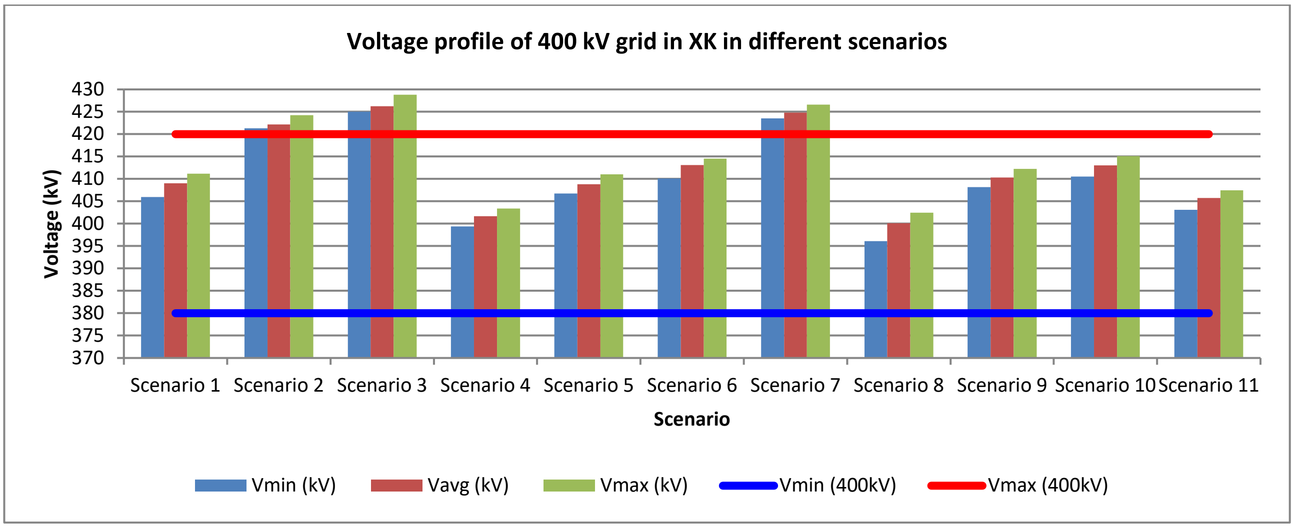


Figure 251: 400 kV voltage profiles (minimum, maximum and average) in the XK area in all analyzed scenarios

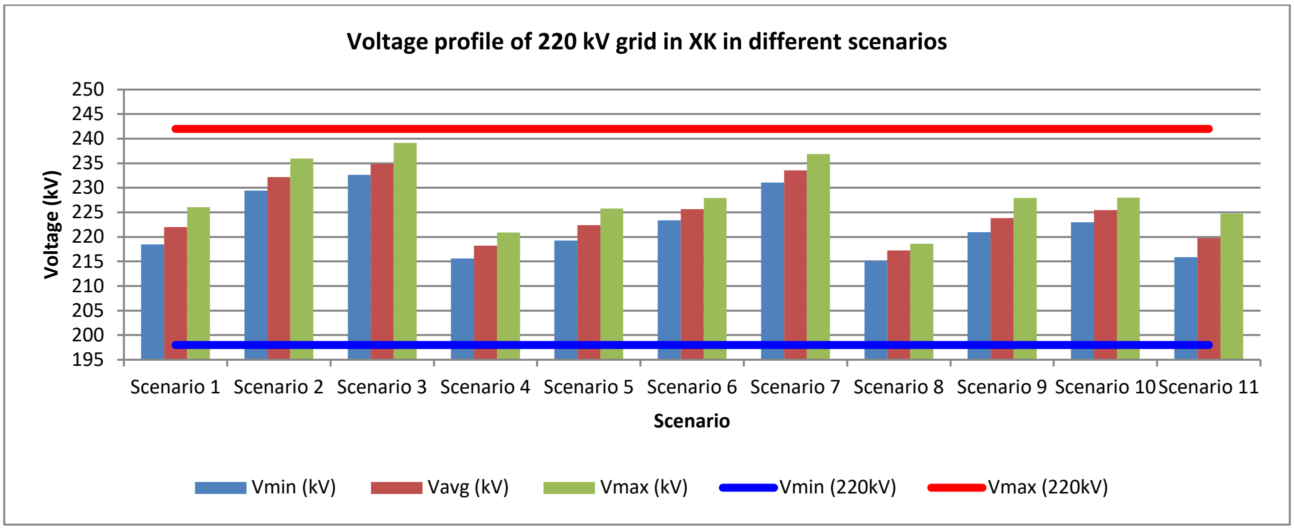


Figure 252: 220 kV voltage profiles (minimum, maximum and average) in the XK area in all analyzed scenarios

7. CONCLUSIONS

The newly adopted EU Energy Law (the "Clean Energy for all Europeans") package has set a medium-term target of 32% for the share of energy from renewable energy systems (RES) in the EU's gross final consumption of energy by 2030. The EMI members are mostly below this target for electricity, especially those in the Western Balkans (WB6). Some of them are from EU member states, while others are aspiring to join the EU, being contracting parties of the Energy Community. The Energy Community Treaty is a binding international agreement that obliges all parties to fully transpose and implement the EU legal framework with regard to electricity markets, RES integration, environmental protection and competition. Therefore, the WB6 members have essentially the same targets as EU members, but with some time delay for its implementation. This means that the EMI working group must be harmonized in its future energy sector targets, using this period as an opportunity to learn from the best practices of those who implement the Energy Law earlier.

In our 2019 regional survey, the EMI members identified RES integration as their highest priority and long-term concern. Other regions of Europe and the world have shown that the integration of large-scale RES in SEE is a significant market and network challenge. So, we launched this study in March 2020 and drafted it in October 2020 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. **It is also important to note that in this Study, we considered only variable wind and solar capacities (and not hydro) as RES capacities.**

This study addresses the impacts on electricity markets and prices in 2030 due to substantial RES and gas development, and how the transmission grid will need to adapt – both internally within the EMI members and between them - to successfully integrate these resources. To do so, this project conducted two interconnected analyses:

1) A study of the changes in the regional electricity market, as they add a rapidly growing share of RES and some gas generation; and

2) An assessment of the network impacts of such development, including where congestion may arise and new transmission network elements may be required.

The market analysis carried out hourly simulations of the power system and provided results for each hour of the year, while the network analyses was focused on snapshots of the grid's operation at moments when the network could be under stress, both for the year 2030.

The market analysis enables EMI members to assess the impacts of RES and gas integration on wholesale prices, energy mix, area balances, cross-border exchanges, CO_2 emissions and congestion costs.

The network analysis enables EMI members to better understand the effects of large-scale RES and gas integration impact (higher than foreseen in their development plans) on network operaton.

This Report consists of 8 chapters on 344 pages, including 297 figures and 197 tables. It provides a detailed overview of the collected input data, electricity market and

network models, methodology and software solutions applied, and market and network analyses results for selected operational regimes (scenarios) in the power systems in Southeast Europe (SEE) in 2030, with different levels of RES integration.

Based on input data from the TSOs, we expect **total regional demand growth from 2018 – 2030 in the range of 20 – 34 TWh (referent vs low demand growth scenarios), or a growth of 8.0 - 13.7%** of electricity demand in 2018. The annual growth rates per market area in the referent scenario ranges from 0.18% (HR) to 2.79% (ME). In the low demand growth scenario, annual growth rates per market area range from 0.09% (HR) to 1.96% (MK).

At the same time, with quite limited demand growth, the markets **in SEE expect a significant increase in wind power capacity in this decade, from 11,833 to 16,269 MW (referent vs high RES scenario), which is 2.68 – 3.15 times more WPP than in 2018**. In a number of cases in SEE, 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 (referent scenarios) to 6,498 MW (high RES scenario), while in relative terms, the largest growth is anticipated in RS (2,691 MW in the referent scenario), or 14.4 times more WPP capacity in 2030 than in 2018, and 3,414 MW in the high RES scenario, or 18 times more than in 2018).

Even more rapid development is expected in solar power capacity. We expect an **additional 11,014 to 17,234 MW (referent vs high RES scenario) of SPP in the region, or 3.14 – 4.34 times more than in 2018**. By far the largest installed SPP capacity (and almost half of the regional new SPP capacity) is expected in Greece (5,255 MW – 7,155 MW), followed by Bulgaria. In 2030, these two market areas combined are expected to comprise 72% and 64% of SPP capacity, respectively, in the referent and high RES scenarios.

All EMI members except BG plan to increase total HPP capacity. The most significant changes in the period 2018-2030, in absolute terms, are expected in GR, AL and HR. For the entire EMI region, the total increase in installed HPP capacity will be significant, with **4,960 MW of new HPP expected by 2030, a growth of 20%** compared to HPP capacities in 2018.

With regard to TPPs, for the entire EMI region, the total decrease in installed capacity is expected to be around 3,000 MW. Although significant number, this is just 8% of total existing TPP capacity in 2018. **So, despite large scale RES integration targets and plans, EMI members are not giving up on TPP generation. However, as noted below, the capacity factors of TPPs cold fall significantly, especially with a high CO2 tax, so there could well be greater TPP retirements over the next decade than projected in today's plans.**

To recap, the expected changes from 2018 to 2030 will be significant in almost all power systems. **Total installed capacities will increase by 30%, or more than 24 GW**, with a decrease in TPPs and an increase in all other technologies. **The largest share of installed generation capacity will remain in TPPs: 36.1% in the Referent RES scenario and 32.6% in the High RES scenario.** The highest TPP shares are found in BG, XK and RS.

The second largest generation portfolio will remain in HPPs: 27% in the Referent RES scenario and 29.9% in the High RES scenario. **From 2018 to 2030, the share of HPPs will decrease 3%, but the share of TPPs will decrease almost 20%. The share of wind and solar capacities will increase from 14% to 33% or 40%, depending on the aggressiveness of RES**

development, and this presents the main change in the next 10 years. It is important to note that this refers to installed capacity (MW) and not generation output (MWh).

WPP installed capacity shares in SEE are in the range of 18.5% in the Referent RES scenario and 20.8% in the High RES scenario. The highest WPP shares in 2030 are found in RS (26.8% - 31.4%), GR (25.8% – 28.5%) and HR (21% – 22.8%).

SPP installed capacity shares in SEE are in the range of 15.4% in the Referent RES scenario and 19.6% in the High RES scenario. The highest SPP shares are found, as expected, in the south of the SEE region: in GR (28.4% - 31.1%), MK (16.7% – 21.0%) and BG (21.3% – 24.9%).

These large increases in RES generation will provide a major opportunity for private sector participation in wind and solar projects throughout the region. In fact, such opportunities are already emerging. Such RES development will also enable countries and customers to benefit from competition, to leverage billions of Euros in private capital, to stimulate electricity markets, to reduce emissions, to lower wholesale prices, and to shift the risk of project development to private firms.

Simulations of the market operation of the zones in the EMI region show that this major shift in the structure of the power system will have a meaningful impact on the generation mix and other measures, including: generation from fossil fuels plants; the level of CO_2 emissions; the balance position of the region and each market area;and wholesale market prices.

We compared the main market indicators for the referent and high RES integration scenarios with different assumptions related to expected development and operating circumstances:

1. Two levels of CO_2 emisison tax (27 and 53 EUR/tCO_2), both based on ENTSO-E TYNDP2020 assumptions related to "National Trends" and "Distributed Generation" Scenarios
2. Two levels of demand in 2030: one based on expected demand growth rate and the other, lower, based on slower demand growth (with rates half of the expected ones).
3. Two different hydro conditions: average and dry, with the aim to investigate the impact of RES in case of more or less energy available in HPPs in the region

The difference in regional RES generation between the referent and high RES scenarios is 17.6 TWh, which is the difference between 57.7 TWh and 75.3 TWh, and an increase of 30%. The increase per market area is between 0.2 and 6 TWh (in the CGES and IPTO market areas), and between 19% and 278% (in the HOPS and ELES market areas).

This change in RES generation causes a decrease in TPPs generation, especially lignite and gas generation, by 10%. In all scenarios, this decrease is smaller than increase in RES generation and, with higher RES generation, the region increases its exports. In all scenarios, higher RES generation causes a larger fall in gas generation than from lignite plants with decrease in capacity factors (equivalent operating hours with installed capacity divided by 8,760 hours): for lignite plants around 2-3% and gas plants around 4-5%.

We find a larger impact on the generation mix and TPPs generation regarding the CO_2 tax scenarios. With a higher CO_2 tax, lignite plants become less competitive and lignite

and gas technologies can change their position in the regional merit order curve. In specific, lignite plants' capacity factor decrease from 60-70% with a referent CO_2 tax to 35-50% with the high CO_2 tax. At gas plants, this change is the opposite, as the capacity factor increases from 16-30% in the referent CO_2 tax case to 36-50% in the high CO_2 tax case.

This change may jeopardize the economics of lignite generation, as well as older gas units. With this in mind, the TSOs and regulators of the EMI region should consider options for additional TPP plant retirements, including how to mitigate this effect and preserve the security of power supplies.

RES generation (depending on the scenario) supplies 21% to 27% of total demand (or 28% with lower demand growth). Separately considered, hydro and RES technologies become the second main technologies in EMI region in 2030, but considered together as "green" technologies, **hydro and RES generation will become the main sources, supplying 39% to 51% of total demand, or in the case of slower demand growth, 54% of total demand**.

Generation from additional RES capacities of 17.6 TWh (ref. RES vs. high RES) supplies 6% of total demand of the EMI region in 2030 (or 7% with lower demand growth). **Due to this increase in RES generation, fossil generation falls by 11 to 13 TWh (8-12%) and consequently, CO_2 emisisons fall by 6-9 $MtCO_2$ (6-12%).**

The EMI region has different net positions in each scenario, ranging **from a net importer position (3.4 TWh or 1% of total demand) in the high CO_2 tax, dry hydrology and referent level of RES generation case, to an exporting position (18.4 TWh or 7% of total demand) in the referent CO_2 tax, average hydrology and high RES generation case.**

The changes in balance positions for all market zones show that in almost all zones where lignite plants have a significant share in the generation mix, exports fall or the zone becomes a net importer (NOSBiH, EMS, KOSTT markets areas) due to an increase in the CO_2 emission tax. In market areas where gas plants have a high impact on generation mix, exports increase (Transelectrica market area) or imports decrease (HOPS market area). The IPTO market area, due to significant added gas generation, even becomes a net exporter in the case of a high CO_2 tax.

Average regional **wholesale market prices are expected to range from 47.4 and 70.5 EUR/MWh** (quite a wide range). High RES integration leads to a decrease of around 2 EUR/MWh or 4% in all scenarios. **The main driver for higher prices is the CO_2 tax:** an increase of CO_2 tax from 27 EUR/tCO_2 to 53 EUR/tCO_2 would lead to wholesale market price increases in the EMI region in 2030 of around 18 EUR/MWh or around 35%. Impact of hydrology and demand level on the wholesale market prices in the region is rather modest: 2 EUR/MWh in case of hydrology and 1.3 EUR/MWh in case of demand.

In the referent CO_2 tax case, there are four price zones in the EMI region, regardless of hydrology, demand growth or level of RES:

1) IPTO, a large importing market area with the highest wholesale market prices
2) ESO EAD and MEPSO – exporting and transiting zones with the second highest prices in the region

3) OST and KOSTT – almost balanced zones between the central zones and IPTO

4) All other market areas

In the high CO_2 tax case, the zones' balance positions would change considerably, as practically all zones ould coupled in one price zone, without congestion between them.

It should be also noted that conventional units (mainly hydro and PSPs) as well as good interconnections between the EMI market zones in SEE, plus export opportunities, provide enough flexibility to cope with hourly variablility in RES generation. The absence of spillages or curtailments in wind, solar or hydro generation in our analysed scenarios confirms this.

We note that our analyses 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), one 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.

Additional gas generation capacities at the level in this report do not change the regional generation mix significantly; however, they compete effectively with generation from older TPPs, and also provide flexibility to the power system to utilize RES and hydro resources in a more technically and economically efficient way. TSOs and regulators should continue to evaluate the impact of added gas generation, as more gas supply options become available.

Based on the above mentioned market analyses, we selected certain system snapshots – during the most critical conditions - and transferred them to the network analyses. **Based on inputs from the TSOs and our market analyses, we created a robust and verified regional power system network 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**

Using this robust and verified model, we identified 73 contingency cases in 11 RES integration scenarios. All of these contingencies appear on 22 elements in the region that could be critical in the future for large scale RES integration. Among them there are:

- 8 critical tie lines (including one phase shift transformer on Slovenian border to Italy)
- 11 internal lines and
- 3 transformers

We found eight critical tie lines, both in the 400 kV network (5 elements) and 220 kV network (3 lines). These elements are located on the following borders:

- Bulgaria – Romania (2 tie lines)
- Bulgaria – Turkey
- Romania – Ukraine
- Slovenia – Italy (3 tie lines)
- Albania – Montenegro

We also found 11 critial internal lines, both in the 400 kV network (3 lines) and the 220 kV network (8 lines). These elements are located in the following networks:

- Albania (two lines on the 220 kV level)
- Greece (one line on the 400 kV level)
- Croatia (two elements both double circuit lines, one on the 400 kV, and the other on the 220 kV level)
- Romania (one line on the 220 kV level)
- Bulgaria (3 lines, one on the 400 kV, and two on the 220 kV level) and
- Bosnia and Herzegovina (two lines on the 220 kV level)

We found three critical transformers in the region, two in Croatia, and one in Romania.

Among all the above-mentioned 22 critical elements, there are six elements with severe overloadings (130% of rated current) in one or more scenarios. Three elements appear to be overloaded in the base cases (with all elements available).

Eight of the 11 EMI TSOs can expect to face network bottlenecks in the EMI's high RES scenarios in 2030 (AL, BA, BG, HR, GR, ME, RO and SI). By contrast, in the scenarios we evaluated, the TSOs of MK, RS and XK will not face network bottlenecks with high RES integration.

The most outages in a single scenario is eight, in scenario 5. The absence of any scenarios with a high number of contingencies is sign of the network's robustness.

We based our network models on the TSOs' official 10-year network development plans. This analysis assumed significant changes by 2030 in all power systems, including an additional 25% of RES capacities on top of the RES capacities included in the official TYNDPs. **From 2018 to 2030, total installed capacities will increase by 30%, or more than 24,000 MW.**

Therefore**, in a network with over 10,000 elements, we only found 22 bottlenecks in the region, in all 11 scenarios, showing that the regional network is quite robust and ready to absorb substantial future RES capacities from a steady state perspective. We did not assess other aspects of large scale RES integration such as regional system balancing or dynamic issues in this study, and can do so in the future.**

Finally, since this region consists mainly of smaller systems (with a few exceptions), its inter-dependence is quite significant. With this modeling toolbox, the EMI members can now – for the first time - conduct regional, combined market and network analyses at a granular level to support their internal market and network development plans, as well as regulatory filings. Such studies are quite valuable, from both the regional and internal perspectives, for TSOs, MOs, regulators, policy makers and potential investors.

9. TABLE OF FIGURES

10. TABLE OF TABLES